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Direct Testimony and Schedules
Michael A. Peppin

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-19-564
Exhibit___(MAP-1)

Class Cost of Service Study and Selected Rate Design

November 1, 2019

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include more than 35 years of experience with Northern States Power Company, doing business as Xcel Energy (NSPM or the Company) and its predecessors in the areas of market research and cost-of-service analysis. A detailed statement of my qualifications and experience is provided as Exhibit___(MAP-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present the proposed 2020, 2021, and 2022 Class Cost of Service Studies (CCOSS) for Northern States Power Company, doing business as Xcel Energy (NSPM or the Company), as required by Minn. R. 7825.4300, Part C; and Order Point 17(e) of the Commission's June 17, 2013 Order in Docket No. E,G999/M-12-587. Copies of these CCOSSs are included in Volume 3, Required Information, of the rate case Application (Volume 3). Additionally, I support certain rate design proposals and address several compliance matters.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present my testimony in the following Sections:

- Section II discusses the compliance items related to the CCOSS and where these compliance items are;

- Section III presents the Company's proposed 2020, 2021 and 2022 CCOSS and examines the methodology used in developing the CCOSSs;
- Section IV presents the Company's proposed revisions to the Windsource and Conservation Improvement Program (CIP) Riders;
- Section V presents proposed changes to the excess footage and winter construction charges listed in Section 6 – Rules and Regulations of the Minnesota Electric Rate Book; and
- Section VI is my conclusion.

II. COMPLIANCE ITEMS

Q. WHAT COMPLIANCE MATTERS WILL YOU ADDRESS?

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

- Basing the D10S capacity allocator on Xcel Energy's system peak coincident with MISO's system peak;
- Excluding the loads of customers who are direct assigned the costs of specific distribution substations from calculation of the D60Sub allocator;
- Providing the Commission with the results of multiple methods for functionalizing distribution costs;
- The allocation of transmission facility costs with the D10S allocator;
- Identifying other production Operation and Maintenance (O&M) costs that vary directly with energy output and allocating the remaining costs using the stratification method;

- Provide a description of each allocation method and reasons why each method is appropriate;
- Provide data linkages in the CCOSS model and more data transparency in the model; and
- Provide CCOSS results in compliance with the Commission's multi-year rate plan Order.

Finally, the Commission also ordered that the Company report on methods to better measure system losses in this rate case. This compliance requirement will be discussed in the testimonies of Company witnesses Ms. Kelly A. Bloch for the distribution system and Mr. Ian R. Benson for the transmission system.

These compliance matters are derived from the following sources: Order Point 9.b., 9.c.ii. and Commission orders on pages 45 and 47 from Docket No. E002/GR-15-826; Order Point Nos. 22 and 23 from the Commission's September 3, 2013, Order in Docket No. E002/GR-12-961; direction from the Commission on pages 67 and 69 and Order Point Nos. 37, 38 and 39 from the Commission's May 8, 2015 Order in Docket No. E002/GR-13-868; Order Point No. 12(a)-12(c) from the Commission's August 31, 2015 Order in Docket No. E002/GR-13-868; and Order Point 17(e) of the Commission's June 17, 2013 Order in Docket No. E,G999/M-12-587.

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

A. Table 1 lists the specific order points included in my testimony.

Table 1

Compliance Items from Recent Dockets

Docket	Compliance Item	Description	Testimony Section
E002/GR-15-826	June 12, 2017 Order Point No. 9.b. at p. 68	Report on methods to measure losses	Section II; p. 3
E002/GR-15-826	June 12, 2017 Order Point No. 9.e.ii. at p. 68	Base the D10S capacity allocator on Xcel's system peak coincident with MISO's system peak	Section II. C. 2. A.
E002/GR-15-826	June 12, 2017 Order at p. 47	Exclude the loads of customers who are direct assign the costs of specific distribution substations from calculation of the D60Sub allocator	Section II. C. 3.
E002/GR-15-826	June 12, 2017 Order at p. 45	Provide the Commission with the results of multiple methods for functionalizing distribution costs	Section II. C. 7. C.
E002/M-19-39	July 15, 2019 Order Point No. 3.C. at p. 22	Provide in future rate cases when Xcel is including costs and revenues related to Google an update to both the overall Incremental Cost and Benefit Analysis and the Rate Case Incremental Cost and Benefit Analysis.	Section VI.

III. CCOSS

A. Overview of CCOSS

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

A. The Company does not propose any changes to the allocation methodology as compared to the Commission's Order in the Company's last rate case (Docket No. E002/GR-15-826). We did, however, update the allocators using more recent system data, and updated the Minimum System/Zero Intercept study for the classification and allocation of Distribution costs.

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

A. The CCOSS allocates jurisdictional costs (in this case, costs of the Company's State of Minnesota electric jurisdiction) to customer classes using class cost allocation factors. The CCOSS measures the contribution each class makes to the Company's overall cost of service, including calculating inter-class and intra-class cost responsibilities. One of the primary goals of the CCOSS is to develop class cost allocation factors that most accurately reflect cost causation. The CCOSS therefore serves as a tool for evaluating and refining the Company's rate structure, as discussed in more detail by Company witness Mr. Steven V. Huso.

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

A. Yes. As discussed by Mr. Huso, a CCOSS is the appropriate starting point for evaluating a given rate design. The Company's proposed CCOSSs are appropriate because they:

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

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

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

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

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

E002/GR-12-961).

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

B. CCOSS Results

1. 2020 CCOSS Results

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2020 CCOSS.

A. Table 2 below provides a summary of the 2020 test year CCOSS (the 2020 CCOSS) results at the class level, showing the resulting class cost responsibilities (as opposed to revenue responsibilities that are addressed by Mr. Huso). Table 2 replicates Exhibit___(MAP-1), Schedule 3. However, for comparison purposes, Schedule 3 also provides the class revenue allocation proposed by Mr. Huso. The detailed 2020 CCOSS output is included in Schedule 4.

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

Table 2

Summary of 2020 Class Cost of Service Study

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

UNADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	3,320,983	1,260,019	116,903	1,913,962	30,098
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	849	495	38	312	4
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,321,832	1,260,514	116,941	1,914,274	30,103
[4]	Present Rates (CCOSS page 2, line 2)	3,120,405	1,165,785	109,370	1,818,541	26,709
[5]	Unadjusted Deficiency (line 3 - line 4)	201,427	94,730	7,571	95,732	3,393
[6]	Defic / Pres (line 5 / line 4)	6.5%	8.1%	6.9%	5.3%	12.7%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.26**	**1.07**	**0.82**	**1.97**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Resid.	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Dev Disc Cost Alloc (CCOSS page 2, line 8)					
						HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(1,893)	1,447	442	4

ADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,320,983	1,258,126	118,350	1,914,404	30,102
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	849	495	38	312	4
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,321,832	1,258,621	118,388	1,914,716	30,106
[16]	Present Rates (line 4)	3,120,405	1,165,785	109,370	1,818,541	26,709
[17]	Adjusted Deficiency (line 15 - line 16)	201,427	92,837	9,018	96,174	3,397
[18]	Defic / Pres Rates (line 17 / line 16)	6.5%	8.0%	8.2%	5.3%	12.7%
[19]	**Ratio: Class % / Total %**	**1.00**	**1.23**	**1.28**	**0.82**	**1.97**

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

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

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

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

Q. How does the Company treat economic development discounts in the CCOSS?

A. Economic development discounts are treated as a reduction in revenues from the Commercial and Industrial (C&I) Demand class. As discussed in more detail below, the cost of these discounts are allocated to each customer class based on 2020 test year present revenues as ordered by the Commission in the Company's 2013 rate case (Docket No. E002/GR-13-868).

Q. How are interruptible rate discounts and economic development discounts reflected in the CCOSS?

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

1. Line 8 on Table 2 above and Schedule 3, labeled "Interruptible Rate Discounts" shows the amount of the total interruptible rate discounts originating from each class. Line 9 on Table 2 above shows the amount of economic development discounts originating from each class. The amounts shown for each class are lost revenues from that class. These discounts reduce the revenue received from the classes and thus have the effect of increasing the revenue requirement for the classes that receive the discounts.
2. Lines 10 and 11 on Table 2 above and Schedule 3, labeled

"Interruptible Rate Disc. Cost Allocation" and "Economic Development Disc. Cost Allocation" shows how the cost of interruptible rate discounts and economic development discounts are allocated to the classes. Interruptible rate discounts are allocated using the applicable generation capacity cost allocation factor, while economic development discounts are allocated based on 2020 test year present revenues.

3. Line 12 on Table 2 above and Schedule 3, labeled "Revenue Requirement Change" shows the net change in the revenue requirement for each customer class.
4. The resulting Line 13 on Table 2 above and Schedule 3, labeled "Adjusted Rate Revenue Requirement" shows the appropriate cost of service for determining class revenue responsibilities. Finally, the adjusted revenue deficiency and percent deficiency are shown on lines 17 and 18, respectively.

Q. IN THE COMPANY'S LAST RATE CASE (DOCKET NO. E002/GR-15-826), THE STREET LIGHTING CLASS SHOWED A DEFICIENCY THAT WAS MUCH LARGER THAN HAD BEEN SEEN IN PRIOR RATE CASES, WHAT WAS THE REASON FOR THE LARGE INCREASE IN THE DEFICIENCY?

A. When the Company filed direct testimony its last rate case, the Street Lighting class had showed a deficiency of 13.6 percent compared to a deficiency of 1.8 percent with the compliance CCOSS in its prior rate case (Docket No. E002/GR-13-868). This was due to the compliance CCOSS not including the results of the Company's 2012 Transmission, Distribution and General Depreciation filing (Docket No. E,G002/D-12-858).

This filing approved a redistribution of depreciation reserve between utility accounts within each functional class. This was done to equitably spread the depreciation reserve between all utility accounts in a functional class. While this redistribution did not change the total reserve within each functional class, it moved reserve from accounts within that functional class. The result of this redistribution for Electric Distribution Street Lighting was to transfer $23.4 million in depreciation reserve from Electric Distribution Street Lighting to other Electric Distribution accounts. This redistribution as approved by the Commission can be seen in Attachment H in the above referenced 2012 filing.

The result was a large increase in the return on rate base directly attributable to the lighting class. It should be noted that since the Company's 2013 rate case (Docket No. E002/GR-13-868), there has been no change to the cost allocation methods or methods used for directly assigning costs to the lighting class.

Q. DID THE RATE INCREASE APPROVED IN THE LAST RATE CASE (DOCKET NO. E-002/GR-15-826) COMPENSATE FOR THIS LARGE DEFICIENCY?

A. No. Although the Company was not required to file a compliance CCOSS in the last rate case, the deficiency for the Street Lighting class remained at 11.3 percent after the ordered increase in Street Lighting rates. As a result, row 18 of Table 2 above shows that the deficiency for the Street Lighting class is 12.7 percent for the 2020 test year.

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

CLASS ALLOCATION?

A. Yes, Schedule 4 shows the detailed CCOSS results. Pages one through three provide a more detailed summary of the CCOSS results. Page one is a summary of the Company's rate base by function and a summary of the Company's income statement. Page two shows the proposed "Cost" responsibility at equal rates of return in total, by cost classification and function. Page three shows the proposed cost of service compared to the proposed rate revenue responsibility. The listing of the detailed cost allocations begins on page four. The column labeled "Alloc" lists the class cost allocator that is used to allocate costs.[1] The column labeled "FERC Accounts" specifies the FERC codes that are being allocated.[2] Pages four through six show the allocation of costs and calculations needed to determine rate base by class. Pages seven through 12 show the allocation of costs and calculations needed for the income statement. Finally, page 13 shows the cost allocators that are generated internally in the CCOSS model, while page 14 shows the data used to calculate the external allocators.

2. 2021 and 2022 CCOSS Results

Q. IN ADDITION TO THE 2020 CCOSS, THE COMPANY HAS ALSO INCLUDED 2021 AND 2022 CCOSSS IN THIS FILING. COULD YOU EXPLAIN HOW THE 2020 CCOSS COMPARES TO THE 2021 AND 2022 CCOSSS?

A. The 2021 and 2022 CCOSSs are essentially the same as the 2020 CCOSS, except they include increases in the revenue deficiency of $146.4 million and

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

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

$118.3 million that reflect the respective 2021 and 2022 revenue requirement increases. Company witness Mr. Benjamin C. Halama discusses the 2021 and 2022 plan year increases in his Direct Testimony. Tables 3 and 4 below provides a summary of the 2021 and 2022 CCOSS results at the class level, showing the resulting class cost responsibilities. Table 3 replicates a portion of Exhibit___(MAP-1), Schedule 5, while Table 4 replicates a portion of Exhibit___(MAP-1), Schedule 7. For comparison purposes, Schedules 5 and 7 include the full 2021 and 2022 CCOSS summaries and the class revenue allocations proposed by Mr. Huso. The detailed 2021 CCOSS output is included in Schedule 6. The detailed 2022 CCOSS output is included in Exhibit___(MAP-1), Schedule 8.

Table 3
Summary of 2021 Class Cost of Service Study
NSPM-Minnesota Electric Jurisdiction
($ Thousands)

ADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Street Ltg
[20]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,426,848	1,306,371	122,813	1,966,314	31,349
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,154	743	54	353	5
[22]	Adjusted Operating Revenues (line 13 + line 14)	3,428,002	1,307,114	122,868	1,966,667	31,354
[23]	Present Rates (line 4)	3,080,208	1,148,029	108,275	1,797,236	26,668
[24]	Adjusted Deficiency (line 15 - line 16)	347,795	159,085	14,592	169,430	4,687
[25]	Defic / Pres Rates (line 17 / line 16)	11.3%	13.9%	13.5%	9.4%	17.6%
[26]	**Ratio: Class % / Total %**	**1.00**	**1.23**	**1.19**	**0.83**	**1.56**

Table 4

Summary of 2022 Class Cost of Service Study

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

ADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Street Ltg
[27]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,533,407	1,361,718	125,980	2,013,504	32,205
[28]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,400	943	68	384	5
[29]	Adjusted Operating Revenues (line 13 + line 14)	3,534,806	1,362,661	126,047	2,013,888	32,210
[30]	Present Rates (line 4)	3,068,702	1,147,973	107,401	1,786,604	26,724
[31]	Adjusted Deficiency (line 15 - line 16)	466,104	214,688	18,646	227,284	5,486
[32]	Defic / Pres Rates (line 17 / line 16)	15.2%	18.7%	17.4%	12.7%	20.5%
[33]	**Ratio: Class % / Total %**	**1.00**	**1.23**	**1.14**	**0.84**	**1.35**

Q. WHAT IS THE PURPOSE OF THE 2021 AND 2022 CCOSSS?

A. First, Mr. Huso uses the 2021 CCOSS to help design 2021 rates. Second, as mentioned above, we are required to provide a 2021 and 2022 CCOSS pursuant to Order Point 17(e) of the Commission's June 17, 2013 Order in Docket No. E,G999/M-12-587.

Q. FROM A RATE DESIGN PERSPECTIVE, IS THERE A MATERIAL DIFFERENCE BETWEEN THE 2020 CCOSS AND THE 2021 AND 2022 CCOSSS?

A. No. The relevant rate design question is whether the additional 2021 and 2022 plan year costs materially impact the relative inter-class cost responsibilities. Tables 2, 3, and 4 above, show the 2021 and 2022 adjustments have a very small impact on the relative inter-class cost responsibilities.

To illustrate why this is the case, Lines 13 through 19 of Table 2 show the Cost Responsibilities (total and relative) for the 2020 CCOSS. Lines 20 through 26 of Table 3 and Lines 27 through 33 of Table 4 show the same data for the 2021 and 2022 CCOSSs. In particular, it is helpful to compare Line 19 for the 2020 CCOSS to the corresponding Line 26 for the 2021 CCOSS and Line 33 of the 2022 CCOSS. The ratios of class-percent-deficiency to overall-percent-deficiency are very similar between the two CCOSSs, particularly for the Residential and C&I Demand classes.

C. CCOSS Methodology

1. Transparency of the CCOSS Model

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

A. No. The proposed CCOSSs incorporate the allocator methodology approved in the Company's two most recent case; Table 5 summarizes the major allocation decisions approved in those cases.

Table 5

CCOSS Methodology Summary

CCOSS Methodology Elements Approved in Docket No. E002/GR-13-868 and Docket No. E002/GR-15-826
• Allocation of Other Production O&M using the "Location" method • Classification and Allocation of All Company-Owned Wind Generation using the Plant Stratification Method • Allocation of CIP CCRC using per kWh method • Allocation of Economic Development Costs to all Customers Based on Present Revenues • Calculation of the D10S Capacity Allocator Using Class Peaks that are Coincident with MISO's Peak for the Test Year

Q. WHAT STEPS HAS THE COMPANY TAKEN TO MAKE ITS CCOSS MODEL MORE TRANSPARENT AND EASIER TO REVIEW?

A. Since the Company's 2013 rate case (Docket No. E002/GR-13-868), the Company has taken several actions to improve the transparency and ease of review of our CCOSS. These steps were discussed in detail in my Direct Testimony from our 2015 rate case (Docket No. E002/GR-15-826). An example of one of these actions is that CCOSS has direct links to all inputs used in the model and the addition of several worksheet tabs to the CCOSS that clearly identify all financial and non-financial inputs with direct linkages for all calculations in the CCOSS model. Exhibit___(MAP-1), Schedule 9 is the "CCOSS Worksheet Tab Index" which provides a description of the contents of each of the 56 tabs to the CCOSS.

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

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

2. Plant Stratification

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

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

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

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

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

A. Yes. As shown in Table 6 below, the Company has updated plant replacement costs and the resulting capacity-energy splits.

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

A. The Plant Stratification analysis used in this case is shown in Table 6 below. Table 6 compares the current-dollar replacement costs of each plant type towards developing stratification percentages.

Table 6

Stratification Allocation by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity Percentage	Energy Percentage
Peaking	$925	$925 / $925	100.0%	0.0%
Nuclear	$4,868	$925 / $4,868	19.0%	81.0%
Fossil	$2,345	$925 / $2,345	39.4%	60.69%
Combined Cycle	$1,327	$925 / $1,327	69.7%	30.3%
Hydro	$5,415	$925 / $5,415	17.1%	82.9%
Wind	$15,233	$925/$15,233	6.1%	93.9%

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 component of the revenue requirements (e.g., book investment, accumulated depreciation, accumulated deferred income taxes, Construction Work in Progress), for each generation plant type.

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

A. From a cost perspective, this method appropriately recognizes that a significant portion of the fixed costs of baseload and intermediate plants are incurred to obtain fuel savings that more than offset the higher fixed costs, thereby minimizing total costs.

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

Q. WHAT WAS THE COMMISSION'S ORDER IN THE COMPANY'S LAST RATE CASE (DOCKET NO. E002/GR-15-826) REGARDING THE D10S CAPACITY ALLOCATOR?

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

"Xcel shall base the D10S capacity allocator on Xcel's system peak that is coincident with MISO's system peak, incorporating any future changes to MISO's method for calculating the system peak."

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

A. Prior to this Commission's Order, the D10S allocator was calculated by using each customer class's forecasted loads that were in the same hour of the NSP System peak.

Q. FOR THE 2020 TEST YEAR DOES MISO FORECAST THE HOUR AND PROJECTED PEAK FOR EACH LOCAL RESOURCE ZONE?

A. First, virtually all of the Company's load is included in MISO's Local Resource Zone 1 (LRZ1) and over 99.9 percent of the Company's capacity requirements are in that zone. MISO does not provide forecast estimates of the day and hour that their peak will occur. Likewise, the forecast of the NSP peak that is coincident to the MISO peak is not dependent on a specific day, month, or hour, but rather what the NSP System peak and MISO peak day weather conditions. As a result, the Company is not able to determine forecasted class loads that would be coincident with MISO's forecasted LRZ1 peak hour for the 2020 test year.

Q. HOW IS EACH PARTICIPATING UTILITY'S CAPACITY REQUIREMENT DETERMINED FOR THE UPCOMING PLANNING YEAR?

A. Each utility provides a forecast of its system peak that is adjusted for a MISO coincidence factor and planning reserve margin (PRM). The PRM is determined by MISO for each planning year. Next, the Company determines its coincidence factor with the MISO LRZ1 peak based on the historical coincidence of the NSP System peak with the MISO peak. The coincidence factor for the upcoming June 2020-May 2021 planning year is 97.12 percent.

Q. WITHOUT A MISO PUBLISHED PEAK HOUR FOR THE 2020 TEST YEAR, HOW DOES THE COMPANY PROPOSE TO DETERMINE CLASS LOADS TO COMPLY WITH THE COMMISSION'S ORDER?

A. In order to comply with the Commission's Order, the Company looked at the hour that MISO's Local Resource Zone 1 (LRZ1) peaked for the each of the last 10 years. The hour that LRZ1 peaked was then compared to the corresponding hourly loads for the NSP System. As shown in Table 7 below, in 5 of the 10 years (2009, 2011, 2015, 2016, and 2017) the hour of the NSP System peak was the same hour as the MISO LRZ1 peak. In three of the 10 years (2010, 2014, and 2018) the MISO peak coincided with NSP's second highest peak hour, in one year (2013) the MISO peak coincided with NSP's third highest peak hour, and in one year (2014) the MISO peak coincided with NSP's fourth highest peak hour.

Table 7

Comparison of MISO LRZ-1 Peak Hours to NSP System Peak Hours

For 2009 - 2018

Year	MISO LRZ1 Peak Day (CST)	MISO LRZ1 Peak Hour (CST)	NSP System Peak Day (CST)	NSP System Peak Hour (CST)	Did NSP and MISO LRZ1 Peak on the Same Day and Hour?	NSP Load Ranking at the MISO LRZ1 Peak Hour
2009	23-Jun-09	13	23-Jun-09	13	Yes	1
2010	9-Aug-10	15	9-Aug-10	16	No	2
2011	20-Jul-11	16	20-Jul-11	16	Yes	1
2012	2-Jul-12	14	2-Jul-12	16	No	4
2013	26-Aug-13	14	26-Aug-13	16	No	3
2014	21-Jul-14	14	21-Jul-14	16	No	2
2015	14-Aug-15	15	14-Aug-15	15	Yes	1
2016	20-Jul-16	16	20-Jul-16	16	Yes	1
2017	17-Jul-17	17	17-Jul-17	17	Yes	1
2018	12-Jul-18	16	29-Jun-18	16	No	2

Q. BASED ON THE ABOVE DATA, WHAT IS YOUR CONCLUSION REGARDING THE D10S ALLOCATOR?

A. Based on 10 years of actual data, the Company is confident that using forecast class loads for the four highest NSP system peak hours for the D10S allocator would encompass the MISO peak hour.

Q. FOR THE 2020 TEST YEAR, WHAT ARE THE FORECASTED FOUR HIGHEST NSP SYSTEM PEAK HOURS?

A. The Company sorted the forecast 2020 NSP System 8,784 loads by load level and the four highest loads for the 2020 test year are shown in Table 8 below:

Table 8

Ranking of Highest NSP System Four Highest 2020 MW Load Levels

Test Year 2020 Forecast

NSP System Load Level Ranking	NSP System Load Forecast (MW)	Time Interval
1	9,099	07/23/2020 03:00 PM
2	9,065	07/23/2020 04:00 PM
3	9,022	07/23/2020 02:00 PM
4	8,901	07/23/2020 01:00 PM

Based on the load forecast, the Company is confident that using the class loads for these four hours would encompass the MISO peak hour.

Q. WHAT ARE THE CORRESPONDING FORECASTED CLASS LOADS FOR THESE HOURS AND THE RESULTING D10S ALLOCATOR?

A. The forecasted coincident loads by class for the hours specified above are shown in Table 9 below along with the resulting D10S allocator:

Table 9

Minnesota MW Class Loads Coincident with

Four Highest NSP System Peak Hours

Test Year 2020 Forecast

Date & Hour	Residential	Commercial Non Demand	C&I Demand	Lighting	Total
07/23/2020 01:00 PM	2,297	218	3,870	0	6,385
07/23/2020 02:00 PM	2,423	233	3,837	0	6,493
07/23/2020 03:00 PM	2,575	229	3,756	0	6,560
07/23/2020 04:00 PM	2,714	205	3,609	0	6,527
4 hour Total	10,009	885	15,071	0	25,965
D10S Allocator	38.55%	3.41%	58.04%	0.00%	100.00%

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

Q. WHAT IS E8760 ALLOCATOR?

A. The E8760 allocator is calculated by taking each class's hourly load for all 8,784 hours of the test year and weighting it by the corresponding hourly marginal energy costs. This energy allocation method has been adopted or is under study for use in future rate cases by many Commission regulated utilities.

Q. WHAT COSTS ARE ALLOCATED USING THE E8760 ALLOCATOR?

A. The E8760 allocator has been used to allocate all cists that have been classified as being energy-related.

Q. HOW ARE THE TEST YEAR LOAD SHAPES CALCULATED?

A. The test year load shapes are calculated by adjusting historical load shapes for test year weather values. First, we used 2014 through 2018 historical load shapes to create the initial 2020 load shape. Next, we forecast 2020 weather values (THI, CDD, HDD), which are used to forecast the 2020 typical meteorological year (TMY) weather normalized (WN) class load shape templates. Next, we used specialized software that removes the magnitude of loads by turning the WN shape into a WN percentage scalar. Finally, the specialized software takes the monthly WN energy kWh forecast and casts it on the WN percentage scalar load shape to arrive at the final 2020 WN load shape. This is the same methodology used in the Company's past six rate cases.

3. Allocation of Distribution Substation Costs - The D60Sub Allocator

Q. WHAT COSTS ARE ALLOCATED USING THE D60SUB ALLOCATOR?

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

Q. HOW IS THE D60SUB ALLOCATOR CALCULATED?

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

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

A. Yes, there are 10 substations that are dedicated to serving specific large industrial customers. The costs for these substations are directly assigned to those specific customer classes.

Q. IN THE COMPANY'S LAST RATE CASE (DOCKET NO. E002/GR-15-826) THE COMMISSION ORDERED THAT LOADS FROM CUSTOMERS WHO ARE SERVED BY DISTRIBUTION SUBSTATIONS WHOSE COSTS ARE DIRECTLY ASSIGNED SHOULD BE EXCLUDED FROM THE CALCULATION OF THE D60SUB ALLOCATOR. HAS THE COMPANY MADE THE REQUIRED ADJUSTMENT TO THE D60SUB ALLOCATOR?

A. Yes, the Company agrees that excluding the peak loads of these customers more accurately reflects cost causation. The MW loads for these customers as shown in Table 10 below have been excluded from the D60Sub allocator.

Table 10

Customer Loads Excluded from the D60Sub Allocator (MW)

Customer Class and Voltage	**MW Loads Excluded from D60Sub Allocator**
C&I Demand Secondary Voltage	3.761
C&I Demand Primary Voltage	28.048
C&I Demand Transmission Transformed Voltage	299.625
C&I Demand Transmission Voltage	16.087
Total	347.520

4. *Allocation of CIP Conservation Cost Recovery Charge (CCRC)*

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

A. No. Consistent with the Commission's Order in the Company's most recent rate case (Docket No. E002/GR-15-826), we allocated both the CCRC and the CIP Adjustment Factor (CAF) using the per kWh method. In the proposed CCOSSs, CCRC costs are allocated to class using the test year sales forecast after subtracting sales to CIP exempt customers.

5. Classification and Allocation of Other Production O&M

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

A. Yes. The Commission required the Company to analyze Other Production O&M costs in order to identify those costs that vary directly with the amount of energy produced.[3]

Based on our analysis, the only Other Production O&M costs that vary directly (*i.e.* increase or decrease based on energy output) with energy output are chemicals and water use costs. In the case of chemicals, which are used for pollution control purposes, as generator energy output increases, chemical use increases in direct proportion. Similarly, with water usage, which is used to control both boiler water quality and replace lost steam, such as for soot blowing, usage changes proportionally to energy output. Total chemical and water use costs for the 2020 test year are $7.9 million and make up only 1.8 percent of total Other Production O&M costs. The remaining $428.2 million of Other Production O&M does not vary directly with energy output.

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

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

A. Yes. Consistent with Order Point 37 from the Company's 2013 rate case (Docket No. E002/GR-13-868), the CCOSS has classified the Other Production O&M costs that vary directly with energy usage as energy-related and classified the remaining Other Production O&M that originate from a specific generator costs based on the type of production plant associated with the costs. I note that there are $13.5 million in costs that are not specific to a generator type and $ 10.6 million of Regional Markets expense that is split into capacity and energy components based on how total plant-specific expense is split. Table 11 shows the resulting classification of the 2020 test year Other Production O&M costs.

Table 11

Classification of Other Production O&M Costs

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

Expense Category	2020 Other Production O&M ($000)	Percent Energy	Percent Capacity	Energy-Related Portion	Capacity-Related Portion
Variable (Chemicals & Water Use)	$7,860.3	100.0%	0.0%	$7,860.3	$0.0
Fossil	$42,967.7	60.56%	39.44%	$26,020.8	$16,946.9
Combustion Turbine	$2,594.9	0.0%	100.0%	$0.0	$2,594.9
Nuclear	$291,711.9	81.00%	19.00%	$236,286.6	$55,425.3
Combined Cycle	$16.011.6	30.29%	69.71%	$4,850.2	$11,161.4
Hydro	$883.4	82.92%	17.08%	$732.5	$150.9
Wind	$49,932.2	93.93%	6.07%	$46,900.2	$3,032.0
Total Generation-Specific Other Production O&M	$411,962.0	**78.32%**	**21.68%**	$322,650.7	$89,311.2
Corporate Other Production O&M not Assigned to Generation Type	$13,499.4	**78.32%**	**21.68%**	$10,572.8	$2,926.6
Regional Market Expense (FERC Codes 575.1 – 575.8)	$10,570.7	**78.32%**	**21.68%**	$8,279.1	$2,291.7
Total Other Production O&M	$436,032.1	**78.32%**	**21.68%**	$341,502.6	$94,529.5

6. *Direct Assignment of Distribution Costs to the Lighting Class*

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

A. Consistent with finding 693 from the 2012 rate case ALJ Report,[4] the Company has directly assigned all of the costs in FERC account 373 to the Street Lighting class and a portion of the costs is FERC account 364. FERC Account 373 includes all street lighting costs except for the cost of wood poles used solely by lighting in overhead distribution areas. The specific cost items included in FERC Account 373 are:

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

As shown on page 4, line 47 of Schedule 4, we directly assigned $74.4 million in 2020 test year FERC Account 373 costs to the Street Lighting class in the 2020 CCOSS. This direct assignment is appropriate because the costs included in FERC 373 are directly attributable to street lighting.

Q. WHAT COSTS ARE INCLUDED IN FERC ACCOUNT 364?

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

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

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

A. Yes. The 2020 CCOSS includes $432.3 million Plant in Service for FERC account 364. Analysis of the FERC account detail shows that 77.7% of this account is the cost of the 432,869 wooden poles. Company-owned street lights are attached to 91,441 of these poles, meaning 21.12 percent of the FERC Account 364 costs are attributable to street lighting. Through consultation with our Street Lighting staff, we determined that 60 percent of the lighting poles serve only Street Lighting customers (*i.e.* they do not have other facilities attached that serve other customer classes).

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

A. We directly assigned $42.6 million in 2020 test year FERC Account 364 costs to the Street Lighting class in the 2020 CCOSS. The calculation of the direct assignment is shown in Table 12 and the direct assignment is included on page 4, line 27 of Schedule 4.

Table 12

Calculation of FERC Account 364 Direct Assignment

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

Line No.		
1	FERC Acct 364	$432,339
2	Wood Pole Cost as a Percent of FERC 364	77.7%
3	FERC Acct 364 Pole Cost (line 1 x line 2)	$335,928
4	MN Company-Owned Street Lights on Wooden Poles	91,441
5	Total MN Wood Poles	432,869
6	Lighting Poles as % of Total Poles (line 4 / line 5)	21.12%
7	Lighting % x FERC 364 Pole Cost (line 1 x line 6)	$70,963
8	Percent of Lighting Poles that only Serve Lighting	60%
9	FERC Acct 364 Direct Assignment to Lighting (line 7 x line 8)	$42,578

Q. IN TOTAL, HOW MUCH PLANT INVESTMENT IS DIRECTLY ASSIGNED TO THE STREET LIGHTING CLASS IN THE 2020 CCOSS?

A. In total, $117.0 million of distribution plant investment is directly assigned to the Street Lighting class in the 2020 CCOSS.

7. Separation of Distribution Costs into Capacity Versus Customer Components; Results of the Minimum System and Zero Intercept Studies

Q. IN THE CONTEXT OF ALLOCATING COSTS OF DISTRIBUTION PLANT INVESTMENT, WHAT IS THE PURPOSE OF MINIMUM SYSTEM AND ZERO INTERCEPT STUDIES?

A. Minimum System and Zero Intercept 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.

a. The Purpose and Prevalence of Classifying Distribution Costs as Customer-Related

Q. IS IT WIDELY ACCEPTED THAT ELECTRIC DISTRIBUTION COSTS SHOULD BE CLASSIFIED AS BOTH CUSTOMER- AND DEMAND-RELATED?

A. Yes. It is widely accepted at the state, regional, and national levels that distribution costs are driven by two factors: 1) the number of customers on the distribution system, and 2) the demand those customers place on the system. With regard to the national prevalence of this classification, the NARUC manual states that only demand and customer components should be considered in classifying distribution costs. Specifically, at Chapter 6, page 89 of the manual, NARUC states:

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

Page 90 of the NARUC manual goes on to say:

> Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

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

Q. WHAT IS THE PURPOSE OF CLASSIFYING ELECTRIC DISTRIBUTION COSTS AS BOTH CUSTOMER- AND DEMAND-RELATED?

A. The purpose of this classification is to allocate costs according to causation. The *customer*-related portion of the distribution system makes service available to the customer. The balance of distribution system costs is *capacity*-related. The costs a utility incurs to connect a customer to the distribution grid without regard to the level of customer load is reasonably classified as customer-related and allocated based on number of customers. The capacity-related cost component – those that are not customer-related – has cost causation based on the level of power demanded by customers above the minimum customer-related level. These costs should be allocated on customer demand and are appropriate to recover through volumetric charges.

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

A. Table 13 below shows how the Company has classified costs for the various distribution property units.

Table 13

Classification of Distribution Plant Investment

Distribution Plant Property Unit	TY 2020 Plant In Service ($000)	Demand Component	Customer Component
Distribution Substations	$658,942	X	
Primary Voltage Transformers	$44,017	X	
Overhead & Underground Primary Distribution Lines	$1,987,277	X	X
Overhead & Underground Secondary Distribution Lines	$321,078	X	X
Overhead & Underground Secondary Voltage Transformers	$362,178	X	X
Service Drops	$284,339	X	X

Note that the above classification is consistent with the FERC classification as shown on page 87 of the NARUC manual with the exception of service drops. Although FERC and many other utilities classify services as being only customer-related, the Company has historically split these costs into capacity and customer-related components.

Q. IN PRIOR RATE CASES, HOW HAS THE COMPANY PERFORMED A SEPARATION OF DISTRIBUTION COSTS INTO CAPACITY AND CUSTOMER-RELATED COMPONENTS?

A. Since the 1980s, the Company has used a Minimum System Study to do this separation. In this case, we fully updated that study and included three new components. First, we performed an extensive review of what equipment would be considered "minimum." Second, we performed an extensive review of the installed cost of distribution equipment. Finally, we performed a Zero Intercept Study in addition to the Minimum System Study. A Zero Intercept

Study is the alternative method to determine the customer component of distribution costs.

Ms. Bloch addresses how we determined the minimum sized equipment and the unit costs for the studies, and I address how the studies were performed and the results. The Company assumed the minimum sized distribution system has a load carrying capacity of 1.5 kW per customer, the same assumption used in prior rate cases.

Q. IN TABLE 13 OF YOUR TESTIMONY, YOU NOTE THAT THE COST FOR SERVICE DROPS WAS ALSO SEPARATED INTO CUSTOMER AND CAPACITY COMPONENTS. HOW WAS THAT COST SEPARATION CONDUCTED?

A. Detailed property records on the configuration or footage of distribution service drops are not available. As a result, we were not able to conduct a detailed Minimum System or Zero Intercept Study for classifying the cost of service drops. As a substitute, we conducted a simplified Minimum System analysis as shown in Attachment P of Exhibit___(MAP-1), Schedule 10.

b. Minimum System and Zero Intercept Studies

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

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

Step 1: Determine the minimum sized conductor, transformer and service is 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 is divided by the total cost of the actual sized distribution plant in the field. This ratio is deemed to be the customer-related portion of distribution plant investment, with the balance being the capacity-related portion.

The assumed minimum property unit configurations used in the Minimum System Study are shown in Ms. Bloch's Direct Testimony.

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

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

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

  - Underground Secondary Conductor
  - Underground Transformers
  - 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.

Q. AS DESCRIBED ABOVE, BOTH MINIMUM SYSTEM AND ZERO INTERCEPT STUDIES REQUIRE DATA ON THE INVENTORY OF DIFFERENT DISTRIBUTION PROPERTY UNIT CONFIGURATIONS, THE PER UNIT INSTALLED COSTS OF DIFFERENT CONFIGURATIONS AND ASSOCIATED LOAD CARRYING CAPACITIES. HOW DID THE COMPANY ACQUIRE THIS INFORMATION?

A. The sources of the required data and the methods used to synthesize it are described of Ms. Bloch's Direct Testimony.

c. Results of Minimum System and Zero Intercept Studies

Q. WHAT WERE THE RESULTS OF THESE STUDIES?

A. The data and results of the Minimum System and Zero Intercept Studies are shown in Schedule 10 of my testimony.

Attachments A through G of Schedule 10 show the inventory of the different equipment configurations for each property unit.

Attachments H through M of Schedule 10 show the graphical results of the Zero Intercept linear regression analysis for each property unit.

Attachment N of Schedule 10 shows the detailed Minimum System and Zero Intercept calculations.

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

A. For each property unit, the table below shows the percent of costs that would be classified as customer-related using the Zero Intercept method compared to the Minimum System method. As shown in Table 14 below, for four of the six property units the Zero Intercept provides a lower customer component, while two of the six have a lower customer component using the Minimum System method.

Table 14

Percent of Distribution Plant Investment Classified as Customer Related

Zero Intercept Method versus 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%

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

A. For a given property unit the Company used the method that provided the lower customer component as shown in Table 15 below.

Table 15

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%	63.1%
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 (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	63.7%	36.3%

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

A. Attachment O shows how the results of the Minimum System and Zero Intercept analyses are used to provide the needed cost separation. The results as shown in column 7 are the inputs to the CCOSS model for the 2020 test year as shown in Schedule 4, page 4, column 1, lines 19 – 42.

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

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

Q. WHAT WOULD HAVE BEEN THE CCOSS RESULT IF THE COMPANY USED ONE METHOD OR THE OTHER INSTEAD OF A HYBRID APPROACH?

A. Table 16 below shows a summary of CCOSS results using the three methods for separating distribution costs into customer and capacity components. In addition to the results using each of the 3 methods of separating distribution costs into customer and capacity components, Table 16 also shows CCOSS results assuming no separation of costs occurs and all distribution costs are treated as capacity-related. This extreme method was referred to as the Basic Customer method in the Company's last rate case (Docket No. E002/GR-15-826).

Table 16

Summary of 2020 CCOSS Results Using Different Methods

For Classifying Distribution Plant Investment

NSPM-Minnesota Electric Jurisdiction

($ Thousands)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Hybrid Method		**Zero Intercept Method**		**Minimum System Method**		**Basic Customer Method**	
Line	**Customer Class**	**$ Defic. ($000)**	**% Defic.**	**$ Defic. ($000)**	**% Defic.**	**$ Defic. ($000)**	**% Defic.**	**$ Defic. ($000)**	**% Defic.**
1	Residential	92,837	8.0%	97,602	8.4%	105,128	9.0%	22,900	2.0%
2	Non-Demand	9,018	8.2%	9,313	8.4%	9,773	8.9%	4,799	4.4%
3	Demand	96,174	5.3%	91,106	5.0%	83,108	4.6%	170,445	9.4%
4	Street Ltg	3,397	12.7%	3,406	12.8	3,418	12.8%	3,283	12.3%
5	Total	201,427	6.5%	201,427	6.5%	201,427	6.5%	201,427	6.5%
6	Cost Based Residential Customer Chg ($ per Resid customer per month)	$16.73		$17.50		$18.63		$5.74	

Columns 1 and 2 above show the dollar deficiency and percent deficiency by customer class using the proposed hybrid method for separating distribution costs into customer and capacity components. Columns 2 and 3 show results using the Zero Intercept method, while columns 5 and 6 show results using the Minimum System method and columns 7 and 8 show results using the Basic Customer method. Line 6 of Table 16 above shows what the cost-based residential customer charge would be using each method.

Q. In the last rate case the Company was asked to show CCOSS results using a "Peak and Average" method whereby distribution costs are classified as capacity and energy-related. Has the Company done this analysis in the current rate case?

A. No. This method separates distribution costs into demand and energy components based on the System load factor. As was discussed in the prior rate case, there is no support in the record of any electric utility commission accepting, or any utility using this method to classify distribution costs.

Q. Does the NARUC manual mention this as a method that should be considered when classifying distribution costs?

A. No. Specifically, at Chapter 6, page 89 of the manual, NARUC states:

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

Page 90 of the NARUC manual goes on to say:

> Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

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

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

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

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

A. Yes. Based on the data in the Company's Geographic Information System, the Company's Distribution staff determined 74.1 percent of residential customers receive service off the single-phase primary distribution system. Table 17 also shows that significantly fewer C&I customers receive service from the single-phase primary distribution system.

Table 17

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

NSPM – Minnesota Electric Jurisdiction

Primary Distribution Line Serving the Customer Premise	Customer Class			
	Residential Customers	C&I Non-Demand	C&I Demand	Lighting Customers
Single-Phase	73.6%	39.9%	11.8%	39.3%
Multi-Phase	26.4%	60.1%	88.2%	60.7%
Total	100.0%	100.0%	100.0%	100.0%

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

A. Yes. We continue to separate distribution lines into capacity and customer components using the Company's Minimum System and Zero Intercept studies, as described in the CCOSS Guide. As we did in the last rate case, we added an additional step to split the classified costs for primary distribution lines into single-phase and multi-phase components. We based the split on miles of single-phase and multi-phase distribution plant and their associated replacement cost (in dollars per mile). The resulting separation of costs is shown on page four of Schedule 4, lines 19-22 (overhead primary distribution lines) and lines 29-32 (underground primary distribution lines). We also created distribution line cost allocators to account for the differing usage of the single-phase portions of the system by different customer classes. Exhibit___(MAP-1), Schedule 11 shows how these allocators were developed.

IV. RATE RIDER REVISIONS

A. Windsource and Renewable*Connect Riders – Capacity Credit

Q. PLEASE EXPLAIN THE CAPACITY CREDIT RELATED TO WINDSOURCE AND RENEWABLE*CONNECT.

A. The capacity credit is a partial offset (credit) to the Windsource and Renewable*Connect purchased energy costs. It is intended to reflect the capacity value that Windsource and Renewable*Connect energy generation brings to the system power-supply portfolio. The amount of this "capacity-credit-based" transfer of costs from the Windsource Program into base rates (applicable to all ratepayers) is determined in general rate cases and then bundled into base rates.

Q. WHAT IMPACT DOES THE CAPACITY CREDIT HAVE ON BASE RATES?

A. The capacity credit cost from these programs results in an increase to base rates. The cost is calculated as the amount of the capacity credit per kWH multiplied by program sales. A summary of the proposed 2020 – 2022 capacity credits from these programs is shown on Exhibit___(MAP-1), Schedule 12, page 1 of 5, with the supporting calculations on pages 2-5.

Q. WHAT CHANGES ARE BEING PROPOSED FOR THE WINDSOURCE CAPACITY CREDIT RATE?

A. The Company is proposing a change to the Windsource capacity credit to update the combustion turbine value and MISO wind capacity factors. We adjusted the levelized cost of a combustion turbine to be consistent with the level filed in the Company's most recent Integrated Resource plan in Docket

No. E002/RP-19-368. We also reflect the MISO Planning Year 2018-2019 Wind Capacity Credit of 15.2 percent. After the Commission Order in this case, the Company would reflect the new capacity credit rate in the Company's next Windsource compliance filing.

Q. ARE YOU PROPOSING CHANGES TO THE RENEWABLE*CONNECT CAPACITY CREDIT RATE?

A. No, the capacity credit rate for the various Renewable*Connect programs were established in Docket Nos. E002/M-15-985 and E002/M-19-33 for the terms of the programs.

Q. HOW DID THE COMPANY CALCULATE THE CAPACITY CREDIT COST ASSOCIATED WITH THE RENEWABLE*CONNECT PROGRAMS?

A. The Renewable*Connect programs include a capacity credit component for each year of the program. We multiplied the approved capacity credit pricing component by the expected program sales to arrive at the total capacity credit expected for the program for each year of the multi-year period. The calculation is shown on Exhibit___(MAP-1), Schedule 12, pages 2-4 and results in $1,339,107 being transferred to base rates in the 2020 Test Year. A summary of the all the capacity credit costs included in base rates for each year of the multi-year period can be found on page 1 of Exhibit___(MAP-1), Schedule 12.

B. CIP Program Rider

Q. PLEASE EXPLAIN HOW CONSERVATION IMPROVEMENT PROGRAM EXPENSES ARE RECOVERED.

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

Q. WHAT ARE THE CURRENT CCRC AND CAF LEVELS?

A. The current CCRC is 0.3133¢ per kWh, and was established in the Company's most recent case based on the 2016 test year level of CIP expenses. The current CAF is 0.1682¢ per kWh, which became effective with Commission approval on July 19, 2019 in Docket No. E002/M-19-258.

