

Direct Testimony and Schedules
Michael A. Peppin

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-20-____
Exhibit____(MAP-1)

Class Cost of Service Study

November 6, 2020

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2
3 Q. PLEASE STATE YOUR NAME AND TITLE.

4 A. My name is Michael A. Peppin. My title is Principal Pricing Analyst.

5
6 Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

7 A. My qualifications include nearly 40 years of experience with Xcel Energy and
8 its predecessors in the areas of market research and cost-of-service analysis. A
9 detailed statement of my qualifications and experience is provided as
10 Exhibit___(MAP-1), Schedule 1.

11
12 Q. FOR WHOM ARE YOU TESTIFYING?

13 A. I am testifying on behalf of Xcel Energy.

14
15 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

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

19
20 **II. CLASS COST OF SERVICE STUDY**

21
22 **A. Overview of Proposed Class Cost of Service Study**

23 Q. HOW DOES THE COMPANY'S PROPOSED CCOSS COMPARE WITH THAT
24 APPROVED BY THE NORTH DAKOTA PUBLIC SERVICE COMMISSION IN THE
25 COMPANY'S LAST GENERAL ELECTRIC RATE CASE, CASE NO. PU-12-813?

26 A. We updated the Company's proposed CCOSS to reflect 2021 forecast data.
27 Specifically, all costs have been updated to reflect 2021 weather normalized

1 costs. The hourly load data, energy use data, and customer-related data have
2 also been updated to reflect forecast weather normalized sales data for 2021,
3 and has been used to update class cost allocation factors. All cost
4 classification and allocation methods are the same as those approved by the
5 Commission in the Company's last rate case, except for the following four
6 refinements:

- 7 • A reevaluation of the distribution costs that are directly assigned to
8 the Street Lighting class;
- 9 • A separation of the investment in overhead and underground
10 primary distribution lines into separate categories for single-phase
11 and multi-phase lines;
- 12 • An update to the analysis used to separate distribution plant costs
13 into customer and capacity related components; and
- 14 • A reevaluation of how Other Production O&M costs are classified
15 into capacity and energy components.

16 The reason for these refinements will be discussed later in my testimony.
17 Other than these refinements, all cost allocation methods are the same as
18 those approved by the Commission in the Company's 2012 rate case.

19
20 Q. HAS THERE BEEN ANY CHANGE TO HOW CUSTOMER CLASSES ARE DEFINED
21 SINCE THE COMPANY'S LAST RATE CASE?

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

- 25 • Residential;
- 26 • Commercial Non-Demand Billed;
- 27 • Commercial and Industrial (C&I) Demand Billed; and

- 1 • Street Lighting.

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

4
5 Q. HAS THE COMPANY PROVIDED ANY OTHER DOCUMENTS EXPLAINING HOW ITS
6 CCOSS IS DEVELOPED?

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

15
16 Q. WHAT IS THE ROLE OF THE CCOSS IN THE RATEMAKING PROCESS?

17 A. The CCOSS allocates jurisdictional costs (in this case, costs of the Company’s
18 State of North Dakota electric jurisdiction) to customer classes using class
19 cost allocation factors. The CCOSS measures the contribution each class
20 makes to the Company’s overall cost of service, including calculating inter-
21 class and intra-class cost responsibilities. One of the primary goals of the
22 CCOSS is to develop class cost allocation factors that accurately reflect cost
23 causation. The CCOSS therefore serves as a tool for evaluating and refining
24 the Company’s rate structure, as discussed in more detail by Company witness
25 Mr. Nicholas N. Paluck.

26

1 Q. IS THE COMPANY'S CCOSS THE APPROPRIATE TOOL FOR EVALUATING THE
2 RATE DESIGN IN THIS CASE?

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

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

15

16 **B. CCOSS Results**

17 Q. PLEASE SUMMARIZE THE RESULTS OF THE 2021 CCOSS.

18 A. Table 1 below provides a summary of the 2021 test year CCOSS (the 2021
19 CCOSS) results at the class level, showing the resulting class cost
20 responsibilities (as opposed to revenue responsibilities that are addressed by
21 Mr. Paluck). A summary of the CCOSS results at the class level is also
22 provided in Exhibit__(MAP-1), Schedule 3. However, for comparison
23 purposes, Schedule 3 also provides the class revenue allocation proposed by
24 Mr. Paluck. The detailed 2021 CCOSS output is shown in Exhibit__(MAP-
25 1), Schedule 4.

26

1 These CCOSS results indicate the changes from present rates that would be
2 necessary to result in equal rates of return on investment for each class (i.e.,
3 the increase in rates necessary to produce equalized rates of return).
4

Table 1
Summary of 2021 Class Cost of Service Study
NSPM-North Dakota Electric Jurisdiction
 (\$ Thousands)

UNADJUSTED COST RESPONSIBILITIES

	<u>Total</u>	<u>Resid</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[1] Unadjusted Rate Revenue Req (CCOSS page 2, line 1)	228,594	91,828	11,737	122,156	2,874
[2] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	<u>50</u>	<u>44</u>	<u>2</u>	<u>4</u>	<u>0</u>
[3] Unadjusted Operating Revenues (line 1 + line 2)	228,644	91,872	11,738	122,160	2,874
[4] Present Rates (CCOSS page 2, line 2)	<u>206,416</u>	<u>83,739</u>	<u>11,379</u>	<u>109,232</u>	<u>2,066</u>
[5] Unadjusted Deficiency (line 3 - line 4)	22,228	8,133	359	12,928	808
[6] Defic / Pres (line 5 / line 4)	10.8%	9.7%	3.2%	11.8%	39.1%
[7] Ratio: Class % / Total %	1.00	0.90	0.29	1.10	3.63

COST RESPONSIBILITIES FOR RATE DISCOUNTS

	<u>Total</u>	<u>Resid</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[8] Interruptible Rate Discounts (CCOSS page 2, line 5)	4,207	799	58	3,350	0
[9] Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)	4,207	1,415	188	2,591	13
[10] Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	616	130	(759)	13

ADJUSTED COST RESPONSIBILITIES

	<u>Total</u>	<u>Resid</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[11] Adjusted Rate Revenue Req (line 1 + line 10)	228,594	92,445	11,866	121,397	2,887
[12] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	<u>50</u>	<u>44</u>	<u>2</u>	<u>4</u>	<u>0</u>
[13] Adjusted Operating Revenues (line 11 + line 12)	228,644	92,489	11,868	121,401	2,887
[14] Present Rates (line 4)	<u>206,416</u>	<u>83,739</u>	<u>11,379</u>	<u>109,232</u>	<u>2,066</u>
[15] Adjusted Deficiency (line 13 - line 14)	22,228	8,749	488	12,169	821
[16] Defic / Pres Rates (line 15 / line 14)	10.8%	10.4%	4.3%	11.1%	39.7%
[17] Ratio: Class % / Total %	1.00	0.97	0.01	1.03	3.69

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

3 A. The distinction between “unadjusted” and “adjusted” cost responsibilities
4 relates to how the cost of interruptible rate discounts are reflected in the
5 CCOSS. The method used to reflect the cost of the interruptible rate
6 discounts is the same as that used in the Company’s last four rate cases.

7
8 Q. HOW DOES THE COMPANY TREAT INTERRUPTIBLE SERVICE IN THE CCOSS?

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

20
21 Q. HOW ARE INTERRUPTIBLE RATE DISCOUNTS REFLECTED IN THE CCOSS?

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

24 1. Line 8 on Table 1 above and Schedule 3, labeled “Interruptible Rate
25 Discounts” shows the amount of the total interruptible rate discounts
26 originating from each class. The amounts shown for each class are lost
27 revenues from that class. These discounts reduce the revenue received

1 from the classes and thus have the effect of increasing the revenue
2 requirement for the classes that receive the discounts.

- 3 2. Line 9 on Table 1 above and Schedule 3, labeled “Interruptible Rate
4 Disc. Cost Allocation” shows how the cost of interruptible rate discounts
5 are allocated to the classes. Interruptible rate discounts are allocated
6 using the applicable generation capacity cost allocation factor.
- 7 3. Line 10 on Table 1 above and Schedule 3, labeled “Revenue Requirement
8 Change” shows the net change in the revenue requirement for each
9 customer class.
- 10 4. The resulting Line 11 on Table 1 above and Schedule 3, labeled
11 “Adjusted Rate Revenue Requirement” shows the appropriate cost of
12 service for determining class revenue responsibilities. Finally, the
13 adjusted revenue deficiency and percent deficiency are shown on lines 15
14 and 16, respectively.

15
16 **C. Production Plant Stratification**

- 17 Q. A SIGNIFICANT PORTION OF THE COMPANY’S TOTAL COSTS ARE DRIVEN BY
18 FIXED PRODUCTION PLANT. DESCRIBE THE PROCESS THE COMPANY USES FOR
19 ALLOCATING FIXED PRODUCTION PLANT COSTS.
- 20 A. The Company classifies fixed production plant into capacity versus energy-
21 related sub-functions using a process called “Plant Stratification.” Though
22 refined over the years, this is the same process the Company has used with
23 Commission approval since the late 1970s. This process has also been
24 referred to in the NARUC manual as the Equivalent Peaker method. This
25 allocation method is also supported by the Commissions in Minnesota and
26 South Dakota.

27

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

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

13

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

16 A. Yes. As shown in Table 2 below, the Company has updated plant
17 replacement costs and the resulting capacity-energy splits.

18

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

20 A. The Plant Stratification analysis used in this case is shown in Table 2 below.
21 Table 2 compares the current-dollar replacement costs of each plant type
22 towards developing stratification percentages.

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Table 2
Stratification Allocation by Plant Type

Plant Type	Replacement Value \$/kW	Capacity Ratio	Capacity Percentage	Energy Percentage
Peaking	\$942	\$942 / \$942	100.0%	0.0%
Nuclear	\$4,952	\$942 / \$4,952	19.0%	81.0%
Fossil	\$2,287	\$942 / \$2,287	39.5%	60.5%
Combined Cycle	\$1,429	\$942 / \$1,429	65.9%	34.1%
Hydro	\$5,557	\$942 / \$5,557	17.0%	83.0%
Wind	\$14,024	\$942/\$14,024	6.7%	93.3%

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.

1 **D. Classification and Allocation of Distribution Plant Costs**

2 1. *Direct Assignment of Distribution Costs to the Street Lighting Class*

3 Q. WHAT DISTRIBUTION COSTS DID THE COMPANY DIRECT ASSIGN TO THE
4 STREET LIGHTING CLASS?

5 A. Consistent with past rate cases, the Company has directly assigned all of the
6 costs in FERC account 373. FERC Account 373 includes all street lighting
7 costs except for the cost of wood poles used solely by lighting in overhead
8 distribution areas. The specific cost items included in FERC Account 373 are:

- 9 • Overhead and underground distribution lines that only serve street
10 lighting;
- 11 • Metal and fiberglass street lighting poles in underground areas;
- 12 • Lamps and fixtures; and
- 13 • Automatic control equipment.

14 As shown on page 4, line 47 of Schedule 4, we directly assigned \$3.2 million of
15 FERC Account 373 costs to the Street Lighting class in the 2021 CCOSS.
16 This direct assignment is appropriate because the costs included in FERC
17 Account 373 are directly attributable to Street Lighting.

18
19 Q. WHAT OTHER DISTRIBUTION COSTS ARE ATTRIBUTABLE TO THE STREET
20 LIGHTING CLASS?

21 A. In a change from the last rate case, the Company has conducted an analysis to
22 determine if there are costs in FERC Account 364 that should be assigned to
23 the Street Lighting class.

24
25 Q. WHAT COSTS ARE INCLUDED IN FERC ACCOUNT 364?

1 A. FERC Account 364 includes the cost of installed poles, towers, and
2 appurtenant fixtures used for supporting overhead distribution conductors
3 and service wires. Many of these poles have street lights attached and the cost
4 of poles that only have street lights attached is not included in FERC Account
5 373.

6

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

8 A. Yes. FERC Account 364 includes the cost of 432,896 wooden poles.
9 Company-owned street lights are attached to 91,441 of these poles, meaning
10 21.12 percent of the Account 364 costs are at least partially attributable to
11 street lighting. Through consultation with our Street Lighting staff, we
12 determined that 60 percent of the lighting poles serve only Street Lighting
13 customers (*i.e.* they do not have facilities attached that serve other customer
14 classes). Since these poles are only used for street lighting, it's appropriate to
15 assign the cost of these poles to the Street Lighting Class. Line 9 of Table 3
16 below estimates lighting pole costs that should be direct assigned to the Street
17 Lighting class. This direct assignment is also shown in Exhibit___(MAP)
18 Schedule 4 on page 4, line 27.

19

Table 3
Calculation of FERC Account 364 Direct Assignment
NSPM-North Dakota Electric Jurisdiction
 (\$ Thousands)

Line No.		
1	FERC 364	\$19,020
2	FERC 365	\$23,964
3	Total FERC 364 and 365 (line 1 + line 2) *	\$42,984
4	MN Company-Owned Street Lights on Wooden Poles	91,441
5	Total MN Poles	432,869
6	Lighting Poles as % of Total Poles (line 4 / line 5)	21.12%
7	Lighting % x FERC 364 (line 1 x line 6)	\$4,018
8	Percent of Lighting Poles that only Serve Lighting	60%
9	FERC Acct 364 Direct Assignment to Lighting (line 7 x line 8)	\$2,411

*See Exhibit___(MAP-1) Schedule 4 at page 4, line 28.

*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?

1 A. Yes. Based on the data in the Company’s Geographic Information System,
 2 the Company’s Distribution staff determined 71.6 percent of North Dakota
 3 residential customers receive service off the single-phase primary distribution
 4 system. Table 4 also shows that significantly fewer C&I customers receive
 5 service from the single-phase primary distribution system.

6
 7 **Table 4**
 8 **Percent of Customers Served by Single-Phase and Multi-Phase**
 9 **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	71.6%	40.3%	13.9%	44.0%
Multi-Phase	28.4%	53.7%	86.1%	56.0%
Total	100.0%	100.0%	100.0%	100.0%

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

20 A. Yes. We continue to separate distribution lines into capacity and customer
 21 components using the Company’s Minimum System and Zero Intercept
 22 studies, as described in the Guide to Class Cost of Service Study. In the
 23 current rate case, we added an additional step to split the classified costs for
 24 primary distribution lines into single-phase and multi-phase components. We
 25 based the split on miles of single-phase and multi-phase distribution plant and
 26 their associated replacement cost (in dollars per mile). The resulting
 27 separation of costs is shown on page four of Schedule 4, lines 19-22 (overhead
 28 primary distribution lines) and lines 29-32 (underground primary distribution

1 lines). We also created distribution line cost allocators to account for the
 2 differing usage of the single-phase portions of the system by different
 3 customer classes. Exhibit____(MAP-1), Schedule 5 shows how these allocators
 4 were developed.

5
 6 *3. Separation of Distribution Plant Costs into Capacity and Customer-Related*
 7 *Components*

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

10 A. Table 5 below shows how the Company has classified costs for the various
 11 distribution property units. This classification is consistent with past rate
 12 cases.

13 **Table 5**
 14 **Classification of Distribution Plant Investment**

Distribution Plant Property Unit	TY 2021 ND Plant Investment (\$000)	Demand Component	Capacity Component
Distribution Substations	\$38,649	X	
Primary Voltage Transformers	\$2,988	X	
Primary Voltage Distribution Lines	\$102,706	X	X
Secondary Voltage Distribution Lines	\$16,246	X	X
Secondary Voltage Transformers	\$24,585	X	X
Services	\$15,226	X	X

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

3 A. Since the 1990s, the Company has used a Minimum System Study to do this
4 separation. In this case, we updated that study and included three new
5 updates. First, we performed an extensive review of what equipment would
6 be considered “minimum.” Second, we performed an extensive review of the
7 installed cost of distribution equipment. Finally, we performed a Zero
8 Intercept study in addition to the Minimum System study. A Zero Intercept
9 study is the alternative method to determine the customer component of
10 distribution costs.

11

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

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

16

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

19

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

22

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

25

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

5
6 Q. WHAT ARE THE ANALYSIS STEPS THAT ARE TAKEN TO COMPLETE A ZERO
7 INTERCEPT STUDY?

8 A. The steps for completing a Zero or Minimum Intercept are described on
9 pages 92-94 of the NARUC manual. A Zero Intercept study requires
10 considerably more data and analysis than a Minimum System study. A Zero
11 Intercept study requires the following data:

- 12 • A listing of all the configurations of equipment installed for the
13 following distribution property units:
 - 14 ○ Overhead Primary Conductor
 - 15 ○ Overhead Secondary Conductor
 - 16 ○ Overhead Transformers
 - 17 ○ Underground Primary Conductor
 - 18 ○ Underground Secondary Conductor
 - 19 ○ Underground Transformers
 - 20 ○ Primary Voltage Stepdown Transformers
- 21 • For each of the above property units, the equipment inventory is
22 obtained for each property unit configuration.
- 23 • The maximum capacity rating for each property unit configuration.
 - 24 ○ Ampacity for conductors
 - 25 ○ kVa for Transformers
- 26 • The installed cost per unit for the most common property unit
27 configurations.

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

3 A. After the data is acquired, the following steps are taken to complete a Zero
4 Intercept study:

5

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

12

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

15

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

19

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

22

23 Q. AS DESCRIBED ABOVE, BOTH MINIMUM SYSTEM AND ZERO INTERCEPT
24 STUDIES REQUIRE DATA ON THE INVENTORY OF DIFFERENT DISTRIBUTION
25 PROPERTY UNIT CONFIGURATIONS, THE MINIMUM SIZE OF DISTRIBUTION

1 EQUIPMENT CURRENTLY INSTALLED, AND THE PER UNIT INSTALLED COSTS OF
2 DIFFERENT CONFIGURATIONS AND ASSOCIATED LOAD CARRYING CAPACITIES.
3 HOW DID THE COMPANY ACQUIRE THIS INFORMATION?

4 A. In short, data on the types, configurations, sizes and quantities of distribution
5 equipment were obtained by querying the Company's Geographic
6 Information System (GIS). Data on the installed unit costs for each
7 equipment configuration were obtained by analyzing the costs of nearly 12,000
8 distribution work orders that were completed over an 11 year period. The
9 goal in this data gathering step was to obtain installed costs for equipment
10 configuration that comprise 90% of the population for a given property unit
11 (i.e., underground primary conductor). More detail on the specific data
12 sources is provided in Schedule 6.

13
14 Q. HOW WAS THE ABOVE-MENTIONED DATA UTILIZED TO CONDUCT MINIMUM
15 SYSTEM AND ZERO INTERCEPT STUDIES?

16 A. The analyses methods, data, and results of the Minimum System and Zero
17 Intercept studies are shown in Schedule 6 of my testimony. Attachments A
18 through G of Schedule 6 show the inventory of the different equipment
19 configurations for each property unit. Attachments H through M of Schedule
20 6 show the graphical results of the Zero Intercept linear regression analysis for
21 each property unit. Attachment N of Schedule 6 shows the detailed Minimum
22 System and Zero Intercept calculations.

23

1 Q. HOW DO THE RESULTS OF THE ZERO INTERCEPT AND MINIMUM SYSTEM
2 APPROACH COMPARE?

3 A. For each property unit, the table below shows the percent of costs that would
4 be classified as customer-related using the Zero Intercept method compared
5 to the Minimum System method. As shown in Table 6 below, for four of the
6 six property units the Zero Intercept provides a lower customer component,
7 while two of the six have a lower customer component using the Minimum
8 System method.

9
10 **Table 6**
11 **% of Distribution Investment Classified as Customer Related**
12 **Zero Intercept Method vs. Minimum System Method**

13

Property Unit	% of Costs Classified as Customer-Related	
	Zero Intercept Method	Minimum System Method
Overhead Primary	34.9%	51.4%
Overhead Secondary	78.3%	89.6%
Overhead Transformers	72.7%	79.5%
Underground Primary	58.1%	53.2%
Underground Secondary	73.8%	100%
Underground Transformers	87.3%	51.5%

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

22 A. For a given property unit a "hybrid" of the two methods was used, in that
23 the Company used the method that provided the lower customer
24 component as shown in Table 7 below.

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Table 7
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)	34.9%	65.1%
Overhead Secondary (used Zero Intercept result)	78.3%	21.7%
Underground Primary (used Minimum System result)	53.2%	46.8%
Underground Secondary (used Zero Intercept result)	73.8%	26.2%
Weighted Average for Overhead and Underground Transformers*	63.7%	36.3%

* 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 CCROSS model for the 2021 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

1 the result which provided the lowest minimum cost provides a reasonable
2 way to ensure we are not overstating the customer classification.

3

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

5 Q. EARLIER YOU MENTIONED THERE HAS BEEN A CHANGE TO THE METHOD
6 USED TO ALLOCATE OTHER PRODUCTION O&M COSTS. WHAT METHOD DID
7 THE COMPANY USE IN ITS LAST NORTH DAKOTA RATE CASE?

8 A. In the last rate case, the Company split Other Production O&M costs into
9 capacity versus energy components based on how Production plant
10 investment (excluding nuclear fuel) was split using the Company's plant
11 stratification analysis as shown on Lines 3 and 4 on Page 4 of Schedule 4.

12

13 Q. WHY DID THE COMPANY MAKE A CHANGE TO THE METHOD USED TO
14 ALLOCATE OTHER PRODUCTION O&M COSTS?

15 A. Upon further examination, it was determined that some plant types, such as
16 the nuclear plants, account for a disproportionate share of Other Production
17 O&M costs.

18

19 Q. WHAT WAS THE IMPROVEMENT THAT WAS MADE TO THE CLASSIFICATION OF
20 NON-FUEL PRODUCTION O&M COSTS?

21 A. The first step was to discuss the nature of the different types of costs with
22 plant operations personnel to identify any non-fuel O&M costs that vary
23 directly with the plant's energy output and classify these costs as 100% energy-
24 related. The costs of chemicals and water use were the only costs that fit into
25 this 100% variable category and were therefore classified as being 100%
26 energy-related.

1 Q. HOW DID THE COMPANY CLASSIFY THE REMAINING PRODUCTION O&M
2 COSTS?

3 A. Since there was no definitive classification as to the fixed or variable nature of
4 O&M costs, the remaining production O&M costs were separated based on
5 the particular plant type that the specific cost originated from. For example,
6 costs that originated from the Company's Prairie Island plant were put into a
7 nuclear category, costs attributed to Sherco in a fossil category, and so on for
8 the other plant types.

9

10 The next step was to apply the capacity and energy-related percentages that
11 resulted from the Company's plant stratification analysis. These percentages
12 are shown in Table 2 and were applied to each category of Non-Fuel
13 Production O&M expense. Costs classified as capacity-related were allocated
14 to customer class using the Commission-approved D10C capacity allocator,
15 while costs classified as energy-related were allocated to customer class using
16 the Commission-approved E8760 allocator.

