Direct Testimony and Schedules
Michael A. Peppin

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company,
a Minnesota corporation
For Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-10-____
Exhibit___(MAP-1)

Class Cost of Service Study
and
Selected Rate Design

December 20, 2010

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael A. Peppin. My business address is 414 Nicollet Mall, 7th Floor, Minneapolis, Minnesota, 55401.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Xcel Energy Services Inc., which is the service company subsidiary of Xcel Energy Inc. My title is Principal Pricing Analyst. I am providing testimony on behalf of Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), operating in North Dakota.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include more than 29 years of experience with the Company 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 IN THIS PROCEEDING?

A. The purpose of my testimony is to present the Company's proposed Class Cost of Service Study ("CCOSS") and selected items from the Company's proposed rate design. Company witness Mr. Steven V. Huso will present the remainder of the Company's proposed rate design changes.

Q. MR. PEPPIN, PLEASE LIST EACH OF THE COST OF SERVICE AND RATE DESIGN TOPICS YOU WILL ADDRESS IN YOUR TESTIMONY.

A. The topics I will address are as follows:

- Class Cost of Service Studies
  - Proposed Test Year 2011 Class Cost of Service Study
  - Proposed 2012 Step-In Class Cost of Service Study

- Selected Rate Design Revisions
  - Voltage Discounts
  - General Rules and Regulations

II. CLASS COST OF SERVICE STUDIES

A. Proposed Class Cost of Service Study

Q. HOW DOES THE COMPANY'S PROPOSED CCOSS COMPARE WITH THAT APPROVED BY THE NORTH DAKOTA PUBLIC SERVICE COMMISSION ("COMMISSION") IN THE COMPANY'S LAST GENERAL ELECTRIC RATE CASE, CASE NO. PU-07-776?

A. The Company's proposed CCOSS reflects new test year ("TY") 2011 data, but no changes have been made in the cost-study process or allocation methods approved by the Commission in the last general electric rate case.

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

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

Q. PLEASE SUMMARIZE THE RESULTS OF THE PROPOSED CCOSS.

A. Table 1 below provides a summary of the CCOSS results at the class level. More information is shown on Exhibit___(MAP-1), Schedule 3. The detailed CCOSS output is shown on Exhibit___(MAP-1), Schedule 4.

Table 1 below shows the resulting class cost responsibilities (as opposed to proposed revenue responsibilities, which are addressed by Mr. Huso). These CCOSS results indicate what change from present rates would be necessary to result in equal rates of return on investment for each class (i.e. the increase in rates necessary to produce equalized rates of return).

Table 1

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

UNADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Ltg
[1]	Unadjusted Rate Revenue Requirement (CCOSS page 2, line 2)	184,155	72,449	11,728	98,374	1,604
[2]	Incr Misc Chrgs and Late Pay (CCOSS page 7, line 21+ line 23)	122	62	9	51	1
[3]	Unadjusted Operating Revenues (line 2 + line 3)	184,277	72,511	11,737	98,425	1,605
[4]	Present Rates (CCOSS page 2, line 3)	164,504	66,011	10,986	85,640	1,867
[5]	Unadjusted Deficiency (line 3 - line 4)	19,773	6,500	751	12,785	(262)
[6]	Defic / Pres (line 5 / line 4)	12.0%	9.8%	6.8%	14.9%	-14.0%
[7]	**Ratio: Class % / Total %**	**1.00**	**0.82**	**0.57**	**1.24**	**-1.17**

CAPACITY COST RESPONSIBILITIES FOR INTERRUPTIBLE RATE DISCOUNT

		Total	Resid	Non-Demand	Demand	Ltg
[8]	Interruption Rate Discounts (CCOSS page 2, line 6)	4,756	718	50	3,988	0
[9]	Interruption Capacity Costs (CCOSS page 2, line 7)	4,756	1,604	282	2,853	17
[10]	Revenue Requirement Shift (line 9 - line 8)	0	886	232	(1,135)	17

ADJUSTED COST RESPONSIBILITIES: TY 2011

		Total	Resid	Non-Demand	Demand	Ltg
[11]	Adjusted Rate Revenue Requirement (line 1 + line 10)	184,155	73,335	11,960	97,239	1,621
[12]	Incr Misc Chrgs and Late Pay (CCOSS page 7, line 21+ line 23)	122	62	9	51	1
[13]	Adjusted Operating Revenues (line 11 + line 12)	184,277	73,397	11,969	97,290	1,622
[14]	Present Rates (line 4)	164,504	66,011	10,986	85,640	1,867
[15]	Adjusted Deficiency (line 13 - line 14)	19,773	7,386	983	11,650	(245)
[16]	Deficiency / Pres Rates (line 15 / line 4)	12.0%	11.2%	8.9%	13.6%	-13.1%
[17]	**Ratio: Class % / Total %**	**1.00**	**0.93**	**0.74**	**1.13**	**-1.09**

ADJUSTED COST RESPONSIBILITIES: 2012 Step-In Adjustment

		Total	Resid	Non-Demand	Demand	Ltg
[18]	Adjusted Rate Revenue Requirement: **2012 Step-In**	188,372	74,992	12,227	99,503	1,650
[19]	Incr Misc Chrgs and Late Pay: **2012 Step-In**	131	69	9	53	1
[20]	Adjusted Operating Revenues (line 18 + line 19)	188,503	75,060	12,237	99,556	1,651
[21]	Present Rates (line 4)	164,504	66,011	10,986	85,640	1,867
[22]	Adjusted Deficiency (line 20 - line 21)	23,999	9,049	1,251	13,916	(216)
[23]	Deficiency / Pres Rates (line 22 / line 21)	14.6%	13.7%	11.4%	16.2%	-11.6%
[24]	**Ratio: Class % / Total %**	**1.00**	**0.94**	**0.78**	**1.11**	**-0.79**

* Figures are rounded to nearest whole numbers.

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

A. The distinction between "adjusted" and "unadjusted" cost responsibilities relates to how the "cost" of interruptible capacity is reflected in the CCOSS. The method used to reflect those costs is the same as that used in the Company's last general electric rate case, Case No. PU-07-776.

Unadjusted cost responsibilities are those that were historically used as the indicators of class cost responsibilities. However, as the size of the Company's interruptible programs grew, it became clear that these traditional unadjusted cost responsibilities did not properly account for the fact that interruptible rate discounts are really the "cost" of this particular source of generation peaking capacity. Therefore, the Company modified the CCOSS to produce adjusted cost responsibilities. The adjusted cost responsibilities appropriately account for the cost of this particular source of peaking capacity. Doing so is appropriate and important, because interruptible rate discounts (lost revenues) are a real cost of service arising from this particular alternative source of peaking capacity.

Q. PLEASE ELABORATE ON WHY INTERRUPTIBLE RATE DISCOUNTS ARE A COST OF GENERATION PEAKING CAPACITY.

A. As the Company indicated in its previous rate case, the economic essence of a utility's "obligation to serve" is to provide low-cost reliable firm electric service. Interruptible "service" is really firm service, attached to which is an after-the-fact purchased-power contract provision. Through this contract provision, the Company has the option to buy back (from willing customers) all or part of their "regulatory entitlement" to firm service. The resulting

capacity purchase transactions occur when, and if, doing so is a cost-effective source of peaking capacity, which 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 DID YOU RECOGNIZE THIS COST IN THE CCOSS?

A. To accomplish this interruptible capacity cost accounting, the Company has added lines to the CCOSS model.

1. Line 8 on Table 1 above and Exhibit___(MAP-1), Schedule 3, labeled "Interruption Rate Discounts," shows the amount of the total interruptible discount originating from each class.
2. Line 9 on page Table 1 above and Exhibit___(MAP-1), Schedule 3, labeled "Interruption Capacity Cost," shows how this interruptible-capacity cost is allocated to the classes using the applicable generation capacity cost allocation factor.
3. The resulting Line 11 on Table 1 above and Exhibit___(MAP-1), Schedule 3, labeled "Adjusted Rate Revenue Requirement," shows the appropriate cost of service for determining class cost responsibilities.

Q. PLEASE EXPLAIN HOW THE RESULTS OF THE COMPANY'S PROPOSED CCOSS ARE USED IN DEVELOPING THE PROPOSED RATES.

A. The Company uses the proposed CCOSS as the basis for evaluating and refining its rate structure. Mr. Huso uses it as a guide in determining the proposed class revenue responsibilities and for determining the proposed rate design for each tariff.

B. Proposed 2012 Step-In Class Cost of Service Study

Q. IN ADDITION TO THE TY 2011 CCOSS DESCRIBED ABOVE, THE COMPANY HAS INCLUDED IN THIS FILING A SECOND 2012 STEP-IN CCOSS. PLEASE EXPLAIN HOW IT COMPARES TO THE TY 2011 CCOSS, AND HOW IT IS USED.

A. The 2012 Step-in CCOSS is based on the TY 2011 CCOSS but includes the Company's request to increase rates, effective January 1, 2012, by an additional $4.2 million. The need for the 2012 Step-in is described by Company witness Ms. Laura McCarten, and the financial adjustments are described by Company witness Ms. Anne E. Heuer in their respective Direct Testimonies. I provide a summary of the results of this 2012 Step-in CCOSS in Table 1, and more information is provided as Exhibit___(MAP-1), Schedule 5. The detailed 2012 Step-in CCOSS output is provided as Exhibit___(MAP-1), Schedule 6.

The purpose of the 2012 Step-in CCOSS, like the TY 2011 CCOSS, is to provide a guide in determining appropriate class cost allocations. Mr. Huso uses it as a guide in determining the proposed class revenue responsibilities and for determining the proposed rate design for each tariff. .

Q. DOES THE RESULT OF THIS 2012 STEP-IN CCOSS INDICATE A MATERIAL IMPACT ON RELATIVE INTER-CLASS COST RESPONSIBILIES?

A. No. There are only small impacts on the relative inter-class cost responsibilities. As Mr. Huso discusses in his testimony, these impacts are not material, and the Company has considered both the TY 2011 and 2012 Step-in class cost responsibilities in developing the proposed class revenue allocation ratios.

To illustrate the similarities in the 2011 TY and 2012 Step-in class cost responsibilities, I draw your attention again to Table 1 above. Lines 11 through 17 show the Cost Responsibilities (total and relative) for the TY 2011 CCOSS. Lines 18 through 24 provide the same analysis for the 2012 Step-in CCOSS. In particular, it is helpful to compare Line 17 for the TY 2011 CCOSS to the corresponding Line 24 for the 2012 Step-in CCOSS. As indicated, these Lines show ratios of class-percent-deficiency to overall-percent-deficiency. In other words, they show the deficiency for each class, relative to the overall deficiency. The fact that these ratios are very similar for TY 2011 and for the 2012 Step-in, and are nearly identical for the two large classes (Residential and Commercial and Industrial Demand ("C&I")), indicates the appropriateness of considering the results of both cost of service studies when allocating revenue responsibility to the customer classes.

III. SELECTED RATE DESIGN REVISIONS

A. Voltage Discounts

Q. WHAT REVISIONS DO YOU PROPOSE TO THE VOLTAGE DISCOUNTS THAT ARE A PART OF THE C&I DEMAND TARIFFS?

A. The results of the TY 2011 CCOSS indicate a decrease in the demand charge discounts (as shown on lines 4 and 6 of page 1 of Exhibit___(MAP-1), Schedule 7) and an increase in energy charge discounts (as shown on columns 4 and 6 of page 2 of Exhibit___(MAP-1), Schedule 7) would move rates closer to the cost of service.

Table 2 below summarizes the cost analysis provided in Exhibit___(MAP-1), Schedule 7. It compares the TY 2011 costs to the present and proposed voltage discounts.

Table 2

Voltage Discount Analysis

C&I Voltage Discounts - Demand			
Rate	**Primary**	**Transmission Transformed**	**Transmission**
CCOSS Revenue Req	$0.34	$0.68	$0.93
Present	$0.85	$1.45	$1.85
Midpoint - between cost and present discount	$0.597	$1.067	$1.389
Proposed	$0.60	$1.10	$1.40
C&I Voltage Discounts - Energy			
Rate	**Primary**	**Transmission Transformed**	**Transmission**
Revenue Req	0.0964¢	0.1989¢	0.2254¢
Present	0.070¢	.10¢	0.15¢
Proposed	0.10¢	0.20¢	0.23¢

Q. THE COMPANY PROPOSES TO ADJUST THE ENERGY DISCOUNTS TO MATCH THE NEW COST LEVELS, BUT IS NOT PROPOSING TO ADJUST THE DEMAND CHARGE DISCOUNTS TO FULLY REFLECT THE NEW LOWER COST LEVELS. PLEASE EXPLAIN WHY.

A. Unlike the energy charge discounts, the demand charge discounts are a function of capital investment costs associated with distribution facilities. Like any cost-of-service item that is driven by capital investments, distribution costs (and the corresponding service-voltage discounts) have a "lumpy" pattern over time. They increase sharply when there is significant new construction investment and then decrease as the asset depreciates. Therefore, when changing the demand discounts, it is appropriate to do so gradually, because

the fluctuating costs can reverse direction between subsequent rate cases. It is for this reason that the Company is proposing a moderated movement toward the current indicated cost level. More specifically, we are proposing to move the demand discounts approximately 50 percent of the way to cost. In contrast, the energy discount reflects the cost of service.

B. 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.

- Service Processing Charge Section 1.2
- Dedicated Switching Charges Section 1.8
- Excess Footage Charge Section 5.1.A.1
- Winter Construction Charges Section 5.1.A.2

The following is an explanation of these proposed changes. A red-line version of all of the proposed changes described below can be reviewed in Volume 2, Proposed Tariffs, of the rate case application.

1. Service Processing Charge--Section 1.2

Q. WHAT REVISIONS ARE BEING PROPOSED FOR THE COMPANY'S SERVICE PROCESSING CHARGE TARIFF?

A. The Company is proposing three revisions in the Service Processing Charge tariff. The first proposal is to increase the Service Reconnection Charge from the present $15.00 to $50.00, as indicated on Sheet No. 6-1 of the General Rules and Regulations. This increase is necessary to reflect the costs

associated with physically reconnecting a customer service line after the customer's service line has been disconnected. This Service Reconnection is distinct from the more common Service Processing activity, where no physical disconnection is involved. Service Reconnections occur where a customer has been disconnected for non-payment or in cases where a customer has requested that their service be disconnected because the premises will be unoccupied for some extended period. The cost analysis supporting the higher costs of reconnection is provided in Exhibit___(MAP-1), Schedule 8, page 1 of 4.

The second revision is the addition of a "Service Relock Charge," detailed on Sheet No. 6-1 of the General Rules and Regulations. A service relock occurs when the Company must return to relock a service that was previously disconnected for non payment, but was reconnected by the customer without Company authorization. Although the costs for Service Relocks are estimated at $53 as indicated in Schedule 8 of Exhibit___(MAP-1), page 1 of 4, the Company is proposing a charge of $100. This higher charge will help discourage these unauthorized reconnections of service by the customers. Unauthorized customer-reconnection of a locked service is dangerous for both the customer and Company employees, who may not realize that a locked service has been re-energized by the customer.

The third revision to Section 1.2 involves some tariff language revisions. These language revisions are:

1. A change in the title from "Service Processing Charge" to "Service Charges," in order to help make it clear that there are three <u>different</u>

charges included. The three are the Service Processing Charge, the Service Reconnection Charge and the Service Relock Charge.

2. Edits to the language of the Service Charge tariff to make the distinction between these three types of charges clear.

3. The addition of two sentences at the end of Section 1.2 to make it clear when either the Service Processing Charge or Service Reconnection Charge applies. The application of one or the other depends on whether a customer requests a simple discontinuance and subsequent reestablishment of electric service within a 12-month period or requests that the service be physically disconnected.

Customer requests for temporary discontinuance of service generally come from those with a summer home not used during the winter months or from customers who move south for part of the winter season.

The language revisions make it clear that for ordinary service discontinuance (i.e. no physically disconnection), the Service Processing Charge of $15.00 applies. However, in cases where the customer requests actual physical disconnection of the service, the higher $50.00 Service Reconnection Charge applies.

2. Dedicated Switching Charges--Section 1.8

Q. IS THE COMPANY PROPOSING A NEW CHARGE ASSOCIATED WITH DEDICATED SWITCHING?

A. Yes, and like most of the special charges included in the Rules and Regulations, the purpose is to help assure that customers who request special kinds of services pay for those services and to avoid having those costs become a burden on other customers.

Q. WHAT IS DEDICATED SWITCHING?

A. Dedicated Switching is a service requested by a few large C&I customers. It typically occurs when a customer needs to perform work on its own facilities and where doing so requires that the electric service be de-energized. This service takes place at a customer-specified date and time, which is often outside of normal business hours. Providing this service requires taking a Company service crew off of normal work activities and dispatching them to de-energize the service so the customer can do their internal work. The Company's crew then restores the customer's service as soon as the customer completes its work. The Company is proposing a specific charge for this service consistent with its Minnesota and South Dakota jurisdictions, as detailed on Sheet No. 6-4 of the General Rules and Regulations.

Q. WHAT IS THE PROPOSED CHARGE FOR THE DEDICATED SWITCHING SERVICE TARIFF?

A. The proposed Dedicated Switching Service tariff provides two hourly rates for this service that reflect current costs. For Dedicated Switching Service provided on Monday through Saturday, the proposed rate is $300.00 per hour. The proposed rate for this service provided on Sundays or Holidays is $400.00 per hour. The cost analysis supporting these charges is provided on Page 2 of Exhibit___(MAP-1), Schedule 8.

3. Excess Footage Charge--Section 5.1.A.1

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

A. The Company is proposing an increase to the existing Excess Footage Charge for Residential Service Lines from $6.85 to $7.90 per foot, as indicated on Sheet No. 6-25 of the General Rules and Regulations. The Company is also

proposing to establish explicit excess footage charges for Non-Residential distribution laterals. There is not a current separate rate for Non-Residential distribution laterals. The proposed charge for an Excess Single Phase Primary or Secondary Extension is $8.00 per foot, and the proposed charge for an Excess Three Phase Primary or Secondary Extension is $13.90 per foot, as indicated on Sheet No. 6-26 of the General Rules and Regulations. The Company proposes retaining the existing free footage allowance.

The cost analysis supporting these charges is provided on page 3 of Schedule 8 of Exhibit___(MAP-1).

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

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

A. There are two components to the Winter Construction Charges, as indicated on Sheet No. 6-26 of the General Rules and Regulations. Based on the cost analysis shown on page 4 of Exhibit___(MAP-1), Schedule 8, the Company is proposing to increase the winter construction Thawing charge from $400 to $600 per frost burner, and to increase the Service, Primary or Secondary Distribution Extension charge from $3.00 per trench foot to $3.80 per trench foot.

IV. CONCLUSION

Q. MR. PEPPIN, DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-10-___

AFFIDAVIT OF
Michael A. Peppin

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

Michael A. Peppin

Subscribed and sworn to before me, this 15th day of December, 2010.

Notary Public

CYNTHIA D. HARRINGTON
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2015

Michael A. Peppin

I graduated from the University of Minnesota, Twin Cities Campus, in 1978 with a Bachelor of Arts degree in Psychology, and in 1980 with a Master of Business Administration degree with an emphasis in Marketing and Statistics.

From October 1979 to December 2000, I was employed with Xcel Energy and its predecessor company, Northern States Power Company ("NSP"), in the positions of Principal Market Research Analyst (10 years), Market Research Manager (10 years) and Manager, Product Development Support (1½ years). In those positions, my responsibilities included conducting research to develop and evaluate NSP's Demand-Side Management programs, including NSP's interruptible and time-of-day rate programs. In January 2001, I accepted the position of Market Research Manager for Xcel Energy's unregulated broadband telecommunications subsidiary, Seren Innovations. My responsibilities involved research regarding the development, pricing and marketing of telecommunications products and services. With Xcel Energy's announced intention to sell Seren Innovations to external buyers, I accepted the position of Senior Market Research Manager with Cargill Corporation in February 2004. In that position I conducted market research studies for many of Cargill's business units, including its Power Marketing unit. Finally, in December 2006, I resumed employment with Xcel Energy in the Pricing and Planning Department as a Principal Pricing Analyst.

My current job responsibilities include conducting Class Cost of Service Studies for various Xcel Energy jurisdictions and various pricing function support for the utility operating subsidiaries of Xcel Energy.

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

I. Overview

Simply stated, the purpose of the Northern States Power Company—Minnesota (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 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 (Move this row down under winter capacity.)	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 and associated substation facilities 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.

Function	FERC Accounts	Sub-Function	Description
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 (and also of the purchased power contract costs) 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 Minnesota rate case (test year 2009) is shown in the table below. It compares the then current-dollar replacement costs of each plant type, to develop stratification percentages.

Plant Type	$/kW	Capacity Ratio	Capacity %	Energy %
Peaking	$630	$630 / $630	100%	0%
Nuclear	$3,247	$630 / $3,347	19.4%	80.6%
Fossil	$1,691	$630 / $1,691	37.3%	62.7%
Hydro	$2,056	$630 / $2,056	30.6%	69.4%

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. book investment, accumulated depreciation, net plant, cost of capital, income taxes, etc.), for each generation plant type.

B. Summer/Winter Split of Generation Capacity-Related Costs

Once the "capacity-related" portion of generation plant costs have been quantified, they are further separated into summer and winter sub-functions. The seasonal sub-function portions are determined as follows.

First, the 12 monthly System peak loads are grouped into a 4-month summer (June, July, August and September) and an 8-month winter seasons. Second, the average hourly load

for the year is subtracted from each monthly peak. Third, the remaining monthly excess loads are averaged for each season and the ratio of these two average seasonal "excess" loads is used to assign the "capacity- related" portion of fixed generation costs to the seasons. This calculation for the TY2009 Minnesota rate case is shown below.

(1)	(2)	(3)	(4) = (3) minus 5,411
Month	**Season**	**Monthly NSP System Peak Load**	**Monthly Peak in Excess of Average Hourly Load**
Jan	Winter	6,927	1,682
Feb	Winter	6,745	1,500
Mar	Winter	6,360	1,115
Apr	Winter	6,185	940
May	Winter	7,215	1,970
Jun	Summer	8,833	3,588
Jul	Summer	9,357	4,112
Aug	Summer	9,009	3,764
Sep	Summer	8,199	2,954
Oct	Winter	6,268	1,023
Nov	Winter	6,718	1,473
Dec	Winter	7,183	1,938
Average Annual Load		**5,245**	
Average Monthly Excess			
Average of Summer Months			3,605
Average of Winter Months			1,455
Total			5,060
Summer Percent			**71.24%** = 3,605/5,060
Winter Percent			**28.76%** = 1,455 / 5,060

As shown above, 75.48% of generation capacity costs were assigned to the summer season while 24.52% were assigned to winter, thereby separating total generation capacity-related costs into summer and winter seasons.

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 the customer's maximum kilowatt ("kW") demand.
2. Energy – Costs that are driven by the customer's 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 Lines	X		X
Primary Transformers	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, primary transformers too; why won't they be?, 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. The analysis used to separate these costs into demand and customer components is called the Minimum Distribution System (MDS) 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 table also shows the percent of each cost element that was classified as "customer" related based on the most recent Minimum System study.

Equipment Type	% Classified as "Customer" Related
Overhead Lines Primary	42.2%
Primary Transformers	0%
Overhead Lines Secondary	54.9%
Underground Lines Primary	85.9%
Underground Lines Secondary	54.3%
Line Transformers Secondary	48.8%
Services	72.7%

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
      - 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 1.

    - 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:
      - PTD – Production, transmission and distribution plant investment.
      - OXDTS – Distribution O&M expenses without supervision and miscellaneous expenses.

Details on the development of the internal allocators used in the CCOSS model are shown in Appendix 2.

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:

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

More detail on customer class definitions is shown in Appendix 3.

VII. CCOSS Data Inputs

As noted earlier, there are a large number of inputs to the CCOSS model including detailed rate base and expense items from the Jurisdictional Cost of Service Study (JCOSS) as well as numerous inputs from other sources used to develop external allocators.