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

A. Yes. The Company is proposing to increase in the CCRC from the current 0.3133¢ per kWh to 0.3741¢ per kWh to reflect 2020 test year CIP costs of $102,371,401. The Company is also proposing a corresponding decrease in the CAF from the current level of 0.1682¢ per kWh to 0.1074¢ per kWh. The lower CAF fully offsets the higher CCRC, resulting in a net zero change in total CIP program cost recovery from current levels. The calculation of these revised CCRC and CAF components is shown in Exhibit___(MAP-1), Schedule 13.

V. 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

A. Excess Footage Charges—Section 5.1.A.1

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

A. There are three excess-footage charges specified on tariff Sheet No. 23 of the General Rules and Regulations. Based on current material, labor and equipment costs, the Company is proposing increases in each, as shown in Table 18 below.

Table 18

Excess Footage Charges (Per Foot)

Type	Present Rate	Proposed Rate
Service Line	$7.90	$11.00
Single Phase Sec or Prim	$8.00	$11.00
Three Phase Sec or Prim	$13.90	$19.00

The cost analysis supporting these increases in charges is provided on page 2 of Exhibit___(MAP-1), Schedule 14.

B. Winter Construction Charges—Section 5.1.A.2

Q. WHAT REVISIONS ARE PROPOSED FOR WINTER CONSTRUCTION CHARGES?

A. There are two components to the Winter Construction Charges, as indicated on Sheet No. 24 of the General Rules and Regulations. The Company is proposing to an increase in each as shown in Table 19 below.

Table 19

Winter Construction Charges

Type	Present Rate	Proposed Rate
Thawing (Per Frost Burner)	$600.00	$650.00
Trenching (Per Foot)	$3.80	$7.30

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 14.

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 $447,193 as shown on page 1 of Exhibit___(MAP-1), Schedule 14. This increase in revenues is shown with the increase in late payment charges on lines 2 and 14 of Schedules 3, 5 and 7 to my testimony. It is also shown on page 7, row 21 of Schedules 4, 6, and 8 to my testimony. The proposed increase in these charges reduces the proposed increase in retail revenues by Mr. Huso.

VI. GOOGLE INCREMENTAL COST AND BENEFIT ANALYSIS

Q. HAS THE COMPANY PERFORMED AN UPDATED INCREMENTAL COST AND BENEFIT ANALYSIS FOR THE AGREEMENT WITH GOOGLE?

A. Yes, in compliance with order point 3. C. in Docket No. E002/M-19-39, updated incremental cost and benefit analyses are included in Exhibit___(MAP-1), Schedule 15.

VII. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE THE CONCLUSIONS FROM YOUR TESTIMONY.

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

- Properly recognize that our investments in baseload generation facilities provide value to all customers, particularly our energy-intensive users;
- Accurately reflect the value of our investments in peaking capacity, transmission and distribution facilities used to meet system peak requirements;
- Recognize the differing impact that seasonal and time usage patterns can have on the cost of service; and

- Recognize that a portion of distribution costs are incurred to simply connect customers to the system and therefore should be allocated to customer class based on the number of customers.

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

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications 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

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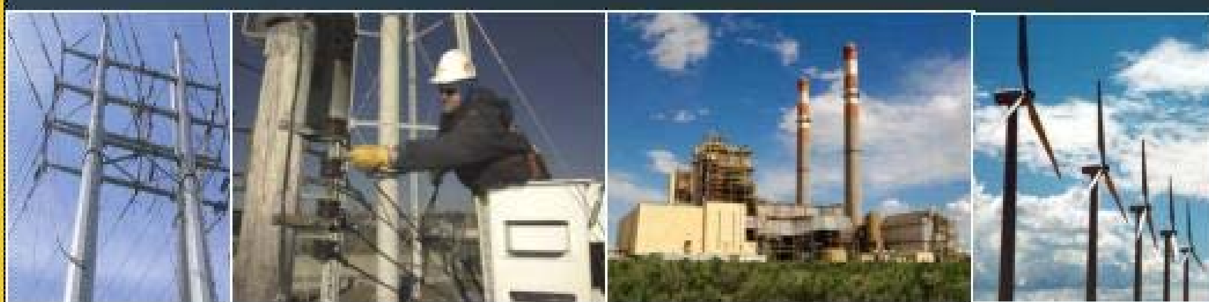

Guide to the Electric Class Cost of Service Study (CCOSS) Northern States Power Co

I. Overview

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

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

II. Major Steps of the Class Cost of Service Study

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

1. Functionalization – The identification of each cost element as one of the basic utility service "functions" (e.g. generation, transmission, distribution and customer).
2. Classification – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. kWs of capacity, kWhs of energy or number of customers).
3. Allocation – The allocation of the functionalized and classified costs to customer classes, based on each class' respective service requirements (e.g. kWs of capacity, kWhs of energy and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

III. Step 1: Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the electric utility system. Costs must be first functionalized because each class' service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The 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	$925	$925 / $925	100.0%	0.0%
Nuclear	$4,868	$925 / $4,868	19.0%	81.0%
Fossil	$2,345	$925 / $2,345	39.4%	60.6%
Combined Cycle	$1,327	$925 / $1,327	69.7%	30.3%
Hydro	$5,415	$925 / $5,415	17.1%	82.9%
Wind	$15,233	$925 / $15,233	6.1%	93.9%

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

IV. Step 2: Cost Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The 3 principle service requirements or billing components are:

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

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

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

As shown in the table above, primary lines, secondary lines, secondary transformers and service drops are classified as both "demand" and "customer" related costs. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. Two methods that are mentioned in the NARUC manual for performing this cost separation are the Minimum Distribution System (MDS) method and the Minimum/Zero Intercept method.

The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used, to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum sized cost.

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

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

For each property unit, the table below shows the percent of costs that were classified as customer-related using the zero intercept method compared to the minimum system method. As shown below, for 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.

	% of Costs Classified as "Customer" Related	
Equipment Type	**Zero Intercept Method**	**Minimum System Method**
Overhead Lines Primary	34.9%	51.4%
Overhead Lines Secondary	78.2%	89.6%
Overhead Transformers	72.6%	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)	78.2%	21.8%
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)	64.1%	35.9%

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

The third step in the CCOSS process is allocation, which is the process of assigning (allocating or directly assigning) functionalized and classified costs to customer classes. Generally, cost assignment occurs in one of 2 ways:

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. Examples of costs that are directly assigned include:

- Customer-dedicated transmission radial lines or dedicated distribution substations
- Street lighting facility costs

- Allocation - Most electric utility costs are incurred in common or jointly in providing service to all or most customers and classes. Therefore, allocation methods have to be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
  - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100%.
  - There are 2 types of allocators:
    - External Allocators –These are the more interesting allocators that are based on data from outside the CCOSS model (e.g. load research data, metering and customer service-related cost ratios). In general, there are 3 types of external allocators:
      - Capacity –related (sometimes referred to as Demand) allocators such as:
        - System coincident peak (CP) responsibility or class contribution to system peak (1CP, 4CP or 12CP)
        - Class peak or non-coincident peak
        - Individual customer maximum demands
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales)
        - kWh at the generator (kWh sales plus loses)
        - kWh energy, weighted by the variable cost of the energy in the hour it's used
      - Customer-related allocators
        - Number of customers
        - Weighted number of customers, where the weights are based on cost of meters, billing, meter-reading, etc.

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

    - Internal Allocators – These are allocators based on combinations of costs already allocated to the classes using external allocators. These internal allocators are used to assign certain costs, which are most appropriately associated with and assigned to classes by some combination of other primary service requirements, such as kWs demand, kWhs of energy or the number of customers. Examples of internal allocators include:
      - Production, transmission and distribution plant investment – Labeled "PTD" in the CCOSS model.
      - Distribution O&M expenses without supervision and miscellaneous expenses – Labeled "OXDTS" in the CCOSS model.

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

VI. Customer Class Definitions

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

1. Residential
2. Non Demand Metered Commercial
3. Demand Metered Commercial & Industrial and
4. Street & Outdoor Lighting

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

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

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

VII. Organization of the CCOSS Model

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

1. Billing Unit:

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

2. Function and Associated Sub-Function:

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

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

   c. Transmission (RR-Transco)

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

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

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

VIII. CCOSS Calculations

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

A. Rate Base Calculation

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

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

B. Revenue Requirements Calculation (Class Cost Responsibility)

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

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

\+

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

\+

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

Where:

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

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

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

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

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

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

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

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

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

XI. CCOSS Output

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

Final CCOSS Printout "Tot" Worksheet			
CCOSS Section	**Page Number**	**Results Detail**	**Line Numbers**
Results Summary	1	Rate Base Summary	1-21
		Income Statement Summary	22-31
	2	**Proposed Cost** Responsibility at <u>Equal ROR</u> (the cost of service) compared to **Present** Rate **Revenue** Responsibility	1-51
	3	**Proposed Cost** Responsibility at <u>Equal ROR</u> (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility	1-54
Rate Base Detail	4	Original Plant in Service	1-50
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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	A00, A01, A02, A03, A04, A05 (if residential), A06 (if residential), A08			• Costs directly attributed to and directly assigned to Street Lighting customers • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers
2	C&I Non Demand Metered	A05 (if C&I), A06 (if C&I), A09, A10, A11, A12, A13, A16, A18, A22, A38, A40, A42,	< 25 kW		• Costs directly attributed to and directly assigned to Street Lighting customers • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not use to provide service to these customers
3	C&I Secondary Voltage	A14, A15, A17, A19, A20, A21, A23, A24, A26, A27, A41, A62, A63	> 25 kW	Secondary	• Costs directly attributed to and directly assigned to Street Lighting customers • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Underground (“UG”) services. C&I customers pay for their own UG services.	The listed facilities and their associated costs are not used to provide service to these customers
4	C&I Primary Voltage	A14, A15, A17, A19, A20, A21, A23, A24, A26, A27, A41, A62, A63	> 25 kW	Primary	• Costs directly attributed to and directly assigned to Street Lighting customers • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Secondary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Transformers that have been classified as either “Customer” or “Capacity” related. • Costs of Service Lines that have been classified as either “Customer” or “Capacity” related.	The listed facilities and their associated costs are not used to provide service to these customers

	Customer Class	**Rate Codes**	**kW Size**	**Voltage Specifications**	**Costs Not Assigned**	**Why Costs Not Assigned**
5	C&I Transmission Transformed Voltage	A14, A15, A17, A19, A20, A21, A23, A24, A26, A27, A41, A62, A63	> 25 kW	Transmission Transformed	• Costs directly attributed to and directly assigned to Street Lighting customers • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Primary Voltage Transformers • Costs of Primary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Transformers that have been classified as either “Customer” or “Capacity” related. • Costs of Service Lines that have been classified as either “Customer” or “Capacity” related.	The listed facilities and their associated costs are not used to provide service to these customers
6	C&I Transmission Voltage	A14, A15, A17, A19, A20, A21, A23, A24, A26, A27, A41, A62, A63	> 25 kW	Transmission	• Costs directly attributed to and directly assigned to Street Lighting customers • Directly assigned costs of specific Transmission Radial Lines • Costs of Distribution Substations • Costs of Primary Voltage Transformers • Costs of Primary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Transformers that have been classified as either “Customer” or “Capacity” related. • Costs of Service Lines that have been classified as either “Customer” or “Capacity” related.	The listed facilities and their associated costs are not used to provide service to these customers
7	Outdoor Lighting	A07, A30, A31, A32, A34, A35, A37			• Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers

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

Code	Allocator for:	Description	Data Source(s)	Derivation	Allocator Rationale
C11	Connection charge revenues	Average monthly customers	- 2019 Customer forecast for TY2020	Forecasted annual bills / 12	Connection charge revenue isn't specifically included in the NARUC manual. New customer connections, by class, follow the pattern of existing customers. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C11WA	Customer accounting costs	Weighted customer accounting costs	- 2019 Customer forecast for TY2020 and - 2019 customer accounting weighting factors	C11 X C11WAF	On page 103, the NARUC manually says customer accounting costs are classified as customer-related, which matches Xcel's approach. As for allocating costs to class, the chosen allocator recognizes that classes with larger customers require more complicated tracking per customer. Thus, such classes should get heavier weights. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C12WM	Meter costs	Weighted meter investment	- 2018 meter, CT and VT model inventory by customer class - 2019 meter, CT and VT replacement costs	C12 X C12WMF	On page 96, the NARUC manual notes that meters are normally classified as customer-related. And on page 98, the manual supports the idea of weighting classes differently to reflect differences in capital investment levels. Xcel's allocator follows both suggestions. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C61PS	The "customer" (minimum system) portion of multi-phase primary distribution line costs	Average monthly customers served at primary or secondary voltage	- Customer 2019 forecast for TY2020 - 2018 Minimum System and Zero Intercept studies	C11 less transmission transformed and transmission voltage customers	On page 87, the NARUC manual only discusses overhead and underground lines in general, rather than primary, multi-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses customer-based costs. It reflects both secondary and primary voltage customers, since both make use of primary lines. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

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

Code	Allocator for:	Description	Data Source(s)	Derivation	Allocator Rationale
C61PS1Ph	The "customer" (minimum system) portion of single phase primary distribution line costs	Average monthly customers that are served by single phase primary distribution facilities	- Customer forecast for TY2020 and 2018 - Minimum System and Zero Intercept studies - GIS data that shows the percent of customers in each class that receive service from the single phase primary distribution system	C61PS multiplied by the percent of customers in each class that receive service from the single phase primary distribution system	On page 87, the NARUC manual only discusses overhead and underground lines in general, rather than primary, single-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses customer-based costs. It reflects both secondary and primary voltage customers, since both make use of primary lines. But it only applies to those served by a single phase. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C62NL	The customer portion of Company owned service costs.	Adjusted average monthly secondary voltage customers	- Customer forecast for TY2020 - 2018 Minimum System and Zero Intercept studies	C62Sec less street lighting and C&I underground customers	On page 87, the NARUC manual discusses services, suggesting just a customer-related classification. Xcel chose instead to extend the minimum system approach to service lines, thus recognizing that a service wire has a capacity aspect, as well as the ability to deliver a minimum electrical connectivity. This allocator only addresses customer-based costs. It excludes lighting customers, since they don't have service wires. And it excludes C&I underground customers, since they own their service wire. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C62Sec	The customer portion of secondary distribution line costs	Average monthly customers served at secondary voltage	- Customer forecast for TY2020 - 2019 Minimum System and Zero Intercept studies	C61PS less primary voltage customers	On page 87, the NARUC manual only discusses overhead and underground lines in general, rather than secondary lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses customer-based costs. It reflects all secondary voltage customers. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

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

Code	Allocator for:	Description	Data Sources	Derivation	Allocator Rationale
D10S	Capacity-related generation costs and all transmission costs	Class contribution to System Peaks at MISO's peak hour for Local Resource Zone 1 (LRZ-1)	- 8760 load research data by class for the years 2014-2018 synched to the 2019 kWh Sales Forecast for TY2020	Since the MISO LRZ-1 peak hour for the test year is not available, used hourly class loads that are in the same hours as the top 4 NSP System loads for the 2020 test year. Loads in the top 4 hours are used because based on 10 years of historical data, one of the 4 highest NSP System load hours is always in the same hour as the MISO LRZ-1 peak hour	Pages 39 through 63 of the NARUC manual discuss numerous methods for allocating generation capital costs to class. And pages 75 through 83 of the manual discuss many of the same methods for allocating transmission line costs. The Company employs a different approach that nonetheless reflects many of the underlying issues in the manual. This approach recognizes that a portion of a utility's generation assets, as well as all of their transmission assets, are built for the purpose of meeting peak load. And this allocator is applied to those costs. This allocator previously reflected the utility's own annual, coincident peak – i.e., a 1CP approach. But because the company has become so fully integrated with MISO, and because MISO basically dispatches the company's power plants, a MISO-coincident peak is now used. A significant portion of the utility's generation investments is made primarily to facilitate the consumption of lower-cost fuel (rather than to meet peak demand). Those costs are allocated to class based on an energy allocator, as discussed for E8760. Such costs are still classified as demand-related. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Code	Allocator for:	Description	Data Sources	Derivation	Allocator Rationale
D60Sub	Distribution substation costs	Class-coincident peak less transmission-level demand	- 8760 load research data by class for the years 2014-2018 synched to the 2019 kWh Sales Forecast for TY2020 - Based on the Commission's order from the Company's last rate case (15-826) the loads for customers who are direct assigned substation costs are excluded from calculation of this allocator		On pages 77 through 83, the NARUC manual discusses several possible class allocation methods for transmission plant, all related to some form of peak demand (other than a direct assignment approach). If a single season (in Xcel Energy's case, summer) clearly has the largest peak, then a 1CP method seems to be the most appropriate. And the Company does use 1CP. In particular, this allocator represents the annual coincident peak demand of every customer class except those served at transmission voltage (since they don't make use of step-down substations). The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
D61PS	The capacity portion of multi-phase primary voltage distribution line costs.	Class-coincident peak for primary and secondary voltage customers	- 8760 load research data by class for the years 2014-2018 synched to the 2019 kWh Sales Forecast for TY2020 - 2019 Minimum System and Zero Intercept studies	D60Sub less Transmission Transformed customer demands, less customer demands served by minimum distribution system and with reduced Residential Space Heating demands to reflect their summer peak is less than their winter peak	On page 87, the NARUC manual only discusses overhead and underground lines in general, rather than primary, multi-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses demand-based costs. It reflects the class-coincident peak for both secondary and primary voltage customers, since both make use of primary lines. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Code	Allocator for:	Description	Data Sources	Derivation	Allocator Rationale
D61PS1Ph	The capacity portion of single phase primary distribution line costs	Class-coincident peak for primary and secondary voltage customers for customers that use the single phase primary distribution system	- 8760 load research data by class for the years 2014-2018 synched to the 2019 kWh Sales Forecast for TY2020 - 2019 Minimum System and Zero Intercept studies - GIS data that shows the percent of customers in each class that receive service from the single phase primary distribution system	D61PS multiplied by the percent of customers in each class that receive service from the single phase primary distribution system.	On page 87, the NARUC manual only discusses overhead and underground lines in general, rather than primary, single-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses demand-based costs. It reflects the class-coincident peak for both secondary and primary voltage customers, since both make use of primary lines. But it only applies to those served by a single phase. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
D62NLL	The capacity portion of company owned service line costs	Secondary voltage demand less lighting	- Individual customer maximum demands from load research for non-demand billed customers and 2018 billing data for demand billed customers - 2019 Minimum system and Zero Intercept studies.	Non-coincident (or "customer peak") demand for secondary voltage customers, less the following: street lighting, area lighting and C&I customers served underground	On page 87, the NARUC manual discusses services, suggesting just a customer-related classification. Xcel chose instead to extend the minimum system approach to service lines, thus recognizing that a service wire has a capacity aspect, as well as the ability to deliver a minimum electrical connectivity. This allocator only addresses demand-based costs. It excludes lighting customers, since they don't have service wires. And it excludes C&I underground service customers, since they own their service wire. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Code	Allocator for	Description	Data Sources	Derivation	Allocator Rationale
D62SecL	The capacity portion of secondary distribution line costs	Average of class-coincident peak, secondary voltage percentages and non-coincident secondary voltage percentages	- TY2020 load research class coincident demands - 2019 Minimum system and Zero Intercept studies - Individual customer maximum demands from load research for non-demand billed customers and billing data for demand billed customers.	First define D62Sec as equal to D61PS, less primary customers. Then for each secondary class, D62SecL equals the average of D62Sec percent and non-coincident (or “customer peak”), secondary voltage percent.	On page 87, the NARUC manual discusses only overhead and underground lines in general, rather than secondary lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel follows that approach. This allocator only addresses demand-based costs. It reflects all secondary voltage customers. These capacity costs are driven by a 50/50 blend of class coincident peak demand and individual customer maximum (non-coincident) demand, less minimum system requirements. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
E8760	Fuel, purchased energy and energy-related fixed generation costs.	Class hourly energy (MWH) requirements weighted to reflect higher on-peak fuel costs	- 8760 load research data by class for the years 2014-2018 synched to the 2019 kWh Sales Forecast for TY2020 - Hourly marginal energy costs for the 2020 test year.	The hourly on-peak sales each class weighted by the hourly marginal energy cost.	On page 64, the NARUC manual notes that fuel costs are almost always classified as energy-related. And some form of time differentiation, such as on-peak vs. off-peak, is most appropriate. Xcel Energy previously used such an on-peak / off-peak approach. Then the Company migrated to a more precise approach that properly weights the marginal energy cost for each of the 8,760 hours in a standard year, along with class consumption during each hour. This allocator is applied to all fuel cost items, including purchased energy. Those costs are classified as energy-related. And as is explained in more detail for the D10S allocator, this allocator is also applied to the fuel-related portions of generation equipment. Those costs are classified as demand-related. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

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

Code	Allocator for	Description	Data Sources	Derivation	Allocator Rationale
E99XCIP	CIP O&M Expenses	TY2020 sales forecast by customer class Less the TY2020 sales forecast for CIP exempt customers	2019 kWh Sales Forecast for TY2020		Programs such as CIP were not anticipated by the NARUC manual. This allocator is simply based on sales. But since it applies to CIP program costs, it excludes sales from CIP-exempt customers. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

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.

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

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

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

Code	Allocator for:	Description	Allocator Justification
C11P10	Expenses and labor related to customer assistance and instructional advertising	This allocator is the average of the Customer-related C11 allocator and the Production Plant investment P10 allocator.	Customer assistance and advertising expenses are driven by # of customers, and since most assistance pertains to helping customers reduce energy use it affects production plant investment.
LABOR	Amortizations, Payroll Taxes and A&G Expenses that are labor related such as Salaries, Pension & Benefits, Injuries & Claims.	Total Labor costs on Page 12 line 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

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

Code	**Allocator for:**	**Description**	**Allocator Justification**
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.
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.

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

Code	**Allocator for:**	**Description**	**Allocator Justification**
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 43 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 45 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.
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 46 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		
RTBASE	Income Tax Addition: Avoided tax interest	Total Rate Base (line 37 of page 6)	Total rate base drives avoided tax interest

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

Code	**Allocator for:**	**Description**	**Allocator Justification**
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 D10S capacity allocator	Energy vs. capacity weighting of Hydro plants drives Step-up Transformer investment. It applies to just the very small portion of generation step-up assets that are hydro-related and are located on the Distribution system, unlike all of the other generation step-up facilities that are located on the Transmission system.
TD	Transmission and Distribution Materials and Supplies that are Rate Base Additions	Total Transmission and Distribution Original Plant in Service (Lines 13 and 46 of page 4)	Total Transmission and distribution plant investment drives investment in miscellaneous transmission and distribution materials and supplies
ZDTS	Supervision & Engineering and Customer Installation Distribution Labor	All Distribution Labor except Supervision and Engineering and Customer Installation. These items are excluded to avoid a circular reference. (All of lines 33 thru 41 on page 12, except 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 2020 Test Year. The allocation is the relationship of the annual class totals of these hourly results to the retail total.	1. Test-Year 8760 load shapes for each customer class are developed from five years of load research data (2014-2018). The resulting load shapes for each class are synced up to the 2019 forecast for the 2020, Test Year. 2. Hourly system marginal energy costs are based on the 2020 Test Year forecast from the Commercial Operations area.
Generation Plant Stratification Analysis	Cost stratification is the term used to identify the capital substitution analysis that separates or "stratifies" fixed generation costs into "capacity-related" and "energy-related" categories. The information used for this analysis includes the 2015 replacement costs of NSPM power plants that were developed by the Capital Asset Accounting area, and the corresponding capacity ratings for those plants. This information is used to define the "capacity-related" component for each type of non-peaking generation plant. This capacity component by plant type is recognized by dividing the peaking plant cost per kW by the non-peaking cost per kW. The remaining "energy-related" component by plant type is the percent determined by subtracting the capacity-related percent from 100 percent. This component is sub-functionalized as "energy-related," because it represents the additional investment above the cost of a peaking plant that is made to obtain lower energy (and total) costs as compared to a peaking plant.	Based on 2019 replacement costs of all NSP Minnesota Company Power Plants

Analysis	**Analysis Description**	**Data Sources and Associated Vintage**
Customer Accounting Weights	The relative costs by customer class for meter reading, back-office support, customer service and billing were developed based on current budgets and the experience of management in the Billing and Customer Service area. Residential customers are assigned a weight of 1. Based on this analysis, the other customer classes are assigned weights based on the relative differences compared to the residential class.	Based on 2020 budgets with the relative weighting estimates provided by management from the Billing and Customer Service areas
Minimum System and Zero Intercept Analyses	The Minimum System and Zero Intercept Analyses is used to separate FERC accounts 364-369 into "Demand/Capacity-Related" and "Customer-Related" cost classifications. As ordered by the Commission in the Company's last rate case (E002/GR-13-868) the Company conducted an updated Minimum System study. The Company was also able to obtain the data for a Zero Intercept study. A detailed description of these studies is provided Schedule 10 of Michael Peppin's direct testimony. The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs. The "capacity" cost component is the difference between total installed cost and the minimum sized cost. The Zero Intercept method attempts to determine the portion of plant that relates to a hypothetical no load or zero intercept situation. By analyzing the actual costs of 12 years of construction work orders, installed costs per unit (e.g. cost per foot of overhead primary conductor) were obtained for equipment configurations that comprise at least 90% distribution plant in the field. The installed cost was regressed against the load carrying capacity of each equipment configuration. The zero intercept of the regression was used as the minimum system cost. The cost of the minimum size facilities determines the "customer" component of total costs.	Based on an analysis of distribution construction work orders in Minnesota that were completed from 2007 to 2018.

Analysis	**Analysis Description**	**Data Sources and Associated Vintage**
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 2018 inventory of meter models, CT models and VT models for each customer. Meter, CT and VT replacement costs are for 2019
Compliance Classification of Other Production O&M Costs	Based on the MNPUC order in Docket Nos. 12-961 and 13-868, consulted with Xcel Generation Cost modeling staff to identify production Other Production O&M expenses that vary directly with energy consumption. Staff in the Generation Cost Modeling area considers Chemicals and Water as the only Other Production O&M costs that vary directly with energy output. These costs were classified as 100% energy related. The remaining cost items were split in groups based on the type of plant (i.e. Nuclear, Fossil, etc) and classified as capacity or energy related based on the plant stratification for that plant type.	2020-2022 budget detail of Other Production O&M expenses and 2019 Plant Stratification Analysis
Direct Assignment of Overhead Secondary Distribution Line Costs to the Lighting Class	In consultation with staff in the Company's Capital Asset Accounting area, identified specific lighting costs that are included in each FERC account code for distribution plant. Discovered that all lighting plant investment is included in FERC account 373 except for the cost of wood poles that are solely used by lighting in overhead distribution areas. These costs are included in FERC account 364. This analysis quantified the amount of overhead distribution pole investment that is attributed to lighting poles only. The costs for cross arms are excluded from the analysis since cross arms are used to carry conductors which means the pole has more than street lights attached.	• TY2020 plant investment in FERC code 364 (overhead distribution poles). • The total number of overhead distribution poles based on 2018 data. • The number of street lights in overhead distribution area in 2018 • Estimated percent of distribution poles with lighting that only serve lighting load

Analysis	Analysis Description	Data Sources and Associated Vintage
Customers Served by 3 Phase Vs 1 Phase Primary Distribution Lines	Customers who do not receive service off the single phase primary distribution system should not pay the costs of this part of the distribution system. Based on data from the Company's GIS system determined the percent of customers in each class the receive service off the 3 phase or 1 phase primary distribution system. This analysis is described on pages 45-46 of Michael Peppin's direct testimony.	2018 listing from the GIS system of all customer premises in MN and whether they receive service off the 3 phase of 1 phase distribution system
Customers Served by Overhead Vs Underground Transformers	C&I secondary voltage customers with underground services own the service. This analysis determined the percent of customers that are served from an underground service. These customers are excluded from the allocation of distribution service costs.	2018 listing from the GIS system of all customer premises in MN and whether they are served from an overhead or underground transformer
Comparison of MISO's LRZ-1 historical peak hour to historical NSP System hourly loads	Conduct a comparison of MISO's LRZ-1 historical peak hour to the historical hourly loads of the NSP System. This is done to determine which hours for the 2020 test year should be used to calculate the D10S class Generation and Transmission capacity cost allocator.	• NSP System Operations area has historical hourly loads for the NSP System. • MISO's most recent Loss of Load Expectations Study lists historical peak days and hours for each LRZ.

Northern States Power Company

Docket No. E002/GR-19-564
Exhibit___(MAP-1), Schedule 3

Summary of 2020 Class Cost of Service Study ($000)

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	3,320,983	1,260,019	116,903	1,913,962	30,098
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	849	495	38	312	4
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,321,832	1,260,514	116,941	1,914,274	30,103
[4]	Present Rates (CCOSS page 2, line 2)	3,120,405	1,165,785	109,370	1,818,541	26,709
[5]	Unadjusted Deficiency (line 3 - line 4)	201,427	94,730	7,571	95,732	3,393
[6]	Defic / Pres (line 5 / line 4)	6.5%	8.1%	6.9%	5.3%	12.7%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.26**	**1.07**	**0.82**	**1.97**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Development Disc Cost Allocation (CCOSS page 2, line 8)					
						HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(1,893)	1,447	442	4

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,320,983	1,258,126	118,350	1,914,404	30,102
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	849	495	38	312	4
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,321,832	1,258,621	118,388	1,914,716	30,106
[16]	Present Rates (line 4)	3,120,405	1,165,785	109,370	1,818,541	26,709
[17]	Adjusted Deficiency (line 15 - line 16)	201,427	92,837	9,018	96,174	3,397
[18]	**Defic / Pres Rates (line 17 / line 16)**	**6.5%**	**8.0%**	**8.2%**	**5.3%**	**12.7%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.23**	**1.28**	**0.82**	**1.97**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	3,320,983	1,253,775	117,863	1,919,662	29,683
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	849	495	38	312	4
[22]	Proposed Operating Revenues (line 20 + line 21)	3,321,832	1,254,270	117,901	1,919,973	29,688
[23]	Proposed Increase (line 22 - line 16)	201,427	88,485	8,531	101,432	2,978
[24]	Difference / Pres (line 23 / line 16)	6.5%	7.6%	7.8%	5.6%	11.2%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.18**	**1.21**	**0.86**	**1.73**

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

Rate Base

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Plant In Service	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	Production		11,115,442	3,537,987	7,547,860	357,124	7,190,736	5,217,574	1,339,369	610,663	23,130	29,595
2	Transmission		3,268,599	1,251,302	2,017,041	110,987	1,906,054	1,423,528	341,202	130,219	11,106	256
3	Distribution		3,883,261	2,519,102	1,233,919	173,748	1,060,171	872,097	177,811	10,029	234	130,240
4	General		1,691,167	676,603	999,743	59,423	940,321	695,564	172,047	69,518	3,191	14,821
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		19,958,469	7,984,995	11,798,563	701,282	11,097,282	8,208,763	2,030,429	820,429	37,661	174,911
7	Production		6,326,757	2,006,203	4,303,410	203,051	4,100,359	2,973,651	764,199	349,326	13,182	17,145
8	Transmission		728,387	279,289	449,066	24,734	424,332	316,760	75,826	28,851	2,896	32
9	Distribution		1,446,041	962,647	450,060	66,314	383,745	318,111	61,772	3,766	96	33,334
10	General		794,234	317,757	469,516	27,907	441,609	326,662	80,800	32,648	1,499	6,960
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		9,295,420	3,565,897	5,672,051	322,007	5,350,045	3,935,185	982,596	414,591	17,673	57,471
13	**Net Plant In Service**		10,663,050	4,419,098	6,126,512	379,275	5,747,237	4,273,578	1,047,833	405,838	19,988	117,440
14	Deducts: Accum Defer Inc Tax		2,301,002	950,124	1,327,014	82,279	1,244,736	926,452	226,583	87,229	4,472	23,864
15	Constr Work In Progress		363,989	132,680	229,544	12,356	217,187	159,072	40,324	17,124	667	1,765
16	Fuel Inventory		65,875	19,715	45,935	2,080	43,854	31,563	8,244	3,908	140	225
17	Materials & Supplies		153,932	52,423	100,843	5,072	95,771	69,820	17,762	7,877	312	666
18	Prepayments		99,733	41,332	57,302	3,547	53,754	39,971	9,800	3,796	187	1,098
19	Non-Plant & Work Cash		(58,674)	(26,968)	(31,069)	(2,049)	(29,020)	(21,890)	(5,212)	(1,802)	(115)	(638)
20	Total Additions		624,853	219,183	402,554	21,006	381,547	278,537	70,918	30,902	1,191	3,116
21	**Rate Base**		8,986,901	3,688,157	5,202,051	318,003	4,884,049	3,625,663	892,167	349,511	16,707	96,692
	Income Statement											
22A	**Tot Oper Rev - Pres**		3,666,158	1,353,685	2,284,375	127,412	2,156,964	1,612,079	374,326	163,268	7,290	28,097
22B	**Tot Oper Rev - Prop**		3,867,585	1,442,171	2,394,339	135,943	2,258,396	1,687,576	393,502	169,797	7,521	31,075
23	Oper & Maint		2,357,626	833,748	1,509,566	81,590	1,427,977	1,046,075	263,627	113,794	4,481	14,312
24	Book Depr + IRS Int		683,392	269,402	406,126	23,845	382,280	282,320	70,001	28,701	1,258	7,865
25	Payroll, Rl Est & Prop Tax		205,616	86,701	116,777	7,448	109,329	81,407	19,873	7,680	369	2,138
26	Deferred Inc Tax & Net ITC		(71,438)	(34,884)	(35,298)	(2,716)	(32,581)	(24,783)	(5,789)	(1,908)	(101)	(1,256)
27A	Present Income Tax		(6,184)	1,940	(8,511)	(77)	(8,434)	1,975	(8,187)	(2,293)	70	388
27B	Proposed Income Tax		51,710	27,372	23,094	2,375	20,720	23,675	(2,675)	(416)	136	1,244
28	Allow Funds Dur Const		28,846	10,486	18,225	973	17,252	12,627	3,209	1,360	57	135
29A	**Present Return**		525,991	207,265	313,941	18,296	295,645	237,712	38,009	18,653	1,271	4,785
29B	**Proposed Return**		669,524	270,318	392,298	24,375	367,923	291,509	51,673	23,306	1,435	6,908
30A	**Pres Ret on Rt Base**		5.85%	5.62%	6.03%	5.75%	6.05%	6.56%	4.26%	5.34%	7.61%	4.95%
30B	**Prop Ret on Rt Base**		**7.45%**	7.33%	7.54%	7.67%	7.53%	8.04%	5.79%	6.67%	8.59%	7.14%
31A	**Pres Ret on Common**		7.17%	6.72%	7.51%	6.98%	7.55%	8.51%	4.13%	6.18%	10.51%	5.45%
31B	**Prop Ret on Common**		**10.21%**	9.98%	10.38%	10.62%	10.37%	11.33%	7.05%	8.72%	12.38%	9.63%

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.45%**		**3,320,983**	**1,260,019**	**2,030,865**	**116,903**	**1,913,962**	**1,409,764**	**351,770**	**146,266**	**6,162**	**30,098**
2	**Present Revenue**		**3,120,405**	**1,165,785**	**1,927,911**	**109,370**	**1,818,541**	**1,364,535**	**311,884**	**135,923**	**6,199**	**26,709**
3	**UnAdj Revenue Deficiency**		**200,578**	**94,234**	**102,954**	**7,534**	**95,421**	**45,229**	**39,886**	**10,343**	**(38)**	**3,389**
4	**UnAdj Deficiency / Present**		**6.43%**	**8.08%**	**5.34%**	**6.89%**	**5.25%**	**3.31%**	**12.79%**	**7.61%**	**-0.61%**	**12.69%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
5	**Pres Int Rate Discounts**											
6	**Pres Econ Dvlp Rate Discounts**											
7	**Pres Int Rate Disc Cost Alloc**	**D10S**										
8	**Pres Econ Dvlp Disc Cost Alloc**	**R01**										
												HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
9	**Revenue Requirement Shift**		**0**	**(1,893)**	**1,889**	**1,447**	**442**	**9,932**	**(2,346)**	**(6,894)**	**(251)**	**4**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,320,983**	**1,258,126**	**2,032,754**	**118,350**	**1,914,404**	**1,419,696**	**349,424**	**139,373**	**5,911**	**30,102**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**200,578**	**92,342**	**104,844**	**8,981**	**95,863**	**55,162**	**37,540**	**3,449**	**(288)**	**3,392**
12	**Adj Deficiency / Adj Present**		**6.43%**	**7.92%**	**5.44%**	**8.21%**	**5.27%**	**4.04%**	**12.04%**	**2.54%**	**-4.65%**	**12.70%**
	Equal Customer Classification											
13	Min Sys & Service Drop		226,596	183,765	20,709	12,313	8,395	8,231	176	(14)	2	22,123
14	Energy Services		61,570	51,157	10,136	5,692	4,444	4,376	64	2	1	278
15	Total Customer **(Cusco)**		288,167	234,922	30,844	18,005	12,839	12,607	240	(12)	4	22,401
16	Ave Monthly Customers		1,334,596	1,170,186	136,525	87,750	48,776	48,273	479	15	9	27,884
17	Svc Drop Reqt	$ / Mo / Cust	$14.15	$13.09	$12.64	$11.69	$14.34	$14.21	$30.66	($79.79)	$19.78	$66.12
18	Ener Svcs Reqt	$ / Mo / Cust	$3.84	$3.64	$6.19	$5.41	$7.59	$7.55	$11.09	$13.80	$13.06	$0.83
19	Total Reqt	$ / Mo / Cust	$17.99	$16.73	$18.83	$17.10	$21.94	$21.76	$41.75	($65.99)	$32.84	$66.95
	Equal Energy Classification											
20	On Peak Rev Reqt		803,816	230,873	571,620	29,495	542,125	396,195	100,388	43,806	1,736	1,323
21	Off Peak Rev Reqt		808,386	251,255	552,827	21,298	531,529	379,481	100,792	49,537	1,719	4,304
22	Total Ener Rev Reqt		1,612,202	482,128	1,124,447	50,792	1,073,654	775,676	201,180	93,343	3,455	5,627
23	Annual MWh Sales		28,838,346.945	8,450,856	20,264,816	853,252	19,411,564	13,765,907	3,724,793	1,856,137	64,727	122,675
24	On Pk Reqt	Mills / kWh	27.873	27.320	28.208	34.567	27.928	28.781	26.951	23.601	26.818	10.783
25	Off Pk Reqt	Mills / kWh	28.032	29.731	27.280	24.960	27.382	27.567	27.060	26.688	26.557	35.085
26	Total Reqt	Mills / kWh	55.905	57.051	55.488	59.528	55.310	56.348	54.011	50.289	53.374	45.868
	Equal Demand Classification											
27	Energy-Related Prod		345,115	106,178	237,880	10,976	226,905	163,940	42,462	19,775	727	1,056
28	Capacity-Related Summer Peak Prod		293,753	112,975	180,778	9,998	170,780	127,974	30,628	11,611	567	0
29	Capacity-Related Winter Peak Prod		88,784	34,146	54,638	3,022	51,617	38,679	9,257	3,509	171	0
30	Total Capacity-Related Prod		382,537	147,121	235,416	13,020	222,396	166,653	39,885	15,120	739	0
31	Total Production		727,652	253,299	473,297	23,996	449,301	330,593	82,347	34,895	1,466	1,056
32	Transmission **(Transco)**		429,619	165,071	264,548	14,608	249,940	187,027	44,739	16,960	1,215	0
33	Primary Dist Subs		83,986	34,131	49,407	3,297	46,110	36,155	8,852	1,080	23	448
34	Prim Dist Lines		151,561	75,452	75,599	5,282	70,318	55,906	14,412	0	0	509
35	Second Dist, Trans		27,795	15,014	12,723	923	11,800	11,800	0	0	0	58
36	Total Distribution **(Disco)**		263,343	124,598	137,730	9,502	128,227	103,861	23,264	1,080	23	1,015
37	Total Demand Rev Reqt		1,420,614	542,969	875,574	48,106	827,469	621,481	150,350	52,935	2,703	2,071
38	Annual Billing kW		50,585,647	0	50,585,647	0	50,585,647	38,601,454	8,076,778	3,687,056	220,358	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$4.70	$0.00	$4.49	$4.25	$5.26	$5.36	$3.30	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.57	$0.00	$3.38	$3.32	$3.79	$3.15	$2.57	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.08	$0.00	$1.02	$1.00	$1.15	$0.95	$0.78	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$9.36	$0.00	$8.88	$8.56	$10.20	$9.46	$6.65	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.23	$0.00	$4.94	$4.85	$5.54	$4.60	$5.51	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$2.72	$0.00	$2.53	$2.69	$2.88	$0.29	$0.10	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$17.31	$0.00	$16.36	$16.10	$18.62	$14.36	$12.27	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	49.261	64.250	43.207	56.379	42.628	45.146	40.365	28.519	41.766	16.882
47	Summer Billing kW		18,568,179	0	18,568,179	0	18,568,179	14,099,351	3,037,682	1,342,582	88,563	0
48	Winter Billing kW		32,017,467	0	32,017,467	0	32,017,467	24,502,103	5,039,096	2,344,474	131,795	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$22.39	$0.00	$21.16	$20.86	$23.76	$18.90	$15.32	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$14.36	$0.00	$13.57	$13.36	$15.51	$11.75	$10.22	$0.00
51	Energy + Production **(Genco)**		2,339,854	735,428	1,597,744	74,788	1,522,956	1,106,269	283,528	128,238	4,921	6,683

2020 Class Cost of Service Study Detail ($000)

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

PROP vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.45%**	**7.33%**	**7.54%**	**7.67%**	**7.53%**	**8.04%**	**5.79%**	**6.67%**	**8.59%**	**7.14%**
2	**UnAdj Equalized Rev Reqt**		**3,320,983**	**1,260,019**	**2,030,865**	**116,903**	**1,913,962**	**1,409,764**	**351,770**	**146,266**	**6,162**	**30,098**
3	**Proposed Revenue**		**3,320,983**	**1,253,775**	**2,037,525**	**117,863**	**1,919,662**	**1,439,792**	**331,010**	**142,431**	**6,429**	**29,683**
4	**UnAdj Revenue Deficiency**		**(0)**	**6,244**	**(6,660)**	**(960)**	**(5,700)**	**(30,028)**	**20,760**	**3,835**	**(267)**	**415**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.50%**	**-0.33%**	**-0.81%**	**-0.30%**	**-2.09%**	**6.27%**	**3%**	**-4%**	**1.40%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
6	**Prop Interrupt Rate Discounts**											
7	**Prop Econ Dev Rate Discounts**											
8	**Prop Int Rate Disc Cost Alloc**	**D10S**										
9	**Prop ED Discount Cost Alloc**	**R01**										
										HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
10	**Revenue Requirement Shift**		**0**	**3,390**	**(3,394)**	**1,687**	**(5,081)**	**7,247**	**(4,225)**	**(7,807)**	**(296)**	**4**
11	**Adj Equal Rev (Rows 2+10)**		**3,320,983**	**1,263,409**	**2,027,472**	**118,590**	**1,908,881**	**1,417,011**	**347,545**	**138,459**	**5,866**	**30,102**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**(0)**	**9,634**	**(10,053)**	**727**	**(10,781)**	**(22,781)**	**16,535**	**(3,972)**	**(563)**	**419**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**0.77%**	**-0.49%**	**0.62%**	**-0.56%**	**-1.58%**	**5.00%**	**-2.79%**	**-8.76%**	**1.41%**
	Prop Customer Component											
14	Min Sys & Service Drop		223,554	180,950	20,895	12,356	8,539	8,384	167	(14)	2	21,709
15	Energy Services		61,564	51,150	10,136	5,692	4,444	4,377	64	2	1	278
16	Total Customer **(Cusco)**		285,118	232,100	31,031	18,048	12,983	12,760	231	(12)	4	21,987
17	Ave Monthly Customers		1,334,596	1,170,186	136,525	87,750	48,776	48,273	479	15	9	27,884
18	Svc Drop Reqt	$ / Mo / Cust	$13.96	$12.89	$12.75	$11.73	$14.59	$14.47	$29.12	($80.21)	$20.16	$64.88
19	Ener Svcs Reqt	$ / Mo / Cust	$3.84	$3.64	$6.19	$5.41	$7.59	$7.56	$11.08	$13.79	$13.06	$0.83
20	Total Reqt	$ / Mo / Cust	$17.80	$16.53	$18.94	$17.14	$22.18	$22.03	$40.21	($66.42)	$33.22	$65.71
	Prop Energy Component											
21	On Peak Rev Reqt		803,628	230,805	571,501	29,493	542,008	396,265	100,239	43,768	1,737	1,322
22	Off Peak Rev Reqt		808,182	251,180	552,699	21,296	531,403	379,548	100,642	49,493	1,720	4,303
23	Total Ener Rev Reqt		1,611,810	481,984	1,124,200	50,789	1,073,412	775,814	200,880	93,261	3,457	5,625
24	Annual MWh Sales		28,838,347	8,450,856	20,264,816	853,252	19,411,564	13,765,907	3,724,793	1,856,137	64,727	122,675
25	On Pk Reqt	Mills / kWh	27.867	27.311	28.202	34.565	27.922	28.786	26.911	23.580	26.833	10.780
26	Off Pk Reqt	Mills / kWh	28.025	29.722	27.274	24.959	27.376	27.572	27.019	26.665	26.572	35.073
27	Total Reqt	Mills / kWh	55.891	57.034	55.475	59.524	55.298	56.358	53.931	50.245	53.405	45.853
	Prop Demand Component											
28	Energy-Related Prod		353,583	107,570	244,948	11,627	233,321	181,945	32,771	17,738	867	1,065
29	Capacity-Related Summer Peak Prod		292,994	112,244	180,750	10,060	170,690	130,473	28,447	11,179	591	0
30	Capacity-Related Winter Peak Prod		88,555	33,925	54,630	3,041	51,589	39,434	8,598	3,379	179	0
31	Total Capacity-Related Prod		381,548	146,168	235,380	13,100	222,279	169,908	37,044	14,557	770	0
32	Total Production		735,131	253,738	480,328	24,728	455,600	351,852	69,816	32,295	1,637	1,065
33	Transmission **(Transco)**		425,900	162,562	263,338	14,691	248,647	192,233	39,267	15,840	1,306	0
34	Primary Dist Subs		85,027	34,300	50,278	3,381	46,897	37,854	7,972	1,046	25	449
35	Prim Dist Lines		150,171	74,334	75,336	5,301	70,035	57,191	12,844	0	0	501
36	Second Dist, Trans		27,826	14,757	13,013	925	12,088	12,088	0	0	0	56
37	Total Distribution **(Disco)**		263,024	123,390	138,628	9,607	129,020	107,133	20,816	1,046	25	1,006
38	Total Demand Rev Reqt		1,424,055	539,691	882,294	49,026	833,268	651,218	129,899	49,182	2,969	2,071
39	Annual Billing kW		50,585,647	0	50,585,647	0	50,585,647	38,601,454	8,076,778	3,687,056	220,358	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.61	$4.71	$4.06	$4.81	$3.94	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.37	$3.38	$3.52	$3.03	$2.68	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.02	$1.02	$1.06	$0.92	$0.81	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$9.01	$9.11	$8.64	$8.76	$7.43	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.92	$4.98	$4.86	$4.30	$5.93	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$2.55	$2.78	$2.58	$0.28	$0.12	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$16.47	$16.87	$16.08	$13.34	$13.47	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	49.381	63.862	43.538	57.458	42.926	47.307	34.874	26.497	45.864	16.880
48	Summer Billing kW		18,568,179	0	18,568,179	0	18,568,179	14,099,351	3,037,682	1,342,582	88,563	0
49	Winter Billing kW		32,017,467	0	32,017,467	0	32,017,467	24,502,103	5,039,096	2,344,474	131,795	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$22.52	$0.00	$21.27	$21.72	$20.86	$17.72	$16.65	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$14.49	$0.00	$13.69	$14.08	$13.20	$10.83	$11.33	$0.00
52	Energy + Production **(Genco)**		2,346,941	735,723	1,604,528	75,516	1,529,012	1,127,666	270,696	125,556	5,094	6,690
53	Prop Rev - Pres Rev (Pg 2)		200,578	87,990	109,614	8,493	101,121	75,257	19,126	6,508	230	2,974
54	Difference / Present		6.43%	7.55%	5.69%	7.77%	5.56%	5.52%	6.13%	4.79%	3.71%	11.13%