17

18 Q. HOW DOES THE COMPANY CLASSIFY O&M COSTS THAT CAN'T BE ASSIGNED
19 TO A PARTICULAR PLANT TYPE?

20 A. For those production expenses that do not apply to a particular generation
21 type, the Company applies the weighted average Capacity versus Energy
22 percentage splits for those costs that do originate from a particular type of
23 generation plant

24

25 Q. HOW IS THIS METHOD FOR CLASSIFYING NON-FUEL PRODUCTION O&M
26 EXPENSE AN IMPROVEMENT OVER THE METHOD THAT THE COMPANY USED IN
27 ITS LAST RATE CASE?

1 A. First, for each expense, it identifies which plant type the expense originated
2 from. It also recognizes the fact that for most expenses, there isn't a black
3 and white distinction as to an expense being 100 percent fixed or 100 percent
4 variable in nature. Although there is a fixed component to many cost types
5 such as labor, it recognizes that many costs can increase as usage of a
6 particular plant type increases. This method also extends the application of
7 the Company's stratification approach, which is also supported by the
8 Commissions in Minnesota and South Dakota. It also recognizes the fact that
9 the role of combustion turbines (CTs) is for providing needed capacity during
10 peak demands. As a result, all O&M expenses from CTs should be treated a
11 capacity-related. Table 8 below shows the resulting classification of Other
12 Production O&M expenses. As shown below, 78.93 percent of costs are
13 classified as energy-related while 21.07 percent of costs are classified as
14 capacity-related.

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Table 8
Classification of Other Production O&M Costs
NSPM-North Dakota Jurisdiction

Plant Type or Expense Type	2021 Other Prod O&M	Percent Energy	Percent Capacity	Energy-Related	Capacity-Related
Variable (Chemicals & Water Use)	\$385,563	100.00%	0.00%	\$385,563	\$0.0
Fossil	\$2,984,157	60.5%	39.5%	\$1,806,344	\$1,177,814
Combustion Turbine	\$180,216	0.00%	100.00%	\$0.0	\$180,216
Nuclear	\$20,946,119	81.0%	19.0%	\$16,960,280	\$3,985,839
Combined Cycle	\$1,111,025	34.1%	65.9%	\$378,896	\$733,128
Hydro	\$177,356	83.0%	17.0%	\$147,283	\$30,072
Wind	\$4,706,297	93.3%	6.7%	\$4,390,078	\$316,219
Total Generation-Related Other Production O&M	\$30,491,732	78.93%	21.07%	\$24,068,444	\$6,423,28
Corporate Other Production O&M not Assigned to Generation Type	\$1,084,782	78.93%	21.07%	\$856,265	\$228,517
Regional Market Expense (FERC Codes 575.1 – 575.8)	\$685,188	78.93%	21.07%	\$540,848	\$144,339
Total Other Production O&M	\$32,201,701	78.93%	21.07%	\$25,465,557	\$6,796,144

III. TARIFF CHANGES: SECTION NO. 6
GENERAL RULES AND REGULATIONS

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

A. The following are the areas in the General Rules and Regulations where the Company is proposing revisions. These costs have not been revised since the Company’s 2010 rate case.

- Excess Footage Charges Section 5.1.A.1
- Winter Construction Charges Section 5.1.A.2

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Table 10
Winter Construction Charges

Type	Present	Proposed
Thawing (Per Frost Burner)	\$600.00	\$685.00
Trenching (Per Foot)	\$3.80	\$8.90

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___(MAP-1), Schedule 7.

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

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

A. The net annual revenue impact from the increase in these rates is \$3,017 as shown on page 1 of Exhibit___(MAP-1), Schedule 7. This increase in revenues is shown with the increase in late payment charges on lines 2 and 14 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 proposed increase in retail revenues by Mr. Paluck.

IV. CONCLUSION

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

A. Yes.

1 STATE OF NORTH DAKOTA
2 BEFORE THE
3 PUBLIC SERVICE COMMISSION
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5

6 In the Matter of the Application of Northern)
7 States Power Company, a Minnesota Corporation)
8 For Authority to Increase Rates for Electric Service) Case No. PU-20-____
9 in North Dakota)

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13 AFFIDAVIT OF
14 Michael A. Peppin
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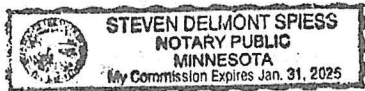
17 I, the undersigned, being duly sworn, depose and say that the foregoing is the
18 Direct Testimony of the undersigned, and that such Direct Testimony and the
19 exhibits or schedules sponsored by me to the best of my knowledge, information
20 and belief, are true, correct, accurate and complete, and I hereby adopt said testimony
21 as if given by me in formal hearing, under oath.
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23
24 Michael A. Peppin
25 Michael A. Peppin
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30 Subscribed and sworn to before me, this 20 day of October, 2020.
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32 Stu D. Spiess
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34 Notary Public

35 My Commission Expires: January 31, 2025
36



Statement of Qualifications and Experience
Michael A. Peppin

OVERVIEW

My qualifications include more than 35 years of experience with Xcel Energy and its predecessors in the areas of market research and cost-of-service analysis. My current 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. I have served as a class cost of service witness in multiple rate cases in Minnesota, South Dakota, North Dakota and Texas.

PROFESSIONAL EXPERIENCE

Principal Pricing Analyst; Xcel Energy, NSPM	2006 – Present
Senior Market Research Manager; Cargill Corporation	2005 – 2006
Manager, Market Research; Seren Innovations, a subsidiary of NSP	2000 – 2005
Manager, Product Development Support; NSP Electric Utility	1998 – 2000
Manager, Market Research; NSP Electric Utility	1990 – 1998
Manager, Market Research; NSP Gas Utility	1986 – 1990
Principal Market Research Analyst; NSP Electric Utility	1979 – 1986

EDUCATIONAL BACKGROUND

University on Minnesota; MBA Marketing and Statistics	1980
University of Minnesota; BA Psychology and Statistics	1978



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

I. Overview

Simply stated, the purpose of the Northern States Power Company (NSP) electric Class Cost of Service (CCOSS) is to allocate *joint* (e.g.) and *common* costs to the designated “classes” of service such as Residential, Non-Demand C&I and Demand C&I. For example, generation capacity costs are “joint” between time periods and overhead costs such as management, are “common” to multiple functions, such as distribution, transmission and generation. The CCOSS also assigns *direct* costs (e.g. a dedicated service extensions or dedicated substations), that may be associated with providing service to a particular customer from a specific class of service. The objective of the CCOSS is to make these cost *allocations* and *assignments* based on identifiable service requirements (e.g. kWh energy requirements and kW capacity requirements), which are the drivers of the costs.

The two basic types of costs are; (1) capital costs associated with investment in generation, transmission and distribution facilities and (2) on-going expenses such as fuel used to produce the energy, labor costs and numerous other operating expenses. The end-result is an allocation of the total utility costs (i.e. the revenue requirements) to customer classes according to each class’ share of the capacity, energy and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A class cost of service study begins with a detailed documentation of the numerous budgetary elements of the total revenue requirement for the jurisdiction in question. The detailed jurisdictional revenue requirements are the data inputs to the CCOSS. At a high level, the CCOSS process consists of the following three (3) basic steps:

1. Functionalization – The identification of each cost element as one of the basic utility service “functions” (e.g. generation, transmission, distribution and customer).
2. Classification – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. kW of capacity, kWh of energy or number of customers).
3. Allocation – The allocation of the functionalized and classified costs to customer classes, based on each class’ respective service requirements (e.g. kW of capacity, kWh 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	\$942	\$942 / \$942	100.0%	0.0%
Nuclear	\$4,952	\$942 / \$4,952	19.0%	81.0%
Fossil	\$2,387	\$942 / \$2,387	39.5%	60.5%
Combined Cycle	\$1,429	\$942 / \$1,429	65.9%	34.1%
Hydro	\$5,557	\$942 / \$5,557	17.0%	83.0%
Wind	\$14,024	\$942 / \$14,024	6.7%	93.3%

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.

Guide to Class Cost of Service Study

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 4 of the 6 property units the zero intercept provides a lower customer component, while 2 of the 6 have a lower customer component using the minimum system method.

Equipment Type	% of Costs Classified as "Customer" Related	
	Zero Intercept Method	Minimum System Method
Overhead Lines Primary	34.9%	51.4%
Overhead Lines Secondary	78.3%	89.6%
Overhead Transformers	72.7%	79.5%
Underground Lines Primary	58.1%	53.2%
Underground Lines Secondary	73.8%	100%
Underground Transformers	87.3%	51.5%

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)	34.9%	65.1%
Overhead Lines Secondary (used Zero Intercept Result)	78.3%	21.7%
Underground Lines Primary (used Minimum System Result)	53.2%	46.8%
Underground Lines Secondary (used Zero Intercept Result)	73.8%	26.2%
Weighted Average for Overhead & Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	63.7%	36.3%

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 losses)
 - 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 kW 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:

$$\begin{aligned} &\text{Retail Revenue Requirement} = \text{Expenses (less off-setting credits from Other Operating} \\ &\text{Revenues)} \\ &\quad + \\ &\quad ((\% \text{ Return on Invest} \times \text{Rate Base}) - \text{AFUDC} - \text{Fed Credits}) \times 1 / (1 - \text{Fed T}) - \text{Fed} \\ &\quad \text{Section 199 Deduc} \times \text{Fed T} / (1 - \text{Fed T}) - \text{State Credits}) \times 1 / (1 - \text{State T}) \\ &\quad + \\ &\quad (\text{Tax Additions} - \text{Tax Deductions}) \times \text{Tax Rate} / (1 - \text{Tax Rate}) \end{aligned}$$

Where:

$$\text{Tax Rate} = 1 - (1 - \text{State T}) \times (1 - \text{Fed T})$$

$$\begin{aligned} \text{Expenses} = &\text{O\&M} + \text{Book Depreciation} + \text{Real Estate \& Property Tax} + \text{Payroll Tax} \\ &+ \text{Net Investment Tax Credit} - \text{Other Retail Revenue} - \text{Other Oper. Revenue} \end{aligned}$$

$$\begin{aligned} \text{Tax Additions} = &\text{Book Depreciation} + \text{Deferred Inc Tax} + \text{Net Inv Tax Credit} \\ &+ \text{Other Misc Expenses.} \end{aligned}$$

$$\text{Tax Deductions} = \text{Tax Depreciation} + \text{Interest Expense} + \text{Other Tax Timing Diff}$$

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.

$$\begin{aligned} \text{Total \$ Return} = &\text{Revenue} - \text{O\&M Expenses} - \text{Book Depr.} \\ &- \text{Real Estate \& Property Taxes} - \text{Provision for Deferred Inc Taxes} - \text{Inv. Tax Credits} \\ &- \text{State \& Federal Income Taxes} + \text{AFUDC} \end{aligned}$$

$$\text{Percent Return on Rate Base} = \text{Total \$ Return} / \$ \text{Rate Base}$$

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

XI. CCOSS Output

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

Final CCOSS Printout “Tot” Worksheet				
CCOSS Section	Page Number	Results Detail	Line Numbers	
Results Summary	1	Rate Base Summary	1-21	
		Income Statement Summary	22-31	
	2	Proposed Cost Responsibility at <u>Equal ROR</u> (the cost of service) compared to Present Rate Revenue Responsibility	1-49	
3	Proposed Cost Responsibility at <u>Equal ROR</u> (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	1-48	

Guide to the Class Cost of Service Study
CCOSS Customer Classes Vs Tariff Cross Reference

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)			<ul style="list-style-type: none"> 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		<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> 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.

Northern States Power Company

Guide to the Class Cost of Service Study
CCOSS Customer Classes Vs Tariff Cross Reference

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	<p>Costs Not Assigned</p> <ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> 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			<ul style="list-style-type: none"> 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.

**Guide to the Class Cost of Service Study
 EXTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS**

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.

Guide to the Class Cost of Service Study
EXTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

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 <u>service-line</u> 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 <u>service line</u> 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	<u>Distribution substation</u> 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 <u>primary distribution line</u> 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 <u>secondary distribution line</u> 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.

Guide to the Class Cost of Service Study
EXTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

Code	Allocator For:	Derivation	Allocator Rationale
D62NLL	The capacity portion of <u>service-line</u> 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 <u>service line costs</u> 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 <u>generation costs</u> .
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 1.4257)) divided by (1 + 1.4257). The 1.4257 ratio is the ratio of the average summer and winter seasonal system peaks.	The driver for <u>transmission costs</u> 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 3.4858)) divided by (1 + 3.4858). The 3.4858 ratio is obtained from the average summer and winter season peak loads, after subtracting the average annual load from each monthly load.	Capacity- related <u>generation costs</u> 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.

Guide to the Class Cost of Service Study
 EXTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

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.

**Guide to the Class Cost of Service Study
INTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS**

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.

Guide to the Class Cost of Service Study
INTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS

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.

**Guide to the Class Cost of Service Study
INTERNAL ALLOCATORS: DESCRIPTIONS AND APPLICATIONS**

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 83% weighting of the E8760 energy allocator and a 17% 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 2021 Test Year. The allocation is the relationship of the annual class totals of these hourly results to the retail total.	<ol style="list-style-type: none"> 1. Test-Year 8760 load shapes for each customer class are developed from five years of load research data (2024-2018). The resulting load shapes for each class are synced up to the 2020 forecast for the 2021, Test Year. 2. Hourly system marginal energy costs are based on the 2021 Test Year forecast from the Commercial Operations area.
Generation Plant Stratification Analysis	<p>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 2017 replacement costs of NSPM power plants that were developed by the Capital Asset Accounting area, and the corresponding capacity ratings for those plants.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p>	Based on 2020 replacement costs of all NSP Minnesota Company Power Plants.
Customer Accounting Weights	Based on 2021 actuals with the relative weighting estimates provided by management from the Billing and Customer Service areas.	

Guide to the Class Cost of Service Study
CCOSS RELATED ANALYSIS

Analysis	Analysis Description	Data Sources and Associated Vintage
Minimum System Analyses	<p>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 2019 the Company conducted a Minimum System study that was updated to 2021 using the Handy Whitman Indices.</p> <p>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.</p>	Based on an analysis of nearly 12,000 distribution construction work orders in Minnesota Company that were completed from 2007 to May of 2018.
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 2019 inventory of meter models, CT models and VT models for each customer. Meter, CT and VT replacement costs are for 2020.
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.	2021 budget detail of Other Production O&M expenses and 2020 Plant Stratification Analysis.

Guide to the Class Cost of Service Study
CCOSS RELATED ANALYSIS

Analysis	Analysis Description	Data Sources and Associated Vintage
<p>Direct Assignment of Overhead Secondary Distribution Line Costs to the Lighting Class</p>	<p>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.</p>	<ul style="list-style-type: none"> • TY2021 plant investment in FERC code 364 (overhead distribution poles). • The total number of overhead distribution poles based on 2016 data. • The number of street lights in overhead distribution area in 2019. • Estimated percent of distribution poles with lighting that only serve lighting load.
<p>Customers Served by 3 Phase Vs 1 Phase Primary Distribution Lines</p>	<p>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.</p>	<p>2020 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.</p>
<p>Customers Served by Overhead Vs Underground Transformers</p>	<p>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.</p>	<p>2020 listing from the GIS system of all customer premises in MNCO and whether they are served from an overhead or underground transformer.</p>

UNADJUSTED COST RESPONSIBILITIES

	<u>Total</u>	<u>Residential</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[1] Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	228,594	91,828	11,737	122,156	2,874
[2] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	<u>50</u>	<u>44</u>	<u>2</u>	<u>4</u>	<u>0</u>
[3] Unadjusted Operating Revenues (line 1 + line 2)	228,644	91,872	11,738	122,160	2,874
[4] Present Rates (CCOSS page 2, line 2)	<u>206,416</u>	<u>83,739</u>	<u>11,379</u>	<u>109,232</u>	<u>2,066</u>
[5] Unadjusted Deficiency (line 3 - line 4)	22,228	8,133	359	12,928	808
[6] Defic / Pres (line 5 / line 4)	10.8%	9.7%	3.2%	11.8%	39.1%
[7] Ratio: Class % / Total %	1.00	0.90	0.29	1.10	3.63

COST RESPONSIBILITIES FOR RATE DISCOUNTS

	<u>Total</u>	<u>Residential</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[8] Interruptible Rate Discounts (CCOSS page 2, line 5)	4,207	799	58	3,350	0
[9] Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)	4,207	1,415	188	2,591	13
[10] Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	616	130	(759)	13

ADJUSTED COST RESPONSIBILITIES

	<u>Total</u>	<u>Residential</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[11] Adjusted Rate Revenue Reqt (line 1 + line 10)	228,594	92,445	11,866	121,397	2,887
[12] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	<u>50</u>	<u>44</u>	<u>2</u>	<u>4</u>	<u>0</u>
[13] Adjusted Operating Revenues (line 11 + line 12)	228,644	92,489	11,868	121,401	2,887
[14] Present Rates (line 4)	<u>206,416</u>	<u>83,739</u>	<u>11,379</u>	<u>109,232</u>	<u>2,066</u>
[15] Adjusted Deficiency (line 13 - line 14)	22,228	8,749	488	12,169	821
[16] Defic / Pres Rates (line 15 / line 14)	10.8%	10.4%	4.3%	11.1%	39.7%
[17] Ratio: Class % / Total %	1.00	0.97	0.40	1.03	3.69

PROPOSED REVENUE RESPONSIBILITIES

	<u>Total</u>	<u>Residential</u>	<u>Non-Demand</u>	<u>Demand</u>	<u>Street Ltg</u>
[18] Proposed Rates (CCOSS page 3, line 3)	228,594	92,644	11,892	121,659	2,399
[19] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	<u>50</u>	<u>44</u>	<u>2</u>	<u>4</u>	<u>0</u>
[20] Proposed Operating Revenues (line 18 + line 19)	228,644	92,688	11,893	121,663	2,399
[21] Proposed Increase (line 20 - line 14)	22,228	8,949	514	12,431	333
[22] Difference / Pres (line 21 / line 14)	10.8%	10.7%	4.5%	11.4%	16.1%
[23] Ratio: Class % / Total %	1.00	0.99	0.42	1.06	1.50

PRES vs Equal Rev Reqts		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Alloc	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SL Lig
1	Total Retail Rev Req	228,594,012	91,928	133,892	11,737	122,156	106,018	16,137	0	0	2,874
2	UnAdj Equal Rev Req @ 7.35%	206,416	83,739	120,611	11,379	109,232	98,462	10,770	0	0	2,066
3	Present Revenue	22,178	8,089	13,281	357	12,924	7,556	5,368	0	0	808
4	UnAdj Revenue Deficiency	10.74%	9.66%	11.01%	3.14%	11.83%	7.67%	49.84%	0.00%	0.00%	39.11%
5	Pres Int Rate Discounts	4,207	798,775	3,408	58	3,350	2,327	1,023	0	0	0
6	Pres Int Rate Disc Cost Alloc D10C	4,207	1,415	2,778	188	2,591	2,173	418	0	0	13
7	Revenue Requirement Shift	0	616	(628)	130	(759)	(154)	(605)	0	0	13
8	Adj Equal Rev Req (Rows 1-7)	228,594	92,445	133,263	11,866	121,397	105,864	15,532	0	0	2,887
9	Adj Rev Defic vs Pres Rev (Row 2)	22,178	8,705	12,652	487	12,165	7,402	4,763	0	0	821
10	Adj Deficiency / Adj Present	10.74%	10.40%	10.49%	4.28%	11.14%	7.52%	44.22%	0.00%	0.00%	39.74%
Equal Customer Classification											
11	Min Sys & Service Drop	14,388	10,925	1,850	1,061	790	773	17	0	0	1,612
12	Energy Services	5,039	3,990	1,034	632	402	398	4	0	0	15
13	Total Customer (Cusco)	19,427	14,915	2,885	1,693	1,192	1,170	21	0	0	167
14	Ave Monthly Customers	96,144	81,342	12,764	8,657	4,107	4,076	31	0	0	2,038
15	Svc Drop Req	\$12.47	\$11.19	\$12.08	\$10.21	\$16.02	\$15.79	\$46.16	\$0.00	\$0.00	\$65.93
16	Enter Svcs Req	\$4.37	\$4.09	\$6.75	\$6.09	\$8.15	\$10.90	\$0.00	\$0.00	\$0.00	\$0.61
17	Total Req	\$16.84	\$15.28	\$18.83	\$16.30	\$24.17	\$23.92	\$57.07	\$0.00	\$0.00	\$66.54
Equal Energy Classification											
18	On Peak Rev Req	48,283	16,593	31,578	2,528	29,050	25,621	3,429	0	0	122
19	Off Peak Rev Req	51,288	20,062	30,691	2,390	28,301	24,893	3,408	0	0	535
20	Total Ener Rev Req	99,581	36,655	62,269	4,917	57,352	50,514	6,837	0	0	667
21	Annual MWh Sales	2,136,485	779,209	1,339,342	102,502	1,236,839	1,086,222	150,618	0	0	17,934
22	On Pk Req	22,604	21,295	23,577	24,659	23,488	23,587	22,769	0.000	0.000	6,802
23	Off Pk Req	24,006	25,746	23,313	23,313	22,882	22,917	22,627	0.000	0.000	29,860
24	Total Req	46,610	47,041	46,492	47,972	46,370	46,505	45,396	0.000	0.000	36,662
Equal Demand Classification											
25	Energy-Related Prod	34,609	12,661	21,729	1,696	20,033	17,576	2,457	0	0	219
26	Capacity-Related Summer Peak Prod	23,247	7,799	15,376	1,038	14,337	12,026	2,312	0	0	72
27	Capacity-Related Winter Peak Prod	5,669	2,237	4,411	298	4,113	3,450	663	0	0	21
28	Total Capacity-Related Prod	29,916	10,036	19,786	1,336	18,450	15,475	2,975	0	0	93
29	Total Production	64,525	22,698	41,515	3,032	38,483	33,051	5,432	0	0	312
30	Transmission (Transco)	30,471	10,817	19,479	1,435	18,044	15,318	2,726	0	0	175
31	Primary Dist Subs	4,645	1,829	2,769	220	2,550	2,115	434	0	0	47
32	Prim Dist Lines	8,507	4,147	4,313	369	3,943	3,256	687	0	0	47
33	Second Dist Trans	1,439	768	663	70	592	592	0	0	0	9
34	Total Distribution (Disco)	14,581	6,744	7,745	659	7,085	5,964	1,121	0	0	103
35	Total Demand Rev Req	109,586	40,259	68,739	5,126	63,612	54,334	9,279	0	0	589
36	Annual Billing kW	3,286,718	0	3,286,718	0	3,286,718	2,990,238	296,480	0	0	0
37	Base Rev Req	\$ / kW	\$0.00	\$6.61	\$0.00	\$6.10	\$6.88	\$8.29	\$0.00	\$0.00	\$0.00
38	Summer Rev Req	\$ / kW	\$0.00	\$4.68	\$0.00	\$4.36	\$4.02	\$7.80	\$0.00	\$0.00	\$0.00
39	Winter Rev Req	\$ / kW	\$0.00	\$1.34	\$0.00	\$1.25	\$1.15	\$2.24	\$0.00	\$0.00	\$0.00
40	Prod Rev Req	\$ / kW	\$0.00	\$12.63	\$0.00	\$11.71	\$11.05	\$18.32	\$0.00	\$0.00	\$0.00
41	Tran Rev Req	\$ / kW	\$0.00	\$5.93	\$0.00	\$5.49	\$5.12	\$9.19	\$0.00	\$0.00	\$0.00
42	Dist Rev Req	\$ / kW	\$0.00	\$2.36	\$0.00	\$2.16	\$1.99	\$3.78	\$0.00	\$0.00	\$0.00
43	Tot Dmd Rev Req	\$ / kW	\$0.00	\$20.91	\$0.00	\$19.35	\$18.17	\$31.30	\$0.00	\$0.00	\$0.00
44	Tot Dmd Rev Req	Mills / kWh	51,293	51,323	50,011	51,431	50,021	61,605	0.000	0.000	32,842
45	Summer Billing kW		0	1,137,231	0	1,137,231	1,031,540	105,690	0	0	0
46	Winter Billing kW		0	2,149,487	0	2,149,487	1,958,698	190,789	0	0	0
47	Tot Summer Req	\$ / kW	\$0.00	\$28.41	\$0.00	\$26.35	\$24.65	\$43.14	\$0.00	\$0.00	\$0.00
48	Tot Winter Req	\$ / kW	\$0.00	\$16.95	\$0.00	\$15.65	\$14.76	\$24.74	\$0.00	\$0.00	\$0.00
49	Energy + Production (Genco)		59,352	103,784	7,949	95,835	83,566	12,269	0	0	969