VIII. Organization of the CCOSS Model

The CCOSS model consists of numerous worksheets which show costs by customer class in Total and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below:

1. Billing Unit:

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

2. Function and Associated Sub-Function:

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

b. Transmission (Trans)

c. Distribution (Dist): Sub-functions include:
   a) Distribution Substations (Psub)
   b) Primary Voltage? (Prim)
   c) Secondary Voltage? (Sec)

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

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

IX. 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 + 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 (including off-setting credits from Other Operating Revenues)
+
(Return on Equity x Rate Base) x 1 / (1-Tax Rate)
+

(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate) Mike what does this mean. Aren't income taxes already in the line above?

+

AFUDC

Where:

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	1-23
		Income Statement Summary	24-34
	2	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Present** Rate **Revenue** Responsibility	1-50
	3	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility	1-54
Rate Base Detail	4	Original Plant in Service	1-48
	5	MINUS Accumulated Depreciation	1-27
		MINUS Accumulated Deferred Income Tax	28-58
	6	PLUS Construction Work in Progress	1-35
		EQUALS Total Rate Base	36
Income Statement Detail	7	Present and Proposed Revenues	1-26
		MINUS O&M Expenses part 1	27-43
	8	MINUS O&M Expenses part 2	1-34
	9	MINUS Book Depreciation	1-25
		MINUS Real Estate & Property Taxes	26-53
	10	MINUS Provision for Deferred Income Tax	1-28
		MINUS Investment Tax Credit	29-41
		EQUALS Present and Proposed Operating Income Before Income Taxes	42A 42B
	11 (Income Tax Calcs.)	Tax Additions	31-37
		MINUS Tax Deductions	1-30
		EQUALS Total Tax Adjustments	39A 39B
		PLUS Present and Proposed Operating Income Before Income Taxes	40A 40B
		EQUALS Present and Proposed Taxable Income	39A 39B
		MULTIPLIED BY State and Federal Tax Rates	
		EQUALS Present and Proposed State and Federal Income Taxes	40A 40B
	11 (Total Return Calcs.)	Present and Proposed Operating Income Before Income Taxes	FROM Page 10, Rows 42A & 42B
		MINUS Present and Proposed State and Federal Income Taxes	40A 40B
		EQUALS Present and Proposed Preliminary Return	41A 41B
		PLUS AFUDC (from page 12)	42
		EQUALS Present and Proposed Total Return	43A 43B

XI. CCOSS Output (continued)

CCOSS Section	Page Number	Results Detail	Line Numbers
Misc Calcs	12	AFUDC	1-26
		Labor Allocator	27-48
	13	Backwards Revenue Calculations	1-36
Allocator Data	14	Internal Allocators and Associated Data	1-32
	15	External Allocators and Associated Data	1-44
Misc CCOSS Data Inputs	16	On Peak Energy Weighting Factor, Summer Factor, Minimum System Splits, Plant Stratification Data, Tax Rates, Capitol Structure, Etc.	1-58

CCOSS Guide Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

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

Code	Allocator for:	Description	Allocator Rationale & Background
C11	**Connection charge revenues**	**Average monthly customers: Forecasted annual bills / 12**	**Customer connection revenues are driven by number of customer services.**
C10	Used to calculate C11	C11 less automatic protective lighting and load management services. C11 less number of customers with a second service.	
C11WA	**Customer accounting costs**	**Average monthly customers weighted by each class' relative rating of customer accounting costs: C11 X C11WAF**	**Customer accounting costs are driven by number of customers and the complexity of their respective rate, billing issues and customer service requirements.**
C11WAF	Used to calculate C11WA allocator	Customer accounting cost weighting factors. The weighting factor for residential customers is set at 1.0. The weighting factors for other classes are defined relative to costs for residential. E.g., if a class were three times costlier, its factor would be 3.0.	Weighting factors are set so as to reflect the relative costs of meter reading, billing and providing customer service for different classes of customers. For example some rate schedules are significantly more complex requiring more sophisticated meter reading capabilities, billing systems and customer service staff.
C12WM	**Meter costs**	**Number of meters multiplied by each class' average meter costs: C12 X C12WMF**	**Metering costs are driven by the number of customers in each class and the respective metering costs.**
C12	Used to calculate C12WM allocator	Reflects actual number of meters. C11 with an adjusted street lighting customer count	
C12WMF	Used to calculate C12WM allocator	Average meter cost for each customer type	
C61PS	**The "customer" (minimum system) portion of primary distribution line costs**	**Average monthly customers served at primary or secondary voltage. C11 less transmission transformed and transmission voltage customers**	**The number of customers served at secondary and primary voltages drives the customer related portion of primary distribution line costs. Transmission and Transmission Transformed voltage customers are excluded since they do not use the distribution system**

CCOSS Guide Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

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

CCOSS Guide Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For	Derivation	Allocator Rationale
D62NLL	The capacity portion of service-line costs	Non-coincident (or "customer peak") demand for secondary voltage customers, less the customer peak demand for street lighting, area lighting and C&I customers served underground	Capacity related service line costs are driven by individual customer maximum demands less the minimum system demand of each class. (The minimum system demand is customer related.) Transmission voltage, primary voltage and lighting customers are excluded since they do not cause service related costs. Also excluded are C&I underground customers since they install their own services.
D10S	Summer season portion of capacity-related generation costs	Each class' % contribution to the single summer system peak. Summer months are June through September.	The class contribution to the system summer peak drives the summer portion of capacity-related generation costs.
D10W	Winter season portion of capacity-related generation costs	Each class' % contribution to the single winter system peak. Winter months are October through May.	The class contribution to the system winter peak drives the winter portion of capacity-related generation costs.
D10T	Transmission plant costs.	Weighted Class Contributions to Summer and Winter Peak loads. Allocator equals (D10W% plus (D10S% times 1.3766)) divided by (1 + 1.3766).; The 1.3766 ratio is the ratio of the average summer and winter seasonal system peaks.	The driver for transmission costs is class contribution to the summer & winter system peaks. To reflect the fact that summer peaks have more impact, the summer peak contribution for each class is weighted by the ratio of average monthly summer and average monthly winter system peaks.
D10C	Capacity-related generation costs.	Weighted of Class Contributions to Summer and Winter system peak loads. Allocator equals (D10W% plus (D10S% times 3.078)) divided by (1 + 3.078). The 3.078 ratio is obtained from the average summer and winter season peak loads, after subtracting the average annual load from each monthly load.	Capacity- related generation costs are driven by class contribution to summer & winter system peaks. To reflect the fact that summer peaks have a disproportionate impact on capacity-related generation costs, the summer peak is weighted by the ratio of average monthly summer and winter system peaks, which are in excess of average annual demand.

CCOSS Guide Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

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

CCOSS Guide Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

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

Code	Allocator for:	Description	Allocator rationale
D56E44	Economic development expenses	This allocator is based on the weighted average of the generation capacity and energy allocators. The weighting is based on an analysis of the fixed-cost-contribution margin of the General service tariff. D56E44 = (% Demand Impacts x D10C) + (% Energy Impacts x E8760). $ Energy Impacts = kWh sales x (Base Energy Charge + Fuel Costs – Marginal Energy Costs) $ Demand Impacts = Annual Billing kW x (((4 x Summer Demand Charge)+ (8 x Winter Demand Charge))/12) The demand portion is further split between Summer and Winter based on D10C; the energy portion is already split between on-peak and off-peak because E8760 is split that way. Total $ Impacts = $ Energy Impacts + $ Demand Impacts	Minn. Stat. §216B.16, subd. 13 (1992) permits the Commission to allow utilities to recover economic development expenses. Pursuant to Docket No: E-002/GR-91-1, the Commission allowed NSP to recover 50% of its economic development expenses. Economic development program costs and benefits are assumed to be a function of the fixed cost (margin) contribution of the demand and energy charges that result from the ED program.
D42E58	CIP expenses	D48E52 = (.4172 x D10C)+(.5828 x E8760).	CIP program expenses are split between capacity and energy according to whether the purpose of program is to reduce peak load or energy requirements. Once program costs are thus split, the standard capacity and energy allocators are applied to the separate pools of $ expenses.
LABOR	Amortizations, Payroll Taxes and A&G Expenses that are labor related such as Salaries, Pension & Benefits, Injuries & Claims.	Total Labor costs on Page 12 line 48 less A&G Labor on Page 12 line 46. A&G Labor is excluded to avoid a circular reference.	The specified expenses are directly related to Labor costs.

CCOSS Guide Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator for:	Description	Allocator rationale
NEPIS	Property Insurance	Electric plant in service less accumulated provision for depreciation	Property insurance is driven by net electric plant in service
OXDTS	Distribution customer installation expenses and miscellaneous distribution expense.	All Distribution O&M Expense, except Supervision and Engineering, Customer Install and Miscellaneous. Supervision & engineering expenses are excluded since they are an overhead expense. Customer installation expenses and miscellaneous distribution expense are excluded to avoid a circular reference. (lines 2 thru 7, 9 and 11 of page 8)	The OXDTS allocator represents the majority of Distribution O&M expenses (excl supervision and customer installation costs) which is a good indicator for miscellaneous distribution expenses.
OXOPD	Used to allocate Capacity-Related Other Production labor costs	Capacity related "Other Production" expenses: Peaking + Base Load (line 39 of page 7)	Capacity-Related Other Production O&M costs are a good indicator of Capacity-Related Production Other Production labor
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 42 & 43 of page 7 and lines 12-15, 18-21, 32 and 33 of page 8). These A&G expenses are excluded to avoid a circular reference	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.	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 labor costs	Total Generation Set-Up Transformer original plant in service: Tran Gener Step Up (line 9 of page 4) + Distrib Substn Step Up (line 14 of page 4)	Generation step-up plant investment drives step-up generation labor costs
P61	Distribution Substation O&M expense and Distribution Substation labor	Distribution Plant: Substations Original Plant in Service (line 18, page 4)	Substation plant original investment drives Distribution Substation plant O&M costs and Distribution Substation Labor.
P68	All costs related to Distribution Plant Line Transformers	Distribution Plant: Line Transformers Original Plant in Service (line 37 of page 4)	Line transformer plant investment drives all line transformer costs.
P69	All costs related to Customer-Connection "Services"	Customer-Connection "Services" Original Plant in Service (line 40 of page 4)	Customer-Connection "Services" plant investment drives all costs of Customer-Connection "Services"

CCOSS Guide Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator for:	Derivation	Allocator rationale
P73	All costs related to Street Lighting	Street Lighting Original Plant in Service (line 42 of page 4)	Street Lighting plant investment drives all Street Lighting costs.
POL	All costs related to Overhead Distribution Lines and Distribution overhead line rent revenues.	Distribution Plant: Overhead Lines Original Plant in Service (line 26 of page 4)	Overhead distribution line plant investment drives all costs related to Overhead Distribution Lines.
PT0	Working Cash	Total Property Taxes (line 50 of page 9)	Working Cash is closely related to Real Estate Taxes
PTD	All costs related to General Plant and Electric Common Plant	Production + Transmission + Distribution Plant Original Plant Investment (lines 6, 13 and 43 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 33 of page 4)	Underground distribution line plant investment drives all costs related to Underground Distribution Lines.
RTBASE	Income Tax Addition: Avoided tax interest	Total Rate Base (line 36 of page 6)	Total rate base drives avoided tax interest
TD	Transmission and Distribution Materials and Supplies	Total Transmission and Distribution Original Plant in Service (Lines 13 and 43 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 27 thru 47 on page 12, except lines 33 and 40)	Distribution labor (excluding Supervision & Engineering) drives Supervision and Engineering and Customer Installation Labor.

CCOSS Guide Appendix 3: CCOSS Customer Classes Vs Tariff Cross Reference

A. Summary Customer Classes

	Customer Class	Rate Codes	Voltage Specifications
1	Residential	D01, D02, D03, D04, D05 (if residential), D10 (if residential)	
2	C&I Non Demand Metered	D05 (if C&I), D10 (if C&I), D12, D14, D15, D18, D19, D34, D40, D42	
3	C&I Secondary Voltage	D16, D17, D20, D21, D22, D41, D62, D63	Secondary
4	C&I Primary Voltage	D16, D17, D20, D21, D22, D41, D62, D63	Primary
5	C&I Transmission Transformed Voltage	D16, D17, D20, D21, D22, D41, D62, D63	Transmission Transformed
6	C&I Transmission Voltage	D16, D17, D20, D21, D22, D41, D62, D63	Transmission
7	Street Lighting	D11, D30, D31, D32, D33	

B. Detailed Customer Sub-Classes

	Customer Class	Rate Codes	kW Size	Voltage Specifications
1	Residential without Space Heating	D01, D02, D03, D04		
2	Residential with Space Heating	D01, D02, D03, D04		
3	Load Management	D05, D10		
4	Small C&I Non Demand Metered	D12, D14, D15, D18, D19, D34,		
5	Small C&I Secondary Voltage	D16, D17, D62	< 1,000 kW	Secondary
6	Small C&I Primary Voltage	D16, D17, D62	< 1,000 kW	Primary
7	Small C&I Transmission Transformed Voltage	D16, D17, D62	< 1,000 kW	Transmission Transformed
8	Small C&I Transmission Voltage	D16, D17, D62	< 1,000 kW	Transmission
9	Small Interruptible All Voltages	D20, D21, D22, D63	< 1,000 kW	All Voltages
10	Large C&I Secondary Voltage	D16, D17, D62	> 1,000 kW	Secondary
11	Large C&I Primary Voltage	D16, D17, D62	> 1,000 kW	Primary
12	Large C&I Transmission Transformed Voltage	D16, D17, D62	> 1,000 kW	Transmission Transformed
13	Large C&I Transmission Voltage	D16, D17, D62	> 1,000 kW	Transmission
14	Large Interruptible All Voltages	D20, D21, D22, D63	> 1,000 kW	All Voltages
15	Municipal not Demand Metered	D40, D42		
16	Municipal Demand Metered	D41		
17	Auto Protective Lighting	D11		
18	Street Lighting – Company Owned	D30		
19	Street Lighting – Customer Owned	D31, D32, D33		

Northern States Power Company, a Minnesota corporation
Electric Utility - North Dakota
Test Year Ending December 31, 2011
Summary of Class Cost of Service Study Results ($000)

Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 3
Page 1 of 1

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 2)	184,155	72,449	11,728	98,374	1,604
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	122	62	9	51	1
[3]	Unadjusted Operating Revenues (line 2 + line 3)	184,277	72,511	11,737	98,425	1,605
[4]	Present Rates (CCOSS page 2, line 3)	164,504	66,011	10,986	85,640	1,867
[5]	Unadjusted Deficiency (line 3 - line 4)	19,773	6,500	751	12,785	(262)
[6]	Defic / Pres (line 5 / line 4)	12.0%	9.8%	6.8%	14.9%	-14.0%
[7]	**Ratio: Class % / Total %**	**1.00**	**0.82**	**0.57**	**1.24**	**-1.17**

CAPACITY COST RESPONSIBILITIES FOR INTERRUPTIBLE RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
[8]	Interruption Rate Discounts (CCOSS page 2, line 6)	4,756	718	50	3,988	0
[9]	Interruption Capacity Costs (CCOSS page 2, line 7)	4,756	1,604	282	2,853	17
[10]	Revenue Requirement Shift (line 9 - line 8)	0	886	232	(1,135)	17

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	184,155	73,335	11,960	97,239	1,621
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	122	62	9	51	1
[13]	Adjusted Operating Revenues (line 11 + line 12)	184,277	73,397	11,969	97,290	1,622
[14]	Present Rates (line 4)	164,504	66,011	10,986	85,640	1,867
[15]	Adjusted Deficiency (line 13 - line 14)	19,773	7,386	983	11,650	(245)
[16]	Defic / Pres Rates (line 15 / line 4)	12.0%	11.2%	8.9%	13.6%	-13.1%
[17]	**Ratio: Class % / Total %**	**1.00**	**0.93**	**0.74**	**1.13**	**-1.09**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[18]	Proposed Rates (CCOSS page 3, line 3)	184,155	73,373	12,061	96,852	1,869
[19]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	122	62	9	51	1
[20]	Proposed Operating Revenues (line 18 + line 19)	184,277	73,435	12,070	96,903	1,870
[21]	Proposed Increase (line 20 - line 14)	19,773	7,424	1,084	11,263	3
[22]	Difference / Pres (line 21 / line 14)	12.0%	11.2%	9.9%	13.2%	0.2%
[23]	**Ratio: Class % / Total %**	**1.00**	**0.94**	**0.82**	**1.09**	**0.01**

Northern States Power Company, a Minnesota corporatior
Electric Utility - State of North Dakota
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Rate Base

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Plant In Service	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Production		478,514	168,585	307,413	28,310	279,103	246,885	32,219	0	0	2,515
2	Transmission		111,382	41,241	69,560	7,141	62,419	56,065	6,354	0	0	581
3	Distribution		125,117	83,364	38,414	10,024	28,390	26,214	2,175	0	0	3,340
4	General		20,607	8,450	11,972	1,311	10,661	9,487	1,174	0	0	185
5	Common		27,597	11,316	16,033	1,755	14,277	12,705	1,573	0	0	248
6	TBT Invest		0	0	0	0	0	0	0	0	0	0
7	Total		763,216	312,955	443,391	48,541	394,850	351,355	43,495	0	0	6,870
	Depreciation Reserve											
8	Production		251,804	89,599	160,779	14,889	145,890	128,587	17,303	0	0	1,427
9	Transmission		34,885	12,911	21,791	2,236	19,556	17,564	1,991	0	0	182
10	Distribution		57,662	37,801	17,723	4,548	13,175	12,142	1,033	0	0	2,138
11	General		8,419	3,452	4,891	535	4,356	3,876	480	0	0	76
12	Common		17,390	7,131	10,103	1,106	8,997	8,006	991	0	0	157
13	Total		370,160	150,894	215,287	23,314	191,973	170,175	21,798	0	0	3,979
14	**Net Plant In Service**		393,057	162,061	228,104	25,227	202,878	181,181	21,697	0	0	2,891
	Deductions											
15	Accum Defer Inc Tax		79,352	34,530	44,392	5,203	39,189	35,042	4,147	0	0	430
	Additions											
16	Constr Work In Progress		2,100	764	1,323	127	1,197	1,058	139	0	0	13
17	Fuel Inventory		5,674	2,049	3,589	335	3,254	2,853	402	0	0	36
18	Materials & Supplies		6,186	2,358	3,784	380	3,404	3,020	384	0	0	44
19	Prepayments		4,024	1,659	2,335	258	2,077	1,855	222	0	0	30
20	Non-Plant Assets & Liab		(6,173)	(2,535)	(3,578)	(411)	(3,167)	(2,811)	(356)	0	0	(59)
21	Working Cash		2,057	896	1,140	136	1,004	896	109	0	0	21
22	Total		13,868	5,190	8,593	824	7,769	6,870	899	0	0	84
23	**Rate Base**		327,573	132,721	192,306	20,848	171,457	153,009	18,449	0	0	2,546

Income Statement

24A	**Tot Oper Rev - Pres**		206,949	81,618	123,206	13,557	109,649	98,454	11,195	0	0	2,125
24B	**Tot Oper Rev - Prop**		226,722	89,042	135,552	14,641	120,912	108,508	12,404	0	0	2,128
25	Oper & Maint		160,796	61,976	97,481	10,148	87,332	77,039	10,293	0	0	1,339
26	Book Depr + IRS Int		17,697	7,227	10,299	1,125	9,174	8,185	989	0	0	171
27	Payroll Tax		1,815	745	1,052	121	931	827	105	0	0	17
28	Real Est & Prop Tax		5,653	2,462	3,133	373	2,760	2,462	298	0	0	58
29	Deferred Inc Taxes		12,712	4,564	8,076	771	7,305	6,508	796	0	0	72
30A	Present Income Tax		(8,337)	(2,260)	(6,232)	(261)	(5,970)	(4,596)	(1,374)	0	0	154
30B	Proposed Income Tax		(581)	(701)	206	(140)	347	(97)	444	0	0	(86)
31	Allow Funds Dur Const		0	0	0	0	0	0	0	0	0	0
32A	**Present Return**		16,613	6,903	9,397	1,280	8,117	8,029	88	0	0	313
32B	**Proposed Return**		28,630	12,768	15,306	2,243	13,063	13,584	(521)	0	0	557
33A	**Pres Ret on Rt Base**		5.07%	5.20%	4.89%	6.14%	4.73%	5.25%	0.48%	0.00%	0.00%	12.31%
33B	**Prop Ret on Rt Base**		8.74%	9.62%	7.96%	10.76%	7.62%	8.88%	-2.83%	0.00%	0.00%	21.88%
34A	**Pres Ret on Common**		4.26%	4.51%	3.91%	6.30%	3.62%	4.60%	-4.48%	0.00%	0.00%	18.04%
34B	**Prop Ret on Common**		11.24%	12.92%	9.76%	15.08%	9.11%	11.51%	-10.76%	0.00%	0.00%	36.24%

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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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Equal Return On Rate Base**		**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**
2	**UnAdj Equalized Rev Reqt**		**184,155**	**72,449**	**110,102**	**11,728**	**98,374**	**87,086**	**11,288**	**0**	**0**	**1,604**
3	**UnAdj Present Revenue**		**164,504**	**66,011**	**96,626**	**10,986**	**85,640**	**77,246**	**8,394**	**0**	**0**	**1,867**
4	**UnAdj Revenue Deficiency**		**19,651**	**6,438**	**13,476**	**742**	**12,734**	**9,840**	**2,894**	**0**	**0**	**(263)**
5	**UnAdj Deficiency / Present**		**11.95%**	**9.75%**	**13.95%**	**6.75%**	**14.87%**	**12.74%**	**34.48%**	**0.00%**	**0.00%**	**-14.07%**
6	**Interruption Rate Discounts**		**4,756**	**718**	**4,038**	**50**	**3,988**	**2,720**	**1,268**	**0**	**0**	**0**
7	**Interruptible Capacity Costs**	D10C	**4,756**	**1,604**	**3,135**	**282**	**2,853**	**2,561**	**292**	**0**	**0**	**17**
8	**Revenue Shift**		**0**	**886**	**(903)**	**232**	**(1,135)**	**(159)**	**(976)**	**0**	**0**	**17**
9	**Adj Equal Rev Reqt (Rows 2+8)**		**184,155**	**73,335**	**109,199**	**11,960**	**97,239**	**86,927**	**10,312**	**0**	**0**	**1,621**
10	**Pres Rev (Row 3)**		**164,504**	**66,011**	**96,626**	**10,986**	**85,640**	**77,246**	**8,394**	**0**	**0**	**1,867**
11	**Adj Revenue Deficiency**		**19,651**	**7,324**	**12,573**	**974**	**11,599**	**9,681**	**1,918**	**0**	**0**	**(246)**
12	**Adj Deficiency / Adj Present**		**11.95%**	**11.09%**	**13.01%**	**8.87%**	**13.54%**	**12.53%**	**22.85%**	**0.00%**	**0.00%**	**-13.18%**
	Customer Classification											
13	Min Sys & Service Drop		9,076	7,149	1,313	880	433	427	6	0	0	615
14	Energy Services		5,282	4,147	1,112	713	398	393	5	0	0	24
15	Total Customer **(Cusco)**		14,358	11,295	2,424	1,593	831	820	11	0	0	638
16	Ave Monthly Customers		90,926	76,564	12,376	8,920	3,456	3,422	33	0	0	1,986
17	Svc Drop Reqt	$ / Mo / Cust	$8.32	$7.78	$8.84	$8.22	$10.44	$10.40	$14.94	$0.00	$0.00	$25.80
18	Ener Svcs Reqt	$ / Mo / Cust	$4.84	$4.51	$7.49	$6.66	$9.61	$9.57	$13.49	$0.00	$0.00	$0.99
19	Total Reqt	$ / Mo / Cust	$13.16	$12.29	$16.32	$14.88	$20.05	$19.97	$28.43	$0.00	$0.00	$26.79
	Energy Classification											
20	On Peak Rev Reqt		42,798	14,195	28,499	2,814	25,685	22,624	3,061	0	0	104
21	Off Peak Rev Reqt		39,117	15,320	23,385	2,023	21,362	18,611	2,751	0	0	412
22	Total Ener Rev Reqt		81,915	29,516	51,884	4,837	47,047	41,235	5,812	0	0	515
23	Annual kWh Sales		2,251,280	805,939	1,426,442	128,671	1,297,771	1,133,621	164,150	0	0	18,899
24	On Pk Reqt	Mills / kWh	19.011	17.613	19.979	21.870	19.791	19.957	18.648	0.000	0.000	5.494
25	Off Pk Reqt	Mills / kWh	17.375	19.009	16.394	15.721	16.461	16.418	16.758	0.000	0.000	21.782
26	Total Reqt	Mills / kWh	36.386	36.623	36.373	37.591	36.252	36.375	35.406	0.000	0.000	27.276
	Demand Classification											
27	Energy-Related Prod		28,998	10,461	18,355	1,713	16,642	14,588	2,054	0	0	183
28	Capacity-Related Summer Peak Prod		26,041	8,001	18,040	1,525	16,515	14,793	1,723	0	0	0
29	Capacity-Related Winter Peak Prod		10,512	4,308	6,075	642	5,433	4,910	524	0	0	128
30	Total Production		65,551	22,770	42,470	3,880	38,591	34,290	4,300	0	0	311
31	Transmission **(Transco)**		15,633	5,797	9,753	1,005	8,748	7,860	888	0	0	82
32	Primary Dist Subs		1,858	847	993	113	880	764	116	0	0	18
33	Prim Dist Lines		2,121	774	1,326	129	1,197	1,036	160	0	0	21
34	Second Dist, Trans		2,719	1,450	1,252	171	1,081	1,081	0	0	0	18
35	Total Distribution **(Disco)**		6,698	3,071	3,571	413	3,157	2,881	276	0	0	57
36	Total Demand Rev Reqt		87,882	31,638	55,794	5,298	50,496	45,031	5,465	0	0	451
37	Annual Billing kW		3,451,562	0	3,451,562	0	3,451,562	3,147,931	303,631	0	0	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$5.32	$0.00	$4.82	$4.63	$6.76	$0.00	$0.00	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$5.23	$0.00	$4.78	$4.70	$5.67	$0.00	$0.00	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.76	$0.00	$1.57	$1.56	$1.73	$0.00	$0.00	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$12.30	$0.00	$11.18	$10.89	$14.16	$0.00	$0.00	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.83	$0.00	$2.53	$2.50	$2.92	$0.00	$0.00	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$1.03	$0.00	$0.91	$0.92	$0.91	$0.00	$0.00	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$16.16	$0.00	$14.63	$14.31	$18.00	$0.00	$0.00	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	39.037	39.256	39.114	41.175	38.910	39.723	33.291	0.000	0.000	23.840
46	Summer Billing kW		1,191,898	0	1,191,898	0	1,191,898	1,082,535	109,363	0	0	0
47	Winter Billing kW		2,259,664	0	2,259,664	0	2,259,664	2,065,396	194,268	0	0	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$24.31	$0.00	$22.13	$21.71	$26.35	$0.00	$0.00	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$11.87	$0.00	$10.68	$10.42	$13.30	$0.00	$0.00	$0.00
50	Energy + Production **(Genco)**		147,466	52,285	94,354	8,716	85,638	75,525	10,112	0	0	827