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,882,738	725,755	1,156,983	64,150	1,092,833	818,949	195,973	74,281	3,630	0
2	WInter Peak	D10S		569,040	219,353	349,687	19,389	330,299	247,519	59,231	22,451	1,097	0
3	Total Peak	D10S		2,451,778	945,108	1,506,670	83,538	1,423,132	1,066,468	255,204	96,732	4,727	0
4	Base Load	E8760		6,231,510	1,864,979	4,345,244	196,782	4,148,462	2,985,764	779,807	369,654	13,236	21,287
5	Nuclear Fuel	E8760		2,432,155	727,900	1,695,946	76,804	1,619,142	1,165,342	304,358	144,276	5,166	8,308
6	Total	28.24%	120, 310-346	11,115,442	3,537,987	7,547,860	357,124	7,190,736	5,217,574	1,339,369	610,663	23,130	29,595
	Transmission												
7	Gen Step Up Base	E8760		74,843	22,399	52,188	2,363	49,825	35,860	9,366	4,440	159	256
8	Gen Step Up Peak	D10S		31,607	12,184	19,423	1,077	18,346	13,748	3,290	1,247	61	0
9	Total Gen Step Up			106,450	34,583	71,611	3,440	68,171	49,609	12,656	5,687	220	256
10	Bulk Transmission	D10S		3,156,387	1,216,719	1,939,668	107,546	1,832,121	1,372,957	328,546	124,532	6,086	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		5,762	0	5,762	0	5,762	962	0	0	4,800	0
13	Total		350-359	3,268,599	1,251,302	2,017,041	110,987	1,906,054	1,423,528	341,202	130,219	11,106	256
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		3,046	957	2,081	97	1,984	1,437	370	170	6	9
15	Bulk Transmission	D10S		1,655	638	1,017	56	960	720	172	65	3	0
16	Distrib Function	D60Sub		658,942	274,306	381,049	26,469	354,581	289,158	65,365	58	0	3,586
17	Direct Assign	Dir Assign		16,505,484	0	16,505	0	16,505	372	6,225	9,703	206	0
18	Total		360-363	680,148	275,901	400,653	26,623	374,030	291,685	72,132	9,997	215	3,595
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		143,947	107,145	36,294	5,345	30,949	22,635	8,314	0	0	509
20	Primary Capacity Multi Phase	D61PS		309,713	113,372	195,332	10,421	184,911	149,306	35,605	0	0	1,009
21	Primary Customer 1 Phase	C61PS1Ph		77,221	73,544	3,491	2,995	496	488	7	0	0	186
22	Primary Customer Multi Phase	C61PS		166,146	148,137	17,308	11,117	6,191	6,130	61	0	0	701
23	Total Primary			697,027	442,198	252,425	29,879	222,547	178,559	43,988	0	0	2,404
24	Second Capacity	D62SecL		35,425	17,481	17,853	1,282	16,572	16,572	0	0	0	90
25	Second Customer	C62Sec		127,454	113,681	13,236	8,532	4,704	4,704	0	0	0	538
26	Total Secondary			162,879	131,162	31,089	9,813	21,276	21,276	0	0	0	628
27	Street Lighting	DASL		42,578	0	0	0	0	0	0	0	0	42,578
28	Total		364,365	902,484	573,360	283,514	39,692	243,823	199,835	43,988	0	0	45,610
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		247,789	184,437	62,476	9,200	53,276	38,964	14,312	0	0	876
30	Primary Capacity Multi Phase	D61PS		356,138	130,366	224,612	11,983	212,629	171,687	40,943	0	0	1,160
31	Primary Customer 1 Phase	C61PS1Ph		281,596	268,189	12,730	10,923	1,807	1,780	27	0	0	677
32	Primary Customer Multi Phase	C61PS		404,727	360,858	42,162	27,082	15,080	14,932	148	0	0	1,707
33	Total Primary			1,290,250	943,850	341,980	59,188	282,792	227,362	55,430	0	0	4,420
34	Second Capacity	D62SecL		41,508	20,483	20,919	1,502	19,418	19,418	0	0	0	106
35	Second Customer	C62Sec		116,691	104,081	12,118	7,811	4,307	4,307	0	0	0	492
36	Total Secondary			158,199	124,564	33,037	9,313	23,725	23,725	0	0	0	598
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,448,449	1,068,413	375,017	68,501	306,517	251,087	55,430	0	0	5,018
	Line Transformers												
39	Primary	D61PS		44,017	16,112	27,761	1,481	26,280	21,219	5,060	0	0	143
40	Second Capacity	D62SecL		131,409	64,846	66,227	4,754	61,473	61,473	0	0	0	335
41	Second Customer	C62Sec		230,769	205,831	23,964	15,447	8,517	8,517	0	0	0	974
42	Total		368	406,195	286,790	117,953	21,682	96,270	91,210	5,060	0	0	1,452
	Services												
43	Second Capacity	D62NLL		63,801	47,500	16,300	1,316	14,984	14,984	0	0	0	0
44	Second Customer	C62NL		220,538	209,265	11,273	7,266	4,006	4,006	0	0	0	0
43	Total Services	C62NL	369	284,339	256,766	27,573	8,582	18,990	18,990	0	0	0	0
44	Meters	C12WM	370	87,270	57,873	29,210	8,668	20,541	19,289	1,200	33	19	188
45	Street Lighting	Dir Assign	373	74,377	0	0	0	0	0	0	0	0	74,377
46	**Total Distribution**			3,883,261	2,519,102	1,233,919	173,748	1,060,171	872,097	177,811	10,029	234	130,240
47	**General & Common Plant**	PTD	303, 389-399	1,691,167	676,603	999,743	59,423	940,321	695,564	172,047	69,518	3,191	14,821
48	Prelim Elec Plant			19,958,469	7,984,995	11,798,563	701,282	11,097,282	8,208,763	2,030,429	820,429	37,661	174,911
49	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
50	**Elec Plant in Serv**			19,958,469	7,984,995	11,798,563	701,282	11,097,282	8,208,763	2,030,429	820,429	37,661	174,911

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

Docket No. E002/GR-19-564
Exhibit___(MAP-1), Schedule 4

	Accum Deprec; Net Plant			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,307,680	504,082	803,597	44,556	759,041	568,811	136,116	51,593	2,521	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,255,886	675,146	1,573,033	71,238	1,501,796	1,080,885	282,300	133,820	4,792	7,706
5	Base Load	E8760		2,763,192	826,974	1,926,779	87,258	1,839,521	1,323,955	345,784	163,913	5,869	9,439
6	Total		108,111,115,120.5	6,326,757	2,006,203	4,303,410	203,051	4,100,359	2,973,651	764,199	349,326	13,182	17,145
	Transmission												
7	Gen Step Up Base	E8760		9,251	2,769	6,451	292	6,159	4,433	1,158	549	20	32
8	Gen Step Up Peak	D10S		13,453	5,186	8,267	458	7,809	5,852	1,400	531	26	0
9	Total Gen Step Up			22,704	7,954	14,718	751	13,967	10,284	2,558	1,080	46	32
10	Bulk Transmission	D10S		703,891	271,335	432,556	23,983	408,573	306,177	73,268	27,771	1,357	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		1,792	0	1,792	0	1,792	299	0	0	1,493	0
13	Total		108,111,115,120.5	728,387	279,289	449,066	24,734	424,332	316,760	75,826	28,851	2,896	32
	Distribution												
14	Generat Step Up	STRATH		2,185	686	1,493	70	1,423	1,030	266	122	5	6
15	Bulk Transmission	D10S		629	243	387	21	365	274	65	25	1	0
16	Distrib Function	D60Sub		226,935	94,469	131,231	9,116	122,115	99,584	22,511	20	0	1,235
17	Direct Assign	Dir Assign		6,080	0	6,080	0	6,080	137	2,293	3,574	76	0
18	Total Substations			235,828	95,398	139,189	9,207	129,982	101,025	25,135	3,741	82	1,241
19	Overhead Lines	POL		332,610	211,311	104,489	14,628	89,861	73,649	16,212	0	0	16,809
20	Underground	PUL		453,955	334,849	117,533	21,469	96,065	78,693	17,372	0	0	1,573
21	Line Transformers	P68		170,728	120,541	49,577	9,113	40,463	38,337	2,127	0	0	610
22	Services	P69		172,656	155,913	16,743	5,211	11,531	11,531	0	0	0	0
23	Meters	C12WM		67,309	44,636	22,529	6,686	15,843	14,877	926	25	15	145
24	Street Lighting	P73		12,956	0	0	0	0	0	0	0	0	12,956
25	Total		108,111,115,120.5	1,446,041	962,647	450,060	66,314	383,745	318,111	61,772	3,766	96	33,334
26	**General & CommonPlant**	PTD	108,111,115,120.5	794,234	317,757	469,516	27,907	441,609	326,662	80,800	32,648	1,499	6,960
27	**Total Accum Depr**			9,295,420	3,565,897	5,672,051	322,007	5,350,045	3,935,185	982,596	414,591	17,673	57,471
28	**Net Elec Plant**			10,663,050	4,419,098	6,126,512	379,275	5,747,237	4,273,578	1,047,833	405,838	19,988	117,440
29	**Net Plant w/ TBT**			10,663,050	4,419,098	6,126,512	379,275	5,747,237	4,273,578	1,047,833	405,838	19,988	117,440
	Subtractions: Accum Defer Inc Tax												
	Production												
30	Peaking Plant	D10S		272,266	104,953	167,313	9,277	158,036	118,429	28,340	10,742	525	0
31	Base Load	E8760		896,139	268,198	624,879	28,299	596,581	429,376	112,142	53,159	1,903	3,061
32	Nuclear Fuel	E8760		2,752	824	1,919	87	1,832	1,319	344	163	6	9
33	Total		190,281,282,283	1,171,157	373,975	794,112	37,662	756,449	549,124	140,827	64,064	2,434	3,071
	Transmission												
34	Gen Step Up Base	E8760		14,581	4,364	10,168	460	9,707	6,987	1,825	865	31	50
35	Gen Step Up Peak	D10S		3,862	1,489	2,373	132	2,242	1,680	402	152	7	0
36	Total Gen Step Up			18,444	5,853	12,541	592	11,949	8,666	2,227	1,017	38	50
37	Bulk Transmission	D10S		698,010	269,068	428,942	23,783	405,159	303,618	72,655	27,539	1,346	0
38	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,181	0	1,181	0	1,181	197	0	0	984	0
40	Total		281,282,283	717,634	274,920	442,664	24,375	418,289	312,482	74,882	28,557	2,368	50
	Distribution												
41	Generat Step Up	STRATH		351	110	240	11	229	166	43	20	1	1
42	Bulk Transmission	D10S		255	98	157	9	148	111	27	10	0	0
43	Distrib Function	D60Sub		110,245	45,893	63,752	4,428	59,323	48,378	10,936	10	0	600
44	Direct Assign	Dir Assign		2,278	0	2,278	0	2,278	51	859	1,339	28	0
45	Total Substations			113,129	46,102	66,427	4,448	61,979	48,706	11,864	1,379	30	601
46	Overhead Lines	POL		149,814	95,179	47,064	6,589	40,475	33,173	7,302	0	0	7,571
47	Underground	PUL		237,803	175,410	61,570	11,246	50,323	41,223	9,100	0	0	824
48	Line Transformers	P68		58,672	41,424	17,037	3,132	13,905	13,175	731	0	0	210
49	Services	P69		19,940	18,006	1,934	602	1,332	1,332	0	0	0	0
50	Meters	C12WM		10,815	7,172	3,620	1,074	2,545	2,390	149	4	2	23
51	Street Lighting	P73		13,969	0	0	0	0	0	0	0	0	13,969
52	Total		281,282,283	604,142	383,293	197,651	27,091	170,560	139,998	29,147	1,383	32	23,198
53	**General & Common Plant**	PTD	281,282,283	141,401	56,572	83,590	4,968	78,622	58,157	14,385	5,813	267	1,239
54	**Total Deferred Tax**			2,634,334	1,088,760	1,518,017	94,097	1,423,919	1,059,761	259,240	99,816	5,101	27,557
55	Net Operating Loss (NOL) Carry F	NEPIS		(356,731)	(147,841)	(204,962)	(12,689)	(192,273)	(142,972)	(35,055)	(13,577)	(669)	(3,929)
56	Non-Plant Related	LABOR		23,399	9,204	13,959	870	13,089	9,663	2,398	990	39	235
57	**Accum Def W/ Adj**			2,301,002	950,124	1,327,014	82,279	1,244,736	926,452	226,583	87,229	4,472	23,864

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

Additions: CWIP, Etc; Rate Base

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		21,948	8,461	13,488	748	12,740	9,547	2,285	866	42	0
2	Base Load	E8760		75,043	22,459	52,328	2,370	49,958	35,956	9,391	4,452	159	256
3	Nuclear Fuel	E8760		124,525	37,268	86,831	3,932	82,899	59,665	15,583	7,387	265	425
4	Total		107	221,516	68,188	152,647	7,050	145,597	105,168	27,258	12,704	466	682
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		2,097	808	1,289	71	1,217	912	218	83	4	0
7	Total Gen Step Up			2,097	808	1,289	71	1,217	912	218	83	4	0
8	Bulk Transmission	D10S		42,172	16,256	25,915	1,437	24,479	18,344	4,390	1,664	81	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	44,269	17,065	27,204	1,508	25,696	19,256	4,608	1,747	85	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		12,998	5,411	7,516	522	6,994	5,704	1,289	1	0	71
15	Direct Assign	Dir Assign		491	0	491	0	491	11	185	289	6	0
16	Total Substations			13,488	5,411	8,007	522	7,485	5,715	1,474	290	6	71
17	Overhead Lines	POL		8,747	5,557	2,748	385	2,363	1,937	426	0	0	442
18	Underground	PUL		16,926	12,485	4,382	800	3,582	2,934	648	0	0	59
19	Line Transformers	P68		928	655	270	50	220	208	12	0	0	3
20	Services	P69		138	125	13	4	9	9	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		107	40,228	24,233	15,420	1,761	13,659	10,803	2,560	290	6	575
24	**General & Common Plant**	PTD	107	57,977	23,195	34,273	2,037	32,236	23,845	5,898	2,383	109	508
25	**Total CWIP**			363,989	132,680	229,544	12,356	217,187	159,072	40,324	17,124	667	1,765
26	Fuel Inventory	E8760	151,152	65,875	19,715	45,935	2,080	43,854	31,563	8,244	3,908	140	225
	Materials & Supplies												
27	Production	P10		137,523	43,773	93,384	4,418	88,965	64,553	16,571	7,555	286	366
28	Trans & Distr	TD		16,409	8,651	7,459	653	6,806	5,267	1,191	322	26	299
29	Total		154	153,932	52,423	100,843	5,072	95,771	69,820	17,762	7,877	312	666
	Prepayments												
30	Miscellaneous	NEPIS		99,733	41,332	57,302	3,547	53,754	39,971	9,800	3,796	187	1,098
31	Fuel	E8760		0	0	0	0	0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0	0	0	0	0
33	Total		235,252,165	99,733	41,332	57,302	3,547	53,754	39,971	9,800	3,796	187	1,098
34	Non-Plant Assets & Liab	LABOR	190,283,	60,475	23,789	36,078	2,249	33,829	24,973	6,198	2,558	101	608
35	Working Cash	PT0	calculated	(119,149)	(50,756)	(67,147)	(4,298)	(62,849)	(46,863)	(11,410)	(4,360)	(216)	(1,245)
36	**Total Additions**			624,853	219,183	402,554	21,006	381,547	278,537	70,918	30,902	1,191	3,116
37	**Total Rate Base**			8,986,901	3,688,157	5,202,051	318,003	4,884,049	3,625,663	892,167	349,511	16,707	96,692
38	**Common Rate Base (@ 52.50%)**			4,718,122.9	1,936,283	2,731,077	166,951	2,564,126	1,903,473	468,388	183,493	8,771	50,763

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Operating Rev (Cal Month)												
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,120,405	1,165,785	1,927,911	109,370	1,818,541	1,364,535	311,884	135,923	6,199	26,709
2	Proposed Rate Revenue	PROREV; (calc)		3,320,983	1,253,775	2,037,525	117,863	1,919,662	1,439,792	331,010	142,431	6,429	29,683
3	Equal Rate Revenue			3,320,983	1,260,019	2,030,865	116,903	1,913,962	1,409,764	351,770	146,266	6,162	30,098
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	735	275	454	26	428	321	73	32	1	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			735	275	454	26	428	321	73	32	1	6
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	406,464	129,375	276,007	13,059	262,947	190,794	48,977	22,330	846	1,082
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	(8,285)	(3,194)	(5,091)	(282)	(4,809)	(3,604)	(862)	(327)	(16)	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	630	188	439	20	419	302	79	37	1	2
12	Dist Overhd Line Rent	POL	454	4,982	3,165	1,565	219	1,346	1,103	243	0	0	252
13	Connection Charges	C11	451	1,930	1,692	197	127	71	70	1	0	0	40
14	Sales For Resale	E8760	447	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		202,231	77,956	124,275	6,891	117,385	87,966	21,050	7,979	390	0
17	MISO	D10S	456	(83,828)	(32,314)	(51,514)	(2,856)	(48,658)	(36,463)	(8,726)	(3,307)	(162)	0
18	Other	D10S	451,456,457	15,207	5,862	9,345	518	8,827	6,615	1,583	600	29	0
19	Late Pay Chg - Pres	R16C; R02		5,687	4,895	787	321	466	441	24	1	1	5
20	**Tot Other Op - Pres**		450	545,018	187,626	356,011	18,017	337,994	247,223	62,368	27,313	1,090	1,381
21	Incr Misc Serv - Prop	R01,		447	167	276	16	261	196	45	19	1	4
22	Incr Inter-Dept'l - Prop	R01; R02		36	14	22	1	21	16	4	2	0	0
23	Incr Late Pay - Prop	(R16C); R02		366	315	51	21	30	28	2	0	0	0
	Tot Incr Other Op			849	495	349	38	312	240	50	21	1	4
24	**Tot Other Op - Prop**			545,867	188,121	356,360	18,054	338,306	247,463	62,418	27,334	1,091	1,386
25	**Tot Oper Rev - Pres**			3,666,158	1,353,685	2,284,375	127,412	2,156,964	1,612,079	374,326	163,268	7,290	28,097
26	**Tot Oper Rev - Prop**			3,867,585	1,442,171	2,394,339	135,943	2,258,396	1,687,576	393,502	169,797	7,521	31,075
	Tot Oper Rev - Eql			3,867,585	1,448,415	2,387,679	134,983	2,252,696	1,657,548	414,262	173,632	7,254	31,491
	Operating & Maint (Pg 1 of 2)												
	Production Expen												
27	**Fuel**	E8760	501,518,547	648,892	194,202	452,474	20,491	431,983	310,910	81,202	38,492	1,378	2,217
	Purchased Power												
28	Purchases: Cap Peak	D10S		95,319	36,743	58,576	3,248	55,328	41,462	9,922	3,761	184	0
29	Purchases: Cap Base	D10S		35,470	13,673	21,797	1,209	20,589	15,429	3,692	1,399	68	0
30	Purchases: Demand		555	130,789	50,416	80,373	4,456	75,916	56,890	13,614	5,160	252	0
31	Purchases: Other Energy	E8760	555	288,737	86,414	201,337	9,118	192,219	138,345	36,132	17,128	613	986
32	Tot Non-Assoc Purch			419,526	136,830	281,709	13,574	268,135	195,235	49,746	22,288	865	986
33	Interchg Agr Capacity	P10WoN	557	32,191	10,418	21,694	1,039	20,655	15,023	3,837	1,729	67	79
34	Interchg Agr Energy	E8760	557	16,285	4,874	11,355	514	10,841	7,803	2,038	966	35	56
35	Tot Wis Interchg Purch			48,476	15,291	33,050	1,553	31,496	22,825	5,875	2,695	101	135
36	**Tot Purchased Power**			468,001	152,121	314,759	15,128	299,631	218,061	55,621	24,983	967	1,121
	Other Production		500,502,505-507 509-514,517-519,520, 523-525,528-532,535, 539,543-546,548-550 552-554,556,557 575.1-575.8										
37	Capacity Related	D10S		94,530	36,439	58,090	3,221	54,870	41,118	9,840	3,730	182	0
38	Energy Related	E8760		341,503	102,206	238,130	10,784	227,346	163,627	42,735	20,258	725	1,167
39	Total Other Produc	21.68%		436,032.144	138,645	296,221	14,005	282,216	204,746	52,575	23,988	908	1,167
40	**Total Production**			1,552,926	484,968	1,063,454	49,624	1,013,830	733,717	189,398	87,463	3,253	4,504
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	245,050	94,461	150,588	8,349	142,239	106,591	25,507	9,668	472	0

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

Operating & Maint (Pg 2 of 2)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	6,898	3,972	2,623	318	2,306	1,847	401	55	2	303
2	Load Dispatching	T20D80	581	7,267	2,981	4,255	283	3,972	3,184	728	58	3	32
3	Substations	P61	582,591,592	9,044	3,669	5,327	354	4,973	3,878	959	133	3	48
4	Overhead Lines	POL	583,593	41,409	26,308	13,009	1,821	11,187	9,169	2,018	0	0	2,093
5	Underground Lines	PUL	584, 594	15,647	11,542	4,051	740	3,311	2,712	599	0	0	54
6	Line Transformers	P68	595	1,377	972	400	74	326	309	17	0	0	5
7	Meters	C12WM	586,597,598	1,997	1,324	668	198	470	441	27	1	0	4
8	Customer Install'n	OXDTS	587	3,750	2,227	1,310	165	1,145	930	205	9	0	213
9	Street Lighting	Dir Assign	585,596	2,273	0	0	0	0	0	0	0	0	2,273
10	Miscellaneous	OXDTS	588	21,261	12,629	7,425	934	6,491	5,275	1,165	49	2	1,207
11	Rents (Pole Attachmts)	POL	589	3,326	2,113	1,045	146	898	736	162	0	0	168
12	**Total Distribution**			114,249	67,735	40,113	5,033	35,081	28,484	6,282	305	10	6,400
13	**Customer Accounting**	C11WA	901-905	48,973	40,628	8,153	4,570	3,583	3,529	52	2	1	192
14	**Sales, Econ Dvlp & Other**	R01	912	(6)	(2)	(3)	(0)	(3)	(2)	(1)	(0)	(0)	(0)
	Admin & General												
15	Salaries	LABOR	920	72,889	28,672	43,485	2,710	40,774	30,100	7,470	3,083	121	732
16	Office Supplies	OXTS	921	48,424	17,123	31,008	1,676	29,332	21,486	5,416	2,338	92	294
17	Admin Transfer Credit	OXTS	922	(41,457)	(14,659)	(26,546)	(1,435)	(25,112)	(18,395)	(4,637)	(2,001)	(79)	(251)
18	Outside Services	LABOR	923	23,767	9,349	14,179	884	13,295	9,815	2,436	1,005	40	239
19	Property Insurance	NEPIS	924	5,732	2,375	3,293	204	3,089	2,297	563	218	11	63
20	Pensions & Benefits	LABOR	926	77,314	30,413	46,124	2,875	43,249	31,927	7,923	3,270	129	777
21	Injuries & Claims	LABOR	925	11,891	4,677	7,094	442	6,652	4,910	1,219	503	20	119
22	Regulatory Exp	R01; R02	928	5,151	1,924	3,182	181	3,002	2,252	515	224	10	44
23	General Advertising	OXTS	930.1	233	82	149	8	141	103	26	11	0	1
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(322)	(114)	(206)	(11)	(195)	(143)	(36)	(16)	(1)	(2)
26	Rents	OXTS	931	42,587	15,059	27,270	1,474	25,797	18,897	4,763	2,056	81	258
27	Maint of General Plant	OXTS	935	757	268	485	26	459	336	85	37	1	5
28	Total			246,966	95,170	149,517	9,034	140,483	103,586	25,743	10,729	426	2,279
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,277	1,360	889	111	778	575	138	63	2	27
30	CIP Total	E99XCIP	908	102,371.401	31,618	70,295	3,192	67,103	51,226	11,952	3,682	242	459
31	Instructional Advertising	C11P10	909	872	521	341	43	298	221	53	24	1	10
32	Total			105,520	33,500	71,525	3,346	68,179	52,022	12,143	3,768	245	496
33	Amortizations	LABOR		43,948	17,288	26,219	1,634	24,585	18,149	4,504	1,859	73	442
34	**Total O&M Expense**			2,357,626	833,748	1,509,566	81,590	1,427,977	1,046,075	263,627	113,794	4,481	14,312

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Book Depreciation												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		99,194	38,237	60,957	3,380	57,577	43,147	10,325	3,914	191	0
2	Base Load	E8760		290,224	86,859	202,374	9,165	193,209	139,058	36,318	17,216	616	991
3	Total		403,413	389,418	125,096	263,331	12,545	250,786	182,205	46,643	21,130	808	991
	Transmission												
4	Gen Step Up Base	E8760		1,239	371	864	39	825	594	155	74	3	4
5	Gen Step Up Peak	D10S		729	281	448	25	423	317	76	29	1	0
6	Total Gen Step Up			1,968	652	1,312	64	1,248	911	231	102	4	4
7	Bulk Transmission	D10S		66,350	25,577	40,774	2,261	38,513	28,861	6,906	2,618	128	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		120	0	120	0	120	20	0	0	100	0
10	Total		403,413	68,438	26,228	42,206	2,325	39,881	29,792	7,137	2,720	232	4
	Distribution												
11	Generat Step Up	STRATH		68	21	47	2	45	32	8	4	0	0
12	Bulk Transmission	D10S		37	14	23	1	22	16	4	1	0	0
13	Distrib Function	D60Sub		14,817	6,168	8,568	595	7,973	6,502	1,470	1	0	81
14	Direct Assign	Dir Assign		360	0	360	0	360	8	136	212	4	0
15	Total Substations		403,413	15,284	6,204	8,999	599	8,400	6,559	1,618	218	5	81
16	Overhead Lines	POL		31,887	20,258	10,017	1,402	8,615	7,061	1,554	0	0	1,612
17	Underground	PUL		36,367	26,826	9,416	1,720	7,696	6,304	1,392	0	0	126
18	Line Transformers	P68		11,127	7,856	3,231	594	2,637	2,499	139	0	0	40
19	Services	P69		10,216	9,225	991	308	682	682	0	0	0	0
20	Meters	C12WM		3,963	2,628	1,327	394	933	876	55	1	1	9
21	Street Lighting	P73		4,015	0	0	0	0	0	0	0	0	4,015
22	Total		403,413	112,860	72,998	33,980	5,017	28,963	23,981	4,757	220	6	5,881
23	**General & Common Plant**	PTD	403,413	112,676	45,079	66,609	3,959	62,650	46,343	11,463	4,632	213	987
24	**Total Book Deprec**		403,404	683,392	269,402	406,126	23,845	382,280	282,320	70,001	28,701	1,258	7,865
	Real Estate & Property Tax												
	Production												
25	Peaking Plant	D10S		25,330	9,764	15,566	863	14,703	11,018	2,637	999	49	0
26	Base Load	E8760		64,379	19,268	44,892	2,033	42,859	30,847	8,056	3,819	137	220
27	Total		408.1	89,709	29,032	60,458	2,896	57,562	41,865	10,693	4,818	186	220
	Transmission												
28	Gen Step Up Base	E8760		909.4034	272	634	29	605	436	114	54	2	3
29	Gen Step Up Peak	D10S		384.0443	148	236	13	223	167	40	15	1	0
30	Total Gen Step Up			1,293.4477	420	870	42	828	603	154	69	3	3
31	Bulk Transmission	D10S		38,352.5481	14,784	23,568	1,307	22,262	16,682	3,992	1,513	74	0
32	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
33	Direct Assign	Dir Assign		70	0	70	0	70	12	0	0	58	0
34	Total		408.1	39,716.004	15,204	24,509	1,349	23,160	17,297	4,146	1,582	135	3
	Distribution												
35	Generat Step Up	STRATH		38	12	26	1	25	18	5	2	0	0
36	Bulk Transmission	D10S		21	8	13	1	12	9	2	1	0	0
37	Distrib Function	D60Sub		8,303	3,456	4,802	334	4,468	3,644	824	1	0	45
38	Direct Assign	Dir Assign		208	0	208	0	208	5	78	122	3	0
39	Total Substations			8,570	3,477	5,049	335	4,713	3,675	909	126	3	45
40	Overhead Lines	POL		11,372	7,225	3,573	500	3,072	2,518	554	0	0	575
41	Underground	PUL		18,252	13,463	4,726	863	3,862	3,164	698	0	0	63
42	Line Transformers	P68		5,118	3,614	1,486	273	1,213	1,149	64	0	0	18
43	Services	P69		3,583	3,235	347	108	239	239	0	0	0	0
44	Meters	C12WM		1,100	729	368	109	259	243	15	0	0	2
45	Street Lighting	P73		937	0	0	0	0	0	0	0	0	937
46	Total		408.1	48,932	31,743	15,548	2,189	13,359	10,989	2,241	126	3	1,641
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			178,357	75,979	100,515	6,434	94,081	70,151	17,079	6,527	323	1,864
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
50	Payroll Taxes	LABOR		27,259	10,723	16,262	1,014	15,248	11,257	2,794	1,153	45	274
51	**Tot Non-Inc Taxes**			205,616	86,701	116,777	7,448	109,329	81,407	19,873	7,680	369	2,138

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

	Provision For Defer Inc Tax			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		(3,008)	(1,160)	(1,849)	(103)	(1,746)	(1,309)	(313)	(119)	(6)	0
2	Nuclear Fuel	E8760		(6,621)	(1,982)	(4,617)	(209)	(4,408)	(3,173)	(829)	(393)	(14)	(23)
3	Base Load	E8760		28,632	8,569	19,965	904	19,061	13,719	3,583	1,698	61	98
4	Total		410, 411	19,002	5,428	13,499	593	12,907	9,238	2,441	1,187	41	75
	Transmission												
5	Gen Step Up Base	E8760		394	118	274	12	262	189	49	23	1	1
6	Gen Step Up Peak	D10S		140	54	86	5	81	61	15	6	0	0
7	Total Gen Step Up			533	172	360	17	343	249	64	29	1	1
8	Bulk Transmission	D10S		10,321	3,978	6,342	352	5,991	4,489	1,074	407	20	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		13	0	13	0	13	2	0	0	11	0
11	Total		410, 411	10,867	4,150	6,716	369	6,347	4,741	1,138	436	32	1
	Distribution												
12	Generat Step Up	STRATH		(27)	(9)	(19)	(1)	(18)	(13)	(3)	(2)	(0)	(0)
13	Bulk Transmission	D10S		(8)	(3)	(5)	(0)	(4)	(3)	(1)	(0)	(0)	0
14	Distrib Function	D60Sub		(1,537)	(640)	(889)	(62)	(827)	(674)	(152)	(0)	0	(8)
15	Direct Assign	Dir Assign		(69)	0	(69)	0	(69)	(2)	(26)	(40)	(1)	0
16	Total Substations			(1,641)	(651)	(981)	(63)	(918)	(692)	(182)	(42)	(1)	(8)
17	Overhead Lines	POL		645	410	203	28	174	143	31	0	0	33
18	Underground	PUL		(3,956)	(2,918)	(1,024)	(187)	(837)	(686)	(151)	0	0	(14)
19	Line Transformers	P68		(2,305)	(1,627)	(669)	(123)	(546)	(517)	(29)	0	0	(8)
20	Services	P69		(1,423)	(1,285)	(138)	(43)	(95)	(95)	0	0	0	0
21	Meters	C12WM		(279)	(185)	(93)	(28)	(66)	(62)	(4)	(0)	(0)	(1)
22	Street Lighting	P73		(319)	0	0	0	0	0	0	0	0	(319)
23	Total		410, 411	(9,277)	(6,256)	(2,703)	(415)	(2,288)	(1,909)	(335)	(42)	(1)	(318)
24	**General & Common Plant**	PTD	410, 411	(2,815)	(1,126)	(1,664)	(99)	(1,565)	(1,158)	(286)	(116)	(5)	(25)
25	**Net Operating Loss (NOL) Carry**	NEPIS		(93,712)	(38,837)	(53,842)	(3,333)	(50,509)	(37,558)	(9,209)	(3,567)	(176)	(1,032)
26	**Non - Plant Related**	LABOR	410, 411	5,719	2,250	3,412	213	3,199	2,362	586	242	10	57
27	**Tot Prov For Defer**			(70,215)	(34,392)	(34,582)	(2,673)	(31,909)	(24,285)	(5,665)	(1,860)	(99)	(1,241)
	Inv Tax Credit; Total Oper Exp												
	Production												
28	Peaking Plant	D10S		(260)	(100)	(160)	(9)	(151)	(113)	(27)	(10)	(1)	0
29	Base Load	E8760		(538)	(161)	(375)	(17)	(358)	(258)	(67)	(32)	(1)	(2)
30	Total		411	(798)	(261)	(535)	(26)	(509)	(371)	(94)	(42)	(2)	(2)
	Transmission												
31	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(0)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
37	Total		411	(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(0)	0
	Distribution												
38	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0	0	0	0	0
43	Overhead Lines	POL		(268)	(170)	(84)	(12)	(72)	(59)	(13)	0	0	(14)
44	Underground	PUL		0	0	0	0	0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
49	Total		411	(268)	(170)	(84)	(12)	(72)	(59)	(13)	0	0	(14)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	(0)
51	**Net Inv Tax Credit**			(1,223)	(492)	(715)	(43)	(672)	(498)	(124)	(48)	(2)	(15)
52	**Total Operating Exp**			**3,175,196**	**1,154,966**	**1,997,171**	**110,166**	**1,887,005**	**1,385,018**	**347,712**	**148,267**	**6,007**	**23,059**
53A	**Pres Op Inc Before Inc Tax**			**490,962**	**198,719**	**287,204**	**17,245**	**269,959**	**227,061**	**26,614**	**15,001**	**1,284**	**5,038**
53B	**Prop Op Inc Before Inc Tax**			**692,389**	**287,204**	**397,168**	**25,777**	**371,391**	**302,557**	**45,789**	**21,530**	**1,515**	**8,016**

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		113,759	43,852	69,908	3,876	66,031	49,483	11,841	4,488	219	0
2	Nuclear Fuel	E8760		88,005	26,338	61,366	2,779	58,587	42,167	11,013	5,220	187	301
3	Base Load	E8760		476,283	142,543	332,113	15,040	317,073	228,206	59,602	28,253	1,012	1,627
4	Total		tax books	678,047	212,733	463,386	21,695	441,691	319,855	82,456	37,962	1,418	1,928
	Transmission												
5	Gen Step Up Base	E8760		3,093	926	2,157	98	2,059	1,482	387	183	7	11
6	Gen Step Up Peak	D10S		1,210	466	743	41	702	526	126	48	2	0
7	Total Gen Step Up			4,303	1,392	2,900	139	2,761	2,008	513	231	9	11
8	Bulk Transmission	D10S		112,468	43,354	69,114	3,832	65,282	48,921	11,707	4,437	217	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		182	0	182	0	182	30	0	0	151	0
11	Total		tax books	116,952	44,746	72,196	3,971	68,225	50,960	12,220	4,669	377	11
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		14	6	9	0	8	6	1	1	0	0
14	Distrib Function	D60Sub		11,679	4,862	6,754	469	6,284	5,125	1,159	1	0	64
15	Direct Assign	Dir Assign		186	0	186	0	186	4	70	109	2	0
16	Total Substations			11,879	4,867	6,948	470	6,478	5,135	1,230	111	2	64
17	Overhead Lines	POL		33,882	21,526	10,644	1,490	9,154	7,502	1,651	0	0	1,712
18	Underground	PUL		32,580	24,032	8,435	1,541	6,895	5,648	1,247	0	0	113
19	Line Transformers	P68		8,952	6,321	2,600	478	2,122	2,010	112	0	0	32
20	Services	P69		6,088	5,497	590	184	407	407	0	0	0	0
21	Meters	C12WM		2,823	1,872	945	280	664	624	39	1	1	6
22	Street Lighting	P73		3,372	0	0	0	0	0	0	0	0	3,372
23	Total		tax books	99,577	64,115	30,162	4,443	25,720	21,326	4,279	112	3	5,299
24	**General & Common Plant**	PTD	tax books	131,166	52,477	77,540	4,609	72,931	53,948	13,344	5,392	248	1,150
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0	0	0	0	0
26	**Total Tax Deprec**			1,025,742	374,071	643,284	34,718	608,566	446,089	112,298	48,134	2,045	8,387
27	Interest Expense		427,431	187,826.23	77,082	108,723	6,646	102,077	75,776	18,646	7,305	349	2,021
28	Other Tax Timing Differ	LABOR		11,855	4,663	7,072	441	6,632	4,895	1,215	501	20	119
29	Meals & Enter	LABOR		584	230	348	22	326	241	60	25	1	6
30	Total Tax Deductions			1,226,007	456,047	759,428	41,827	717,601	527,002	132,219	55,965	2,415	10,533
	Inc Tax Additions												
31	Book Depreciation			683,392	269,402	406,126	23,845	382,280	282,320	70,001	28,701	1,258	7,865
32	Deferred Inc Tax & ITC			(71,438.19)	(34,884)	(35,298)	(2,716)	(32,581)	(24,783)	(5,789)	(1,908)	(101)	(1,256)
33	Nuclear Fuel Book Burn	E8760		105,136	31,465	73,311	3,320	69,991	50,375	13,157	6,237	223	359
34	Tax Capitalized Leases	PTD		43,158	17,266	25,513	1,516	23,996	17,750	4,391	1,774	81	378
35	Avoided Tax Interest	RTBASE		16,356	6,712	9,468	579	8,889	6,599	1,624	636	30	176
36	Total Tax Additions			776,603	289,962	479,119	26,544	452,575	332,260	83,383	35,440	1,492	7,522
37	**Total Inc Tax Adjustments**			(449,404)	(166,085)	(280,308)	(15,282)	(265,026)	(194,742)	(48,836)	(20,525)	(923)	(3,011)
38A	**Pres Taxable Net Income**			41,558	32,634	6,896	1,963	4,933	32,319	(22,222)	(5,524)	360	2,027
38B	**Prop Taxable Net Income**			242,985	121,119	116,860	10,494	106,365	107,816	(3,047)	1,005	591	5,006
39A	Pres Fed & State Inc Tax			(6,184)	1,940	(8,511)	(77)	(8,434)	1,975	(8,187)	(2,293)	70	388
39B	Prop Fed & State Inc Tax			51,710	27,372	23,094	2,375	20,720	23,675	(2,675)	(416)	136	1,244
40A	Pres Preliminary Return	(total); BASE		497,145	196,779	295,716	17,323	278,393	225,085	34,800	17,294	1,214	4,651
40B	Prop Preliminary Return	(total); BASE		640,678	259,832	374,073	23,402	350,672	278,883	48,465	21,946	1,378	6,773
41	Total AFUDC			28,846	10,486	18,225	973	17,252	12,627	3,209	1,360	57	135
42A	**Present Total Return**			525,991	207,265	313,941	18,296	295,645	237,712	38,009	18,653	1,271	4,785
42B	**Proposed Total Return**			669,524	270,318	392,298	24,375	367,923	291,509	51,673	23,306	1,435	6,908
43A	**Pres % Return on Rate Base**			5.85%	5.62%	6.03%	5.75%	6.05%	6.56%	4.26%	5.34%	7.61%	4.95%
43B	**Prop % Return on Rate Base**			7.45%	7.33%	7.54%	7.67%	7.53%	8.04%	5.79%	6.67%	8.59%	7.14%
44A	**Present Common Return**			338,165	130,183	205,218	11,650	193,568	161,935	19,363	11,348	922	2,765
44B	**Proposed Common Return**			481,698	193,236	283,575	17,729	265,847	215,733	33,027	16,001	1,086	4,887
45A	**Pres % Ret on Common Rt Base**			7.17%	6.72%	7.51%	6.98%	7.55%	8.51%	4.13%	6.18%	10.51%	5.45%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.98%	10.38%	10.62%	10.37%	11.33%	7.05%	8.72%	12.38%	9.63%

Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

	Allow For Funds Used During Constr			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,742	672	1,071	59	1,011	758	181	69	3	0
2	Nuclear Fuel	E8760		7,990	2,391	5,572	252	5,319	3,828	1,000	474	17	27
3	Base Load	E8760		7,966	2,384	5,555	252	5,303	3,817	997	473	17	27
4	Total		419.1,432	17,698	5,447	12,197	563	11,634	8,403	2,178	1,015	37	55
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		356	137	219	12	207	155	37	14	1	0
7	Total Gen Step Up			356	137	219	12	207	155	37	14	1	0
8	Bulk Transmission	D10S		2,862	1,103	1,759	98	1,661	1,245	298	113	6	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		5	0	5	0	5	1	0	0	4	0
11	Total		419.1,432	3,224	1,241	1,983	110	1,874	1,401	335	127	11	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		1,677	698	970	67	903	736	166	0	0	9
15	Direct Assign	Dir Assign		70	0	70	0	70	2	27	41	1	0
16	Total Substations			1,748	698	1,040	67	973	738	193	42	1	9
17	Overhead Lines	POL		598	380	188	26	161	132	29	0	0	30
18	Underground	PUL		1,007	743	261	48	213	175	39	0	0	3
19	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
20	Services	P69		296	267	29	9	20	20	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		419.1,432	3,649	2,088	1,518	150	1,367	1,064	261	42	1	43
24	**General & Common Plant**	PTD	419.1,432	4,275	1,710	2,527	150	2,377	1,758	435	176	8	37
25	**Total AFUDC**			28,846	10,486	18,225	973	17,252	12,627	3,209	1,360	57	135
	Labor Allocator												
	Production												
26	Other Prod - Cap	D10S		60,183	23,199	36,984	2,051	34,933	26,178	6,264	2,374	116	0
27	Other Prod - Ene	E8760		152,964	45,779	106,662	4,830	101,831	73,291	19,142	9,074	325	523
28	Total		500 through 557	213,147	68,979	143,646	6,881	136,765	99,469	25,406	11,448	441	523
	Transmission												
29	Stepup Subtrans	P5161A		676	219	455	22	433	315	80	36	1	2
30	Bulk Power Subs	D10S		20,037	7,724	12,313	683	11,631	8,716	2,086	791	39	0
31	Total		560 through 571	20,713	7,943	12,768	705	12,064	9,031	2,166	827	40	2
	Distribution												
32	Superv & Eng	ZDTS	580, 590	5,991	3,449	2,278	276	2,002	1,604	348	48	2	263
33	Load Dispatch	D10S	581	6,658	2,567	4,092	227	3,865	2,896	693	263	13	0
34	Substation	P61	582, 592	5,901	2,394	3,476	231	3,245	2,531	626	87	2	31
35	Overhead Lines	POL	583, 593	10,679	6,784	3,355	470	2,885	2,365	520	0	0	540
36	Underground Lines	PUL	584, 594	9,996	7,373	2,588	473	2,115	1,733	383	0	0	35
37	Line Transformer	P68	595	1,162	820	337	62	275	261	14	0	0	4
38	Meter	C12WM	586, 597	3,465	2,298	1,160	344	816	766	48	1	1	7
39	Cust Installation	ZDTS	587	3,415	1,966	1,299	157	1,141	915	199	27	1	150
40	Street Lighting	P73	585, 596	997	0	0	0	0	0	0	0	0	997
41	Miscellaneous	OXDTS	588	7,404	4,398	2,586	325	2,260	1,837	406	17	1	420
42	Total			55,668	32,049	21,171	2,565	18,606	14,907	3,237	443	19	2,448
43	**Cust Accounting**	C11WA	901,902,903,904,905	10,731	8,903	1,787	1,001	785	773	11	0	0	42
44	**Sales Expense**	C11P10	912	0	0	0	0	0	0	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	151,374	59,546	90,308	5,629	84,679	62,511	15,513	6,403	252	1,521
46	**Service & Inform**	C11P10	908, 909	1,168	698	456	57	399	295	71	32	1	14
47	**Labor**			452,801	178,117	270,135	16,838	253,297	186,986	46,404	19,153	754	4,549