PROP vs Equal Rev Reqs

	1-2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SLtLg
	7.35%	7.57%	7.28%	7.69%	7.25%	8.23%	0.95%	0.00%	0.00%	2.02%
1	Total Retail Rev Reqt	91,828	133,892	11,737	122,156	106,018	16,137	0	0	2,874
2	Proposed Ret On Rt Base	228,594	133,550	11,892	121,659	109,655	12,004	0	0	2,399
3	UnAdj Equalized Rev Reqt	0	342	(816)	497	(3,637)	4,134	0	0	475
4	Proposed Revenue	0.00%	0.26%	-0.88%	0.41%	-3.32%	34.44%	0%	0%	19.79%
5	UnAdj Revenue Deficiency	3,614	3,574	60	3,514	2,444	1,070	0	0	0
6	UnAdj Revenue Deficiency / Proposed	3,614	2,387	151	2,225	1,867	359	0	0	11
7	Prop Interruption Rate Discounts	0	(1,187)	102	(1,288)	(577)	0	0	0	11
8	Prop Int Rate Disc Cost/Alloc	228,594	132,706	11,838	120,867	105,441	15,426	0	0	2,885
9	Revenue Requirement Shift	0	(845)	(64)	(791)	(4,214)	3,423	0	0	486
10	Adj Equal Rev (Rows 2+8)	0.00%	-0.63%	-0.45%	-0.65%	-3.84%	28.51%	0.00%	0.00%	20.25%
11	Adj Rev Defic vs Prop Rev (Row 3)	14,353	1,897	1,080	817	803	13	0	0	1,401
12	Adj Deficiency / Adj Prop	5,039	3,990	632	402	398	4	0	0	15
13	Prop Customer Component	19,393	2,931	1,713	1,219	1,201	17	0	0	1,416
14	Min Sys & Service Drop	81,342	12,764	6,657	4,107	4,076	31	0	0	2,038
15	Total Customer (Cusco)	\$12,444	\$12,368	\$10,440	\$16,577	\$16,442	\$35,833	\$0.00	\$0.00	\$57,300
16	Ave Monthly Customers	\$4,377	\$6,029	\$6,029	\$6,156	\$8,114	\$10,886	\$0.00	\$0.00	\$0.60
17	Svc Drop Reqt	\$4,377	\$6,029	\$6,029	\$6,156	\$8,114	\$10,886	\$0.00	\$0.00	\$0.60
18	Ener Svcs Reqt	\$4,377	\$6,029	\$6,029	\$6,156	\$8,114	\$10,886	\$0.00	\$0.00	\$0.60
19	Total Reqt	\$16,811	\$19,114	\$16,499	\$24,727	\$24,356	\$46,770	\$0.00	\$0.00	\$57,911
20	Prop Energy Component	48,299	31,560	2,529	29,051	25,650	3,401	0	0	121
21	On Peak Rev Reqt	51,291	30,692	2,391	28,301	24,922	3,379	0	0	532
22	Off Peak Rev Reqt	99,590	62,722	4,919	57,353	50,572	6,780	0	0	663
23	Total Ener Rev Reqt	2,136,485	1,336,342	102,502	1,236,839	1,066,222	150,618	0	0	17,934
24	Annual MWh Sales	21,301	23,579	24,671	23,488	23,614	22,579	0.000	0.000	6,755
25	On Pk Reqt	24,007	22,916	23,323	22,882	22,944	22,437	0.000	0.000	29,652
26	Off Pk Reqt	24,007	22,916	23,323	22,882	22,944	22,437	0.000	0.000	29,652
27	Total Reqt	46,614	46,495	47,994	46,370	46,556	45,016	0.000	0.000	36,407
28	Prop Demand Component	34,910	21,831	1,766	20,064	19,433	631	0	0	72
29	Energy-Related Prod	23,152	15,229	1,052	14,177	12,429	1,748	0	0	57
30	Capacity-Related Summer Peak Prod	6,642	4,369	302	4,067	3,566	501	0	0	16
31	Capacity-Related Winter Peak Prod	14,559	19,598	1,354	18,244	15,994	2,250	0	0	74
32	Total Capacity-Related Prod	64,705	41,429	3,120	38,308	35,428	2,881	0	0	146
33	Total Production	30,347	19,260	1,466	17,794	16,167	1,627	0	0	116
34	Transmission (Transco)	4,592	2,704	226	2,478	2,260	219	0	0	27
35	Primary Dist Subs	8,473	4,247	375	3,871	3,392	480	0	0	35
36	Prim Dist Lines	1,494	708	72	636	636	0	0	0	5
37	Second Dist, Trans	14,559	7,659	673	6,985	6,287	686	0	0	68
38	Total Distribution (Disco)	109,611	66,347	5,260	63,087	57,881	5,206	0	0	330
39	Total Demand Rev Reqt	3,286,718	3,286,718	0	3,286,718	2,990,238	296,480	0	0	0
40	Annual Billing KW	\$0.00	\$0.00	\$0.00	\$6.50	\$2.13	\$2.13	\$0.00	\$0.00	\$0.00
41	Base Rev Reqt	\$0.00	\$0.00	\$0.00	\$4.31	\$4.16	\$5.90	\$0.00	\$0.00	\$0.00
42	Summer Rev Reqt	\$0.00	\$0.00	\$0.00	\$1.24	\$1.19	\$1.69	\$0.00	\$0.00	\$0.00
43	Winter Rev Reqt	\$0.00	\$0.00	\$0.00	\$11.66	\$11.85	\$9.72	\$0.00	\$0.00	\$0.00
44	Prod Rev Reqt	\$0.00	\$0.00	\$0.00	\$5.41	\$5.41	\$5.49	\$0.00	\$0.00	\$0.00
45	Tran Rev Reqt	\$0.00	\$0.00	\$0.00	\$2.13	\$2.10	\$2.35	\$0.00	\$0.00	\$0.00
46	Dist Rev Reqt	\$0.00	\$0.00	\$0.00	\$19.19	\$19.36	\$17.56	\$0.00	\$0.00	\$0.00
47	Tot Dmd Rev Reqt	\$1,304	\$1,030	\$1,313	\$1,007	\$3,287	\$4,564	\$0.00	\$0.00	\$0.00
48	Summer Billing KW	1,137,231	1,137,231	0	1,137,231	1,031,540	105,690	0	0	0
49	Winter Billing KW	2,149,487	2,149,487	0	2,149,487	1,958,698	190,789	0	0	0
50	Tot Summer Reqt	\$0.00	\$0.00	\$0.00	\$26.11	\$26.06	\$26.51	\$0.00	\$0.00	\$0.00
51	Tot Winter Reqt	\$0.00	\$16.86	\$0.00	\$15.54	\$15.83	\$12.60	\$0.00	\$0.00	\$0.00
52	Energy + Production (Genco)	164,295	103,701	8,040	95,661	86,000	9,661	0	0	799
	Prop Rev - Pres Rev (Pg 2)	22,178	12,939	512	12,427	11,193	1,234	0	0	333
	Difference / Present	10.74%	10.73%	4.50%	11.38%	11.37%	11.46%	0.00%	0.00%	16.13%

	1-2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SLtLg
	7.35%	7.57%	7.28%	7.69%	7.25%	8.23%	0.95%	0.00%	0.00%	2.02%
1	Total Retail Rev Reqt	91,828	133,892	11,737	122,156	106,018	16,137	0	0	2,874
2	Proposed Ret On Rt Base	228,594	133,550	11,892	121,659	109,655	12,004	0	0	2,399
3	UnAdj Equalized Rev Reqt	0	342	(816)	497	(3,637)	4,134	0	0	475
4	Proposed Revenue	0.00%	0.26%	-0.88%	0.41%	-3.32%	34.44%	0%	0%	19.79%
5	UnAdj Revenue Deficiency	3,614	3,574	60	3,514	2,444	1,070	0	0	0
6	UnAdj Revenue Deficiency / Proposed	3,614	2,387	151	2,225	1,867	359	0	0	11
7	Prop Interruption Rate Discounts	0	(1,187)	102	(1,288)	(577)	0	0	0	11
8	Prop Int Rate Disc Cost/Alloc	228,594	132,706	11,838	120,867	105,441	15,426	0	0	2,885
9	Revenue Requirement Shift	0	(845)	(64)	(791)	(4,214)	3,423	0	0	486
10	Adj Equal Rev (Rows 2+8)	0.00%	-0.63%	-0.45%	-0.65%	-3.84%	28.51%	0.00%	0.00%	20.25%
11	Adj Rev Defic vs Prop Rev (Row 3)	14,353	1,897	1,080	817	803	13	0	0	1,401
12	Adj Deficiency / Adj Prop	5,039	3,990	632	402	398	4	0	0	15
13	Prop Customer Component	19,393	2,931	1,713	1,219	1,201	17	0	0	1,416
14	Min Sys & Service Drop	81,342	12,764	6,657	4,107	4,076	31	0	0	2,038
15	Total Customer (Cusco)	\$12,444	\$12,368	\$10,440	\$16,577	\$16,442	\$35,833	\$0.00	\$0.00	\$57,300
16	Ave Monthly Customers	\$4,377	\$6,029	\$6,029	\$6,156	\$8,114	\$10,886	\$0.00	\$0.00	\$0.60
17	Svc Drop Reqt	\$4,377	\$6,029	\$6,029	\$6,156	\$8,114	\$10,886	\$0.00	\$0.00	\$0.60
18	Ener Svcs Reqt	\$4,377	\$6,029	\$6,029	\$6,156	\$8,114	\$10,886	\$0.00	\$0.00	\$0.60
19	Total Reqt	\$16,811	\$19,114	\$16,499	\$24,727	\$24,356	\$46,770	\$0.00	\$0.00	\$57,911
20	Prop Energy Component	48,299	31,560	2,529	29,051	25,650	3,401	0	0	121
21	On Peak Rev Reqt	51,291	30,692	2,391	28,301	24,922	3,379	0	0	532
22	Off Peak Rev Reqt	99,590	62,722	4,919	57,353	50,572	6,780	0	0	663
23	Total Ener Rev Reqt	2,136,485	1,336,342	102,502	1,236,839	1,066,222	150,618	0	0	17,934
24	Annual MWh Sales	21,301	23,579	24,671	23,488	23,614	22,579	0.000	0.000	6,755
25	On Pk Reqt	24,007	22,916	23,323	22,882	22,944	22,437	0.000	0.000	29,652
26	Off Pk Reqt	24,007	22,916	23,323	22,882	22,944	22,437	0.000	0.000	29,652
27	Total Reqt	46,614	46,495	47,994	46,370	46,556	45,016	0.000	0.000	36,407
28	Prop Demand Component	34,910	21,831	1,766	20,064	19,433	631	0	0	72
29	Energy-Related Prod	23,152	15,229	1,052	14,177	12,429	1,748	0	0	57
30	Capacity-Related Summer Peak Prod	6,642	4,369	302	4,067	3,566	501	0	0	16
31	Capacity-Related Winter Peak Prod	14,559	19,598	1,354	18,244	15,994	2,250	0	0	74
32	Total Capacity-Related Prod	64,705	41,429	3,120	38,308	35,428	2,881	0	0	146
33	Total Production	30,347	19,260	1,466	17,794	16,167	1,627	0	0	116
34	Transmission (Transco)	4,592	2,704	226	2,478	2,260	219	0	0	27
35	Primary Dist Subs	8,473	4,247	375	3,871	3,392	480	0	0	35
36	Prim Dist Lines	1,494	708	72	636	636	0	0	0	5
37	Second Dist, Trans	14,559	7,659	673	6,985	6,287	686	0	0	68
38	Total Distribution (Disco)	109,611	66,347	5,260	63,087	57,881	5,206	0	0	330
39	Total Demand Rev Reqt	3,286,718	3,286,718	0	3,286,718	2,990,238	296,480	0	0	0
40	Annual Billing KW	\$0.00	\$0.00	\$0.00	\$6.50	\$2.13	\$2.13	\$0.00	\$0.00	\$0.00
41	Base Rev Reqt	\$0.00	\$0.00	\$0.00	\$4.31	\$4.16	\$5.90	\$0.00	\$0.00	\$0.00
42	Summer Rev Reqt	\$0.00	\$0.00	\$0.00	\$1.24	\$1.19	\$1.69	\$0.00	\$0.00	\$0.00
43	Winter Rev Reqt	\$0.00	\$0.00	\$0.00	\$11.66	\$11.85	\$9.72	\$0.00	\$0.00	\$0.00
44	Prod Rev Reqt	\$0.00	\$0.00							

Original Plant in Service

	1-2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr-Transf	Trans	St Ltg
1	141,981	47,767	93,775	6,337	87,438	73,343	14,095	0	0	439
2	40,731	13,703	26,902	1,818	25,084	21,040	4,043	0	0	126
3	182,712	61,470	120,677	8,155	112,522	94,383	18,138	0	0	566
4	523,519	193,236	328,836	25,825	301,011	265,131	35,880	0	0	3,447
5	179,706	66,331	112,191	8,865	103,326	91,010	12,316	0	0	1,183
6	885,937	321,037	559,704	42,845	516,859	450,525	66,334	0	0	5,196
Transmission										
7	6,389	2,358	3,989	315	3,674	3,236	438	0	0	42
8	2,412	811	1,593	108	1,485	1,246	239	0	0	7
9	8,801	3,170	5,682	423	5,159	4,482	677	0	0	50
10	231,458	82,400	147,734	10,898	136,835	116,205	20,630	0	0	1,325
11	0	0	0	0	0	0	0	0	0	0
12	61	0	61	0	61	0	61	0	0	0
13	240,321	85,570	153,377	11,321	142,056	120,687	21,369	0	0	1,374
Distributions:										
Substations										
14	216	79	136	10	126	110	16	0	0	1
15	121	43	77	6	71	61	11	0	0	1
16	38,649	15,252	23,007	1,828	21,180	17,571	3,609	0	0	390
17	0	0	0	0	0	0	0	0	0	0
18	36,986	15,374	23,221	1,844	21,377	17,742	3,635	0	0	392
Overhead Lines										
19	6,792	4,907	1,885	317	1,568	1,283	285	0	0	0
20	14,613	5,288	9,201	603	8,593	7,110	1,483	0	0	125
21	3,644	3,407	236	203	34	33	0	0	0	0
22	7,839	6,760	1,059	716	343	340	3	0	0	20
23	32,888	20,362	12,391	1,843	10,538	8,767	1,770	0	0	145
24	1,671	864	787	83	714	714	0	0	0	11
25	6,014	5,188	810	549	261	261	0	0	0	16
26	7,685	6,051	1,608	633	975	975	0	0	0	26
27	4,411	0	0	0	0	0	0	0	0	2,411
28	42,964	26,413	13,989	2,476	11,513	9,743	1,770	0	0	2,582
Underground Lines										
29	13,408	9,687	3,721	626	3,095	2,633	562	0	0	0
30	19,271	6,973	12,134	802	11,332	9,377	1,955	0	0	164
31	15,290	14,249	989	848	141	140	1	0	0	0
32	21,900	18,886	2,958	2,000	958	951	7	0	0	57
33	69,818	49,795	19,802	4,275	15,526	13,001	2,526	0	0	221
34	2,246	1,160	1,071	112	959	959	0	0	0	14
35	6,314	5,447	851	577	274	274	0	0	0	16
36	8,560	6,607	1,922	689	1,233	1,233	0	0	0	31
37	0	0	0	0	0	0	0	0	0	0
38	78,378	56,402	21,724	4,964	16,760	14,234	2,526	0	0	252
Line Transformers										
39	2,988	1,081	1,881	124	1,757	1,454	303	0	0	25
40	8,320	4,608	4,255	445	3,809	3,809	0	0	0	57
41	15,665	13,513	2,111	1,431	681	681	0	0	0	41
42	27,573	19,203	8,247	2,000	6,247	5,944	303	0	0	123
Services										
43	862	682	180	26	154	154	0	0	0	0
44	14,364	13,413	952	645	307	307	0	0	0	0
45	15,226	14,095	1,132	671	460	460	0	0	0	0
46	6,715	4,042	2,667	845	1,821	1,753	68	0	0	7
47	3,163	0	0	0	0	0	0	0	0	3,163
48	213,025	135,528	70,979	12,801	58,178	49,876	8,302	0	0	6,518
General & Common Plant										
49	132,512	53,640	77,577	6,626	70,951	61,452	9,499	0	0	1,295
50	1,471,794	595,774	861,637	73,593	788,043	682,539	105,504	0	0	14,383
51	0	0	0	0	0	0	0	0	0	0
52	1,471,794	595,774	861,637	73,593	788,043	682,539	105,504	0	0	14,383

FERC-Accounts

120, 310-346

350-359

360-363

364,365

366,367

368

369

370
373

303, 369-399

	1-2+3+10	2	3-4+5	4	5-6+9	6	7	8	9	10
	ND	Res	C<ot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SLUg
1 Production	127	43	64	6	78	66	13	0	0	0
2 Peaking Plant	784	290	490	39	451	397	54	0	0	0
3 Base Load	343	127	214	17	197	174	24	0	0	5
4 Nuclear Fuel	1,255	459	786	61	727	637	90	0	0	2
5 Total										8
6 Transmission										
7 Gen Step Up Base	3	1	2	0	2	1	0	0	0	0
8 Gen Step Up Peak	10	3	7	0	6	5	1	0	0	0
9 Total Gen Step Up	13	4	8	0	8	7	1	0	0	0
10 Bulk Transmission	159	57	102	7	94	80	14	0	0	1
11 Distrib Function	0	0	0	0	0	0	0	0	0	0
12 Dir Assgn	0	0	0	0	0	0	0	0	0	0
13 Total	172	61	110	8	102	87	15	0	0	1
14 Distribution										
15 General Step Up	0	0	0	0	0	0	0	0	0	0
16 Bulk Transmission	0	0	0	0	0	0	0	0	0	0
17 Distrib Function	39	16	23	2	22	18	4	0	0	0
18 Dir Assgn	0	0	0	0	0	0	0	0	0	0
19 Total Substations	39	16	23	2	22	18	4	0	0	0
20 Overhead Lines	9	9	5	1	4	3	1	0	0	1
21 Underground	22	16	6	1	5	4	1	0	0	0
22 Line Transformers	0	0	0	0	0	0	0	0	0	0
23 P68	0	0	0	0	0	0	0	0	0	0
24 P69	0	0	0	0	0	0	0	0	0	0
25 C12WM	0	0	0	0	0	0	0	0	0	0
26 Meters	0	0	0	0	0	0	0	0	0	0
27 Street Lighting	(0)	0	0	0	0	0	0	0	0	(0)
28 Total	76	40	34	4	30	25	5	0	0	1
29 General & Common Plant										
30 PTD	411	166	241	21	220	191	29	0	0	4
31 Total CWIP	1,914	727	1,173	94	1,079	939	140	0	0	14
32 Fuel Inventory	6,579	2,428	4,107	325	3,783	3,332	451	0	0	43
33 Materials & Supplies										
34 Production	9,662	3,501	6,104	467	5,637	4,914	723	0	0	57
35 Trans & Dislr	1,144	558	566	61	505	431	75	0	0	20
36 Total	10,807	4,059	6,671	528	6,142	5,344	798	0	0	77
37 Prepayments										
38 Miscellaneous	9,435	3,838	5,503	474	5,029	4,345	684	0	0	93
39 Fuel	0	0	0	0	0	0	0	0	0	0
40 Insurance	0	0	0	0	0	0	0	0	0	0
41 Total	9,435	3,838	5,503	474	5,029	4,345	684	0	0	93
42 Non-Plant Assets & Liab										
43 LABOR	8,415	3,394	4,850	444	4,406	3,822	584	0	0	172
44 PTD	(7,103)	(2,863)	(4,171)	(353)	(3,818)	(3,293)	(525)	0	0	(68)
45 Working Cash	190,283	11,583	18,132	1,511	16,621	14,489	2,132	0	0	331
46 Total Additions	30,046									
47 Total Rate Base	676,755	274,754	395,271	34,064	361,207	312,381	48,826	0	0	6,730
48 Common Rate Base (@ 52.50%)	355,296.2	144,246	207,517	17,884	189,634	164,000	25,634	0	0	3,533

FERC Accounts	107	107	151,152	154	135,143,184,186,232 235,252,165	190,283, calculated
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Operating & Maint (Pg 2 of 2)