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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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**8.74%**	**9.62%**	**7.96%**	**10.76%**	**7.62%**	**8.88%**	**-2.83%**	**0.00%**	**0.00%**	**21.88%**
2	**UnAdj Equalized Rev Reqt**		**184,155**	**72,449**	**110,102**	**11,728**	**98,374**	**87,086**	**11,288**	**0**	**0**	**1,604**
3	**UnAdj Proposed Revenue**		**184,155**	**73,373**	**108,913**	**12,061**	**96,852**	**87,253**	**9,599**	**0**	**0**	**1,869**
4	**UnAdj Revenue Deficiency**		**(0)**	**(924)**	**1,189**	**(333)**	**1,522**	**(167)**	**1,689**	**0**	**0**	**(265)**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**-1.26%**	**1.09%**	**-2.76%**	**1.57%**	**-0.19%**	**17.60%**	**0%**	**0%**	**-14.16%**
6	**Interruption Rate Discounts**		**4,756**	**718**	**4,038**	**50**	**3,988**	**2,720**	**1,268**	**0**	**0**	**0**
7	**Interruptible Capacity Costs**	**D10C**	**4,756**	**1,604**	**3,135**	**282**	**2,853**	**2,561**	**292**	**0**	**0**	**17**
8	**Revenue Shift**		**0**	**886**	**(903)**	**232**	**(1,135)**	**(159)**	**(976)**	**0**	**0**	**17**
9	**Adj Equal Rev (Rows 2+8)**		**184,155**	**73,335**	**109,199**	**11,960**	**97,239**	**86,927**	**10,312**	**0**	**0**	**1,621**
10	**Prop Rev (Row 3)**		**184,155**	**73,373**	**108,913**	**12,061**	**96,852**	**87,253**	**9,599**	**0**	**0**	**1,869**
11	**Adj Revenue Deficiency**		**(0)**	**(38)**	**286**	**(101)**	**387**	**(326)**	**713**	**0**	**0**	**(248)**
12	**Adj Deficiency / Adj Prop**		**0.00%**	**-0.05%**	**0.26%**	**-0.84%**	**0.40%**	**-0.37%**	**7.43%**	**0.00%**	**0.00%**	**-13.27%**
	Customer Component											
13	Min Sys & Service Drop		9,076	6,365	2,125	843	1,282	1,315	(33)	0	0	586
14	Energy Services		5,282	4,151	1,108	714	394	388	6	0	0	23
15	Total Customer **(Cusco)**		14,358	10,516	3,233	1,557	1,675	1,703	(28)	0	0	609
16	Ave Monthly Customers		90,926	76,564	12,376	8,920	3,456	3,422	33	0	0	1,986
17	Svc Drop Reqt	$ / Mo / Cust	$8.32	$6.93	$14.31	$7.88	$30.90	$32.02	($83.57)	$0.00	$0.00	$24.60
18	Ener Svcs Reqt	$ / Mo / Cust	$4.84	$4.52	$7.46	$6.67	$9.49	$9.45	$14.08	$0.00	$0.00	$0.98
19	Total Reqt	$ / Mo / Cust	$13.16	$11.45	$21.77	$14.55	$40.40	$41.47	($69.49)	$0.00	$0.00	$25.58
	Energy Component											
20	On Peak Rev Reqt		42,798	14,215	28,476	2,816	25,659	22,614	3,045	0	0	107
21	Off Peak Rev Reqt		39,117	15,329	23,375	2,027	21,348	18,611	2,737	0	0	413
22	Total Ener Rev Reqt		81,915	29,544	51,851	4,843	47,007	41,225	5,782	0	0	520
23	Annual kWh Sales		2,251,280	805,939	1,426,442	128,671	1,297,771	1,133,621	164,150	0	0	18,899
24	On Pk Reqt	Mills / kWh	19.011	17.638	19.963	21.888	19.772	19.949	18.551	0.000	0.000	5.654
25	Off Pk Reqt	Mills / kWh	17.375	19.020	16.387	15.754	16.450	16.417	16.671	0.000	0.000	21.858
26	Total Reqt	Mills / kWh	36.386	36.658	36.350	37.642	36.221	36.366	35.222	0.000	0.000	27.512
	Demand Component											
27	Base Load Prod		28,998	11,038	17,688	1,844	15,845	14,396	1,449	0	0	272
28	Summer Peak Prod		26,041	8,734	17,204	1,630	15,575	14,299	1,276	0	0	103
29	Winter Peak Prod		10,512	4,384	5,984	679	5,305	4,926	378	0	0	144
30	Total Production		65,551	24,155	40,876	4,152	36,724	33,621	3,103	0	0	520
31	Transmission **(Transco)**		15,633	6,127	9,360	1,067	8,293	7,737	556	0	0	145
32	Primary Dist Subs		1,858	842	993	121	873	792	80	0	0	23
33	Prim Dist Lines		2,121	810	1,286	137	1,149	1,030	119	0	0	25
34	Second Dist, Trans		2,719	1,378	1,314	183	1,131	1,144	(13)	0	0	27
35	Total Distribution **(Disco)**		6,698	3,030	3,593	441	3,152	2,966	186	0	0	75
36	Total Demand Rev Reqt		87,882	33,313	53,830	5,660	48,170	44,325	3,845	0	0	740
37	Annual Billing kW		3,451,562	0	3,451,562	0	3,451,562	3,147,931	303,631	0	0	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$5.12	$0.00	$4.59	$4.57	$4.77	$0.00	$0.00	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$4.98	$0.00	$4.51	$4.54	$4.20	$0.00	$0.00	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.73	$0.00	$1.54	$1.56	$1.25	$0.00	$0.00	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$11.84	$0.00	$10.64	$10.68	$10.22	$0.00	$0.00	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.71	$0.00	$2.40	$2.46	$1.83	$0.00	$0.00	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$1.04	$0.00	$0.91	$0.94	$0.61	$0.00	$0.00	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$15.60	$0.00	$13.96	$14.08	$12.66	$0.00	$0.00	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	39.037	41.334	37.737	43.989	37.117	39.100	23.424	0.000	0.000	39.133
46	Summer Billing kW		1,191,898	0	1,191,898	0	1,191,898	1,082,535	109,363	0	0	0
47	Winter Billing kW		2,259,664	0	2,259,664	0	2,259,664	2,065,396	194,268	0	0	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$23.31	$0.00	$20.97	$21.18	$18.88	$0.00	$0.00	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$11.53	$0.00	$10.25	$10.36	$9.16	$0.00	$0.00	$0.00
50	Energy + Production **(Genco)**		147,466	53,700	92,727	8,996	83,731	74,847	8,885	0	0	1,040
51	Prop Rev - Pres Rev (Pg 2)		19,651	7,362	12,287	1,075	11,212	10,007	1,205	0	0	2
52	Difference / Present		11.95%	11.15%	12.72%	9.79%	13.09%	12.95%	14.36%	0.00%	0.00%	0.11%
53	Adj Prop - Adj Pres (Pg 2)		19,651	7,362	12,287	1,075	11,212	10,007	1,205	0	0	2
54	Difference / Adj Present		11.95%	11.15%	12.72%	9.79%	13.09%	12.95%	14.36%	0.00%	0.00%	0.11%

Northern States Power Company, a Minnesota corporatior
Electric Utility - State of North Dakota
Test Year Ending December 31, 2011
Proposed Class Cost of Service Study Detail

Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 4

Original Plant in Service

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S	125,735	38,693	87,042	7,366	79,676	71,365	8,310	0	0	0
2	WInter Peak	D10W	50,761	20,831	29,311	3,100	26,211	23,684	2,527	0	0	619
3	Total Peak	[D10C]	176,496	59,524	116,353	10,466	105,887	95,049	10,838	0	0	619
4	Base Load	E8760	199,391	72,002	126,138	11,781	114,357	100,241	14,116	0	0	1,252
5	Nuclear Fuel	E8760	102,627	37,059	64,923	6,063	58,859	51,594	7,265	0	0	644
6	Total	46.95%	478,514	168,585	307,413	28,310	279,103	246,885	32,219	0	0	2,515
	Transmission											
7	Gen Step Up Base	E8760	1,276	461	807	75	732	641	90	0	0	8
8	Gen Step Up Peak	D10C	3,306	1,115	2,179	196	1,983	1,780	203	0	0	12
9	Total Gen Step Up		4,582	1,576	2,987	271	2,715	2,422	293	0	0	20
10	Bulk Transmission	D10T	106,787	39,665	66,560	6,870	59,691	53,643	6,048	0	0	561
11	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign	13	0	13	0	13	0	13	0	0	0
13	Total		111,382	41,241	69,560	7,141	62,419	56,065	6,354	0	0	581
	Distribution: Substations											
14	Generat Step Up	STRATH	203	72	130	12	118	104	14	0	0	1
15	Bulk Transmission	D10T	105	39	65	7	59	53	6	0	0	1
16	Distrib Function	D60Sub	16,532	7,547	8,821	1,006	7,816	6,783	1,033	0	0	164
17	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
18	Total		16,840	7,658	9,017	1,024	7,992	6,940	1,053	0	0	165
	Overhead Lines											
19	Primary Capacity	D61PS	9,738	3,562	6,081	594	5,487	4,753	734	0	0	94
20	Primary Customer	C61PS	7,126	6,130	989	711	278	275	3	0	0	7
21	Total Primary		16,864	9,692	7,070	1,305	5,765	5,028	737	0	0	102
22	Second Capacity	D62SecL	3,684	1,866	1,792	243	1,549	1,549	0	0	0	26
23	Second Customer	C62Sec	4,489	3,863	621	448	174	174	0	0	0	5
24	Total Secondary		8,173	5,729	2,413	691	1,722	1,722	0	0	0	31
25	Street Lighting	DASL	975	0	0	0	0	0	0	0	0	975
26	Total		26,012	15,421	9,483	1,996	7,488	6,751	737	0	0	1,107
	Underground Lines											
27	Primary Capacity	D61PS	3,623	1,325	2,263	221	2,041	1,768	273	0	0	35
28	Primary Customer	C61PS	22,106	19,016	3,068	2,205	862	854	8	0	0	23
29	Total Primary		25,729	20,341	5,330	2,426	2,904	2,623	281	0	0	58
30	Second Capacity	D62SecL	10,110	5,121	4,917	666	4,251	4,251	0	0	0	72
31	Second Customer	C62Sec	12,020	10,343	1,664	1,199	465	465	0	0	0	12
32	Total Secondary		22,130	15,465	6,581	1,866	4,715	4,715	0	0	0	84
33	Total		47,859	35,806	11,911	4,292	7,619	7,338	281	0	0	142
	Line Transformers											
34	Primary	D61PS	753	275	470	46	424	368	57	0	0	7
35	Second Capacity	D62SecL	6,807	3,448	3,311	449	2,862	2,862	0	0	0	48
36	Second Customer	C62Sec	6,481	5,577	897	647	251	251	0	0	0	7
37	Total		14,041	9,301	4,678	1,141	3,537	3,480	57	0	0	62
	Services											
38	Second Capacity	D62NLL	3,228	2,657	571	99	472	472	0	0	0	0
39	Second Customer	C62NL	8,582	7,931	651	469	182	182	0	0	0	0
40	Total		11,810	10,589	1,221	568	653	653	0	0	0	0
41	Meters	C12WM	6,694	4,590	2,103	1,003	1,100	1,052	48	0	0	2
42	Street Lighting	Dir Assign	1,861	0	0	0	0	0	0	0	0	1,861
43	**Total Distribution**		125,117	83,364	38,414	10,024	28,390	26,214	2,175	0	0	3,340
44	**General Plant**	PTD	20,607	8,450	11,972	1,311	10,661	9,487	1,174	0	0	185
45	**Electric Common**	PTD	27,597	11,316	16,033	1,755	14,277	12,705	1,573	0	0	248
46	Prelim Elec Plant		763,216	312,955	443,391	48,541	394,850	351,355	43,495	0	0	6,870
47	TBT Investment	NEPIS	0	0	0	0	0	0	0	0	0	0
48	**Elec Plant in Serv**		763,216	312,955	443,391	48,541	394,850	351,355	43,495	0	0	6,870

Northern States Power Company, a Minnesota corporatior
Electric Utility - State of North Dakota
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Proposed Class Cost of Service Study Detail

Case No. PU-10-_____
Exhibit No. _____(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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	55,744	18,800	36,749	3,305	33,443	30,020	3,423	0	0	196
2	Nuclear Fuel	E8760	92,443	33,382	58,481	5,462	53,019	46,475	6,544	0	0	580
3	Base Load	E8760	103,617	37,417	65,550	6,122	59,428	52,092	7,335	0	0	651
4	Total		251,804	89,599	160,779	14,889	145,890	128,587	17,303	0	0	1,427
	Transmission											
5	Gen Step Up Base	E8760	452	163	286	27	259	227	32	0	0	3
6	Gen Step Up Peak	D10C	1,171	395	772	69	703	631	72	0	0	4
7	Total Gen Step Up		1,623	558	1,058	96	962	858	104	0	0	7
8	Bulk Transmission	D10T	33,258	12,353	20,729	2,140	18,590	16,706	1,883	0	0	175
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	4	0	4	0	4	0	4	0	0	0
11	Total		34,885	12,911	21,791	2,236	19,556	17,564	1,991	0	0	182
	Distribution											
12	Generat Step Up	STRATH	90	32	58	5	52	46	6	0	0	0
13	Bulk Transmission	D10T	42	16	26	3	23	21	2	0	0	0
14	Distrib Function	D60Sub	8,491	3,876	4,531	516	4,014	3,484	531	0	0	84
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		8,623	3,924	4,615	524	4,090	3,551	539	0	0	85
17	Overhead Lines	POL	11,349	6,728	4,138	871	3,267	2,945	321	0	0	483
18	Underground	PUL	21,094	15,781	5,250	1,892	3,358	3,234	124	0	0	63
19	Line Transformers	P68	6,531	4,326	2,176	531	1,645	1,619	26	0	0	29
20	Services	P69	5,470	4,904	566	263	303	303	0	0	0	0
21	Meters	C12WM	3,117	2,137	979	467	512	490	22	0	0	1
22	Street Lighting	P73	1,478	0	0	0	0	0	0	0	0	1,478
23	Total		57,662	37,801	17,723	4,548	13,175	12,142	1,033	0	0	2,138
24	**General Plant**	PTD	8,419	3,452	4,891	535	4,356	3,876	480	0	0	76
25	**Electric Common**	PTD	17,390	7,131	10,103	1,106	8,997	8,006	991	0	0	157
26	**Total Accum Depr**		370,160	150,894	215,287	23,314	191,973	170,175	21,798	0	0	3,979
27	**Net Elec Plant**		393,057	162,061	228,104	25,227	202,878	181,181	21,697	0	0	2,891

Subtractions: Accum Defer Inc Tax

	Production											
28	Peaking Plant	D10C	22,489	7,585	14,826	1,334	13,492	12,111	1,381	0	0	79
29	Base Load	E8760	21,337	7,705	13,498	1,261	12,238	10,727	1,511	0	0	134
30	Nuclear Fuel	E8760	214	77	135	13	123	108	15	0	0	1
31	Total		44,041	15,367	28,459	2,607	25,853	22,946	2,907	0	0	214
	Transmission											
32	Gen Step Up Base	E8760	130	47	82	8	75	65	9	0	0	1
33	Gen Step Up Peak	D10C	336	113	222	20	202	181	21	0	0	1
34	Total Gen Step Up		466	160	304	28	276	246	30	0	0	2
35	Bulk Transmission	D10T	14,109	5,241	8,794	908	7,887	7,087	799	0	0	74
36	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
37	Direct Assign	Dir Assign	2	0	2	0	2	0	2	0	0	0
38	Total		14,577	5,401	9,100	935	8,165	7,334	831	0	0	76
	Distribution											
39	Generat Step Up	STRATH	42	15	27	2	24	22	3	0	0	0
40	Bulk Transmission	D10T	14	5	9	1	8	7	1	0	0	0
41	Distrib Function	D60Sub	2,218	1,013	1,183	135	1,049	910	139	0	0	22
42	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
43	Total Substations		2,274	1,033	1,219	138	1,081	939	142	0	0	22
44	Overhead Lines	POL	3,449	2,045	1,257	265	993	895	98	0	0	147
45	Underground	PUL	7,873	5,890	1,959	706	1,253	1,207	46	0	0	23
46	Line Transformers	P68	2,215	1,467	738	180	558	549	9	0	0	10
47	Services	P69	2,020	1,811	209	97	112	112	0	0	0	0
48	Meters	C12WM	1,072	735	337	161	176	169	8	0	0	0
49	Street Lighting	P73	(79)	0	0	0	0	0	0	0	0	(79)
50	Total		18,824	12,981	5,720	1,547	4,173	3,870	303	0	0	124
51	**General Plant**	PTD	2,406	986	1,398	153	1,245	1,108	137	0	0	22
52	**Electric Common**	PTD	2,019	828	1,173	128	1,045	930	115	0	0	18
53	**Total Deferred Tax**		81,867	35,563	45,850	5,370	40,479	36,187	4,292	0	0	454
54	TBT Acc Def Tax	NEPIS	0	0	0	0	0	0	0	0	0	0
55	Non-Plant Related	LABOR	(2,515)	(1,033)	(1,458)	(168)	(1,290)	(1,145)	(145)	0	0	(24)
56	**Accum Def W/ Adj**		79,352	34,530	44,392	5,203	39,189	35,042	4,147	0	0	430

	Additions: CWIP, Etc; Rate Base		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	CWIP											
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	312	105	206	18	187	168	19	0	0	1
2	Base Load	E8760	971	351	614	57	557	488	69	0	0	6
3	Nuclear Fuel	E8760	358	129	226	21	205	180	25	0	0	2
4	Total		1,641	585	1,046	97	949	836	113	0	0	9
	Transmission											
5	Gen Step Up Base	E8760	2	1	1	0	1	1	0	0	0	0
6	Gen Step Up Peak	D10C	5	2	3	0	3	3	0	0	0	0
7	Total Gen Step Up		7	3	5	0	4	4	0	0	0	0
8	Bulk Transmission	D10T	349	130	218	22	195	175	20	0	0	2
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		357	132	222	23	200	179	20	0	0	2
	Distribution											
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	8	5	3	1	2	2	0	0	0	0
18	Underground	PUL	9	7	2	1	1	1	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	1	0	0	0	0	0	0	0	0	1
23	Total		18	11	5	1	4	4	0	0	0	1
24	**General Plant**	PTD	34	14	20	2	17	15	2	0	0	0
25	**Electric Common**	PTD	51	21	30	3	27	24	3	0	0	0
26	**Total CWIP**		2,100	764	1,323	127	1,197	1,058	139	0	0	13
27	Fuel Inventory	E8760	5,674	2,049	3,589	335	3,254	2,853	402	0	0	36
	Materials & Supplies											
28	Production	P10	5,162	1,819	3,316	305	3,011	2,663	348	0	0	27
29	Trans & Distr	TD	1,024	540	468	74	393	356	37	0	0	17
30	Total		6,186	2,358	3,784	380	3,404	3,020	384	0	0	44
	Prepayments											
31	Miscellaneous	NEPIS	4,024	1,659	2,335	258	2,077	1,855	222	0	0	30
32	Total		4,024	1,659	2,335	258	2,077	1,855	222	0	0	30
33	Non-Plant Assets & Liab	LABOR	(6,173)	(2,535)	(3,578)	(411)	(3,167)	(2,811)	(356)	0	0	(59)
34	Working Cash	PT0	2,057	896	1,140	136	1,004	896	109	0	0	21
35	**Total Additions**		13,868	5,190	8,593	824	7,769	6,870	899	0	0	84
36	**Total Rate Base**		327,573	132,721	192,306	20,848	171,457	153,009	18,449	0	0	2,546
37	**Common Rate Base (@ 52.56%)**		172,172.4	69,758	101,076	10,958	90,118	80,421	9,697	0	0	1,338

Northern States Power Company, a Minnesota corporatior
Electric Utility - State of North Dakota
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Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 4

