Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Minnesota Power
for Authority to Increase Rates for Electric Utility
Service in Minnesota

Docket No. E015/GR-16-664

Exhibit ________

JURISDICTIONAL COSTS AND CLASS COST OF SERVICE STUDY

November 2, 2016

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Stewart J. Shimmin and my business address is 30 West Superior Street, Duluth, Minnesota 55802.

Q. By whom are you employed and in what position?

A. I am employed by ALLETE, Inc., doing business as Minnesota Power ("Minnesota Power" or the "Company"). My current position is Supervisor, Revenue Requirements.

Q. Please summarize your qualifications and experience.

A. I have over 10 years of experience with Minnesota Power within the Rates Department. My responsibilities include supporting retail and wholesale general rate cases and other financial regulatory filings, including cost recovery riders. I am responsible for maintaining Minnesota Power's class cost of service model and for overall revenue requirement determination and analysis, as well as for coordinating various Rate Department activities and projects.

I earned a Bachelor of Science in Economics from the University of Utah and a Master's Degree in International Management from the American Graduate School of International Management – Thunderbird. Prior to joining Minnesota Power, most of my career was in various positions in Indonesia. I provided specialty chemicals and services to multinational oil and gas companies throughout Indonesia for a Fortune 500 company. I was an economist for a leading international engineering consulting firm where I carried out feasibility analyses of public sector infrastructure, and rural and agricultural development projects financed by the World Bank and other international financing agencies. As a financial analyst, I carried out financial planning, capital budgeting, feasibility analyses, and economic and financial forecasting of private and public sector development projects, including toll roads, ports, and mass transit systems. I also served as General Manager and Financial Controller at the Indonesian office of an international manpower supply company serving the mining and oil and gas industries in Indonesia.

Q. What is the purpose of your testimony?

A. I present Minnesota Power's 2017 Class Cost of Service Study ("CCOSS"). My testimony summarizes the process of jurisdictional separation of costs, the functional assignment and classification of costs, and the allocation of costs to customer classes, including the development of allocation factors used in the CCOSS. Additionally, I address several compliance matters and a number of changes and updates to the CCOSS.

Q. How is your testimony organized?

A. In Section II, I address the compliance matters arising from Minnesota Power's last Minnesota rate case. Section III presents the results of the 2017 CCOSS and discusses the improvements and changes to the CCOSS model since the Company's last rate case. Section IV addresses the separation of jurisdictional costs, and Section V addresses the allocation of costs to retail customer classes and various analyses used in the CCOSS.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following schedules to my Direct Testimony:

- Exhibit ___ (SJS), Schedule 1 – Guide to Minnesota Power's CCOSS
- Exhibit ___ (SJS), Schedule 2 – Summary of Marginal Energy Cost Study

I am also sponsoring the following exhibits that are included in other volumes of the Company's Initial Filing:

(1) For interim rates, I am sponsoring the following exhibits in Volume II:

- Schedule B-5 (IR) – Comparison of Changes in Jurisdictional Allocation Factors
- Schedule C-l (IR) – 2017 Jurisdictional Test Year Interim Rate Cost of Service
- Schedule C-2 (IR) – Projected 2016 Jurisdictional Cost of Service
- Schedule C-3 (IR) – Actual 2015 Jurisdictional Cost of Service
- Schedule C-4 (IR) – Final Ordered Cost of Service in Docket No. E015/GR-09-1151

(2) For general rates, I am sponsoring the following CCOSSs in Volume IV:

- Schedule B-l – 2017 Jurisdictional Test Year General Rate Cost of Service
- Schedule B-2 – Projected 2016 Jurisdictional Cost of Service
- Schedule B-3 – Actual 2015 Jurisdictional Cost of Service
- Schedule B-4 – Comparison of Changes in Jurisdictional Allocation Factors
- Schedule C-l – 2017 Test Year General Rate Class Cost of Service

Included in Volume V, Workpapers, under Reconciliation (RECON), are the following cost of service reconciling documents:

(1) 2017 FERC Income Statement to COSS per Budget and Workpapers
(2) 2016 FERC Income Statement to COSS and Workpapers
(3) 2015 GAAP General Ledger to FERC Balance Sheet
(4) 2015 GAAP General Ledger to FERC Income Statement
(5) 2015 FERC Balance Sheet to COSS and Workpapers
(6) 2015 FERC Income Statement COSS and Workpapers

Also in Volume V, Workpapers, under Cost of Service (COS) is the COS-1 2017 CCOSS per Budget, as well as several other cost of service versions as discussed below:

(1) 2017 COSS 1CP
(2) 2017 COSS 12CP
(3) 2017 COSS 3WMISOCP
(4) 2017 COSS 3SMISOCP
(5) 2017 COSS 3W3SMISOCP

Finally, I sponsor the 2012 Distribution Plant Study included in Volume V, under Other.

II. COMPLIANCE MATTERS

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I address CCOSS-related compliance requirements arising from the Minnesota Public Utilities Commission's ("Commission") Order in Minnesota Power's last Minnesota electric rate case (Docket No. E015/GR-09-1151).

Q. What compliance matters will you address?

A. I address the following order points from Docket No. E015/GR-09-1151:

- Order Point 20: In future rate case filings, the Company shall conduct any CCOSS by calculating and assigning income taxes by class based on the adjusted net taxable income by class as determined by the CCOSS;
- Order Point 21: In its next rate case filing, the Company shall provide a description and an explanation of each classification and allocation method used in its CCOSS and justify why that method is appropriate and superior to alternative methods considered;
- Order Point 22: In its next rate case filing, the Company shall provide a marginal energy cost study; and
- Order Point 23: Minnesota Power shall start a new load research study by the end of 2011.

Q. Has the Company complied with Order Point 20 from Docket No. E015/GR-09-1151?

A. Yes. The CCOSS calculates and assigns income taxes by class based on the adjusted net taxable income by class as determined by the CCOSS. When the CCOSS is run, the revenue requirements for each function, sub-function, and classification component by class and jurisdiction are calculated by what is sometimes called the "Reverse or Backwards Revenue Requirement" calculation. The basic formula is shown in Figure 1 below:

<u>Figure 1</u>: Reverse Revenue Requirement Calculation

1		Cost of Service Revenue Requirements
2	=	Rate of Return (Current Authorized or Proposed)
3	x	Rate Base
4	+	Total Operation & Maintenance Expense
5	+	Depreciation and Amortization Expense
6	+	Taxes Other than Income Taxes
7	=	Operating Income Before Income Taxes
8	+/-	Additions/Deduction for Tax
9	+	CCOSS calculation of State and Federal Income Taxes
10	+	Provision for Deferred Income Taxes – Net
11	+	Investment Tax Credit
12	-	Investment Tax Credit Feedback
13	-	AFDUC
14	-	Total Other Operating Revenue
15	-	Total Other Sales Revenue
16	-	Total Inter System Sales Revenue

The above calculation illustrates that when the CCOSS is run, the required revenues to be at cost are calculated based on the same rate of return (either current authorized or proposed) for each function, sub-function, component, class, and jurisdiction. The CCOSS calculates and assigns income taxes by class based on the adjusted net taxable income of each function, sub-function, component, and jurisdiction as determined solely by the CCOSS. As shown above, present rate revenues are not in the backwards revenue requirements formula; therefore, the CCOSS calculates and assigns income taxes by class based on the adjusted net taxable income by class as determined by the CCOSS.