	<u>Alloc</u>	<u>FERC Accounts</u>
1	Distribution Expen	580,590
2	Supervision & Eng'g	561
3	Load Dispatching	T20D80
4	Substations	P61
5	Overhead Lines	582,591,592
6	Underground Lines	583,593
7	Line Transformers	584,594
8	Meters	595
9	Customer Installn	586,597,598
10	Street Lighting	587
11	Miscellaneous	585,596
12	Rents (Pole/Attachments)	588
	Total Distribution	589
13	Customer Accounting	901-905
14	Sales, Econ Dvlp & Other	912
15	Admin & General	920
16	Salaries	921
17	Office Supplies	922
18	Admin Transfer Credit	923
19	Outside Services	924
20	Property Insurance	925
21	Pensions & Benefits	926
22	Injuries & Claims	928
23	Regulatory Exp	930.1
24	General Advertising	929, 930.2
25	Contributions	931
26	Misc General Exp	935
27	Rents	
28	Main Of General Plant	
29	Cust Service & Info	808
30	Cust Assist Exp - Non-CIP	808
31	Instructional Advertising	809
32	Total	
33	Amortizations	
34	Total O&M Expense	

1-2+3+10	ND	924
		79
		458
		2,284
		1,474
		3
		273
		290
		312
		2,143
		289
		8,529
		4,008
		119
		6,096
		4,196
		(3,407)
		1,096
		414
		4,998
		842
		34
		38
		0
		0
		(37)
		2,458
		54
		16,782
		233
		0
		51
		284,060
		6,232
		156,105

	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SLLLg
	509	314	56	258	221	37	0	0	101
	30	48	4	45	37	4	0	0	1
	181	273	22	251	208	43	0	0	5
	1,403	743	132	612	518	94	0	0	137
	1,061	409	93	315	268	48	0	0	5
	2	1	0	1	1	0	0	0	0
	164	108	34	74	71	3	0	0	0
	169	94	17	77	65	12	0	0	27
	0	0	0	0	0	0	0	0	0
	1,251	695	125	570	484	86	0	0	312
	178	94	17	77	66	12	0	0	197
	4,948	2,780	500	2,280	1,939	341	0	0	801
	3,170	829	506	323	320	3	0	0	9
	48	69	7	63	57	6	0	0	1
	2,458	3,513	321	3,192	2,769	423	0	0	125
	1,643	2,500	216	2,284	1,985	298	0	0	53
	(1,334)	(2,030)	(176)	(1,854)	(1,612)	(242)	0	0	(43)
	442	631	58	574	498	76	0	0	22
	168	241	21	221	191	30	0	0	4
	2,015	2,880	263	2,617	2,270	347	0	0	102
	340	485	44	441	382	58	0	0	17
	14	20	2	18	16	2	0	0	0
	15	23	2	21	18	3	0	0	0
	0	0	0	0	0	0	0	0	0
	(14)	(22)	(2)	(20)	(17)	(3)	0	0	(0)
	962	1,464	127	1,337	1,163	175	0	0	31
	21	32	3	30	26	4	0	0	1
	6,731	9,739	880	8,859	7,868	1,171	0	0	312
	141	89	16	73	64	9	0	0	3
	0	0	0	0	0	0	0	0	0
	31	19	4	16	14	2	0	0	1
	172	109	20	89	78	11	0	0	4
	2,513	3,691	328	3,263	2,830	432	0	0	127
	61,131	93,003	8,046	84,957	73,861	11,096	0	0	1,971

Book Depreciation

	Alloc	FERC Accounts
1 Production	D10C	
2 Peaking Plant	E8760	403,413
3 Base Load		
4 Transmission		
5 Gen Step Up Base	E8760	
6 Gen Step Up Peak	D10C	
7 Total Gen Step Up		
8 Bulk Transmission	D10T	
9 Dir Trib Function	D60Sub	
10 Direct Assign	Dir Assign	403,413
11 Distribution		
12 General Step Up	STRATH	
13 Bulk Transmission	D10T	
14 Dir Trib Function	D60Sub	
15 Direct Assign	Dir Assign	403,413
16 Total Substations		
17 Overhead Lines	POL	
18 Underground	PUL	
19 Line Transformers	P88	
20 Services	P69	
21 Meters	C12WM	
22 Street Lighting	P73	403,413
23 General & Common Plant	PTD	403,413
24 Total Book Deprec		403,404

Real Estate & Property Tax

25 Production	D10C	
26 Peaking Plant	E8760	408.1
27 Base Load		
28 Transmission		
29 Gen Step Up Base	E8760	
30 Gen Step Up Peak	D10C	
31 Total Gen Step Up		
32 Bulk Transmission	D10T	
33 Dir Trib Function	D60Sub	
34 Direct Assign	Dir Assign	408.1
35 Distribution		
36 General Step Up	STRATH	
37 Bulk Transmission	D10T	
38 Dir Trib Function	D60Sub	
39 Direct Assign	Dir Assign	408.1
40 Total Substations		
41 Overhead Lines	POL	
42 Underground	PUL	
43 Line Transformers	P88	
44 Services	P69	
45 Meters	C12WM	
46 Street Lighting	P73	408.1
47 General & Common Plant	PTD	408.1
48 Tot RI Est & Pr Tax		11,495
49 Gross Earnings Tax	R01, R02	0
50 Payroll Taxes	LABOR	2,032
51 Tot Non-Inc Taxes		13,527

1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
ND	Res	CS&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SL Lig
8,450	2,843	5,561	377	5,204	4,365	839	0	0	26
23,818	9,530	16,118	1,274	14,844	13,075	1,769	0	0	170
34,267	12,372	21,699	1,651	20,048	17,440	2,608	0	0	196
104	38	65	5	60	53	7	0	0	1
52	21	41	3	38	32	6	0	0	0
166	59	106	8	98	85	13	0	0	1
4,651	1,656	2,969	219	2,750	2,335	415	0	0	27
0	0	0	0	0	0	0	0	0	0
1	0	1	0	1	0	1	0	0	0
4,818	1,715	3,076	227	2,849	2,420	429	0	0	28
5	2	3	0	3	2	0	0	0	0
861	1	2	0	2	1	0	0	0	0
0	340	512	41	472	391	80	0	0	9
868	0	0	0	0	0	0	0	0	0
1,457	342	517	41	476	395	81	0	0	9
2,493	895	474	84	390	330	60	0	0	87
672	1,794	2,457	158	533	453	80	0	0	8
1,144	468	201	49	152	145	7	0	0	3
273	1,059	85	50	35	35	0	0	0	0
151	164	108	34	74	71	3	0	0	0
7,058	4,723	2,077	416	1,660	1,429	231	0	0	151
8,400	3,400	4,918	420	4,498	3,895	602	0	0	82
54,544	22,211	31,769	2,714	29,055	25,184	3,871	0	0	564
1,706	574	1,127	76	1,051	881	169	0	0	5
4,889	1,805	3,052	241	2,811	2,476	335	0	0	32
6,595	2,379	4,179	317	3,862	3,357	504	0	0	37
81,8044	30	51	4	47	41	6	0	0	1
30,8806	10	20	1	19	16	3	0	0	0
112,6650	41	71	5	66	57	9	0	0	0
2,963,5650	1,055	1,892	140	1,752	1,488	264	0	0	17
0	0	0	0	0	0	0	0	0	0
1	0	1	0	1	0	1	0	0	0
3,077,036	1,096	1,964	145	1,819	1,545	274	0	0	18
2	1	1	0	1	1	0	0	0	0
1	0	1	0	1	1	0	0	0	0
331	131	197	16	181	150	31	0	0	3
0	0	0	0	0	0	0	0	0	0
334	132	199	16	183	152	31	0	0	3
368	226	120	21	99	83	15	0	0	22
671	483	186	42	143	122	22	0	0	2
236	164	71	17	53	51	3	0	0	1
130	121	10	6	4	4	0	0	0	0
57	35	23	7	16	15	1	0	0	0
27	0	0	0	0	0	0	0	0	0
1,823	1,160	607	110	498	427	71	0	0	27
0	0	0	0	0	0	0	0	0	0
11,495	4,634	6,750	572	6,178	5,329	849	0	0	111
0	0	0	0	0	0	0	0	0	0
2,032	819	1,171	107	1,064	923	141	0	0	42
13,527	5,453	7,921	679	7,242	6,252	990	0	0	152

Provision For Defer Inc Tax		FERC Accounts		1-2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Alloc			ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SL Lig
1	Production			(423)	(142)	(279)	(19)	(260)	(216)	(42)	0	0	0
2	Peaking Plant	D10C	410, 411	(169)	(62)	(106)	(8)	(97)	(86)	(12)	0	0	(1)
3	Nuclear Fuel	E8760		4,244	1,785	3,019	239	2,781	2,449	331	0	0	(1)
4	Base Load	E8760			1,580	2,634	211	2,423	2,145	278	0	0	32
	Total												29
5	Transmission			92	34	57	5	53	47	6	0	0	1
6	Gen Step Up Base	E8760		33	11	22	1	20	17	3	0	0	0
7	Gen Step Up Peak	D10C		125	45	79	6	73	63	10	0	0	1
8	Total Gen Step Up	D10T		927	330	592	44	548	465	83	0	0	5
9	Bulk Transmission	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Distrib Function	Dir Assign		1,052	375	671	50	621	529	92	0	0	6
	Total												
12	Distribution			(2)	(1)	(1)	(0)	(1)	(1)	(0)	0	0	(0)
13	General Step Up	STRATH		(1)	(1)	(1)	(0)	(0)	(1)	(0)	0	0	(0)
14	Bulk Transmission	D10T		103	41	61	5	57	47	10	0	0	1
15	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
16	Dir Assign	Dir Assign		101	40	60	5	55	46	9	0	0	1
17	Total Substations			(65)	(40)	(21)	(2)	(18)	(15)	(3)	0	0	(4)
18	Overhead Lines	POL		(417)	(300)	(116)	(26)	(89)	(76)	(13)	0	0	(1)
19	Underground	PUL		(99)	(69)	(30)	(7)	(32)	(21)	(1)	0	0	(0)
20	Line Transformers	P68		(136)	(126)	(10)	(6)	(4)	(5)	(0)	0	0	(0)
21	Services	P69		(20)	(12)	(8)	0	(6)	(5)	(0)	0	0	(0)
22	Meters	C12WM		(29)	0	0	0	0	0	0	0	0	(29)
23	Street Lighting	P73		(665)	(507)	(125)	(41)	(64)	(76)	(8)	0	0	(33)
	Total												
24	General & Common Plant	PTD	410, 411	104	42	61	5	55	48	7	0	0	1
25	Net Operating Loss (NOL) Carr	NEPIS	410, 411	(12,403)	(5,046)	(7,234)	(623)	(6,811)	(5,712)	(899)	0	0	(123)
26	Non - Plant Related	LABOR	410, 411	301	121	173	16	158	137	21	0	0	6
27	Tot Prov For Defer			(7,367)	(3,435)	(3,819)	(382)	(3,437)	(2,929)	(509)	0	0	(113)

Inv Tax Credit; Total Oper Exp		FERC Accounts		1-2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Alloc			ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SL Lig
28	Production			(18)	(6)	(12)	(1)	(11)	(10)	(2)	0	0	(0)
29	Peaking Plant	D10C	411	(38)	(14)	(24)	(2)	(22)	(19)	(3)	0	0	(0)
30	Base Load	E8760		(57)	(20)	(36)	(3)	(33)	(29)	(4)	0	0	(0)
	Total												
31	Transmission			0	0	0	0	0	0	0	0	0	0
32	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
33	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
34	Total Gen Step Up	D10T		(11)	(4)	(7)	(1)	(6)	(5)	(1)	0	0	(0)
35	Bulk Transmission	D60Sub		0	0	0	0	0	0	0	0	0	0
36	Distrib Function	Dir Assign		0	0	0	0	0	0	0	0	0	0
	Total			(11)	(4)	(7)	(1)	(6)	(5)	(1)	0	0	(0)
38	Distribution			0	0	0	0	0	0	0	0	0	0
39	General Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
40	Bulk Transmission	D10T		0	0	0	0	0	0	0	0	0	0
41	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
42	Dir Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
43	Total Substations			0	0	0	0	0	0	0	0	0	0
44	Overhead Lines	POL		0	0	0	0	0	0	0	0	0	0
45	Underground	PUL		0	0	0	0	0	0	0	0	0	0
46	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
47	Services	P69		0	0	0	0	0	0	0	0	0	0
48	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
49	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
	Total												
50	General & Common Plant	PTD	411	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	(0)
51	Net Inv Tax Credit			(68)	(24)	(43)	(3)	(40)	(34)	(5)	0	0	(0)
52	Total Operating Exp			216,741	85,336	128,831	11,054	117,777	102,335	15,443	0	0	2,574
53A	Pres Op Inc Before Inc Tax			29,236,030	13,178	16,313	2,240	14,073	15,747	(1,674)	0	0	(255)
53B	Prop Op Inc Before Inc Tax			51,464	22,127	29,258	2,754	26,504	26,944	(440)	0	0	78

	1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
Production	MD	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Ir Transf	Trans	SL Lig
1 Peaking Plant	8,496	2,858	5,612	379	5,232	4,389	843	0	0	26
2 Nuclear Fuel	E8760	2,412	4,080	322	3,758	3,310	448	0	0	43
3 Base Load	E8760	18,459	31,222	2,467	28,755	25,327	3,427	0	0	329
4 Total	65,042	23,730	40,914	3,169	37,745	33,026	4,719	0	0	399
Transmission										
5 Gen Step Up Base	452	167	282	22	260	229	31	0	0	3
6 Gen Step Up Peak	163	55	108	7	101	84	16	0	0	1
7 Total Gen Step Up	615	222	390	30	360	313	47	0	0	3
8 Bulk Transmission	8,550	3,044	5,457	403	5,055	4,493	762	0	0	49
9 Distrib Function	0	0	0	0	0	0	0	0	0	0
10 Dir Assign	0	0	0	0	0	0	0	0	0	0
11 Total	9,168	3,266	5,850	432	5,417	4,606	811	0	0	52
Distribution										
12 General Step Up	0	0	0	0	0	0	0	0	0	0
13 Bulk Transmission	1	0	1	0	1	1	0	0	0	0
14 Distrib Function	1,311	518	781	62	719	596	122	0	0	13
15 Dir Assign	0	0	0	0	0	0	0	0	0	0
16 Total Substations	1,313	518	781	62	719	597	123	0	0	13
17 Overhead Lines	1,270	781	413	73	340	288	52	0	0	76
18 Underground	1,598	1,150	443	101	342	290	51	0	0	5
19 Line Transformers	1,043	726	312	76	236	225	11	0	0	5
20 Services	280	259	21	12	6	6	0	0	0	0
21 Meters	246	148	98	31	67	64	2	0	0	0
22 Street Lighting	81	0	0	0	0	0	0	0	0	0
23 Total	5,831	3,583	2,068	355	1,713	1,472	240	0	0	81
24 General & Common Plant	10,813	4,377	6,330	541	5,790	5,015	775	0	0	106
25 Net Operating Loss (NOL) Carry (INEPS)	0	0	0	0	0	0	0	0	0	0
Total Tax Deprec	90,854	34,955	55,162	4,497	50,665	44,119	6,546	0	0	737
27 Interest Expense	13,467.42	5,468	7,866	678	7,188	6,216	972	134	0	134
28 Other Tax Timing Differ	(283)	(114)	(163)	(15)	(148)	(128)	(20)	0	0	(6)
29 Meals & Entle	79	32	46	4	41	36	5	0	0	2
30 Total Tax Deductions	104,118	40,341	62,910	5,164	57,746	50,243	7,503	0	0	867
Inc Tax Additions										
31 Book Depreciation	54,544	22,211	31,769	2,714	29,055	25,184	3,871	0	0	564
32 Deferred Inc Tax & ITC	(7,435.17)	(3,459)	(3,863)	(385)	(3,477)	(2,963)	(514)	0	0	(114)
33 Nuclear Fuel Book Burn	7,025	2,593	4,386	347	4,039	3,558	481	0	0	46
34 Tax Capitalized Leases	2,953	1,195	1,729	148	1,581	1,369	212	0	0	29
35 Avoided Tax Interest	1,117	453	652	56	596	516	81	0	0	11
36 Total Tax Additions	58,204	22,994	34,673	2,879	31,794	27,664	4,130	0	0	557
37 Total Inc Tax Adjustments	(45,915)	(17,347)	(28,237)	(2,285)	(25,952)	(22,579)	(3,373)	0	0	(330)
38A Pres Taxable Net Income	(16,679)	(4,169)	(11,924)	(45)	(11,879)	(6,832)	(5,047)	0	0	(586)
38B Prop Taxable Net Income	5,549	4,780	1,021	469	552	4,365	(3,813)	0	0	(252)
39A Pres Fed & State Inc Tax	(3,702)	(868)	(2,695)	8	(2,703)	(1,498)	(1,205)	0	0	(139)
39B Prop Fed & State Inc Tax	1,722	1,316	464	133	331	1,235	(904)	0	0	(58)
40A Pres Preliminary Return	32,938	14,046	19,008	2,233	16,776	17,245	(469)	0	0	(116)
40B Prop Preliminary Return	49,741	20,811	28,794	2,621	26,173	25,709	464	0	0	136
41 Total AFUDC	0	0	0	0	0	0	0	0	0	0
42A Present Total Return	32,938	14,046	19,008	2,233	16,776	17,245	(469)	0	0	(116)
42B Proposed Total Return	49,741	20,811	28,794	2,621	26,173	25,709	464	0	0	136
43A Pres % Return on Rate Base	4.87%	5.11%	4.81%	6.55%	4.64%	5.52%	-0.36%	0.00%	0.00%	-1.73%
43B Prop % Return on Rate Base	7.35%	7.28%	7.28%	7.69%	7.25%	8.23%	0.95%	0.00%	0.00%	2.02%
44A Present Common Return	19,471	8,579	11,142	1,555	9,588	11,028	(1,441)	0	0	(250)
44B Proposed Common Return	36,274	15,344	20,928	1,943	18,985	19,493	(508)	0	0	2
45A Pres % Ret on Common Rt Base	5.48%	5.95%	5.37%	8.69%	5.06%	6.72%	-5.62%	0.00%	0.00%	-7.08%
45B Prop % Ret on Common Rt Base	10.21%	10.64%	10.09%	10.87%	10.01%	11.89%	-1.98%	0.00%	0.00%	0.05%

	FERC Accounts
tax books	
tax books	
tax books	
tax books	
427,431	

Northern States Power Company
 North Dakota 2021 Proposed CCROSS (\$000)

	1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SL Lig
1	100.00%	60.42%	38.23%	6.92%	31.31%	27.55%	3.76%	0.00%	0.00%	1.35%
2	100.00%	33.64%	66.05%	4.46%	61.56%	51.66%	9.93%	0.00%	0.00%	0.31%
3	100.00%	36.91%	62.43%	4.93%	57.50%	50.64%	6.85%	0.00%	0.00%	0.66%
4	100.00%	36.91%	62.43%	4.93%	57.50%	50.64%	6.85%	0.00%	0.00%	0.66%
5	100.00%	37.84%	61.36%	4.62%	56.74%	47.04%	9.69%	0.00%	0.00%	0.81%
6	100.00%	40.33%	57.65%	5.27%	52.36%	45.42%	6.94%	0.00%	0.00%	2.04%
7	100.00%	40.68%	56.33%	5.02%	53.30%	46.05%	7.25%	0.00%	0.00%	0.99%
8	100.00%	58.37%	32.42%	5.83%	26.59%	22.59%	3.99%	0.00%	0.00%	9.21%
9	100.00%	39.16%	59.58%	5.15%	54.42%	47.32%	7.11%	0.00%	0.00%	1.26%
10	100.00%	36.24%	63.18%	4.84%	58.34%	50.85%	7.49%	0.00%	0.00%	0.59%
11	100.00%	36.07%	63.37%	4.81%	58.55%	50.91%	7.65%	0.00%	0.00%	0.57%
12	100.00%	36.02%	63.41%	4.81%	58.61%	50.92%	7.69%	0.00%	0.00%	0.56%
13	100.00%	63.62%	33.32%	6.01%	27.31%	23.41%	3.90%	0.00%	0.00%	3.06%
14	100.00%	39.43%	59.56%	4.73%	54.83%	45.51%	9.32%	0.00%	0.00%	1.00%
15	100.00%	69.64%	29.91%	7.25%	22.66%	21.56%	1.10%	0.00%	0.00%	0.45%
16	100.00%	92.57%	7.43%	4.41%	3.02%	3.02%	0.00%	0.00%	0.00%	0.00%
17	100.00%	61.45%	32.54%	5.76%	26.78%	22.67%	4.12%	0.00%	0.00%	6.01%
18	100.00%	40.31%	58.72%	4.97%	53.75%	46.36%	7.39%	0.00%	0.00%	0.96%
19	100.00%	40.48%	58.54%	5.00%	53.54%	46.37%	7.17%	0.00%	0.00%	0.98%
20	100.00%	71.96%	27.72%	6.33%	21.38%	18.16%	3.22%	0.00%	0.00%	0.32%
21	100.00%	40.60%	58.41%	5.03%	53.37%	46.16%	7.21%	0.00%	0.00%	0.99%
22	100.00%	36.36%	63.04%	4.85%	58.19%	50.82%	7.37%	0.00%	0.00%	1.74%
23	100.00%	48.77%	49.49%	5.32%	44.17%	37.62%	6.54%	0.00%	0.00%	0.60%
24	100.00%	55.10%	34.01%	6.10%	27.91%	23.90%	4.01%	0.00%	0.00%	10.89%
INTERNAL DATA										
25	26.075	10,515	15,027	1,374	13,653	11,844	1,809	0	0	533
26	5,172	3,019	1,677	302	1,375	1,168	207	0	0	476
27	152,768	59,824	91,016	7,874	83,142	72,282	10,859	0	0	1,929
28	9,017	3,248	5,718	433	5,285	4,591	693	0	0	51
29	1,339,282	542,134	784,060	66,967	717,093	621,087	96,005	0	0	13,088
30	453,345	221,097	224,356	24,122	200,234	170,563	29,671	0	0	7,892
31	2,721	1,499	926	166	760	650	109	0	0	296

INTERNAL ALLOCATORS Intern:

1 50% Cus, 50% Prod Pit C11P10

2 Peaking Plant Capacity D10S

3 57% Dmd; 43% Energy, Sales & ID57E43

4 40% Dmd; 60% Energy, CIP D40E60

5 20% D10T; 80% D60Sub T20D80

6 Labor w/o (or w) A&G LABOR

7 Net Plant In Service NEPS

8 Dis O&M w/o Sup & Misc OXDTS

9 O&M w/o Reg Ex & OXTS-Alloc'd OXTS

10 Production Plant P10

11 Production Plant Wo Nuclear P10WoN

12 Total P51 & P61A P5161A

13 Distribution Plant P60

14 Dist Substn Plant P61

15 Line Transformer Plant P68

16 Services Plant P69

17 Dist PIT Overhead Lines POL

18 Real Est. & Property Tax PT0

19 Produc. Trans & Distrib PTD

20 Dist PIT Underground Lines PUL

21 Rate Base (Non-Column) RTBASE

22 Stratified Hydro Baseload STRATH

23 Transmission & Distrib TD

24 Labor Dis w/o Sup & Eng ZDTS

INTERNAL DATA

25 Labor w/o A&G LABOR(S)

26 Dis O&M w/o Sup, Cust Install & IOXDTS

27 O&M w/o Reg Ex & OXTS-Alloc'd OXTS

28 Total P51 & P61A P5161A

29 Produc, Trans & Distrib PTD

30 Transmission & Distrib TD

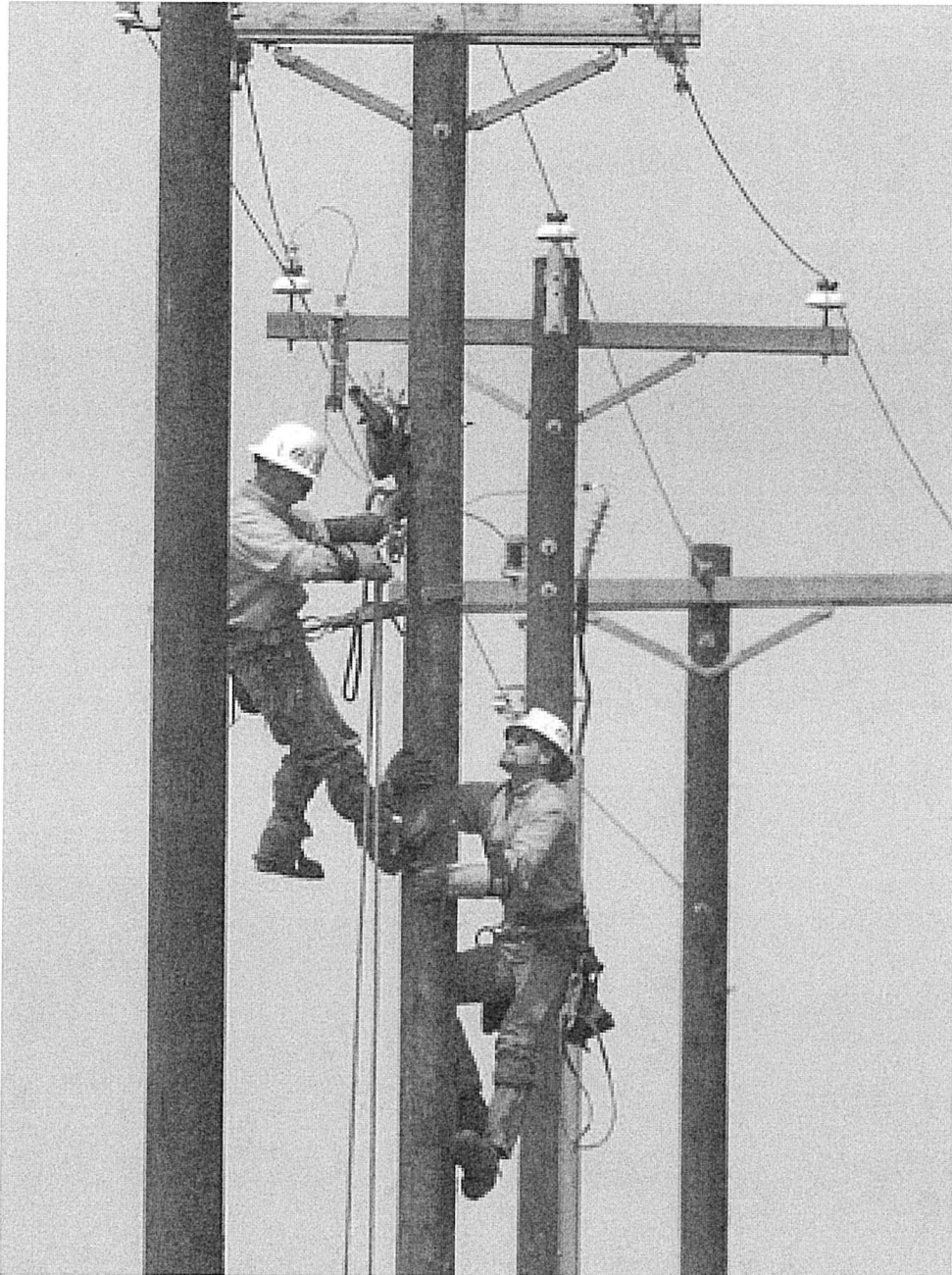
31 Labor Dis w/o Sup & Eng, Cust In ZDTS

EXTERNAL ALLOCATORS		Extern:	1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
			ND	Res	C<ot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SL Lig
1	Customers - Ave Monthly	C11	100.00%	84,600	13,288	9,00%	0.00%	4.24%	0.03%	0.00%	0.00%	2.12%
2	Cust Acctg Wtg Factor	C11WA	100.00%	79,088	12,622	100.00%	8.07%	7.98%	0.00%	0.00%	0.00%	0.24%
3	Mo Cus Wld By Mfr Invest	C12WM	100.00%	60,191	39,711	12,59%	27.12%	26.11%	1.01%	0.00%	0.00%	0.10%
4	Sec & Pti Customers	C61PS	100.00%	86,244	13,514	9.13%	4.38%	4.34%	0.00%	0.00%	0.00%	0.26%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	93,511	6,49%	5.57%	0.92%	0.92%	0.01%	0.00%	0.00%	0.00%
6	C62Sec, w/o Lig & C/I Undergroi	C62NL	100.00%	93,371	6.63%	4.49%	2.14%	2.14%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	86,266	13.48%	9.13%	4.34%	4.34%	0.00%	0.00%	0.00%	0.26%
8	Summer Peak Resp KW	D10S	100.00%	31,344	68.66%	4.17%	64.49%	53.37%	11.12%	0.00%	0.00%	0.00%
9	Transmission Demand %	D10T	100.00%	35,680	63.83%	4.71%	59.12%	50.21%	8.91%	0.00%	0.00%	0.00%
10	Winter Peak Resp KW	D10W	100.00%	41,688	56.94%	5.47%	51.47%	45.70%	5.76%	0.00%	0.00%	1.39%
11	Alternative Production Allocator	D10C	100.00%	33,644	66.05%	4.46%	61.58%	51.66%	9.93%	0.00%	0.00%	0.31%
12	Sec. Pri. & TT. Class Coin KW @	D60Sub	100.00%	39,466	59.55%	4.73%	54.80%	45.46%	9.34%	0.00%	0.00%	1.01%
13	Sec & Pti, Cl Coin KW (no Min Sy	D61PS	100.00%	36,181	62.96%	4.16%	58.80%	48.66%	10.15%	0.00%	0.00%	0.85%
14	Pri & Sec Coin KW Served w/ 1 P	D61PS1Ph	100.00%	72,244	27.76%	4.67%	23.09%	18.89%	4.19%	0.00%	0.00%	0.00%
15	D62Sec, w/o Lig & C/I Undergroi	D62NLL	100.00%	79,133	20.87%	3.05%	17.82%	17.82%	0.00%	0.00%	0.00%	0.00%
16	Sec. Class Coin KW (w/o Min Sys	D62Secl	100.00%	51,668	47.70%	4.99%	42.70%	42.70%	0.00%	0.00%	0.00%	0.64%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	36,911	62.43%	4.93%	57.50%	50.64%	6.85%	0.00%	0.00%	0.66%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	Present Rev	R01	100.00%	40,571	58.43%	5.51%	52.92%	47.70%	5.22%	0.00%	0.00%	1.00%
21	Late Fee Revenue Allocator	LateFee	100.00%	87,791	12,20%	3.04%	9.16%	9.13%	0.03%	0.00%	0.00%	0.01%

EXTERNAL DATA		Extern:	1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
			ND	Res	C<ot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	SL Lig
22	Customers - B Basis	C10	93,865	80,944	12,677	8,570	4,107	4,076	31	0	0	243
23	Cust - Ave Monthly (C10-Area L)	C11	96,144	81,342	12,764	8,657	4,107	4,076	31	0	0	2,038
24	Mo Cus Wld By Cus Acct	C11WA	102,860	81,342	21,276	12,985	8,291	8,207	84	0	0	242
25	Cust Acctg Wtg Factor	C11WAF	7.34	1.00	6.22	1.50	4.72	2.01	2.71	0.00	0.00	0.12
26	Cust-Ave Mo (C11 w/ Dir Assign	C12	94,230	81,342	12,764	8,657	4,107	4,076	31	0	0	124
27	Mo Cus Wld By Mfr Invest	C12WM	12,656,917	7,617,987	5,026,114	1,593,062	3,433,051	3,304,939	128,112	0	0	12,816
28	Meier Invest / Cust Factor	C12WMF	5,324	94	5,127	184	4,943	811	4,133	0	0	103
29	Sec & Pti Customers	C61PS	93,865	80,944	12,677	8,570	4,107	4,076	31	0	0	243
30	% Served by Primary Single Phase	C61PS1Ph	0.0%	71,60%	0.0%	40.26%	0.0%	13.93%	14.81%	0.00%	0.00%	44.01%
31	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	61,976	57,954	4,022	3,450	572	568	5	0	0	0
32	C62Sec, w/o Lig & C/I Undergroi	C62NL	86,688	80,944	5,744	3,892	1,851	1,851	0	0	0	0
33	Secondary Customers	C62Sec	93,834	80,944	12,646	8,570	4,076	4,076	0	0	0	243
34	Summer Peak Resp KW	D10S	414	130	284	17	287	221	46	0	0	0
35	Dmd (D10S x Fact + D10W)/100	D10T	10,000,000	3,560,028	6,362,730	470,864	5,911,876	5,020,560	891,317	0	0	57,242
36	Winter Peak Resp KW	D10W	332	138	189	18	171	152	19	0	0	5
37	Alternative Production Allocator	D10C	10,000,000	3,364,298	6,604,749	446,334	6,158,415	5,165,684	982,731	0	0	30,853
38	Sec. Pri. & TT. Class Coin KW @	D60Sub	492,965	194,540	293,455	23,310	270,145	224,118	46,027	0	0	4,970
39	Sec & Pti, Class Coin KW (w/o Mfr	D61PS	453,056	163,938	285,253	18,844	266,409	220,444	45,965	0	0	3,866
40	Pri & Sec Coin KW Served w/ 1 P	D61PS1Ph	162,467	117,374	45,093	7,586	37,507	30,697	6,810	0	0	0
41	D62Sec, w/o Lig & C/I Undergroi	D62NLL	941,532	745,034	186,499	28,754	167,745	167,745	0	0	0	0
42	Sec. Class Coin KW (w/o Min Sys	D62Secl	10,000,000	5,166,364	4,769,801	499,350	4,270,451	4,270,451	0	0	0	63,835
43	Annual Billing KW	D99S	3,286,718	0	3,287	0	3,287	2,990	296	0	0	0
44	Summer Billing KW	D99W	1,137,231	0	1,137	0	1,137	1,032	106	0	0	0
45	Winter Billing KW	D99W	2,149,487	0	2,149	0	2,149	1,959	191	0	0	0
46	Non-Coinc PK Second	DN-Sec	745,034	452,629	292,405	63,307	369,322	369,322	0	0	0	3,866
47	MWh Sales	E99	779,209	1,339,342	1,339,342	102,502	1,236,839	1,066,222	150,618	0	0	17,934
48	Late Fee Revenue Allocation	LateFee	100.00%	87,791	12,20%	3.04%	9.16%	9.13%	0.03%	0.00%	0.00%	0.01%

Test Year Ending December 31, 2021
Primary Distribution Cost Allocator Calculations

Line	Primary Distribution Cost	Allocator Derivation	Allocator Label	ND	Resid	Customer Class			
						Commercial Non Demand	C&I Demand Secondary	C&I Demand Primary	Ltg
1	Customer Portion of Multi-Phase Primary Lines	Number of Customers	C61PS	93,865	80,944	8,570	4,076	31	243
2	Capacity Portion of Multi-Phase Primary Lines	Class Coincident Peak Demands	D61PS	453,056	163,938	18,844	220,444	45,965	3,866
3	% of Customers Served by Primary Single-Phase Lines				71.6%	40.3%	13.9%	14.8%	44.0%
4	Customer Portion of Single-Phase Primary Lines	line 1 x line 3	C61PS1Ph	61,976	57,954	3,450	568	5	0
5	Capacity Portion of Single-Phase Primary Lines	line 2 x line 3	D61PS1Ph	162,467	117,374	7,586	30,697	6,810	0
6	Customer Portion of Multi-Phase Primary Lines	Cost Allocator %	C61PS	100.0%	86.2%	9.1%	4.3%	0.0%	0.3%
7	Capacity Portion of Multi-Phase Primary Lines	Cost Allocator %	D61PS	100.0%	36.2%	4.2%	48.7%	10.1%	0.9%
8	Customer Portion of Single-Phase Primary Lines	Cost Allocator %	C61PS1Ph	100.0%	93.5%	5.6%	0.9%	0.0%	0.0%
9	Capacity Portion of Single-Phase Primary Lines	Cost Allocator %	D61PS1Ph	100.0%	72.2%	4.7%	18.9%	4.2%	0.0%



**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

Function/Sub-Function	Cost Classification	
	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. In this rate case the Company has completed both Minimum System and Zero Intercept studies. This exhibit describes the steps the Company has taken to complete these studies.

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 plant 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 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 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 of nearly 12,000 distribution work orders that were completed over an 11 year period. 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).

The Company acquired the data for both studies from the following sources:

- Distribution Equipment Inventory - This data was obtained by querying all of the data available on conductors, cables, transformers and secondary equipment in the Company’s Geographic Information System (GIS) database. This data was then split into the following specific Property

Units: Overhead (OH) Primary, Underground (UG) Primary, OH Secondary, UG Secondary, OH Transformers and UG Transformers.

These Property Units were then further divided into specific sizes and configurations (i.e. 1/0 AL 3ph under the UG Primary Property Unit). The total length (feet) in the GIS was calculated for each specific configuration of conductors and cables, and the total amount of units in the GIS was calculated for each specific configuration of transformers.

- Minimum Size of Distribution Equipment - The minimum-size conductor, cable, transformer, and secondary service equipment used in the Minimum System Study were selected by the Engineering Organization according to its field experience and its evaluation of the smallest practical-sized equipment inventories held in the Company's inventory. The "smallest practical-sized equipment" presently utilized on the Company's distribution system in Minnesota has been developed and refined over a number of decades as our industry has matured and progressed.
- Per Unit Installed Costs - To acquire the data needed to determine the installed unit costs, the GIS was queried for all Work Orders added to the database for an 11 year period. When new equipment such as a cable or a transformer is added to the GIS, or when existing equipment is changed, the equipment is associated with a specific Work Order number. The Work Order number is an identification number for the specific job that was done to install the equipment. Therefore, when the Work Orders were queried from the GIS, all of the specific equipment installed in those Work Orders was acquired. This provided a large dataset of specific jobs that have been done in the past five years, as well as what was installed in those jobs.

To determine the costs associated with each Work Order, the Work Orders pulled from GIS were queried in the Company's financial management system. This query was able to pull the total cost for each Work Order, and the breakdown of how much was charged to each cost area (regular labor, overtime labor, equipment, stocked materials, etc). This then gave a breakdown of historic jobs, what was installed in those jobs, and how much the jobs cost.

Using the Work Order and cost data, the Work Orders were then filtered down to those in which only one Property Unit and one specific configuration was installed (i.e., a Work Order that only installs 350 feet of 1/0 AL 3ph would be used for the study, but a Work Order that installs both 350 feet of 1/0 AL 3ph and 200 feet of 750 AL 3ph would be filtered out). This was done to ensure accuracy in calculating the installed unit cost for a single specific configuration because we could not parse out the costs for the two different configurations from the entire cost of a Work Order. After filtering, the cost from nearly 12,000 work orders were used to develop the per unit installed costs.

- Load Carrying Capacity of Distribution Equipment Configurations - The load-carrying capability was factored into the analysis using the unique load-carrying capacity value for each specific configuration. For transformers, this value was the nameplate kVA value. For conductors, cables and secondary equipment, this value was the ampacity. The values for ampacity of the various conductors, cables and secondary service equipment were acquired from the Company's Distribution design and construction manuals. For three-phase conductors and cables, this ampacity value was calculated as three times the single-phase value listed in the Company's Distribution Design and Construction manuals.

5. Analysis Results

The data and results of the minimum system and zero intercept studies are shown in Attachments A to P of Schedule 5.

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 4 of the 6 property units the zero intercept method provided a lower customer component, while 2 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

Property Unit	% of Costs Classified as Customer-Related	
	Zero Intercept Method	Minimum System Method
Overhead Primary	34.9%	51.4%
Overhead Secondary	78.3%	89.6%
Overhead Transformers	72.7%	79.5%
Underground Primary	58.1%	53.2%
Underground Secondary	73.8%	100%
Underground Transformers	87.3%	51.5%

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	% Classified as Customer-Related	% Classified as Capacity-Related
Overhead Primary (used Zero Intercept result)	34.9%	63.1%
Overhead Secondary (used Zero Intercept result)	78.2%	21.8%
Underground Primary (used Minimum System result)	53.2%	46.8%
Underground Secondary (used Zero Intercept result)	73.8%	26.2%
Weighted Average for Overhead and Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	63.7%	36.3%

Attachment O of Schedule 11 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 on Page 13 of Michael Peppin'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 2021 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 wasn't 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 40 feet.

In order to 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.

Inventory of Underground Primary by Conductor Configuration

Attachment A

Page 1 of 1

<u>Phase</u>	<u>Configuration Details Underground</u>		<u>% of 1 Phase</u>	<u>Cumulative % of 1</u>	<u>% of All UG</u>	<u>Cumulative % of All</u>	
	<u>Primary</u>	<u>Footage</u>	<u>Footage</u>	<u>Phase Footage</u>	<u>Primary</u>	<u>UG Primary</u>	
1 Phase	1/0 AL 1ph	15,663,066	52.91%	52.91%	30.09%	30.09%	
	2 AL 1ph	13,190,012	44.56%	97.47%	25.34%	55.43%	
	1/0 Unknown 1ph	250,307	0.85%	98.31%	0.48%	55.92%	
	1 AL 1ph	238,717	0.81%	99.12%	0.46%	56.37%	
	Unknown AL 1ph	78,819	0.27%	99.38%	0.15%	56.53%	
	Unknown Unknown 1ph	50,350	0.17%	99.55%	0.10%	56.62%	
	0 0 1ph	43,038	0.15%	99.70%	0.08%	56.70%	
	2 Unknown 1ph	34,982	0.12%	99.82%	0.07%	56.77%	
	1/0 CU 1ph	16,400	0.06%	99.87%	0.03%	56.80%	
	2/0 AL 1ph	9,574	0.03%	99.91%	0.02%	56.82%	
	2 CU 1ph	8,547	0.03%	99.93%	0.02%	56.84%	
	Unknown CU 1ph	4,504	0.02%	99.95%	0.01%	56.85%	
	4/0 AL 1ph	4,020	0.01%	99.96%	0.01%	56.85%	
	Footage of 16 Remaining 1 Phase Underground Primary Conductor Configurations		11,050	0.04%	100.00%	0.02%	56.88%
	Total 1 Phase	29,603,387	100.00%		56.88%		

<u>Phase</u>	<u>Config Details Underground</u>		<u>% of 3 Phase</u>	<u>Cumulative % of 3</u>	<u>% of All UG</u>	<u>Cumulative % of All</u>
	<u>Primary</u>	<u>Footage</u>	<u>Footage</u>	<u>Phase Footage</u>	<u>Primary</u>	<u>UG Primary</u>
3 Phase	1/0 AL 3ph	12,837,974	57.20%	57.20%	24.67%	81.54%
	750 AL 3ph	4,426,067	19.72%	76.92%	8.50%	90.04%
	2 AL 3ph	1,161,402	5.17%	82.09%	2.23%	92.28%
	600 CU 3ph	862,737	3.84%	85.93%	1.66%	93.93%
	500 CU 3ph	543,913	2.42%	88.36%	1.05%	94.98%
	1000 AL 3ph	542,869	2.42%	90.78%	1.04%	96.02%
	500 AL 3ph	474,292	2.11%	92.89%	0.91%	96.93%
	1/0 Unknown 3ph	353,252	1.57%	94.46%	0.68%	97.61%
	750 CU 3ph	291,013	1.30%	95.76%	0.56%	98.17%
	Unknown Unknown 3ph	167,672	0.75%	96.51%	0.32%	98.49%
	500 Unknown 3ph	137,705	0.61%	97.12%	0.26%	98.76%
	1 AL 3ph	119,022	0.53%	97.65%	0.23%	98.99%
	350 CU 3ph	99,870	0.44%	98.09%	0.19%	99.18%
	4/0 CU 3ph	96,745	0.43%	98.53%	0.19%	99.36%
	1/0 CU 3ph	87,647	0.39%	98.92%	0.17%	99.53%
	0 0 3ph	54,888	0.24%	99.16%	0.11%	99.64%
	400 CU 3ph	46,278	0.21%	99.37%	0.09%	99.73%
	750 Unknown 3ph	27,563	0.12%	99.49%	0.05%	99.78%
	Unknown AL 3ph	23,418	0.10%	99.59%	0.04%	99.82%
	2 Unknown 3ph	23,162	0.10%	99.70%	0.04%	99.87%
	4/0 Unknown 3ph	20,396	0.09%	99.79%	0.04%	99.91%
	600 Unknown 3ph	13,656	0.06%	99.85%	0.03%	99.93%
Footage of 17 Remaining 3 Phase Underground Primary Conductor Configurations		34,023	0.15%	100.00%	0.07%	100.00%
Total 3 Phase	22,445,564	100.00%		43.12%		
Total 1 and 3 Phase	52,048,950			100.00%		