	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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	164,504	66,011	96,626	10,986	85,640	77,246	8,394	0	0	1,867
2	Proposed Rate Revenue	PROREV; (calc	184,155	73,373	108,913	12,061	96,852	87,253	9,599	0	0	1,869
	Other Retail Revenue											
3	Interdepartmental	R01; R02	0	0	0	0	0	0	0	0	0	0
4	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0
5	CIP Adjustment to Program Costs	D42E58	**0**	0	0	0	0	0	0	0	0	0
6	**Tot Other Retail Rev**		0	0	0	0	0	0	0	0	0	0
	Other Operating Revenue											
7	Interchg Prod Capacity	P10	11,506	4,054	7,392	681	6,711	5,936	775	0	0	60
8	Interchg Prod Energy	E8760	12,968	4,683	8,204	766	7,438	6,519	918	0	0	81
9	Interchg Tr Bulk Supply	D10T	2,415	897	1,505	155	1,350	1,213	137	0	0	13
10	Dist Int Sales; Oth Serv	E8760	0	0	0	0	0	0	0	0	0	0
11	Dist Overhd Line Rent	POL	255	151	93	20	73	66	7	0	0	11
12	Connection Charges	C11	243	205	33	24	9	9	0	0	0	5
13	Sales For Resale	E8760	9,166	3,310	5,799	542	5,257	4,608	649	0	0	58
14	Joint Op Agree-Other PSCo Rev	D10T	(307)	(114)	(191)	(20)	(172)	(154)	(17)	0	0	(2)
15	Production Assoc'd Rev	E8760	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10T	5,721	2,125	3,566	368	3,198	2,874	324	0	0	30
17	MISO	D10T	775	288	483	50	433	389	44	0	0	4
18	Other	D10T	(652)	(242)	(406)	(42)	(364)	(328)	(37)	0	0	(3)
19	Late Pay Chg - Pres	R16C; R02	355.0000	251	103	28	76	74	2	0	0	0
20	**Tot Other Op - Pres**		42,445	15,607	26,580	2,571	24,009	21,208	2,801	0	0	258
21	Incr Misc Serv - Prop	R01,	80	32	47	5	42	38	4	0	0	1
22	Incr Inter Departmental - Prop	R01; R02	0	0	0	0	0	0	0	0	0	0
23	Incr Late Pay - Prop	(R16C); R02	42	30	12	3	9	9	0	0	0	0
24	**Tot Other Op - Prop**		42,567	15,669	26,639	2,580	24,060	21,255	2,805	0	0	259
25	**Tot Oper Rev - Pres**		206,949	81,618	123,206	13,557	109,649	98,454	11,195	0	0	2,125
26	**Tot Oper Rev - Prop**		226,722	89,042	135,552	14,641	120,912	108,508	12,404	0	0	2,128
	Operating & Maint (Pg 1 of 2)											
	Production Expen											
27	**Fuel**	E8760	41,458	14,971	26,227	2,449	23,777	20,842	2,935	0	0	260
	Purchased Power											
28	Purchases: Cap Peak	D10C	7,009	2,364	4,621	416	4,205	3,775	430	0	0	25
29	Purchases: Cap Base	E8760	2,705	977	1,711	160	1,551	1,360	191	0	0	17
30	Purchases: Demand		9,714	3,341	6,332	575	5,756	5,135	622	0	0	42
31	Purchases: Other Energy	E8760	38,992	14,080	24,667	2,304	22,363	19,603	2,760	0	0	245
32	Tot Non-Assoc Purch		48,706	17,421	30,999	2,879	28,120	24,737	3,382	0	0	286
33	Interchg Agr Capacity	P10WoN	2,752	963	1,775	163	1,612	1,430	183	0	0	14
34	Interchg Agr Energy	E8760	1,193	431	755	70	684	600	84	0	0	7
35	Tot Wis Interchg Purch		3,945	1,394	2,530	233	2,297	2,030	267	0	0	21
36	**Tot Purchased Power**		52,651	18,815	33,529	3,113	30,416	26,767	3,649	0	0	308
	Other Production											
37	Capacity Peaking	D10C	5,218	1,760	3,440	309	3,130	2,810	320	0	0	18
38	Capacity Baseload	E8760	5,894	2,128	3,729	348	3,380	2,963	417	0	0	37
39	Total Capacity		11,112	3,888	7,169	658	6,511	5,773	738	0	0	55
40	Energy	E8760	19,015	6,866	12,029	1,123	10,906	9,560	1,346	0	0	119
41	Total Other Produc		30,127	10,755	19,198	1,781	17,417	15,333	2,084	0	0	175
42	**Total Production**		124,236	44,540	78,953	7,343	71,610	62,942	8,668	0	0	743
43	**Transmission Exp**	D10T	11,419	4,241	7,117	735	6,383	5,736	647	0	0	60

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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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	582	356	205	49	156	142	13	0	0	21
2	Load Dispatching	D10T	278	103	173	18	155	140	16	0	0	1
3	Substations	P61	411	187	220	25	195	169	26	0	0	4
4	Overhead Lines	POL	1,319	782	481	101	380	342	37	0	0	56
5	Underground Lines	PUL	1,713	1,282	426	154	273	263	10	0	0	5
6	Line Transformers	P68	8	5	3	1	2	2	0	0	0	0
7	Meters	C12WM	331	227	104	50	54	52	2	0	0	0
8	Customer Install'n	OXDTS	210	127	70	17	52	48	5	0	0	13
9	Street Lighting	Dir Assign	209	0	0	0	0	0	0	0	0	209
10	Miscellaneous	OXDTS	1,046	633	346	85	261	239	23	0	0	67
11	Rents (Pole Attachmts)	POL	185	110	67	14	53	48	5	0	0	8
12	**Total Distribution**		6,292	3,812	2,095	513	1,582	1,445	137	0	0	385
13	**Customer Accounting**	C11WA	4,339	3,393	931	595	336	331	5	0	0	15
14	**Sales, Econ Dvlp & Other**	D56E44	66	23	43	4	39	34	4	0	0	0
	Admin & General											
15	Salaries	LABOR	3,202	1,315	1,856	213	1,643	1,458	185	0	0	31
16	Office Supplies	OXTS	2,449	944	1,485	155	1,330	1,173	157	0	0	20
17	Admin Transfer Credit	OXTS	(966)	(372)	(586)	(61)	(525)	(463)	(62)	0	0	(8)
18	Outside Services	LABOR	818	336	474	54	420	372	47	0	0	8
19	Property Insurance	NEPIS	686	283	398	44	354	316	38	0	0	5
20	Pensions & Benefits	LABOR	4,828	1,983	2,799	322	2,477	2,199	279	0	0	46
21	Injuries & Claims	LABOR	805	331	467	54	413	367	46	0	0	8
22	Regulatory Exp	R01; R02	411	165	241	27	214	193	21	0	0	5
23	General Advertising	OXTS	20	8	12	1	11	10	1	0	0	0
24	Contributions	OXTS	0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	80	31	49	5	43	38	5	0	0	1
26	Rents	OXTS	967	373	586	61	525	463	62	0	0	8
27	Maint of General Plant	OXTS	22	8	13	1	12	11	1	0	0	0
28	Total		13,322	5,404	7,795	877	6,918	6,137	780	0	0	124
	Cust Service & Info											
29	Cust Assist Exp - Non-CIP	C11P10	376	225	146	30	117	104	13	0	0	5
30	CIP Total	D42E58	0	0	0	0	0	0	0	0	0	0
31	Instructional Advertising	C11P10	172	103	67	14	53	48	6	0	0	2
32	Total		548	327	213	43	170	152	19	0	0	7
33	Amortizations	LABOR	574	236	333	38	294	261	33	0	0	6
34	**Total O&M Expense**		160,796	61,976	97,481	10,148	87,332	77,039	10,293	0	0	1,339

Book Depreciation

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	5,370	1,811	3,540	318	3,222	2,892	330	0	0	19
2	Base Load	E8760	4,755	1,717	3,008	281	2,727	2,391	337	0	0	30
3	Total		10,125	3,528	6,548	599	5,949	5,282	666	0	0	49
	Transmission											
4	Gen Step Up Base	E8760	28	10	18	2	16	14	2	0	0	0
5	Gen Step Up Peak	D10C	71	24	47	4	43	38	4	0	0	0
6	Total Gen Step Up		99	34	65	6	59	52	6	0	0	0
7	Bulk Transmission	D10T	2,182	810	1,360	140	1,220	1,096	124	0	0	11
8	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
10	Total		2,281	845	1,425	146	1,278	1,148	130	0	0	12
	Distribution											
11	Generat Step Up	STRATH	6	2	4	0	3	3	0	0	0	0
12	Bulk Transmission	D10T	3	1	2	0	2	2	0	0	0	0
13	Distrib Function	D60Sub	323	147	172	20	153	133	20	0	0	3
14	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
15	Total Substations		332	151	178	20	158	137	21	0	0	3
16	Overhead Lines	POL	485	288	177	37	140	126	14	0	0	21
17	Underground	PUL	893	668	222	80	142	137	5	0	0	3
18	Line Transformers	P68	383	254	128	31	96	95	2	0	0	2
19	Services	P69	322	289	33	15	18	18	0	0	0	0
20	Meters	C12WM	183	125	57	27	30	29	1	0	0	0
21	Street Lighting	P73	58	0	0	0	0	0	0	0	0	58
22	Total		2,656	1,774	796	212	584	541	43	0	0	86
23	**General Plant**	PTD	956	392	555	61	495	440	54	0	0	9
24	**Electric Common**	PTD	1,679	688	975	107	869	773	96	0	0	15
25	**Total Book Deprec**		17,697	7,227	10,299	1,125	9,174	8,185	989	0	0	171

Real Estate & Property Tax

	Production											
26	Peaking Plant	D10C	692	233	456	41	415	373	42	0	0	2
27	Base Load	E8760	1,980	715	1,253	117	1,136	995	140	0	0	12
28	Total		2,672	948	1,709	158	1,551	1,368	183	0	0	15
	Transmission											
29	Gen Step Up Base	E8760	72	26	46	4	41	36	5	0	0	0
30	Gen Step Up Peak	D10C	253	85	167	15	152	136	16	0	0	1
31	Total Gen Step Up		325	111	212	19	193	172	21	0	0	1
32	Bulk Transmission	D10T	1,142	424	712	73	638	574	65	0	0	6
33	Distrib Function	D60Sub	1	0	1	0	0	0	0	0	0	0
34	Direct Assign	Dir Assign	1	0	1	0	1	0	1	0	0	0
35	Total		1,469	536	926	93	833	747	86	0	0	7
	Distribution											
36	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
37	Bulk Transmission	D10T	24	9	15	2	13	12	1	0	0	0
38	Distrib Function	D60Sub	247	113	132	15	117	101	15	0	0	2
39	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
40	Total Substations		271	122	147	17	130	113	17	0	0	3
41	Overhead Lines	POL	281	167	102	22	81	73	8	0	0	12
42	Underground	PUL	423	316	105	38	67	65	2	0	0	1
43	Line Transformers	P68	289	191	96	23	73	72	1	0	0	1
44	Services	P69	116	104	12	6	6	6	0	0	0	0
45	Meters	C12WM	113	77	35	17	19	18	1	0	0	0
46	Street Lighting	P73	19	0	0	0	0	0	0	0	0	19
47	Total		1,512	978	498	122	376	347	29	0	0	36
48	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
49	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0
50	**Tot Rl Est & Pr Tax**		5,653	2,462	3,133	373	2,760	2,462	298	0	0	58
51	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0
52	Payroll Taxes	LABOR	1,815	745	1,052	121	931	827	105	0	0	17
53	**Tot Non-Inc Taxes**		7,468	3,207	4,185	494	3,691	3,288	403	0	0	76

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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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	6,452	2,176	4,254	383	3,871	3,475	396	0	0	23
2	Nuclear Fuel	E8760	(338)	(122)	(214)	(20)	(194)	(170)	(24)	0	0	(2)
3	Base Load	E8760	4,316	1,558	2,730	255	2,475	2,170	306	0	0	27
4	Total		10,430	3,612	6,770	618	6,152	5,475	678	0	0	48
	Transmission											
5	Gen Step Up Base	E8760	24	9	15	1	14	12	2	0	0	0
6	Gen Step Up Peak	D10C	61	21	40	4	37	33	4	0	0	0
7	Total Gen Step Up		85	29	55	5	50	45	5	0	0	0
8	Bulk Transmission	D10T	1,494	555	931	96	835	750	85	0	0	8
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		1,579	584	987	101	885	795	90	0	0	8
	Distribution											
12	Generat Step Up	STRATH	1	0	1	0	1	1	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	(8)	(4)	(4)	(0)	(4)	(3)	(0)	0	0	(0)
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		(7)	(3)	(4)	(0)	(3)	(3)	(0)	0	0	(0)
17	Overhead Lines	POL	143	85	52	11	41	37	4	0	0	6
18	Underground	PUL	159	119	40	14	25	24	1	0	0	0
19	Line Transformers	P68	(54)	(36)	(18)	(4)	(14)	(13)	(0)	0	0	(0)
20	Services	P69	11	10	1	1	1	1	0	0	0	0
21	Meters	C12WM	15	10	5	2	2	2	0	0	0	0
22	Street Lighting	P73	5	0	0	0	0	0	0	0	0	5
23	Total		272	185	76	23	53	48	4	0	0	11
24	**General Plant**	PTD	208	85	121	13	108	96	12	0	0	2
25	**Electric Common**	PTD	(248)	(102)	(144)	(16)	(128)	(114)	(14)	0	0	(2)
26	**TBT Defer Inc Tax**	NEPIS	0	0	0	0	0	0	0	0	0	0
27	**Non - Plant Related**	LABOR	582	239	337	39	299	265	34	0	0	6
28	**Tot Prov For Defer**		12,823	4,604	8,147	778	7,368	6,565	804	0	0	72

Inv Tax Credit; Total Oper Exp

	Production											
29	Peaking Plant	D10C	(27)	(9)	(18)	(2)	(16)	(15)	(2)	0	0	(0)
30	Base Load	E8760	(51)	(18)	(32)	(3)	(29)	(26)	(4)	0	0	(0)
31	Total		(78)	(28)	(50)	(5)	(45)	(40)	(5)	0	0	(0)
	Transmission											
32	Bulk Transmission	D10T	(32)	(12)	(20)	(2)	(18)	(16)	(2)	0	0	(0)
33	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
34	Total		(32)	(12)	(20)	(2)	(18)	(16)	(2)	0	0	(0)
	Distribution											
35	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0
36	Underground	PUL	0	0	0	0	0	0	0	0	0	0
37	Total		0	0	0	0	0	0	0	0	0	0
38	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
39	**Electric Common**	PTD	(1)	(0)	(1)	(0)	(1)	(0)	(0)	0	0	(0)
40	**Net Inv Tax Credit**		(111)	(40)	(71)	(7)	(64)	(57)	(7)	0	0	(1)
41	**Total Operating Exp**		198,673	76,975	120,041	12,538	107,502	95,021	12,482	0	0	1,657
42A	**Pres Op Inc Before Inc Tax**		8,276	4,643	3,166	1,019	2,147	3,433	(1,287)	0	0	468
42B	**Prop Op Inc Before Inc Tax**		28,049	12,067	15,512	2,102	13,409	13,487	(77)	0	0	471

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	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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	21,975	7,411	14,487	1,303	13,184	11,835	1,349	0	0	77
2	Nuclear Fuel	E8760	5,440	1,964	3,441	321	3,120	2,735	385	0	0	34
3	Base Load	E8760	18,163	6,559	11,490	1,073	10,417	9,131	1,286	0	0	114
4	Total		45,578	15,934	29,418	2,698	26,721	23,700	3,020	0	0	225
	Transmission											
5	Gen Step Up Base	E8760	59	21	37	3	34	30	4	0	0	0
6	Gen Step Up Peak	D10C	153	52	101	9	92	82	9	0	0	1
7	Total Gen Step Up		212	73	138	13	126	112	14	0	0	1
8	Bulk Transmission	D10T	6,058	2,250	3,776	390	3,386	3,043	343	0	0	32
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	1	0	1	0	1	0	1	0	0	0
11	Total		6,271	2,323	3,915	402	3,513	3,155	358	0	0	33
	Distribution											
12	Generat Step Up	STRATH	9	3	6	1	5	5	1	0	0	0
13	Bulk Transmission	D10T	3	1	2	0	2	2	0	0	0	0
14	Distrib Function	D60Sub	312	142	166	19	148	128	19	0	0	3
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		324	147	174	20	154	134	20	0	0	3
17	Overhead Lines	POL	841	499	307	65	242	218	24	0	0	36
18	Underground	PUL	1,322	989	329	119	210	203	8	0	0	4
19	Line Transformers	P68	232	154	77	19	58	58	1	0	0	1
20	Services	P69	420	377	43	20	23	23	0	0	0	0
21	Meters	C12WM	198	136	62	30	33	31	1	0	0	0
22	Street Lighting	P73	70	0	0	0	0	0	0	0	0	70
23	Total		3,407	2,300	993	272	721	667	54	0	0	114
24	**General Plant**	PTD	1,787	733	1,038	114	924	823	102	0	0	16
25	**Electric Common**	PTD	1,071	439	622	68	554	493	61	0	0	10
26	**TBT Defer Inc Tax**	NEPIS	0	0	0	0	0	0	0	0	0	0
			0									
27	**Total Tax Deprec**		58,113	21,729	35,986	3,553	32,433	28,838	3,595	0	0	398
28	Interest Expense		9,270	3,756	5,442	590	4,852	4,330	522	0	0	72
29	Other Tax Timing Differ		1,407	523	877	91	786	707	80	0	0	7
30	Total Tax Deductions		68,791	26,008	42,305	4,234	38,072	33,875	4,197	0	0	477
	Inc Tax Additions											
31	Book Depreciation		17,697	7,227	10,299	1,125	9,174	8,185	989	0	0	171
32	Deferred Inc Tax & ITC		12,712	4,564	8,076	771	7,305	6,508	796	0	0	72
33	Nuclear Fuel Book Burn	E8760	6,478	2,339	4,098	383	3,715	3,257	459	0	0	41
34	Nuclear Fuel Disposal	E8760	0	0	0	0	0	0	0	0	0	0
35	Meals & Entertainment	LABOR	(39)	(16)	(23)	(3)	(20)	(18)	(2)	0	0	(0)
36	Avoided Tax Interest	RTBASE	2,520	1,021	1,479	160	1,319	1,177	142	0	0	20
37	Total Tax Additions		42,948	16,604	26,010	2,664	23,345	20,758	2,588	0	0	334
38	**Total Inc Tax Adjustments**		(25,843)	(9,404)	(16,296)	(1,569)	(14,726)	(13,117)	(1,609)	0	0	(143)
39A	**Pres Taxable Net Income**		(17,567)	(4,762)	(13,130)	(550)	(12,580)	(9,684)	(2,896)	0	0	325
39B	**Prop Taxable Net Income**		2,207	2,663	(784)	533	(1,317)	369	(1,686)	0	0	328
40A	Pres Fed & State Inc Tax		(8,337)	(2,260)	(6,232)	(261)	(5,970)	(4,596)	(1,374)	0	0	154
40B	Prop Fed & State Inc Tax		(581)	(701)	206	(140)	347	(97)	444	0	0	(86)
41A	Pres Preliminary Return	(total); BASE	16,613	6,903	9,397	1,280	8,117	8,029	88	0	0	313
41B	Prop Preliminary Return	(total); BASE	28,630	12,768	15,306	2,243	13,063	13,584	(521)	0	0	557
42	Total AFUDC		0	0	0	0	0	0	0	0	0	0
43A	**Present Total Return**		16,613	6,903	9,397	1,280	8,117	8,029	88	0	0	313
43B	**Proposed Total Return**		28,630	12,768	15,306	2,243	13,063	13,584	(521)	0	0	557
44A	**Pres % Return on Rate Base**		5.07%	5.20%	4.89%	6.14%	4.73%	5.25%	0.48%	0.00%	0.00%	12.31%
44B	**Prop % Return on Rate Base**		8.74%	9.62%	7.96%	10.76%	7.62%	8.88%	-2.83%	0.00%	0.00%	21.88%
45A	**Present Common Return**		7,343	3,147	3,955	690	3,265	3,699	(434)	0	0	241
45B	**Proposed Common Return**		19,360	9,012	9,863	1,653	8,210	9,254	(1,043)	0	0	485
46A	**Pres % Ret on Common Rate Base**		4.26%	4.51%	3.91%	6.30%	3.62%	4.60%	-4.48%	0.00%	0.00%	18.04%
46B	**Prop % Ret on Common Rate Base**		11.24%	12.92%	9.76%	15.08%	9.11%	11.51%	-10.76%	0.00%	0.00%	36.24%

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	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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	0	0	0	0	0	0	0	0	0	0
2	Nuclear Fuel	E8760	0	0	0	0	0	0	0	0	0	0
3	Base Load	E8760	0	0	0	0	0	0	0	0	0	0
4	Total		0	0	0	0	0	0	0	0	0	0
	Transmission											
5	Gen Step Up Base	E8760	0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	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	D10T	0	0	0	0	0	0	0	0	0	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		0	0	0	0	0	0	0	0	0	0
	Distribution											
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0
18	Underground	PUL	0	0	0	0	0	0	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	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		0	0	0	0	0	0	0	0	0	0
24	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
25	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0
26	**Total AFUDC**		0	0	0	0	0	0	0	0	0	0
	Labor Allocator											
	Production											
27	Other Prod - Cap	OXOPD	11,064	3,871	7,138	655	6,483	5,748	734	0	0	55
28	Other Prod - Ene	E8760	4,271	1,542	2,702	252	2,450	2,147	302	0	0	27
29	Total		15,335	5,414	9,839	907	8,932	7,895	1,037	0	0	82
	Transmission											
30	Stepup Subtrans	P5161A	41	14	27	2	24	22	3	0	0	0
31	Bulk Power Subs	D10T	945	351	589	61	528	475	54	0	0	5
32	Total		986	365	616	63	553	496	56	0	0	5
	Distribution											
33	Superv & Eng	ZDTS	431	264	152	36	115	105	10	0	0	16
34	Load Dispatch	D10T	237	88	148	15	132	119	13	0	0	1
35	Substation	P61	189	86	101	11	90	78	12	0	0	2
36	Overhead Lines	POL	396	235	144	30	114	103	11	0	0	17
37	Underground Lines	PUL	758	567	189	68	121	116	4	0	0	2
38	Line Transformer	P68	0	0	0	0	0	0	0	0	0	0
39	Meter	C12WM	186	128	58	28	31	29	1	0	0	0
40	Cust Installation	ZDTS	233	143	82	20	62	57	5	0	0	8
41	Street Lighting	P73	34	0	0	0	0	0	0	0	0	34
42	Miscellaneous	OXDTS	336	203	111	27	84	77	7	0	0	21
43	Total		2,800	1,713	985	236	749	684	65	0	0	102
44	Cust Accounting	C11WA	941	736	202	129	73	72	1	0	0	3
45	Sales Expense	C11P10	1	1	0	0	0	0	0	0	0	0
46	Admin & General	LABOR	8,712	3,578	5,050	580	4,470	3,967	503	0	0	84
47	Service & Inform	C11P10	66	39	26	5	21	18	2	0	0	1
48	**Labor**		28,841	11,846	16,719	1,921	14,797	13,134	1,664	0	0	276