Q. Has the Company complied with Order Point 21 from Docket No. E015/GR-09-1151?

A. Yes. Order Point 21 provides that "[i]n its next rate case filing, the Company shall provide a description and an explanation of each classification and allocation method used in its Class Cost of Service Study and justify why that method is appropriate and superior to alternative methods considered." In an effort to provide greater overall transparency into and documentation of Minnesota Power's CCOSS, the Company developed a "Guide to Minnesota Power's CCOSS," which is attached as Exhibit ___

(SJS), Schedule 1 to my Direct Testimony. This guide discusses the functionalization, classification, and allocation methodologies used in the CCOSS process.

Q. Please provide additional information regarding the Guide to Minnesota Power's CCOSS.

A. This guide is basically a compilation of hundreds of information requests on the CCOSS to which the Company responded in our last two rate cases. The Guide to Minnesota Power's CCOSS includes:

- A description, explanation, and justification of the functionalization, classification, and allocation of each rate base and income statement cost in the CCOSS in the order that they are shown in the CCOSS. The guide also includes the description and explanation of the externally-developed allocation factors.
- A description and explanation of internally-developed allocation factors.
- A summary table providing the functionalization, classification, and allocation of each rate base and income statement cost, as presented in the CCOSS. The table lists each CCOSS line item cost as it is functionalized, indicating (1) the related Federal Energy Regulatory Commission ("FERC") account or Minnesota Power function code; (2) how the item is functionalized, classified, and allocated to jurisdiction and class; (3) whether it is allocated with an internal or external allocator; (4) the name or number of the allocator; and (5) the allocator code in the CCOSS.
- A table that identifies the internally-developed allocation factors along with references on how they are calculated in the CCOSS.

Throughout the guide, related workpapers, studies, and other inputs are referenced as appropriate to provide the location of those items in the rate filing. The Company believes this guide is very responsive to the need for documentation regarding Minnesota Power's CCOSS, and the Company hopes the guide will help alleviate much of the discovery burden on all stakeholders in the present and future rate cases.

Q. Has the Company also compared its CCOSS to other methods and provided support for the Company's approach?

A. Yes. In Section III of my Direct Testimony, below, I compare the Company's CCOSS to other potential methods and explain why the Company's recommended method is superior to these alternatives.

Q. Has the Company complied with Order Point 22 from Docket No. E015/GR-09-1151?

A. Yes. As previously noted, Order Point 22 required that "[i]n its next rate case filing, the Company shall provide a marginal energy cost study." The results of the Company's marginal energy cost study are provided in Exhibit ___ (SJS), Schedule 2. This marginal energy cost study was completed in August 2016 by Minnesota Power's Utility Planning area. The marginal energy costs in the study are projections of the annual incremental cost of energy to serve new load on Minnesota Power's system. The results were not directly used in the Company's rate design but are available if needed for consideration by the Commission or other parties. In general, energy rates for any customer class or increment of service should not be lower than the marginal energy cost, or customers could be incentivized to consume an economically-inefficient level of electricity.

Q. Has the Company complied with Order Point 23 from Docket No. E015/GR-09-1151?

A. Yes. As previously noted, Order Point 23 required that "Minnesota Power shall start a new load research study by the end of 2011." The Company began a load research study in July 2011. Initially, an internal working group was formed and tasked with designing and conducting the load research study. In December of 2011, Power Systems Engineering, Inc. ("PSE") was selected as a consultant to help with the development and implementation of a short-term and long-term plan for the load research efforts. During 2011 and 2012, Minnesota Power developed the strategy for the study and worked to improve in-house knowledge on load research processes and best practices. During 2012, the sample selection process was completed and load research meters and equipment were purchased and deployed. Sample data was collected and validated beginning in

January of 2013. The 2013 Load Research Study results are based on data from April 1, 2013, through March 31, 2014.

The overall goal for this study was to gain improved insight on customer loads by meeting the requirements set by the Commission. Throughout the process, Minnesota Power worked with PSE to develop the study and sample design. With a sample design and selection in place, Minnesota Power also worked with Landis+Gyr to place equipment needed for data collection and to assist in validating, editing, and estimating the load research data. The analysis of the data collected during the study was completed in April of 2015.

Q. Can you provide a summary of the study results that are used in the current rate proceeding?

A. Yes. Table 1, below, summarizes the key results of the 2013 load research study that were used in developing the allocation factors in the present rate filing.

Table 1

2013 Load Research Results Summary				Peak (KW)			Average KW / Customer	
Retail Class	**Study Period**	**Population**	**Sampled**	**Class NCP**	**Class CP**	**Sum NCP**	**Class NCP**	**Sum NCP**
Residential (Excl. Dual Fuel)	2013-2014	111,455	140	225,807	187,941	590,990	2.03	5
Residential Dual Fuel		7,324	48	53,444	35,731	77,234	7.56	11
GS -Demand		8,368	234	114,323	99,855	176,618	13.70	21
GS - Non-Demand		11,165	137	14,277	11,826	29,697	1.27	3
General Service		19,533	371	127,031	109,730	206,315	6.50	10
Commercial Dual Fuel		539	74	8,750	7,328	13,765	16.45	28
Muni-Pumping		237	72	6,792	5,315	12,086	38.81	61
Large Light & Power		455	78	223,085	200,744	273,961	507.63	639
Large Power		9		792,559	759,016	843,542	508	1,576
Resale		17		277,411	255,887	282,798	15,412	15,711
Total		139,570		1,714,880	1,561,692	2,300,690	12	16

Q. How does the 2013 study compare to the study completed in 2003?

A. The 2013 and 2003 load research studies differed in that the 2013 load research study was more comprehensive than the 2003 study, but the results were fairly consistent. Roughly 800 sample points covering seven rate classes were used in the 2013 study, compared to 350 sample points among three rate classes in 2003. The 2013 analysis was initiated in-house and reviewed by a third party, as compared to the 2003 study that was handled almost entirely by a third party. As shown below, a comparison of the 2013 results and the 2003 results for the Residential and General Service classes shows that the classes have remained fairly similar even though ten years have passed between studies.

Table 2: 2013 and 2003 Load Research Study Results

2013 Load Research	Average KW / Customer			
	Class NCP	Sum NCP	Load Factor	Coincidence Factors
Residential (Excl. Dual Fuel)	2.03	5.42	0.59	0.69
GS -Demand	13.70	21.14	0.63	0.85
GS - Non-Demand	1.27	2.75	0.57	0.75

2003 Load Research	Average KW / Customer			
	Class NCP	Sum NCP	Load Factor	Coincidence Factors
Residential (Excl. Dual Fuel)	1.94	5.57	0.62	0.81
GS -Demand	19.22	26.07	0.64	0.84
GS - Non-Demand	1.52	3.21	0.55	0.76

Q. How are the results from the load research study used in the current rate case?

A. The coincident peak and non-coincident peak data were used in the development of the Minnesota jurisdictional and class demand allocators used in the CCOSS. Additionally, the hourly load research data was used to scale the test year budgeted energy in the calculation of the E8760 class energy allocation factors. Exhibit ___ (SJS), Schedule 1 provides additional explanation regarding how the allocation factors are developed. Details regarding the calculation of the allocation factor areas are included in Volume V, Workpapers, under Allocation Factors.