Inventory of Underground Secondary by Conductor Configuration

Attachment B

Page 1 of 1

<u>Configuration Details</u> <u>Underground Secondary</u>	<u>Total Footage</u>	<u>% of UG Secondary</u>	<u>Cumulative % UG</u> <u>Secondary</u>
6 AL Duplex	5,314,262	44.34%	44.34%
4/0 AL Triplex	3,261,342	27.21%	71.56%
2/0 AL Triplex	900,641	7.52%	79.07%
1/0 AL Triplex	566,227	4.72%	83.80%
350 AL Triplex	382,109	3.19%	86.98%
6 CU Open Wire	350,384	2.92%	89.91%
6 AL Triplex	151,586	1.26%	91.17%
6 CU Triplex	125,589	1.05%	92.22%
8 CU Triplex	123,334	1.03%	93.25%
2 AL Triplex	94,397	0.79%	94.04%
8 CU Open Wire	82,331	0.69%	94.72%
Unknown Unknown Unknown	72,070	0.60%	95.33%
4 CU Open Wire	53,879	0.45%	95.78%
4 CU Triplex	45,804	0.38%	96.16%
8 AL Triplex	27,276	0.23%	96.38%
0 0 Unknown	23,232	0.19%	96.58%
2 Unknown Triplex	19,835	0.17%	96.74%
8 CU Duplex	19,746	0.16%	96.91%
2 Unknown Open Wire	17,030	0.14%	97.05%
2 Unknown Duplex	16,627	0.14%	97.19%
4 CU Duplex	16,573	0.14%	97.33%
4 CU N/A	16,440	0.14%	97.47%
2 AL Duplex	15,606	0.13%	97.60%
4/0 AL Duplex	15,086	0.13%	97.72%
6 AL Open Wire	14,818	0.12%	97.84%
0 0 Duplex	13,775	0.11%	97.96%
6 CU Duplex	11,974	0.10%	98.06%
0 0 Triplex	11,835	0.10%	98.16%
4/0 AL Quadraplex	11,605	0.10%	98.26%
6 CU Unknown	11,569	0.10%	98.35%
Unknown Unknown Duplex	10,588	0.09%	98.44%
6 CU Quadraplex	10,421	0.09%	98.53%
6 CU N/A	10,355	0.09%	98.61%
8 AL Duplex	9,036	0.08%	98.69%
4 AL Triplex	8,333	0.07%	98.76%
1/0 AL Duplex	8,012	0.07%	98.83%
6 Unknown Duplex	7,438	0.06%	98.89%
8 CU N/A	7,423	0.06%	98.95%
4/0 AL Unknown	7,278	0.06%	99.01%
350 AL Duplex	6,918	0.06%	99.07%
Footage of 114 Remaining Underground Secondary Conductor Configurations	111,706	0.93%	100.00%
	11,984,490	100.00%	

Inventory of Underground Transformers by Transformer Configuration

<u>Configuration Details 1 Phase Underground Transformers</u>	<u>Number of Transformers</u>	<u>1 Phase %</u>	<u>Cumulative Percent of 1 Phase Transformers</u>	<u>% of All Underground Transformers</u>	<u>Cumulative Percent of All Transformers</u>
1 Phase Wye 50 kVA	1 Phase	24,744	42.39%	30.42%	30.42%
1 Phase Wye 25 kVA	1 Phase	18,632	31.92%	22.91%	53.33%
1 Phase Wye 37.5 kVA	1 Phase	9,273	15.89%	11.40%	64.73%
1 Phase Wye 15 kVA	1 Phase	2,480	4.25%	3.05%	67.78%
1 Phase Wye 75 kVA	1 Phase	1,299	2.23%	1.60%	69.37%
1 Phase Wye 100 kVA	1 Phase	1,198	2.05%	1.47%	70.85%
1 Phase Wye 10 kVA	1 Phase	322	0.55%	0.40%	71.24%
1 Phase Wye 167 kVA	1 Phase	206	0.35%	0.25%	71.50%
1 Phase Wye 0 kVA	1 Phase	134	0.23%	0.16%	71.66%
1 Phase Delta 50 kVA	1 Phase	32	0.05%	0.04%	71.70%
1 Phase Wye 250 kVA	1 Phase	16	0.03%	0.02%	71.72%
Number of Transformers for 18 Remaining Single Phase Transformer Configurations		35	0.06%	0.04%	
Total 1 Phase Transformers		58,371	100.00%	71.76%	
<u>Configuration Details 2 Phase Underground Transformers</u>	<u>Number of Transformers</u>	<u>2 Phase %</u>	<u>Cumulative Percent of 2 Phase Transformers</u>	<u>% of All UG Transformers</u>	<u>Cumulative Percent of All Transformers</u>
2 Phase Wye/Delta 75 kVA	2 Phase	294	31.85%	0.36%	72.12%
2 Phase Wye/Delta 125 kVA	2 Phase	175	18.96%	0.22%	72.34%
2 Phase Wye/Delta 204.5 kVA	2 Phase	116	12.57%	0.14%	72.48%
2 Phase Wye/Delta 50 kVA	2 Phase	61	6.61%	0.07%	72.56%
2 Phase Wye/Delta 300 kVA	2 Phase	59	6.39%	0.07%	72.63%
2 Phase Wye/Delta 100 kVA	2 Phase	35	3.79%	0.04%	72.67%
2 Phase Wye/Delta 62.5 kVA	2 Phase	32	3.47%	0.04%	72.71%
2 Phase Wye/Delta 150 kVA	2 Phase	23	2.49%	0.03%	72.74%
2 Phase Wye/Delta 30 kVA	2 Phase	23	2.49%	0.03%	72.77%
2 Phase Wye/Delta 87.5 kVA	2 Phase	14	1.52%	0.02%	72.79%
Number of Transformers for 26 Remaining 2 Phase Transformer Configurations		91	9.86%	0.11%	72.90%
Total 2 Phase Transformers		923	100.00%	1.13%	
<u>Configuration Details 3 Phase Underground Transformers</u>	<u>Number of Transformers</u>	<u>3 Phase %</u>	<u>Cumulative Percent of 3 Phase Transformers</u>	<u>% of All UG Transformers</u>	<u>Cumulative Percent of All Transformers</u>
3 Phase Wye/Wye 150 kVA	3 Phase	3,569	16.19%	4.39%	77.29%
3 Phase Wye/Wye 300 kVA	3 Phase	3,453	15.66%	4.25%	81.53%
3 Phase Wye/Wye 75 kVA	3 Phase	3,365	15.26%	4.14%	85.67%
3 Phase Wye/Wye 500 kVA	3 Phase	2,889	13.11%	3.55%	89.22%
3 Phase Wye/Wye 112 kVA	3 Phase	2,094	9.50%	2.57%	91.79%
3 Phase Wye/Wye 225 kVA	3 Phase	1,874	8.50%	2.30%	94.10%
3 Phase Wye/Wye 750 kVA	3 Phase	1,506	6.83%	1.85%	95.95%
3 Phase Wye/Wye 1000 kVA	3 Phase	974	4.42%	1.20%	97.15%
3 Phase Wye/Wye 1500 kVA	3 Phase	856	3.88%	1.05%	98.20%
3 Phase Wye/Wye 45 kVA	3 Phase	536	2.43%	0.66%	98.86%
3 Phase Wye/Wye 2000 kVA	3 Phase	443	2.01%	0.54%	99.40%
3 Phase Wye/Wye 2500 kVA	3 Phase	113	0.51%	0.14%	99.54%
3 Phase Wye/Wye 0 kVA	3 Phase	64	0.29%	0.08%	99.62%
3 Phase Wye/Delta 300 kVA	3 Phase	27	0.12%	0.03%	99.65%
3 Phase Wye/Delta 500 kVA	3 Phase	23	0.10%	0.03%	99.68%
Number of Transformers for 65 Remaining 3 Phase Transformer Configurations		259	1.17%	0.32%	100.11%
Total 3 Phase Transformers		22,045	100.00%	27.10%	
Total All Underground Transformers		81,339		100.00%	

Inventory of Overhead Primary by Conductor Configuration

Attachment D

Page 1 of 1

Phase	Configuration Details Overhead Primary	Footage	Cumulative %		% of All OH Primary	Cumulative % of All OH Primary
			% of 1 Phase Footage	of 1 Phase Footage		
1 Phase	4 ACSR 1ph	10,859,454	26.74%	26.74%	15.47%	15.47%
	2 ACSR 1ph	9,678,158	23.83%	50.56%	13.79%	29.25%
	6A CUWD 1ph	8,014,369	19.73%	70.29%	11.42%	40.67%
	6 CU 1ph	6,987,194	17.20%	87.50%	9.95%	50.62%
	3/10 CU 1ph	1,648,191	4.06%	91.55%	2.35%	52.97%
	Unknown Unknown 1ph	811,788	2.00%	93.55%	1.16%	54.13%
	4 CU 1ph	760,417	1.87%	95.43%	1.08%	55.21%
	2/0 ACSR 1ph	235,097	0.58%	96.00%	0.33%	55.55%
	3/8 CU 1ph	218,309	0.54%	96.54%	0.31%	55.86%
	8A CUWD 1ph	172,486	0.42%	96.97%	0.25%	56.10%
	2 CU 1ph	145,310	0.36%	97.32%	0.21%	56.31%
	1/0 ACSR 1ph	138,229	0.34%	97.66%	0.20%	56.51%
	Unknown CU 1ph	133,578	0.33%	97.99%	0.19%	56.70%
	130 Steel 1ph	90,440	0.22%	98.22%	0.13%	56.82%
	4A CUWD 1ph	75,089	0.18%	98.40%	0.11%	56.93%
	1/0 CU 1ph	68,617	0.17%	98.57%	0.10%	57.03%
	336 AL 1ph	55,401	0.14%	98.71%	0.08%	57.11%
	6A CU 1ph	50,587	0.12%	98.83%	0.07%	57.18%
	8 CU 1ph	48,324	0.12%	98.95%	0.07%	57.25%
	336 ACSR 1ph	42,901	0.11%	99.06%	0.06%	57.31%
	Footage of 66 Remaining Single Phase Overhead Primary Conductor Configurations	383,745	0.94%	100.00%	0.55%	57.86%
	Total 1 Phase	40,617,685	100.00%		57.86%	

Phase	Config Details OH Primary	Footage	Cumulative %		% of All OH Primary	Cumulative % of All OH Primary
			% of 3 Phase Footage	% of 3 Phase Footage		
3 Phase	336 AL 3ph	7,078,360	23.92%	23.92%	10.08%	67.94%
	2 ACSR 3ph	5,887,683	19.90%	43.83%	8.39%	76.33%
	336 ACSR 3ph	3,804,835	12.86%	56.69%	5.42%	81.75%
	2/0 ACSR 3ph	2,437,313	8.24%	64.92%	3.47%	85.22%
	4 ACSR 3ph	1,906,163	6.44%	71.37%	2.72%	87.93%
	6 CU 3ph	1,333,107	4.51%	75.87%	1.90%	89.83%
	1/0 ACSR 3ph	845,598	2.86%	78.73%	1.20%	91.04%
	4/0 CU 3ph	831,557	2.81%	81.54%	1.18%	92.22%
	6A CUWD 3ph	806,062	2.72%	84.27%	1.15%	93.37%
	Unknown Unknown 3ph	504,695	1.71%	85.97%	0.72%	94.09%
	4/0 ACSR 3ph	476,335	1.61%	87.58%	0.68%	94.77%
	556 AL 3ph	456,240	1.54%	89.12%	0.65%	95.42%
	4 CU 3ph	409,354	1.38%	90.51%	0.58%	96.00%
	3/8 CU 3ph	350,840	1.19%	91.69%	0.50%	96.50%
	556 ACSR 3ph	313,772	1.06%	92.75%	0.45%	96.95%
	3/10 CU 3ph	303,618	1.03%	93.78%	0.43%	97.38%
	1/0 CU 3ph	229,219	0.77%	94.55%	0.33%	97.71%
	336 AAC 3ph	219,522	0.74%	95.30%	0.31%	98.02%
	3/6 CU 3ph	206,220	0.70%	95.99%	0.29%	98.31%
	2 CU 3ph	157,043	0.53%	96.52%	0.22%	98.54%
2/0 CU 3ph	154,819	0.52%	97.05%	0.22%	98.76%	
336 CU 3ph	123,373	0.42%	97.46%	0.18%	98.93%	
556 AAC 3ph	120,854	0.41%	97.87%	0.17%	99.10%	
2/0 AL 3ph	84,143	0.28%	98.16%	0.12%	99.22%	
	Footage of 68 Remaining 3 Phase Overhead Primary Conductor Configurations	545,045	1.84%	100.00%	0.78%	100.00%
	Total 3 Phase	29,585,771	100.00%		42.14%	
	Total All OH Primary	70,203,456				

Inventory of Overhead Secondary by Conductor Configuration

<u>Configuration Details Overhead Secondary</u>	<u>Total Footage</u>	<u>% of Total Overhead Secondary</u>	<u>Cumulative % Overhead Secondary</u>
2 ACSR Open Wire	18,398,559	23.46%	23.46%
4 ACSR Open Wire	8,445,823	10.77%	34.23%
1/0 ACSR Open Wire	6,875,855	8.77%	43.00%
6A CUWD Open Wire	6,495,877	8.28%	51.28%
6 CU Open Wire	5,944,768	7.58%	58.86%
4 CU Open Wire	5,809,064	7.41%	66.27%
2 CU Open Wire	5,372,600	6.85%	73.12%
1/0 AL Triplex	2,716,408	3.46%	76.58%
1/0 AL Triplex, Lashed	2,703,151	3.45%	80.03%
6 ACSR Duplex	2,501,466	3.19%	83.22%
3/10 CU Open Wire	1,417,755	1.81%	85.03%
1/0 CU Open Wire	1,026,461	1.31%	86.34%
2 AL Triplex	968,987	1.24%	87.57%
Unknown CU Open Wire	882,598	1.13%	88.70%
2/0 ACSR Open Wire	836,644	1.07%	89.76%
2 ACSR N/A	835,222	1.07%	90.83%
6 AL Duplex	748,802	0.95%	91.78%
3/8 CU Open Wire	538,822	0.69%	92.47%
1/0 AL Open Wire	447,898	0.57%	93.04%
2 ACSR Neutral	427,705	0.55%	93.59%
2/0 ACSR Neutral	401,964	0.51%	94.10%
2 AL Open Wire	286,818	0.37%	94.47%
6 AL Triplex	258,183	0.33%	94.79%
Unknown Unknown Unknown	229,020	0.29%	95.09%
3/6 CU Open Wire	199,882	0.25%	95.34%
6 CUWD Open Wire	166,286	0.21%	95.55%
8A CUWD Open Wire	162,708	0.21%	95.76%
2 ACSR Triplex	155,722	0.20%	95.96%
1/0 ACSR Quadruplex	130,745	0.17%	96.13%
4A CUWD Open Wire	127,475	0.16%	96.29%
2/0 CU Open Wire	124,658	0.16%	96.45%
1/0 ACSR Triplex, Lashed	122,346	0.16%	96.60%
2 ACSR Triplex, Lashed	121,566	0.16%	96.76%
4/0 CU Open Wire	107,564	0.14%	96.90%
336 ACSR Open Wire	89,242	0.11%	97.01%
4 AL Open Wire	86,774	0.11%	97.12%
4 ACSR Triplex	76,402	0.10%	97.22%
4/0 AL Triplex	75,490	0.10%	97.31%
Unknown Steel Martin Open Wire	74,760	0.10%	97.41%
8 CU Open Wire	73,538	0.09%	97.50%
Footage of 333 Remaining Overhead Secondary Conductor Configurations	1,958,037	2.50%	
Total OH Secondary	78,423,646	100.00%	

Inventory of Overhead Transformers by Transformer Configuration

Attachment F

Page 1 of 1

<u>Config Details 1 Phase Overhead Transformers</u>	<u>Number of Transformers</u>	<u>1 Phase %</u>	<u>1 Phase Cumulative %</u>	<u>% of All Overhead Transformers</u>	<u>Cumulative Percent of All OH Transformers</u>
1 Phase Wye 25 kVA	32,366	32.45%	32.45%	28.84%	28.84%
1 Phase Wye 10 kVA	19,792	19.85%	52.30%	17.64%	46.48%
1 Phase Wye 37.5 kVA	16,543	16.59%	68.89%	14.74%	61.22%
1 Phase Wye 15 kVA	16,343	16.39%	85.28%	14.56%	75.79%
1 Phase Wye 50 kVA	12,139	12.17%	97.45%	10.82%	86.60%
1 Phase Wye 75 kVA	819	0.82%	98.27%	0.73%	87.33%
1 Phase Wye 100 kVA	550	0.55%	98.82%	0.49%	87.82%
1 Phase Wye 5 kVA	452	0.45%	99.27%	0.40%	88.23%
1 Phase Wye 0 kVA	159	0.16%	99.43%	0.14%	88.37%
1 Phase Wye 3 kVA	126	0.13%	99.56%	0.11%	88.48%
1 Phase Delta Unknown kVA	71	0.07%	99.63%	0.06%	88.54%
1 Phase Wye 167 kVA	60	0.06%	99.69%	0.05%	88.60%

Number of Transformers for 28 Remaining 1 Phase Transformer Configurations

	308	0.31%	100.00%	0.27%	88.87%
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Total 1 Phase Transformers 99,728 100.00%

<u>Config Details 2 Phase Overhead Transformers</u>	<u>Number of Transformers</u>	<u>2 Phase %</u>	<u>2 Phase Cumulative %</u>	<u>% of All Overhead Transformers</u>	<u>Cumulative Percent of All OH Transformers</u>
2 Phase Wye/Delta 75 kVA	651	12.29%	12.29%	0.58%	89.45%
2 Phase Wye/Delta 40 kVA	447	8.44%	20.74%	0.40%	89.85%
2 Phase Wye/Delta 35 kVA	419	7.91%	28.65%	0.37%	90.22%
2 Phase Wye/Delta 20 kVA	315	5.95%	34.60%	0.28%	90.50%
2 Phase Wye/Delta 62.5 kVA	314	5.93%	40.53%	0.28%	90.78%
2 Phase Wye/Delta 52.5 kVA	298	5.63%	46.16%	0.27%	91.05%
2 Phase Wye/Delta 100 kVA	294	5.55%	51.71%	0.26%	91.31%
2 Phase Wye/Delta 65 kVA	282	5.33%	57.03%	0.25%	91.56%

Number of Transformers for 48 Remaining 2 Phase Transformer Configurations

	2,275	42.97%	100.00%	2.03%	93.59%
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Total 2 Phase Transformers 5,295 100.00%

<u>Config Details 3 Phase OH Transformers</u>	<u>Number of Transformers</u>	<u>3 Phase %</u>	<u>3 Phase Cumulative %</u>	<u>% of All OH Transformers</u>	<u>Cumulative Percent of All OH Transformers</u>
3 Phase Wye/Wye 75 kVA	1,178	16.38%	16.38%	1.05%	94.64%
3 Phase Wye/Wye 150 kVA	919	12.78%	29.16%	0.82%	95.46%
3 Phase Wye/Wye 45 kVA	696	9.68%	38.83%	0.62%	96.08%
3 Phase Wye/Wye 112 kVA	627	8.72%	47.55%	0.56%	96.64%
3 Phase Wye/Wye 300 kVA	448	6.23%	53.78%	0.40%	97.04%
3 Phase Wye/Wye 225 kVA	319	4.44%	58.22%	0.28%	97.32%
3 Phase Wye/Delta 150 kVA	207	2.88%	61.10%	0.18%	97.51%
3 Phase Wye/Wye 30 kVA	207	2.88%	63.97%	0.18%	97.69%
3 Phase Wye/Wye 500 kVA	172	2.39%	66.37%	0.15%	97.84%
3 Phase Wye/Delta 175 kVA	153	2.13%	68.49%	0.14%	97.98%
3 Phase Wye/Delta 125 kVA	138	1.92%	70.41%	0.12%	98.10%
3 Phase Wye/Delta 75 kVA	132	1.84%	72.25%	0.12%	98.22%
3 Phase Wye/Delta 112 kVA	111	1.54%	73.79%	0.10%	98.32%
3 Phase Wye/Delta 100 kVA	100	1.39%	75.18%	0.09%	98.41%
3 Phase Wye/Delta 250 kVA	89	1.24%	76.42%	0.08%	98.49%