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			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	59.76%	39.07%	4.89%	34.17%	25.28%	6.04%	2.75%	0.10%	1.18%
2	Peaking Plant Capacity	D10S	100.00%	38.55%	61.45%	3.41%	58.04%	43.50%	10.41%	3.95%	0.19%	0.00%
3	57% Dmd, 43% Energy: Sales & E	D57E43	100.00%	29.93%	69.73%	3.16%	66.57%	47.91%	12.51%	5.93%	0.21%	0.34%
4	40% Dmd, 60% Energy: CIP	D40E60	100.00%	29.93%	69.73%	3.16%	66.57%	47.91%	12.51%	5.93%	0.21%	0.34%
5	20%D10T, 80%D60Sub	T20D80	100.00%	41.01%	58.55%	3.89%	54.66%	43.81%	10.02%	0.80%	0.04%	0.44%
6	Labor w/o (or w/) A&G	LABOR	100.00%	39.34%	59.66%	3.72%	55.94%	41.30%	10.25%	4.23%	0.17%	1.00%
7	Net Plant In Service	NEPIS	100.00%	41.44%	57.46%	3.56%	53.90%	40.08%	9.83%	3.81%	0.19%	1.10%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	59.40%	34.92%	4.39%	30.53%	24.81%	5.48%	0.23%	0.01%	5.68%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	35.36%	64.03%	3.46%	60.57%	44.37%	11.18%	4.83%	0.19%	0.61%
10	Production Plant	P10	100.00%	31.83%	67.90%	3.21%	64.69%	46.94%	12.05%	5.49%	0.21%	0.27%
11	Production Plant Wo Nuclear	P10WoN	100.00%	32.36%	67.39%	3.23%	64.16%	46.67%	11.92%	5.37%	0.21%	0.25%
12	Total P51 & P61A	P5161A	100.00%	32.46%	67.30%	3.23%	64.07%	46.62%	11.90%	5.35%	0.21%	0.24%
13	Distribution Plant	P60	100.00%	64.87%	31.78%	4.47%	27.30%	22.46%	4.58%	0.26%	0.01%	3.35%
14	Distr Substn Plant	P61	100.00%	40.56%	58.91%	3.91%	54.99%	42.89%	10.61%	1.47%	0.03%	0.53%
15	Line Transformer Plant	P68	100.00%	70.60%	29.04%	5.34%	23.70%	22.45%	1.25%	0.00%	0.00%	0.36%
16	Services Plant	P69	100.00%	90.30%	9.70%	3.02%	6.68%	6.68%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	63.53%	31.41%	4.40%	27.02%	22.14%	4.87%	0.00%	0.00%	5.05%
18	Real Est & Property Tax	PT0	100.00%	42.60%	56.36%	3.61%	52.75%	39.33%	9.58%	3.66%	0.18%	1.05%
19	Produc, Trans & Distrib	PTD	100.00%	40.01%	59.12%	3.51%	55.60%	41.13%	10.17%	4.11%	0.19%	0.88%
20	Dist Plt Undground Lines	PUL	100.00%	73.76%	25.89%	4.73%	21.16%	17.33%	3.83%	0.00%	0.00%	0.35%
21	Rate Base (Non-Column)	RTBASE	100.00%	41.04%	57.88%	3.54%	54.35%	40.34%	9.93%	3.89%	0.19%	1.08%
22	Stratified Hydro Baseload	STRATH	100.00%	31.40%	68.32%	3.20%	65.12%	47.16%	12.15%	5.59%	0.21%	0.28%
23	Transmission & Distrib	TD	100.00%	52.72%	45.46%	3.98%	41.47%	32.10%	7.26%	1.96%	0.16%	1.82%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	57.57%	38.03%	4.61%	33.42%	26.78%	5.81%	0.80%	0.03%	4.40%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	301,427	118,572	179,827	11,209	168,618	124,476	30,891	12,750	502	3,028
26	Dis O&M w/o Sup, Cust Install & M	OXDTS	82,339	48,908	28,755	3,616	25,139	20,430	4,511	192	6	4,676
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,302,253	814,065	1,474,224	79,671	1,394,553	1,021,538	257,495	111,145	4,375	13,964
28	Total P51 & P61A	P5161A	109,496	35,539	73,692	3,538	70,154	51,045	13,026	5,857	226	264
29	Produc, Trans & Distrib	PTD	18,267,302	7,308,392	10,798,820	641,859	10,156,961	7,513,199	1,858,382	750,910	34,470	160,090
30	Transmission & Distrib	TD	7,151,860	3,770,404	3,250,960	284,735	2,966,225	2,295,625	519,013	140,248	11,340	130,495
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	46,262	26,634	17,594	2,132	15,462	12,388	2,690	368	16	2,035

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Northern States Power Company

2020 Class Cost of Service Study Detail ($000)

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.68%	10.23%	6.58%	3.65%	3.62%	0.04%	0.00%	0.00%	2.09%
2	Cust Acctg Wtg Factor	C11WA	100.00%	82.96%	16.65%	9.33%	7.32%	7.21%	0.11%	0.00%	0.00%	0.39%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	66.31%	33.47%	9.93%	23.54%	22.10%	1.38%	0.04%	0.02%	0.22%
4	Sec & Pri Customers	C61PS	100.00%	89.16%	10.42%	6.69%	3.73%	3.69%	0.04%	0.00%	0.00%	0.42%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.24%	4.52%	3.88%	0.64%	0.63%	0.01%	0.00%	0.00%	0.24%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	94.89%	5.11%	3.29%	1.82%	1.82%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.19%	10.38%	6.69%	3.69%	3.69%	0.00%	0.00%	0.00%	0.42%
8	Summer Peak Resp KW	D10S	100.00%	38.55%	61.45%	3.41%	58.04%	43.50%	10.41%	3.95%	0.19%	0.00%
9	Transmission Demand %	D10T	100.00%	35.79%	63.89%	3.35%	60.54%	44.91%	10.76%	4.68%	0.19%	0.32%
10	Winter Peak Resp KW	D10W	100.00%	31.90%	67.32%	3.26%	64.06%	46.91%	11.25%	5.73%	0.18%	0.77%
11	Alternative Production Allocator	1CP	100.00%	38.55%	61.45%	3.41%	58.04%	43.50%	10.41%	3.95%	0.19%	0.00%
12	Sec, Pri & TT, Class Coin kW @ S	D60Sub	100.00%	41.63%	57.83%	4.02%	53.81%	43.88%	9.92%	0.01%	0.00%	0.54%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	36.61%	63.07%	3.36%	59.70%	48.21%	11.50%	0.00%	0.00%	0.33%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	74.43%	25.21%	3.71%	21.50%	15.72%	5.78%	0.00%	0.00%	0.35%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	74.45%	25.55%	2.06%	23.49%	23.49%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	49.35%	50.40%	3.62%	46.78%	46.78%	0.00%	0.00%	0.00%	0.26%
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%	29.93%	69.73%	3.16%	66.57%	47.91%	12.51%	5.93%	0.21%	0.34%
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	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	30.89%	68.67%	3.12%	65.548%	50.04%	11.68%	3.60%	0.24%	0.45%
21	Present Rev	R01	100.00%	37.36%	61.78%	3.50%	58.28%	43.73%	9.99%	4.36%	0.20%	0.86%
22	Late Fee Revenue Allocator	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%
			6	**7**	**11**	**12**	**13**	**15**	**16**	**17**	**18**	**36**
			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
23	Customers - B Basis	C10	1,308,442	1,166,597	136,327	87,551	48,776	48,273	479	15	9	5,518
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,334,596	1,170,186	136,525	87,750	48,776	48,273	479	15	9	27,884
25	Mo Cus Wtd By Cus Acct	C11WA	1,410,543	1,170,186	234,839	131,625	103,214	101,636	1,487	58	33	5,518
26	Cust Acctg Wtg Factor	C11WAF	15.25	1.00	14.25	1.50	12.75	2.11	3.11	3.88	3.67	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign S	C12	1,309,242	1,170,186	136,525	87,750	48,776	48,273	479	15	9	2,531
28	Mo Cus Wtd By Mtr Invest	C12WM	168,074,379	111,457,771	56,254,898	16,694,462	39,560,436	37,149,248	2,311,593	62,595	36,999	361,709
29	Meter Invest / Cust Factor	C12WMF	14,311	95	14,073	190	13,883	770	4,829	4,173	4,111	143
30	Sec & Pri Customers	C61PS	1,308,418	1,166,597	136,303	87,551	48,752	48,273	479	0	0	5,518
31	% Served by Primary Single Phase		0.0%	73.59%	0.00%	39.93%	0.00%	11.80%	18.18%	0.00%	0.00%	39.28%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	901,370	858,455	40,747	34,962	5,785	5,698	87	0	0	2,167
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,229,438	1,166,597	62,841	40,507	22,334	22,334	0	0	0	0
34	Secondary Customers	C62Sec	1,307,939	1,166,597	135,824	87,551	48,273	48,273	0	0	0	5,518
35	Summer Peak Resp KW	D10S	25,965	10,009	15,956	885	15,071	11,294	2,703	1,024	50	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,579,045	6,388,895	334,711	6,054,184	4,491,177	1,075,603	468,465	18,938	32,060
37	Winter Peak Resp KW	D10W	4,222	1,347	2,842	138	2,705	1,980	475	242	8	33
38	Alternative Production Allocator	1CP	25,965	10,009	15,956	885	15,071	11,294	2,703	1,024	50	0
39	Sec, Pri & TT, Class Coin kW @ S	D60Sub	6,631,290	2,760,494	3,834,708	266,370	3,568,338	2,909,950	657,806	582	0	36,088
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	5,962,429	2,182,570	3,760,440	200,622	3,559,818	2,874,362	685,456	0	0	19,419
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	2,157,736	1,606,071	544,037	80,116	463,921	339,293	124,628	0	0	7,628
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	10,485,113	7,806,290	2,678,823	216,305	2,462,517	2,462,517	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	4,934,673	5,039,796	361,776	4,678,020	4,678,020	0	0	0	25,531
44	Annual Billing kW	D99	50,585.647	0	50,586	0	50,586	38,601	8,077	3,687	220	0
45	Summer Billing kW	D99S	18,568.179	0	18,568	0	18,568	14,099	3,038	1,343	89	0
46	Winter Billing kW	D99W	32,017.467	0	32,017	0	32,017	24,502	5,039	2,344	132	0
47	Non-Coinc Pk Second	DN-Sec	13,615,653	7,806,290	5,789,944	467,517	5,322,426	5,322,426	0	0	0	19,419
48	MWh Sales	E99	28,838,347	8,450,856	20,264,816	853,252	19,411,564	13,765,907	3,724,793	1,856,137	64,727	122,675
49	MWh Sales Excl CIP Exempt	E99XCIP	27,361,954	8,450,856	18,788,423	853,090	17,935,333	13,691,871	3,194,646	984,089	64,727	122,675
50	Late Fee Revenue Allocation	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

Northern States Power Company

Summary of 2021 Class Cost of Service Study ($000)

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	3,426,848	1,308,331	121,389	1,965,782	31,346
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,154	743	54	353	5
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,428,002	1,309,073	121,443	1,966,135	31,351
[4]	Present Rates (CCOSS page 2, line 2)	3,080,208	1,148,029	108,275	1,797,236	26,668
[5]	Unadjusted Deficiency (line 3 - line 4)	347,795	161,045	13,168	168,899	4,683
[6]	Defic / Pres (line 5 / line 4)	11.3%	14.0%	12.2%	9.4%	17.6%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.24**	**1.08**	**0.83**	**1.56**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Development Disc Cost Allocation (CCOSS page 2, line 8)					
				HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(1,960)	1,424	532	4

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,426,848	1,306,371	122,813	1,966,314	31,349
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,154	743	54	353	5
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,428,002	1,307,114	122,868	1,966,667	31,354
[16]	Present Rates (line 4)	3,080,208	1,148,029	108,275	1,797,236	26,668
[17]	Adjusted Deficiency (line 15 - line 16)	347,795	159,085	14,592	169,430	4,687
[18]	Defic / Pres Rates (line 17 / line 16)	11.3%	13.9%	13.5%	9.4%	17.6%
[19]	**Ratio: Class % / Total %**	**1.00**	**1.23**	**1.19**	**0.83**	**1.56**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	3,426,848	1,299,084	122,225	1,974,609	30,930
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,154	743	54	353	5
[22]	Proposed Operating Revenues (line 20 + line 21)	3,428,003	1,299,827	122,279	1,974,962	30,935
[23]	Proposed Increase (line 22 - line 16)	347,795	151,798	14,004	177,726	4,267
[24]	Difference / Pres (line 23 / line 16)	11.3%	13.2%	12.9%	9.9%	16.0%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.17**	**1.15**	**0.88**	**1.42**

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Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Rate Base

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Plant In Service	Alloc	MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
1	Production		11,481,125	3,640,788	7,809,495	369,641	7,439,854	5,400,291	1,382,047	628,604	28,912	30,843
2	Transmission		3,359,259	1,281,836	2,077,128	114,282	1,962,846	1,466,151	350,613	133,460	12,622	296
3	Distribution		4,136,381	2,684,186	1,317,510	184,768	1,132,742	931,527	191,034	9,934	247	134,685
4	General		1,841,188	738,038	1,087,062	64,879	1,022,183	756,584	186,643	74,902	4,054	16,089
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		20,817,953	8,344,847	12,291,194	733,569	11,557,625	8,554,553	2,110,338	846,900	45,834	181,912
7	Production		6,774,974	2,141,031	4,615,448	217,910	4,397,538	3,190,484	817,335	372,632	17,087	18,495
8	Transmission		787,936	301,294	486,605	26,812	459,793	343,337	81,986	31,095	3,375	37
9	Distribution		1,519,172	1,008,064	474,046	69,424	404,622	335,565	65,240	3,716	101	37,062
10	General		922,457	369,766	544,631	32,505	512,126	379,058	93,510	37,527	2,031	8,061
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		10,004,539	3,820,155	6,120,730	346,651	5,774,079	4,248,444	1,058,071	444,970	22,594	63,654
13	**Net Plant In Service**		10,813,415	4,524,692	6,170,464	386,918	5,783,546	4,306,109	1,052,267	401,930	23,240	118,258
14	Deducts: Accum Defer Inc Tax		2,187,638	894,128	1,271,284	78,102	1,193,182	887,867	216,780	83,553	4,983	22,226
15	Constr Work In Progress		417,804	163,884	251,587	14,607	236,981	175,066	43,555	17,501	858	2,332
16	Fuel Inventory		65,875	19,647	46,001	2,085	43,916	31,623	8,231	3,892	170	227
17	Materials & Supplies		153,932	52,292	100,975	5,082	95,892	69,934	17,740	7,843	374	665
18	Prepayments		92,118	38,545	52,565	3,296	49,269	36,683	8,964	3,424	198	1,007
19	Non-Plant & Work Cash		(45,960)	(22,532)	(22,916)	(1,585)	(21,331)	(16,266)	(3,797)	(1,165)	(103)	(512)
20	Total Additions		683,768	251,836	428,213	23,485	404,728	297,040	74,694	31,495	1,498	3,719
21	**Rate Base**		9,309,544	3,882,400	5,327,393	332,301	4,995,091	3,715,283	910,181	349,872	19,755	99,751
	Income Statement											
22A	**Tot Oper Rev - Pres**		3,641,182	1,339,706	2,273,352	126,831	2,146,521	1,604,333	371,710	161,875	8,603	28,125
22B	**Tot Oper Rev - Prop**		3,988,977	1,491,504	2,465,081	140,835	2,324,246	1,736,869	404,203	173,990	9,184	32,392
23	Oper & Maint		2,409,148	853,857	1,540,176	83,901	1,456,275	1,067,897	267,922	114,958	5,499	15,115
24	Book Depr + IRS Int		719,524	283,406	428,008	25,147	402,861	297,629	73,627	30,043	1,562	8,110
25	Payroll, Rl Est & Prop Tax		210,876	88,984	119,720	7,651	112,069	83,490	20,335	7,805	439	2,172
26	Deferred Inc Tax & Net ITC		(172,672)	(74,739)	(95,678)	(6,274)	(89,403)	(66,818)	(16,165)	(6,074)	(346)	(2,254)
27A	Present Income Tax		59,576	25,772	32,768	2,108	30,661	30,460	(893)	865	228	1,036
27B	Proposed Income Tax		159,540	69,402	87,875	6,133	81,742	68,554	8,446	4,347	396	2,263
28	Allow Funds Dur Const		31,000	12,055	18,796	1,075	17,721	13,105	3,253	1,296	67	148
29A	**Present Return**		445,729	174,481	267,154	15,373	251,780	204,780	30,138	15,574	1,289	4,094
29B	**Proposed Return**		693,561	282,650	403,777	25,352	378,424	299,223	53,291	24,207	1,703	7,135
30A	**Pres Ret on Rt Base**		4.79%	4.49%	5.01%	4.63%	5.04%	5.51%	3.31%	4.45%	6.52%	4.10%
30B	**Prop Ret on Rt Base**		**7.45%**	7.28%	7.58%	7.63%	7.58%	8.05%	5.86%	6.92%	8.62%	7.15%
31A	**Pres Ret on Common**		5.14%	4.58%	5.57%	4.83%	5.62%	6.52%	2.33%	4.50%	8.44%	3.84%
31B	**Prop Ret on Common**		**10.21%**	9.89%	10.46%	10.55%	10.45%	11.36%	7.17%	9.20%	12.44%	9.64%

2021 Class Cost of Service Study Detail ($000)

PRES vs Equal Rev Reqts

Line	Total Retail Rev Reqt	Alloc	1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
1	**UnAdj Equal Rev Reqt @ 7.45%**		**3,426,848**	**1,308,331**	**2,087,171**	**121,389**	**1,965,782**	**1,449,685**	**360,199**	**148,393**	**7,505**	**31,346**
2	**Present Revenue**		**3,080,208**	**1,148,029**	**1,905,512**	**108,275**	**1,797,236**	**1,348,907**	**307,387**	**133,692**	**7,250**	**26,668**
3	**UnAdj Revenue Deficiency**		**346,640**	**160,302**	**181,660**	**13,113**	**168,546**	**100,778**	**52,811**	**14,701**	**256**	**4,678**
4	**UnAdj Deficiency / Present**		**11.25%**	**13.96%**	**9.53%**	**12.11%**	**9.38%**	**7.47%**	**17.18%**	**11.00%**	**3.53%**	**17.54%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
5	**Pres Int Rate Discounts**											
6	**Pres Econ Dvlp Rate Discounts**											
7	**Pres Int Rate Disc Cost Alloc**	**D10S**										
8	**Pres Econ Dvlp Disc Cost Alloc**	**R01**										
												HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
9	**Revenue Requirement Shift**		**0**	**(1,960)**	**1,956**	**1,424**	**532**	**9,840**	**(2,299)**	**(6,787)**	**(223)**	**4**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,426,848**	**1,306,371**	**2,089,127**	**122,813**	**1,966,314**	**1,459,526**	**357,900**	**141,606**	**7,282**	**31,349**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**346,640**	**158,343**	**183,616**	**14,538**	**169,078**	**110,618**	**50,513**	**7,914**	**32**	**4,682**
12	**Adj Deficiency / Adj Present**		**11.25%**	**13.79%**	**9.64%**	**13.43%**	**9.41%**	**8.20%**	**16.43%**	**5.92%**	**0.45%**	**17.56%**
	Equal Customer Classification											
13	Min Sys & Service Drop		251,521	204,307	24,084	13,892	10,192	9,946	255	(12)	3	23,130
14	Energy Services		60,997	50,709	10,008	5,620	4,388	4,321	63	2	1	280
15	Total Customer **(Cusco)**		312,517	255,016	34,092	19,512	14,580	14,267	318	(10)	5	23,409
16	Ave Monthly Customers		1,345,380	1,180,196	137,160	88,160	49,001	48,497	479	15	9	28,024
17	Svc Drop Reqt	$ / Mo / Cust	$15.58	$14.43	$14.63	$13.13	$17.33	$17.09	$44.37	($68.10)	$29.39	$68.78
18	Ener Svcs Reqt	$ / Mo / Cust	$3.78	$3.58	$6.08	$5.31	$7.46	$7.42	$10.90	$13.56	$12.84	$0.83
19	Total Reqt	$ / Mo / Cust	$19.36	$18.01	$20.71	$18.44	$24.80	$24.52	$55.27	($54.54)	$42.22	$69.61
	Equal Energy Classification											
20	On Peak Rev Reqt		810,664	231,977	577,345	29,812	547,533	400,346	101,091	43,981	2,114	1,342
21	Off Peak Rev Reqt		815,151	252,470	558,312	21,523	536,788	383,436	101,491	49,735	2,128	4,370
22	Total Ener Rev Reqt		1,625,815	484,447	1,135,657	51,335	1,084,321	783,782	202,582	93,716	4,242	5,712
23	Annual MWh Sales		28,388,116.803	8,289,824	19,976,823	841,814	19,135,010	13,576,274	3,661,168	1,819,766	77,801	121,470
24	On Pk Reqt	Mills / kWh	28.556	27.983	28.901	35.414	28.614	29.489	27.612	24.169	27.173	11.047
25	Off Pk Reqt	Mills / kWh	28.715	30.455	27.948	25.568	28.053	28.243	27.721	27.330	27.349	35.975
26	Total Reqt	Mills / kWh	57.271	58.439	56.849	60.982	56.667	57.732	55.333	51.499	54.521	47.022
	Equal Demand Classification											
27	Energy-Related Prod		360,354	110,510	248,732	11,487	237,245	171,484	44,273	20,566	921	1,111
28	Capacity-Related Summer Peak Prod		303,199	116,299	186,900	10,341	176,559	132,339	31,593	11,935	692	0
29	Capacity-Related Winter Peak Prod		91,639	35,150	56,489	3,126	53,363	39,998	9,549	3,607	209	0
30	Total Capacity-Related Prod		394,839	151,449	243,389	13,467	229,922	172,337	41,141	15,542	901	0
31	Total Production		755,192	261,960	492,122	24,954	467,167	343,822	85,415	36,108	1,823	1,111
32	Transmission **(Transco)**		444,192	170,230	273,962	15,135	258,827	193,728	46,224	17,463	1,411	0
33	Primary Dist Subs		90,773	36,819	53,466	3,573	49,892	39,175	9,577	1,115	25	488
34	Prim Dist Lines		169,157	84,070	84,520	5,909	78,610	62,527	16,083	0	0	567
35	Second Dist. Trans		29,201	15,788	13,353	969	12,384	12,384	0	0	0	60
36	Total Distribution **(Disco)**		289,131	136,678	151,339	10,452	140,887	114,087	25,660	1,115	25	1,114
37	Total Demand Rev Reqt		1,488,515	568,868	917,423	50,541	866,881	651,637	157,299	54,687	3,259	2,225
38	Annual Billing kW		49,881,486	0	49,881,486	0	49,881,486	38,073,588	7,940,141	3,618,195	249,562	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$4.99	$0.00	$4.76	$4.50	$5.58	$5.68	$3.69	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.75	$0.00	$3.54	$3.48	$3.98	$3.30	$2.77	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.13	$0.00	$1.07	$1.05	$1.20	$1.00	$0.84	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$9.87	$0.00	$9.37	$9.03	$10.76	$9.98	$7.30	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.49	$0.00	$5.19	$5.09	$5.82	$4.83	$5.65	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.03	$0.00	$2.82	$3.00	$3.23	$0.31	$0.10	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$18.39	$0.00	$17.38	$17.12	$19.81	$15.11	$13.06	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	52.434	68.622	45.924	60.039	45.303	47.998	42.964	30.052	41.889	18.315
47	Summer Billing kW		18,305,301	0	18,305,301	0	18,305,301	13,906,603	2,991,491	1,319,367	87,840	0
48	Winter Billing kW		31,576,184	0	31,576,184	0	31,576,184	24,166,985	4,948,650	2,298,828	161,722	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$23.72	$0.00	$22.41	$22.11	$25.19	$19.86	$17.33	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$15.30	$0.00	$14.46	$14.24	$16.56	$12.39	$10.74	$0.00
51	Energy + Production **(Genco)**		2,381,008	746,407	1,627,778	76,290	1,551,489	1,127,604	287,996	129,824	6,064	6,823

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

PROP vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.45%**	**7.28%**	**7.58%**	**7.63%**	**7.58%**	**8.05%**	**5.86%**	**6.92%**	**8.62%**	**7.15%**
2	**UnAdj Equalized Rev Reqt**		**3,426,848**	**1,308,331**	**2,087,171**	**121,389**	**1,965,782**	**1,449,685**	**360,199**	**148,393**	**7,505**	**31,346**
3	**Proposed Revenue**		**3,426,848**	**1,299,084**	**2,096,834**	**122,225**	**1,974,609**	**1,481,169**	**339,826**	**145,785**	**7,830**	**30,930**
4	**UnAdj Revenue Deficiency**		**(0)**	**9,247**	**(9,663)**	**(836)**	**(8,827)**	**(31,483)**	**20,372**	**2,608**	**(324)**	**416**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.71%**	**-0.46%**	**-0.68%**	**-0.45%**	**-2.13%**	**5.99%**	**2%**	**-4%**	**1.35%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
6	**Prop Interrupt Rate Discounts**											
7	**Prop Econ Dev Rate Discounts**											
8	**Prop Int Rate Disc Cost Alloc**	**D10S**										
9	**Prop ED Discount Cost Alloc**	**R01**										
												HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
10	**Revenue Requirement Shift**		**0**	**3,272**	**(3,276)**	**1,665**	**(4,942)**	**7,201**	**(4,168)**	**(7,702)**	**(273)**	**4**
11	**Adj Equal Rev (Rows 2+10)**		**3,426,848**	**1,311,603**	**2,083,895**	**123,054**	**1,960,841**	**1,456,887**	**356,031**	**140,691**	**7,232**	**31,350**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**(0)**	**12,519**	**(12,939)**	**829**	**(13,769)**	**(24,282)**	**16,205**	**(5,094)**	**(598)**	**421**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**0.96%**	**-0.62%**	**0.68%**	**-0.70%**	**-1.64%**	**4.77%**	**-3.49%**	**-7.63%**	**1.36%**
	Prop Customer Component											
14	Min Sys & Service Drop		247,923	200,866	24,322	13,945	10,377	10,139	247	(12)	3	22,735
15	Energy Services		60,986	50,699	10,008	5,620	4,388	4,321	63	2	1	280
16	Total Customer **(Cusco)**		308,910	251,565	34,330	19,565	14,765	14,460	310	(10)	5	23,015
17	Ave Monthly Customers		1,345,380	1,180,196	137,160	88,160	49,001	48,497	479	15	9	28,024
18	Svc Drop Reqt	$ / Mo / Cust	$15.36	$14.18	$14.78	$13.18	$17.65	$17.42	$42.99	($68.35)	$29.70	$67.61
19	Ener Svcs Reqt	$ / Mo / Cust	$3.78	$3.58	$6.08	$5.31	$7.46	$7.43	$10.89	$13.55	$12.84	$0.83
20	Total Reqt	$ / Mo / Cust	$19.13	$17.76	$20.86	$18.49	$25.11	$24.85	$53.88	($54.80)	$42.54	$68.44
	Prop Energy Component											
21	On Peak Rev Reqt		810,461	231,888	577,232	29,809	547,423	400,427	100,932	43,949	2,115	1,341
22	Off Peak Rev Reqt		814,931	252,372	558,191	21,521	536,670	383,513	101,331	49,698	2,129	4,368
23	Total Ener Rev Reqt		1,625,392	484,260	1,135,423	51,330	1,084,093	783,939	202,263	93,646	4,245	5,710
24	Annual MWh Sales		28,388,117	8,289,824	19,976,823	841,814	19,135,010	13,576,274	3,661,168	1,819,766	77,801	121,470
25	On Pk Reqt	Mills / kWh	28.549	27.973	28.895	35.410	28.608	29.495	27.568	24.151	27.190	11.044
26	Off Pk Reqt	Mills / kWh	28.707	30.444	27.942	25.565	28.047	28.249	27.677	27.310	27.367	35.962
27	Total Reqt	Mills / kWh	57.256	58.416	56.837	60.975	56.655	57.743	55.246	51.461	54.557	47.006
	Prop Demand Component											
28	Energy-Related Prod		364,638	109,434	254,100	11,910	242,190	187,474	34,537	19,096	1,083	1,104
29	Capacity-Related Summer Peak Prod		302,690	115,358	187,332	10,394	176,939	135,053	29,522	11,643	722	0
30	Capacity-Related Winter Peak Prod		91,485	34,866	56,620	3,141	53,478	40,818	8,923	3,519	218	0
31	Total Capacity-Related Prod		394,175	150,224	243,952	13,535	230,417	175,871	38,444	15,161	940	0
32	Total Production		758,814	259,658	498,052	25,445	472,607	363,345	72,981	34,258	2,023	1,104
33	Transmission **(Transco)**		445,815	168,975	276,839	15,364	261,476	201,751	41,349	16,845	1,531	0
34	Primary Dist Subs		90,726	36,416	53,827	3,612	50,215	40,607	8,535	1,046	27	483
35	Prim Dist Lines		168,003	82,766	84,678	5,940	78,738	64,350	14,388	0	0	559
36	Second Dist, Trans		29,188	15,445	13,685	969	12,716	12,716	0	0	0	58
37	Total Distribution **(Disco)**		287,918	134,626	152,190	10,522	141,669	117,673	22,923	1,046	27	1,101
38	Total Demand Rev Reqt		1,492,546	563,260	927,082	51,331	875,751	682,769	137,253	52,148	3,581	2,205
39	Annual Billing kW		49,881,486	0	49,881,486	0	49,881,486	38,073,588	7,940,141	3,618,195	249,562	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.86	$4.92	$4.35	$5.28	$4.34	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.55	$3.55	$3.72	$3.22	$2.89	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.07	$1.07	$1.12	$0.97	$0.87	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$9.47	$9.54	$9.19	$9.47	$8.11	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.24	$5.30	$5.21	$4.66	$6.13	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$2.84	$3.09	$2.89	$0.29	$0.11	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$17.56	$17.93	$17.29	$14.41	$14.35	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	52.576	67.946	46.408	60.976	45.767	50.291	37.489	28.657	46.022	18.153
48	Summer Billing kW		18,305,301	0	18,305,301	0	18,305,301	13,906,603	2,991,491	1,319,367	87,840	0
49	Winter Billing kW		31,576,184	0	31,576,184	0	31,576,184	24,166,985	4,948,650	2,298,828	161,722	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$23.93	$0.00	$22.60	$23.03	$22.31	$19.05	$18.80	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$15.49	$0.00	$14.63	$15.00	$14.25	$11.75	$11.93	$0.00
52	Energy + Production **(Genco)**		2,384,206	743,917	1,633,475	76,775	1,556,700	1,147,284	275,244	127,904	6,268	6,814
53	Prop Rev - Pres Rev (Pg 2)		346,640	151,056	191,323	13,950	177,373	132,261	32,439	12,093	580	4,262
54	Difference / Present		11.25%	13.16%	10.04%	12.88%	9.87%	9.81%	10.55%	9.05%	8.00%	15.98%

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,929,004	741,648	1,187,356	65,864	1,121,492	840,647	200,655	75,794	4,396	0
2	WInter Peak	D10S		583,024	224,156	358,868	19,907	338,961	254,078	60,646	22,908	1,329	0
3	Total Peak	D10S		2,512,028	965,804	1,546,224	85,771	1,460,453	1,094,725	261,302	98,702	5,724	0
4	Base Load	E8760		6,433,729	1,918,824	4,492,781	203,626	4,289,155	3,088,476	803,935	380,110	16,633	22,124
5	Nuclear Fuel	E8760		2,535,368	756,160	1,770,490	80,244	1,690,246	1,217,090	316,810	149,792	6,555	8,719
6	Total	28.08%	120, 310-346	11,481,125	3,640,788	7,809,495	369,641	7,439,854	5,400,291	1,382,047	628,604	28,912	30,843
	Transmission												
7	Gen Step Up Base	E8760		86,031	25,658	60,077	2,723	57,354	41,299	10,750	5,083	222	296
8	Gen Step Up Peak	D10S		35,990	13,837	22,153	1,229	20,924	15,684	3,744	1,414	82	0
9	Total Gen Step Up			122,022	39,496	82,230	3,952	78,278	56,983	14,494	6,497	304	296
10	Bulk Transmission	D10S		3,231,290	1,242,340	1,988,950	110,330	1,878,620	1,408,175	336,119	126,963	7,363	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		5,947	0	5,947	0	5,947	993	0	0	4,954	0
13	Total		350-359	3,359,259	1,281,836	2,077,128	114,282	1,962,846	1,466,151	350,613	133,460	12,622	296
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		3,046	953	2,084	98	1,986	1,439	370	170	8	9
15	Bulk Transmission	D10S		1,745	671	1,074	60	1,015	761	182	69	4	0
16	Distrib Function	D60Sub		694,361	288,632	401,920	27,980	373,940	305,642	68,855	(557)	0	3,808
17	Direct Assign	Dir Assign		17,385,902	0	17,386	0	17,386	392	6,557	10,221	217	0
18	Total		360-363	716,539	290,257	422,465	28,137	394,328	308,234	75,963	9,903	228	3,817
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		157,624	117,149	39,919	5,875	34,044	24,916	9,128	0	0	556
20	Primary Capacity Multi Phase	D61PS		339,139	123,659	214,380	11,428	202,953	163,958	38,995	0	0	1,100
21	Primary Customer 1 Phase	C61PS1Ph		84,558	80,543	3,808	3,268	541	533	8	0	0	207
22	Primary Customer Multi Phase	C61PS		181,932	162,266	18,886	12,131	6,755	6,689	66	0	0	780
23	Total Primary			763,253	483,616	276,994	32,702	244,292	196,096	48,196	0	0	2,643
24	Second Capacity	D62SecL		38,791	19,114	19,579	1,405	18,174	18,174	0	0	0	98
25	Second Customer	C62Sec		139,563	124,522	14,442	9,309	5,133	5,133	0	0	0	599
26	Total Secondary			178,354	143,636	34,021	10,714	23,307	23,307	0	0	0	697
27	Street Lighting	DASL		46,623	0	0	0	0	0	0	0	0	46,623
28	Total		364,365	988,231	627,253	311,015	43,416	267,599	219,402	48,196	0	0	49,963
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		271,332	201,659	68,716	10,113	58,603	42,891	15,712	0	0	957
30	Primary Capacity Multi Phase	D61PS		389,975	142,195	246,516	13,141	233,375	188,535	44,840	0	0	1,265
31	Primary Customer 1 Phase	C61PS1Ph		308,351	293,709	13,888	11,916	1,972	1,942	30	0	0	754
32	Primary Customer Multi Phase	C61PS		443,181	395,274	46,006	29,551	16,454	16,293	161	0	0	1,901
33	Total Primary			1,412,839	1,032,837	375,125	64,722	310,403	249,661	60,743	0	0	4,877
34	Second Capacity	D62SecL		45,452	22,396	22,941	1,646	21,295	21,295	0	0	0	115
35	Second Customer	C62Sec		127,778	114,007	13,223	8,523	4,699	4,699	0	0	0	548
36	Total Secondary			173,230	136,403	36,164	10,170	25,994	25,994	0	0	0	663
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,586,069	1,169,240	411,289	74,891	336,398	275,655	60,743	0	0	5,540
	Line Transformers												
39	Primary	D61PS		43,157	15,736	27,281	1,454	25,827	20,865	4,962	0	0	140
40	Second Capacity	D62SecL		128,844	63,486	65,031	4,667	60,365	60,365	0	0	0	326
41	Second Customer	C62Sec		226,264	201,879	23,414	15,093	8,321	8,321	0	0	0	971
42	Total		368	398,265	281,102	115,726	21,214	94,513	89,551	4,962	0	0	1,437
	Services												
43	Second Capacity	D62NLL		67,429	50,209	17,220	1,392	15,828	15,828	0	0	0	0
44	Second Customer	C62NL		220,538	209,306	11,232	7,240	3,992	3,992	0	0	0	0
43	Total Services	C62NL	369	287,967	259,515	28,452	8,632	19,820	19,820	0	0	0	0
44	Meters	C12WM	370	85,566	56,820	28,564	8,478	20,086	18,865	1,170	32	19	183
45	Street Lighting	Dir Assign	373	73,745	0	0	0	0	0	0	0	0	73,745
46	**Total Distribution**			4,136,381	2,684,186	1,317,510	184,768	1,132,742	931,527	191,034	9,934	247	134,685
47	**General & Common Plant**	PTD	303, 389-399	1,841,188	738,038	1,087,062	64,879	1,022,183	756,584	186,643	74,902	4,054	16,089
48	Prelim Elec Plant			20,817,953	8,344,847	12,291,194	733,569	11,557,625	8,554,553	2,110,338	846,900	45,834	181,912
49	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
50	**Elec Plant in Serv**			20,817,953	8,344,847	12,291,194	733,569	11,557,625	8,554,553	2,110,338	846,900	45,834	181,912

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Accum Deprec; Net Plant

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,396,686	536,986	859,699	47,689	812,011	608,666	145,283	54,878	3,183	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,359,851	703,812	1,647,923	74,689	1,573,235	1,132,833	294,878	139,422	6,101	8,115
5	Base Load	E8760		3,018,438	900,232	2,107,825	95,533	2,012,293	1,448,984	377,173	178,332	7,803	10,380
6	Total		108,111,115,120.5	6,774,974	2,141,031	4,615,448	217,910	4,397,538	3,190,484	817,335	372,632	17,087	18,495
	Transmission												
7	Gen Step Up Base	E8760		10,615	3,166	7,412	336	7,076	5,096	1,326	627	27	37
8	Gen Step Up Peak	D10S		14,243	5,476	8,767	486	8,281	6,207	1,482	560	32	0
9	Total Gen Step Up			24,858	8,642	16,179	822	15,357	11,303	2,808	1,187	60	37
10	Bulk Transmission	D10S		761,180	292,652	468,528	25,990	442,538	331,717	79,178	29,908	1,734	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		1,898	0	1,898	0	1,898	317	0	0	1,581	0
13	Total		108,111,115,120.5	787,936	301,294	486,605	26,812	459,793	343,337	81,986	31,095	3,375	37
	Distribution												
14	Generat Step Up	STRATH		2,253	705	1,542	72	1,469	1,065	274	126	6	6
15	Bulk Transmission	D10S		657	253	404	22	382	286	68	26	1	0
16	Distrib Function	D60Sub		238,905	99,308	138,287	9,627	128,660	105,161	23,690	(191)	0	1,310
17	Direct Assign	Dir Assign		6,346	0	6,346	0	6,346	143	2,393	3,731	79	0
18	Total Substations			248,161	100,266	146,579	9,722	136,857	106,654	26,426	3,691	86	1,317
19	Overhead Lines	POL		355,467	225,623	111,872	15,617	96,255	78,919	17,336	0	0	17,972
20	Underground	PUL		479,353	353,376	124,303	22,634	101,668	83,310	18,358	0	0	1,674
21	Line Transformers	P68		174,667	123,283	50,754	9,304	41,450	39,274	2,176	0	0	630
22	Services	P69		177,215	159,705	17,509	5,312	12,197	12,197	0	0	0	0
23	Meters	C12WM		68,988	45,811	23,029	6,835	16,194	15,210	944	26	15	147
24	Street Lighting	P73		15,322	0	0	0	0	0	0	0	0	15,322
25	Total		108,111,115,120.5	1,519,172	1,008,064	474,046	69,424	404,622	335,565	65,240	3,716	101	37,062
26	**General & CommonPlant**	PTD	108,111,115,120.5	922,457	369,766	544,631	32,505	512,126	379,058	93,510	37,527	2,031	8,061
27	**Total Accum Depr**			10,004,539	3,820,155	6,120,730	346,651	5,774,079	4,248,444	1,058,071	444,970	22,594	63,654
28	**Net Elec Plant**			10,813,415	4,524,692	6,170,464	386,918	5,783,546	4,306,109	1,052,267	401,930	23,240	118,258
29	**Net Plant w/ TBT**			10,813,415	4,524,692	6,170,464	386,918	5,783,546	4,306,109	1,052,267	401,930	23,240	118,258

Subtractions: Accum Defer Inc Tax

	Production												
30	Peaking Plant	D10S		268,788	103,341	165,446	9,178	156,269	117,136	27,959	10,561	612	0
31	Base Load	E8760		921,482	274,827	643,486	29,165	614,322	442,352	115,145	54,442	2,382	3,169
32	Nuclear Fuel	E8760		(3,040)	(907)	(2,123)	(96)	(2,027)	(1,459)	(380)	(180)	(8)	(10)
33	Total		190,281,282,283	1,187,230	377,262	806,810	38,246	768,564	558,029	142,725	64,824	2,987	3,158
	Transmission												
34	Gen Step Up Base	E8760		15,020	4,480	10,489	475	10,014	7,210	1,877	887	39	52
35	Gen Step Up Peak	D10S		4,020	1,545	2,474	137	2,337	1,752	418	158	9	0
36	Total Gen Step Up			19,040	6,025	12,963	613	12,351	8,962	2,295	1,045	48	52
37	Bulk Transmission	D10S		707,910	272,172	435,739	24,171	411,568	308,503	73,637	27,815	1,613	0
38	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,194	0	1,194	0	1,194	199	0	0	994	0
40	Total		281,282,283	728,144	278,197	449,896	24,784	425,112	317,664	75,932	28,860	2,655	52
	Distribution												
41	Generat Step Up	STRATH		324	101	222	10	211	153	39	18	1	1
42	Bulk Transmission	D10S		247	95	152	8	144	108	26	10	1	0
43	Distrib Function	D60Sub		108,854	45,248	63,008	4,386	58,622	47,915	10,794	(87)	0	597
44	Direct Assign	Dir Assign		2,213	0	2,213	0	2,213	50	835	1,301	28	0
45	Total Substations			111,638	45,445	65,596	4,405	61,190	48,226	11,694	1,242	29	598
46	Overhead Lines	POL		150,543	95,553	47,379	6,614	40,765	33,423	7,342	0	0	7,611
47	Underground	PUL		234,114	172,587	60,709	11,054	49,654	40,688	8,966	0	0	818
48	Line Transformers	P68		56,322	39,753	16,366	3,000	13,366	12,664	702	0	0	203
49	Services	P69		18,607	16,768	1,838	558	1,281	1,281	0	0	0	0
50	Meters	C12WM		10,491	6,967	3,502	1,039	2,463	2,313	143	4	2	22
51	Street Lighting	P73		13,630	0	0	0	0	0	0	0	0	13,630
52	Total		281,282,283	595,346	377,074	195,390	26,671	168,719	138,595	28,847	1,246	31	22,882
53	**General & Common Plant**	PTD	281,282,283	138,474	55,507	81,757	4,879	76,877	56,902	14,037	5,633	305	1,210
54	**Total Deferred Tax**			2,649,194	1,088,039	1,533,852	94,580	1,439,272	1,071,190	261,541	100,563	5,978	27,302
55	Net Operating Loss (NOL) Carry F	NEPIS		(489,606)	(204,868)	(279,384)	(17,519)	(261,866)	(194,971)	(47,644)	(18,198)	(1,052)	(5,354)
56	Non-Plant Related	LABOR		28,051	10,957	16,817	1,041	15,776	11,647	2,883	1,189	57	278
57	**Accum Def W/ Adj**			2,187,638	894,128	1,271,284	78,102	1,193,182	887,867	216,780	83,553	4,983	22,226

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Additions: CWIP, Etc; Rate Base

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		30,029	11,545	18,484	1,025	17,458	13,086	3,124	1,180	68	0
2	Base Load	E8760		74,469	22,210	52,003	2,357	49,646	35,748	9,305	4,400	193	256
3	Nuclear Fuel	E8760		96,871	28,891	67,647	3,066	64,581	46,503	12,105	5,723	250	333
4	Total		107	201,369	62,646	138,133	6,448	131,685	95,337	24,534	11,303	511	589
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		386	149	238	13	225	168	40	15	1	0
7	Total Gen Step Up			386	149	238	13	225	168	40	15	1	0
8	Bulk Transmission	D10S		74,831	28,770	46,060	2,555	43,505	32,611	7,784	2,940	171	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	75,217	28,919	46,298	2,568	43,730	32,779	7,824	2,955	171	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		10,014	4,163	5,796	404	5,393	4,408	993	(8)	0	55
15	Direct Assign	Dir Assign		20	0	20	0	20	0	8	12	0	0
16	Total Substations			10,034	4,163	5,817	404	5,413	4,408	1,001	4	0	55
17	Overhead Lines	POL		17,267	10,960	5,434	759	4,676	3,834	842	0	0	873
18	Underground	PUL		33,242	24,506	8,620	1,570	7,051	5,777	1,273	0	0	116
19	Line Transformers	P68		928	655	270	49	220	209	12	0	0	3
20	Services	P69		138	125	14	4	10	10	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		107	61,610	40,408	20,155	2,785	17,369	14,238	3,128	4	0	1,047
24	**General & Common Plant**	PTD	107	79,608	31,911	47,001	2,805	44,196	32,713	8,070	3,239	175	696
25	**Total CWIP**			417,804	163,884	251,587	14,607	236,981	175,066	43,555	17,501	858	2,332
26	Fuel Inventory	E8760	151,152	65,875	19,647	46,001	2,085	43,916	31,623	8,231	3,892	170	227
	Materials & Supplies												
27	Production	P10		137,523	43,610	93,543	4,428	89,116	64,685	16,554	7,530	346	369
28	Trans & Distr	TD		16,409	8,682	7,431	655	6,777	5,249	1,186	314	28	295
29	Total		154	153,932	52,292	100,975	5,082	95,892	69,934	17,740	7,843	374	665
	Prepayments												
30	Miscellaneous	NEPIS		92,118	38,545	52,565	3,296	49,269	36,683	8,964	3,424	198	1,007
31	Fuel	E8760		0	0	0	0	0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0	0	0	0	0
33	Total		235,252,165	92,118	38,545	52,565	3,296	49,269	36,683	8,964	3,424	198	1,007
34	Non-Plant Assets & Liab	LABOR	190,283,	81,070	31,665	48,601	3,008	45,593	33,662	8,333	3,435	163	804
35	Working Cash	PT0	calculated	(127,030)	(54,198)	(71,517)	(4,593)	(66,924)	(49,928)	(12,129)	(4,600)	(266)	(1,316)
36	**Total Additions**			683,768	251,836	428,213	23,485	404,728	297,040	74,694	31,495	1,498	3,719
37	**Total Rate Base**			9,309,544	3,882,400	5,327,393	332,301	4,995,091	3,715,283	910,181	349,872	19,755	99,751
38	**Common Rate Base (@ 52.50%)**			4,887,510.5	2,038,260	2,796,881	174,458	2,622,423	1,950,523	477,845	183,683	10,372	52,369