III. CCOSS MODEL AND RESULTS

Q. Please provide an overview of the final allocation of revenue requirement to class for the 2017 test year general rates based on the CCOSS.

A. The results of the CCOSS are summarized in Table 3, below, and also found in Volume IV, Schedule C-1, page 2:

Table 3

Required revenue increase to be at cost of service ($) & (%)
Based on 2017 Test Year General Rates CCOSS

Total Retail	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Lighting
55,123,680	35,715,411	2,876,942	3,842,874	12,243,652	612,107	(167,305)
9.24%	35.30%	4.43%	3.34%	3.95%	36.49%	-4.72%

Q. Can you provide some additional background regarding these results?

A. Yes. The higher required increase for the Residential class is not an unexpected result. In Minnesota Power's last rate case (Docket No. E015/GR-09-1151), the final revenue allocation selected by the Commission moved the class away from its cost of service due to broader market conditions immediately following the 2008 financial recession. As a result, the Residential class is well below its cost of service.

The higher required increase shown for the Municipal Pumping class is a result of a shift of customers and load from this class to General Service since our last rate case. The Municipal Pumping class rates were designed in our last rate case with higher billings than the class currently has. Therefore, this class's current rates are low in relation to its present billing units. While the class is being allocated less cost responsibility, its relatively low rates result in a larger required increase.

Q. How does the Company propose to use the CCOSS results?

A. The results at the class level show the class cost revenue requirement outcomes and indicate the change from present rate revenues that would be required for each class to provide equal rates of return on investment.

As discussed in more detail by Company witness Ms. Marcia Podratz, the Company considers the resulting class cost revenue requirements by the three classification components (demand, energy, and customers) to be appropriate starting points for rate design. The revenue requirements by classification provide direction to rate design that would result in customer rates and cost recovery that are more closely aligned with cost causation, resulting in a reasonable overall cost for each class.

Q. Has the Company tested other cost allocation methodologies in the CCOSS to provide a check that the Company's current method is reasonable and appropriate for the Commission to use as a basis for allocation of cost responsibility?

A. Yes, the Company tested five other retail cost allocation methods. To ensure that the results were comparable, the methods were tested only for the Minnesota jurisdiction. Also, the tests were applied to the two main demand allocation factors: Power Supply Production – Demand (D-01) and Power Supply Production – Transmission (D-02).

Q. What are the methods that were tested?

A. The first method is the single coincident peak method or 1CP. The 1CP method allocates all fixed production and transmission revenue requirements on each class's proportional contribution to the single highest one hour peak. The second method is the average 12-month coincident peak method or 12CP. The 12CP method allocates all fixed production and transmission revenue requirements on each class's proportional contribution to the 12-month average of the peaks. The third method is the 3WCP method that allocates all fixed production and transmission revenue requirements on each class's proportional contribution to the average three-winter-month peaks. The fourth method is the 3SCP method that allocates all fixed production and transmission revenue requirements on each class's proportional contribution to the average three-summer-month peaks. The fifth method is the 3W3SCP method that is a combination of the third and fourth methods.

The calculation of the above allocation factors is shown in Volume V, Workpapers, under Allocation Factors.

Q. Could you briefly provide a rationale for each method?

A. Yes. Proponents of the 1CP method argue that a utility's system is designed to meet the highest single peak. Proponents of the 12CP see the average of the 12-month peaks as more appropriate. Further, as stated by the National Association of Regulatory Utility Commissioners ("NARUC") in its Electric Utility Cost Allocation Manual ("NARUC Electric Manual"), this method is usually used when the monthly peaks lie within a narrow range, i.e., when the annual load shape is not spiky. This is a characteristic of Minnesota Power and the method used to allocate the jurisdictional Power Supply Production – Demand (D-01) and Power Supply Production – Transmission (D-02).

The 3WCP could be appropriate for winter peaking utilities, and the 3SCP could be appropriate for summer peaking utilities. The 3W3SCP could be appropriate for utilities that need to plan for both summer and winter peaks. Minnesota Power is a winter peaking utility, but bases its resource need on the summer season. Most other utilities are summer peaking and have large winter capacity surpluses. Therefore, winter capacity is typically available for purchase, and prices are expected to be lower than summer capacity.

Q. What were the results of the testing?

A. As shown in Table 4 below, the results indicate that Minnesota Power's current Peak and Average ("P&A") method has required increases for General Service, Large Light and Power, and Large Power classes that are fairly uniform compared to the other methods. The Company's method also has the lowest required increase for the Residential class, which further supports the importance of moving the class closer to cost.

Table 4

Comparison of various Production and Transmission allocation methodologies
Required revenue increase to be at cost of service ($) & (%)
Based on 2017 Test Year General Rates CCOSS

	Total Retail	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Lighting
MP's P&A	55,123,680	35,715,411	2,876,942	3,842,874	12,243,652	612,107	(167,305)
	9.24%	35.30%	4.43%	3.34%	3.95%	36.49%	-4.72%
1CP	55,123,680	54,447,886	5,461,136	(2,955,423)	(3,588,266)	1,187,191	571,157
	9.24%	53.81%	8.41%	-2.57%	-1.16%	70.78%	16.13%
12CP	55,123,680	39,324,098	5,574,243	766,372	8,775,382	1,283,542	(599,958)
	9.24%	38.87%	8.59%	0.67%	2.83%	76.53%	-16.94%
3WCP	55,123,680	57,416,476	5,002,341	(754,618)	(8,315,623)	1,370,507	404,597
	9.24%	56.75%	7.71%	-0.66%	-2.68%	81.71%	11.42%
3SCP	55,123,680	43,226,028	15,711,953	7,003,159	(10,787,716)	1,237,461	(1,267,204)
	9.24%	42.72%	24.20%	6.09%	-3.48%	73.78%	-35.78%
3W3SCP	55,123,680	50,143,636	10,488,099	3,221,709	(9,578,899)	1,303,480	(454,344)
	9.24%	49.56%	16.15%	2.80%	-3.09%	77.72%	-12.83%

Q. Does the Company's current CCOSS use the same classification and allocation methodologies as approved by the Commission in Minnesota Power's last rate case (Docket No. E015/GR-09-1151)?

A. Yes, the CCOSS in the present filing uses the same classification and allocation methodologies approved by the Commission in Minnesota Power's last rate case. As noted above, in this rate case the Company has also provided additional descriptions of and support for these classification and allocation methodologies.

Q. Have there been any changes to the CCOSS since Minnesota Power's last rate case?

A. Yes. Since its last rate case, Minnesota Power has identified a number of refinements to the CCOSS to reflect interim FERC orders, updated information, and other proposals in this current rate case. These refinements include:

(1) Updating the presentation of contra allowance for funds used during construction ("AFUDC") to reflect a 2010 FERC Order;

(2) Obtaining the latest CCOSS model macros and layout from a model vendor;

(3) Incorporating the proposed inclusion of the Prepaid Pension Asset in rate base in the CCOSS;

(4) Updating components of Other Assets and Liabilities included in rate base, resulting in:

- Adding the Minnesota Power regulated amount of the Worker Compensation Deposit, FERC Account 1864-0093;
- Deducting the Other Deferred Credit – Hibbard, FERC Account 253000-9058/9; and
- Deducting the Wind Performance Deposit, FERC Account 25300-9091;

(5) Including the Net Operating Loss ("NOL") Reclass to Deferred Tax Benefit in the calculation of state and federal income taxes in the CCOSS; and

(6) Including a new proposed customer allocation factor.