Number of Transformers for 110 Remaining 3 Phase Transformer Configurations

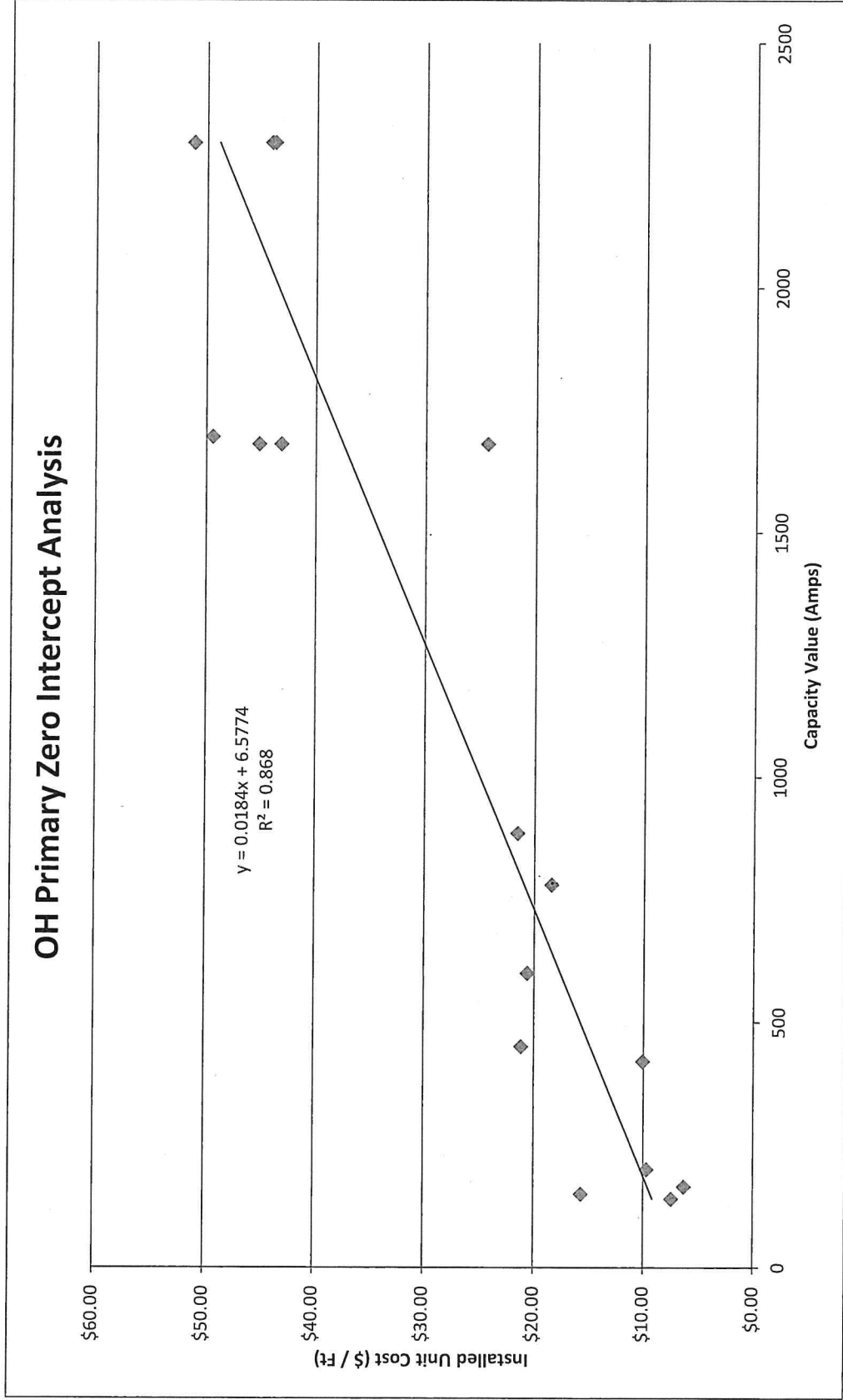
	1,696	23.58%	100.00%	1.51%	100.00%
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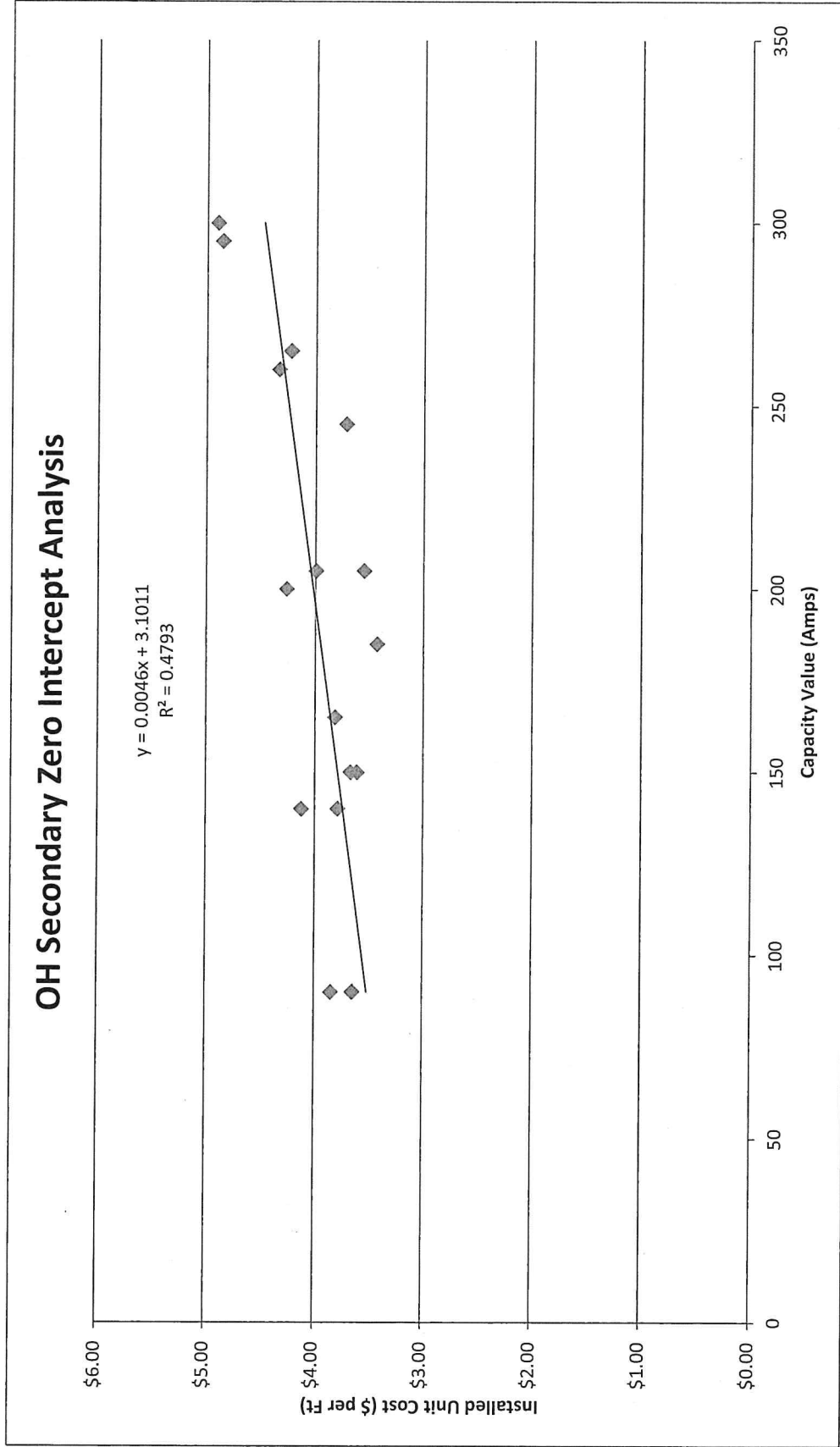
Total 3 Phase Transformers 7,192 100.00% 6.41%

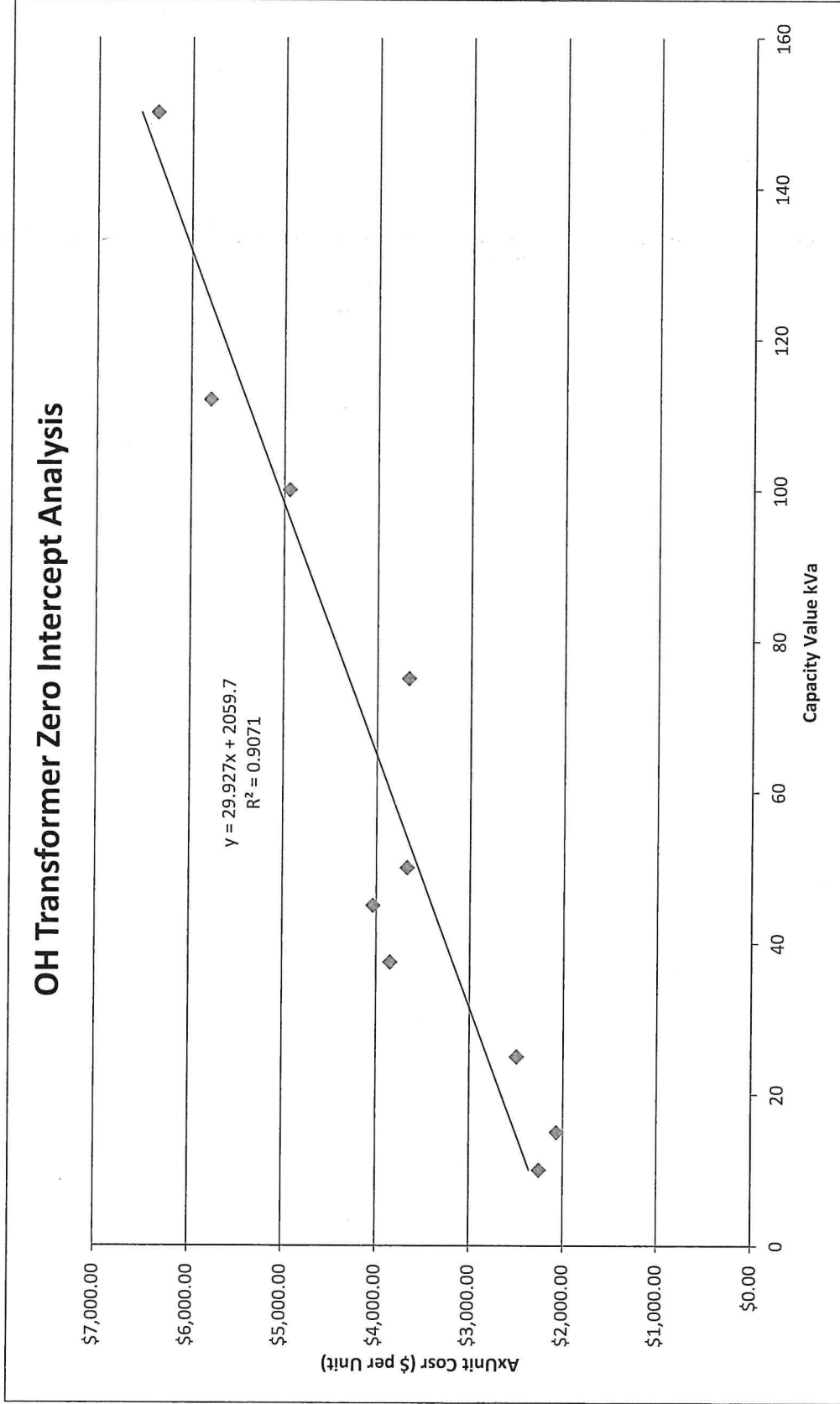
Total OH Transformers 112,215 100.00%

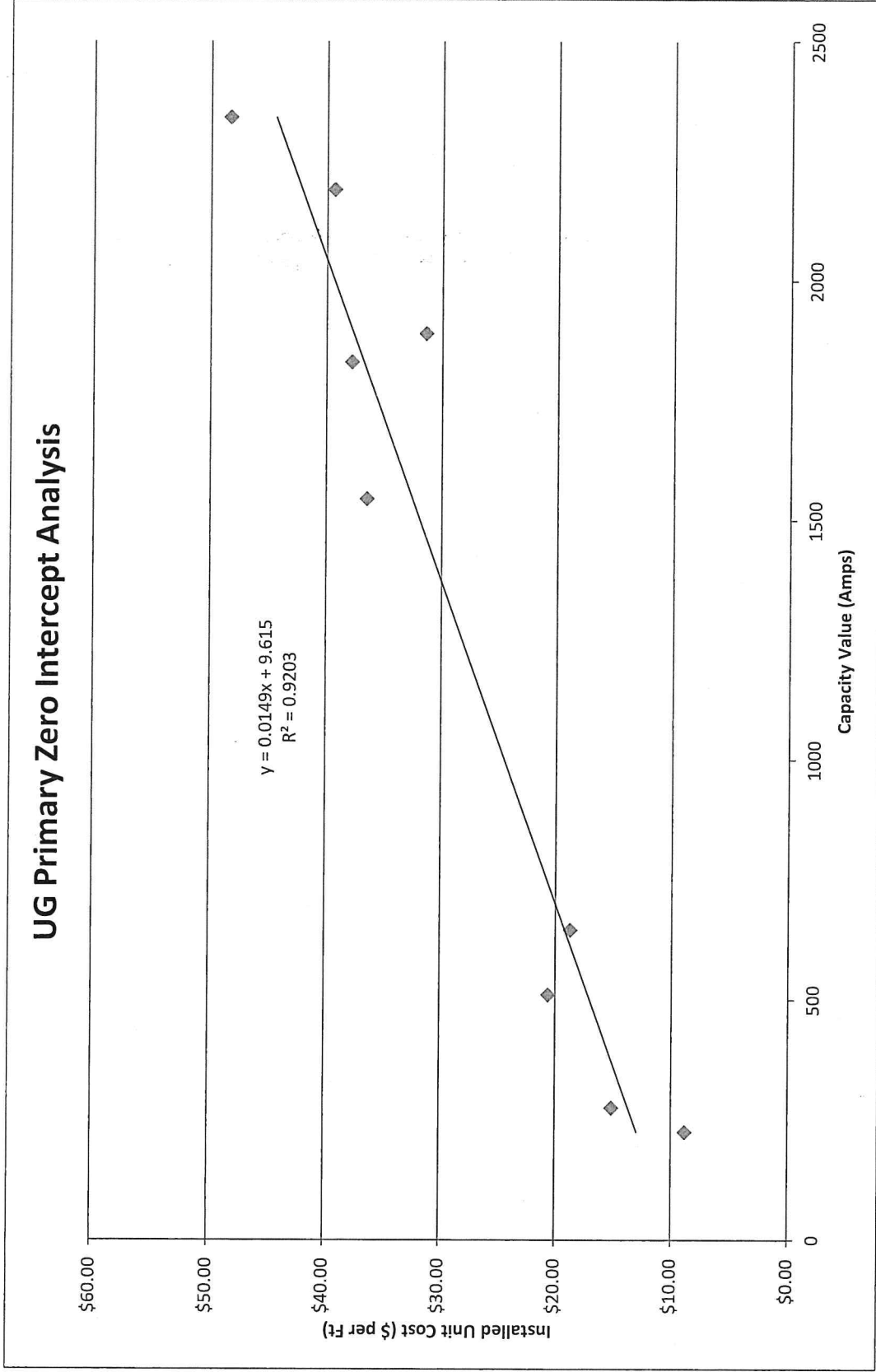
Inventory of Primary Voltage Step-Down Transformers by Transformer Configuration

	<u>Number OH 1</u>		<u>% of OH 1</u>		<u>Cumulative % of OH 1 Phase</u>	<u>% of All OH Step-Down Transformers</u>	<u>Load Carrying Capacity (kVA)</u>	<u>Installed Unit Cost</u>	<u>Total Replacement Costs</u>
	<u>Phase</u>	<u>Phase</u>	<u>Phase</u>	<u>Phase</u>					
Overhead 1 Phase									
OH 1 phase 34.5/13.8 kV 500 kVA		170	17.14%	17.14%	17.14%	12.36%	500	\$44,094	\$7,495,948
OH 1 phase 34.5/12.47 kV 500 kVA		98	9.88%	27.02%	27.02%	7.13%	500	\$44,095	\$4,321,333
OH 1 phase 34.5/12.47 kV 50 kVA		81	8.17%	35.18%	35.18%	5.89%	50	\$10,067	\$815,400
OH 1 phase 19.92/7.2 kV 167 kVA		66	6.65%	41.83%	41.83%	4.80%	167	\$22,743	\$1,501,029
OH 1 phase 19.92/7.97 kV 50 kVA		53	5.34%	47.18%	47.18%	3.85%	50	\$10,067	\$533,533
OH 1 phase 34.5/13.8 kV 250 kVA		62	6.25%	53.43%	53.43%	4.51%	250	\$31,030	\$1,923,866
OH 1 phase 19.92/7.2 kV 100 kVA		46	4.64%	58.06%	58.06%	3.35%	100	\$20,005	\$920,219
OH 1 phase 34.5/12.47 kV 333 kVA		57	5.75%	63.81%	63.81%	4.15%	333	\$37,814	\$2,155,414
OH 1 phase 34.5/12.47 kV 250 kVA		46	4.64%	68.45%	68.45%	3.35%	250	\$31,029	\$1,427,314
OH 1 phase 34.5/13.8 kV 333 kVA		46	4.64%	73.08%	73.08%	3.35%	333	\$37,814	\$1,739,457
Number of Transformers and Cost of Transformers for 49 Remaining 1 Phase OH Transformer Configurations		267	26.92%			18.15%		\$55,293.65	\$14,763,405
Total OH 1 Phase		992	100.00%			72.15%		\$37,900.12	\$37,596,919
	<u>Number OH 2</u>		<u>% of OH 2</u>		<u>Cumulative % of OH 2 Phase</u>	<u>% of All OH Step-Down Transformers</u>	<u>Load Carrying Capacity (kVA)</u>	<u>Installed Unit Cost</u>	<u>Total Replacement Costs</u>
	<u>Phase</u>	<u>Phase</u>	<u>Phase</u>	<u>Phase</u>					
Overhead 2 Phase									
OH 2 phase 34.5/13.8 kV 1000 kVA		7	12.28%	12.28%	12.28%	0.51%	1000	\$66,139	\$462,975
OH 2 phase 13.8/4.16 kV 500 kVA		4	7.02%	19.30%	19.30%	0.29%	500	\$28,550	\$114,200
OH 2 phase 34.5/12.47 kV 1000 kVA		4	7.02%	26.32%	26.32%	0.29%	1000	\$66,139	\$264,557
OH 2 phase 34.5/12.47 kV 500 kVA		4	7.02%	33.33%	33.33%	0.29%	500	\$46,543	\$186,171
OH 2 phase 34.5/13.8 kV 200 kVA		4	7.02%	40.35%	40.35%	0.29%	200	\$24,850	\$99,400
Number of Transformers and Cost of Transformers for 22 Remaining 2 Phase OH Transformer Configurations		34	59.65%			2.47%		\$34,935	\$1,187,796
Total OH 2 Phase		57	100.00%			4.15%		\$40,616	\$2,315,100
	<u>Number OH 3</u>		<u>% of OH 3</u>		<u>Cumulative % of OH 3 Phase</u>	<u>% of All OH Step-Down Transformers</u>	<u>Load Carrying Capacity (kVA)</u>	<u>Installed Unit Cost</u>	<u>Total Replacement Costs</u>
	<u>Phase</u>	<u>Phase</u>	<u>Phase</u>	<u>Phase</u>					
Overhead 3 Phase									
OH 3 phase 34.5/13.8 kV 1500 kVA		29	8.90%	8.90%	8.90%	2.11%	1500	\$81,703	\$2,369,385
OH 3 phase 13.8/4.16 kV 1000 kVA		25	7.67%	16.56%	16.56%	1.82%	1000	\$56,982	\$1,424,559
OH 3 phase 34.5/12.47 kV 1500 kVA		18	5.52%	22.09%	22.09%	1.31%	1500	\$81,706	\$1,470,706
OH 3 phase 13.8/4.16 kV 500 kVA		14	4.29%	26.38%	26.38%	1.02%	500	\$33,865	\$474,106
OH 3 phase 34.5/12.47 kV 1000 kVA		12	3.68%	30.06%	30.06%	0.87%	1000	\$70,068	\$840,812
OH 3 phase 34.5/13.8 kV 500 kVA		11	3.37%	33.44%	33.44%	0.80%	500	\$42,141	\$463,553
OH 3 phase 13.8/12.47 kV 1500 kVA		10	3.07%	36.50%	36.50%	0.73%	1500	\$93,865	\$938,647
OH 3 phase 13.8/12.47 kV 5000 kVA		10	3.07%	39.57%	39.57%	0.73%	5000	\$305,750	\$3,057,500
OH 3 phase 13.8/4.16 kV 1500 kVA		10	3.07%	42.64%	42.64%	0.73%	1500	\$66,715	\$667,147
Number of Transformers and Cost of Transformers for 60 Remaining 3 Phase OH Transformer Configurations		187	57.36%			13.60%		\$55,413	\$10,362,271
Total OH 3 Phase		326	100.00%			23.71%		\$67,695	\$22,068,685
Total OH Step-Down Transformers		1,375						\$45,077	\$61,980,704
	<u>Number UG 1</u>		<u>% of UG 1</u>		<u>Cumulative % of UG 1 Phase</u>	<u>% of All UG Step-Down Transformers</u>	<u>Load Carrying Capacity (kVA)</u>	<u>Installed Unit Cost</u>	<u>Total Replacement Costs</u>
	<u>Phase</u>	<u>Phase</u>	<u>Phase</u>	<u>Phase</u>					
Underground 1 Phase									
UG 1 phase 19.92/7.2 kV 167 kVA		2	15.38%	15.38%	15.38%	2.08%	167	\$7,967	\$15,933
UG 1 phase 19.92/7.97 kV 250 kVA		2	15.38%	30.77%	30.77%	2.08%	250	\$11,106	\$22,211
UG 1 phase 19.92/7.97 kV 500 kVA		2	15.38%	46.15%	46.15%	2.08%	500	\$22,211	\$44,422
Number of Transformers and Cost of Transformers for 7 Remaining 1 Phase UG Transformer Configurations		7	53.85%			7.29%		\$12,338	\$86,369
Total UG 1 Phase		13	100.00%			13.54%		\$12,995	\$168,936
	<u>Number UG 3</u>		<u>% of UG 3</u>		<u>Cumulative % of UG 3 Phase</u>	<u>% of All UG Step-Down Transformers</u>	<u>Load Carrying Capacity (kVA)</u>	<u>Installed Unit Cost</u>	<u>Total Replacement Costs</u>
	<u>Phase</u>	<u>Phase</u>	<u>Phase</u>	<u>Phase</u>					
Underground 3 Phase									
UG 3 phase 34.5/13.8 kV 5000 kVA		31	37.35%	37.35%	37.35%	32.29%	5000	\$194,366	\$6,025,331
UG 3 phase 34.5/13.8 kV 3750 kVA		16	19.28%	56.63%	56.63%	16.67%	3750	\$381,179	\$6,098,869
UG 3 phase 34.5/12.47 kV 5000 kVA		11	13.25%	69.88%	69.88%	11.46%	5000	\$194,366	\$2,138,021
UG 3 phase 34.5/4.16 kV 11250 kVA		4	4.82%	74.70%	74.70%	4.17%	11250	\$1,143,538	\$4,574,152
Number of Transformers and Cost of Transformers for 16 Remaining 3 Phase UG Transformer Configurations		21	25.30%			21.88%		\$220,386	\$4,628,103
Total UG 3 Phase		83	100.00%			86.46%		\$282,705	\$23,464,476
Total UG Step-Down Transformers		96							\$23,633,412
All OH & UG Primary Step-Down Tran		1,471						\$58,201	\$85,614,116