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Operating Rev (Cal Month)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,080,208	1,148,029	1,905,512	108,275	1,797,236	1,348,907	307,387	133,692	7,250	26,668
2	Proposed Rate Revenue	PROREV; (calc)		3,426,848	1,299,084	2,096,834	122,225	1,974,609	1,481,169	339,826	145,785	7,830	30,930
3	Equal Rate Revenue			3,426,848	1,308,331	2,087,171	121,389	1,965,782	1,449,685	360,199	148,393	7,505	31,346
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	736	274	455	26	430	322	73	32	2	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			736	274	455	26	430	322	73	32	2	6
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	428,299	135,818	291,330	13,789	277,541	201,456	51,557	23,450	1,079	1,151
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	(9,521)	(3,660)	(5,860)	(325)	(5,535)	(4,149)	(990)	(374)	(22)	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	630	188	440	20	420	303	79	37	2	2
12	Dist Overhd Line Rent	POL	454	5,006	3,177	1,575	220	1,356	1,111	244	0	0	253
13	Connection Charges	C11	451	1,930	1,693	197	126	70	70	1	0	0	40
14	Sales For Resale	E8760	447	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		204,100	78,471	125,629	6,969	118,661	88,946	21,231	8,019	465	0
17	MISO	D10S	456	(90,113)	(34,646)	(55,467)	(3,077)	(52,390)	(39,271)	(9,374)	(3,541)	(205)	0
18	Other	D10S	451,456,457	14,220	5,467	8,753	486	8,267	6,197	1,479	559	32	0
19	Late Pay Chg - Pres	R16C; R02		5,687	4,895	787	321	466	441	24	1	1	5
20	**Tot Other Op - Pres**		450	560,238	191,403	367,384	18,530	348,855	255,103	64,250	28,151	1,351	1,451
21	Incr Misc Serv - Prop	R01,		447	167	277	16	261	196	45	19	1	4
22	Incr Inter-Dept'l - Prop	R01; R02		67	25	42	2	39	29	7	3	0	1
23	Incr Late Pay - Prop	(R16C); R02		640	551	89	36	52	50	3	0	0	1
	Tot Incr Other Op			1,154	743	407	54	353	275	54	22	1	5
24	**Tot Other Op - Prop**			561,393	192,145	367,791	18,584	349,207	255,378	64,304	28,173	1,353	1,456
25	**Tot Oper Rev - Pres**			3,641,182	1,339,706	2,273,352	126,831	2,146,521	1,604,333	371,710	161,875	8,603	28,125
26	**Tot Oper Rev - Prop**			3,988,977	1,491,504	2,465,081	140,835	2,324,246	1,736,869	404,203	173,990	9,184	32,392
	Tot Oper Rev - Eql			3,988,977	1,500,751	2,455,418	139,999	2,315,419	1,705,386	424,576	176,598	8,860	32,808

Operating & Maint (Pg 1 of 2)

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production Expen												
27	**Fuel**	E8760	501,518,547	649,247	193,634	453,380	20,548	432,832	311,668	81,128	38,358	1,678	2,233
	Purchased Power												
28	Purchases: Cap Peak	D10S		98,827	37,996	60,831	3,374	57,456	43,068	10,280	3,883	225	0
29	Purchases: Cap Base	D10S		36,775	14,139	22,636	1,256	21,380	16,026	3,825	1,445	84	0
30	Purchases: Demand		555	135,602	52,135	83,467	4,630	78,837	59,094	14,105	5,328	309	0
31	Purchases: Other Energy	E8760	555	288,737	86,114	201,630	9,138	192,491	138,606	36,079	17,059	746	993
32	Tot Non-Assoc Purch			424,339	138,249	285,096	13,768	271,328	197,701	50,185	22,387	1,055	993
33	Interchg Agr Capacity	P10WoN	557	39,885	12,861	26,925	1,290	25,635	18,651	4,749	2,135	100	99
34	Interchg Agr Energy	E8760	557	15,635	4,663	10,918	495	10,424	7,506	1,954	924	40	54
35	Tot Wis Interchg Purch			55,521	17,524	37,844	1,785	36,059	26,157	6,703	3,059	140	152
36	**Tot Purchased Power**			479,859	155,774	322,940	15,554	307,387	223,858	56,888	25,445	1,196	1,145
	Other Production		500,502,505-507 509-514,517-519,520,										
37	Capacity Related	D10S	523-525,528-532,535,	96,876	37,246	59,630	3,308	56,322	42,218	10,077	3,806	221	0
38	Energy Related	E8760	539,543-546,548-550	351,128	104,722	245,199	11,113	234,085	168,557	43,876	20,745	908	1,207
39	Total Other Produc	21.62%	552-554,556,557 575.1-575.8	448,003.864	141,968	304,828	14,421	290,408	210,775	53,953	24,551	1,129	1,207
40	**Total Production**			1,577,110	491,376	1,081,149	50,523	1,030,626	746,300	191,968	88,355	4,003	4,585
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	249,696	96,001	153,695	8,526	145,170	108,816	25,973	9,811	569	0

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Operating & Maint (Pg 2 of 2)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	7,015	4,039	2,670	326	2,345	1,881	406	55	3	306
2	Load Dispatching	T20D80	581	7,395	3,028	4,335	289	4,046	3,248	740	53	3	32
3	Substations	P61	582,591,592	9,205	3,729	5,427	361	5,066	3,960	976	127	3	49
4	Overhead Lines	POL	583,593	44,053	27,961	13,864	1,935	11,929	9,780	2,148	0	0	2,227
5	Underground Lines	PUL	584, 594	15,820	11,662	4,102	747	3,355	2,749	606	0	0	55
6	Line Transformers	P68	595	1,405	991	408	75	333	316	17	0	0	5
7	Meters	C12WM	586,597,598	5,828	3,870	1,945	577	1,368	1,285	80	2	1	12
8	Customer Install'n	OXDTS	587	3,865	2,308	1,347	179	1,168	955	205	8	0	210
9	Street Lighting	Dir Assign	585,596	2,299	0	0	0	0	0	0	0	0	2,299
10	Miscellaneous	OXDTS	588	31,895	19,050	11,114	1,475	9,639	7,882	1,689	65	3	1,731
11	Rents (Pole Attachmts)	POL	589	3,360	2,133	1,058	148	910	746	164	0	0	170
12	**Total Distribution**			132,140	78,771	46,271	6,112	40,159	32,804	7,031	310	13	7,098
13	**Customer Accounting**	C11WA	901-905	48,931	40,617	8,119	4,551	3,568	3,514	51	2	1	195
14	**Sales, Econ Dvlp & Other**	R01	912	(5)	(2)	(3)	(0)	(3)	(2)	(1)	(0)	(0)	(0)
	Admin & General												
15	Salaries	LABOR	920	74,547	29,117	44,690	2,766	41,924	30,953	7,662	3,158	150	739
16	Office Supplies	OXTS	921	50,072	17,745	32,013	1,744	30,269	22,196	5,570	2,390	114	314
17	Admin Transfer Credit	OXTS	922	(40,981)	(14,523)	(26,201)	(1,427)	(24,774)	(18,166)	(4,559)	(1,956)	(94)	(257)
18	Outside Services	LABOR	923	22,264	8,696	13,347	826	12,521	9,244	2,288	943	45	221
19	Property Insurance	NEPIS	924	6,485	2,714	3,701	232	3,468	2,582	631	241	14	71
20	Pensions & Benefits	LABOR	926	78,336	30,597	46,962	2,907	44,055	32,527	8,052	3,319	158	777
21	Injuries & Claims	LABOR	925	12,126	4,736	7,270	450	6,820	5,035	1,246	514	24	120
22	Regulatory Exp	R01; R02	928	5,179	1,930	3,204	182	3,022	2,268	517	225	12	45
23	General Advertising	OXTS	930.1	234	83	149	8	141	104	26	11	1	1
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(314)	(111)	(201)	(11)	(190)	(139)	(35)	(15)	(1)	(2)
26	Rents	OXTS	931	43,543	15,431	27,839	1,516	26,323	19,302	4,844	2,078	99	273
27	Maint of General Plant	OXTS	935	779	276	498	27	471	345	87	37	2	5
28	Total			252,269	96,691	153,271	9,220	144,051	106,251	26,329	10,946	525	2,307
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,288	1,366	895	112	783	579	138	63	3	27
30	CIP Total	E99XCIP	908	102,371.401	31,534	70,375	3,202	67,173	51,362	11,910	3,605	296	462
31	Instructional Advertising	C11P10	909	873	521	341	43	299	221	53	24	1	10
32	Total			105,532	33,421	71,611	3,356	68,255	52,162	12,101	3,692	300	499
33	Amortizations	LABOR		43,475	16,981	26,063	1,613	24,450	18,052	4,469	1,842	88	431
34	**Total O&M Expense**			2,409,148	853,857	1,540,176	83,901	1,456,275	1,067,897	267,922	114,958	5,499	15,115

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Book Depreciation												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		103,652	39,851	63,801	3,539	60,262	45,171	10,782	4,073	236	0
2	Base Load	E8760		305,366	91,074	213,242	9,665	203,578	146,589	38,157	18,041	789	1,050
3	Total		403,413	409,019	130,925	277,043	13,204	263,840	191,760	48,939	22,114	1,026	1,050
	Transmission												
4	Gen Step Up Base	E8760		1,489	444	1,040	47	993	715	186	88	4	5
5	Gen Step Up Peak	D10S		854	328	526	29	497	372	89	34	2	0
6	Total Gen Step Up			2,343	773	1,566	76	1,489	1,087	275	122	6	5
7	Bulk Transmission	D10S		67,399	25,913	41,486	2,301	39,185	29,372	7,011	2,648	154	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		124	0	124	0	124	21	0	0	103	0
10	Total		403,413	69,867	26,686	43,176	2,378	40,798	30,480	7,286	2,770	263	5
	Distribution												
11	Generat Step Up	STRATH		68	21	47	2	45	32	8	4	0	0
12	Bulk Transmission	D10S		40	15	24	1	23	17	4	2	0	0
13	Distrib Function	D60Sub		15,709	6,530	9,093	633	8,460	6,915	1,558	(13)	0	86
14	Direct Assign	Dir Assign		383	0	383	0	383	9	144	225	5	0
15	Total Substations		403,413	16,200	6,567	9,547	637	8,910	6,973	1,714	218	5	86
16	Overhead Lines	POL		34,449	21,866	10,842	1,513	9,328	7,648	1,680	0	0	1,742
17	Underground	PUL		39,378	29,029	10,211	1,859	8,352	6,844	1,508	0	0	138
18	Line Transformers	P68		10,884	7,682	3,163	580	2,583	2,447	136	0	0	39
19	Services	P69		10,422	9,392	1,030	312	717	717	0	0	0	0
20	Meters	C12WM		3,886	2,581	1,297	385	912	857	53	1	1	8
21	Street Lighting	P73		3,981	0	0	0	0	0	0	0	0	3,981
22	Total		403,413	119,199	77,116	36,089	5,287	30,803	25,486	5,091	219	6	5,994
23	**General & Common Plant**	PTD	403,413	121,439	48,679	71,699	4,279	67,420	49,902	12,310	4,940	267	1,061
24	**Total Book Deprec**		403,404	719,524	283,406	428,008	25,147	402,861	297,629	73,627	30,043	1,562	8,110
	Real Estate & Property Tax												
	Production												
25	Peaking Plant	D10S		25,834	9,933	15,902	882	15,020	11,258	2,687	1,015	59	0
26	Base Load	E8760		66,166	19,734	46,205	2,094	44,110	31,762	8,268	3,909	171	228
27	Total		408.1	92,000	29,666	62,106	2,976	59,130	43,021	10,955	4,924	230	228
	Transmission												
28	Gen Step Up Base	E8760		1,030.5229	307	720	33	687	495	129	61	3	4
29	Gen Step Up Peak	D10S		431.1112	166	265	15	251	188	45	17	1	0
30	Total Gen Step Up			1,461.6340	473	985	47	938	683	174	78	4	4
31	Bulk Transmission	D10S		38,705.9909	14,881	23,825	1,322	22,503	16,868	4,026	1,521	88	0
32	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
33	Direct Assign	Dir Assign		71	0	71	0	71	12	0	0	59	0
34	Total		408.1	40,238.864	15,354	24,881	1,369	23,512	17,562	4,200	1,599	151	4
	Distribution												
35	Generat Step Up	STRATH		38	12	26	1	25	18	5	2	0	0
36	Bulk Transmission	D10S		22	8	13	1	13	9	2	1	0	0
37	Distrib Function	D60Sub		8,609	3,579	4,983	347	4,636	3,790	854	(7)	0	47
38	Direct Assign	Dir Assign		216	0	216	0	216	5	81	127	3	0
39	Total Substations			8,884	3,599	5,238	349	4,889	3,822	942	123	3	47
40	Overhead Lines	POL		12,253	7,777	3,856	538	3,318	2,720	598	0	0	619
41	Underground	PUL		19,665	14,497	5,099	929	4,171	3,418	753	0	0	69
42	Line Transformers	P68		4,938	3,485	1,435	263	1,172	1,110	62	0	0	18
43	Services	P69		3,570	3,218	353	107	246	246	0	0	0	0
44	Meters	C12WM		1,061	704	354	105	249	234	15	0	0	2
45	Street Lighting	P73		914	0	0	0	0	0	0	0	0	914
46	Total		408.1	51,286	33,280	16,335	2,291	14,044	11,550	2,369	123	3	1,670
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			183,524	78,301	103,322	6,636	96,686	72,133	17,523	6,646	384	1,901
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
50	Payroll Taxes	LABOR		27,352	10,683	16,397	1,015	15,382	11,357	2,811	1,159	55	271
51	**Tot Non-Inc Taxes**			210,876	88,984	119,720	7,651	112,069	83,490	20,335	7,805	439	2,172

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Provision For Defer Inc Tax

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		(5,518)	(2,121)	(3,396)	(188)	(3,208)	(2,405)	(574)	(217)	(13)	0
2	Nuclear Fuel	E8760		(3,042)	(907)	(2,124)	(96)	(2,028)	(1,460)	(380)	(180)	(8)	(10)
3	Base Load	E8760		6,994	2,086	4,884	221	4,663	3,357	874	413	18	24
4	Total		410, 411	(1,566)	(943)	(636)	(63)	(573)	(507)	(80)	17	(2)	14
	Transmission												
5	Gen Step Up Base	E8760		589	176	412	19	393	283	74	35	2	2
6	Gen Step Up Peak	D10S		216	83	133	7	126	94	22	8	0	0
7	Total Gen Step Up			805	259	545	26	519	377	96	43	2	2
8	Bulk Transmission	D10S		8,468	3,256	5,212	289	4,923	3,690	881	333	19	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		10	0	10	0	10	2	0	0	8	0
11	Total		410, 411	9,283	3,515	5,767	315	5,451	4,069	977	376	29	2
	Distribution												
12	Generat Step Up	STRATH		(27)	(9)	(19)	(1)	(18)	(13)	(3)	(2)	(0)	(0)
13	Bulk Transmission	D10S		(8)	(3)	(5)	(0)	(4)	(3)	(1)	(0)	(0)	0
14	Distrib Function	D60Sub		(906)	(377)	(524)	(37)	(488)	(399)	(90)	1	0	(5)
15	Direct Assign	Dir Assign		(53)	0	(53)	0	(53)	(1)	(20)	(31)	(1)	0
16	Total Substations			(994)	(388)	(601)	(38)	(564)	(416)	(114)	(32)	(1)	(5)
17	Overhead Lines	POL		1,007	639	317	44	273	223	49	0	0	51
18	Underground	PUL		(2,803)	(2,067)	(727)	(132)	(595)	(487)	(107)	0	0	(10)
19	Line Transformers	P68		(2,497)	(1,763)	(726)	(133)	(593)	(562)	(31)	0	0	(9)
20	Services	P69		(1,037)	(934)	(102)	(31)	(71)	(71)	0	0	0	0
21	Meters	C12WM		(472)	(313)	(158)	(47)	(111)	(104)	(6)	(0)	(0)	(1)
22	Street Lighting	P73		(404)	0	0	0	0	0	0	0	0	(404)
23	Total		410, 411	(7,202)	(4,826)	(1,997)	(337)	(1,660)	(1,417)	(210)	(33)	(1)	(378)
24	**General & Common Plant**	PTD	410, 411	(3,513)	(1,408)	(2,074)	(124)	(1,950)	(1,443)	(356)	(143)	(8)	(31)
25	**Net Operating Loss (NOL) Carry**	NEPIS		(172,039)	(71,987)	(98,171)	(6,156)	(92,015)	(68,509)	(16,741)	(6,395)	(370)	(1,881)
26	**Non - Plant Related**	LABOR	410, 411	3,587	1,401	2,150	133	2,017	1,489	369	152	7	36
27	**Tot Prov For Defer**			(171,449)	(74,248)	(94,961)	(6,231)	(88,730)	(66,319)	(16,042)	(6,025)	(344)	(2,239)

Inv Tax Credit; Total Oper Exp

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
28	Peaking Plant	D10S		(260)	(100)	(160)	(9)	(151)	(113)	(27)	(10)	(1)	0
29	Base Load	E8760		(538)	(160)	(376)	(17)	(359)	(258)	(67)	(32)	(1)	(2)
30	Total		411	(798)	(260)	(536)	(26)	(510)	(372)	(94)	(42)	(2)	(2)
	Transmission												
31	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(0)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
37	Total		411	(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(0)	0
	Distribution												
38	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0	0	0	0	0
43	Overhead Lines	POL		(268)	(170)	(84)	(12)	(73)	(60)	(13)	0	0	(14)
44	Underground	PUL		0	0	0	0	0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
49	Total		411	(268)	(170)	(84)	(12)	(73)	(60)	(13)	0	0	(14)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	(0)
51	**Net Inv Tax Credit**			(1,223)	(491)	(717)	(43)	(673)	(499)	(124)	(48)	(2)	(15)
52	**Total Operating Exp**			**3,166,876**	**1,151,508**	**1,992,226**	**110,425**	**1,881,801**	**1,382,197**	**345,718**	**146,732**	**7,153**	**23,143**
53A	**Pres Op Inc Before Inc Tax**			**474,306**	**188,198**	**281,126**	**16,406**	**264,720**	**222,136**	**25,992**	**15,143**	**1,450**	**4,982**
53B	**Prop Op Inc Before Inc Tax**			**822,101**	**339,996**	**472,855**	**30,410**	**442,446**	**354,672**	**58,485**	**27,258**	**2,031**	**9,249**

Northern States Power Company

2021 Class Cost of Service Study Detail ($000)

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		107,112	41,182	65,931	3,657	62,273	46,679	11,142	4,209	244	0
2	Nuclear Fuel	E8760		94,243	28,107	65,811	2,983	62,829	45,241	11,776	5,568	244	324
3	Base Load	E8760		419,862	125,222	293,197	13,289	279,908	201,553	52,464	24,806	1,085	1,444
4	Total		tax books	621,218	194,511	424,939	19,929	405,010	293,472	75,383	34,582	1,573	1,768
	Transmission												
5	Gen Step Up Base	E8760		3,916	1,168	2,735	124	2,611	1,880	489	231	10	13
6	Gen Step Up Peak	D10S		1,534	590	944	52	892	668	160	60	3	0
7	Total Gen Step Up			5,450	1,758	3,679	176	3,503	2,548	649	292	14	13
8	Bulk Transmission	D10S		105,711	40,643	65,068	3,609	61,459	46,068	10,996	4,154	241	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		175	0	175	0	175	29	0	0	146	0
11	Total		tax books	111,336	42,401	68,922	3,786	65,136	48,646	11,645	4,445	400	13
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		14	5	9	0	8	6	1	1	0	0
14	Distrib Function	D60Sub		14,773	6,141	8,551	595	7,956	6,503	1,465	(12)	0	81
15	Direct Assign	Dir Assign		266	0	266	0	266	6	100	156	3	0
16	Total Substations			15,053	6,146	8,826	596	8,230	6,515	1,567	145	3	81
17	Overhead Lines	POL		37,522	23,816	11,809	1,648	10,160	8,330	1,830	0	0	1,897
18	Underground	PUL		39,143	28,856	10,150	1,848	8,302	6,803	1,499	0	0	137
19	Line Transformers	P68		8,119	5,730	2,359	432	1,927	1,826	101	0	0	29
20	Services	P69		7,552	6,806	746	226	520	520	0	0	0	0
21	Meters	C12WM		2,256	1,498	753	224	530	497	31	1	0	5
22	Street Lighting	P73		3,086	0	0	0	0	0	0	0	0	3,086
23	Total		tax books	112,730	72,853	34,643	4,975	29,668	24,491	5,028	146	4	5,234
24	**General & Common Plant**	PTD	tax books	138,561	55,542	81,808	4,883	76,926	56,938	14,046	5,637	305	1,211
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0	0	0	0	0
26	**Total Tax Deprec**			983,845	365,306	610,313	33,572	576,741	423,547	106,101	44,810	2,282	8,227
27	Interest Expense		427,431	194,569.47	81,142	111,343	6,945	104,397	77,649	19,023	7,312	413	2,085
28	Other Tax Timing Differ	LABOR		3,725	1,455	2,233	138	2,095	1,547	383	158	8	37
29	Meals & Enter	LABOR		584	228	350	22	328	242	60	25	1	6
30	Total Tax Deductions			1,182,723	448,131	724,238	40,677	683,561	502,985	125,567	52,305	2,704	10,354
	Inc Tax Additions												
31	Book Depreciation			719,524	283,406	428,008	25,147	402,861	297,629	73,627	30,043	1,562	8,110
32	Deferred Inc Tax & ITC			(172,671.72)	(74,739)	(95,678)	(6,274)	(89,403)	(66,818)	(16,165)	(6,074)	(346)	(2,254)
33	Nuclear Fuel Book Burn	E8760		102,794	30,658	71,783	3,253	68,529	49,346	12,845	6,073	266	353
34	Tax Capitalized Leases	PTD		41,788	16,751	24,672	1,472	23,200	17,172	4,236	1,700	92	365
35	Avoided Tax Interest	RTBASE		18,089	7,544	10,352	646	9,706	7,219	1,769	680	38	194
36	Total Tax Additions			709,523	263,618	439,137	24,244	414,892	304,547	76,311	32,423	1,611	6,768
37	**Total Inc Tax Adjustments**			(473,200)	(184,513)	(285,101)	(16,432)	(268,669)	(198,438)	(49,256)	(19,883)	(1,093)	(3,586)
38A	**Pres Taxable Net Income**			1,106	3,685	(3,975)	(26)	(3,949)	23,697	(23,264)	(4,740)	357	1,396
38B	**Prop Taxable Net Income**			348,901	155,484	187,754	13,977	173,777	156,233	9,229	7,375	939	5,663
39A	Pres Fed & State Inc Tax			59,576	25,772	32,768	2,108	30,661	30,460	(893)	865	228	1,036
39B	Prop Fed & State Inc Tax			159,540	69,402	87,875	6,133	81,742	68,554	8,446	4,347	396	2,263
40A	Pres Preliminary Return	(total); BASE		414,729	162,426	248,358	14,298	234,060	191,675	26,885	14,278	1,221	3,946
40B	Prop Preliminary Return	(total); BASE		662,561	270,594	384,980	24,277	360,703	286,118	50,039	22,911	1,636	6,986
41	Total AFUDC			31,000	12,055	18,796	1,075	17,721	13,105	3,253	1,296	67	148
42A	**Present Total Return**			445,729	174,481	267,154	15,373	251,780	204,780	30,138	15,574	1,289	4,094
42B	**Proposed Total Return**			693,561	282,650	403,777	25,352	378,424	299,223	53,291	24,207	1,703	7,135
43A	**Pres % Return on Rate Base**			4.79%	4.49%	5.01%	4.63%	5.04%	5.51%	3.31%	4.45%	6.52%	4.10%
43B	**Prop % Return on Rate Base**			7.45%	7.28%	7.58%	7.63%	7.58%	8.05%	5.86%	6.92%	8.62%	7.15%
44A	**Present Common Return**			251,160	93,339	155,811	8,428	147,383	127,131	11,115	8,262	876	2,009
44B	**Proposed Common Return**			498,992	201,508	292,434	18,407	274,027	221,573	34,269	16,895	1,290	5,050
45A	**Pres % Ret on Common Rt Base**			5.14%	4.58%	5.57%	4.83%	5.62%	6.52%	2.33%	4.50%	8.44%	3.84%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.89%	10.46%	10.55%	10.45%	11.36%	7.17%	9.20%	12.44%	9.64%

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				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Allow For Funds Used During Constr												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		2,108	810	1,297	72	1,225	918	219	83	5	0
2	Nuclear Fuel	E8760		6,658	1,986	4,650	211	4,439	3,196	832	393	17	23
3	Base Load	E8760		6,298	1,878	4,398	199	4,199	3,023	787	372	16	22
4	Total		419.1,432	15,064	4,674	10,345	482	9,863	7,138	1,838	848	38	45
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		415	159	255	14	241	181	43	16	1	0
7	Total Gen Step Up			415	159	255	14	241	181	43	16	1	0
8	Bulk Transmission	D10S		7,189	2,764	4,425	245	4,180	3,133	748	282	16	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		4	0	4	0	4	1	0	0	4	0
11	Total		419.1,432	7,608	2,924	4,685	260	4,425	3,315	791	299	21	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		1,149	478	665	46	619	506	114	(1)	0	6
15	Direct Assign	Dir Assign		2	0	2	0	2	0	1	1	0	0
16	Total Substations			1,151	478	667	46	621	506	115	0	0	6
17	Overhead Lines	POL		1,147	728	361	50	311	255	56	0	0	58
18	Underground	PUL		2,142	1,579	555	101	454	372	82	0	0	7
19	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
20	Services	P69		228	206	23	7	16	16	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		419.1,432	4,669	2,991	1,606	205	1,401	1,149	253	0	0	72
24	**General & Common Plant**	PTD	419.1,432	3,659	1,467	2,161	129	2,032	1,504	371	149	8	32
25	**Total AFUDC**			31,000	12,055	18,796	1,075	17,721	13,105	3,253	1,296	67	148
	Labor Allocator												
	Production												
26	Other Prod - Cap	D10S		62,298	23,952	38,346	2,127	36,219	27,149	6,480	2,448	142	0
27	Other Prod - Ene	E8760		159,555	47,586	111,420	5,050	106,370	76,593	19,937	9,427	412	549
28	Total		500 through 557	221,853	71,538	149,766	7,177	142,589	103,742	26,418	11,874	554	549
	Transmission												
29	Stepup Subtrans	P5161A		776	251	523	25	498	362	92	41	2	2
30	Bulk Power Subs	D10S		20,551	7,901	12,650	702	11,948	8,956	2,138	807	47	0
31	Total		560 through 571	21,327	8,152	13,173	727	12,446	9,319	2,230	849	49	2
	Distribution												
32	Superv & Eng	ZDTS	580, 590	6,110	3,518	2,326	284	2,042	1,639	353	48	2	267
33	Load Dispatch	D10S	581	6,805	2,616	4,189	232	3,956	2,966	708	267	16	0
34	Substation	P61	582, 592	6,036	2,445	3,559	237	3,322	2,597	640	83	2	32
35	Overhead Lines	POL	583, 593	10,867	6,898	3,420	477	2,943	2,413	530	0	0	549
36	Underground Lines	PUL	584, 594	10,202	7,521	2,646	482	2,164	1,773	391	0	0	36
37	Line Transformer	P68	595	1,189	839	346	63	282	267	15	0	0	4
38	Meter	C12WM	586, 597	3,554	2,360	1,187	352	834	784	49	1	1	8
39	Cust Installation	ZDTS	587	3,530	2,032	1,344	164	1,180	947	204	27	1	154
40	Street Lighting	P73	585, 596	1,023	0	0	0	0	0	0	0	0	1,023
41	Miscellaneous	OXDTS	588	7,542	4,505	2,628	349	2,279	1,864	399	15	1	409
42	Total			56,860	32,734	21,643	2,641	19,002	15,248	3,289	443	23	2,483
43	**Cust Accounting**	C11WA	901,902,903,904,905	10,285	8,538	1,707	957	750	739	11	0	0	41
44	**Sales Expense**	C11P10	912	0	0	0	0	0	0	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	154,012	60,156	92,329	5,715	86,614	63,949	15,830	6,525	310	1,527
46	**Service & Inform**	C11P10	908, 909	1,202	718	470	59	411	304	73	33	2	14
47	**Labor**			465,539	181,836	279,088	17,275	261,813	193,301	47,850	19,725	938	4,615

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			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	59.72%	39.11%	4.89%	34.22%	25.32%	6.04%	2.74%	0.13%	1.18%
2	Peaking Plant Capacity	D10S	100.00%	38.45%	61.55%	3.41%	58.14%	43.58%	10.40%	3.93%	0.23%	0.00%
3	57% Dmd; 43% Energy: Sales & I	D57E43	100.00%	29.82%	69.83%	3.16%	66.67%	48.00%	12.50%	5.91%	0.26%	0.34%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	29.82%	69.83%	3.16%	66.67%	48.00%	12.50%	5.91%	0.26%	0.34%
5	20%D10T; 80%D60Sub	T20D80	100.00%	40.94%	58.62%	3.91%	54.71%	43.93%	10.01%	0.72%	0.05%	0.44%
6	Labor w/o (or w/) A&G	LABOR	100.00%	39.06%	59.95%	3.71%	56.24%	41.52%	10.28%	4.24%	0.20%	0.99%
7	Net Plant In Service	NEPIS	100.00%	41.84%	57.06%	3.58%	53.48%	39.82%	9.73%	3.72%	0.21%	1.09%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	59.73%	34.85%	4.62%	30.22%	24.71%	5.29%	0.20%	0.01%	5.43%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	35.44%	63.93%	3.48%	60.45%	44.33%	11.12%	4.77%	0.23%	0.63%
10	Production Plant	P10	100.00%	31.71%	68.02%	3.22%	64.80%	47.04%	12.04%	5.48%	0.25%	0.27%
11	Production Plant Wo Nuclear	P10WoN	100.00%	32.25%	67.51%	3.24%	64.27%	46.76%	11.91%	5.35%	0.25%	0.25%
12	Total P51 & P61A	P5161A	100.00%	32.34%	67.41%	3.24%	64.18%	46.71%	11.88%	5.33%	0.25%	0.24%
13	Distribution Plant	P60	100.00%	64.89%	31.85%	4.47%	27.38%	22.52%	4.62%	0.24%	0.01%	3.26%
14	Distr Substn Plant	P61	100.00%	40.51%	58.96%	3.93%	55.03%	43.02%	10.60%	1.38%	0.03%	0.53%
15	Line Transformer Plant	P68	100.00%	70.58%	29.06%	5.33%	23.73%	22.49%	1.25%	0.00%	0.00%	0.36%
16	Services Plant	P69	100.00%	90.12%	9.88%	3.00%	6.88%	6.88%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	63.47%	31.47%	4.39%	27.08%	22.20%	4.88%	0.00%	0.00%	5.06%
18	Real Est & Property Tax	PT0	100.00%	42.67%	56.30%	3.62%	52.68%	39.30%	9.55%	3.62%	0.21%	1.04%
19	Produc, Trans & Distrib	PTD	100.00%	40.08%	59.04%	3.52%	55.52%	41.09%	10.14%	4.07%	0.22%	0.87%
20	Dist Plt Undground Lines	PUL	100.00%	73.72%	25.93%	4.72%	21.21%	17.38%	3.83%	0.00%	0.00%	0.35%
21	Rate Base (Non-Column)	RTBASE	100.00%	41.70%	57.23%	3.57%	53.66%	39.91%	9.78%	3.76%	0.21%	1.07%
22	Stratified Hydro Baseload	STRATH	100.00%	31.30%	68.42%	3.21%	65.21%	47.25%	12.14%	5.57%	0.25%	0.29%
23	Transmission & Distrib	TD	100.00%	52.91%	45.29%	3.99%	41.30%	31.99%	7.23%	1.91%	0.17%	1.80%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	57.57%	38.06%	4.64%	33.42%	26.82%	5.78%	0.78%	0.04%	4.37%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	311,527	121,680	186,758	11,560	175,199	129,352	32,020	13,199	628	3,089
26	Dis O&M w/o Sup, Cust Install & I	OXDTS	89,364	53,374	31,139	4,133	27,007	22,085	4,732	183	8	4,850
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,350,637	833,027	1,502,874	81,862	1,421,012	1,041,987	261,473	112,187	5,365	14,736
28	Total P51 & P61A	P5161A	125,068	40,449	84,314	4,049	80,265	58,422	14,864	6,667	312	305
29	Produc, Trans & Distrib	PTD	18,976,765	7,606,809	11,204,133	668,691	10,535,442	7,797,969	1,923,695	771,998	41,780	165,823
30	Transmission & Distrib	TD	7,495,640	3,966,022	3,394,638	299,050	3,095,588	2,397,678	541,648	143,394	12,869	134,980
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	47,220	27,185	17,974	2,193	15,781	12,663	2,731	368	19	2,062

2021 Class Cost of Service Study Detail ($000)

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	87.72%	10.19%	6.55%	3.64%	3.60%	0.04%	0.00%	0.00%	2.08%
2	Cust Acctg Wtg Factor	C11WA	100.00%	83.01%	16.59%	9.30%	7.29%	7.18%	0.10%	0.00%	0.00%	0.40%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	66.40%	33.38%	9.91%	23.47%	22.05%	1.37%	0.04%	0.02%	0.21%
4	Sec & Pri Customers	C61PS	100.00%	89.19%	10.38%	6.67%	3.71%	3.68%	0.04%	0.00%	0.00%	0.43%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.25%	4.50%	3.86%	0.64%	0.63%	0.01%	0.00%	0.00%	0.24%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	94.91%	5.09%	3.28%	1.81%	1.81%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.22%	10.35%	6.67%	3.68%	3.68%	0.00%	0.00%	0.00%	0.43%
8	Summer Peak Resp KW	D10S	100.00%	38.45%	61.55%	3.41%	58.14%	43.58%	10.40%	3.93%	0.23%	0.00%
9	Transmission Demand %	D10T	100.00%	35.69%	63.99%	3.35%	60.64%	45.00%	10.75%	4.67%	0.23%	0.32%
10	Winter Peak Resp KW	D10W	100.00%	31.80%	67.43%	3.27%	64.16%	47.00%	11.23%	5.71%	0.22%	0.78%
11	Alternative Production Allocator	1CP	100.00%	38.45%	61.55%	3.41%	58.14%	43.58%	10.40%	3.93%	0.23%	0.00%
12	Sec, Pri & TT, Class Coin kW @ !	D60Sub	100.00%	41.57%	57.88%	4.03%	53.85%	44.02%	9.92%	-0.08%	0.00%	0.55%
13	Sec & Pri, Cl Coin kW (no Min Sy:	D61PS	100.00%	36.46%	63.21%	3.37%	59.84%	48.35%	11.50%	0.00%	0.00%	0.32%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	74.32%	25.33%	3.73%	21.60%	15.81%	5.79%	0.00%	0.00%	0.35%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	74.46%	25.54%	2.06%	23.47%	23.47%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	49.27%	50.47%	3.62%	46.85%	46.85%	0.00%	0.00%	0.00%	0.25%
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%	29.82%	69.83%	3.16%	66.67%	48.00%	12.50%	5.91%	0.26%	0.34%
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	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	30.80%	68.74%	3.13%	65.617%	50.17%	11.63%	3.52%	0.29%	0.45%
21	Present Rev	R01	100.00%	37.27%	61.86%	3.52%	58.35%	43.79%	9.98%	4.34%	0.24%	0.87%
22	Late Fee Revenue Allocator	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
23	Customers - B Basis	C10	1,319,164	1,176,546	136,961	87,960	49,001	48,497	479	15	9	5,658
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,345,380	1,180,196	137,160	88,160	49,001	48,497	479	15	9	28,024
25	Mo Cus Wtd By Cus Acct	C11WA	1,421,780	1,180,196	235,927	132,239	103,687	102,106	1,490	58	33	5,658
26	Cust Acctg Wtg Factor	C11WAF	15.26	1.00	14.26	1.50	12.76	2.11	3.11	3.88	3.67	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign !	C12	1,319,887	1,180,196	137,160	88,160	49,001	48,497	479	15	9	2,531
28	Mo Cus Wtd By Mtr Invest	C12WM	169,282,003	112,411,179	56,509,115	16,772,418	39,736,697	37,321,888	2,315,215	62,595	36,999	361,709
29	Meter Invest / Cust Factor	C12WMF	14,311	95	14,073	190	13,883	770	4,829	4,173	4,111	143
30	Sec & Pri Customers	C61PS	1,319,140	1,176,546	136,937	87,960	48,977	48,497	479	0	0	5,658
31	% Served by Primary Single Phase		0.0%	73.59%	0.00%	39.93%	0.00%	11.80%	18.18%	0.00%	0.00%	39.28%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	908,936	865,776	40,938	35,126	5,812	5,725	87	0	0	2,222
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,239,680	1,176,546	63,135	40,696	22,438	22,438	0	0	0	0
34	Secondary Customers	C62Sec	1,318,661	1,176,546	136,458	87,960	48,497	48,497	0	0	0	5,658
35	Summer Peak Resp KW	D10S	25,569	9,831	15,739	873	14,865	11,143	2,660	1,005	58	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,568,754	6,398,972	335,441	6,063,530	4,499,780	1,074,569	466,640	22,541	32,274
37	Winter Peak Resp KW	D10W	4,156	1,321	2,802	136	2,666	1,953	467	237	9	32
38	Alternative Production Allocator	1CP	25,569	9,831	15,739	873	14,865	11,143	2,660	1,005	58	0
39	Sec, Pri & TT, Class Coin kW @ !	D60Sub	6,521,671	2,710,931	3,774,971	262,798	3,512,174	2,870,693	646,707	(5,227)	0	35,769
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	5,864,995	2,138,528	3,707,447	197,629	3,509,818	2,835,455	674,363	0	0	19,020
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	2,117,366	1,573,663	536,232	78,920	457,312	334,700	122,611	0	0	7,471
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	10,491,064	7,811,811	2,679,252	216,573	2,462,679	2,462,679	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	4,927,402	5,047,295	362,191	4,685,105	4,685,105	0	0	0	25,303
44	Annual Billing kW	D99	49,881.486	0	49,881	0	49,881	38,074	7,940	3,618	250	0
45	Summer Billing kW	D99S	18,305.301	0	18,305	0	18,305	13,907	2,991	1,319	88	0
46	Winter Billing kW	D99W	31,576.184	0	31,576	0	31,576	24,167	4,949	2,299	162	0
47	Non-Coinc Pk Second	DN-Sec	13,621,703	7,811,811	5,790,872	468,096	5,322,776	5,322,776	0	0	0	19,020
48	MWh Sales	E99	28,388,117	8,289,824	19,976,823	841,814	19,135,010	13,576,274	3,661,168	1,819,766	77,801	121,470
49	MWh Sales Excl CIP Exempt	E99XCIP	26,911,724	8,289,824	18,500,430	841,651	17,658,779	13,502,239	3,131,021	947,718	77,801	121,470
50	Late Fee Revenue Allocation	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

Northern States Power Company

Docket No. E002/GR-19-564
Exhibit___(MAP-1), Schedule 7

Summary of 2022 Class Cost of Service Study ($000)

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	3,533,407	1,363,157	124,527	2,013,534	32,188
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,400	943	68	384	5
[3]	Unadjusted Operating Revenues (line 1 + line 2)	3,534,806	1,364,100	124,595	2,013,918	32,193
[4]	Present Rates (CCOSS page 2, line 2)	3,068,702	1,147,973	107,401	1,786,604	26,724
[5]	Unadjusted Deficiency (line 3 - line 4)	466,104	216,127	17,194	227,314	5,470
[6]	Defic / Pres (line 5 / line 4)	15.2%	18.8%	16.0%	12.7%	20.5%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.24**	**1.05**	**0.84**	**1.35**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Development Disc Cost Allocation (CCOSS page 2, line 8)					
				HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	(1,439)	1,452	(30)	17

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	3,533,407	1,361,718	125,980	2,013,504	32,205
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,400	943	68	384	5
[15]	Adjusted Operating Revenues (line 13 + line 14)	3,534,806	1,362,661	126,047	2,013,888	32,210
[16]	Present Rates (line 4)	3,068,702	1,147,973	107,401	1,786,604	26,724
[17]	Adjusted Deficiency (line 15 - line 16)	466,104	214,688	18,646	227,284	5,486
[18]	Defic / Pres Rates (line 17 / line 16)	15.2%	18.7%	17.4%	12.7%	20.5%
[19]	**Ratio: Class % / Total %**	**1.00**	**1.23**	**1.14**	**0.84**	**1.35**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	3,533,407	1,351,742	125,400	2,024,419	31,846
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	1,400	943	68	384	5
[22]	Proposed Operating Revenues (line 20 + line 21)	3,534,807	1,352,685	125,467	2,024,803	31,851
[23]	Proposed Increase (line 22 - line 16)	466,105	204,712	18,066	238,199	5,128
[24]	Difference / Pres (line 23 / line 16)	15.2%	17.8%	16.8%	13.3%	19.2%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.17**	**1.11**	**0.88**	**1.26**

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Docket No. E002/GR-19-564
Exhibit___(MAP-1), Schedule 8

	Rate Base		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Plant In Service	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Production		11,673,805	3,713,396	7,928,741	373,698	7,555,044	5,458,954	1,396,546	634,192	65,352	31,667
2	Transmission		3,490,183	1,336,133	2,153,737	118,071	2,035,666	1,514,313	362,081	137,523	21,749	313
3	Distribution		4,500,875	2,934,596	1,424,641	200,448	1,224,193	1,005,938	207,980	10,004	271	141,638
4	General		2,035,329	826,363	1,190,996	71,645	1,119,351	825,854	203,545	80,908	9,043	17,970
5	Common		0	0	0	0	0	0	0	0	0	0
6	Total Plant In Service		21,700,191	8,810,488	12,698,115	763,862	11,934,254	8,805,060	2,170,152	862,627	96,415	191,588
7	Production		7,136,281	2,261,334	4,855,241	228,195	4,627,046	3,341,519	855,805	389,660	40,062	19,707
8	Transmission		848,684	325,554	523,087	28,718	494,369	367,662	87,790	33,229	5,689	42
9	Distribution		1,597,559	1,059,382	497,286	72,624	424,663	352,091	68,710	3,747	114	40,890
10	General		1,059,356	430,109	619,895	37,290	582,604	429,844	105,942	42,112	4,707	9,353
11	Common		0	0	0	0	0	0	0	0	0	0
12	Total Depreciation Reserve		10,641,880	4,076,379	6,495,509	366,826	6,128,683	4,491,116	1,118,247	468,748	50,571	69,992
13	**Net Plant In Service**		11,058,311	4,734,109	6,202,607	397,036	5,805,571	4,313,943	1,051,905	393,880	45,843	121,596
14	Deducts: Accum Defer Inc Tax		2,015,705	817,993	1,177,664	71,344	1,106,320	819,587	200,216	77,373	9,144	20,048
15	Constr Work In Progress		507,890	201,906	303,356	17,680	285,676	210,684	52,048	20,686	2,258	2,628
16	Fuel Inventory		65,875	19,719	45,928	2,073	43,854	31,433	8,177	3,859	385	228
17	Materials & Supplies		153,932	52,515	100,752	5,056	95,696	69,484	17,622	7,774	815	665
18	Prepayments		85,979	36,808	48,226	3,087	45,139	33,541	8,179	3,062	356	945
19	Non-Plant & Work Cash		(50,542)	(25,581)	(24,419)	(1,779)	(22,640)	(17,264)	(4,015)	(1,182)	(178)	(542)
20	Total Additions		763,134	285,367	473,842	26,118	447,725	327,878	82,011	34,200	3,637	3,925
21	**Rate Base**		9,805,740	4,201,483	5,498,785	351,810	5,146,976	3,822,234	933,700	350,707	40,335	105,472
	Income Statement											
22A	**Tot Oper Rev - Pres**		3,644,178	1,344,927	2,271,022	126,320	2,144,702	1,596,648	369,909	160,836	17,308	28,228
22B	**Tot Oper Rev - Prop**		4,110,282	1,549,639	2,527,287	144,387	2,382,900	1,773,787	412,985	175,467	20,660	33,356
23	Oper & Maint		2,426,359	858,902	1,552,491	83,654	1,468,837	1,072,446	268,953	115,138	12,300	14,966
24	Book Depr + IRS Int		760,859	302,864	449,518	26,537	422,981	311,411	76,984	31,173	3,414	8,477
25	Payroll, Rl Est & Prop Tax		224,526	95,685	126,528	8,119	118,409	87,934	21,407	8,137	930	2,313
26	Deferred Inc Tax & Net ITC		(190,897)	(78,986)	(109,658)	(6,787)	(102,871)	(76,103)	(18,635)	(7,320)	(813)	(2,252)
27A	Present Income Tax		56,478	19,940	35,632	1,930	33,703	32,111	(177)	1,625	144	906
27B	Proposed Income Tax		190,446	78,779	109,288	7,122	102,166	83,024	12,204	5,830	1,108	2,379
28	Allow Funds Dur Const		33,500	13,321	20,017	1,160	18,857	13,913	3,430	1,358	156	162
29A	**Present Return**		400,352	159,843	236,528	14,028	222,500	182,762	24,808	13,440	1,489	3,981
29B	**Proposed Return**		732,489	305,717	419,137	26,902	392,235	308,988	55,504	23,866	3,878	7,635
30A	**Pres Ret on Rt Base**		4.08%	3.80%	4.30%	3.99%	4.32%	4.78%	2.66%	3.83%	3.69%	3.77%
30B	**Prop Ret on Rt Base**		**7.47%**	7.28%	7.62%	7.65%	7.62%	8.08%	5.94%	6.81%	9.61%	7.24%
31A	**Pres Ret on Common**		3.76%	3.23%	4.17%	3.58%	4.22%	5.09%	1.04%	3.28%	3.01%	3.17%
31B	**Prop Ret on Common**		**10.21%**	9.84%	10.50%	10.55%	10.50%	11.38%	7.30%	8.94%	14.29%	9.77%