I will provide additional information about each of these updates in this section of my testimony.

Q. What is the first change to the CCOSS?

A. The first change involves the presentation of contra AFUDC. A number of line items for contra AFUDC have been added to the CCOSS to reflect implementation of a December 2010 FERC directive (Docket No. ER11-134-000) that the Company implemented subsequent to our last rate case. In its December 2010 directive, FERC prescribed specific accounting treatment for AFUDC, which requires the Company to record the Pre-Funded AFUDC Regulatory Liability by debiting Account 407.3, Regulatory Debits, and crediting Account 254, Other Regulatory Liabilities, in accordance with the instructions of those accounts. In addition, the Company is required to amortize the Pre-Funded AFUDC Regulatory Liability as an offset to depreciation expense by debiting Account 254 and crediting Account 407.4, Regulatory Credits. The Company is also required to maintain all necessary controls to ensure the amount of the Pre-Funded AFUDC Regulatory Liability recorded in Account 254 includes the total amount of AFUDC accrued on its rider projects. This FERC-directed methodology for the application of AFUDC is currently being applied to all of Minnesota Power's current cost recovery rider projects.

The contra AFUDC lines have been added in the CCOSS to Plant, Construction Work in Progress ("CWIP"), Accumulated Reserve, and Deprecation Expense. As an example, see Steam Plant lines 5 to 6 on page 5 of the CCOSS model in Volume IV, Schedule C-1. The contra AFUDC is functionalized, classified, and allocated following the associated rate base or cost component. In comparison to Minnesota Power's last rate case, the contra AFUDC amounts are now visible, as opposed to being already netted in the associated components in our last rate case.

Q. What is the second change to the CCOSS?

A. Since Minnesota Power's last rate case, the Company worked with the CCOSS model vendor to obtain the latest CCOSS model macros and to improve the layout of the model. The updated macros improved the functioning of the model, for example, by providing built-in check formulas to ensure that the revenue requirement calculations by function, classification, jurisdiction, and class are calculated and allocated correctly when the model is run. Other macro updates improved printing and viewing options and made the overall model more user-friendly and efficient to use. The CCOSS layout was also changed to make the model easier to review and to significantly reduce the number of printed pages. By eliminating blank columns and rows that were not utilized, the Company was able to reduce the number of printed pages from about 140 to less than 50.

Q. What is the third change to the CCOSS?

A. For general rates, Minnesota Power is proposing to include the Prepaid Pension Asset in rate base as discussed in the Direct Testimony of Company witness Mr. Patrick Cutshall. In the CCOSS, the Prepaid Pension Asset was added as a separate line item in cash working capital. This is shown in Volume IV, Schedule C-1, page 13, line 22. The Prepaid Pension Asset is internally classified and allocated to demand, energy, and customer components following total operation and maintenance ("O&M") labor ratios less administrative and general ("A&G"). This approach is consistent with the approach followed in Minnesota Power's last two retail rate cases for other labor-related A&G costs. The use of labor ratios is also set forth in the NARUC Electric Manual (Chapter 8).

Q. What is the fourth change to the CCOSS?

A. In preparation for this rate case, the Company reviewed its other assets and liabilities for items that may have been missed in the last rate case and that should be included in rate base or deducted from rate base. As a result of this review, the Company identified three updates:

- First, the Company has included the Minnesota Power regulated amount of $91,500 (Total Company)[1] for the Worker Compensation Deposit, FERC account 1864-0093, in rate base as shown in Volume IV, Schedule C-1, page 13, line 44. The Worker Compensation Deposit is internally classified and allocated to demand, energy, and customer components following total O&M labor ratios less A&G. This approach is consistent with the approach followed in Minnesota Power's last two retail rate cases for other labor-related A&G costs and consistent with FERC methodology approved in Minnesota Power's last FERC rate case. This method is also discussed in the NARUC Electric Manual (Chapter 8).
- Second, the Company determined that $339,222 (Total Company) in Other Deferred Credit – Hibbard, FERC account 253000-9058/9, should be deducted from rate base. This amount relates to the Company's 1994 rate case, in which the Company proposed and received approval to create a regulatory asset for the costs of decommissioning its Hibbard Units 1, 2, 3, and 4, which were no longer in service, and create an offsetting deferred liability. The Company also proposed and received approval to then amortize the regulatory asset to Account 40500–Amortization of Other Electric Plan over a five-year period, beginning in 1994 through 1998. The Company did not seek an unamortized balance in rate base in the 1994 rate case.

[1] "Total Company" refers to total Minnesota Power regulated, without Minnesota Power's non-regulated entities.

Some costs have been spent for decommissioning/demolition work for Hibbard Units 1 and 2 over the years, but not the entire amount. No costs have been spent to date for decommissioning/demolition costs for Hibbard Units 3 and 4, as the units were returned to service. The amounts in account 25300, subaccounts 9058 and 9059 consist of the remaining deferred credits recorded on our books after the 1994 rate case for decommissioning Hibbard Units 1 and 2 and Hibbard Units 3 and 4. The amount is functionally assigned, classified, and allocated following Depreciable Steam Plant – Demand as shown in Volume IV, Schedule C-1, page 15, line 7. This approach is consistent with the treatment of Hibbard in rate base.

- Third, the Company determined that $150,000 (Total Company) for the Wind Performance Deposit, FERC account 25300-9091, should be deducted from rate base. This deposit was received in connection with the Company's Power Purchase Agreement ("PPA") for the generation of the Oliver wind farm, and provides a performance security with respect to the operation, maintenance, and delivery of capacity and energy. Because the amount is in the nature of a security, the amount is functionally assigned, classified, and allocated following Depreciable Wind Plant – Demand as shown in Volume IV, Schedule C-1, page 15, line 8. This approach is consistent with the treatment of other wind plant in rate base.

Q. What is the fifth change to the CCOSS since Minnesota Power's last rate case (Docket No. E015/GR-09-1151)?

A. As discussed by Company witness Ms. Jamie Jago, as a result of the NOL carryforward created by bonus depreciation, the current federal and state taxable income for the test year is being fully offset by the NOL carryforward. The NOL Reclass to Deferred Tax Benefit is included in the calculation of state and federal income taxes in the CCOSS. These amounts are internally functionalized, classified, and allocated following plant as shown in in Volume IV, Schedule C-1, page 27, lines 2 and 11. This treatment reflects costs causation in that the investment in plant and related bonus deprecation created the NOL.