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	Backwards Revenue Calc	1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	(1A) Modified Pres Rev	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Preliminary Return (Before AFUDC)	16,613	6,903	9,397	1,280	8,117	8,029	88	0	0	313
2	1/(1-T) Rev Reqt (= 1.9033)	31,620	13,138	17,886	2,436	15,449	15,282	167	0	0	597
3	Total Inc Tax Adjustments	(25,843)	(9,404)	(16,296)	(1,569)	(14,726)	(13,117)	(1,609)	0	0	(143)
4	T/(1-T) Rev Reqt (= 0.9033)	(23,344)	(8,495)	(14,720)	(1,418)	(13,303)	(11,849)	(1,453)	0	0	(129)
5	Tot Op Exp W/o Regul Exp	198,262	76,810	119,799	12,511	107,288	94,828	12,461	0	0	1,652
6	- Other Retail Rev W/o Gr Earn, Etc	0	0	0	0	0	0	0	0	0	0
7	- Other Op Rev W/o Late Pay, Etc.	42,090	15,356	26,477	2,543	23,933	21,134	2,799	0	0	257
8	Modified Pres Net Oper Exp	156,172	61,455	93,322	9,967	83,355	73,694	9,661	0	0	1,395
9	**Mod Pres Rev (R02) (component alloc)**	164,448	66,097	96,488	10,986	85,502	77,127	8,375	0	0	1,863
	(1B) Present Revenue										
10	Tot Oper Exp (w/ Regul Exp)	198,673	76,975	120,041	12,538	107,502	95,021	12,482	0	0	1,657
11	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0	0
12	- Other Oper Rev (w/ Late Pay, Etc)	42,445	15,607	26,580	2,571	24,009	21,208	2,801	0	0	258
13	Net Oper Exp Rev Reqt	156,228	61,368	93,460	9,967	83,493	73,813	9,681	0	0	1,399
14	**Tot Pres Rate Rev Reqt (R01)**	164,504	66,011	96,626	10,986	85,640	77,246	8,394	0	0	1,867
		0	0	0	0	0	0	0	0	0	0
	(2) Proposed Return										
15	Total Operating Exp	198,673	76,975	120,041	12,538	107,502	95,021	12,482	0	0	1,657
16	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0	0
17	- Prop Other Operating Rev	42,567	15,669	26,639	2,580	24,060	21,255	2,805	0	0	259
18	Prop Net Oper Exp Rev Reqt	156,106	61,306	93,401	9,959	83,443	73,766	9,676	0	0	1,398
19	Prop Preliminary Return	28,630	12,768	15,306	2,243	13,063	13,584	(521)	0	0	557
20	1/(1-T) Rev Reqt (= 0.7916)	22,663	10,107	12,115	1,775	10,340	10,753	(413)	0	0	441
21	T/(1-T) Rev Reqt (= -0.2084)	5,386	1,960	3,396	327	3,069	2,734	335	0	0	30
22	**Total Proposed Rate Rev Reqt**	184,155	73,373	108,913	12,061	96,852	87,253	9,599	0	0	1,869
	(3) Equal Return Rev										
23	T/(1-T) Rev Reqt (= -0.2084)	5,386	1,960	3,396	327	3,069	2,734	335	0	0	30
24	Equal Net Oper Exp Rev Reqt	156,106	61,306	93,401	9,959	83,443	73,766	9,676	0	0	1,398
25	Equal Rate of Ret (8.74%) x Rate Base	28,630	11,600	16,808	1,822	14,986	13,373	1,612	0	0	223
26	- AFUDC	0	0	0	0	0	0	0	0	0	0
27	Net Return	28,630	11,600	16,808	1,822	14,986	13,373	1,612	0	0	223
28	1/(1-T) Rev Reqt (= 0.7916)	22,663	9,182	13,305	1,442	11,862	10,586	1,276	0	0	176
29	**Net Equal-Ret Rate Rev-Reqt (R99)**	184,155	72,449	110,102	11,728	98,374	87,086	11,288	0	0	1,604
30	Tot Oper Rev - Equal	226,722	88,118	136,742	14,308	122,434	108,341	14,093	0	0	1,863
31	- Total Operating Exp	198,673	76,975	120,041	12,538	107,502	95,021	12,482	0	0	1,657
32	Equal Op Inc Before Inc Tax	28,049	11,142	16,701	1,769	14,932	13,320	1,612	0	0	206
33	Equal Taxable Net Income	2,207	1,738	405	200	205	203	3	0	0	63
34	Equal Fed & State Inc Tax	(581)	(458)	(107)	(53)	(54)	(53)	(1)	0	0	(17)
35	Proposed Common Return	19,360	7,844	11,366	1,232	10,133	9,043	1,090	0	0	150
36	Equal Return on Common	11.24%	11.24%	11.24%	11.24%	11.24%	11.24%	11.24%	0.00%	0.00%	11.24%

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			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL ALLOCATORS		Intern:	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Rate Base: Col %'s**	**BASE-COL**	**1000.000%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
			100.000%									
2	50% Cus, 50% Prod Plt	C11P10	100.000%	59.718%	38.927%	7.863%	31.064%	27.679%	3.385%	0.000%	0.000%	1.355%
3	Peaking Plant Capacity	D10C	100.000%	33.725%	65.924%	5.930%	59.994%	53.854%	6.140%	0.000%	0.000%	0.351%
4	56% Sum/Win Dmd, 44% Ene	D56E44	100.000%	34.780%	64.747%	5.920%	58.826%	52.271%	6.556%	0.000%	0.000%	0.473%
5	61% Sum/Win Dmd, 39% Ene	D42E58	100.000%	33.754%	65.892%	5.929%	59.962%	53.810%	6.152%	0.000%	0.000%	0.354%
6	Labor w/o (or w/) A&G	LABOR	100.000%	41.073%	57.968%	6.662%	51.306%	45.538%	5.769%	0.000%	0.000%	0.959%
7	Net Plant In Service	NEPIS	100.000%	41.231%	58.033%	6.418%	51.615%	46.095%	5.520%	0.000%	0.000%	0.736%
8	Dis O&M w/o Sup & Misc	OXDTS	100.000%	60.522%	33.108%	8.130%	24.978%	22.811%	2.166%	0.000%	0.000%	6.370%
9	Other Prod Capac O&M	OXOPD	100.000%	34.991%	64.512%	5.918%	58.593%	51.955%	6.638%	0.000%	0.000%	0.498%
10	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	100.000%	38.539%	60.629%	6.310%	54.318%	47.914%	6.405%	0.000%	0.000%	0.832%
11	Production Plant	P10	100.000%	35.231%	64.243%	5.916%	58.327%	51.594%	6.733%	0.000%	0.000%	0.526%
12	Production Plant Wo Nuclear	P10WoN	100.000%	34.991%	64.512%	5.918%	58.593%	51.955%	6.639%	0.000%	0.000%	0.498%
13	Total P51 & P61A	P5161A	100.000%	34.432%	65.135%	5.923%	59.212%	52.794%	6.418%	0.000%	0.000%	0.433%
14	Distribution Plant	P60	100.000%	66.628%	30.702%	8.012%	22.690%	20.952%	1.739%	0.000%	0.000%	2.669%
15	Distr Substn Plant	P61	100.000%	45.475%	53.544%	6.083%	47.461%	41.210%	6.251%	0.000%	0.000%	0.981%
16	Line Transformer Plant	P68	100.000%	66.238%	33.318%	8.129%	25.190%	24.785%	0.404%	0.000%	0.000%	0.443%
17	Services Plant	P69	100.000%	89.658%	10.342%	4.811%	5.531%	5.531%	0.000%	0.000%	0.000%	0.000%
18	Dist Plt Overhead Lines	POL	100.000%	59.285%	36.458%	7.673%	28.785%	25.953%	2.832%	0.000%	0.000%	4.257%
19	Real Est & Property Tax	PT0	100.000%	43.552%	55.417%	6.596%	48.821%	43.545%	5.276%	0.000%	0.000%	1.031%
20	Produc, Trans & Distrib	PTD	100.000%	41.005%	58.095%	6.360%	51.735%	46.036%	5.699%	0.000%	0.000%	0.900%
21	Dist Plt Undground Lines	PUL	100.000%	74.815%	24.889%	8.968%	15.921%	15.333%	0.588%	0.000%	0.000%	0.297%
22	Rev w/o Reg, etc: Col %	R02-COL	1000.000%	N/A	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
			100.000%	41.55%	56.56%	7.71%	48.86%	48.33%	0.53%	0.00%	0.00%	1.89%
			100.000%	44.60%	53.46%	7.83%	45.63%	47.45%	-1.82%	0.00%	0.00%	1.95%
23	Rate Base (Non-Column)	RTBASE	100.000%	40.517%	58.706%	6.365%	52.342%	46.710%	5.632%	0.000%	0.000%	0.777%
24	Stratified Hydro Baseload	STRATH	100.000%	35.380%	64.077%	5.915%	58.162%	51.370%	6.792%	0.000%	0.000%	0.543%
25	Transmission & Distrib	TD	100.000%	52.687%	45.655%	7.258%	38.397%	34.791%	3.606%	0.000%	0.000%	1.658%
26	Labor Dis w/o Sup & Eng	ZDTS	100.000%	61.176%	35.188%	8.440%	26.748%	24.430%	2.318%	0.000%	0.000%	3.636%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
27	Labor w/o A&G	LABOR(S)	20,129	8,268	11,668	1,341	10,327	9,166	1,161	0	0	193
28	Dis O&M w/o Sup, Cust Install & Misc	OXDTS	4,454	2,696	1,475	362	1,113	1,016	96	0	0	284
29	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	157,813	60,820	95,680	9,958	85,721	75,614	10,107	0	0	1,313
30	Total P51 & P61A	P5161A	4,785	1,648	3,117	283	2,833	2,526	307	0	0	21
31	Produc, Trans & Distrib	PTD	715,012	293,189	415,387	45,475	369,912	329,164	40,748	0	0	6,436
32	Transmission & Distrib	TD	236,499	124,604	107,974	17,166	90,808	82,279	8,529	0	0	3,921
33	Labor Dis w/o Sup & Eng, Cust Install	ZDTS	2,136	1,307	752	180	571	522	50	0	0	78

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			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	84.21%	13.61%	9.81%	3.80%	3.76%	0.04%	0.00%	0.00%	2.18%
2	Cust Acctg Wtg Factor	C11WA	100.00%	78.20%	21.46%	13.71%	7.74%	7.64%	0.11%	0.00%	0.00%	0.34%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	68.56%	31.41%	14.98%	16.43%	15.72%	0.71%	0.00%	0.00%	0.03%
4	Sec & Pri Customers	C61PS	100.00%	86.02%	13.88%	9.97%	3.90%	3.86%	0.04%	0.00%	0.00%	0.10%
5	C62Sec, w/o Ltg & C/I Underground	C62NL	100.00%	92.42%	7.58%	5.47%	2.12%	2.12%	0.00%	0.00%	0.00%	0.00%
6	Secondary Customers	C62Sec	100.00%	86.05%	13.84%	9.98%	3.87%	3.87%	0.00%	0.00%	0.00%	0.10%
7	Summer Peak Resp KW	D10S	100.00%	30.77%	69.23%	5.86%	63.37%	56.76%	6.61%	0.00%	0.00%	0.00%
8	Transmission Demand %	D10T	100.00%	37.14%	62.33%	6.43%	55.90%	50.23%	5.66%	0.00%	0.00%	0.53%
9	Winter Peak Resp KW	D10W	100.00%	41.04%	57.74%	6.11%	51.64%	46.66%	4.98%	0.00%	0.00%	1.22%
11	Sec, Pri & TT, Class Coin kW @ Subst	D60Sub	100.00%	45.65%	53.36%	6.08%	47.28%	41.03%	6.25%	0.00%	0.00%	0.99%
12	Sec & Pri, Cl Coin kW (no Min Sys; ad	D61PS	100.00%	36.58%	62.45%	6.10%	56.35%	48.81%	7.54%	0.00%	0.00%	0.97%
13	D62Sec, w/o Ltg & C/I Underground	D62NLL	100.00%	82.32%	17.68%	3.07%	14.61%	14.61%	0.00%	0.00%	0.00%	0.00%
14	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	100.00%	50.65%	48.64%	6.59%	42.05%	42.05%	0.00%	0.00%	0.00%	0.71%
15	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%
16	On + Off Sales MWH	E8760	100.00%	36.11%	63.26%	5.91%	57.35%	50.27%	7.08%	0.0000%	0.0000%	0.63%
17	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%
18	Present Rev	R01	100.00%	40.13%	58.74%	6.68%	52.06%	46.96%	5.10%	0.00%	0.00%	1.13%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
APPLIED EXTERNAL DATA			**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - B Basis	C10	88,572	76,190	12,291	8,835	3,456	3,422	33	0	0	92
2	Cust - Ave Monthly (C10-Area Lt)	C11	90,926	76,564	12,376	8,920	3,456	3,422	33	0	0	1,986
3	Mo Cus Wtd By Cus Acct	C11WA	96,333	75,335	20,671	13,210	7,461	7,359	102	0	0	327
4	Cust Acctg Wtg Factor	C11WAF	7.67	0.98	6.69	1.48	5.20	2.15	3.05	0.00	0.00	N/A
5	Cust-Ave Mo (C11 w/ Dir Assign St Ltg	C12	88,955	76,564	12,376	8,920	3,456	3,422	33	0	0	15
6	Mo Cus Wtd By Mtr Invest	C12WM	10,476,614	7,183,237	3,290,587	1,569,127	1,721,460	1,646,882	74,578	0	0	2,791
7	Meter Invest / Cust Factor	C12WMF	3,177	94	2,893	176	2,717	481	2,236	0	0	190
8	Sec & Pri Customers	C61PS	88,572	76,190	12,291	8,835	3,456	3,422	33	0	0	92
9	C62Sec, w/o Ltg & C/I Underground	C62NL	82,441	76,190	6,251	4,506	1,745	1,745	0	0	0	0
10	Secondary Customers	C62Sec	88,539	76,190	12,257	8,835	3,422	3,422	0	0	0	92
11	Summer Peak Resp KW	D10S	475,445	146,312	329,133	27,853	301,280	269,856	31,424	0	0	0
12	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,714,410	6,233,029	643,320	5,589,709	5,023,376	566,333	0	0	52,562
13	Winter Peak Resp KW	D10W	397,194	162,995	229,354	24,256	205,098	185,322	19,775	0	0	4,845
15	Sec, Pri & TT, Class Coin kW @ Subst	D60Sub	548,153	250,245	292,487	33,341	259,145	224,897	34,249	0	0	5,422
16	Sec & Pri, Class Coin kW (w/o Min Sys	D61PS	453,593	165,936	283,268	27,683	255,585	221,394	34,192	0	0	4,389
17	D62Sec, w/o Ltg & C/I Underground	D62NLL	814,953	670,875	144,078	25,030	119,049	119,049	0	0	0	0
18	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	10,000,000	5,065,401	4,863,722	659,109	4,204,612	4,204,612	0	0	0	70,877
19	Annual Billing kW	D99	3,452	0	3,452	0	3,452	3,148	304	0	0	0
20	Summer Billing kW	D99S	1,192	0	1,192	0	1,192	1,083	109	0	0	0
21	Winter Billing kW	D99W	2,260	0	2,260	0	2,260	2,065	194	0	0	0
22	Non-Coinc Pk Second	DN-Sec	1,086,560	670,875	411,653	71,514	340,139	340,139	0	0	0	4,033
23	kWh Sales @ Meter	E99	2,251,280	805,939	1,426,442	128,671	1,297,771	1,133,621	164,150	0	0	18,899

Northern States Power Company, a Minnesota corporation
Electric Utility - North Dakota
2012 Step-In Adjustment
Summary of Class Cost of Service Study Results ($000)

Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 5
Page 1 of 1

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 2)	188,372	74,106	11,995	100,638	1,633
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	131	69	9	53	1
[3]	Unadjusted Operating Revenues (line 2 + line 3)	188,503	74,174	12,005	100,691	1,634
[4]	Present Rates (CCOSS page 2, line 3)	164,504	66,011	10,986	85,640	1,867
[5]	Unadjusted Deficiency (line 3 - line 4)	23,999	8,163	1,019	15,051	(233)
[6]	Defic / Pres (line 5 / line 4)	14.6%	12.4%	9.3%	17.6%	-12.5%
[7]	**Ratio: Class % / Total %**	**1.00**	**0.85**	**0.64**	**1.20**	**-0.86**

CAPACITY COST RESPONSIBILITIES FOR INTERRUPTIBLE RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
[8]	Interruption Rate Discounts (CCOSS page 2, line 6)	4,756	718	50	3,988	0
[9]	Interruption Capacity Costs (CCOSS page 2, line 7)	4,756	1,604	282	2,853	17
[10]	Revenue Requirement Shift (line 9 - line 8)	0	886	232	(1,135)	17

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	188,372	74,992	12,227	99,503	1,650
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	131	69	9	53	1
[13]	Adjusted Operating Revenues (line 11 + line 12)	188,503	75,060	12,237	99,556	1,651
[14]	Present Rates (line 4)	164,504	66,011	10,986	85,640	1,867
[15]	Adjusted Deficiency (line 13 - line 14)	23,999	9,049	1,251	13,916	(216)
[16]	Defic / Pres Rates (line 15 / line 4)	14.6%	13.7%	11.4%	16.2%	-11.6%
[17]	**Ratio: Class % / Total %**	**1.00**	**0.94**	**0.78**	**1.11**	**-0.79**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[18]	Proposed Rates (CCOSS page 3, line 3)	188,372	75,053	12,337	99,070	1,912
[19]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	131	69	9	53	1
[20]	Proposed Operating Revenues (line 18 + line 19)	188,503	75,122	12,346	99,123	1,913
[21]	Proposed Increase (line 20 - line 14)	23,999	9,111	1,360	13,483	46
[22]	Difference / Pres (line 21 / line 14)	14.6%	13.8%	12.4%	15.7%	2.5%
[23]	**Ratio: Class % / Total %**	**1.00**	**0.95**	**0.85**	**1.08**	**0.17**

Northern States Power Company, a Minnesota corporatior
Electric Utility - State of North Dakota
2012 Step-In Adjustment
Class Cost of Service Study Detail

Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 6

Rate Base

	Plant In Service	Alloc	1=2+3+10 ND	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	Production		495,234	174,358	318,286	29,300	288,986	255,688	33,298	0	0	2,590
2	Transmission		115,591	42,804	72,183	7,412	64,771	58,179	6,592	0	0	603
3	Distribution		125,117	83,364	38,414	10,024	28,390	26,214	2,175	0	0	3,340
4	General		20,607	8,415	12,009	1,309	10,700	9,523	1,178	0	0	183
5	Common		27,597	11,269	16,083	1,753	14,330	12,753	1,577	0	0	245
6	TBT Invest		0	0	0	0	0	0	0	0	0	0
7	Total		784,145	320,210	456,975	49,798	407,178	362,357	44,821	0	0	6,960
	Depreciation Reserve											
8	Production		251,416	89,451	160,542	14,866	145,675	128,403	17,272	0	0	1,423
9	Transmission		35,754	13,234	22,333	2,292	20,041	18,001	2,041	0	0	186
10	Distribution		57,662	37,801	17,723	4,548	13,175	12,142	1,033	0	0	2,138
11	General		8,419	3,438	4,906	535	4,372	3,890	481	0	0	75
12	Common		17,390	7,101	10,134	1,104	9,030	8,036	994	0	0	154
13	Total		370,641	151,025	215,638	23,345	192,293	170,472	21,821	0	0	3,977
14	**Net Plant In Service**		413,505	169,184	241,337	26,453	214,884	191,885	23,000	0	0	2,983
	Deductions											
15	Accum Defer Inc Tax		82,841	35,742	46,654	5,412	41,241	36,874	4,367	0	0	445
	Additions											
16	Constr Work In Progress		2,100	764	1,324	127	1,197	1,058	139	0	0	13
17	Fuel Inventory		5,674	2,049	3,589	335	3,254	2,853	402	0	0	36
18	Materials & Supplies		6,186	2,354	3,788	380	3,409	3,024	384	0	0	44
19	Prepayments		4,681	1,915	2,732	299	2,432	2,172	260	0	0	34
20	Non-Plant Assets & Liab		(6,173)	(2,535)	(3,579)	(411)	(3,168)	(2,812)	(356)	0	0	(59)
21	Working Cash		1,734	747	970	114	856	763	93	0	0	17
22	Total		14,202	5,294	8,823	843	7,980	7,058	922	0	0	84
23	**Rate Base**		344,865	138,736	203,507	21,884	181,623	162,068	19,555	0	0	2,623

Income Statement

24A	**Tot Oper Rev - Pres**		206,949	81,615	123,209	13,557	109,652	98,458	11,194	0	0	2,124
24B	**Tot Oper Rev - Prop**		230,948	90,726	138,052	14,917	123,135	110,512	12,623	0	0	2,170
25	Oper & Maint		161,283	62,143	97,799	10,178	87,621	77,299	10,321	0	0	1,341
26	Book Depr + IRS Int		19,228	7,756	11,295	1,216	10,079	8,991	1,088	0	0	177
27	Payroll Tax		1,815	745	1,052	121	931	827	105	0	0	17
28	Real Est & Prop Tax		6,021	2,594	3,367	395	2,972	2,650	322	0	0	60
29	Deferred Inc Taxes		12,596	4,509	8,017	765	7,253	6,470	783	0	0	69
30A	Present Income Tax		(9,550)	(2,705)	(6,990)	(342)	(6,648)	(5,227)	(1,421)	0	0	144
30B	Proposed Income Tax		(136)	(133)	11	(25)	37	(30)	67	0	0	(15)
31	Allow Funds Dur Const		0	0	0	0	0	0	0	0	0	0
32A	**Present Return**		15,556	6,573	8,668	1,224	7,444	7,449	(5)	0	0	315
32B	**Proposed Return**		30,141	13,111	16,510	2,268	14,242	14,305	(63)	0	0	520
33A	**Pres Ret on Rt Base**		4.51%	4.74%	4.26%	5.60%	4.10%	4.60%	-0.03%	0.00%	0.00%	12.00%
33B	**Prop Ret on Rt Base**		8.74%	9.45%	8.11%	10.37%	7.84%	8.83%	-0.32%	0.00%	0.00%	19.81%
34A	**Pres Ret on Common**		3.20%	3.63%	2.72%	5.26%	2.41%	3.36%	-5.44%	0.00%	0.00%	17.44%
34B	**Prop Ret on Common**		11.24%	12.60%	10.05%	14.34%	9.53%	11.41%	-6.00%	0.00%	0.00%	32.31%