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

PRES vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.47%**		**3,533,407**	**1,363,157**	**2,138,062**	**124,527**	**2,013,534**	**1,479,876**	**367,275**	**149,986**	**16,397**	**32,188**
2	**Present Revenue**		**3,068,702**	**1,147,973**	**1,894,005**	**107,401**	**1,786,604**	**1,335,970**	**304,267**	**132,106**	**14,261**	**26,724**
3	**UnAdj Revenue Deficiency**		**464,705**	**215,184**	**244,056**	**17,126**	**226,930**	**143,906**	**63,008**	**17,880**	**2,136**	**5,464**
4	**UnAdj Deficiency / Present**		**15.14%**	**18.74%**	**12.89%**	**15.95%**	**12.70%**	**10.77%**	**20.71%**	**13.53%**	**14.98%**	**20.45%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
5	**Pres Int Rate Discounts**											
6	**Pres Econ Dvlp Rate Discounts**											
7	**Pres Int Rate Disc Cost Alloc**	**D10S**										
8	**Pres Econ Dvlp Disc Cost Alloc**	**R01**										
										HIGHLY CONFIDENTIAL TRADE SECRET ENDS]		
9	**Revenue Requirement Shift**		**0**	**(1,439)**	**1,422**	**1,452**	**(30)**	**10,326**	**(2,136)**	**(6,664)**	**(1,557)**	**17**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**3,533,407**	**1,361,718**	**2,139,484**	**125,980**	**2,013,504**	**1,490,202**	**365,139**	**143,322**	**14,841**	**32,205**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**464,705**	**213,745**	**245,479**	**18,579**	**226,900**	**154,232**	**60,872**	**11,216**	**580**	**5,481**
12	**Adj Deficiency / Adj Present**		**15.14%**	**18.62%**	**12.96%**	**17.30%**	**12.70%**	**11.54%**	**20.01%**	**8.49%**	**4.06%**	**20.51%**
	Equal Customer Classification											
13	Min Sys & Service Drop		274,928	225,154	26,002	15,170	10,832	10,581	261	(12)	2	23,771
14	Energy Services		54,342	45,267	8,819	4,991	3,827	3,774	50	2	1	257
15	Total Customer **(Cusco)**		329,270	270,421	34,821	20,162	14,659	14,355	311	(10)	3	24,028
16	Ave Monthly Customers		1,355,363	1,189,448	137,784	88,563	49,222	48,719	479	15	9	28,131
17	Svc Drop Reqt	$ / Mo / Cust	$16.90	$15.77	$15.73	$14.27	$18.34	$18.10	$45.39	($67.04)	$20.08	$70.42
18	Ener Svcs Reqt	$ / Mo / Cust	$3.34	$3.17	$5.33	$4.70	$6.48	$6.46	$8.72	$10.43	$9.97	$0.76
19	Total Reqt	$ / Mo / Cust	$20.24	$18.95	$21.06	$18.97	$24.82	$24.55	$54.12	($56.60)	$30.04	$71.18
	Equal Energy Classification											
20	On Peak Rev Reqt		815,092	234,129	579,602	29,814	549,788	400,237	100,997	43,850	4,705	1,360
21	Off Peak Rev Reqt		820,046	254,833	560,785	21,524	539,261	383,338	101,399	49,586	4,938	4,429
22	Total Ener Rev Reqt		1,635,138	488,962	1,140,387	51,338	1,089,049	783,575	202,396	93,436	9,643	5,788
23	Annual MWh Sales		28,303,153.466	8,293,789	19,887,270	834,457	19,052,812	13,451,925	3,625,493	1,798,766	176,628	122,095
24	On Pk Reqt	Mills / kWh	28.799	28.229	29.144	35.729	28.856	29.753	27.858	24.378	26.636	11.136
25	Off Pk Reqt	Mills / kWh	28.974	30.726	28.198	25.794	28.303	28.497	27.968	27.567	27.957	36.273
26	Total Reqt	Mills / kWh	57.772	58.955	57.343	61.523	57.160	58.250	55.826	51.944	54.593	47.409
	Equal Demand Classification											
27	Energy-Related Prod		371,923	114,584	256,187	11,794	244,393	175,868	45,371	21,026	2,129	1,151
28	Capacity-Related Summer Peak Prod		314,088	120,874	193,213	10,653	182,561	136,282	32,530	12,261	1,488	0
29	Capacity-Related Winter Peak Prod		94,930	36,533	58,397	3,220	55,177	41,190	9,832	3,706	450	0
30	Total Capacity-Related Prod		409,018	157,407	251,610	13,872	237,738	177,473	42,361	15,967	1,938	0
31	Total Production		780,941	271,992	507,797	25,666	482,131	353,340	87,732	36,992	4,067	1,151
32	Transmission **(Transco)**		472,886	181,841	291,045	16,023	275,022	205,017	48,911	18,436	2,658	0
33	Primary Dist Subs		95,549	38,987	56,044	3,749	52,295	41,091	10,046	1,132	27	518
34	Prim Dist Lines		188,989	94,409	93,942	6,572	87,370	69,490	17,880	0	0	638
35	Second Dist, Trans		30,633	16,545	14,025	1,018	13,007	13,007	0	0	0	63
36	Total Distribution **(Disco)**		315,172	149,940	164,011	11,339	152,673	123,589	27,926	1,132	27	1,220
37	Total Demand Rev Reqt		1,568,999	603,774	962,854	53,028	909,826	681,946	164,568	56,560	6,752	2,371
38	Annual Billing kW		49,661,671	0	49,661,671	0	49,661,671	37,724,544	7,862,754	3,578,561	495,812	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$5.16	$0.00	$4.92	$4.66	$5.77	$5.88	$4.29	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.89	$0.00	$3.68	$3.61	$4.14	$3.43	$3.00	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.18	$0.00	$1.11	$1.09	$1.25	$1.04	$0.91	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$10.23	$0.00	$9.71	$9.37	$11.16	$10.34	$8.20	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$5.86	$0.00	$5.54	$5.43	$6.22	$5.15	$5.36	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.30	$0.00	$3.07	$3.28	$3.55	$0.32	$0.05	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$19.39	$0.00	$18.32	$18.08	$20.93	$15.81	$13.62	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	55.435	72.798	48.416	63.548	47.753	50.695	45.392	31.444	38.225	19.423
47	Summer Billing kW		18,171,839	0	18,171,839	0	18,171,839	13,728,851	2,953,825	1,300,914	188,249	0
48	Winter Billing kW		31,489,831	0	31,489,831	0	31,489,831	23,995,693	4,908,929	2,277,647	307,562	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$24.95	$0.00	$23.58	$23.30	$26.56	$20.77	$17.61	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.18	$0.00	$15.29	$15.09	$17.55	$12.97	$11.17	$0.00
51	Energy + Production **(Genco)**		2,416,078	760,954	1,648,185	77,004	1,571,181	1,136,915	290,128	130,428	13,709	6,940

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

PROP vs Equal Rev Reqts

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.47%**	**7.28%**	**7.62%**	**7.65%**	**7.62%**	**8.08%**	**5.94%**	**6.81%**	**9.61%**	**7.24%**
2	**UnAdj Equalized Rev Reqt**		**3,533,407**	**1,363,157**	**2,138,062**	**124,527**	**2,013,534**	**1,479,876**	**367,275**	**149,986**	**16,397**	**32,188**
3	**Proposed Revenue**		**3,533,407**	**1,351,742**	**2,149,819**	**125,400**	**2,024,419**	**1,512,808**	**347,286**	**146,713**	**17,611**	**31,846**
4	**UnAdj Revenue Deficiency**		**(0)**	**11,415**	**(11,757)**	**(872)**	**(10,885)**	**(32,933)**	**19,989**	**3,272**	**(1,213)**	**342**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.84%**	**-0.55%**	**-0.70%**	**-0.54%**	**-2.18%**	**5.76%**	**2%**	**-7%**	**1.07%**
			[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS									
6	**Prop Interrupt Rate Discounts**											
7	**Prop Econ Dev Rate Discounts**											
8	**Prop Int Rate Disc Cost Alloc**	**D10S**										
9	**Prop ED Discount Cost Alloc**	**R01**										
												HIGHLY CONFIDENTIAL TRADE SECRET ENDS]
10	**Revenue Requirement Shift**		**0**	**3,715**	**(3,732)**	**1,693**	**(5,425)**	**7,746**	**(3,962)**	**(7,568)**	**(1,641)**	**17**
11	**Adj Equal Rev (Rows 2+10)**		**3,533,407**	**1,366,872**	**2,134,329**	**126,220**	**2,008,109**	**1,487,621**	**363,313**	**142,418**	**14,756**	**32,205**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**(0)**	**15,130**	**(15,489)**	**821**	**(16,310)**	**(25,187)**	**16,027**	**(4,295)**	**(2,855)**	**359**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**1.12%**	**-0.72%**	**0.65%**	**-0.81%**	**-1.66%**	**4.61%**	**-2.93%**	**-16.21%**	**1.13%**
	Prop Customer Component											
14	Min Sys & Service Drop		270,277	220,567	26,264	15,219	11,045	10,801	253	(12)	2	23,447
15	Energy Services		54,332	45,257	8,819	4,991	3,828	3,775	50	2	1	257
16	Total Customer **(Cusco)**		324,609	265,823	35,082	20,210	14,872	14,576	304	(10)	3	23,703
17	Ave Monthly Customers		1,355,363	1,189,448	137,784	88,563	49,222	48,719	479	15	9	28,131
18	Svc Drop Reqt	$ / Mo / Cust	$16.62	$15.45	$15.88	$14.32	$18.70	$18.48	$44.09	($67.23)	$20.59	$69.46
19	Ener Svcs Reqt	$ / Mo / Cust	$3.34	$3.17	$5.33	$4.70	$6.48	$6.46	$8.72	$10.43	$9.98	$0.76
20	Total Reqt	$ / Mo / Cust	$19.96	$18.62	$21.22	$19.02	$25.18	$24.93	$52.81	($56.80)	$30.56	$70.22
	Prop Energy Component											
21	On Peak Rev Reqt		814,879	234,030	579,490	29,810	549,679	400,320	100,838	43,810	4,711	1,359
22	Off Peak Rev Reqt		819,815	254,724	560,664	21,521	539,142	383,418	101,238	49,542	4,945	4,427
23	Total Ener Rev Reqt		1,634,694	488,754	1,140,153	51,331	1,088,822	783,738	202,076	93,352	9,657	5,787
24	Annual MWh Sales		28,303,153	8,293,789	19,887,270	834,457	19,052,812	13,451,925	3,625,493	1,798,766	176,628	122,095
25	On Pk Reqt	Mills / kWh	28.791	28.218	29.139	35.724	28.850	29.759	27.813	24.356	26.674	11.133
26	Off Pk Reqt	Mills / kWh	28.965	30.713	28.192	25.791	28.297	28.503	27.924	27.542	27.997	36.261
27	Total Reqt	Mills / kWh	57.757	58.930	57.331	61.515	57.148	58.262	55.737	51.898	54.672	47.394
	Prop Demand Component											
28	Energy-Related Prod		374,849	112,722	260,975	12,156	248,819	190,885	36,095	19,090	2,749	1,151
29	Capacity-Related Summer Peak Prod		315,519	120,538	194,981	10,772	184,209	139,933	30,693	11,969	1,615	0
30	Capacity-Related Winter Peak Prod		95,363	36,432	58,931	3,256	55,676	42,293	9,277	3,618	488	0
31	Total Capacity-Related Prod		410,882	156,970	253,912	14,027	239,885	182,226	39,969	15,587	2,103	0
32	Total Production		785,731	269,692	514,887	26,183	488,704	373,112	76,065	34,676	4,852	1,151
33	Transmission **(Transco)**		475,861	180,650	295,211	16,303	278,908	214,131	44,060	17,647	3,069	0
34	Primary Dist Subs		94,664	38,149	56,003	3,757	52,246	42,266	8,901	1,049	30	511
35	Prim Dist Lines		187,216	92,500	94,084	6,597	87,487	71,607	15,880	0	0	631
36	Second Dist, Trans		30,634	16,174	14,398	1,018	13,380	13,380	0	0	0	62
37	Total Distribution **(Disco)**		312,513	146,823	164,485	11,373	153,113	127,252	24,782	1,049	30	1,205
38	Total Demand Rev Reqt		1,574,105	597,165	974,583	53,859	920,724	714,495	144,907	53,372	7,951	2,356
39	Annual Billing kW		49,661,671	0	49,661,671	0	49,661,671	37,724,544	7,862,754	3,578,561	495,812	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.01	$5.06	$4.59	$5.33	$5.54	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.71	$3.71	$3.90	$3.34	$3.26	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.12	$1.12	$1.18	$1.01	$0.98	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$9.84	$9.89	$9.67	$9.69	$9.78	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.62	$5.68	$5.60	$4.93	$6.19	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.08	$3.37	$3.15	$0.29	$0.06	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$18.54	$18.94	$18.43	$14.91	$16.04	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	55.616	72.002	49.005	64.543	48.325	53.115	39.969	29.671	45.016	19.297
48	Summer Billing kW		18,171,839	0	18,171,839	0	18,171,839	13,728,851	2,953,825	1,300,914	188,249	0
49	Winter Billing kW		31,489,831	0	31,489,831	0	31,489,831	23,995,693	4,908,929	2,277,647	307,562	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$25.24	$0.00	$23.85	$24.30	$23.74	$19.76	$20.37	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$16.38	$0.00	$15.48	$15.87	$15.24	$12.15	$13.38	$0.00
52	Energy + Production **(Genco)**		2,420,424	758,446	1,655,040	77,514	1,577,526	1,156,849	278,141	128,028	14,508	6,938
53	Prop Rev - Pres Rev (Pg 2)		464,705	203,769	255,813	17,999	237,814	176,838	43,019	14,608	3,349	5,122
54	Difference / Present		15.14%	17.75%	13.51%	16.76%	13.31%	13.24%	14.14%	11.06%	23.49%	19.17%

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Original Plant in Service

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S		1,945,856	750,616	1,195,240	66,070	1,129,170	842,970	201,181	75,818	9,201	0
2	WInter Peak	D10S		588,117	226,867	361,250	19,969	341,281	254,780	60,805	22,915	2,781	0
3	Total Peak	D10S		2,533,973	977,483	1,556,490	86,039	1,470,451	1,097,750	261,986	98,733	11,982	0
4	Base Load	E8760		6,505,593	1,947,381	4,535,671	204,751	4,330,920	3,104,238	807,562	381,131	37,988	22,540
5	Nuclear Fuel	E8760		2,634,239	788,532	1,836,580	82,908	1,753,672	1,256,965	326,997	154,327	15,382	9,127
6	Total	28.03%	120, 310-346	11,673,805	3,713,396	7,928,741	373,698	7,555,044	5,458,954	1,396,546	634,192	65,352	31,667
	Transmission												
7	Gen Step Up Base	E8760		90,419	27,066	63,040	2,846	60,194	43,145	11,224	5,297	528	313
8	Gen Step Up Peak	D10S		38,085	14,691	23,393	1,293	22,100	16,499	3,938	1,484	180	0
9	Total Gen Step Up			128,504	41,757	86,433	4,139	82,295	59,644	15,162	6,781	708	313
10	Bulk Transmission	D10S		3,355,467	1,294,376	2,061,092	113,932	1,947,160	1,453,633	346,920	130,741	15,866	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		6,211	0	6,211	0	6,211	1,037	0	0	5,174	0
13	Total		350-359	3,490,183	1,336,133	2,153,737	118,071	2,035,666	1,514,313	362,081	137,523	21,749	313
	Distribution:												
	Substations												
14	Generat Step Up	STRATH		3,046	957	2,081	97	1,983	1,431	367	168	17	9
15	Bulk Transmission	D10S		1,829	705	1,123	62	1,061	792	189	71	9	0
16	Distrib Function	D60Sub		726,855	303,941	418,888	29,198	389,690	318,865	71,786	(962)	0	4,026
17	Direct Assign	Dir Assign		18,193.613	0	18,194	0	18,194	410	6,861	10,696	227	0
18	Total		360-363	749,924	305,604	440,285	29,357	410,928	321,498	79,204	9,973	253	4,035
	Overhead Lines												
19	Primary Capacity 1 Phase	D61PS1Ph		178,277	132,748	44,896	6,601	38,295	28,029	10,266	0	0	633
20	Primary Capacity Multi Phase	D61PS		383,575	140,512	241,808	12,876	228,932	184,953	43,979	0	0	1,255
21	Primary Customer 1 Phase	C61PS1Ph		95,637	91,107	4,294	3,684	610	600	9	0	0	236
22	Primary Customer Multi Phase	C61PS		205,770	183,580	21,297	13,681	7,617	7,543	74	0	0	893
23	Total Primary			863,259	547,946	312,295	36,842	275,454	221,125	54,328	0	0	3,017
24	Second Capacity	D62SecL		43,873	21,653	22,108	1,586	20,522	20,522	0	0	0	112
25	Second Customer	C62Sec		157,850	140,878	16,287	10,498	5,788	5,788	0	0	0	685
26	Total Secondary			201,723	162,532	38,395	12,085	26,310	26,310	0	0	0	797
27	Street Lighting	DASL		52,732	0	0	0	0	0	0	0	0	52,732
28	Total		364,365	1,117,714	710,478	350,690	48,926	301,764	247,436	54,328	0	0	56,546
	Underground Lines												
29	Primary Capacity 1 Phase	D61PS1Ph		306,884	228,510	77,284	11,363	65,921	48,249	17,672	0	0	1,090
30	Primary Capacity Multi Phase	D61PS		441,072	161,575	278,054	14,806	263,248	212,677	50,571	0	0	1,443
31	Primary Customer 1 Phase	C61PS1Ph		348,753	332,232	15,659	13,436	2,223	2,190	33	0	0	862
32	Primary Customer Multi Phase	C61PS		501,249	447,195	51,880	33,325	18,555	18,374	181	0	0	2,174
33	Total Primary			1,597,957	1,169,511	422,876	72,930	349,946	281,490	68,457	0	0	5,570
34	Second Capacity	D62SecL		51,408	25,372	25,905	1,859	24,046	24,046	0	0	0	131
35	Second Customer	C62Sec		144,520	128,981	14,911	9,612	5,299	5,299	0	0	0	627
36	Total Secondary			195,928	154,353	40,816	11,470	29,346	29,346	0	0	0	758
37	Street Lighting	DASL		0	0	0	0	0	0	0	0	0	0
38	Total		366,367	1,793,885	1,323,864	463,693	84,400	379,292	310,836	68,457	0	0	6,328
	Line Transformers												
39	Primary	D61PS		42,315	15,501	26,675	1,420	25,255	20,403	4,852	0	0	138
40	Second Capacity	D62SecL		126,328	62,348	63,658	4,567	59,091	59,091	0	0	0	322
41	Second Customer	C62Sec		221,847	197,994	22,890	14,755	8,135	8,135	0	0	0	963
42	Total		368	390,490	275,843	113,224	20,742	92,481	87,629	4,852	0	0	1,423
	Services												
43	Second Capacity	D62NLL		68,335	50,875	17,461	1,412	16,048	16,048	0	0	0	0
44	Second Customer	C62NL		223,503	212,155	11,348	7,315	4,033	4,033	0	0	0	0
43	Total Services	C62NL	369	291,839	263,030	28,808	8,727	20,081	20,081	0	0	0	0
44	Meters	C12WM	370	83,896	55,777	27,941	8,295	19,646	18,458	1,139	31	18	178
45	Street Lighting	Dir Assign	373	73,127	0	0	0	0	0	0	0	0	73,127
46	**Total Distribution**			4,500,875	2,934,596	1,424,641	200,448	1,224,193	1,005,938	207,980	10,004	271	141,638
47	**General & Common Plant**	PTD	303, 389-399	2,035,329	826,363	1,190,996	71,645	1,119,351	825,854	203,545	80,908	9,043	17,970
48	Prelim Elec Plant			21,700,191	8,810,488	12,698,115	763,862	11,934,254	8,805,060	2,170,152	862,627	96,415	191,588
49	TBT Investment	NEPIS		0	0	0	0	0	0	0	0	0	0
50	**Elec Plant in Serv**			21,700,191	8,810,488	12,698,115	763,862	11,934,254	8,805,060	2,170,152	862,627	96,415	191,588

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Accum Deprec; Net Plant

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		1,448,443	558,738	889,704	49,180	840,524	627,484	149,754	56,437	6,849	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,464,907	737,844	1,718,522	77,578	1,640,944	1,176,166	305,978	144,407	14,393	8,540
5	Base Load	E8760		3,222,932	964,751	2,247,014	101,436	2,145,579	1,537,869	400,074	188,816	18,820	11,167
6	Total		108,111,115,120.5	7,136,281	2,261,334	4,855,241	228,195	4,627,046	3,341,519	855,805	389,660	40,062	19,707
	Transmission												
7	Gen Step Up Base	E8760		12,177	3,645	8,490	383	8,106	5,810	1,512	713	71	42
8	Gen Step Up Peak	D10S		15,144	5,842	9,302	514	8,788	6,561	1,566	590	72	0
9	Total Gen Step Up			27,321	9,487	17,792	897	16,895	12,371	3,077	1,303	143	42
10	Bulk Transmission	D10S		819,356	316,067	503,288	27,820	475,468	354,956	84,713	31,925	3,874	0
11	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,006	0	2,006	0	2,006	335	0	0	1,672	0
13	Total		108,111,115,120.5	848,684	325,554	523,087	28,718	494,369	367,662	87,790	33,229	5,689	42
	Distribution												
14	Generat Step Up	STRATH		2,322	729	1,586	74	1,512	1,090	280	128	13	7
15	Bulk Transmission	D10S		687	265	422	23	398	297	71	27	3	0
16	Distrib Function	D60Sub		251,562	105,193	144,975	10,105	134,870	110,358	24,845	(333)	0	1,394
17	Direct Assign	Dir Assign		6,633	0	6,633	0	6,633	149	2,502	3,899	83	0
18	Total Substations			261,203	106,187	153,616	10,203	143,413	111,895	27,697	3,722	99	1,400
19	Overhead Lines	POL		380,147	241,642	119,274	16,640	102,633	84,156	18,478	0	0	19,232
20	Underground	PUL		507,234	374,332	131,112	23,865	107,248	87,891	19,357	0	0	1,789
21	Line Transformers	P68		178,607	126,168	51,787	9,487	42,300	40,081	2,219	0	0	651
22	Services	P69		182,065	164,093	17,972	5,444	12,528	12,528	0	0	0	0
23	Meters	C12WM		70,634	46,960	23,525	6,984	16,541	15,541	959	26	15	150
24	Street Lighting	P73		17,668	0	0	0	0	0	0	0	0	17,668
25	Total		108,111,115,120.5	1,597,559	1,059,382	497,286	72,624	424,663	352,091	68,710	3,747	114	40,890
26	**General & CommonPlant**	PTD	108,111,115,120.5	1,059,356	430,109	619,895	37,290	582,604	429,844	105,942	42,112	4,707	9,353
27	**Total Accum Depr**			10,641,880	4,076,379	6,495,509	366,826	6,128,683	4,491,116	1,118,247	468,748	50,571	69,992
28	**Net Elec Plant**			11,058,311	4,734,109	6,202,607	397,036	5,805,571	4,313,943	1,051,905	393,880	45,843	121,596
29	**Net Plant w/ TBT**			11,058,311	4,734,109	6,202,607	397,036	5,805,571	4,313,943	1,051,905	393,880	45,843	121,596

Subtractions: Accum Defer Inc Tax

				MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	St Ltg
	Production												
30	Peaking Plant	D10S		262,786	101,370	161,416	8,923	152,494	113,843	27,169	10,239	1,243	0
31	Base Load	E8760		922,212	276,055	642,962	29,025	613,937	440,047	114,477	54,028	5,385	3,195
32	Nuclear Fuel	E8760		(5,980)	(1,790)	(4,169)	(188)	(3,981)	(2,854)	(742)	(350)	(35)	(21)
33	Total		190,281,282,283	1,179,019	375,635	800,209	37,759	762,450	551,036	140,904	63,917	6,593	3,175
	Transmission												
34	Gen Step Up Base	E8760		15,609	4,672	10,883	491	10,391	7,448	1,938	914	91	54
35	Gen Step Up Peak	D10S		4,237	1,635	2,603	144	2,459	1,836	438	165	20	0
36	Total Gen Step Up			19,847	6,307	13,486	635	12,850	9,284	2,376	1,080	111	54
37	Bulk Transmission	D10S		716,137	276,251	439,886	24,316	415,570	310,240	74,041	27,903	3,386	0
38	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,204	0	1,204	0	1,204	201	0	0	1,003	0
40	Total		281,282,283	737,187	282,558	454,576	24,951	429,625	319,725	76,417	28,983	4,500	54
	Distribution												
41	Generat Step Up	STRATH		296	93	203	9	193	139	36	16	2	1
42	Bulk Transmission	D10S		240	92	147	8	139	104	25	9	1	0
43	Distrib Function	D60Sub		108,063	45,188	62,277	4,341	57,936	47,406	10,673	(143)	0	599
44	Direct Assign	Dir Assign		2,163	0	2,163	0	2,163	49	816	1,272	27	0
45	Total Substations			110,762	45,373	64,790	4,359	60,431	47,698	11,549	1,154	30	599
46	Overhead Lines	POL		151,859	96,529	47,647	6,647	40,999	33,618	7,381	0	0	7,683
47	Underground	PUL		231,810	171,073	59,920	10,906	49,013	40,167	8,846	0	0	818
48	Line Transformers	P68		53,788	37,996	15,596	2,857	12,739	12,071	668	0	0	196
49	Services	P69		17,643	15,902	1,742	528	1,214	1,214	0	0	0	0
50	Meters	C12WM		9,990	6,642	3,327	988	2,340	2,198	136	4	2	21
51	Street Lighting	P73		13,205	0	0	0	0	0	0	0	0	13,205
52	Total		281,282,283	589,058	373,515	193,021	26,285	166,736	136,966	28,580	1,158	32	22,522
53	**General & Common Plant**	PTD	281,282,283	135,318	54,940	79,183	4,763	74,420	54,907	13,533	5,379	601	1,195
54	**Total Deferred Tax**			2,640,583	1,086,648	1,526,989	93,758	1,433,231	1,062,633	259,434	99,437	11,726	26,945
55	Net Operating Loss (NOL) Carry F	NEPIS		(654,397)	(280,150)	(367,051)	(23,495)	(343,556)	(255,286)	(62,249)	(23,309)	(2,713)	(7,196)
56	Non-Plant Related	LABOR		29,519	11,495	17,726	1,080	16,646	12,240	3,030	1,244	131	298
57	**Accum Def W/ Adj**			2,015,705	817,993	1,177,664	71,344	1,106,320	819,587	200,216	77,373	9,144	20,048

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Additions: CWIP, Etc; Rate Base

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		65,518	25,274	40,244	2,225	38,020	28,383	6,774	2,553	310	0
2	Base Load	E8760		83,328	24,944	58,096	2,623	55,474	39,761	10,344	4,882	487	289
3	Nuclear Fuel	E8760		86,691	25,950	60,441	2,728	57,712	41,366	10,761	5,079	506	300
4	Total		107	235,537	76,167	158,781	7,576	151,205	109,510	27,879	12,513	1,303	589
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		115,059	44,384	70,675	3,907	66,768	49,845	11,896	4,483	544	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
11	Total		107	115,059	44,384	70,675	3,907	66,768	49,845	11,896	4,483	544	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		5,702	2,384	3,286	229	3,057	2,501	563	(8)	0	32
15	Direct Assign	Dir Assign		28	0	28	0	28	1	10	16	0	0
16	Total Substations			5,729	2,384	3,314	229	3,085	2,502	574	9	0	32
17	Overhead Lines	POL		20,874	13,269	6,549	914	5,636	4,621	1,015	0	0	1,056
18	Underground	PUL		37,030	27,328	9,572	1,742	7,829	6,416	1,413	0	0	131
19	Line Transformers	P68		928	656	269	49	220	208	12	0	0	3
20	Services	P69		138	125	14	4	10	10	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		107	64,700	43,761	19,718	2,938	16,779	13,757	3,013	9	0	1,222
24	**General & Common Plant**	PTD	107	92,593	37,594	54,182	3,259	50,923	37,571	9,260	3,681	411	817
25	**Total CWIP**			507,890	201,906	303,356	17,680	285,676	210,684	52,048	20,686	2,258	2,628
26	Fuel Inventory	E8760	151,152	65,875	19,719	45,928	2,073	43,854	31,433	8,177	3,859	385	228
	Materials & Supplies												
27	Production	P10		137,523	43,745	93,404	4,402	89,002	64,309	16,452	7,471	770	373
28	Trans & Distr	TD		16,409	8,770	7,348	654	6,694	5,175	1,171	303	45	291
29	Total		154	153,932	52,515	100,752	5,056	95,696	69,484	17,622	7,774	815	665
	Prepayments												
30	Miscellaneous	NEPIS		85,979	36,808	48,226	3,087	45,139	33,541	8,179	3,062	356	945
31	Fuel	E8760		0	0	0	0	0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0	0	0	0	0
33	Total		235,252,165	85,979	36,808	48,226	3,087	45,139	33,541	8,179	3,062	356	945
34	Non-Plant Assets & Liab	LABOR	190,283,	90,346	35,181	54,252	3,307	50,945	37,462	9,274	3,808	400	913
35	Working Cash	PT0	calculated	(140,888)	(60,762)	(78,670)	(5,086)	(73,584)	(54,726)	(13,290)	(4,990)	(578)	(1,455)
36	**Total Additions**			763,134	285,367	473,842	26,118	447,725	327,878	82,011	34,200	3,637	3,925
37	**Total Rate Base**			9,805,740	4,201,483	5,498,785	351,810	5,146,976	3,822,234	933,700	350,707	40,335	105,472
38	**Common Rate Base (@ 52.50%)**			5,148,013.7	2,205,778	2,886,862	184,700	2,702,162	2,006,673	490,192	184,121	21,176	55,373

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Operating Rev (Cal Month)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,068,702	1,147,973	1,894,005	107,401	1,786,604	1,335,970	304,267	132,106	14,261	26,724
2	Proposed Rate Revenue	PROREV; (calc)		3,533,407	1,351,742	2,149,819	125,400	2,024,419	1,512,808	347,286	146,713	17,611	31,846
3	Equal Rate Revenue			3,533,407	1,363,157	2,138,062	124,527	2,013,534	1,479,876	367,275	149,986	16,397	32,188
	Other Retail Revenue												
4	Interdepartmental	R01; R02	448	736	275	454	26	428	320	73	32	3	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**			736	275	454	26	428	320	73	32	3	6
	Other Operating Revenue												
8	Interchg Prod Capacity	P10	456	441,574	140,463	299,913	14,136	285,777	206,491	52,826	23,989	2,472	1,198
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10S	456	(9,963)	(3,843)	(6,120)	(338)	(5,781)	(4,316)	(1,030)	(388)	(47)	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	630	189	439	20	420	301	78	37	4	2
12	Dist Overhd Line Rent	POL	454	5,006	3,182	1,571	219	1,352	1,108	243	0	0	253
13	Connection Charges	C11	451	1,930	1,694	196	126	70	69	1	0	0	40
14	Sales For Resale	E8760	447	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
15	Joint Op Agree-Other PSCo Rev	D10S	456	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10S		211,973	81,769	130,204	7,197	123,007	91,830	21,916	8,259	1,002	0
17	MISO	D10S	456	(94,933)	(36,620)	(58,312)	(3,223)	(55,089)	(41,126)	(9,815)	(3,699)	(449)	0
18	Other	D10S	451,456,457	12,835	4,951	7,884	436	7,448	5,560	1,327	500	61	0
19	Late Pay Chg - Pres	R16C; R02		5,687	4,895	787	321	466	441	24	1	1	5
20	**Tot Other Op - Pres**		450	574,740	196,679	376,563	18,894	357,669	260,358	65,569	28,699	3,044	1,498
21	Incr Misc Serv - Prop	R01,		447	167	276	16	260	195	44	19	2	4
22	Incr Inter-Dept'l - Prop	R01; R02		91	34	56	3	53	40	9	4	0	1
23	Incr Late Pay - Prop	(R16C); R02		861	741	119	49	71	67	4	0	0	1
	Tot Incr Other Op			1,400	943	452	68	384	301	57	23	3	5
24	**Tot Other Op - Prop**			576,140	197,622	377,014	18,961	358,053	260,659	65,626	28,722	3,046	1,504
25	**Tot Oper Rev - Pres**			3,644,178	1,344,927	2,271,022	126,320	2,144,702	1,596,648	369,909	160,836	17,308	28,228
26	**Tot Oper Rev - Prop**			4,110,282	1,549,639	2,527,287	144,387	2,382,900	1,773,787	412,985	175,467	20,660	33,356
	Tot Oper Rev - Eql			4,110,282	1,561,054	2,515,530	143,514	2,372,016	1,740,855	432,975	178,739	19,447	33,698

Operating & Maint (Pg 1 of 2)

	Production Expen												
27	**Fuel**	E8760	501,518,547	648,552	194,137	452,168	20,412	431,756	309,466	80,507	37,996	3,787	2,247
	Purchased Power												
28	Purchases: Cap Peak	D10S		104,467	40,298	64,169	3,547	60,622	45,256	10,801	4,070	494	0
29	Purchases: Cap Base	D10S		38,875	14,996	23,879	1,320	22,559	16,841	4,019	1,515	184	0
30	Purchases: Demand		555	143,342	55,294	88,047	4,867	83,180	62,097	14,820	5,585	678	0
31	Purchases: Other Energy	E8760	555	288,737	86,430	201,306	9,087	192,218	137,775	35,842	16,916	1,686	1,000
32	Tot Non-Assoc Purch			432,078	141,724	289,353	13,954	275,399	199,872	50,662	22,501	2,364	1,000
33	Interchg Agr Capacity	P10WoN	557	40,363	13,060	27,203	1,298	25,904	18,763	4,776	2,143	223	101
34	Interchg Agr Energy	E8760	557	16,433	4,919	11,457	517	10,940	7,841	2,040	963	96	57
35	Tot Wis Interchg Purch			56,797	17,979	38,660	1,816	36,844	26,604	6,816	3,105	319	158
36	**Tot Purchased Power**			488,875	159,704	328,013	15,770	312,243	226,476	57,478	25,606	2,683	1,158
	Other Production		500,502,505-507 509-514,517-519,520, 523-525,528-532,535, 539,543-546,548-550 552-554,556,557 575.1-575.8										
37	Capacity Related	D10S		95,752	36,936	58,816	3,251	55,564	41,481	9,900	3,731	453	0
38	Energy Related	E8760		352,538	105,529	245,788	11,095	234,693	168,219	43,762	20,654	2,059	1,221
39	Total Other Produc	21.36%		448,290.033	142,465	304,604	14,347	290,257	209,700	53,662	24,384	2,511	1,221
40	**Total Production**			1,585,717	496,306	1,084,784	50,529	1,034,256	745,642	191,646	87,986	8,981	4,627
41	**Transmission Exp**	D10S	560-563, 565-568 570-573	259,023	99,919	159,105	8,795	150,310	112,212	26,780	10,093	1,225	0

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

Operating & Maint (Pg 2 of 2)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	6,951	4,004	2,642	322	2,320	1,860	401	54	5	305
2	Load Dispatching	T20D80	581	7,517	3,095	4,389	293	4,097	3,290	749	51	7	33
3	Substations	P61	582,591,592	9,370	3,818	5,501	367	5,134	4,017	990	125	3	50
4	Overhead Lines	POL	583,593	42,847	27,236	13,443	1,876	11,568	9,485	2,083	0	0	2,168
5	Underground Lines	PUL	584, 594	15,816	11,672	4,088	744	3,344	2,740	604	0	0	56
6	Line Transformers	P68	595	1,433	1,012	415	76	339	322	18	0	0	5
7	Meters	C12WM	586,597,598	6,274	4,171	2,090	620	1,469	1,380	85	2	1	13
8	Customer Install'n	OXDTS	587	3,920	2,342	1,365	182	1,184	968	207	8	1	212
9	Street Lighting	Dir Assign	585,596	2,326	0	0	0	0	0	0	0	0	2,326
10	Miscellaneous	OXDTS	588	27,100	16,193	9,438	1,256	8,182	6,695	1,429	54	4	1,469
11	Rents (Pole Attachmts)	POL	589	3,532	2,245	1,108	155	953	782	172	0	0	179
12	**Total Distribution**			127,086	75,789	44,480	5,890	38,590	31,540	6,736	293	21	6,816
13	**Customer Accounting**	C11WA	901-905	43,907	36,511	7,220	4,078	3,142	3,098	41	2	1	177
14	**Sales, Econ Dvlp & Other**	R01	912	(5)	(2)	(3)	(0)	(3)	(2)	(0)	(0)	(0)	(0)
	Admin & General												
15	Salaries	LABOR	920	76,411	29,755	45,884	2,797	43,087	31,684	7,844	3,221	338	773
16	Office Supplies	OXTS	921	51,853	18,353	33,180	1,788	31,393	22,920	5,749	2,461	263	320
17	Admin Transfer Credit	OXTS	922	(42,366)	(14,995)	(27,110)	(1,461)	(25,649)	(18,726)	(4,697)	(2,011)	(215)	(261)
18	Outside Services	LABOR	923	18,894	7,357	11,346	692	10,654	7,834	1,940	796	84	191
19	Property Insurance	NEPIS	924	6,726	2,880	3,773	242	3,531	2,624	640	240	28	74
20	Pensions & Benefits	LABOR	926	79,517	30,964	47,749	2,910	44,838	32,972	8,163	3,352	352	804
21	Injuries & Claims	LABOR	925	12,738	4,960	7,649	466	7,183	5,282	1,308	537	56	129
22	Regulatory Exp	R01; R02	928	5,281	1,975	3,259	185	3,074	2,299	524	227	25	46
23	General Advertising	OXTS	930.1	235	83	150	8	142	104	26	11	1	1
24	Contributions	OXTS		0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(306)	(108)	(196)	(11)	(185)	(135)	(34)	(15)	(2)	(2)
26	Rents	OXTS	931	50,518	17,880	32,326	1,742	30,584	22,329	5,601	2,398	256	311
27	Maint of General Plant	OXTS	935	802	284	513	28	485	354	89	38	4	5
28	Total			260,301	99,388	158,523	9,385	149,138	109,540	27,151	11,256	1,191	2,391
	Cust Service & Info												
29	Cust Assist Exp - Non-CIP	C11P10	908	2,328	1,392	909	113	796	586	140	63	7	27
30	CIP Total	E99XCIP	908	102,371	31,649	70,256	3,184	67,073	51,050	11,812	3,536	674	466
31	Instructional Advertising	C11P10	909	873	522	341	42	298	220	52	24	2	10
32	Total			105,572	33,563	71,506	3,340	68,167	51,856	12,004	3,623	683	503
33	Amortizations	LABOR		44,757	17,428	26,876	1,638	25,238	18,558	4,594	1,887	198	453
34	**Total O&M Expense**			2,426,359	858,902	1,552,491	83,654	1,468,837	1,072,446	268,953	115,138	12,300	14,966

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Book Depreciation												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		109,606	42,281	67,325	3,722	63,604	47,483	11,332	4,271	518	0
2	Base Load	E8760		318,036	95,201	221,733	10,010	211,724	151,756	39,479	18,632	1,857	1,102
3	Total		403,413	427,642	137,482	289,059	13,731	275,328	199,238	50,811	22,903	2,375	1,102
	Transmission												
4	Gen Step Up Base	E8760		1,638	490	1,142	52	1,091	782	203	96	10	6
5	Gen Step Up Peak	D10S		950	366	583	32	551	411	98	37	4	0
6	Total Gen Step Up			2,588	857	1,725	84	1,642	1,193	302	133	14	6
7	Bulk Transmission	D10S		69,952	26,984	42,968	2,375	40,593	30,304	7,232	2,726	331	0
8	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign		129	0	129	0	129	22	0	0	107	0
10	Total		403,413	72,668	27,841	44,822	2,459	42,363	31,519	7,534	2,859	452	6
	Distribution												
11	Generat Step Up	STRATH		68	22	47	2	45	32	8	4	0	0
12	Bulk Transmission	D10S		42	16	26	1	24	18	4	2	0	0
13	Distrib Function	D60Sub		16,464	6,885	9,488	661	8,827	7,223	1,626	(22)	0	91
14	Direct Assign	Dir Assign		403	0	403	0	403	9	152	237	5	0
15	Total Substations		403,413	16,978	6,922	9,964	665	9,299	7,282	1,791	221	6	91
16	Overhead Lines	POL		38,976	24,775	12,229	1,706	10,523	8,628	1,894	0	0	1,972
17	Underground	PUL		44,870	33,114	11,598	2,111	9,487	7,775	1,712	0	0	158
18	Line Transformers	P68		10,854	7,667	3,147	577	2,570	2,436	135	0	0	40
19	Services	P69		10,574	9,530	1,044	316	728	728	0	0	0	0
20	Meters	C12WM		3,810	2,533	1,269	377	892	838	52	1	1	8
21	Street Lighting	P73		3,947	0	0	0	0	0	0	0	0	3,947
22	Total		403,413	130,010	84,542	39,251	5,752	33,499	27,687	5,584	222	6	6,217
23	**General & Common Plant**	PTD	403,413	130,538	53,000	76,386	4,595	71,791	52,967	13,055	5,189	580	1,153
24	**Total Book Deprec**		403,404	760,859	302,864	449,518	26,537	422,981	311,411	76,984	31,173	3,414	8,477
	Real Estate & Property Tax												
	Production												
25	Peaking Plant	D10S		27,235	10,506	16,729	925	15,804	11,799	2,816	1,061	129	0
26	Base Load	E8760		69,922	20,930	48,749	2,201	46,549	33,364	8,680	4,096	408	242
27	Total		408.1	97,157	31,436	65,479	3,125	62,353	45,163	11,496	5,158	537	242
	Transmission												
28	Gen Step Up Base	E8760		1,115.6734	334	778	35	743	532	138	65	7	4
29	Gen Step Up Peak	D10S		469.9201	181	289	16	273	204	49	18	2	0
30	Total Gen Step Up			1,585.5936	515	1,066	51	1,015	736	187	84	9	4
31	Bulk Transmission	D10S		41,402.6416	15,971	25,432	1,406	24,026	17,936	4,281	1,613	196	0
32	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
33	Direct Assign	Dir Assign		77	0	77	0	77	13	0	0	64	0
34	Total		408.1	43,064.877	16,486	26,575	1,457	25,118	18,685	4,468	1,697	268	4
	Distribution												
35	Generat Step Up	STRATH		38	12	26	1	25	18	5	2	0	0
36	Bulk Transmission	D10S		23	9	14	1	13	10	2	1	0	0
37	Distrib Function	D60Sub		9,184	3,840	5,293	369	4,924	4,029	907	(12)	0	51
38	Direct Assign	Dir Assign		230	0	230	0	230	5	87	135	3	0
39	Total Substations			9,475	3,861	5,563	371	5,192	4,062	1,001	126	3	51
40	Overhead Lines	POL		14,122	8,977	4,431	618	3,813	3,126	686	0	0	714
41	Underground	PUL		22,666	16,727	5,859	1,066	4,792	3,927	865	0	0	80
42	Line Transformers	P68		4,934	3,485	1,431	262	1,169	1,107	61	0	0	18
43	Services	P69		3,687	3,323	364	110	254	254	0	0	0	0
44	Meters	C12WM		1,060	705	353	105	248	233	14	0	0	2
45	Street Lighting	P73		924	0	0	0	0	0	0	0	0	924
46	Total		408.1	56,869	37,079	18,000	2,533	15,468	12,710	2,628	126	3	1,790
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			197,091	85,002	110,054	7,115	102,939	76,558	18,591	6,981	809	2,036
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0	0	0	0	0
50	Payroll Taxes	LABOR		27,435	10,683	16,475	1,004	15,470	11,376	2,816	1,156	122	277
51	**Tot Non-Inc Taxes**			224,526	95,685	126,528	8,119	118,409	87,934	21,407	8,137	930	2,313