Q. What is the sixth change to the CCOSS?

A. As discussed by Company witness Ms. Tina Koecher, the Company is proposing to recover bank card processing fees through its O&M so that customers will no longer incur individual per-transaction fees when paying utility invoices with credit or debit cards. This amount was included in O&M expense as shown on Volume IV, Schedule C-1, page 19, line 21 – Customer Accounting Credit Cards. As this proposal is designed to benefit the Residential and General Service classes, a new allocation factor was developed to allocate those costs to the classes that will benefit. The allocation factor was calculated based on the overall costs for the Residential and General Service classes that were used to develop the Company's main Customer Accounting allocator ("CACCTS"). The CACCTS allocator values and the new Customer Accounting Credit Card ("CACCTSC") values are shown in Volume IV, Schedule C-1, page 36, lines 38 and 41, and the resulting allocation factors are on page 42, lines 38 and 41.

Q. What do you conclude with respect to the Company's CCOSS?

A. The Company's CCOSS model is robust, corroborated by comparable alternative methodologies, and intuitive in light of known factors affecting the Company's rate classes. In addition, we have incorporated adjustments developed since Minnesota Power's last rate case in order to properly reflect the Company's cost of service. As such, the CCOSS model and results provide an appropriate starting point for developing a rate design outcome, which is discussed in more detail by Company witness Ms. Podratz.

IV. SEPARATION OF JURISDICTIONAL COSTS

Q. Please describe the process used to determine the separation of jurisdictional costs.

A. The process used to determine the separation of jurisdictional costs involves the three steps common to all cost of service studies, that is: functionalization, classification, and allocation. Costs are assigned to 28 major functions in Minnesota Power's CCOSS, as shown below. Each of these functions, except revenues, are classified as demand, energy, or customer related, and are then allocated among jurisdictions and to classes based on allocation factors.

Production

1. Power Supply Production – Demand
2. Power Supply Production – Energy

Transmission

3. Power Supply Transmission – Demand

Distribution Bulk Delivery

4. Distribution Bulk Delivery – Demand
5. Distribution Bulk Delivery – Specific Assignments - Demand

Distribution

6. Distribution Substations – Demand

Overhead Lines

7. Primary – Demand
8. Primary – Customer
9. Secondary – Demand
10. Secondary – Customer

Underground Lines

11. Primary – Demand
12. Primary – Customer
13. Secondary – Demand
14. Secondary – Customer

Line Transformers

15. Overhead – Demand
16. Overhead – Customer
17. Underground – Demand
18. Underground – Customer

Services

19. Overhead – Demand
20. Overhead – Customer
21. Underground – Demand
22. Underground – Customer

23. Leased Property – Customer
24. Street Lighting – Customer
25. Meters – Customer
26. Customer Accounts – Customer
27. Customer Sales – Customer
28. Customer Service and Information – Customer

Q. Please describe these major functions.

A. The production function includes Minnesota Power's steam, wind, biomass, solar, and hydraulic generating facilities. The transmission function includes the costs associated with 115 kV and above transmission lines and substations. The distribution bulk delivery function relates to 46 kV, 34 kV, and 23 kV facilities. Distribution plant has several functions, which follow the major accounts defined in the FERC Uniform System of Accounts. These major distribution functions are subdivided into primary and secondary, overhead and underground, and further subdivided between demand and customer classification components. The subdivision of distribution plant costs is based on a Distribution Plant Study on Minnesota Power's system, which was conducted in 2012. The report is included in Volume V, Workpapers, under Other.

The meters, leased property, customer accounts, and sales functions correspond to the Company's accounting classifications.

The revenue function contains the sales of electricity to the Minnesota jurisdictional and non-jurisdictional classes. Since sales revenues cannot be classified or assigned to functions, this treatment of revenues allows the demand, energy, and customer components of all other costs to remain segregated until final allocation takes place.

Any cost item other than power production, transmission, and distribution ("PT&D") plant in service described above was assigned to a specific class or function according to an analysis of the individual components making up the cost item, or assigned on the basis of related items in plant and internally-generated allocation factors.

Q. Please describe the three classification components.

A. Demand-related costs include those rate base and expense items that relate to demands coincident with the system peak or annual maximum non-coincident demands and include all PT&D bulk delivery costs. Production costs include both demand-related and energy-related costs. Energy-related costs include those rate base and expense items which are related to the total kilowatt-hour requirements. The energy-related costs consist of fuel and purchased power, reservoirs for the Company's hydro generating stations, fuel inventory, and O&M expenses charged to FERC Accounts 501, 510, 512, 513, and 544. Customer-related costs include rate base and expense items that relate to the number of customers. These costs are fixed and occur even when no electricity is used. The costs related to meters, customer accounts, and customer services are classified as customer-related costs.

Q. Please describe the last step involved in the separation of costs between jurisdictions.

A. The last step is to allocate the functionalized and classified costs between Minnesota Power's FERC and Minnesota jurisdictions. The separation of costs between jurisdictions in the present filing follows the same procedures approved in Minnesota Power's last two rate cases before the Commission (Docket Nos. E015/GR-08-415 and E015/GR-09-1151), and the Company's last FERC wholesale rate case (Docket No. ER08-397-000).

Q. What is the basis used for the jurisdictional separation of Power Supply Production – Demand and Power Supply Transmission – Demand costs?

A Both Power Supply Production – Demand and Power Supply Transmission – Demand costs are allocated based on the 12CP method. These costs were apportioned between FERC and Minnesota jurisdictions based on the relationship between the total of all class loads in each jurisdiction at the time of Minnesota Power's 12 monthly system peaks.

In Minnesota Power's last rate case, duel fuel interruptible load and the large power interruptible load were deducted from the system peak load in the allocation factor calculations to recognize the interruptible customers and to distribute the costs associated with these customers to all of the Company's standard retail and wholesale classes of customers. This treatment of these loads is consistent with Minnesota Power's treatment of the revenues from these services as revenue credits. As revenue credits, the revenues from these services are distributed back to the Company's standard retail and wholesale classes of customers.

In the present rate case, the interruptible loads are now accounted for in the system peak forecasts so no deductions are necessary in calculating the allocation factors.

Q. What is the basis used for jurisdictional separation of distribution bulk delivery costs?

A Distribution bulk delivery facilities are used to deliver power on a localized basis to the distribution system for both FERC wholesale customers and Minnesota retail customers. Therefore, these facilities are functionalized and kept distinct from power supply transmission facilities. Because of the localized nature of the loads served off the distribution bulk delivery system, their diversity is less than that on the power supply transmission system. Annual maximum non-coincident demands reflect the customer loads that are considered in designing the system and therefore are used for jurisdictional separation purposes. The separation is accomplished by aggregating the non-coincident demands of all FERC jurisdictional customers served from distribution bulk delivery points of output and separately aggregating such demands for all Minnesota retail customers. As a result, the Minnesota jurisdictional responsibility is the retail aggregated demands divided by the total of the FERC and retail aggregated non-coincident demands.

Q. Would you explain the basis for the separation factor relative to energy responsibility?

A. The energy responsibility factors are based on Minnesota and FERC jurisdictional kilowatt hour ("kWh") sales, excluding Large Power Replacement Firm Power Service

("RFPS") energy, all of which are adjusted for losses to the production level. The jurisdictional energy allocator was developed in the same manner as approved by the Commission in our last rate case.