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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Equal Return On Rate Base**		**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**	**8.74%**
2	**UnAdj Equalized Rev Reqt**		**188,372**	**74,106**	**112,633**	**11,995**	**100,638**	**89,116**	**11,522**	**0**	**0**	**1,633**
3	**UnAdj Present Revenue**		**164,504**	**66,011**	**96,626**	**10,986**	**85,640**	**77,246**	**8,394**	**0**	**0**	**1,867**
4	**UnAdj Revenue Deficiency**		**23,868**	**8,095**	**16,007**	**1,009**	**14,998**	**11,870**	**3,128**	**0**	**0**	**(234)**
5	**UnAdj Deficiency / Present**		**14.51%**	**12.26%**	**16.57%**	**9.19%**	**17.51%**	**15.37%**	**37.27%**	**0.00%**	**0.00%**	**-12.54%**
6	**Interruption Rate Discounts**		**4,756**	**718**	**4,038**	**50**	**3,988**	**2,720**	**1,268**	**0**	**0**	**0**
7	**Interruptible Capacity Costs**	D10C	**4,756**	**1,604**	**3,135**	**282**	**2,853**	**2,561**	**292**	**0**	**0**	**17**
8	**Revenue Shift**		**0**	**886**	**(903)**	**232**	**(1,135)**	**(159)**	**(976)**	**0**	**0**	**17**
9	**Adj Equal Rev Reqt (Rows 2+8)**		**188,372**	**74,992**	**111,731**	**12,227**	**99,503**	**88,957**	**10,546**	**0**	**0**	**1,650**
10	**Pres Rev (Row 3)**		**164,504**	**66,011**	**96,626**	**10,986**	**85,640**	**77,246**	**8,394**	**0**	**0**	**1,867**
11	**Adj Revenue Deficiency**		**23,868**	**8,981**	**15,105**	**1,241**	**13,863**	**11,711**	**2,152**	**0**	**0**	**(217)**
12	**Adj Deficiency / Adj Present**		**14.51%**	**13.60%**	**15.63%**	**11.30%**	**16.19%**	**15.16%**	**25.64%**	**0.00%**	**0.00%**	**-11.64%**
	Customer Classification											
13	Min Sys & Service Drop		9,408	7,421	1,361	912	449	443	6	0	0	625
14	Energy Services		5,284	4,148	1,112	714	399	393	5	0	0	24
15	Total Customer **(Cusco)**		14,691	11,569	2,473	1,626	848	836	12	0	0	649
16	Ave Monthly Customers		90,926	76,564	12,376	8,920	3,456	3,422	33	0	0	1,986
17	Svc Drop Reqt	$ / Mo / Cust	$8.62	$8.08	$9.16	$8.52	$10.83	$10.78	$15.61	$0.00	$0.00	$26.25
18	Ener Svcs Reqt	$ / Mo / Cust	$4.84	$4.51	$7.49	$6.67	$9.61	$9.57	$13.50	$0.00	$0.00	$0.99
19	Total Reqt	$ / Mo / Cust	$13.46	$12.59	$16.65	$15.19	$20.44	$20.35	$29.11	$0.00	$0.00	$27.24
	Energy Classification											
20	On Peak Rev Reqt		43,335	14,373	28,857	2,849	26,007	22,908	3,099	0	0	105
21	Off Peak Rev Reqt		39,608	15,513	23,679	2,048	21,630	18,845	2,785	0	0	417
22	Total Ener Rev Reqt		82,943	29,886	52,535	4,898	47,638	41,753	5,885	0	0	522
23	Annual kWh Sales		2,251,280	805,939	1,426,442	128,671	1,297,771	1,133,621	164,150	0	0	18,899
24	On Pk Reqt	Mills / kWh	19.249	17.834	20.230	22.145	20.040	20.208	18.882	0.000	0.000	5.563
25	Off Pk Reqt	Mills / kWh	17.594	19.248	16.600	15.918	16.667	16.624	16.969	0.000	0.000	22.055
26	Total Reqt	Mills / kWh	36.843	37.082	36.830	38.063	36.707	36.831	35.851	0.000	0.000	27.619
	Demand Classification											
27	Energy-Related Prod		28,523	10,289	18,055	1,685	16,370	14,350	2,020	0	0	180
28	Capacity-Related Summer Peak Prod		27,658	8,498	19,160	1,620	17,541	15,711	1,830	0	0	0
29	Capacity-Related Winter Peak Prod		11,164	4,576	6,452	682	5,771	5,214	556	0	0	136
30	Total Production		67,346	23,362	43,668	3,986	39,682	35,275	4,406	0	0	316
31	Transmission **(Transco)**		16,424	6,091	10,246	1,056	9,190	8,258	933	0	0	87
32	Primary Dist Subs		1,942	885	1,038	118	920	798	122	0	0	19
33	Prim Dist Lines		2,187	799	1,367	133	1,234	1,069	165	0	0	21
34	Second Dist, Trans		2,839	1,515	1,306	178	1,127	1,127	(0)	0	0	18
35	Total Distribution **(Disco)**		6,968	3,198	3,711	430	3,281	2,994	287	0	0	59
36	Total Demand Rev Reqt		90,737	32,651	57,625	5,472	52,153	46,527	5,626	0	0	462
37	Annual Billing kW		3,451,562	0	3,451,562	0	3,451,562	3,147,931	303,631	0	0	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$5.23	$0.00	$4.74	$4.56	$6.65	$0.00	$0.00	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$5.55	$0.00	$5.08	$4.99	$6.03	$0.00	$0.00	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.87	$0.00	$1.67	$1.66	$1.83	$0.00	$0.00	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$12.65	$0.00	$11.50	$11.21	$14.51	$0.00	$0.00	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.97	$0.00	$2.66	$2.62	$3.07	$0.00	$0.00	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$1.08	$0.00	$0.95	$0.95	$0.94	$0.00	$0.00	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$16.70	$0.00	$15.11	$14.78	$18.53	$0.00	$0.00	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	40.305	40.513	40.398	42.527	40.186	41.043	34.272	0.000	0.000	24.443
46	Summer Billing kW		1,191,898	0	1,191,898	0	1,191,898	1,082,535	109,363	0	0	0
47	Winter Billing kW		2,259,664	0	2,259,664	0	2,259,664	2,065,396	194,268	0	0	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$25.35	$0.00	$23.07	$22.65	$27.40	$0.00	$0.00	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$12.13	$0.00	$10.91	$10.66	$13.53	$0.00	$0.00	$0.00
50	Energy + Production **(Genco)**		150,289	53,248	96,203	8,884	87,320	77,028	10,291	0	0	838

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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	**Proposed Ret On Rt Base**		**8.74%**	**9.45%**	**8.11%**	**10.37%**	**7.84%**	**8.83%**	**-0.32%**	**0.00%**	**0.00%**	**19.81%**
2	**UnAdj Equalized Rev Reqt**		**188,372**	**74,106**	**112,633**	**11,995**	**100,638**	**89,116**	**11,522**	**0**	**0**	**1,633**
3	**UnAdj Proposed Revenue**		**188,372**	**75,053**	**111,407**	**12,337**	**99,070**	**89,251**	**9,819**	**0**	**0**	**1,912**
4	**UnAdj Revenue Deficiency**		**(0)**	**(947)**	**1,226**	**(342)**	**1,568**	**(135)**	**1,703**	**0**	**0**	**(279)**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**-1.26%**	**1.10%**	**-2.77%**	**1.58%**	**-0.15%**	**17.35%**	**0%**	**0%**	**-14.60%**
6	**Interruption Rate Discounts**		**4,756**	**718**	**4,038**	**50**	**3,988**	**2,720**	**1,268**	**0**	**0**	**0**
7	**Interruptible Capacity Costs**	**D10C**	**4,756**	**1,604**	**3,135**	**282**	**2,853**	**2,561**	**292**	**0**	**0**	**17**
8	**Revenue Shift**		**0**	**886**	**(903)**	**232**	**(1,135)**	**(159)**	**(976)**	**0**	**0**	**17**
9	**Adj Equal Rev (Rows 2+8)**		**188,372**	**74,992**	**111,731**	**12,227**	**99,503**	**88,957**	**10,546**	**0**	**0**	**1,650**
10	**Prop Rev (Row 3)**		**188,372**	**75,053**	**111,407**	**12,337**	**99,070**	**89,251**	**9,819**	**0**	**0**	**1,912**
11	**Adj Revenue Deficiency**		**(0)**	**(61)**	**324**	**(110)**	**433**	**(294)**	**727**	**0**	**0**	**(262)**
12	**Adj Deficiency / Adj Prop**		**0.00%**	**-0.08%**	**0.29%**	**-0.89%**	**0.44%**	**-0.33%**	**7.41%**	**0.00%**	**0.00%**	**-13.72%**
	Customer Component											
13	Min Sys & Service Drop		9,408	6,444	2,378	860	1,517	1,518	(1)	0	0	585
14	Energy Services		5,284	4,153	1,107	715	393	387	5	0	0	23
15	Total Customer **(Cusco)**		14,691	10,598	3,485	1,575	1,910	1,906	4	0	0	609
16	Ave Monthly Customers		90,926	76,564	12,376	8,920	3,456	3,422	33	0	0	1,986
17	Svc Drop Reqt	$ / Mo / Cust	$8.62	$7.01	$16.01	$8.04	$36.59	$36.97	($2.67)	$0.00	$0.00	$24.57
18	Ener Svcs Reqt	$ / Mo / Cust	$4.84	$4.52	$7.46	$6.68	$9.47	$9.43	$13.61	$0.00	$0.00	$0.98
19	Total Reqt	$ / Mo / Cust	$13.46	$11.53	$23.46	$14.71	$46.06	$46.40	$10.94	$0.00	$0.00	$25.55
	Energy Component											
20	On Peak Rev Reqt		43,335	14,395	28,832	2,851	25,980	22,896	3,084	0	0	108
21	Off Peak Rev Reqt		39,608	15,521	23,669	2,053	21,616	18,845	2,771	0	0	418
22	Total Ener Rev Reqt		82,943	29,916	52,501	4,904	47,596	41,741	5,855	0	0	526
23	Annual kWh Sales		2,251,280	805,939	1,426,442	128,671	1,297,771	1,133,621	164,150	0	0	18,899
24	On Pk Reqt	Mills / kWh	19.249	17.862	20.212	22.161	20.019	20.198	18.786	0.000	0.000	5.732
25	Off Pk Reqt	Mills / kWh	17.594	19.258	16.593	15.954	16.656	16.624	16.882	0.000	0.000	22.125
26	Total Reqt	Mills / kWh	36.843	37.120	36.805	38.115	36.675	36.821	35.668	0.000	0.000	27.857
	Demand Component											
27	Base Load Prod		28,523	10,932	17,315	1,826	15,490	14,105	1,385	0	0	275
28	Summer Peak Prod		27,658	9,387	18,151	1,736	16,415	15,062	1,353	0	0	121
29	Winter Peak Prod		11,164	4,645	6,369	722	5,647	5,237	410	0	0	151
30	Total Production		67,346	24,964	41,835	4,283	37,552	34,403	3,148	0	0	547
31	Transmission **(Transco)**		16,424	6,447	9,823	1,117	8,705	8,102	603	0	0	154
32	Primary Dist Subs		1,942	874	1,045	126	919	833	87	0	0	23
33	Prim Dist Lines		2,187	836	1,326	141	1,185	1,061	123	0	0	25
34	Second Dist, Trans		2,839	1,419	1,392	190	1,202	1,204	(2)	0	0	28
35	Total Distribution **(Disco)**		6,968	3,128	3,764	457	3,306	3,098	208	0	0	76
36	Total Demand Rev Reqt		90,737	34,539	55,422	5,858	49,564	45,604	3,960	0	0	777
37	Annual Billing kW		3,451,562	0	3,451,562	0	3,451,562	3,147,931	303,631	0	0	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$5.02	$0.00	$4.49	$4.48	$4.56	$0.00	$0.00	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$5.26	$0.00	$4.76	$4.78	$4.46	$0.00	$0.00	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.85	$0.00	$1.64	$1.66	$1.35	$0.00	$0.00	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$12.12	$0.00	$10.88	$10.93	$10.37	$0.00	$0.00	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.85	$0.00	$2.52	$2.57	$1.99	$0.00	$0.00	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$1.09	$0.00	$0.96	$0.98	$0.69	$0.00	$0.00	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$16.06	$0.00	$14.36	$14.49	$13.04	$0.00	$0.00	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	40.305	42.856	38.853	45.526	38.191	40.229	24.122	0.000	0.000	41.103
46	Summer Billing kW		1,191,898	0	1,191,898	0	1,191,898	1,082,535	109,363	0	0	0
47	Winter Billing kW		2,259,664	0	2,259,664	0	2,259,664	2,065,396	194,268	0	0	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$24.18	$0.00	$21.74	$21.95	$19.61	$0.00	$0.00	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$11.77	$0.00	$10.47	$10.57	$9.34	$0.00	$0.00	$0.00
50	Energy + Production **(Genco)**		150,289	54,880	94,336	9,188	85,148	76,145	9,003	0	0	1,073
51	Prop Rev - Pres Rev (Pg 2)		23,868	9,042	14,781	1,351	13,430	12,005	1,425	0	0	45
52	Difference / Present		14.51%	13.70%	15.30%	12.30%	15.68%	15.54%	16.98%	0.00%	0.00%	2.41%
53	Adj Prop - Adj Pres (Pg 2)		23,868	9,042	14,781	1,351	13,430	12,005	1,425	0	0	45
54	Difference / Adj Present		14.51%	13.70%	15.30%	12.30%	15.68%	15.54%	16.98%	0.00%	0.00%	2.41%

Northern States Power Company, a Minnesota corporatior
Electric Utility - State of North Dakota
2012 Step-In Adjustment
Class Cost of Service Study Detail

Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 6

Original Plant in Service

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Summer Peak	D10S	133,643	41,127	92,516	7,829	84,687	75,854	8,833	0	0	0
2	WInter Peak	D10W	53,954	22,141	31,155	3,295	27,860	25,174	2,686	0	0	658
3	Total Peak	[D10C]	187,597	63,268	123,671	11,124	112,547	101,028	11,519	0	0	658
4	Base Load	E8760	205,010	74,031	129,692	12,113	117,579	103,066	14,513	0	0	1,287
5	Nuclear Fuel	E8760	102,627	37,059	64,923	6,063	58,859	51,594	7,265	0	0	644
6	Total	47.78%	495,234	174,358	318,286	29,300	288,986	255,688	33,298	0	0	2,590
	Transmission											
7	Gen Step Up Base	E8760	1,276	461	807	75	732	641	90	0	0	8
8	Gen Step Up Peak	D10C	3,306	1,115	2,179	196	1,983	1,780	203	0	0	12
9	Total Gen Step Up		4,582	1,576	2,987	271	2,715	2,422	293	0	0	20
10	Bulk Transmission	D10T	110,996	41,228	69,184	7,141	62,043	55,757	6,286	0	0	583
11	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign	13	0	13	0	13	0	13	0	0	0
13	Total		115,591	42,804	72,183	7,412	64,771	58,179	6,592	0	0	603
	Distribution: Substations											
14	Generat Step Up	STRATH	203	72	130	12	118	104	14	0	0	1
15	Bulk Transmission	D10T	105	39	65	7	59	53	6	0	0	1
16	Distrib Function	D60Sub	16,532	7,547	8,821	1,006	7,816	6,783	1,033	0	0	164
17	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
18	Total		16,840	7,658	9,017	1,024	7,992	6,940	1,053	0	0	165
	Overhead Lines											
19	Primary Capacity	D61PS	9,738	3,562	6,081	594	5,487	4,753	734	0	0	94
20	Primary Customer	C61PS	7,126	6,130	989	711	278	275	3	0	0	7
21	Total Primary		16,864	9,692	7,070	1,305	5,765	5,028	737	0	0	102
22	Second Capacity	D62SecL	3,684	1,866	1,792	243	1,549	1,549	0	0	0	26
23	Second Customer	C62Sec	4,489	3,863	621	448	174	174	0	0	0	5
24	Total Secondary		8,173	5,729	2,413	691	1,722	1,722	0	0	0	31
25	Street Lighting	DASL	975	0	0	0	0	0	0	0	0	975
26	Total		26,012	15,421	9,483	1,996	7,488	6,751	737	0	0	1,107
	Underground Lines											
27	Primary Capacity	D61PS	3,623	1,325	2,263	221	2,041	1,768	273	0	0	35
28	Primary Customer	C61PS	22,106	19,016	3,068	2,205	862	854	8	0	0	23
29	Total Primary		25,729	20,341	5,330	2,426	2,904	2,623	281	0	0	58
30	Second Capacity	D62SecL	10,110	5,121	4,917	666	4,251	4,251	0	0	0	72
31	Second Customer	C62Sec	12,020	10,343	1,664	1,199	465	465	0	0	0	12
32	Total Secondary		22,130	15,465	6,581	1,866	4,715	4,715	0	0	0	84
33	Total		47,859	35,806	11,911	4,292	7,619	7,338	281	0	0	142
	Line Transformers											
34	Primary	D61PS	753	275	470	46	424	368	57	0	0	7
35	Second Capacity	D62SecL	6,807	3,448	3,311	449	2,862	2,862	0	0	0	48
36	Second Customer	C62Sec	6,481	5,577	897	647	251	251	0	0	0	7
37	Total		14,041	9,301	4,678	1,141	3,537	3,480	57	0	0	62
	Services											
38	Second Capacity	D62NLL	3,228	2,657	571	99	472	472	0	0	0	0
39	Second Customer	C62NL	8,582	7,931	651	469	182	182	0	0	0	0
40	Total		11,810	10,589	1,221	568	653	653	0	0	0	0
41	Meters	C12WM	6,694	4,590	2,103	1,003	1,100	1,052	48	0	0	2
42	Street Lighting	Dir Assign	1,861	0	0	0	0	0	0	0	0	1,861
43	**Total Distribution**		125,117	83,364	38,414	10,024	28,390	26,214	2,175	0	0	3,340
44	**General Plant**	PTD	20,607	8,415	12,009	1,309	10,700	9,523	1,178	0	0	183
45	**Electric Common**	PTD	27,597	11,269	16,083	1,753	14,330	12,753	1,577	0	0	245
46	Prelim Elec Plant		784,145	320,210	456,975	49,798	407,178	362,357	44,821	0	0	6,960
47	TBT Investment	NEPIS	0	0	0	0	0	0	0	0	0	0
48	**Elec Plant in Serv**		784,145	320,210	456,975	49,798	407,178	362,357	44,821	0	0	6,960

Accum Deprec; Net Plant

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	56,052	18,904	36,952	3,324	33,628	30,186	3,442	0	0	197
2	Nuclear Fuel	E8760	92,443	33,382	58,481	5,462	53,019	46,475	6,544	0	0	580
3	Base Load	E8760	102,921	37,165	65,109	6,081	59,028	51,742	7,286	0	0	646
4	Total		251,416	89,451	160,542	14,866	145,675	128,403	17,272	0	0	1,423
	Transmission											
5	Gen Step Up Base	E8760	452	163	286	27	259	227	32	0	0	3
6	Gen Step Up Peak	D10C	1,171	395	772	69	703	631	72	0	0	4
7	Total Gen Step Up		1,623	558	1,058	96	962	858	104	0	0	7
8	Bulk Transmission	D10T	34,127	12,676	21,271	2,195	19,076	17,143	1,933	0	0	179
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	4	0	4	0	4	0	4	0	0	0
11	Total		35,754	13,234	22,333	2,292	20,041	18,001	2,041	0	0	186
	Distribution											
12	Generat Step Up	STRATH	90	32	58	5	52	46	6	0	0	0
13	Bulk Transmission	D10T	42	16	26	3	23	21	2	0	0	0
14	Distrib Function	D60Sub	8,491	3,876	4,531	516	4,014	3,484	531	0	0	84
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		8,623	3,924	4,615	524	4,090	3,551	539	0	0	85
17	Overhead Lines	POL	11,349	6,728	4,138	871	3,267	2,945	321	0	0	483
18	Underground	PUL	21,094	15,781	5,250	1,892	3,358	3,234	124	0	0	63
19	Line Transformers	P68	6,531	4,326	2,176	531	1,645	1,619	26	0	0	29
20	Services	P69	5,470	4,904	566	263	303	303	0	0	0	0
21	Meters	C12WM	3,117	2,137	979	467	512	490	22	0	0	1
22	Street Lighting	P73	1,478	0	0	0	0	0	0	0	0	1,478
23	Total		57,662	37,801	17,723	4,548	13,175	12,142	1,033	0	0	2,138
24	**General Plant**	PTD	8,419	3,438	4,906	535	4,372	3,890	481	0	0	75
25	**Electric Common**	PTD	17,390	7,101	10,134	1,104	9,030	8,036	994	0	0	154
26	**Total Accum Depr**		370,641	151,025	215,638	23,345	192,293	170,472	21,821	0	0	3,977
27	**Net Elec Plant**		413,505	169,184	241,337	26,453	214,884	191,885	23,000	0	0	2,983

Subtractions: Accum Defer Inc Tax

	Production											
28	Peaking Plant	D10C	24,490	8,260	16,145	1,452	14,693	13,189	1,504	0	0	86
29	Base Load	E8760	22,148	7,998	14,011	1,309	12,703	11,135	1,568	0	0	139
30	Nuclear Fuel	E8760	214	77	135	13	123	108	15	0	0	1
31	Total		46,853	16,335	30,292	2,773	27,518	24,431	3,087	0	0	226
	Transmission											
32	Gen Step Up Base	E8760	130	47	82	8	75	65	9	0	0	1
33	Gen Step Up Peak	D10C	336	113	222	20	202	181	21	0	0	1
34	Total Gen Step Up		466	160	304	28	276	246	30	0	0	2
35	Bulk Transmission	D10T	14,786	5,492	9,216	951	8,265	7,428	837	0	0	78
36	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
37	Direct Assign	Dir Assign	2	0	2	0	2	0	2	0	0	0
38	Total		15,254	5,652	9,522	979	8,543	7,674	869	0	0	80
	Distribution											
39	Generat Step Up	STRATH	42	15	27	2	24	22	3	0	0	0
40	Bulk Transmission	D10T	14	5	9	1	8	7	1	0	0	0
41	Distrib Function	D60Sub	2,218	1,013	1,183	135	1,049	910	139	0	0	22
42	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
43	Total Substations		2,274	1,033	1,219	138	1,081	939	142	0	0	22
44	Overhead Lines	POL	3,449	2,045	1,257	265	993	895	98	0	0	147
45	Underground	PUL	7,873	5,890	1,959	706	1,253	1,207	46	0	0	23
46	Line Transformers	P68	2,215	1,467	738	180	558	549	9	0	0	10
47	Services	P69	2,020	1,811	209	97	112	112	0	0	0	0
48	Meters	C12WM	1,072	735	337	161	176	169	8	0	0	0
49	Street Lighting	P73	(79)	0	0	0	0	0	0	0	0	(79)
50	Total		18,824	12,981	5,720	1,547	4,173	3,870	303	0	0	124
51	**General Plant**	PTD	2,406	982	1,402	153	1,249	1,112	138	0	0	21
52	**Electric Common**	PTD	2,019	825	1,177	128	1,049	933	115	0	0	18
53	**Total Deferred Tax**		85,356	36,775	48,112	5,580	42,532	38,020	4,512	0	0	469
54	TBT Acc Def Tax	NEPIS	0	0	0	0	0	0	0	0	0	0
55	Non-Plant Related	LABOR	(2,515)	(1,033)	(1,458)	(168)	(1,291)	(1,146)	(145)	0	0	(24)
56	**Accum Def W/ Adj**		82,841	35,742	46,654	5,412	41,241	36,874	4,367	0	0	445

	Additions: CWIP, Etc; Rate Base		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	CWIP											
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	312	105	206	18	187	168	19	0	0	1
2	Base Load	E8760	971	351	614	57	557	488	69	0	0	6
3	Nuclear Fuel	E8760	358	129	226	21	205	180	25	0	0	2
4	Total		1,641	585	1,046	97	949	836	113	0	0	9
	Transmission											
5	Gen Step Up Base	E8760	2	1	1	0	1	1	0	0	0	0
6	Gen Step Up Peak	D10C	5	2	3	0	3	3	0	0	0	0
7	Total Gen Step Up		7	3	5	0	4	4	0	0	0	0
8	Bulk Transmission	D10T	349	130	218	22	195	175	20	0	0	2
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		357	132	222	23	200	179	20	0	0	2
	Distribution											
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	8	5	3	1	2	2	0	0	0	0
18	Underground	PUL	9	7	2	1	1	1	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	1	0	0	0	0	0	0	0	0	1
23	Total		18	11	5	1	4	4	0	0	0	1
24	**General Plant**	PTD	34	14	20	2	17	16	2	0	0	0
25	**Electric Common**	PTD	51	21	30	3	27	24	3	0	0	0
26	**Total CWIP**		2,100	764	1,324	127	1,197	1,058	139	0	0	13
27	Fuel Inventory	E8760	5,674	2,049	3,589	335	3,254	2,853	402	0	0	36
	Materials & Supplies											
28	Production	P10	5,162	1,817	3,318	305	3,012	2,665	347	0	0	27
29	Trans & Distr	TD	1,024	537	470	74	396	359	37	0	0	17
30	Total		6,186	2,354	3,788	380	3,409	3,024	384	0	0	44
	Prepayments											
31	Miscellaneous	NEPIS	4,681	1,915	2,732	299	2,432	2,172	260	0	0	34
32	Total		4,681	1,915	2,732	299	2,432	2,172	260	0	0	34
33	Non-Plant Assets & Liab	LABOR	(6,173)	(2,535)	(3,579)	(411)	(3,168)	(2,812)	(356)	0	0	(59)
34	Working Cash	PT0	1,734	747	970	114	856	763	93	0	0	17
35	**Total Additions**		14,202	5,294	8,823	843	7,980	7,058	922	0	0	84
36	**Total Rate Base**		344,865	138,736	203,507	21,884	181,623	162,068	19,555	0	0	2,623
37	**Common Rate Base (@ 52.56%)**		181,261.3	72,920	106,963	11,502	95,461	85,183	10,278	0	0	1,379

Northern States Power Company, a Minnesota corporatior
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Schedule 6