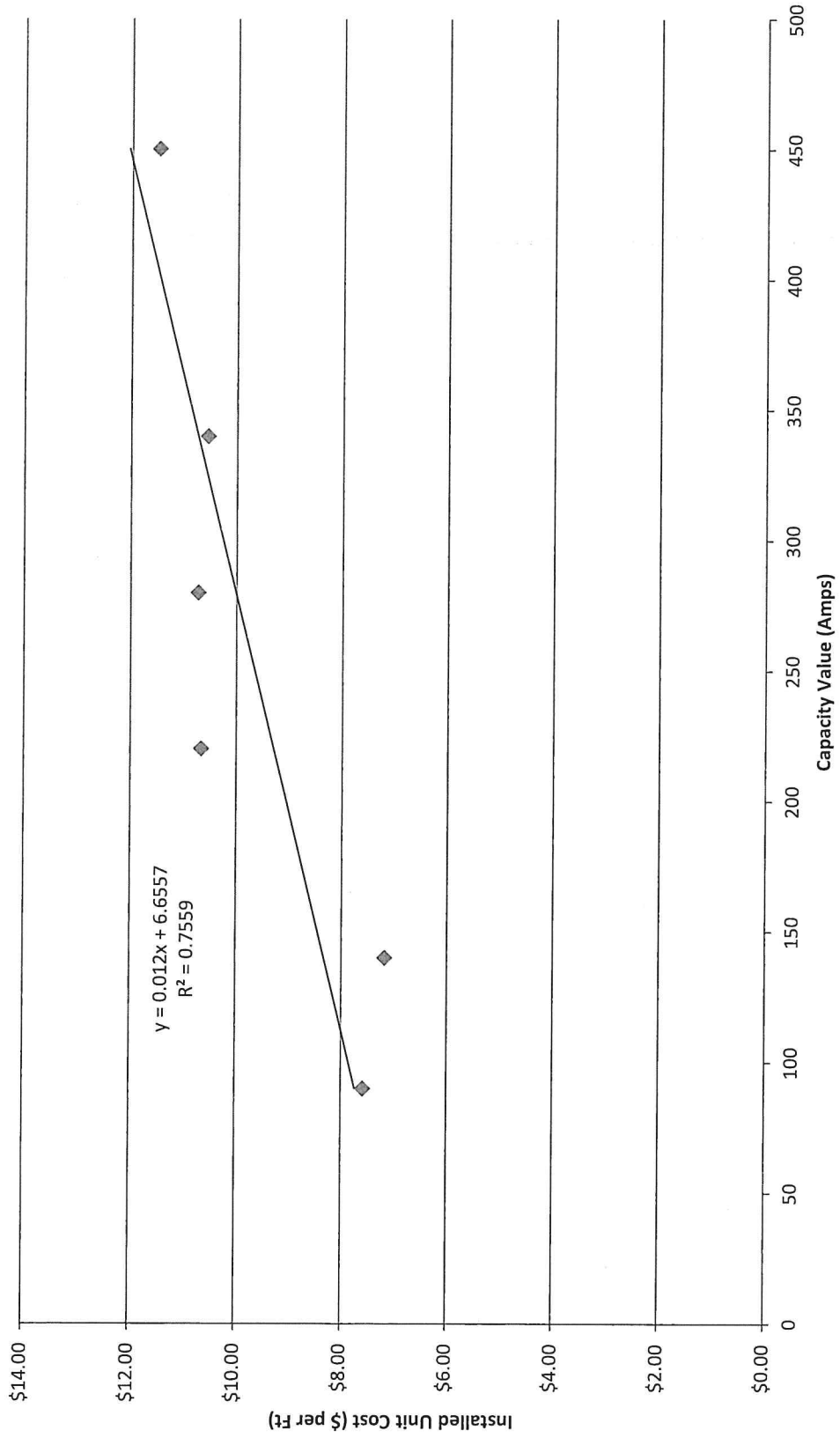


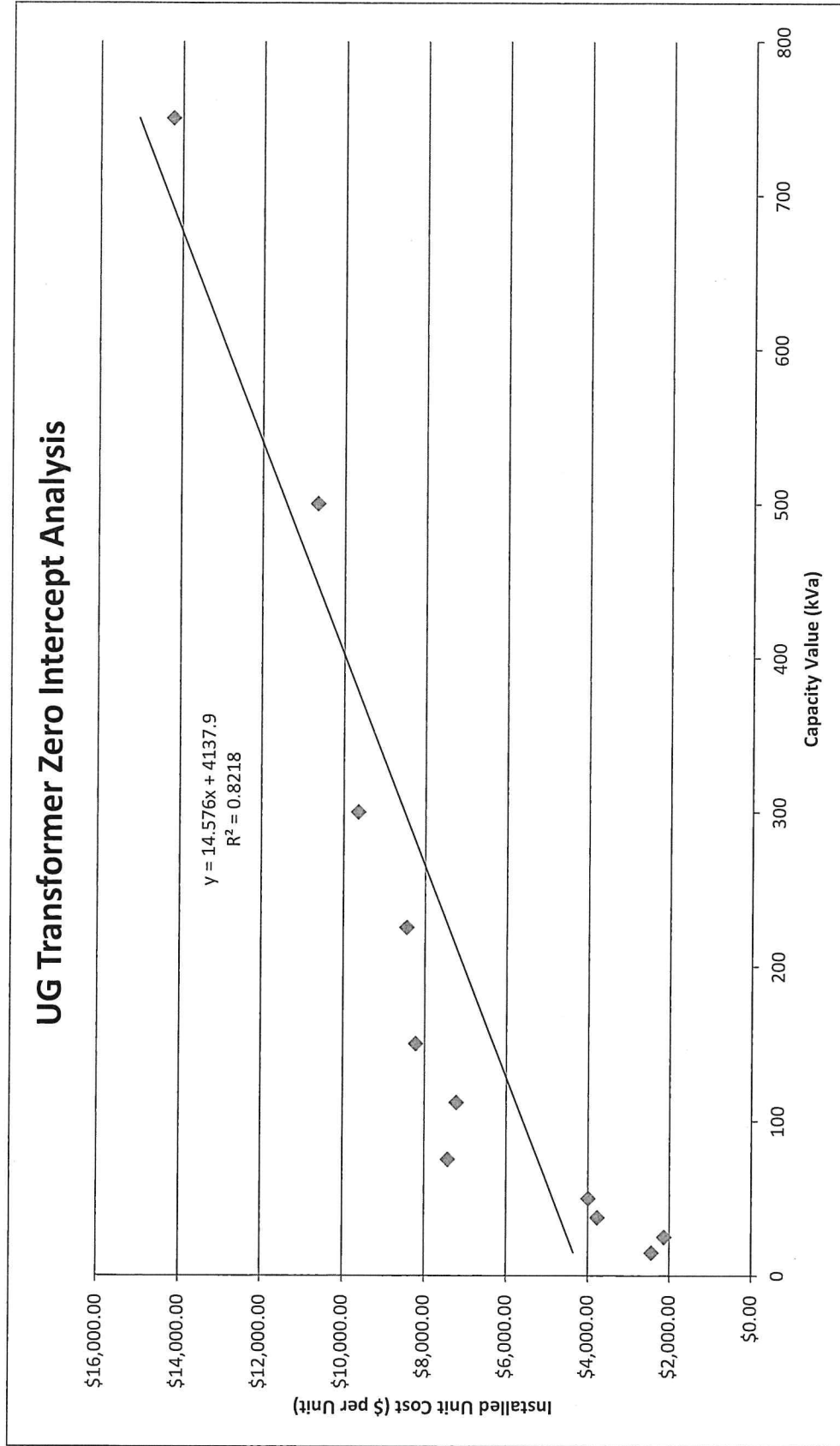






UG Secondary Zero Intercept Analysis





Line	Property Unit	Phase	Config Details	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
				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	10,859,454	15.5%	15.5%	150	\$15.68	\$170,305,310	\$6.58	\$71,455,205	\$9.70	\$105,283,566	
2	OH Primary	1 ph	2 ACSR 1ph	9,678,158	13.8%	29.3%	200	\$9.70	\$93,830,776	\$6.58	\$63,682,279	\$9.70	\$93,830,776	
3	OH Primary	1 ph	6A CUWVD 1ph	8,014,369	11.4%	40.7%	140	\$7.45	\$59,692,680	\$6.58	\$52,734,549	\$9.70	\$77,700,167	
4	OH Primary	1 ph	6 CU 1ph	6,987,194	10.0%	50.6%	140	\$7.45	\$52,054,593	\$6.58	\$45,975,734	\$9.70	\$67,741,590	
5	OH Primary	1 ph	3/10 CU 1ph	1,548,191	2.3%	53.0%	165	\$6.28	\$10,358,351	\$6.58	\$10,845,100	\$9.70	\$15,979,393	
6	OH Primary	Total 1 Phase Primary in Sample			37,187,366				\$10.39	\$386,241,710		\$244,692,868		\$360,535,492
7	OH Primary	3 ph	336 AL 3ph	7,078,360	10.1%	63.1%	1660	\$43.13	\$305,312,256	\$6.58	\$46,575,608	\$9.70	\$68,625,457	
8	OH Primary	3 ph	2 ACSR 3ph	5,887,683	8.4%	71.4%	600	\$20.63	\$121,491,704	\$6.58	\$36,740,952	\$9.70	\$57,081,714	
9	OH Primary	3 ph	336 ACSR 3ph	3,804,835	5.4%	76.9%	1695	\$49.41	\$187,995,678	\$6.58	\$25,035,814	\$9.70	\$36,888,281	
10	OH Primary	3 ph	210 ACSR 3ph	2,437,313	3.5%	80.3%	885	\$21.57	\$52,580,782	\$6.58	\$16,037,518	\$9.70	\$23,630,008	
11	OH Primary	3 ph	4 ACSR 3ph	1,906,163	2.7%	83.0%	450	\$21.17	\$40,353,481	\$6.58	\$12,542,556	\$9.70	\$18,480,459	
12	OH Primary	3 ph	6 CU 3ph	1,333,107	1.9%	84.9%	420	\$10.06	\$13,411,056	\$6.58	\$8,771,843	\$9.70	\$12,924,614	
13	OH Primary	3 ph	6A CUWVD 3ph	806,062	1.1%	86.1%	420	\$10.06	\$8,107,342	\$6.58	\$5,303,887	\$9.70	\$7,814,855	
14	OH Primary	3 ph	110 ACSR 3ph	845,598	1.2%	87.3%	780	\$18.44	\$15,595,854	\$6.58	\$5,564,038	\$9.70	\$8,198,168	
15	OH Primary	3 ph	410 CU 3ph	831,557	1.2%	88.5%	1680	\$24.41	\$20,284,478	\$6.58	\$5,471,643	\$9.70	\$9,082,031	
16	OH Primary	3 ph	556 AL 3ph	456,240	0.6%	89.1%	2295	\$43.77	\$19,971,291	\$6.58	\$3,002,058	\$9.70	\$4,423,294	
17	OH Primary	3 ph	556 ACSR 3ph	313,772	0.4%	89.6%	2295	\$44.06	\$13,823,950	\$6.58	\$2,054,623	\$9.70	\$3,042,058	
18	OH Primary	3 ph	336 AAC 3ph	219,522	0.3%	89.9%	1680	\$45.14	\$10,000,000	\$6.58	\$1,000,000	\$9.70	\$1,000,000	
19	OH Primary	3 ph	556 AAC 3ph	120,854	0.2%	90.1%	2295	\$51.19	\$6,200,000	\$6.58	\$620,000	\$9.70	\$620,000	
20	OH Primary	Total 3 Phase Primary in Sample			26,041,066				\$30.68	\$798,331,902		\$169,110,540		\$249,170,939
19	OH Primary	Total 1 Ph & 3 Ph OH Primary in Sample			63,228,432				\$18.74	\$1,185,173,613		\$413,803,408		\$609,706,431

% Customer
Related Costs
Using Zero
Intercept =

34.92%

% Customer
Related Costs
Using Minimum
System =

51.44%

Minimum System / Zero Intercept Distribution System Cost Analysis

Line	Property Unit	Phase	Config Details	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
				Conductor Footage/Number Transformers	% of Total Population Footage/ Transformers	Cumulative % of Total Population Footage/ Transformers	Load Carrying Capacity (A _s 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	18,398,559	23.5%	23.5%	200	\$4.26	\$78,421,555	\$3.10	\$57,035,533	\$3.55	\$65,316,026			
22	OH Secondary	4	ACSR Open Wire	8,445,623	10.8%	34.2%	150	\$3.61	\$30,508,867	\$3.10	\$26,182,052	\$3.55	\$29,983,196			
23	OH Secondary	1/0	ACSR Open Wire	6,875,855	8.8%	43.0%	260	\$4.34	\$29,810,243	\$3.10	\$21,315,150	\$3.55	\$24,409,710			
24	OH Secondary	6	CU Open Wire	5,944,768	7.6%	50.6%	140	\$4.12	\$24,507,739	\$3.10	\$18,428,762	\$3.55	\$21,104,296			
25	OH Secondary	6A	CUWD Open Wire	6,495,877	8.3%	58.9%	140	\$3.79	\$24,601,573	\$3.10	\$20,137,218	\$3.55	\$23,060,795			
26	OH Secondary	4	CU Open Wire	5,609,064	7.4%	66.3%	185	\$3.43	\$19,904,932	\$3.10	\$18,008,098	\$3.55	\$20,622,537			
27	OH Secondary	2	CU Open Wire	5,372,600	6.9%	73.1%	245	\$3.72	\$19,975,072	\$3.10	\$16,655,061	\$3.55	\$19,073,064			
28	OH Secondary	1/0	AL Triplex	2,716,408	3.5%	76.6%	205	\$3.55	\$9,643,415	\$3.10	\$8,420,864	\$3.55	\$9,643,415			
29	OH Secondary	6	ACSR Duplex	2,501,466	3.2%	79.8%	90	\$3.65	\$9,123,936	\$3.10	\$7,754,544	\$3.55	\$8,880,358			
30	OH Secondary	1/0	AL Triplex, Lashed	2,703,151	3.4%	83.2%	205	\$3.99	\$10,795,628	\$3.10	\$8,379,770	\$3.55	\$9,596,355			
31	OH Secondary	3/10	CU Open Wire	1,417,755	1.8%	85.0%	165	\$3.81	\$5,406,260	\$3.10	\$4,395,041	\$3.55	\$5,033,118			
32	OH Secondary	1/0	CU Open Wire	1,026,461	1.3%	86.3%	300	\$4.90	\$5,032,175	\$3.10	\$3,182,029	\$3.55	\$3,644,000			
33	OH Secondary	2	AL Triplex	988,987	1.2%	87.6%	150	\$3.67	\$3,556,408	\$3.10	\$3,003,860	\$3.55	\$3,439,964			
34	OH Secondary	2/0	ACSR Open Wire	836,644	1.1%	88.6%	295	\$4.86	\$4,066,091	\$3.10	\$2,593,597	\$3.55	\$2,970,139			
35	OH Secondary	6	AL Duplex	748,802	1.0%	89.6%	90	\$3.84	\$2,878,937	\$3.10	\$2,321,287	\$3.55	\$2,658,294			
36	OH Secondary	1/0	AL Open Wire	447,898	0.6%	90.2%	265	\$4.23	\$1,894,190	\$3.10	\$1,388,485	\$3.55	\$1,590,067			
37	Total OH Secondary in Sample												\$251,025,306			

% Customer Related Costs Using Zero Intercept =

% Customer Related Costs Using Minimum System =

78.25%

89.61%

Minimum System / Zero Intercept Distribution System Cost Analysis

Line	Property Unit	Phase	Config Details	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
				Conductor Footage/Number Transformers	% of Total Population Footage/ Transformers	Cumulative % of Total Population Footage/ Transformers	Load Carrying Capacity (A, or kVA)	Installed Unit Cost	Total Cost	Y Intercept Minimum Cost per Unit	Total Cost Using Y Intercept Unit Cost	Minimum System Cost per Unit	Total Cost Using Minimum System Cost per Unit	
39	OH Transformers	1 Phase Wye 25 kVA		32,366	28.8%	28.8%	25	\$2,497	\$60,626,637	\$2,060	\$66,673,960	\$2,253	\$72,920,598	
40	OH Transformers	1 Phase Wye 10 kVA		19,792	17.6%	46.5%	10	\$2,253	\$44,584,676	\$2,060	\$40,771,520	\$2,253	\$44,581,376	
41	OH Transformers	1 Phase Wye 37.5 kVA		16,543	14.7%	61.2%	37.5	\$3,851	\$63,715,349	\$2,060	\$34,078,580	\$2,253	\$37,271,379	
42	OH Transformers	1 Phase Wye 15 kVA		16,343	14.6%	75.9%	15	\$2,065	\$33,751,805	\$2,060	\$33,666,580	\$2,253	\$36,820,779	
43	OH Transformers	1 Phase Wye 50 kVA		12,139	10.8%	86.6%	50	\$3,673	\$44,587,443	\$2,060	\$25,006,340	\$2,253	\$27,349,167	
44	OH Transformers	3 Phase Wye/Wye 75 kVA		1,178	1.0%	87.7%	75	\$3,662	\$4,314,234	\$2,060	\$2,426,680	\$2,253	\$2,654,034	
45	OH Transformers	3 Phase Wye/Wye 150 kVA		919	0.8%	88.5%	150	\$6,371	\$5,854,792	\$2,060	\$1,893,140	\$2,253	\$2,070,507	
46	OH Transformers	3 Phase Wye/Wye 112 kVA		627	0.6%	89.0%	112	\$5,789	\$3,629,692	\$2,060	\$1,291,620	\$2,253	\$1,412,631	
47	OH Transformers	3 Phase Wye/Wye 45 kVA		686	0.6%	89.7%	45	\$4,034	\$2,807,811	\$2,060	\$1,433,760	\$2,253	\$1,568,068	
48	OH Transformers	1 Phase Wye 100 kVA		550	0.5%	90.1%	100	\$4,941	\$2,717,436	\$2,060	\$1,133,000	\$2,253	\$1,239,150	
49			Total OH Transformers in Sample	101,153				\$2,835.21	\$286,790,075		\$208,376,180		\$227,897,709	
50										72.66%			79.46%	
51	UG Primary	1 ph	1/0 AL 1ph	15,663,066	30.1%	30.1%	275	\$15.13	\$236,951,289	\$9.61	\$150,522,067	\$8.79	\$137,715,665	
52	UG Primary	1 ph	2 AL 1ph	13,190,012	25.3%	55.4%	225	\$8.79	\$115,971,630	\$9.61	\$126,756,019	\$8.79	\$115,971,630	
53			Total 1 Phase Primary in Sample	28,853,079				\$12.23	\$452,922,919		\$277,278,085		\$253,687,294	
54														
55	UG Primary	3 ph	1/0 AL 3ph	12,837,974	24.7%	80.1%	645	\$18.72	\$240,311,035	\$9.61	\$123,372,928	\$8.79	\$112,876,372	
56	UG Primary	3 ph	750 AL 3ph	4,428,067	8.5%	88.6%	1890	\$31.38	\$138,910,770	\$9.61	\$42,534,499	\$8.79	\$38,915,669	
57	UG Primary	3 ph	2 AL 3ph	1,161,402	2.2%	90.8%	510	\$20.62	\$23,948,111	\$9.61	\$11,161,074	\$8.79	\$10,211,491	
58	UG Primary	3 ph	1000 AL 3ph	542,869	1.0%	91.9%	2190	\$39.34	\$21,354,087	\$9.61	\$5,216,976	\$8.79	\$4,773,116	
59	UG Primary	3 ph	500 AL 3ph	474,292	0.9%	92.8%	1545	\$36.51	\$17,316,384	\$9.61	\$4,557,942	\$8.79	\$4,170,153	
60	UG Primary	3 ph	500 CU 3ph	543,913	1.0%	93.8%	1830	\$37.84	\$20,582,764	\$9.61	\$5,227,000	\$8.79	\$4,792,287	
61	UG Primary	3 ph	750 CU 3ph	291,013	0.6%	94.4%	2340	\$48.32	\$14,060,328	\$9.61	\$2,796,636	\$8.79	\$2,558,699	
62			Total 3 Phase Primary in Sample	19,803,238				\$23.19	\$459,167,097		\$194,867,055		\$178,287,786	
63														
64			Total 1 Ph & 3 Ph UG Primary in Sample	48,656,316					\$812,090,015		\$472,145,140		\$431,975,080	
65										58.14%			53.19%	

% Customer Related Costs Using Minimum System =

% Customer Related Costs Using Zero Intercept =

% Customer Related Costs Using Minimum System =

Northern States Power Company
 Minimum System Analysis for Distribution Services

[1]	[2]	[3]	[4]	[5]	[6] = [3] x [4] x [5] / 1000	[7]	[8] = [6] / [7]	[9] = 1 - [8]
Services	<u>Minimum Conductor Configuration</u>	<u>Minimum Footage per Service</u>	<u>Installed Cost per Foot</u>	<u>Number of Customers</u>	<u>Total Minimum Installed Cost (\$000)</u>	<u>Test Year Plant Investment Distribution Services (\$000)</u>	<u>Customer Component Distribution Services</u>	<u>Capacity Component Distribution Services</u>
1	OH Services 2 ACSR Triplex	40	\$4.03	73,472	\$11,844			
2	UG Services 1/0 Triplex	40	\$2.81	13,216	\$1,486			
3	Total Services			86,688	\$13,329	\$15,226	87.54%	12.46%

Tariff	Description	Present Price	Proposed Price	2019 Units	Present \$	Proposed \$	Difference
5.1.A.1	Standard Installation and Extension Rules						
	Excess service charge - Services	\$7.90	\$12.50	379	\$2,994	\$4,738	\$1,743
	Excess service charge - Excess single phase primary	\$8.00	\$13.00	-	\$0	\$0	\$0
	Excess service charge - Excess three phase primary	\$13.90	\$21.00	-	\$0	\$0	\$0
5.1.A.2.	Winter Construction						
	Per Thaw Unit	\$600.00	\$685.00	4	\$2,400	\$2,740	\$340
	Per Trench Foot	\$3.80	\$8.90	183	\$695	\$1,629	\$933
			REVENUE IMPACT		\$6,090	\$9,106	\$3,016.70

Section 6.5.1.A1.	
Excess Footage Charge	Current Electric tariff per circuit foot
Services	\$7.90
Excess single phase primary or secondary extension	\$8.00
Excess three phase primary or secondary extension	\$13.90

Task	SAP	Overhead	Total Costs
Services	\$ 8.81	42.78%	\$12.58
Excess single phase primary or secondary extension	\$ 9.27	42.78%	\$13.24
Excess three phase primary or secondary extension	\$ 14.57	42.78%	\$20.80

TARIFF	Current Electric tariff per circuit foot	Proposed Tariff Charge per circuit foot
Services	\$7.90	\$12.50
Excess single phase primary or secondary extension	\$8.00	\$13.00
Excess three phase primary or secondary extension	\$13.90	\$21.00

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
 Engineering and Supervision Overhead: average rate 42.78%

2020 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	\$93.59	\$93.59				
Re-tank thaw unit	Two man crew	0	\$93.59	\$0.00				
Remove thaw unit	Two man crew	0.5	\$93.59	\$46.80				
Total Labor				\$140.39				
Labor Loading @ 76.87%				\$107.91				
Labor w/ Loading				\$248.30				\$248.30
Vehicle & Equipment	truck and trailer	1.5	13.11	\$19.67				\$19.67
Propane Cost						2.02	15	\$30.30
Costs (before E&S)				\$298.26				\$298.26
E&S Cost @ 42.78%				\$127.60				\$127.60
Total Cost				\$425.86				\$425.86

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	\$93.59	\$93.59				
Re-tank thaw unit	Two man crew	1	\$93.59	\$93.59				
Remove thaw unit	Two man crew	0.5	\$93.59	\$46.80				
Total Labor				\$233.98				
Labor Loading @ 76.87%				\$179.86				
Labor w/ Loading				\$413.83				\$413.83
Vehicle & Equipment	truck and trailer	2.5	13.11	\$32.78				\$32.78
Propane Cost						2.02	22.5	\$45.45
Costs (before E&S)				\$492.06				\$492.06
E&S Cost @ 42.78%				\$210.50				\$210.50
Total Cost				\$702.56				\$702.56

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

Before and after January Costs	Percentage	
\$425.86	10%	\$42.59
\$702.56	90%	\$632.30
		\$674.89
Billing Labor		\$10.00
Producing Bill		\$0.11
Postage		\$0.40
Total Cost of a Thaw Unit		\$685.39

2019 Winter Construction Per Foot Charge

Winter Construction billed for in Winter of 2019

Average Cost per Foot Winter 2019 Services =	\$28.07
Average Cost per Foot Non-Winter Months Services =	\$19.16
Difference for Winter Construction	\$8.91

2020 Updates to Charges

Current Electric Charges		Tariff		Proposed Tariff Charge	
		Updated Costs			
Service Extension	\$600.00 per thaw unit	\$685.39 per thaw unit	Thawing	\$685.00 per thaw unit	
	plus per trench foot	\$8.91 per trench foot	Secondary distribution extension	\$8.90 per foot	