Q. How are the jurisdictional separation factors for customers costs developed?

A. There are three jurisdictional separation factors for customer costs – meters, customer accounts, and customer services. The meter allocation factor is based on the total meter plant balance. The meter costs are first allocated by identifying (1) the original investment meter cost ("OIC") for each wholesale customer, and (2) the OIC for Large Power customers. These identified amounts from specific plant records are subtracted from the total meter costs. An average OIC is then calculated using the number of meters in each of the remaining rate classes and the meter costs in the specific plant records. The remaining meter costs (miscellaneous cost) are subsequently split using a specific program run by the meter department which distributes the remainder costs.

The jurisdictional separation of costs assigned to customer accounts and customer services are based on actual historic dollar amounts and the number of hours worked by employees. The number of hours are allocated according to the amount of time spent among the two jurisdictions by rate classes and these ratios are then applied to the dollar amounts. The projected and test year budgeted amounts are allocated using the same ratios.

The jurisdictional separation of customer costs in the present filing follows the same procedures approved in Minnesota Power's last two retail rate cases (Docket Nos. E015/GR-08-415 and E015/GR-09-1151) and the Company's last FERC wholesale rate case (Docket No. ER08-397-000).

Q. How do the allocation factors described above for jurisdictional separation compare to those used in Minnesota Power's last retail filing?

A. The comparison of the jurisdictional allocation factors are shown in Volume II, Schedule B-5 (IR), and Volume IV, Schedule B-4.

The test year jurisdictional allocation factor ratios used in the Company's CCOSS can be found in Volume II, Schedule C-1 (IR), pages 41 through 46. These ratios are based on values shown in Volume II, Schedule C-1 (IR), pages 35 through 40. The development of the allocation factor values is detailed in Volume V, Workpapers, under Allocation Factors (AF). In addition to the allocation factors described above, which are referred to as externally developed, there are also a number of internally-developed allocation factors that are generated by the cost of service program. These allocation factors are generated based on one or more revenue, expense, or rate base items that have been allocated to jurisdiction and class within the Class Cost of Service model using one or more of the externally-developed allocators. Additional details regarding the internally-developed allocation factors are set forth in the Guide to Minnesota Power's CCOSS attached to my Direct Testimony as Exhibit ___ (SJS), Schedule 1.

V. ALLOCATION OF COSTS TO RETAIL CLASSES

Q. Please describe the basis on which allocation of costs was made among the retail classes of customers.

A. Three basic types of allocation factors are required to allocate the costs of serving retail customers. These are based on the demand (instantaneous power or load, which can be measured in kilowatts ("kW")) placed on the system by the customers, the energy (quantity or amount of electricity, which is commonly measured in kWh) supplied to the customers, and the number of customers being served. Each of these factors is developed for application to the related classified costs. The test year jurisdictional allocation factor ratios are the same for interim and general rates. The test year jurisdictional and class allocation factor ratios used for general rates can be found in Volume IV, Schedule C-1, pages 41 through 46. These ratios are based on values shown in Volume IV, Schedule C-1, pages 35 through 40. The development of the allocation factor values is detailed in Volume V, Workpapers, under Allocation Factors (AF).

Q. Were the retail class allocation factors developed using the same methodologies approved in Minnesota Power's last rate case?

A. Yes.

Q. What analyses were used to produce inputs to the CCOSS in this rate case?

A. Below is a list and brief description of analyses used to produce inputs into the CCOSS.

(1) Demand allocation factors analyses – Analyses of demands were carried out by jurisdiction, by class, and, in some cases, by customer. The analyses were based on the most recently available historical load data from 2015, as well as from test year projected demands. In developing the distribution demand allocators, 2013 load research results were used for the average demand contribution per customer for coincidental peak and non-coincidental peak. Refer to Exhibit __ (SJS), Schedule 1 and to Volume V, Workpapers, under Allocation Factors (AF).

(2) Energy allocation factors analyses – Analyses of energy usage were carried out by jurisdiction, by class, and, in some cases, by customer. The analyses were based on the most recently available historical energy data from 2015, as well as from test year projected usage. In developing the E8760 energy allocator, 2013 load research results on the annual hourly load shapes were used in scaling 2017 test year budgeted energy. Refer to Exhibit __ (SJS), Schedule 1 and to Volume V, Workpapers, under Allocation Factors (AF).

(3) Customer allocation factors analyses – Analyses of the number of customers using facilities, plant balances by class, and labor expenses and hours were carried out in developing the customer allocation factors. The analyses were based on the most recently available historical data from 2015, as well as from test year projected numbers of customers. Refer to Exhibit ___ (SJS), Schedule 1 and to Volume V, Workpapers, under Allocation Factors (AF).

(4) Distribution Plant Study, including minimum-system – Results from the Distribution Plant Study were utilized to sub-functionalize and classify distribution plant into both demand- and customer-related components. The Distribution Plant Study was updated since our last rate case and is based on analyses of 2012 data and field conditions. The report is included in Volume V, Workpapers, under Other.

(5) Lead-Lag Study – Revenue lead days and expense lag days from the 2012 Lead-Lag Study were utilized in estimating test year cash working capital. The Lead-Lag Study was developed based on 2012 data.

VI. CONCLUSION

Q. Does this complete your testimony?

A. Yes.

Guide to Minnesota Power's CCOSS

Functionalization, Classification and Allocation of Rate Base and Income Statement

Guide to Minnesota Power's CCOSS
Functionalization, Classification and Allocation of Rate Base and Income Statement

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Tables

Description of Externally Developed Allocation Factors

Introduction

In the MPUC Order dated 11/2/2010 for Minnesota Power Docket E015/GR-09-1151, Order point 21 states that:

"In its next rate case filing, the Company shall provide a description and an explanation of each classification and allocation method used in its Class Cost of Service Study and justify why that method is appropriate and superior to alternative methods considered."

In compliance with this Order point, MP is providing this Guide to the Minnesota Power Class Cost of Service Study (CCOSS) process. This guide discusses the functionalization, classification and allocation methodologies used in the CCOSS process. It includes:

- A description, explanation and justification of the functionalization, classification and allocation of each rate base and income statement cost in the CCOSS in the order that they are shown in the CCOSS. The discussions also include the description and explanation of the externally developed allocation factors.

- A description and explanation of internally developed allocation factors.

- A summary table (Table 4) providing the functionalization, classification and allocation of each rate base and income statement cost, as presented in the CCOSS, is attached. The table lists each CCOSS line item cost as it is functionalized, indicating the related FERC account or MP function code, how the item is classified, how the item is allocated to jurisdiction and class, whether it is allocated with an internal or external allocator, the name or number of the allocator and the allocator code in the CCOSS.

- Table 5 which identifies the internally developed allocation factors along with references on how they are calculated in the CCOSS.

Throughout this guide related work papers, studies and other inputs are referenced as appropriate to provide the location of those items in the rate filing.

All functionalization, classification and allocation methodologies used in the present rate case CCOSS are the same as those approved in MP's last rate case, Docket E015/GR-09-1151.

The Company believes this Guide is very responsive to the need for documentation regarding Minnesota Power's CCOSS, and the Company hopes the guide will help alleviate much of the discovery burden on all stakeholders in the present and future rate cases.