			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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	164,504	66,011	96,626	10,986	85,640	77,246	8,394	0	0	1,867
2	Proposed Rate Revenue	PROREV; (calc	188,372	75,053	111,407	12,337	99,070	89,251	9,819	0	0	1,912
	Other Retail Revenue											
3	Interdepartmental	R01; R02	0	0	0	0	0	0	0	0	0	0
4	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0
5	CIP Adjustment to Program Costs	D42E58	**0**	0	0	0	0	0	0	0	0	0
6	**Tot Other Retail Rev**		0	0	0	0	0	0	0	0	0	0
	Other Operating Revenue											
7	Interchg Prod Capacity	P10	11,506	4,051	7,395	681	6,714	5,941	774	0	0	60
8	Interchg Prod Energy	E8760	12,968	4,683	8,204	766	7,438	6,519	918	0	0	81
9	Interchg Tr Bulk Supply	D10T	2,415	897	1,505	155	1,350	1,213	137	0	0	13
10	Interchg Decomm		0	0	0	0	0	0	0	0	0	0
10	Dist Int Sales; Oth Serv	E8760	0	0	0	0	0	0	0	0	0	0
11	Dist Overhd Line Rent	POL	255	151	93	20	73	66	7	0	0	11
12	Connection Charges	C11	243	205	33	24	9	9	0	0	0	5
13	Sales For Resale	E8760	9,166	3,310	5,799	542	5,257	4,608	649	0	0	58
14	Joint Op Agree-Other PSCo Rev	D10T	(307)	(114)	(191)	(20)	(172)	(154)	(17)	0	0	(2)
15	Production Assoc'd Rev	E8760	0	0	0	0	0	0	0	0	0	0
16	Misc Ancillary Trans Rev	D10T	5,721	2,125	3,566	368	3,198	2,874	324	0	0	30
17	MISO	D10T	775	288	483	50	433	389	44	0	0	4
18	Other	D10T	(652)	(242)	(406)	(42)	(364)	(328)	(37)	0	0	(3)
19	Late Pay Chg - Pres	R16C; R02	355.0000	251	103	28	76	74	2	0	0	0
20	**Tot Other Op - Pres**		42,445	15,604	26,583	2,571	24,012	21,212	2,800	0	0	257
21	Incr Misc Serv - Prop	R01,	80	32	47	5	42	38	4	0	0	1
22	Incr Inter Departmental - Prop	R01; R02	0	0	0	0	0	0	0	0	0	0
23	Incr Late Pay - Prop	(R16C); R02	52	36	15	4	11	11	0	0	0	0
24	**Tot Other Op - Prop**		42,576	15,673	26,645	2,580	24,065	21,261	2,804	0	0	258
25	**Tot Oper Rev - Pres**		206,949	81,615	123,209	13,557	109,652	98,458	11,194	0	0	2,124
26	**Tot Oper Rev - Prop**		230,948	90,726	138,052	14,917	123,135	110,512	12,623	0	0	2,170
	Operating & Maint (Pg 1 of 2)											
	Production Expen											
27	**Fuel**	E8760	41,458	14,971	26,227	2,449	23,777	20,842	2,935	0	0	260
	Purchased Power											
28	Purchases: Cap Peak	D10C	7,009	2,364	4,621	416	4,205	3,775	430	0	0	25
29	Purchases: Cap Base	E8760	2,705	977	1,711	160	1,551	1,360	191	0	0	17
30	Purchases: Demand		9,714	3,341	6,332	575	5,756	5,134	622	0	0	42
31	Purchases: Other Energy	E8760	38,992	14,080	24,667	2,304	22,363	19,603	2,760	0	0	245
32	Tot Non-Assoc Purch		48,706	17,421	30,999	2,879	28,120	24,737	3,382	0	0	286
33	Interchg Agr Capacity	P10WoN	2,752	962	1,776	163	1,613	1,431	182	0	0	14
34	Interchg Agr Energy	E8760	1,193	431	755	70	684	600	84	0	0	7
35	Tot Wis Interchg Purch		3,945	1,393	2,531	233	2,297	2,030	267	0	0	21
36	**Tot Purchased Power**		52,651	18,814	33,529	3,113	30,417	26,768	3,649	0	0	308
	Other Production											
37	Capacity Peaking	D10C	5,502	1,856	3,627	326	3,301	2,963	338	0	0	19
38	Capacity Baseload	E8760	6,013	2,171	3,804	355	3,449	3,023	426	0	0	38
39	Total Capacity		11,515	4,027	7,431	682	6,750	5,986	764	0	0	57
40	Energy	E8760	18,883	6,819	11,946	1,116	10,830	9,493	1,337	0	0	119
41	Total Other Produc		30,398	10,846	19,377	1,797	17,579	15,479	2,100	0	0	176
42	**Total Production**		124,507	44,631	79,133	7,359	71,774	63,089	8,685	0	0	743
43	**Transmission Exp**	D10T	11,635	4,322	7,252	749	6,504	5,845	659	0	0	61

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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	582	356	205	49	156	142	13	0	0	21
2	Load Dispatching	D10T	278	103	173	18	155	140	16	0	0	1
3	Substations	P61	411	187	220	25	195	169	26	0	0	4
4	Overhead Lines	POL	1,319	782	481	101	380	342	37	0	0	56
5	Underground Lines	PUL	1,713	1,282	426	154	273	263	10	0	0	5
6	Line Transformers	P68	8	5	3	1	2	2	0	0	0	0
7	Meters	C12WM	331	227	104	50	54	52	2	0	0	0
8	Customer Install'n	OXDTS	210	127	70	17	52	48	5	0	0	13
9	Street Lighting	Dir Assign	209	0	0	0	0	0	0	0	0	209
10	Miscellaneous	OXDTS	1,046	633	346	85	261	239	23	0	0	67
11	Rents (Pole Attachmts)	POL	185	110	67	14	53	48	5	0	0	8
12	**Total Distribution**		6,292	3,812	2,095	513	1,582	1,445	137	0	0	385
13	**Customer Accounting**	C11WA	4,339	3,393	931	595	336	331	5	0	0	15
14	**Sales, Econ Dvlp & Other**	D56E44	66	23	43	4	39	34	4	0	0	0
	Admin & General											
15	Salaries	LABOR	3,202	1,315	1,857	213	1,643	1,459	185	0	0	31
16	Office Supplies	OXTS	2,449	944	1,485	155	1,331	1,174	157	0	0	20
17	Admin Transfer Credit	OXTS	(966)	(372)	(586)	(61)	(525)	(463)	(62)	0	0	(8)
18	Outside Services	LABOR	818	336	474	54	420	373	47	0	0	8
19	Property Insurance	NEPIS	686	281	400	44	356	318	38	0	0	5
20	Pensions & Benefits	LABOR	4,828	1,983	2,799	322	2,478	2,199	278	0	0	46
21	Injuries & Claims	LABOR	805	331	467	54	413	367	46	0	0	8
22	Regulatory Exp	R01; R02	411	165	241	27	214	193	21	0	0	5
23	General Advertising	OXTS	20	8	12	1	11	10	1	0	0	0
24	Contributions	OXTS	0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	80	31	49	5	43	38	5	0	0	1
26	Rents	OXTS	967	373	586	61	525	463	62	0	0	8
27	Maint of General Plant	OXTS	22	8	13	1	12	11	1	0	0	0
28	Total		13,322	5,400	7,798	877	6,922	6,141	780	0	0	123
	Cust Service & Info											
29	Cust Assist Exp - Non-CIP	C11P10	376	224	146	30	117	104	13	0	0	5
30	CIP Total	D42E58	0	0	0	0	0	0	0	0	0	0
31	Instructional Advertising	C11P10	172	103	67	14	53	48	6	0	0	2
32	Total		548	327	213	43	170	152	19	0	0	7
33	Amortizations	LABOR	574	236	333	38	295	261	33	0	0	5
34	**Total O&M Expense**		161,283	62,143	97,799	10,178	87,621	77,299	10,321	0	0	1,341

Book Depreciation

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	6,247	2,107	4,119	370	3,748	3,364	384	0	0	22
2	Base Load	E8760	5,323	1,922	3,367	314	3,053	2,676	377	0	0	33
3	Total		11,570	4,029	7,486	685	6,801	6,040	760	0	0	55
	Transmission											
4	Gen Step Up Base	E8760	28	10	18	2	16	14	2	0	0	0
5	Gen Step Up Peak	D10C	71	24	47	4	43	38	4	0	0	0
6	Total Gen Step Up		99	34	65	6	59	52	6	0	0	0
7	Bulk Transmission	D10T	2,268	842	1,414	146	1,268	1,139	128	0	0	12
8	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
10	Total		2,367	876	1,478	152	1,326	1,192	135	0	0	12
	Distribution											
11	Generat Step Up	STRATH	6	2	4	0	3	3	0	0	0	0
12	Bulk Transmission	D10T	3	1	2	0	2	2	0	0	0	0
13	Distrib Function	D60Sub	323	147	172	20	153	133	20	0	0	3
14	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
15	Total Substations		332	151	178	20	158	137	21	0	0	3
16	Overhead Lines	POL	485	288	177	37	140	126	14	0	0	21
17	Underground	PUL	893	668	222	80	142	137	5	0	0	3
18	Line Transformers	P68	383	254	128	31	96	95	2	0	0	2
19	Services	P69	322	289	33	15	18	18	0	0	0	0
20	Meters	C12WM	183	125	57	27	30	29	1	0	0	0
21	Street Lighting	P73	58	0	0	0	0	0	0	0	0	58
22	Total		2,656	1,774	796	212	584	541	43	0	0	86
23	**General Plant**	PTD	956	390	557	61	496	442	55	0	0	8
24	**Electric Common**	PTD	1,679	686	978	107	872	776	96	0	0	15
25	**Total Book Deprec**		19,228	7,756	11,295	1,216	10,079	8,991	1,088	0	0	177

Real Estate & Property Tax

	Production											
26	Peaking Plant	D10C	761	257	502	45	457	410	47	0	0	3
27	Base Load	E8760	2,180	787	1,379	129	1,250	1,096	154	0	0	14
28	Total		2,941	1,044	1,881	174	1,707	1,506	201	0	0	16
	Transmission											
29	Gen Step Up Base	E8760	77	28	49	5	44	39	5	0	0	0
30	Gen Step Up Peak	D10C	270	91	178	16	162	145	17	0	0	1
31	Total Gen Step Up		347	119	227	21	206	184	22	0	0	1
32	Bulk Transmission	D10T	1,219	453	760	78	681	612	69	0	0	6
33	Distrib Function	D60Sub	1	0	1	0	0	0	0	0	0	0
34	Direct Assign	Dir Assign	1	0	1	0	1	0	1	0	0	0
35	Total		1,568	572	988	99	889	797	92	0	0	8
	Distribution											
36	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
37	Bulk Transmission	D10T	24	9	15	2	13	12	1	0	0	0
38	Distrib Function	D60Sub	247	113	132	15	117	101	15	0	0	2
39	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
40	Total Substations		271	122	147	17	130	113	17	0	0	3
41	Overhead Lines	POL	281	167	102	22	81	73	8	0	0	12
42	Underground	PUL	423	316	105	38	67	65	2	0	0	1
43	Line Transformers	P68	289	191	96	23	73	72	1	0	0	1
44	Services	P69	116	104	12	6	6	6	0	0	0	0
45	Meters	C12WM	113	77	35	17	19	18	1	0	0	0
46	Street Lighting	P73	19	0	0	0	0	0	0	0	0	19
47	Total		1,512	978	498	122	376	347	29	0	0	36
48	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
49	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0
50	**Tot Rl Est & Pr Tax**		6,021	2,594	3,367	395	2,972	2,650	322	0	0	60
51	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0
52	Payroll Taxes	LABOR	1,815	745	1,052	121	931	827	105	0	0	17
53	**Tot Non-Inc Taxes**		7,836	3,339	4,419	516	3,903	3,476	427	0	0	78

	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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	7,009	2,364	4,620	416	4,205	3,774	430	0	0	25
2	Nuclear Fuel	E8760	(338)	(122)	(214)	(20)	(194)	(170)	(24)	0	0	(2)
3	Base Load	E8760	3,643	1,316	2,305	215	2,090	1,832	258	0	0	23
4	Total		10,314	3,557	6,711	611	6,100	5,436	664	0	0	45
	Transmission											
5	Gen Step Up Base	E8760	24	9	15	1	14	12	2	0	0	0
6	Gen Step Up Peak	D10C	61	21	40	4	37	33	4	0	0	0
7	Total Gen Step Up		85	29	55	5	50	45	5	0	0	0
8	Bulk Transmission	D10T	1,494	555	931	96	835	750	85	0	0	8
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		1,579	584	987	101	885	795	90	0	0	8
	Distribution											
12	Generat Step Up	STRATH	1	0	1	0	1	1	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	(8)	(4)	(4)	(0)	(4)	(3)	(0)	0	0	(0)
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		(7)	(3)	(4)	(0)	(3)	(3)	(0)	0	0	(0)
17	Overhead Lines	POL	143	85	52	11	41	37	4	0	0	6
18	Underground	PUL	159	119	40	14	25	24	1	0	0	0
19	Line Transformers	P68	(54)	(36)	(18)	(4)	(14)	(13)	(0)	0	0	(0)
20	Services	P69	11	10	1	1	1	1	0	0	0	0
21	Meters	C12WM	15	10	5	2	2	2	0	0	0	0
22	Street Lighting	P73	5	0	0	0	0	0	0	0	0	5
23	Total		272	185	76	23	53	48	4	0	0	11
24	**General Plant**	PTD	208	85	121	13	108	96	12	0	0	2
25	**Electric Common**	PTD	(248)	(101)	(145)	(16)	(129)	(115)	(14)	0	0	(2)
26	**TBT Defer Inc Tax**	NEPIS	0	0	0	0	0	0	0	0	0	0
27	**Non - Plant Related**	LABOR	582	239	337	39	299	265	34	0	0	6
28	**Tot Prov For Defer**		12,707	4,549	8,088	771	7,317	6,527	790	0	0	70
	Inv Tax Credit; Total Oper Exp											
	Production											
29	Peaking Plant	D10C	(27)	(9)	(18)	(2)	(16)	(15)	(2)	0	0	(0)
30	Base Load	E8760	(51)	(18)	(32)	(3)	(29)	(26)	(4)	0	0	(0)
31	Total		(78)	(28)	(50)	(5)	(45)	(40)	(5)	0	0	(0)
	Transmission											
32	Bulk Transmission	D10T	(32)	(12)	(20)	(2)	(18)	(16)	(2)	0	0	(0)
33	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
34	Total		(32)	(12)	(20)	(2)	(18)	(16)	(2)	0	0	(0)
	Distribution											
35	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0
36	Underground	PUL	0	0	0	0	0	0	0	0	0	0
37	Total		0	0	0	0	0	0	0	0	0	0
38	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
39	**Electric Common**	PTD	(1)	(0)	(1)	(0)	(1)	(0)	(0)	0	0	(0)
40	**Net Inv Tax Credit**		(111)	(40)	(71)	(7)	(64)	(57)	(7)	0	0	(1)
41	**Total Operating Exp**		200,943	77,747	121,531	12,674	108,856	96,236	12,620	0	0	1,665
42A	**Pres Op Inc Before Inc Tax**		6,006	3,868	1,679	883	796	2,222	(1,426)	0	0	459
42B	**Prop Op Inc Before Inc Tax**		30,005	12,979	16,522	2,243	14,279	14,275	3	0	0	505

Northern States Power Company, a Minnesota corporatior
Electric Utility - State of North Dakota
2012 Step-In Adjustment
Class Cost of Service Study Detail

Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 6

	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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	24,019	8,101	15,834	1,424	14,410	12,935	1,475	0	0	84
2	Nuclear Fuel	E8760	5,440	1,964	3,441	321	3,120	2,735	385	0	0	34
3	Base Load	E8760	17,110	6,179	10,824	1,011	9,813	8,602	1,211	0	0	107
4	Total		46,569	16,243	30,100	2,757	27,343	24,272	3,071	0	0	226
	Transmission											
5	Gen Step Up Base	E8760	59	21	37	3	34	30	4	0	0	0
6	Gen Step Up Peak	D10C	153	52	101	9	92	82	9	0	0	1
7	Total Gen Step Up		212	73	138	13	126	112	14	0	0	1
8	Bulk Transmission	D10T	6,144	2,282	3,830	395	3,434	3,086	348	0	0	32
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	1	0	1	0	1	0	1	0	0	0
11	Total		6,357	2,355	3,969	408	3,561	3,198	363	0	0	33
	Distribution											
12	Generat Step Up	STRATH	9	3	6	1	5	5	1	0	0	0
13	Bulk Transmission	D10T	3	1	2	0	2	2	0	0	0	0
14	Distrib Function	D60Sub	312	142	166	19	148	128	19	0	0	3
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		324	147	174	20	154	134	20	0	0	3
17	Overhead Lines	POL	841	499	307	65	242	218	24	0	0	36
18	Underground	PUL	1,322	989	329	119	210	203	8	0	0	4
19	Line Transformers	P68	232	154	77	19	58	58	1	0	0	1
20	Services	P69	420	377	43	20	23	23	0	0	0	0
21	Meters	C12WM	198	136	62	30	33	31	1	0	0	0
22	Street Lighting	P73	70	0	0	0	0	0	0	0	0	70
23	Total		3,407	2,300	993	272	721	667	54	0	0	114
24	**General Plant**	PTD	1,787	730	1,041	113	928	826	102	0	0	16
25	**Electric Common**	PTD	1,071	437	624	68	556	495	61	0	0	10
26	**TBT Defer Inc Tax**	NEPIS	0	0	0	0	0	0	0	0	0	0
			0									
27	**Total Tax Deprec**		59,190	22,066	36,726	3,617	33,109	29,458	3,651	0	0	398
28	Interest Expense		9,760	3,926	5,759	619	5,140	4,587	553	0	0	74
29	Other Tax Timing Differ		1,407	523	877	91	786	707	80	0	0	7
30	Total Tax Deductions		70,357	26,515	43,362	4,327	39,035	34,751	4,284	0	0	480
	Inc Tax Additions											
31	Book Depreciation		19,228	7,756	11,295	1,216	10,079	8,991	1,088	0	0	177
32	Deferred Inc Tax & ITC		12,596	4,509	8,017	765	7,253	6,470	783	0	0	69
33	Nuclear Fuel Book Burn	E8760	6,478	2,339	4,098	383	3,715	3,257	459	0	0	41
34	Nuclear Fuel Disposal	E8760	0	0	0	0	0	0	0	0	0	0
35	Meals & Entertainment	LABOR	(39)	(16)	(23)	(3)	(20)	(18)	(2)	0	0	(0)
36	Avoided Tax Interest	RTBASE	1,579	635	932	100	832	742	90	0	0	12
37	Total Tax Additions		43,693	16,796	26,564	2,705	23,859	21,221	2,637	0	0	333
38	**Total Inc Tax Adjustments**		(26,664)	(9,719)	(16,799)	(1,622)	(15,177)	(13,530)	(1,647)	0	0	(147)
39A	**Pres Taxable Net Income**		(20,658)	(5,851)	(15,120)	(739)	(14,381)	(11,308)	(3,073)	0	0	312
39B	**Prop Taxable Net Income**		3,341	3,260	(277)	621	(898)	746	(1,644)	0	0	358
40A	Pres Fed & State Inc Tax		(9,550)	(2,705)	(6,990)	(342)	(6,648)	(5,227)	(1,421)	0	0	144
40B	Prop Fed & State Inc Tax		(136)	(133)	11	(25)	37	(30)	67	0	0	(15)
41A	Pres Preliminary Return	(total); BASE	15,556	6,573	8,668	1,224	7,444	7,449	(5)	0	0	315
41B	Prop Preliminary Return	(total); BASE	30,141	13,111	16,510	2,268	14,242	14,305	(63)	0	0	520
42	Total AFUDC		0	0	0	0	0	0	0	0	0	0
43A	**Present Total Return**		15,556	6,573	8,668	1,224	7,444	7,449	(5)	0	0	315
43B	**Proposed Total Return**		30,141	13,111	16,510	2,268	14,242	14,305	(63)	0	0	520
44A	**Pres % Return on Rate Base**		4.51%	4.74%	4.26%	5.60%	4.10%	4.60%	-0.03%	0.00%	0.00%	12.00%
44B	**Prop % Return on Rate Base**		8.74%	9.45%	8.11%	10.37%	7.84%	8.83%	-0.32%	0.00%	0.00%	19.81%
45A	**Present Common Return**		5,796	2,647	2,909	605	2,304	2,863	(559)	0	0	240
45B	**Proposed Common Return**		20,382	9,185	10,751	1,649	9,102	9,719	(617)	0	0	445
46A	**Pres % Ret on Common Rate Base**		3.20%	3.63%	2.72%	5.26%	2.41%	3.36%	-5.44%	0.00%	0.00%	17.44%
46B	**Prop % Ret on Common Rate Base**		11.24%	12.60%	10.05%	14.34%	9.53%	11.41%	-6.00%	0.00%	0.00%	32.31%

	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**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Peaking Plant	D10C	0	0	0	0	0	0	0	0	0	0
2	Nuclear Fuel	E8760	0	0	0	0	0	0	0	0	0	0
3	Base Load	E8760	0	0	0	0	0	0	0	0	0	0
4	Total		0	0	0	0	0	0	0	0	0	0
	Transmission											
5	Gen Step Up Base	E8760	0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	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	D10T	0	0	0	0	0	0	0	0	0	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		0	0	0	0	0	0	0	0	0	0
	Distribution											
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0
18	Underground	PUL	0	0	0	0	0	0	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	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		0	0	0	0	0	0	0	0	0	0
24	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
25	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0
26	**Total AFUDC**		0	0	0	0	0	0	0	0	0	0
	Labor Allocator											
	Production											
27	Other Prod - Cap	OXOPD	11,064	3,869	7,140	655	6,485	5,752	734	0	0	55
28	Other Prod - Ene	E8760	4,271	1,542	2,702	252	2,450	2,147	302	0	0	27
29	Total		15,335	5,411	9,842	907	8,935	7,899	1,036	0	0	82
	Transmission											
30	Stepup Subtrans	P5161A	39	13	25	2	23	21	3	0	0	0
31	Bulk Power Subs	D10T	947	352	590	61	529	476	54	0	0	5
32	Total		986	365	616	63	552	496	56	0	0	5
	Distribution											
33	Superv & Eng	ZDTS	431	264	152	36	115	105	10	0	0	16
34	Load Dispatch	D10T	237	88	148	15	132	119	13	0	0	1
35	Substation	P61	189	86	101	11	90	78	12	0	0	2
36	Overhead Lines	POL	396	235	144	30	114	103	11	0	0	17
37	Underground Lines	PUL	758	567	189	68	121	116	4	0	0	2
38	Line Transformer	P68	0	0	0	0	0	0	0	0	0	0
39	Meter	C12WM	186	128	58	28	31	29	1	0	0	0
40	Cust Installation	ZDTS	233	143	82	20	62	57	5	0	0	8
41	Street Lighting	P73	34	0	0	0	0	0	0	0	0	34
42	Miscellaneous	OXDTS	336	203	111	27	84	77	7	0	0	21
43	Total		2,800	1,713	985	236	749	684	65	0	0	102
44	Cust Accounting	C11WA	941	736	202	129	73	72	1	0	0	3
45	Sales Expense	C11P10	1	1	0	0	0	0	0	0	0	0
46	Admin & General	LABOR	8,712	3,577	5,051	580	4,471	3,969	502	0	0	83
47	Service & Inform	C11P10	66	39	26	5	21	18	2	0	0	1
48	**Labor**		28,841	11,843	16,722	1,921	14,801	13,138	1,662	0	0	276