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HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Provision For Defer Inc Tax												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		(7,850)	(3,028)	(4,822)	(267)	(4,555)	(3,401)	(812)	(306)	(37)	0
2	Nuclear Fuel	E8760		(2,604)	(779)	(1,815)	(82)	(1,733)	(1,242)	(323)	(153)	(15)	(9)
3	Base Load	E8760		(23,809)	(7,127)	(16,600)	(749)	(15,850)	(11,361)	(2,956)	(1,395)	(139)	(82)
4	Total		410, 411	(34,263)	(10,934)	(23,237)	(1,098)	(22,139)	(16,004)	(4,090)	(1,853)	(191)	(92)
	Transmission												
5	Gen Step Up Base	E8760		587	176	409	18	391	280	73	34	3	2
6	Gen Step Up Peak	D10S		224	86	137	8	130	97	23	9	1	0
7	Total Gen Step Up			811	262	547	26	521	377	96	43	4	2
8	Bulk Transmission	D10S		7,252	2,797	4,454	246	4,208	3,142	750	283	34	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		12	0	12	0	12	2	0	0	10	0
11	Total		410, 411	8,075	3,059	5,014	272	4,741	3,521	846	326	49	2
	Distribution												
12	Generat Step Up	STRATH		(27)	(9)	(19)	(1)	(18)	(13)	(3)	(2)	(0)	(0)
13	Bulk Transmission	D10S		(8)	(3)	(5)	(0)	(5)	(3)	(1)	(0)	(0)	0
14	Distrib Function	D60Sub		(409)	(171)	(236)	(16)	(219)	(179)	(40)	1	0	(2)
15	Direct Assign	Dir Assign		(39)	0	(39)	0	(39)	(1)	(15)	(23)	(0)	0
16	Total Substations			(483)	(183)	(298)	(18)	(281)	(197)	(59)	(24)	(1)	(2)
17	Overhead Lines	POL		2,340	1,487	734	102	632	518	114	0	0	118
18	Underground	PUL		(646)	(476)	(167)	(30)	(136)	(112)	(25)	0	0	(2)
19	Line Transformers	P68		(2,655)	(1,876)	(770)	(141)	(629)	(596)	(33)	0	0	(10)
20	Services	P69		(720)	(649)	(71)	(22)	(50)	(50)	0	0	0	0
21	Meters	C12WM		(596)	(396)	(199)	(59)	(140)	(131)	(8)	(0)	(0)	(1)
22	Street Lighting	P73		(493)	0	0	0	0	0	0	0	0	(493)
23	Total		410, 411	(3,253)	(2,093)	(770)	(167)	(603)	(567)	(11)	(24)	(1)	(390)
24	**General & Common Plant**	PTD	410, 411	(2,040)	(828)	(1,194)	(72)	(1,122)	(828)	(204)	(81)	(9)	(18)
25	**Net Operating Loss (NOL) Carry**	NEPIS		(157,543)	(67,445)	(88,366)	(5,656)	(82,709)	(61,459)	(14,986)	(5,611)	(653)	(1,732)
26	**Non - Plant Related**	LABOR	410, 411	(651)	(253)	(391)	(24)	(367)	(270)	(67)	(27)	(3)	(7)
27	**Tot Prov For Defer**			(189,674)	(78,494)	(108,944)	(6,745)	(102,199)	(75,607)	(18,513)	(7,272)	(808)	(2,237)
	Inv Tax Credit; Total Oper Exp												
	Production												
28	Peaking Plant	D10S		(260)	(100)	(160)	(9)	(151)	(113)	(27)	(10)	(1)	0
29	Base Load	E8760		(538)	(161)	(375)	(17)	(358)	(257)	(67)	(32)	(3)	(2)
30	Total		411	(798)	(261)	(535)	(26)	(509)	(369)	(94)	(42)	(4)	(2)
	Transmission												
31	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
34	Bulk Transmission	D10S		(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(1)	0
35	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
37	Total		411	(150)	(58)	(92)	(5)	(87)	(65)	(16)	(6)	(1)	0
	Distribution												
38	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
39	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0	0	0	0	0
43	Overhead Lines	POL		(267)	(170)	(84)	(12)	(72)	(59)	(13)	0	0	(14)
44	Underground	PUL		0	0	0	0	0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
49	Total		411	(267)	(170)	(84)	(12)	(72)	(59)	(13)	0	0	(14)
50	**General & Common Plant**	PTD	411	(7)	(3)	(4)	(0)	(4)	(3)	(1)	(0)	(0)	(0)
51	**Net Inv Tax Credit**			(1,222)	(492)	(715)	(43)	(672)	(496)	(123)	(48)	(5)	(15)
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0	0	0	0	0
52	**Total Operating Exp**			**3,220,847**	**1,178,465**	**2,018,879**	**111,522**	**1,907,357**	**1,395,688**	**348,708**	**147,129**	**15,831**	**23,504**
53A	**Pres Op Inc Before Inc Tax**			**423,330**	**166,463**	**252,143**	**14,798**	**237,345**	**200,960**	**21,201**	**13,708**	**1,477**	**4,725**
53B	**Prop Op Inc Before Inc Tax**			**889,435**	**371,175**	**508,408**	**32,864**	**475,544**	**378,099**	**64,277**	**28,338**	**4,829**	**9,852**

2022 Class Cost of Service Study Detail ($000)

Tax Deprec; Inc Tax & Return

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		102,374	39,491	62,883	3,476	59,407	44,350	10,584	3,989	484	0
2	Nuclear Fuel	E8760		95,708	28,649	66,727	3,012	63,715	45,668	11,881	5,607	559	332
3	Base Load	E8760		318,090	95,217	221,771	10,011	211,760	151,781	39,486	18,635	1,857	1,102
4	Total		tax books	516,172	163,357	351,381	16,500	334,882	241,800	61,951	28,231	2,900	1,434
	Transmission												
5	Gen Step Up Base	E8760		4,008	1,200	2,795	126	2,668	1,913	498	235	23	14
6	Gen Step Up Peak	D10S		1,607	620	987	55	933	696	166	63	8	0
7	Total Gen Step Up			5,615	1,820	3,782	181	3,601	2,609	664	297	31	14
8	Bulk Transmission	D10S		105,255	40,602	64,653	3,574	61,079	45,598	10,882	4,101	498	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		190	0	190	0	190	32	0	0	158	0
11	Total		tax books	111,060	42,422	68,624	3,755	64,870	48,239	11,546	4,399	687	14
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		14	5	9	0	8	6	1	1	0	0
14	Distrib Function	D60Sub		17,370	7,263	10,010	698	9,313	7,620	1,716	(23)	0	96
15	Direct Assign	Dir Assign		339	0	339	0	339	8	128	199	4	0
16	Total Substations			17,722	7,269	10,357	698	9,659	7,634	1,845	177	4	96
17	Overhead Lines	POL		46,095	29,301	14,463	2,018	12,445	10,204	2,241	0	0	2,332
18	Underground	PUL		51,841	38,258	13,400	2,439	10,961	8,983	1,978	0	0	183
19	Line Transformers	P68		7,515	5,309	2,179	399	1,780	1,686	93	0	0	27
20	Services	P69		8,618	7,767	851	258	593	593	0	0	0	0
21	Meters	C12WM		1,946	1,294	648	192	456	428	26	1	0	4
22	Street Lighting	P73		2,776	0	0	0	0	0	0	0	0	2,776
23	Total		tax books	136,513	89,197	41,898	6,004	35,894	29,528	6,183	177	5	5,418
24	**General & Common Plant**	PTD	tax books	151,748	61,611	88,797	5,342	83,456	61,573	15,176	6,032	674	1,340
25	Net Operating Loss (NOL) Carry F	NEPIS		0	0	0	0	0	0	0	0	0	0
26	**Total Tax Deprec**			915,494	356,588	550,701	31,600	519,101	381,140	94,856	38,840	4,266	8,206
27	Interest Expense		427,431	206,901.12	88,651	116,024	7,423	108,601	80,649	19,701	7,400	851	2,225
28	Other Tax Timing Differ	LABOR		(12,176)	(4,741)	(7,312)	(446)	(6,866)	(5,049)	(1,250)	(513)	(54)	(123)
29	Meals & Enter	LABOR		584	227	350	21	329	242	60	25	3	6
30	Total Tax Deductions			1,110,803	440,725	659,764	38,599	621,165	456,982	113,367	45,751	5,066	10,314
	Inc Tax Additions												
31	Book Depreciation			760,859	302,864	449,518	26,537	422,981	311,411	76,984	31,173	3,414	8,477
32	Deferred Inc Tax & ITC			(190,896.73)	(78,986)	(109,658)	(6,787)	(102,871)	(76,103)	(18,635)	(7,320)	(813)	(2,252)
33	Nuclear Fuel Book Burn	E8760		107,318	32,125	74,822	3,378	71,444	51,208	13,322	6,287	627	372
34	Tax Capitalized Leases	PTD		41,215	16,734	24,117	1,451	22,667	16,723	4,122	1,638	183	364
35	Avoided Tax Interest	RTBASE		20,828	8,924	11,680	747	10,932	8,119	1,983	745	86	224
36	Total Tax Additions			739,323	281,660	450,478	25,325	425,153	311,359	77,775	32,523	3,496	7,184
37	**Total Inc Tax Adjustments**			(371,480)	(159,064)	(209,286)	(13,274)	(196,012)	(145,624)	(35,592)	(13,227)	(1,569)	(3,130)
38A	**Pres Taxable Net Income**			51,850	7,398	42,857	1,524	41,333	55,336	(14,391)	480	(92)	1,595
38B	**Prop Taxable Net Income**			517,955	212,110	299,122	19,590	279,532	232,476	28,685	15,111	3,260	6,723
39A	Pres Fed & State Inc Tax			56,478	19,940	35,632	1,930	33,703	32,111	(177)	1,625	144	906
39B	Prop Fed & State Inc Tax			190,446	78,779	109,288	7,122	102,166	83,024	12,204	5,830	1,108	2,379
40A	Pres Preliminary Return	(total); BASE		366,852	146,522	216,511	12,868	203,643	168,849	21,378	12,083	1,333	3,819
40B	Prop Preliminary Return	(total); BASE		698,989	292,396	399,120	25,742	373,378	295,075	52,073	22,508	3,721	7,473
41	Total AFUDC			33,500	13,321	20,017	1,160	18,857	13,913	3,430	1,358	156	162
42A	**Present Total Return**			400,352	159,843	236,528	14,028	222,500	182,762	24,808	13,440	1,489	3,981
42B	**Proposed Total Return**			732,489	305,717	419,137	26,902	392,235	308,988	55,504	23,866	3,878	7,635
43A	**Pres % Return on Rate Base**			4.08%	3.80%	4.30%	3.99%	4.32%	4.78%	2.66%	3.83%	3.69%	3.77%
43B	**Prop % Return on Rate Base**			7.47%	7.28%	7.62%	7.65%	7.62%	8.08%	5.94%	6.81%	9.61%	7.24%
44A	**Present Common Return**			193,451	71,192	120,503	6,605	113,898	102,113	5,107	6,040	638	1,756
44B	**Proposed Common Return**			525,588	217,066	303,113	19,479	283,634	228,339	35,802	16,466	3,027	5,410
45A	**Pres % Ret on Common Rt Base**			3.76%	3.23%	4.17%	3.58%	4.22%	5.09%	1.04%	3.28%	3.01%	3.17%
45B	**Prop % Ret on Common Rt Base**			10.21%	9.84%	10.50%	10.55%	10.50%	11.38%	7.30%	8.94%	14.29%	9.77%

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

				1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Allow For Funds Used During Constr												
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10S		4,187	1,615	2,572	142	2,430	1,814	433	163	20	0
2	Nuclear Fuel	E8760		4,647	1,391	3,240	146	3,093	2,217	577	272	27	16
3	Base Load	E8760		6,095	1,824	4,249	192	4,058	2,908	757	357	36	21
4	Total		419.1,432	14,929	4,831	10,061	480	9,581	6,939	1,766	792	83	37
	Transmission												
5	Gen Step Up Base	E8760		0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10S		0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10S		8,297	3,201	5,096	282	4,815	3,594	858	323	39	0
9	Distrib Function	D60Sub		0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign		9	0	9	0	9	2	0	0	8	0
11	Total		419.1,432	8,306	3,201	5,106	282	4,824	3,596	858	323	47	0
	Distribution												
12	Generat Step Up	STRATH		0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10S		0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub		586	245	338	24	314	257	58	(1)	0	3
15	Direct Assign	Dir Assign		1	0	1	0	1	0	0	1	0	0
16	Total Substations			587	245	339	24	315	257	58	(0)	0	3
17	Overhead Lines	POL		1,197	761	376	52	323	265	58	0	0	61
18	Underground	PUL		2,108	1,556	545	99	446	365	80	0	0	7
19	Line Transformers	P68		0	0	0	0	0	0	0	0	0	0
20	Services	P69		284	256	28	8	20	20	0	0	0	0
21	Meters	C12WM		0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0	0	0	0	0
23	Total		419.1,432	4,177	2,818	1,288	184	1,104	907	197	(0)	0	71
24	**General & Common Plant**	PTD	419.1,432	6,089	2,472	3,563	214	3,348	2,471	609	242	27	54
25	**Total AFUDC**			33,500	13,321	20,017	1,160	18,857	13,913	3,430	1,358	156	162
	Labor Allocator												
	Production												
26	Other Prod - Cap	D10S		61,563	23,748	37,815	2,090	35,725	26,670	6,365	2,399	291	0
27	Other Prod - Ene	E8760		158,053	47,312	110,194	4,974	105,219	75,417	19,620	9,260	923	548
28	Total		500 through 557	219,616	71,059	148,009	7,065	140,944	102,087	25,985	11,658	1,214	548
	Transmission												
29	Stepup Subtrans	P5161A		807	262	543	26	517	375	95	43	4	2
30	Bulk Power Subs	D10S		21,081	8,132	12,949	716	12,233	9,133	2,180	821	100	0
31	Total		560 through 571	21,888	8,394	13,492	742	12,750	9,507	2,275	864	104	2
	Distribution												
32	Superv & Eng	ZDTS	580, 590	6,043	3,481	2,297	280	2,017	1,617	348	47	5	265
33	Load Dispatch	D10S	581	6,927	2,672	4,255	235	4,019	3,001	716	270	33	0
34	Substation	P61	582, 592	6,174	2,516	3,625	242	3,383	2,647	652	82	2	33
35	Overhead Lines	POL	583, 593	10,967	6,971	3,441	480	2,961	2,428	533	0	0	555
36	Underground Lines	PUL	584, 594	10,285	7,590	2,659	484	2,175	1,782	393	0	0	36
37	Line Transformer	P68	595	1,218	860	353	65	288	273	15	0	0	4
38	Meter	C12WM	586, 597	3,648	2,425	1,215	361	854	803	50	1	1	8
39	Cust Installation	ZDTS	587	3,585	2,065	1,363	166	1,196	959	207	28	3	157
40	Street Lighting	P73	585, 596	1,050	0	0	0	0	0	0	0	0	1,050
41	Miscellaneous	OXDTS	588	7,608	4,546	2,649	353	2,297	1,880	401	15	1	412
42	Total			57,505	33,128	21,856	2,665	19,191	15,390	3,315	443	44	2,521
43	**Cust Accounting**	C11WA	901,902,903,904,905	8,129	6,760	1,337	755	582	574	8	0	0	33
44	**Sales Expense**	C11P10	912	0	0	0	0	0	0	0	0	0	0
45	**Admin & General**	LABOR	920,921,922,923,924,	156,977	61,127	94,263	5,746	88,517	65,091	16,114	6,617	695	1,587
46	**Service & Inform**	C11P10	908, 909	1,243	743	485	60	425	313	75	34	3	15
47	**Labor**			465,357	181,211	279,441	17,032	262,409	192,961	47,770	19,616	2,061	4,705

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INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	59.78%	39.04%	4.87%	34.17%	25.18%	6.00%	2.72%	0.28%	1.17%
2	Peaking Plant Capacity	D10S	100.00%	38.58%	61.42%	3.40%	58.03%	43.32%	10.34%	3.90%	0.47%	0.00%
3	57% Dmd; 43% Energy: Sales & I	D57E43	100.00%	29.93%	69.72%	3.15%	66.57%	47.72%	12.41%	5.86%	0.58%	0.35%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	29.93%	69.72%	3.15%	66.57%	47.72%	12.41%	5.86%	0.58%	0.35%
5	20%D10T; 80%D60Sub	T20D80	100.00%	41.17%	58.39%	3.89%	54.50%	43.76%	9.97%	0.67%	0.09%	0.44%
6	Labor w/o (or w/) A&G	LABOR	100.00%	38.94%	60.05%	3.66%	56.39%	41.47%	10.27%	4.22%	0.44%	1.01%
7	Net Plant In Service	NEPIS	100.00%	42.81%	56.09%	3.59%	52.50%	39.01%	9.51%	3.56%	0.41%	1.10%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	59.75%	34.83%	4.63%	30.19%	24.71%	5.27%	0.20%	0.01%	5.42%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	35.39%	63.99%	3.45%	60.54%	44.20%	11.09%	4.75%	0.51%	0.62%
10	Production Plant	P10	100.00%	31.81%	67.92%	3.20%	64.72%	46.76%	11.96%	5.43%	0.56%	0.27%
11	Production Plant Wo Nuclear	P10WoN	100.00%	32.36%	67.39%	3.22%	64.18%	46.48%	11.83%	5.31%	0.55%	0.25%
12	Total P51 & P61A	P5161A	100.00%	32.47%	67.29%	3.22%	64.07%	46.43%	11.80%	5.28%	0.55%	0.24%
13	Distribution Plant	P60	100.00%	65.20%	31.65%	4.45%	27.20%	22.35%	4.62%	0.22%	0.01%	3.15%
14	Distr Substn Plant	P61	100.00%	40.75%	58.71%	3.91%	54.80%	42.87%	10.56%	1.33%	0.03%	0.54%
15	Line Transformer Plant	P68	100.00%	70.64%	29.00%	5.31%	23.68%	22.44%	1.24%	0.00%	0.00%	0.36%
16	Services Plant	P69	100.00%	90.13%	9.87%	2.99%	6.88%	6.88%	0.00%	0.00%	0.00%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	63.57%	31.38%	4.38%	27.00%	22.14%	4.86%	0.00%	0.00%	5.06%
18	Real Est & Property Tax	PT0	100.00%	43.13%	55.84%	3.61%	52.23%	38.84%	9.43%	3.54%	0.41%	1.03%
19	Produc, Trans & Distrib	PTD	100.00%	40.60%	58.52%	3.52%	55.00%	40.58%	10.00%	3.98%	0.44%	0.88%
20	Dist Plt Undground Lines	PUL	100.00%	73.80%	25.85%	4.70%	21.14%	17.33%	3.82%	0.00%	0.00%	0.35%
21	Rate Base (Non-Column)	RTBASE	100.00%	42.85%	56.08%	3.59%	52.49%	38.98%	9.52%	3.58%	0.41%	1.08%
22	Stratified Hydro Baseload	STRATH	100.00%	31.41%	68.30%	3.19%	65.11%	46.97%	12.06%	5.52%	0.56%	0.29%
23	Transmission & Distrib	TD	100.00%	53.44%	44.78%	3.99%	40.79%	31.54%	7.13%	1.85%	0.28%	1.78%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	57.61%	38.01%	4.63%	33.37%	26.76%	5.76%	0.77%	0.08%	4.38%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	308,380	120,084	185,178	11,287	173,891	127,870	31,656	12,999	1,366	3,118
26	Dis O&M w/o Sup, Cust Install & M	OXDTS	89,114	53,249	31,035	4,130	26,905	22,016	4,700	178	12	4,830
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,360,344	835,430	1,510,368	81,375	1,428,993	1,043,301	261,696	112,028	11,968	14,546
28	Total P51 & P61A	P5161A	131,550	42,714	88,514	4,236	84,278	61,074	15,529	6,949	725	322
29	Produc, Trans & Distrib	PTD	19,664,862	7,984,125	11,507,120	692,217	10,814,903	7,979,206	1,966,607	781,719	87,372	173,618
30	Transmission & Distrib	TD	7,991,058	4,270,729	3,578,378	318,519	3,259,859	2,520,252	570,061	147,527	22,020	141,951
31	Labor Dis w/o Sup & Eng, Cust In:	ZDTS	47,876	27,581	18,196	2,219	15,977	12,813	2,760	368	37	2,099

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Northern States Power Company

2022 Class Cost of Service Study Detail ($000)

	EXTERNAL ALLOCATORS	Extern:	1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
1	Customers - Ave Monthly	C11	100.00%	87.76%	10.17%	6.53%	3.63%	3.59%	0.04%	0.00%	0.00%	2.08%
2	Cust Acctg Wtg Factor	C11WA	100.00%	83.15%	16.44%	9.29%	7.16%	7.06%	0.09%	0.00%	0.00%	0.40%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	66.48%	33.30%	9.89%	23.42%	22.00%	1.36%	0.04%	0.02%	0.21%
4	Sec & Pri Customers	C61PS	100.00%	89.22%	10.35%	6.65%	3.70%	3.67%	0.04%	0.00%	0.00%	0.43%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.26%	4.49%	3.85%	0.64%	0.63%	0.01%	0.00%	0.00%	0.25%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	94.92%	5.08%	3.27%	1.80%	1.80%	0.00%	0.00%	0.00%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.25%	10.32%	6.65%	3.67%	3.67%	0.00%	0.00%	0.00%	0.43%
8	Summer Peak Resp KW	D10S	100.00%	38.58%	61.42%	3.40%	58.03%	43.32%	10.34%	3.90%	0.47%	0.00%
9	Transmission Demand %	D10T	100.00%	35.82%	63.86%	3.34%	60.52%	44.74%	10.68%	4.63%	0.48%	0.33%
10	Winter Peak Resp KW	D10W	100.00%	31.93%	67.29%	3.25%	64.04%	46.73%	11.16%	5.66%	0.49%	0.78%
11	Alternative Production Allocator	1CP	100.00%	38.58%	61.42%	3.40%	58.03%	43.32%	10.34%	3.90%	0.47%	0.00%
12	Sec, Pri & TT, Class Coin kW @ S	D60Sub	100.00%	41.82%	57.63%	4.02%	53.61%	43.87%	9.88%	-0.13%	0.00%	0.55%
13	Sec & Pri, Cl Coin kW (no Min Sys	D61PS	100.00%	36.63%	63.04%	3.36%	59.68%	48.22%	11.47%	0.00%	0.00%	0.33%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	74.46%	25.18%	3.70%	21.48%	15.72%	5.76%	0.00%	0.00%	0.36%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	74.45%	25.55%	2.07%	23.48%	23.48%	0.00%	0.00%	0.00%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	49.35%	50.39%	3.62%	46.78%	46.78%	0.00%	0.00%	0.00%	0.25%
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%	29.93%	69.72%	3.15%	66.57%	47.72%	12.41%	5.86%	0.58%	0.35%
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	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	30.92%	68.63%	3.11%	65.519%	49.87%	11.54%	3.45%	0.66%	0.46%
21	Present Rev	R01	100.00%	37.41%	61.72%	3.50%	58.22%	43.54%	9.92%	4.30%	0.46%	0.87%
22	Late Fee Revenue Allocator	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

	EXTERNAL DATA		1=2+3+10 MN	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 9 Demand	6 Second	7 Primary	8 Tr Transf	9 Trans	10 St Ltg
23	Customers - B Basis	C10	1,329,086	1,185,737	137,584	88,362	49,222	48,719	479	15	9	5,765
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,355,363	1,189,448	137,784	88,563	49,222	48,719	479	15	9	28,131
25	Mo Cus Wtd By Cus Acct	C11WA	1,430,425	1,189,448	235,212	132,844	102,368	100,941	1,348	51	29	5,765
26	Cust Acctg Wtg Factor	C11WAF	13.98	1.00	12.98	1.50	11.48	2.07	2.81	3.38	3.22	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign S	C12	1,329,763	1,189,448	137,784	88,563	49,222	48,719	479	15	9	2,531
28	Mo Cus Wtd By Mtr Invest	C12WM	170,408,154	113,292,404	56,754,041	16,849,089	39,904,952	37,492,155	2,313,203	62,595	36,999	361,709
29	Meter Invest / Cust Factor	C12WMF	14,311	95	14,073	190	13,883	770	4,829	4,173	4,111	143
30	Sec & Pri Customers	C61PS	1,329,062	1,185,737	137,560	88,362	49,198	48,719	479	0	0	5,765
31	% Served by Primary Single Phase		0.0%	73.59%	0.00%	39.93%	0.00%	11.80%	18.18%	0.00%	0.00%	39.28%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	915,928	872,539	41,124	35,286	5,838	5,751	87	0	0	2,265
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,249,160	1,185,737	63,423	40,882	22,541	22,541	0	0	0	0
34	Secondary Customers	C62Sec	1,328,583	1,185,737	137,081	88,362	48,719	48,719	0	0	0	5,765
35	Summer Peak Resp KW	D10S	25,491	9,833	15,658	866	14,793	11,043	2,636	993	121	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,581,601	6,385,863	333,614	6,052,249	4,473,606	1,067,963	462,852	47,828	32,536
37	Winter Peak Resp KW	D10W	4,141	1,322	2,787	135	2,652	1,935	462	234	20	32
38	Alternative Production Allocator	1CP	25,491	9,833	15,658	866	14,793	11,043	2,636	993	121	0
39	Sec, Pri & TT, Class Coin kW @ S	D60Sub	6,484,843	2,711,697	3,737,224	260,498	3,476,726	2,844,845	640,463	(8,582)	0	35,922
40	Sec & Pri, Class Coin kW (w/o Mir	D61PS	5,827,222	2,134,644	3,673,508	195,604	3,477,904	2,809,781	668,123	0	0	19,070
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	2,109,554	1,570,805	531,259	78,112	453,147	331,670	121,477	0	0	7,491
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	10,486,622	7,807,161	2,679,460	216,700	2,462,760	2,462,760	0	0	0	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	4,935,395	5,039,122	361,546	4,677,576	4,677,576	0	0	0	25,483
44	Annual Billing kW	D99	49,661.671	0	49,662	0	49,662	37,725	7,863	3,579	496	0
45	Summer Billing kW	D99S	18,171.839	0	18,172	0	18,172	13,729	2,954	1,301	188	0
46	Winter Billing kW	D99W	31,489.831	0	31,490	0	31,490	23,996	4,909	2,278	308	0
47	Non-Coinc Pk Second	DN-Sec	13,617,552	7,807,161	5,791,322	468,371	5,322,950	5,322,950	0	0	0	19,070
48	MWh Sales	E99	28,303,153	8,293,789	19,887,270	834,457	19,052,812	13,451,925	3,625,493	1,798,766	176,628	122,095
49	MWh Sales Excl CIP Exempt	E99XCIP	26,826,760	8,293,789	18,410,877	834,295	17,576,581	13,377,890	3,095,346	926,718	176,628	122,095
50	Late Fee Revenue Allocation	LateFee	100.00%	86.07%	13.84%	5.65%	8.19%	7.75%	0.41%	0.01%	0.02%	0.09%

Tab No.	CCOSS Spreadsheet Tab Label	Spreadsheet Tab Description
1	CCOSS Worksheet Tab Index	Describes the data and analysis within each CCOSS worksheet tab
2	CCOSS Summary	Shows a summary of CCOSS results; specifically Unadjusted Revenue Requirement, Adjusted Revenue Requirements and Revenue Deficiency are shown by Customer Class.
3	Err_Chk	Conducts error checking to insure costs and revenues are appropriately allocated to Cost Classification, Function, Subfunction and Customer Classes. Also insures the class subtotals are correct.
4	RR-TOT	Shows detailed revenue requirement calculations for all functions and cost classifications combined.
5	RR-CUS	Shows detailed revenue requirement calculations for costs that have been classified as Customer-Related. It includes the customer-related portion of primary and secondary distribution lines/transformers, service line costs, metering, meter reading, billing, customer service costs and costs of back office support. RR-Cus = RR-Svc_Drop + RR-En_Svc
6	RR-DMD	Shows detailed revenue requirement calculations for costs that have been classified as Demand-Related.
7	RR-ENE	Shows detailed revenue requirement calculations for costs that have been classified as Energy-Related. RR-ENE = RR-On + RR-Off
8	RR-Genco	Shows detailed revenue requirement calculations for costs that have been functionalized as being generation related. This includes all energy-related costs and all fixed production costs. RR-Genco = RR-ENE + RR-G_Dmd
9	RR-G_Dmd	Shows detailed revenue requirement calculations for all generation costs except those that are classified as Energy-Related. RR-G_Dmd = RR-Base + RR_Summ + RR_Wint
10	RR-Base	Shows detailed revenue requirement calculations for the fixed cost of generation plant investment and purchased capacity costs which have been stratified as Energy-Related.
11	RR-Summ	Shows detailed revenue requirement calculations for the fixed cost of generation plant investment and purchased capacity costs which have been stratified as Capacity-Related and are associated with the summer system peak load requirements.
12	RR-Wint	Shows detailed revenue requirement calculations for the fixed cost of generation plant investment and purchased capacity costs which have been stratified as Capacity-Related and are associated with the winter system peak load requirements.
13	RR-On	Shows detailed revenue requirement calculations for costs of fuel and purchases of energy for on-peal hours.
14	RR-Off	Shows detailed revenue requirement calculations for costs of fuel and purchases of energy for off-peal hours.
15	RR-Transco	Shows detailed revenue requirement calculations for the transmission function. It includes costs of transmission lines used to transport power from its origin generation stations or delivery points to the high voltage side of the distribution substations.
16	RR-Disco	Shows detailed revenue requirement calculations for the Distribution function. It includes costs of distribution substations and the capacity-related portion of primary and secondary distribution lines and transformers. RR-Disco = RR-Psub + RR-Prim + RR_Sec
17	RR-Psub	Shows detailed revenue requirement calculations for Distribution substations.
18	RR-Prim	Shows detailed revenue requirement calculations for the capacity-related portion of primary voltage conductors, transformers and related facilities.
19	RR-Sec	Shows detailed revenue requirement calculations for the capacity-related portion of secondary voltage conductors, transformers and related facilities.
20	RR-Svc_Drop	Shows detailed revenue requirement calculations for the customer-related portion of primary and secondary distribution lines/transformers, service line costs and metering.
21	RR_En_Svc	Shows detailed revenue requirement calculations for costs of meter reading, billing, customer service and costs of back office support.
22	JCOSS-Complete Rev Req	Shows overall JCOSS cost of service results. Also shows a line-item comparison of selected revenue and cost items between the JCOSS and CCOSS models
23	JCOSS-Basic Inputs	Provides basic financial inputs from the Jurisdictional Cost of Service Study. Inputs include state and federal tax rates and capital structure inputs. Calculations are also included to insure JCOSS and CCOSS revenue requirement and deficiency results tie-out.
24	JCOSS-Detailed Inputs	Provides detailed JCOSS line item FERC code level inputs to the CCOSS model. All detailed rate base and expense related line items are provided in this tab.
25	JCOSS-Financial Details	Provides the derivation of line item details including base level data and all adjustments applied to derive the final JCOSS detailed inputs

Tab No.	CCOSS Spreadsheet Tab Label	Spreadsheet Tab Description
26	JCOSS-Labels	Shows JCOSS line-item labels used in the Revenue Analysis RIS System
27	JCOSS-O&M for Labor	Has JCOSS O&M data for calculating the LABOR internal allocation factor that is used for allocating several cost items to customer class
28	JCOSS-Plant Stratified	Shows the results of the plant stratification analysis. Based on the Plant Stratification results, baseload versus peaking ratios are applied to various cost items that stratified
29	Alloc-Input Data	Provides external allocator data for input to the CCOSS model. Data is provided for all external allocators including production and transmission allocators, distribution capacity allocators and customer allocators.
30	Alloc-Prod Trans	Provides allocator calculations for all fixed production and transmission cost allocators. Note calculation of the D10S allocator is based on class hourly loads that are coincident with the forecasted MISO 2020 peak hour for Local Resource Zone 1.
31	Alloc-Dist Cap	Provides allocator calculations for all distribution costs that are capacity-related.
32	Alloc-Cust	Provides allocator calculations for all allocators that are used to allocate customer-related costs.
33	Alloc-E8760	Has the calculations for the E8760 energy allocation factor.
34	InputData-NSP Syst Peaks	Has the TY2020 forecasted hourly loads for the NSP System. Also calculates the NSP System Load Factor
35	InputData-NSP Syst Peaks Sorted	Has the TY2020 forecasted hourly loads for the NSP System sorted by load level. This tab is used to identify hours that should be used for the D10S allocator.
36	InputData-8760 Loads	Has TY2020 Minnesota forecasted hourly loads by customer class. Hourly loads are shown with and without load management. This tab also shows monthly system coincident and class coincident peaks by customer class. Summaries are shown with and without load management.
37	InputData-E8760	Has the hourly load data and hourly marginal energy costs for calculating the E8760 allocator. The hourly loads used in the calcultion of the E8760 allocator assume no load management
38	InputData-Cust Max kW	Based on a query of the customer billing system has the sum of individual customer maximum actual demands by customer class for demand billed customers. Loss factors are applied to these quantities. For the customer classes that are not demand billed, the data is provided by the Load Research Dept. These quanitites are used in calculating certain distribution capacity allocators.
39	InputData-Cust Fcst	Has the results of the 2020 customer forecast by customer class. These results were used in calculation allocation factors for customer-related costs.
40	InputData-MWh Sales Fcst	Has the results of the 2020 kWh sales forecast by customer class.
41	InputData-kWh Fcst CIP Exmpt	Has the sales forecast for CIP exempt customers. When allocating CIP costs these sales are excluded when calculating the CIP cost allocation factor.
42	InputData-Summ Wint	Has the NSP System monthly peaks that are used to are used to split Production Capacity costs into summer and winter seasons.
43	InputData-OthProdOM	Has the split of Other Production O&M costs into energy-related and capacity-related components using the "Location" method.
44	InputData-PlantStrat2019	Has the plant stratification analysis results. These peaking versus baseload results were applied as shown on the "JCOSS-Plant Stratified" and "InputData-OthProdOM" tabs.
45	InputData-MeterCost	Has average metering costs by customer class. Metering costs include the cost of meters, current transformers and voltage transformers. These costs were used in calculating the meter cost allocation factor.
46	InputData-Dist1Ph3Ph	Shows the percent of customers that are served off 3 phase primary distribution lines versus 1 phase distribution lines.
47	InputData-OHUGSvc	Shows the results of the analysis that shows the percent of C&I customers that are served by an overhead versus underground service. C&I customers that are served by an underground service own the service and shouldn't be allocated these costs.
48	InputData-OHLtg	Shows the results of an analysis that quantifies the amount of pole p1ant investement that should be directly assigned to the lighting class.
49	InputData-PSHLMeters	Based on a query of the customer billing system, shows the number of street lighting meters that is used in the allocation of metering costs.
50	InputData-CustAcctgWt	Relative weighting by customer class for costs of meter reading, billing and collections and uncollectible accounts.
51	InputData-LateFees	Based on budgeted late fees for C&I versus Residential customers and a query of 2014 late fee revenues by customer class, provides an allocation factor for late fee revenues.
52	InputData-T&D Direct Assign $	Based on the customers served by direct assignment distribution substations and transmission radials, provides allocation factors for allocating these costs.

Tab No.	CCOSS Spreadsheet Tab Label	Spreadsheet Tab Description
53	InputData-T&D Direct Assign MW	Has the MW loads of customers that have Distribution Substation costs directly assigned to them. These MW loads are excluded from the loads that are used to calculate the D60Sub Allocator
54	InputData-Dist Cap Vs Cust	Based on the results of the Minimum System and Zero Intercept studies, shows how distribution plant investment should be split into capacity and customer-related components
55	InputData-2020 Pres Revenue	Has present revenues by customer class with and without load management discounts. Also has the amount of the economic development discounts by customer class.
56	InputData-2020 Prop Revenue	Has proposed revenues by customer class with and without load management discounts. Also has the amount of the economic development discounts by customer class.

Results of Xcel Energy Minimum Distribution System & Zero Intercept Studies

1. Overview

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

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

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

Table 1
FERC Classification of Distribution Plant Investment

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

As shown in the table above, primary lines, secondary lines and secondary transformers are classified as both "demand" and "customer" related costs. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system.

The Minimum System and Zero Intercept methods are two widely used methods for determining the percent of distribution plant investment that is customer-related and allocated to class with a customer based allocation factor, versus the percent of costs that are capacity-related and allocated to class with a demand based allocator. These methods are described on pages 86-96 of the NARUC Electric Utility Cost Allocation Manual.

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

2. Steps for Completing a Minimum System Study

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

> **Step 1:** Determine the minimum sized conductor, transformer and service that are installed on the distribution system.
>
> **Step 2:** Determine the installed cost per unit for the minimum sized plant. Installed costs include material costs, labor costs and equipment costs.
>
> **Step 3:** Multiply the cost per unit of the minimum sized plant by the total inventory of each plant type
>
> **Step 4:** The total cost of the minimum sized plat it divided by the total cost of the actual sized distribution plant in the field. This ratio is deemed to be the customer-related portion of distribution plant investment, with the balance being the capacity-related portion.
>
> The assumed minimum property unit configurations used in the minimum system study are shown in Section VIII – Minimum System Study and Zero Intercept Analysis of Company witness Ms. Kelly Bloch's testimony.

3. Steps for Completing a Zero Intercept Study

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

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

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

  - o kVa for Transformers

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

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

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

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

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

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

4. Minimum System and Zero Intercept Data Sources

The data sources used to complete both studies are described in detail in Section VIII – Minimum System Study and Zero Intercept Analysis of Ms. Bloch's direct testimony. In short, data on the types, configurations, sizes and quantities of distribution equipment were obtained by querying the Company's Geographic Information System (GIS). Data on the installed unit costs for each equipment configuration were obtained by analyzing the costs distribution work orders that were completed from 2007-2018. The goal in this data gathering step was to obtain installed costs for equipment configuration that comprise 90% of the population for a given property unit (i.e. underground primary conductor).

5. **Analysis Results**

The data and results of the minimum system and zero intercept studies are shown in Attachments A to P of Schedule 11.

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

	% of Costs Classified as Customer-Related	
Property Unit	**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%	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 (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 xx on Page 28). 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 2016 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 50 feet.

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

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

8. Load Carrying Capability of Minimum System Design

As stated in Section VIII – Minimum System Study and Zero Intercept Analysis, Part F – Load-Carrying Capability of Ms. Bloch's testimony, the Company used the same 1.5 kW per customer for the load carrying capability 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

Phase	Configuration Details Underground Primary	Footage	% of 1 Phase Footage	Cummulative % of 1 Phase Footage	% of All UG Primary	Cummulative % of All UG Primary
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%**	

Phase	Config Details Underground Primary	Footage	% of 3 Phase Footage	Cummulative % of 3 Phase Footage	% of All UG Primary	Cummulative % of All UG Primary
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

Configurateion Details Underground Secondary	Total Footage	% of UG Secondary	Cummulative % UG Secondary
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

Configuration Details 1 Phase Underground Transformers	Number of Transformers	1 Phase %	Cummulative Percent of 1 Phase Transformers	% of All Underground Transformers	Cummulative Percent of All Transformers
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%	

Configuration Details 2 Phase Underground Transformers	Number of Transformers	2 Phase %	Cummulative Percent of 2 Phase Transformers	% of All UG Transformers	Cummulative Percent of All Transformers
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%	

Configuration Details 3 Phase Underground Transformers	Number of Transformers	3 Phase %	Cummulative Percent of 3 Phase Transformers	% of All UG Transformers	Cummulative Percent of All Transformers
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%	

Phase	Configuration Details Overhead Primary	Footage	% of 1 Phase Footage	Cummulative % of 1 Phase Footage	% of All OH Primary	Cummulative % of All OH Primary
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	% of 3 Phase Footage	Cummulative % of 3 Phase Footage	% of All OH Primary	Cummulative % of All OH Primary
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 Promary	70,203,456				

Inventory of Overhead Secondary by Conductor Configuration

Configuration Details Overhead Secondary	Total Footage	% of Total Overhead Secondary	Cummulative % Overhead Secondary
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 Quadraplex	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

Config Details 1 Phase Overhead Transformers	Number of Transformers	1 Phase %	1 Phase Cummulative %	% of All Overhead Transformers	Cummulative Percent of All OH Transformers
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%
Total 1 Phase Transformers	99,728	100.00%			

Config Details 2 Phase Overhead Transformers	Number of Transformers	2 Phase %	2 Phase Cummulative %	% of All Overhead Transformers	Cummulative Percent of All OH Transformers
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%
Total 2 Phase Transformers	5,295	100.00%			

Config Details 3 Phase OH Transformers	Number of Transformers	3 Phase %	3 Phase Cummulative %	% of All OH Transformers	Cummulative Percent of All OH Transformers
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%
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

Overhead 1 Phase	Number OH 1 Phase	% of OH 1 Phase	Cummulative % of OH 1 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 1 phase 34.5/13.8 kV 500 kVA	170	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%	7.13%	500	$44,095	$4,321,333
OH 1 phase 34.5/12.47 kV 50 kVA	81	8.17%	35.18%	5.89%	50	$10,067	$815,400
OH 1 phase 19.92/7.2 kV 167 kVA	66	6.65%	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%	3.85%	50	$10,067	$533,533
OH 1 phase 34.5/13.8 kV 250 kVA	62	6.25%	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%	3.35%	100	$20,005	$920,219
OH 1 phase 34.5/12.47 kV 333 kVA	57	5.75%	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%	3.35%	250	$31,029	$1,427,314
OH 1 phase 34.5/13.8 kV 333 kVA	46	4.64%	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

Overhead 2 Phase	Number OH 2 Phase	% of OH 2 Phase	Cummulative % of OH 2 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 2 phase 34.5/13.8 kV 1000 kVA	7	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%	0.29%	500	$28,550	$114,200
OH 2 phase 34.5/12.47 kV 1000 kVA	4	7.02%	26.32%	0.29%	1000	$66,139	$264,557
OH 2 phase 34.5/12.47 kV 500 kVA	4	7.02%	33.33%	0.29%	500	$46,543	$186,171
OH 2 phase 34.5/13.8 kV 200 kVA	4	7.02%	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

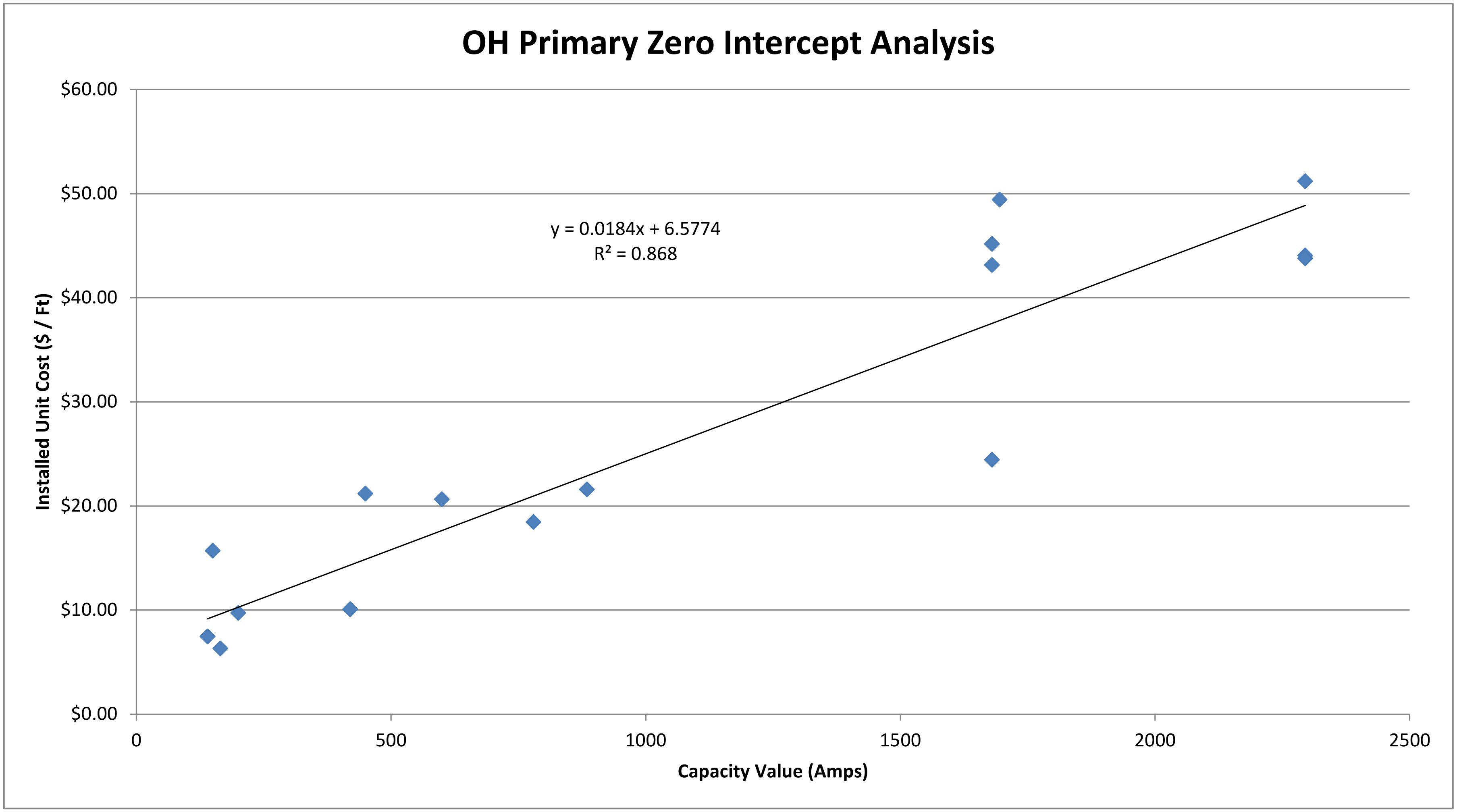
Overhead 3 Phase	Number OH 3 Phase	% of OH 3 Phase	Cummulative % of OH 3 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 3 phase 34.5/13.8 kV 1500 kVA	29	8.90%	8.90%	2.11%	1500	$81,703	$2,369,385
OH 3 phase 13.8/4.16 kV 1000 kVA	25	7.67%	16.56%	1.82%	1000	$56,982	$1,424,559
OH 3 phase 34.5/12.47 kV 1500 kVA	18	5.52%	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%	1.02%	500	$33,865	$474,106
OH 3 phase 34.5/12.47 kV 1000 kVA	12	3.68%	30.06%	0.87%	1000	$70,068	$840,812
OH 3 phase 34.5/13.8 kV 500 kVA	11	3.37%	33.44%	0.80%	500	$42,141	$463,553
OH 3 phase 13.8/12.47 kV 1500 kVA	10	3.07%	36.50%	0.73%	1500	$93,865	$938,647
OH 3 phase 13.8/12.47 kV 5000 kVA	10	3.07%	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%	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