RATE BASE

Intangible Plant: FERC accounts 301-303

Intangible Plant is functionalized, classified and allocated internally in the CCOSS model using labor ratios in a multi-step process. *Refer to the description of internally developed allocators and Table 5 for additional information on internal allocators.*

First, labor ratios based on Operation & Maintenance – Labor Only costs are applied to assign Total Intangible Plant to Intangible Plant – Production Energy and to Intangible Plant – Other. When the CCOSS program is run, Intangible Plant – Other is further assigned into all of the other demand and customer components: 1) production demand, 2) transmission demand, 3) distribution bulk delivery demand, 4) distribution primary demand, 5) distribution secondary demand, 6) customer meters, 7) customer services and 8) customer distribution.

The use of labor ratios for the classification and allocation of Intangible Plant is the same process MP uses to classify General Plant, as discussed below, and is one of the methods suggested by the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual (NARUC) (Chapter 8).

This treatment is consistent with MP's last two retail rate cases (Dockets E015/GR-08-415 and E015/GR-09-1151) as well as our last FERC wholesale rate case (Docket No. ER08-397-000).

Steam Plant: FERC accounts 310-317

Steam Production Plant is assigned to the Power Supply Production function and is classified as 100% demand.

This assignment is consistent with Minnesota Power's last two retail rates. (MP Docket 08-415 and MP Docket 09-1151). It is also consistent with NARUC's classification of Steam Production Plant to 100% demand if no direct assignment or exclusive use cost are assigned directly to customers.

Steam Production Plant – Demand is allocated between MP's FERC and MPUC jurisdictions based on the 12-month average coincident peak (12CP) method where costs are apportioned based on the relationship between the total of all class loads in each jurisdiction at the time of MP's twelve monthly system peaks. This method is appropriate since Minnesota Power's system historically reflects very little seasonality or significant deviations in monthly peaks.

This method was used and was approved in MP's last two retail rate cases as well is our last FERC wholesale rate case. This method is also one of the methods suggested by NARUC (Chapter 4).

In Minnesota Power's last rate case Duel Fuel Interruptible load and the Large Power Interruptible load were deducted from the system peak load in the allocation factor calculations to recognize the interruptible customers and to distribute the costs associated with these customers to all of the Company's standard retail and wholesale classes of customers. This treatment of these loads is consistent with Minnesota Power's treatment of the revenues from these services as revenue credits. As revenue credits, the revenues from these services are distributed back to the Company's standard retail and wholesale classes of customers.

In the present rate case, the interruptible loads are now accounted for in the system peak forecasts so no deductions are necessary in calculating the allocation factors.

Since Minnesota Power's last rate case, a number of line items for Contra AFUDC have been added to the CCOSS to reflect implementation of a FERC directive (Docket #ER11-134-000) that the Company implemented subsequent to our last rate case. In the December 2010 directive, FERC prescribed specific accounting treatment for AFUDC, which requires the Company to record the Pre-funded AFUDC Regulatory Liability by debiting Account 407.3, Regulatory Debits, and crediting Account 254, Other Regulatory Liabilities, in accordance with the instructions of those accounts. In addition, the Company is required to amortize the Pre-funded AFUDC Regulatory Liability as an offset to depreciation expense by debiting Account 254 and crediting Account 407.4, Regulatory Credits. The Company is also required to maintain all necessary controls to ensure the amount of the Pre-funded AFUDC Regulatory Liability recorded in Account 254 includes the total amount of AFUDC accrued on their rider projects. This FERC directed methodology for the application of AFUDC is currently begin applied to all Minnesota Power current cost recovery rider projects. The Contra AFUDC lines have been added in the CCOSS to Plant, CWIP, Accumulated Reserve and Deprecation Expense. As an example, see Steam Plant lines 5 to 6 on page 5 in the CCOSS model in Volume 1, Schedule C-1. The Contra AFUDC is functionalized, classified and allocated following the associated rate base or cost component. In comparison to MP's last rate case, the contra AFUDC amounts are now visible, as opposed to being already netted in the associated components in our last rate case.

<u>Power Supply Production and Power Supply Transmission</u> are allocated using the Peak & Average (P&A) methodology as described below.

In four retail rate cases from 1980 to 1994, Minnesota Power developed its retail Power Supply Production and Power Supply Transmission allocation factors on the Average and Excess/Probability of Deficiency (A&E/POD) methodology, or CAPSUBPOD as it was often called. After MP's 1994 rate case, the computer platform on which this program ran was replaced, rendering the program obsolete. Because the consultant that developed and updated the program was no longer available prior to MP's subsequent 2008 rate case, it was necessary to select a new methodology.

In Docket No. E015/GR-80-76, the Minnesota Department of Public Service, (now Division of Energy Resources), staff recommended the Peak & Average methodology as the alternative to the much more complex and data intensive CAPSUBPOD methodology. The Peak & Average methodology was recommended "because it does a reasonably good job of allocating the revenue requirements to the various classes and it is also understandable and a reasonably straight forward method." see 7/11/80 Testimony of Phillip Zins, Docket No. E015/GR-80-76, at 29. In addition, the methodology results in allocation factors that are very similar to those developed using MP's historic methodology, the CAPSUBPOD method. Based on these considerations, MP selected the Peak & Average (P&A) methodology as the basis for developing the Power Supply Production and Power Supply Transmission allocation factors. This methodology, as explained below, was used and was approved by the Commission in MP's last two retail rate cases.

The P&A methodology allocates fixed production and transmission costs to class based on a composite allocation factor that is composed of two parts – 1) an average demand (or energy) and 2) a coincidental peak. Similar to the traditional Average and Excess method and other energy weighting methods, all plant costs may remain classified as demand-related despite the use of a composite energy/demand allocator. NARUC (Chapter 4) characterizes these methods as "partial energy weighing methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy load but do not take the second step of classifying the costs as energy-related."

The initial step is accomplished by the Peak and Average (P&A) method in the first part of the composite allocator – the average demand part. Each class's proportion of total average demand (or energy) is multiplied by the system load factor to yield that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor.

The second step of the P&A allocator allocates the balance of the costs on each class's proportional contribution to coincidental peak. The composite allocator can be shown as follows:

$$\text{Composite Allocation Factor} = \text{LF} \times (\text{Average Demand Factor}) + (100 - \text{LF}) \times (\text{CP Demand Factor})$$

As can be seen, the closer the system load factor is to one (which means a larger share of generation should be base load), the closer the P&A allocator is to the average demand allocator (average demand drives the need for base load generation). Since MP's system has a very high load factor it is reasonable that our customer's energy requirements drive the need of our generation and that they should pay their proportional share. On the opposite side, the lower the load factor, the closer the P&A allocator moves to the CP demand allocator. The second part of the allocator acknowledges that utilities build generation and transmission to also handle the greatest demand placed on it in a single instant and that each class should be responsible for their proportional share of that peak.

The Company believes this is an appropriate allocator for our system characteristics and is superior to other methods, such as the 1CP or other peaker methods. The 1CP method allocates all fixed production and transmission revenue requirements on each class's proportional contribution to the single highest one hour peak. If MP's system had a very low load factor and our generation portfolio consisted of multiple peaker units of varying size along with some base load generation built to meet occasional high peaks while serving relatively low overall annual energy requirements, the 1CP or other peaker methods might be appropriate.