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	Backwards Revenue Calc	1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	(1A) Modified Pres Rev	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Present Preliminary Return (Before AFUDC)	15,556	6,573	8,668	1,224	7,444	7,449	(5)	0	0	315
2	1/(1-T) Rev Reqt (= 1.8597)	28,929	12,223	16,120	2,277	13,843	13,853	(10)	0	0	585
3	Total Inc Tax Adjustments	(26,664)	(9,719)	(16,799)	(1,622)	(15,177)	(13,530)	(1,647)	0	0	(147)
4	T/(1-T) Rev Reqt (= 0.8597)	(22,923)	(8,355)	(14,442)	(1,394)	(13,047)	(11,631)	(1,416)	0	0	(126)
5	Tot Op Exp W/o Regul Exp	200,532	77,582	121,289	12,647	108,642	96,043	12,599	0	0	1,661
6	- Other Retail Rev W/o Gr Earn, Etc	0	0	0	0	0	0	0	0	0	0
7	- Other Op Rev W/o Late Pay, Etc.	42,090	15,353	26,480	2,543	23,936	21,138	2,798	0	0	257
8	Modified Pres Net Oper Exp	158,442	62,229	94,809	10,103	84,706	74,905	9,801	0	0	1,404
9	**Mod Pres Rev (R02) (component alloc)**	164,448	66,097	96,488	10,986	85,502	77,127	8,375	0	0	1,863
	(1B) Present Revenue										
10	Tot Oper Exp (w/ Regul Exp)	200,943	77,747	121,531	12,674	108,856	96,236	12,620	0	0	1,665
11	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0	0
12	- Other Oper Rev (w/ Late Pay, Etc)	42,445	15,604	26,583	2,571	24,012	21,212	2,800	0	0	257
13	Net Oper Exp Rev Reqt	158,498	62,143	94,947	10,103	84,844	75,024	9,820	0	0	1,408
14	**Tot Pres Rate Rev Reqt (R01)**	164,504	66,011	96,626	10,986	85,640	77,246	8,394	0	0	1,867
		0	0	0	0	0	0	0	0	0	0
	(2) Proposed Return										
15	Total Operating Exp	200,943	77,747	121,531	12,674	108,856	96,236	12,620	0	0	1,665
16	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0	0
17	- Prop Other Operating Rev	42,576	15,673	26,645	2,580	24,065	21,261	2,804	0	0	258
18	Prop Net Oper Exp Rev Reqt	158,367	62,074	94,885	10,094	84,791	74,976	9,816	0	0	1,407
19	Prop Preliminary Return	30,141	13,111	16,510	2,268	14,242	14,305	(63)	0	0	520
20	1/(1-T) Rev Reqt (= 0.9609)	28,963	12,599	15,865	2,180	13,685	13,746	(61)	0	0	499
21	T/(1-T) Rev Reqt (= -0.0391)	1,043	380	657	63	593	529	64	0	0	6
22	**Total Proposed Rate Rev Reqt**	188,372	75,053	111,407	12,337	99,070	89,251	9,819	0	0	1,912
	(3) Equal Return Rev										
23	T/(1-T) Rev Reqt (= -0.0391)	1,043	380	657	63	593	529	64	0	0	6
24	Equal Net Oper Exp Rev Reqt	158,367	62,074	94,885	10,094	84,791	74,976	9,816	0	0	1,407
25	Equal Rate of Ret (8.74%) x Rate Base	30,141	12,126	17,787	1,913	15,874	14,165	1,709	0	0	229
26	- AFUDC	0	0	0	0	0	0	0	0	0	0
27	Net Return	30,141	12,126	17,787	1,913	15,874	14,165	1,709	0	0	229
28	1/(1-T) Rev Reqt (= 0.9609)	28,963	11,651	17,091	1,838	15,253	13,611	1,642	0	0	220
29	**Net Equal-Ret Rate Rev-Reqt (R99)**	188,372	74,106	112,633	11,995	100,638	89,116	11,522	0	0	1,633
30	Tot Oper Rev - Equal	230,948	89,779	139,279	14,576	124,703	110,376	14,327	0	0	1,891
31	- Total Operating Exp	200,943	77,747	121,531	12,674	108,856	96,236	12,620	0	0	1,665
32	Equal Op Inc Before Inc Tax	30,005	12,031	17,748	1,901	15,847	14,140	1,707	0	0	226
33	Equal Taxable Net Income	3,341	2,313	949	279	670	610	60	0	0	79
34	Equal Fed & State Inc Tax	(136)	(94)	(39)	(11)	(27)	(25)	(2)	0	0	(3)
35	Proposed Common Return	20,382	8,199	12,027	1,293	10,734	9,578	1,156	0	0	155
36	Equal Return on Common	11.24%	11.24%	11.24%	11.24%	11.24%	11.24%	11.24%	0.00%	0.00%	11.24%

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			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL ALLOCATORS		Intern:	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Rate Base: Col %'s	BASE-COL	1000.000%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
			100.000%									
2	50% Cus, 50% Prod Plt	C11P10	100.000%	59.706%	38.941%	7.863%	31.077%	27.697%	3.380%	0.000%	0.000%	1.353%
3	Peaking Plant Capacity	D10C	100.000%	33.725%	65.924%	5.930%	59.994%	53.854%	6.140%	0.000%	0.000%	0.351%
4	56% Sum/Win Dmd, 44% Ene	D56E44	100.000%	34.780%	64.747%	5.920%	58.826%	52.271%	6.556%	0.000%	0.000%	0.473%
5	61% Sum/Win Dmd, 39% Ene	D42E58	100.000%	33.754%	65.892%	5.929%	59.962%	53.810%	6.152%	0.000%	0.000%	0.354%
6	Labor w/o (or w/) A&G	LABOR	100.000%	41.063%	57.980%	6.662%	51.318%	45.554%	5.764%	0.000%	0.000%	0.957%
7	Net Plant In Service	NEPIS	100.000%	40.915%	58.364%	6.397%	51.967%	46.404%	5.562%	0.000%	0.000%	0.721%
8	Dis O&M w/o Sup & Misc	OXDTS	100.000%	60.522%	33.108%	8.130%	24.978%	22.811%	2.166%	0.000%	0.000%	6.370%
9	Other Prod Capac O&M	OXOPD	100.000%	34.971%	64.533%	5.919%	58.615%	51.984%	6.631%	0.000%	0.000%	0.495%
10	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	100.000%	38.527%	60.643%	6.310%	54.333%	47.930%	6.403%	0.000%	0.000%	0.831%
11	Production Plant	P10	100.000%	35.207%	64.270%	5.916%	58.353%	51.630%	6.724%	0.000%	0.000%	0.523%
12	Production Plant Wo Nuclear	P10WoN	100.000%	34.971%	64.534%	5.919%	58.615%	51.984%	6.631%	0.000%	0.000%	0.495%
13	Total P51 & P61A	P5161A	100.000%	34.432%	65.135%	5.923%	59.212%	52.794%	6.418%	0.000%	0.000%	0.433%
14	Distribution Plant	P60	100.000%	66.628%	30.702%	8.012%	22.690%	20.952%	1.739%	0.000%	0.000%	2.669%
15	Distr Substn Plant	P61	100.000%	45.475%	53.544%	6.083%	47.461%	41.210%	6.251%	0.000%	0.000%	0.981%
16	Line Transformer Plant	P68	100.000%	66.238%	33.318%	8.129%	25.190%	24.785%	0.404%	0.000%	0.000%	0.443%
17	Services Plant	P69	100.000%	89.658%	10.342%	4.811%	5.531%	5.531%	0.000%	0.000%	0.000%	0.000%
18	Dist Plt Overhead Lines	POL	100.000%	59.285%	36.458%	7.673%	28.785%	25.953%	2.832%	0.000%	0.000%	4.257%
19	Real Est & Property Tax	PT0	100.000%	43.076%	55.922%	6.561%	49.361%	44.007%	5.355%	0.000%	0.000%	1.002%
20	Produc, Trans & Distrib	PTD	100.000%	40.836%	58.277%	6.351%	51.926%	46.210%	5.716%	0.000%	0.000%	0.888%
21	Dist Plt Undground Lines	PUL	100.000%	74.815%	24.889%	8.968%	15.921%	15.333%	0.588%	0.000%	0.000%	0.297%
22	Rev w/o Reg, etc: Col %	R02-COL	1000.000%	N/A	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
			100.000%	42.25%	55.72%	7.87%	47.85%	47.89%	-0.03%	0.00%	0.00%	2.02%
			100.000%	43.50%	54.78%	7.53%	47.25%	47.46%	-0.21%	0.00%	0.00%	1.72%
23	Rate Base (Non-Column)	RTBASE	100.000%	40.229%	59.010%	6.346%	52.665%	46.995%	5.670%	0.000%	0.000%	0.761%
24	Stratified Hydro Baseload	STRATH	100.000%	35.380%	64.077%	5.915%	58.162%	51.370%	6.792%	0.000%	0.000%	0.543%
25	Transmission & Distrib	TD	100.000%	52.415%	45.947%	7.244%	38.703%	35.061%	3.642%	0.000%	0.000%	1.638%
26	Labor Dis w/o Sup & Eng	ZDTS	100.000%	61.176%	35.188%	8.440%	26.748%	24.430%	2.318%	0.000%	0.000%	3.636%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
INTERNAL DATA			**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
27	Labor w/o A&G	LABOR(S)	20,129	8,265	11,671	1,341	10,330	9,169	1,160	0	0	193
28	Dis O&M w/o Sup, Cust Install & Misc	OXDTS	4,454	2,696	1,475	362	1,113	1,016	96	0	0	284
29	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	158,300	60,988	95,998	9,988	86,009	75,873	10,136	0	0	1,315
30	Total P51 & P61A	P5161A	4,785	1,648	3,117	283	2,833	2,526	307	0	0	21
31	Produc, Trans & Distrib	PTD	735,941	300,525	428,883	46,736	382,147	340,081	42,066	0	0	6,532
32	Transmission & Distrib	TD	240,708	126,168	110,597	17,436	93,161	84,393	8,768	0	0	3,943
33	Labor Dis w/o Sup & Eng, Cust Install	ZDTS	2,136	1,307	752	180	571	522	50	0	0	78

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			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
EXTERNAL ALLOCATORS		Extern:	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	84.21%	13.61%	9.81%	3.80%	3.76%	0.04%	0.00%	0.00%	2.18%
2	Cust Acctg Wtg Factor	C11WA	100.00%	78.20%	21.46%	13.71%	7.74%	7.64%	0.11%	0.00%	0.00%	0.34%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	68.56%	31.41%	14.98%	16.43%	15.72%	0.71%	0.00%	0.00%	0.03%
4	Sec & Pri Customers	C61PS	100.00%	86.02%	13.88%	9.97%	3.90%	3.86%	0.04%	0.00%	0.00%	0.10%
5	C62Sec, w/o Ltg & C/I Underground	C62NL	100.00%	92.42%	7.58%	5.47%	2.12%	2.12%	0.00%	0.00%	0.00%	0.00%
6	Secondary Customers	C62Sec	100.00%	86.05%	13.84%	9.98%	3.87%	3.87%	0.00%	0.00%	0.00%	0.10%
7	Summer Peak Resp KW	D10S	100.00%	30.77%	69.23%	5.86%	63.37%	56.76%	6.61%	0.00%	0.00%	0.00%
8	Transmission Demand %	D10T	100.00%	37.14%	62.33%	6.43%	55.90%	50.23%	5.66%	0.00%	0.00%	0.53%
9	Winter Peak Resp KW	D10W	100.00%	41.04%	57.74%	6.11%	51.64%	46.66%	4.98%	0.00%	0.00%	1.22%
11	Sec, Pri & TT, Class Coin kW @ Subs	D60Sub	100.00%	45.65%	53.36%	6.08%	47.28%	41.03%	6.25%	0.00%	0.00%	0.99%
12	Sec & Pri, Cl Coin kW (no Min Sys; ad	D61PS	100.00%	36.58%	62.45%	6.10%	56.35%	48.81%	7.54%	0.00%	0.00%	0.97%
13	D62Sec, w/o Ltg & C/I Underground	D62NLL	100.00%	82.32%	17.68%	3.07%	14.61%	14.61%	0.00%	0.00%	0.00%	0.00%
14	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	100.00%	50.65%	48.64%	6.59%	42.05%	42.05%	0.00%	0.00%	0.00%	0.71%
15	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%
16	On + Off Sales MWH	E8760	100.00%	36.11%	63.26%	5.91%	57.35%	50.27%	7.08%	0.0000%	0.0000%	0.63%
17	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%
18	Present Rev	R01	100.00%	40.13%	58.74%	6.68%	52.06%	46.96%	5.10%	0.00%	0.00%	1.13%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
APPLIED EXTERNAL DATA (BIG or LITTLE)			**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**St Ltg**
1	Customers - B Basis	C10	88,572	76,190	12,291	8,835	3,456	3,422	33	0	0	92
2	Cust - Ave Monthly (C10-Area Lt)	C11	90,926	76,564	12,376	8,920	3,456	3,422	33	0	0	1,986
3	Mo Cus Wtd By Cus Acct	C11WA	96,333	75,335	20,671	13,210	7,461	7,359	102	0	0	327
4	Cust Acctg Wtg Factor	C11WAF	7.67	0.98	6.69	1.48	5.20	2.15	3.05	0.00	0.00	N/A
5	Cust-Ave Mo (C11 w/ Dir Assign St Lt	C12	88,955	76,564	12,376	8,920	3,456	3,422	33	0	0	15
6	Mo Cus Wtd By Mtr Invest	C12WM	10,476,614	7,183,237	3,290,587	1,569,127	1,721,460	1,646,882	74,578	0	0	2,791
7	Meter Invest / Cust Factor	C12WMF	3,177	94	2,893	176	2,717	481	2,236	0	0	190
8	Sec & Pri Customers	C61PS	88,572	76,190	12,291	8,835	3,456	3,422	33	0	0	92
9	C62Sec, w/o Ltg & C/I Underground	C62NL	82,441	76,190	6,251	4,506	1,745	1,745	0	0	0	0
10	Secondary Customers	C62Sec	88,539	76,190	12,257	8,835	3,422	3,422	0	0	0	92
11	Summer Peak Resp KW	D10S	475,445	146,312	329,133	27,853	301,280	269,856	31,424	0	0	0
12	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,714,410	6,233,029	643,320	5,589,709	5,023,376	566,333	0	0	52,562
13	Winter Peak Resp KW	D10W	397,194	162,995	229,354	24,256	205,098	185,322	19,775	0	0	4,845
15	Sec, Pri & TT, Class Coin kW @ Subs	D60Sub	548,153	250,245	292,487	33,341	259,145	224,897	34,249	0	0	5,422
16	Sec & Pri, Class Coin kW (w/o Min Sy	D61PS	453,593	165,936	283,268	27,683	255,585	221,394	34,192	0	0	4,389
17	D62Sec, w/o Ltg & C/I Underground	D62NLL	814,953	670,875	144,078	25,030	119,049	119,049	0	0	0	0
18	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	10,000,000	5,065,401	4,863,722	659,109	4,204,612	4,204,612	0	0	0	70,877
19	Annual Billing kW	D99	3,452	0	3,452	0	3,452	3,148	304	0	0	0
20	Summer Billing kW	D99S	1,192	0	1,192	0	1,192	1,083	109	0	0	0
21	Winter Billing kW	D99W	2,260	0	2,260	0	2,260	2,065	194	0	0	0
22	Non-Coinc Pk Second	DN-Sec	1,086,560	670,875	411,653	71,514	340,139	340,139	0	0	0	4,033
26	kWh Sales @ Meter	E99	2,251,280	805,939	1,426,442	128,671	1,297,771	1,133,621	164,150	0	0	18,899

Northern States Power Company, a Minnesota corporation
Electric Utility - North Dakota
Test Year Ending December 31, 2011
VOLTAGE DISCOUNT ANALYSIS - DEMAND ($/kW)

Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 7

Includes losses to indicate additional billing kW low voltage customers would have at higher voltage.

	Secondary Costs	Primary Costs	
1. Revenue Requirement ($000s):	Lines & Transformers	Lines & Transformers	Distribution Substation
(CCOSS; p. 2; lines 34,33,32)	$1,080.643	$1,196.590	$880.032
2. Billing KW (Workpaper attached)			
Secondary Voltage kW	3,147,931	3,147,931	3,147,931
Loss 1		0.9087	0.9283
* 2009 North Dakota Loss Factors		0.8907	0.8907
Loss Factor	1.0000	1.0202	1.0422
Secondary With Losses	**3,147,931**	**3,211,547**	**3,280,818**
Primary Voltage kW		303,631	303,631
Loss 1			0.9283
Loss 2			0.9087
Loss Factor		1.0000	1.0216
Primary With Losses		**303,631**	**310,180**
Transmission Transformed Voltage kW			**0**
Total kW (Metered Sales + Losses)	**3,147,931**	**3,515,178**	**3,590,998**
3. Rev Reqt / kW (Line 1 / Line 2)	$0.3433	$0.3404	$0.2451
4. Cumulative Rev Reqt/ kW	**$0.34**	**$0.68**	**$0.93**
5. Present Individual Discounts	$0.85	$0.60	$0.40
6. Cumulative Present Discount	**$0.85**	**$1.45**	**$1.85**
7. Midpoint-Pres and Rev Reqt (Lines 4+ 6 /2)	$0.60	$1.07	$1.39
8. Cumulative Proposed Discount (Rounded to nearest $0.05)	**$0.60**	**$1.10**	**$1.40**

Northern States Power Company, a Minnesota corporation
Electric Utility - North Dakota
Test Year Ending December 31, 2011

Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 7
Page 2 of 2

VOLTAGE DISCOUNT ANALYSIS - ENERGY (¢/kWh)

Voltage	[1] E8760 Losses	[2] Percent Difference	[3] Energy Charge	[4] Cost-Based Discount	[5] Proposed Discount	[6] Present Discount	
Secondary	10.95%	0.00%	5.367	0.0000	**0.000**	0.000	¢ per kWh
Primary	9.15%	1.80%	5.271	0.0964	**0.100**	0.070	¢ per kWh
T Transformed	7.24%	3.71%	5.168	0.1989	**0.200**	0.100	¢ per kWh
Transmission	6.75%	4.20%	5.142	0.2254	**0.230**	0.150	¢ per kWh

Northern States Power Company, a Minnesota corporation
Electric Utility - North Dakota
Test Year Ending December 31, 2011
Service Reconnection Charge Cost Analysis

Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 8

TARIFF	Current Tariff Charge	2010 Costs	Proposed Tariff Charge
Service Reconnection Charge	$ 15.00	$ 58.44	**$ 50.00**
Service Relock Charge	None	$ 52.72	**$ 100.00**

Service Charges Section 6.1.2	Costs	
Description	**Reconnects (1)**	**Re-Lock (2)**
Customer Call Center (CCC)		
Call Center reps to process service application	$ -	$ -
Administrative charge to process service application	$ -	$ -
Call Center reps to lock	$ 1.54	$ -
Administrative charge to lock	$ 3.68	$ -
Call Center reps to unlock	$ 1.54	$ -
Administrative charge to unlock	$ 3.68	$ -
Call Center reps to relock	$ -	$ 1.54
Administrative charge to relock	$ -	$ 7.34
Credit Field Calls (lock)		
Vehicle charge to lock	$ 2.85	$ -
Labor needed to Lock Meter (Credit)	$ 19.17	$ -
Credit Field Calls (unlock)		
Vehicle charge to unlock	$ 2.85	$ -
Labor needed to Unlock Meter (Credit)	$ 19.17	$ -
Vehicle charge to verify/relock	$ -	$ 2.66
Labor needed to verify/relock Meter (Credit)	$ -	$ 22.52
Travel to UNLOCK or RELOCK	$ 3.15	$ 17.85
Producing bill	$ 0.10	$ 0.10
Mailing bill	$ 0.35	$ 0.35
New customer packet cost	**$ -**	**$ -**
Call Center IT costs per call	$ 0.36	$ 0.36
Cost Per Transaction	**$ 58.44**	**$ 52.72**

NOTES:

Note 1: The cost for reconnecting service which has been disconnected for non-payment.
Note 2: The cost for relocking a service that has been reconnected without Company authorization

Northern States Power Company, a Minnesota corporation
Electric Utility - North Dakota
Test Year Ending December 31, 2011
Dedicated Switching Cost Analysis

Case No. PU-10-_____
Exhibit No. _____(MAP-1)
Schedule 8

	Normal 2010 $ $/hour	Overtime Mon-Sat x 1.5% 2010 $/hour	Overtime Sun-Fed Holidays x 2.0% 2010 $/hour
Dispatching labor cost	$ 3.55	$ 5.32	$ 10.64
Troubleman labor	$ 183.07	$ 274.61	$ 366.14
Administrative @ 5% of Troubleman labor	$ 9.15	$ 13.73	$ 18.31
Sub total labor	**$ 195.77**	**$ 293.66**	**$ 395.09**
Trouble truck	$ 42.35	$ 42.35	$ 42.35
Total Trouble Costs	**$ 238.12**	**$ 336.01**	**$ 437.44**
Call Center labor cost per call	$ 1.54	$ 1.54	$ 1.54
Call Center IT costs per call	$ 0.36	$ 0.36	$ 0.36
Producing bill	$ 0.10	$ 0.10	$ 0.10
Postage for bill	$ 0.35	$ 0.35	$ 0.35
Total Billing Costs	**$ 2.35**	**$ 2.35**	**$ 2.35**
TOTAL COSTS	**$ 240.47**	**$ 338.36**	**$ 439.79**

TARIFF	Charge per hour		
Requested Appointment Date	**Tariff $**	**2010 $**	**Proposed 2011 $**
Monday through Saturday	$ 250.00	$ 338.36	**$ 300.00**
Sunday and federally observed holidays	$ 300.00	$ 439.79	**$ 400.00**

Labor	p/hour Loaded
Straight time/hour	**68.92%**
$ 42.01	$ 70.96
$ 39.41	$ 66.57
Troubleman Overtime @ 1.5%	
Hourly rate @ 1.5%	**$ 99.86**

Troubleman Overtime @ 2.0%	
Hourly rate @ 2.0%	$ 133.14

Time for Avg Dedicated Switch Call	
Task	Minutes
Dispatch tasks	
Scheduling	**3**
Troubleman tasks	
Drive to site	**40**
Drive from/to next site	**35**
Site work	**90**
Total	**165**

Trouble Truck Analysis	
Monthly lease	**$ 2,664.00**
Monthly hours	**173**
Hourly cost	$ 15.40

Current Costs from Passport System

TARIFF	Passport costs	Overhead	Total Costs	Current Electric tariff per circuit foot	Proposed Tariff Charge per circuit foot
Services	$ 5.92	34.00%	$7.93	$6.85	**$7.90**
Excess single phase primary or secondary extension	$ 6.00	34.00%	$8.04	$6.98	**$8.00**
Excess three phase primary or secondary extension	$ 10.41	34.00%	$13.95	$8.76	**$13.90**

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 from January to Aug 2010 is 34%

2010 Updates to Charges

TARIFF								
Current Electric Charge			20010 Costs		Proposed Tariff Charge			
Service Extension	$ 400.00	per frost burner	$ 597.20	per frost burner	Thawing	$ 600.00	per frost burner
	$ 3.00	plus per trench foot	$ 3.81	plus per trench foot	Service, Primary, or Secondary distribution extension	$ 3.80	per foot

2010 Winter Construction Burner Costs

Before January 1st
Typically burn for 2 days
A burner requires 3 - 20 lbs propane tanks to run for 2 days (20lbs 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	$75.00	$75.00				
Re-tank burner	Two man crew	0	$75.00	$0.00				
Remove burner	Two man crew	0.5	$75.00	$37.50				
Total Labor				$112.50				
Labor Loading @ 68.92%				$77.54				
Labor w/Loading				$190.04				$190.04
Vehicle & Equipment	truck and trailer	1.5	36	$54.00				$54.00
Propane Cost						2.18	15 $32.70	$32.70
Costs (before E&S)				$276.74				$276.74
E&S cost @ 34%				$94.09				$94.09
Total Cost								$370.82

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	$75.00	$75.00				
Re-tank burner	Two man crew	1	$75.00	$75.00				
Remove burner	Two man crew	0.5	$75.00	$37.50				
Total Labor				$187.50				
Labor Loading @ 68.92%				$129.23				
Labor w/Loading				$316.73				$316.73
Vehicle & Equipment	truck and trailer	2.5	36	$90.00				$90.00
Propane Cost						2.18	22.5 $49.05	$49.05
Costs (before E&S)				$455.78				$455.78
E&S cost @ 34%				$154.96				$154.96
Total Cost								$610.74

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

Before and after January Costs	Percentage	
$370.82	10%	$37.08
$610.74	90%	$549.66
		$586.75
Billing Labor		$10.00
Producing Bill		$0.10
Postage		$0.35
Total Cost of a Burner		**$597.20**

2010 Winter Construction Per foot Charge

Winter Construction billed for in Winter of 09/10.

2010 Winter Construction Per foot Charge

See/attach spreadsheets
Winter Construction billed for in Winter of 09/10.

Average Cost per foot Winter 2009-10 Services =	$14.45	per foot
Average Cost per foot non Winter Months Services =	$10.64	per foot
Difference for Winter Construction	**$3.81**	**per foot**