Underground 1 Phase	Number UG 1 Phase	% of UG 1 Phase	Cummulative % of UG 1 Phase	% of All UG Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
UG 1 phase 19.92/7.2 kV 167 kVA	2	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%	2.08%	250	$11,106	$22,211
UG 1 phase 19.92/7.97 kV 500 kVA	2	15.38%	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**

Underground 3 Phase	Number UG 3 Phase	% of UG 3 Phase	Cummulative % of UG 3 Phase	% of All UG Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
UG 3 phase 34.5/13.8 kV 5000 kVA	31	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%	16.67%	3750	$381,179	$6,098,869
UG 3 phase 34.5/12.47 kV 5000 kVA	11	13.25%	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%	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 Transfo	**1,471**					$58,201	**$85,614,116**

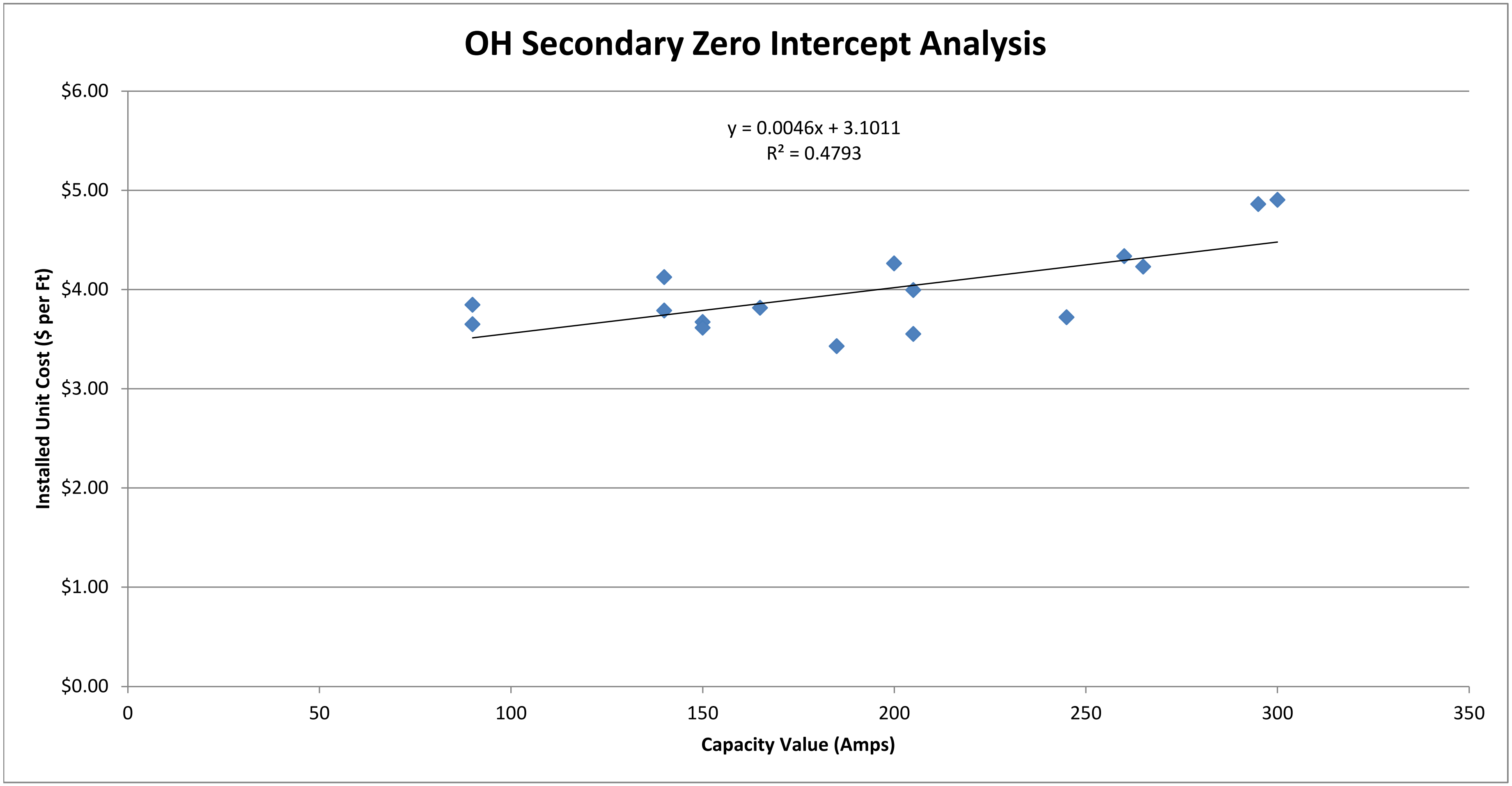
Northern States Power Company

Overhead Primary Zero Intercept Analysis



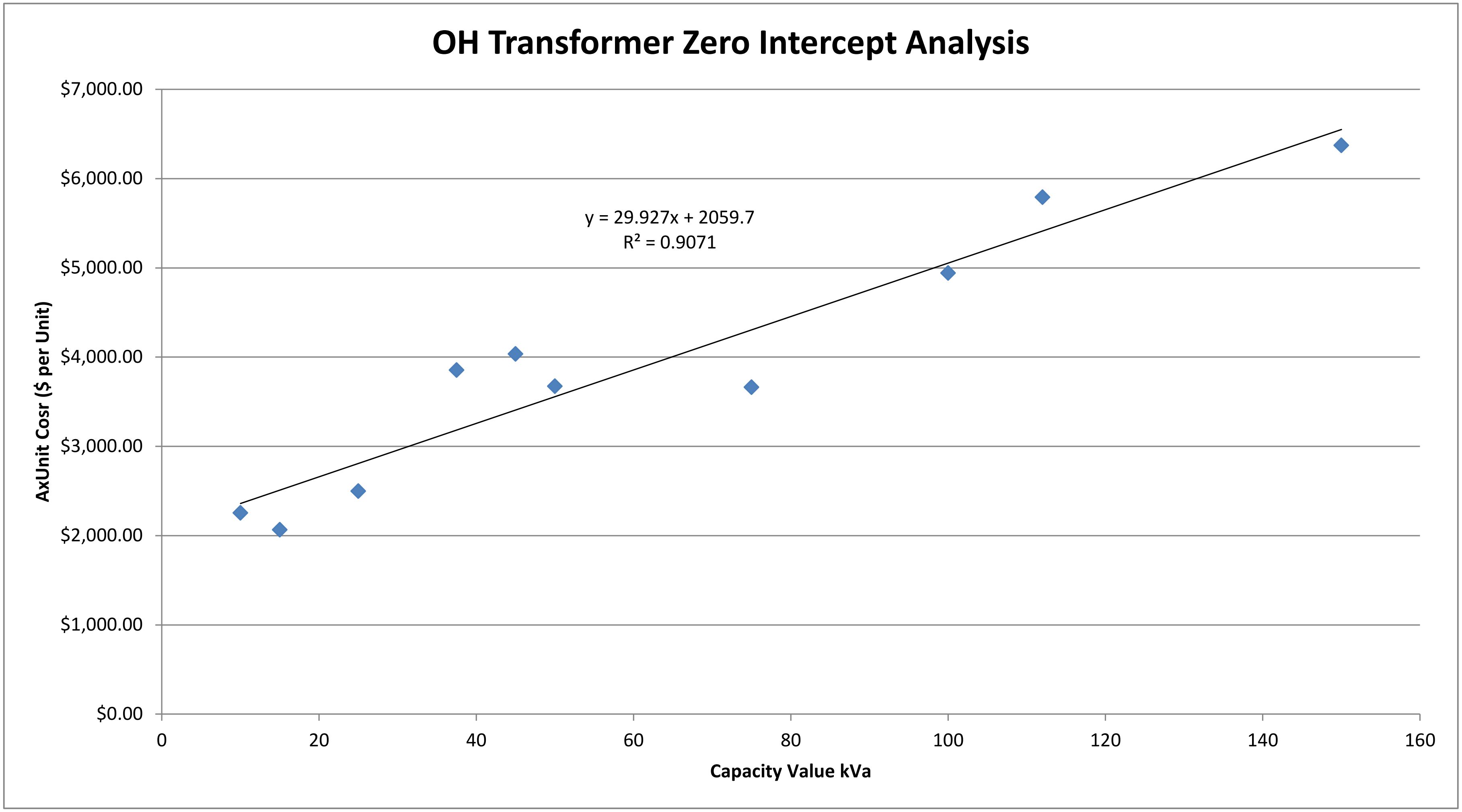
Northern States Power Company

Overhead Secondary Zero Intercept Analysis



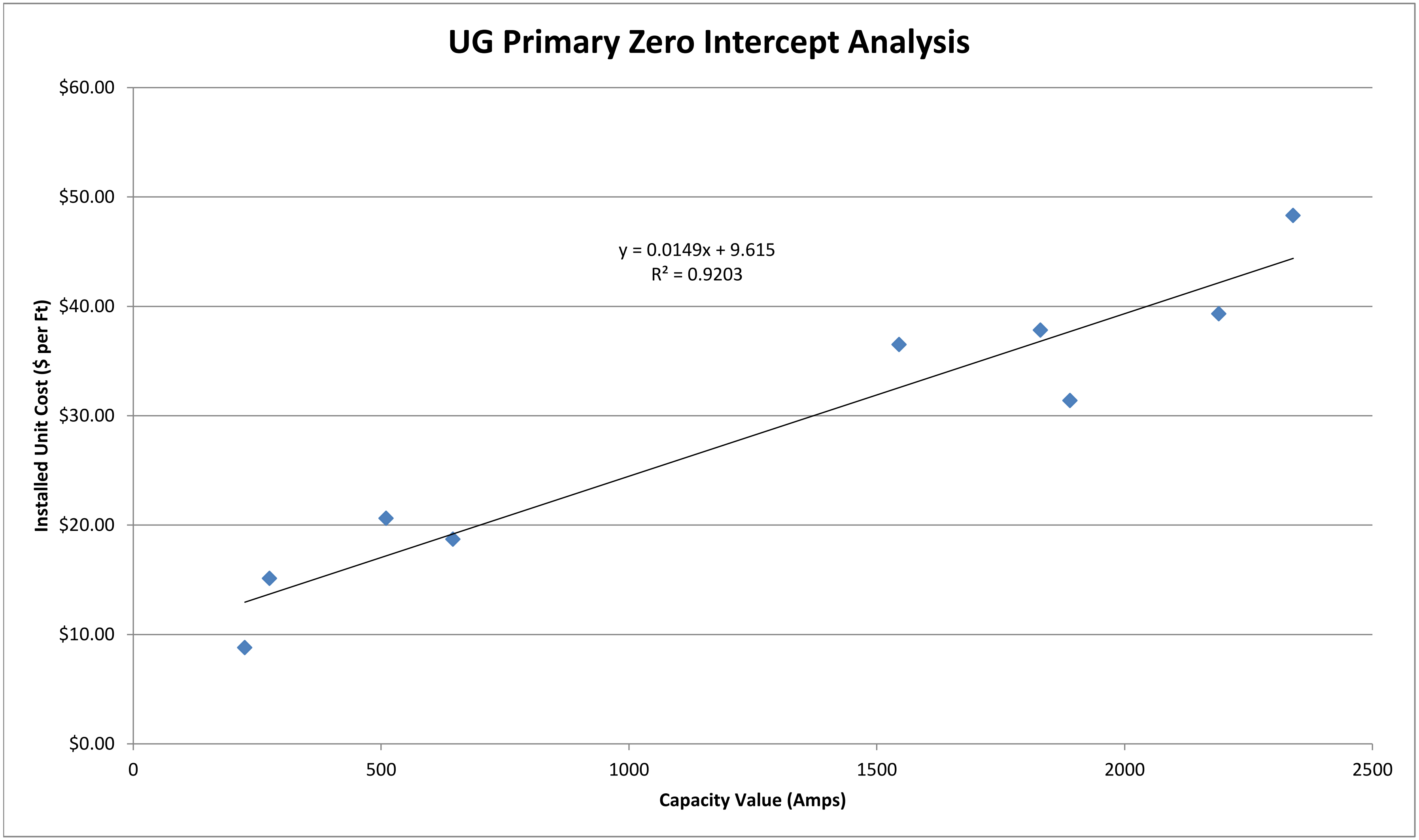
Northern States Power Company

Overhead Transformer Zero Intercept Analysis



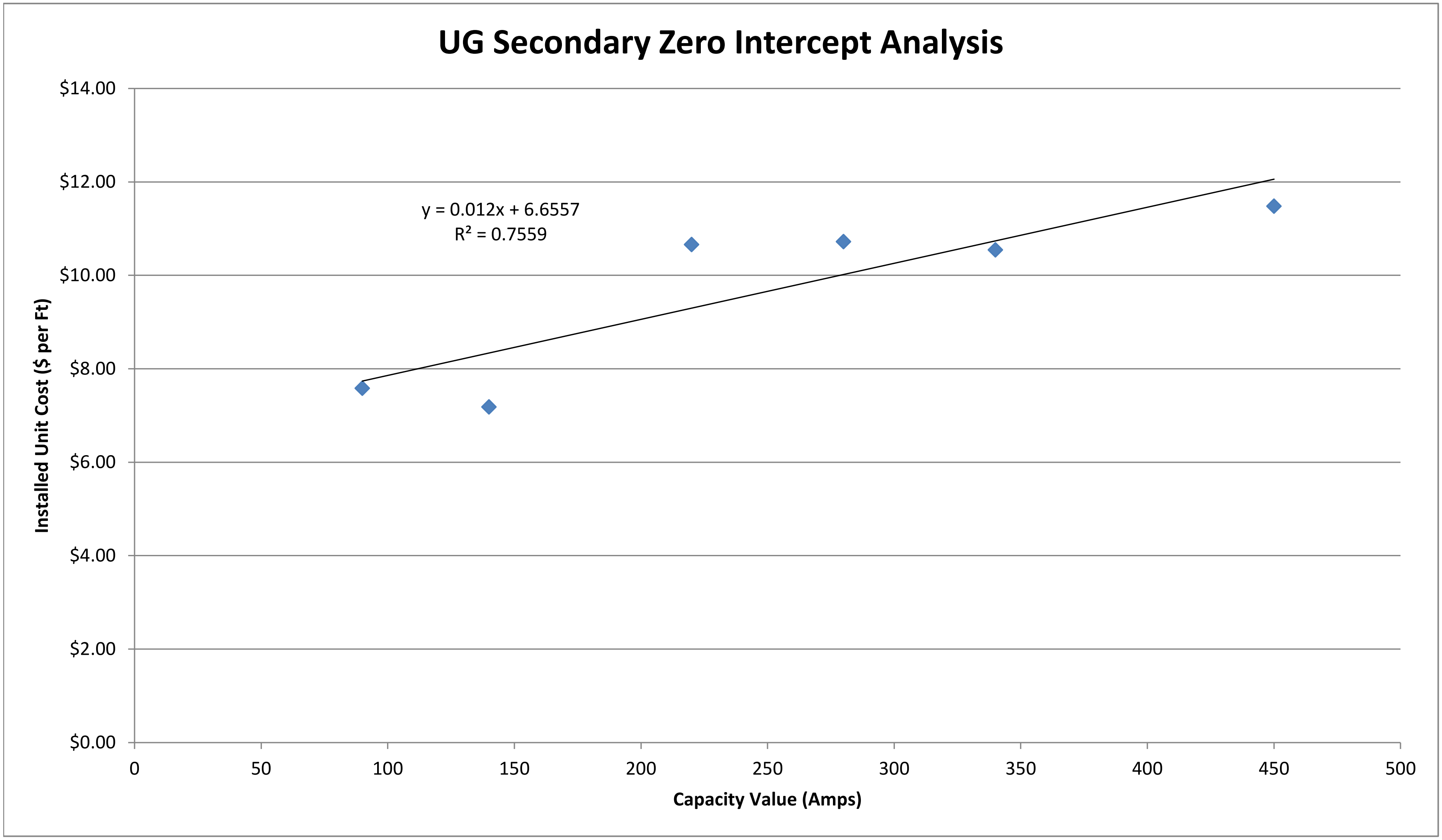
Northern States Power Company

Underground Primary Zero Intercept Analysis



Northern States Power Company

Underground Secondary Zero Intercept Analysis



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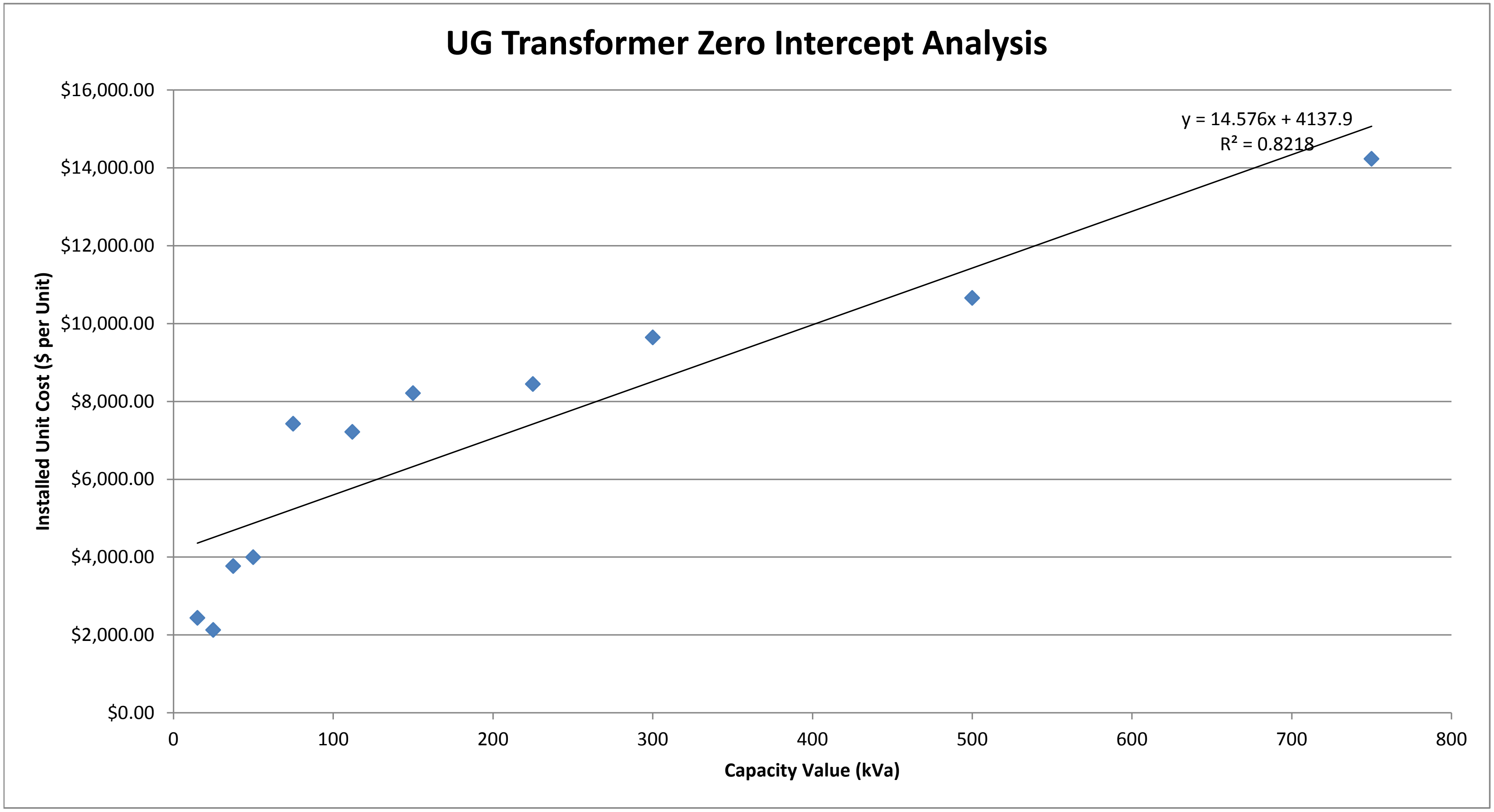
Underground Transformer Zero Intercept Analysis



Northern States Poser Company

Docket No. E002/GR-19-564
Exhibit___(MAP-1), Schedule 10
Attachment N

Minimum System / Zero Intercept Distribution System Cost Analysis

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cummulative % 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 CUWD 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	1,648,191	2.3%	53.0%	165	$6.28	$10,358,351	$6.58	$10,845,100	$9.70	$15,979,393
6		**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%	1680	$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	$38,740,952	$9.70	$57,081,714
9	OH Primary	3 ph	336 ACSR 3ph	3,804,835	5.4%	76.9%	1695	$49.41	$187,989,678	$6.58	$25,035,814	$9.70	$36,888,281
10	OH Primary	3 ph	2/0 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 CUWD 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	1/0 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	4/0 CU 3ph	831,557	1.2%	88.5%	1680	$24.41	$20,294,478	$6.58	$5,471,643	$9.70	$8,062,031
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	$13,823,980	$6.58	$2,064,623	$9.70	$3,042,058
18	OH Primary		336 AAC 3ph	219,522	0.3%	89.9%	1680	$45.14					
19	OH Primary		556 AAC 3ph	120,854	0.2%	90.1%	2295	$51.19					
20	OH Primary	**Total 3 Phase Primary in Sample**		26,041,066				**$30.68**	$798,931,902		$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
20										**% Customer Related Costs Using Zero Intercept =**	**34.92%**	**% Customer Related Costs Using Minimum System =**	**51.44%**

Minimum System / Zero Intercept Distribution System Cost Analysis

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cummulative % of Total Population Footage/ Transformers**	**Load Carrying Capacity (A, or kVA)**	**Installed Unit Cost**	**Total Cost**	**Y Intercept Minimum Cost per Unit**	**Total Cost Using Y Intercept Unit Cost**	**Minimum System Cost per Unit**	**Total Cost Using Minimum System Cost per Unit**
21	OH Secondary		2 ACSR Open Wire	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	8,445,823	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	$18,428,782	$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	$23,060,765
26	OH Secondary		4 CU Open Wire	5,809,064	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	968,987	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**		70,710,119				**$3.96**	$280,127,022		$219,201,369		$251,025,306
38										**% Customer Related Costs Using Zero Intercept =**	**78.25%**	**% Customer Related Costs Using Minimum System =**	**89.61%**

Northern States Poser Company

Minimum System / Zero Intercept Distribution System Cost Analysis

Docket No. E002/GR-19-564
Exhibit___(MAP-1), Schedule 10
Attachment N

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cummulative % 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	$80,826,837	$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	$44,591,376
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%	75.8%	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	696	0.6%	89.7%	45	$4,034	$2,807,811	$2,060	$1,433,760	$2,253	$1,568,088
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**		**$208,375,180**		**$227,897,709**
50										**% Customer Related Costs Using Zero Intercept =**	**72.66%**	**% Customer Related Costs Using Minimum System =**	**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**	**$352,922,919**		**$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	4,426,067	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	$4,782,287
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										**% Customer Related Costs Using Zero Intercept =**	**58.14%**	**% Customer Related Costs Using Minimum System =**	**53.19%**

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	Property Unit	Phase	Config Details	Conductor Footage/Number Transformers	% of Total Population Footage/ Transformers	Cummulative % of Total Population Footage/ Transformers	Load Carrying Capacity (A, or kVA)	Installed Unit Cost	Total Cost	Y Intercept Minimum Cost per Unit	Total Cost Using Y Intercept Unit Cost	Minimum System Cost per Unit	Total Cost Using Minimum System Cost per Unit
66	UG Secondary		6 AL Duplex	5,314,262	44.3%	44.3%	90	$7.58	$40,294,985	$6.66	$35,392,987	$10.66	$56,637,927
67	UG Secondary		4/0 AL Triplex	3,261,342	27.2%	71.6%	340	$10.55	$34,395,627	$6.66	$21,720,539	$10.66	$34,758,477
68	UG Secondary		2/0 AL Triplex	900,641	7.5%	79.1%	280	$10.72	$9,657,679	$6.66	$5,998,268	$10.66	$9,598,779
69	UG Secondary		1/0 AL Triplex	566,227	4.7%	83.8%	220	$10.66	$6,034,686	$6.66	$3,771,070	$10.66	$6,034,686
70	UG Secondary		6 CU Open Wire	350,384	2.9%	86.7%	140	$7.18	$2,516,918	$6.66	$2,333,559	$10.66	$3,734,298
71	UG Secondary		350 AL Triplex	382,109	3.2%	89.9%	450	$11.48	$4,387,853	$6.66	$2,544,848	$10.66	$4,072,415
72		**Total UG Secondary in Sample**		10,774,966				**$9.03**	**$97,287,748**		**$71,761,272**		**$114,836,584**
73										**% Customer Related Costs Using Zero Intercept =**	**73.76%**	**% Customer Related Costs Using Minimum System =**	**100.00%**
74	UG Transformers		1 Phase Wye 50 kVA	24,744	30.4%	30.4%	50	$3,994	$98,835,224	$4,138	$102,390,672	$2,440	$60,385,072
75	UG Transformers		1 Phase Wye 25 kVA	18,632	22.9%	53.3%	25	$2,129	$39,672,528	$4,138	$77,099,216	$2,440	$45,469,393
76	UG Transformers		1 Phase Wye 37.5 kVA	9,273	11.4%	64.7%	37.5	$3,770	$34,954,679	$4,138	$38,371,674	$2,440	$22,629,760
77	UG Transformers		3 Phase Wye/Wye 150 kVA	3,569	4.4%	69.1%	150	$8,212	$29,307,560	$4,138	$14,768,522	$2,440	$8,709,761
78	UG Transformers		3 Phase Wye/Wye 300 kVA	3,453	4.2%	73.4%	300	$9,642	$33,293,491	$4,138	$14,288,514	$2,440	$8,426,675
79	UG Transformers		3 Phase Wye/Wye 75 kVA	3,365	4.1%	77.5%	75	$7,423	$24,979,015	$4,138	$13,924,370	$2,440	$8,211,921
80	UG Transformers		3 Phase Wye/Wye 500 kVA	2,889	3.6%	81.0%	500	$10,656	$30,784,844	$4,138	$11,954,682	$2,440	$7,050,294
81	UG Transformers		1 Phase Wye 15 kVA	2,480	3.0%	84.1%	15	$2,440	$6,052,173	$4,138	$10,262,240	$2,440	$6,052,173
82	UG Transformers		3 Phase Wye/Wye 112 kVA	2,094	2.6%	86.7%	112	$7,217	$15,111,535	$4,138	$8,664,972	$2,440	$5,110,182
83	UG Transformers		3 Phase Wye/Wye 225 kVA	1,874	2.3%	89.0%	225	$8,446	$15,828,535	$4,138	$7,754,612	$2,440	$4,573,296
84	UG Transformers		3 Phase Wye/Wye 750 kVA	1,506	1.9%	90.8%	750	$14,231	$21,431,235	$4,138	$6,231,828	$2,440	$3,675,231
85		**Total UG Transformers in Sample**		73,879				**$4,740.87**	**$350,250,819**		**$305,711,302**		**$180,293,758**
86										**% Customer Related Costs Using Zero Intercept =**	**87.28%**	**% Customer Related Costs Using Minimum System =**	**51.48%**
87		**Total OH and UG Transformers in Sample**		175,032				**$3,640**	**$637,040,895**		**$514,086,482**		**$408,191,467**
88										**% Customer Related Costs Using Zero Intercept =**	**80.70%**	**% Customer Related Costs Using Minimum System =**	**64.08%**

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

Docket No. E002/GR-19-564
Exhibit___(MAP-1),Schedule 10
Attachment O

		[1]	[2]	[3] = [1] x [2]	[4] = % of Line 11	[5] = [Col 5 Line 11 - Line 10] x [4]	[6] = (Customer % from Attachment N)	[7]	[8]
Line	**Overhead Distribution Plant**	**Total Footage**	**Average Cost per Foot**	**Total Replacement Cost ($000)**	**% of Total Replacement Cost**	**Test Year Plant in Service ($000)**	**% Customer or Capacity Related**	**Final Test Year Plant in Service ($000)**	**% of Total Overhead Dist Costs**
1	OH Primary Single Phase Capacity						65.08%	$143,947	15.95%
2	OH Primary Single Phase Customer						34.92%	$77,221	8.56%
3	Total OH Primary Single Phase	40,617,685	$10.39	$421,870	25.72%	$221,168	100.00%	$221,168	
4	OH Primary Multi Phase Capacity						65.08%	$309,713	34.32%
5	OH Primary Multi Phase Customer						34.92%	$166,146	18.41%
6	Total OH Primary Multi Phase	29,585,771	$30.68	$907,682	55.34%	$475,859	100.00%	$475,859	
7	OH Secondary Capacity						21.75%	$35,425	3.93%
8	OH Secondary Customer						78.25%	$127,454	14.12%
9	Total OH Secondary	78,423,646	$3.96	$310,685	18.94%	$162,879	100.00%	$162,879	
10	Street Lighting (see Line 9 of Schedule XX)					$42,578		$42,578	4.72%
11	Total Overhead (see Schedule X, Page 4, Column 1, Line XX)			$1,640,238	100.00%	$902,484		$902,484	100.00%

		[1]	[2]	[3] = [1] x [2]	[4] = % of Line 22	[5] = [Col 5 Line 22 - Line 21] x [4]	[6] = (Customer % from Attachment N)	[7]	[8]
	Underground Distribution Plant	**Total Footage**	**Average Cost per Foot**	**Total Replacement Cost ($000)**	**% of Total Replacement Cost**	**Test Year Plant in Service ($000)**	**% Customer or Capacity Related**	**Final Test Year Plant in Service ($000)**	**% of Total Underground Distr Costs**
12	UG Primary Single Phase Capacity						46.81%	$247,789	17.11%
13	UG Primary Single Phase Customer						53.19%	$281,596	19.44%
14	Total UG Primary Single Phase	29,603,387	$12.23	$362,100	36.55%	$529,385	100.00%	$529,385	
15	UG Primary Multi Phase Capacity						46.81%	$356,138	24.59%
16	UG Primary Multi Phase Customer						53.19%	$404,727	27.94%
17	Total UG Primary Multi Phase	22,445,564	$23.19	$520,433	52.53%	$760,865	100.00%	$760,865	
18	UG Secondary Capacity						26.24%	$41,508	2.87%
19	UG Secondary Customer						73.76%	$116,691	8.06%
20	Total UG Secondary	11,984,490	$9.03	$108,209	10.92%	$158,199	100.00%	$158,199	
21	Street Lighting					$0		$0	0.00%
22	Total Underground			$990,742		$1,448,449		$1,448,449	100.00%

		[1]	[2]	[3] = [1] x [2]	[4] = % of Line 27	[5] = [Col 5 Line 27] x [4]	[6] = (Customer % from Attachment N)	[7]	[8]
	Transformers	**Number of Transformers**	**Average Cost Per Transformer**	**Total Replacement Cost ($000)**	**% of Total Replacement Cost**	**Test Year Plant in Service ($000)**	**% Customer or Capacity Related**	**Final Test Year Plant in Service ($000)**	**% of Total Transformer Costs**
23	Primary	1,471	$58,201	$85,614	10.84%	$44,017	100% Capacity	$44,017	10.84%
24	Secondary Capacity						36.28%	$131,409	32.35%
25	Secondary Customer						63.72%	$230,769	56.81%
26	Total Secondary	193,554	$3,640	$704,453	89.16%	$362,178	100.00%	$362,178	89.16%
27	Total Transformers			$790,067		$406,195		$406,195	100.00%

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	**Minimum Conductor Configuration**	**Minimum Footage per Service**	**Installed Cost per Foot**	**Number of Customers**	**Total Minimum Installed Cost ($000)**	**Test Year Plant Investment Distribution Services ($000)**	**Customer Component Distribution Services**	**Capacity Component Distribution Services**
1	OH Services	2 ACSR Triplex	50	$4.03	783,638	$157,903			
2	UG Services	1/0 Triplex	50	$2.81	445,800	$62,635			
3	Total Services				1,229,438	$220,538	$284,339	77.56%	22.44%

Northern States Power Company

Docket No. E002/GR-19-564
Exhibit___(MAP-1), Schedule 11
Page 1 of 1

Test Year Ending December 31, 2020
Primary Distribution Cost Allocator Calculations

					Customer Class				
Line	**Primary Distribution Cost**	**Allocator Derivation**	**Allocator Label**	**MN**	**Resid**	**Commercial Non Demand**	**C&I Demand Secondary**	**C&I Demand Primary**	**Ltg**
1	Customer Portion of **Multi-Phase** Primary Lines	Number of Customers	C61PS	1,308,418	1,166,597	87,551	48,273	479	5,518
2	Capacity Portion of **Multi-Phase** Primary Lines	Class Coincident Peak Demands	D61PS	5,962,429	2,182,570	200,622	2,874,362	685,456	19,419
3	% of Customers Served by Primary **Single Phase** Lines				**73.6%**	**39.9%**	**11.8%**	**18.2%**	**39.3%**
4	Customer Portion of **Single-Phase** Primary Lines	line 1 x line 3	C61PS1Ph	901,370	858,455	34,962	5,698	87	2,167
5	Capacity Portion of Single-Phase Primary Lines	line 2 x line 3	D61PS1Ph	2,157,736	1,606,071	80,116	339,293	124,628	7,628
6	Customer Portion of **Multi-Phase** Primary Lines	Cost Allocator %	C61PS	100.0%	89.2%	6.7%	3.7%	0.0%	0.4%
7	Capacity Portion of **Multi-Phase** Primary Lines	Cost Allocator %	D61PS	100.0%	36.6%	3.4%	48.2%	11.5%	0.3%
8	Customer Portion of **Single-Phase** Primary Lines	Cost Allocator %	C61PS1Ph	100.0%	95.2%	3.9%	0.6%	0.0%	0.2%
9	Capacity Portion of **Single-Phase** Primary Lines	Cost Allocator %	D61PS1Ph	100.0%	74.4%	3.7%	15.7%	5.8%	0.4%

Renewable Programs Capacity Credit Cost Summary

	2020	2021	2022
Windsource	$779,021	$779,021	$244,236
Renewable*Connect Pilot	$1,339,107	$1,364,067	$1,397,980
Renewable*Connect Standard	$0	$0	$1,232,287
Renewable*Connect High Off-Peak	$0	$0	$1,232,287
Total Capacity Credit	$2,118,129	$2,143,088	$4,106,790

		2020	2021	2022
[1]	Levelized CT Carrying Costs	$54.48	$54.48	$54.48
[2]	MISO Accredited Capacity per kW of Wind Capacity [1]	15.20%	15.20%	15.20%
[3]	Costs Avoided (Line 1 * Line 2)	$8.28	$8.28	$8.28
[4]	Avg Annual Windsource Capacity Factor	34.82%	34.82%	34.82%
[5]	Availability Factor	95%	95%	95%
[6]	Hour/Year	8,760	8,760	8,760
[7]	Annual Hour of Operation (Line 4 * Line 5 * Line 6)	2,898	2,898	2,898
[8]	**Capacity Credit $ per kWh (Line 3 / Line 7)**	**$0.00286**	**$0.00286**	**$0.00286**
[9]	Windsource Generation Forecast (kWh)	272,385,117	272,385,117	85,397,356
[10]	Windsource Capacity Credit (Line 8 * Line 9) [2]	**$779,021**	**$779,021**	**$244,236**

[1] Source: "Midwest ISO Planning Year 2018-2019 Loss of Load Expectation Study Report and Planning Year 2018-2019 Wind Capacity Credit.
[2] This Windsource Credit is included in the TY2020, TY2021, and TY2022 Revenue Requirements.

		2020	2021	2022
[1]	Renewable*Connect Pilot Sales (kWh)	179,000,000	178,000,000	178,000,000
[2]	Renewable*Connect Government Pilot Sales (kWh)	10,407,000	10,407,000	10,407,000
[3]	Total Renewable*Connect Pilot Sales (kWh) (Line 1 + Line 2	189,407,000	188,407,000	188,407,000
[4]	Capacity Credit $ per kWh*	$0.00707	0.00724	0.00742
[5]	**Total Renewable*Connect Capacity Credit (Line 3 * Line**	**$1,339,107**	**$1,364,067**	**$1,397,980**

*Approved in Docket E002/M-15-985

Renewable*Connect - Standard Capacity Credit

		2020	2021	2022
[1]	Renewable*Connect - Standard Sales (kWh)	0	0	231,198,300
[2]	Capacity Credit $ per kWh *	$0.00000	$0.00000	0.00533
[3]	**Renewable*Connect Capacity Credit (Line 1 * Line 2)**	**$0**	**$0**	**$1,232,287**

*Approved in Docket E002/M-19-33

Renewable*Connect - High Off-Peak Capacity Credit

		2020	2021	2022
[1]	Renewable*Connect - Standard Sales (kWh)	0	0	231,198,300
[2]	Capacity Credit $ per kWh*	$0.00000	$0.00000	0.00533
[3]	**Renewable*Connect Capacity Credit (Line 1 * Line 2)**	**$0**	**$0**	**$1,232,287**

*Approved in Docket E002/M-19-33

Northern States Power Company

CIP Program Rider--Conservation Cost Recovery Charge (CCRC) and Conservation Adjustment Factor (CAF) Calculations

TY20 -2020 CIP Extension Plan Filed Spending[1]	
Business	$ 42,339,176
Residential	$ 29,703,346
Low-Income	$ 2,490,344
Planning	$ 8,151,775
Research, Evaluations, & Pilots	$3,751,148
Regulatory Assessments	$1,974,981
EUI	$ 0
Alternative Filings	$13,960,630
2020 Filed CIP Budget	**$ 102,371,401**
TY20 kWh	
TY 2020 MN kWh Sales	28,838,346,945
TY 2020 CIP Exempt Cust Sales (Est.)	1,476,393,030
Net CIP Sales	27,361,953,916
CCRC = TY20 CIP Expense / TY2020 kWh Sales	**0.3741** **¢ per kWh**

	Current	**TY 2020**	**Difference**
CCRC (cents/kWh)	**0.3133** [2]	**0.3741** [3]	0.0608
CIP Adjustment Factor (cents/kWh)	**0.1682** [4]	**0.1074** [5]	-0.0608
Total (cents/kWh)	0.4815	0.4815	0

[1] The 2020 CIP Budget was filed with the 2020 CIP Extension Plan on July 1, 2019 in Docket No. E,G002/CIP-16-115.

[2] The 0.3133 cents/kWh CCRC approved by MPUC on June 12, 2017 in Docket No. E002/GR-15-826.

[3] The 0.3741 cents/kWh CCRC for TY 2020 determined above.

[4] The 0.1682 cents/kWh CIP Adjustment Factor for 2019/2020 was approved by MPUC on July 19, 2019 in Docket No. E002/M-19-258.

[5] The 0.1074 cents/kWh CIP Adjust Factor for TY 2020 determined as shown above: (0.1682 CIP Adjust plus 0.0608 Difference in CCRC).

Norhern States Power Company
Electric Utility - Minnesota
Test Year Ending December 31, 2020
Excess Footage and Winter Construction Revenue Impact

Tariff	Description	Pres Price	Prop Price	2018 Units	Pres $	Prop $	Differ
5.1	**Standard Installation and Extension Rules**						
	Excess service charge - Services	$7.90	$11.00	46,324	$365,960	$509,564	$143,604
	Excess service charge - Excess single phase primary	$8.00	$11.00	-	$0	$0	$0
	Excess service charge - Excess three phase primary	$13.90	$19.00	-	$0	$0	$0
5.1.A.2.	**Winter Construction**						
	Per Frost Burner	$600.00	$650.00	930	$558,000	$604,500	$46,500
	Per Trench Foot	$3.80	$7.30	73,454	$279,125	$536,214	$257,089
			REVENUE IMPACT		**$1,203,085**	**$1,650,278**	**$447,193.40**

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	$ 7.93	38.55%	$10.99
Excess single phase primary or secondary extension	$ 8.15	38.55%	$11.29
Excess three phase primary or secondary extension	$ 13.62	38.55%	$18.87

TARIFF	Current Electric tariff per circuit foot	Proposed Tariff Charge per circuit foot
Services	$7.90	**$11.00**
Excess single phase primary or secondary extension	$8.00	**$11.00**
Excess three phase primary or secondary extension	$13.90	**$19.00**

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 with installation
3 Phase primary or secondary = 1/0 alum 3/0 primary w/installation
Engineering and Supervision Overhead: average rate is 38.55%

Before January 1st
Typically burn for 2 days
A burner requires 3 - 20 lb propane tanks to run for 2 days (20 lb tank = 5 gallons)

process	Crew or Vehicle	time to do	cost pr hr	cost	cost per gallon	gallons used	propane cost	Totals
Set burner	Two man crew	1	$80.00	$80.00				
Re-tank burner	Two man crew	0	$80.00	$0.00				
Remove burner	Two man crew	0.5	$80.00	$40.00				
Total Labor				$120.00				
Labor Loading @ 76.87%				$92.24				
Labor w/Loading				$212.24				$212.24
Vehicle & Equipment	truck and trailer	1.5	37	$55.50				$55.50
Propane Cost					1.6	15	$24.00	$24.00
Costs (before E&S)				$291.74				$291.74
E&S cost @ 38.55%				$112.47				$112.47
Total Cost				$404.21				$404.21

After January 1st
Typically burn for 3 days

process	Crew or Vehicle	time to do	cost pr hr	cost	cost per gallon	gallons used	propane cost	Totals
Set burner	Two man crew	1	$80.00	$80.00				
Re-tank burner	Two man crew	1	$80.00	$80.00				
Remove burner	Two man crew	0.5	$80.00	$40.00				
Total Labor				$200.00				
Labor Loading @ 76.87%				$153.74				
Labor w/Loading				$353.74				$353.74
Vehicle & Equipment	truck and trailer	2.5	37	$92.50				$92.50
					1.6	22.5	$36.00	$36.00
Propane Cost								
Costs (before E&S)				$482.24				$482.24
E&S cost @ 38.55%				$185.90				$185.90
Total Cost				$668.14				$668.14

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

Before and after January Costs	Percentage	
$404.21	10%	$40.42
$668.14	90%	$601.33
		$641.75
Billing Labor		$10.00
Producing Bill		$0.10
Postage		$0.39
Total Cost of a Burner		**$652.24**

2019 Winter Construction Per foot Charge

Winter Construction billed for in Winter of 2017.

Average Cost per foot Winter 2017 Services =	$17.43	per foot
Average Cost per foot non Winter Months Services	$10.14	per foot
Difference for Winter Construction	**$7.29**	per foot

2019 Updates to Charges

TARIFF							
Current Electric Charge			**Updated Costs**		**Proposed Tariff Charge**		
Service Extension	**$ 600.00**	**per frost burner**	**$652.24**	**per frost burner**	**Thawing**	**$ 650.00**	**per frost burner**
	$ 3.80	**plus per trench foot**	**$7.29**	**plus per trench foot**	**Service, Primary, or Secondary distribution extension**	**$ 7.30**	**per foot**

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Google Data Center Incremental Cost Analysis

		kWh Sales					Incremental Energy Costs ($ per kWh)				
		Summer		Winter			Summer		Winter		
		1	2	3	4	5 = 1 + 2 +3 +4	6	7	8	9	10
Year	Peak Load (kW)	On Peak	Off Peak	On Peak	Off Peak	Total kWh Usage	On Peak	Off Peak	On Peak	Off Peak	Total Incremental Energy Costs
	[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS										
1											
2											
											HIGHLY CONFIDENTIAL TRADE SECRET ENDS]

	11	12	13	14	15	16 = 10 + 12 + 13 + 14 + 15		17	18	19	20	21	22 = 21 - 16
Year	Peak Load (kW)	Total Incremental Capacity Costs	Juris. Cost Allocation Increase to MN	MISO Costs	Total Incremental Transmission Costs	Total Incremental Costs		Rate Forecast ($ per kWh)	Revenues Before Discount	Rate Forecast under Discount ($ per kWh)	Total Discount	Revenues Remaining After Discount	Contribution to Margin
	[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS												
1													
2													
													HIGHLY CONFIDENTIAL TRADE SECRET ENDS]

Google Data Center Rate Case Incremental Cost Analysis

		kWh Sales					Incremental Energy Costs ($ per kWh)				
		Summer		Winter			Summer		Winter		
		1	2	3	4	5 = 1 + 2 +3 +4	6	7	8	9	10
Year	Peak Load (kW)	On Peak	Off Peak	On Peak	Off Peak	Total kWh Usage	On Peak	Off Peak	On Peak	Off Peak	Total Incremental Energy Costs
	[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS										
1											
2											
					HIGHLY CONFIDENTIAL TRADE SECRET ENDS]						

	11	12	13	14	15	16 = 10 + 12 + 13 + 14 + 15		17	18	19	20	21	22 = 21 - 16
Year	Peak Load (kW)	Total Incremental Capacity Costs	Juris. Cost Allocation Increase to MN	MISO Costs	Total Incremental Transmission Costs	Total Incremental Costs		Rate Forecast ($ per kWh)	Revenues Before Discount	Rate Forecast under Discount ($ per kWh)	Total Discount	Revenues Remaining After Discount	Contribution to Margin
	[HIGHLY CONFIDENTIAL TRADE SECRET BEGINS												
1													
2													
													HIGHLY CONFIDENTIAL TRADE SECRET ENDS]