The development of the Power Supply Production – Demand jurisdictional and class allocators (D-01) are detailed in Volume V, Workpapers, under Allocation Factors (AF).

<u>Hydro Plant: FERC accounts 331-337</u>

<u>Hydro Plant</u> is assigned to MP's Power Supply Production function. All regulated hydro reservoir projects and assets at reservoir facilities are classified as energy and all remaining hydro plant is classified as demand.

This method is consistent with MPs' last two retail rate cases, MP's last FERC rate case, and is also consistent with NARUC (Chapter 4).

<u>Hydro Production – Demand</u> is allocated to jurisdiction and customer class following the same methodologies as described above for the Power Supply Production - Demand function.

<u>Hydro Production – Energy</u> is allocated between MP's FERC and MPUC jurisdictions based on energy. The energy responsibility factors (E-01) are based on MPUC and FERC jurisdictional kWh sales, excluding Large Power Replacement Firm Power Service ("RFPS") energy, all of which are adjusted for losses to the production level.

Excluding RFPS is consistent with Minnesota Power's last two retail rate case as well as Minnesota Power's treatment of the revenues from RFPS as revenue credits which are distributed back to the Company's standard retail and wholesale classes of customers.

<u>Hydro Production - Energy</u> is allocated among MP's retail customer classes using the E8760 energy allocator.

Minnesota Power's E8760 energy allocator was initially developed and approved for use in Minnesota Power's Boswell 3 Emissions Reduction Plan Cost Allocation and Rate Design. It was modeled after Xcel Energy's E8760 allocator and adapted for MP's use. Xcel's E8760 allocator was initially approved in Xcel's 2005 rate case, Docket GR-05-1328. MP's E8760 allocator was used in and approved by the MPUC in MP's last two retail rate cases.

The E8760 allocator is an energy-cost allocator based on the time-of-use concept, which recognizes the importance of linking the time when a customer consumes electricity to the cost of providing electricity at that given time. A customer class that consumes proportionately more of its energy during periods of high or peak demand, when the market price for electricity is higher, should be expected to be charged more than if the opposite was the case.

The E8760 is based on Minnesota Power's system Locational Marginal Price ("LMP") hourly cost and the hourly energy use of each class. It is derived by multiplying the hourly energy usage of each class by the system's LMP cost by hour, summing and taking the ratio of the sum of each class to the total. Applied as a cost allocator, the E8760 will yield class-specific responsibilities that take into account class use-patterns and time-variant system costs. In contrast to a straight non-weighted energy allocator, the E8760 results in a slight shift of class-specific responsibilities away from classes that use proportionately more of their energy during off-peak periods, to classes that use proportionately more of their energy during more expensive on-peak periods.

The E8760 factors are based on MPUC jurisdictional retail classes kWh sales, excluding RFPS energy and Economy energy, all of which are adjusted for losses to the production level. This method of recognizing non-firm customers and distributing the costs associated with these customers to all of the Company's standard retail and wholesale classes of customers is consistent with Minnesota Power's last two retail rate cases. This method is also consistent with Minnesota Power's treatment of revenues from these services as revenue credits, which also distributes the revenues from these services back to the Company's standard retail and wholesale classes of customers. This method most appropriately reflects cost and is superior to other possible energy allocators.

The development of the Power Supply Production – Energy jurisdictional and class allocators (D-01 and E8760) are detailed in Volume V, Workpapers, under Allocation Factors (AF).

Wind Plant: FERC accounts 341-347

Wind Plant is assigned to MP's Power Supply Production function and is classified as demand.

Wind Plant Production – Demand is allocated to jurisdiction and to customer classes following the same methodologies as described above for the Power Supply Production - Demand function; that is, 12-month average coincident peak method for jurisdictional allocation and P&A method for retail class allocations.

This treatment of wind plant was approved in MP's two last retail rate cases and is consistent with the method approved in MP's Renewable Resources Rider.

Transmission Plant: FERC accounts 352-359

Transmission Plant is functionalized to Production – Demand and to Production - Transmission.

Transmission Plant that is functionalized to Production – Demand consists of step-up transformers at generating stations booked in transmission plant. The remainder of transmission plant is functionalized to the Production - Transmission function.

Production – Demand is allocated to jurisdiction and to customer classes following the same methodologies as described above for the Power Supply Production - Demand function.

Costs functionalized to Production - Transmission are allocated to jurisdiction based on the 12-month average coincident peak (12CP) method and to retail classes using the Peak & Average (P&A) method, both calculated at the transmission level. Refer to Steam Plant above for explanation of 12CP and P&A methodologies. This treatment of transmission plant was approved in MP's two last retail rate cases and is consistent with the method approved in MP's Transmission Cost Recovery Rider.

The development of the Power Supply Production - Transmission jurisdictional and class allocators (D-02) are detailed in Volume V, Workpapers, under Allocation Factors (AF).

Distribution Plant: FERC accounts 361-373

Due to the complexity of the functionalization, classification and allocation of distribution plant, the functionalization and classification will be described first before allocation.

Functionalization and Classification of Distribution Plant

Minnesota Power first assigns distribution plant by function, then by sub-function, and then classifies as appropriate. Table 1 below lists MP's sub-function codes with their corresponding FERC accounts. It should be noted that for FERC accounts 360 to 367, each sub-function includes more than one FERC sub-account. Therefore the functionalization / classification will be described by sub-function.

Substations

D100 Distribution – Substations Non Bulk Delivery is classified as demand.
D123 Distribution – Substations 23kv Bulk Delivery is classified as demand.
D134 Distribution – Substations 34kv Bulk Delivery is classified as demand.
D146 Distribution – Substations 46kv Bulk Delivery is classified as demand.
D200 Distribution – Generation. Step-up transformers at generating stations booked in distribution plant (D200) are sub-functionalized / classified as demand.

The above classifications are consistent with MP's last two retail rate cases and are also consistent with NARUC's classification of substations.

Distribution Bulk Delivery (Sub-transmission)

D223 Distribution – Bulk Delivery Lines 23kv is classified as demand.
D234 Distribution – Bulk Delivery Lines 34kv is classified as demand.
D246 Distribution – Bulk Delivery Lines 46kv is classified as demand.

The above classifications are consistent with MP's last two retail rate cases and are also consistent with NARUC's classification of sub-transmission (distribution bulk delivery) facilities.

Demand and Customer Related

D300 Distribution – Overhead Lines is classified as demand and customer following the minimum system methodology.

D400 Distribution – Underground Lines is classified as demand and customer following the minimum system methodology.
D500 Distribution – Line Transformers is classified as demand and customer following the minimum system methodology.
D600 Distribution – Services is classified as demand and customer following the minimum system methodology.

The above classifications are consistent with MP's last two retail rate cases and are also consistent with NARUC's classification using the minimum system methodology, where the minimum system is classified as customer-related and the remaining portion is classified as demand-related.

The minimum-size system was determined in the 2012 Distribution Plant Study where "the Minimum – Size Method" was employed. This method is outlined by NARUC (Chapter 6) and defined as follows:

> "[T]he minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable transformer and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each plant account, the minimum size distribution system is classified as customer-related costs."

Refer to the 2012 Distribution Plant Study in Volume V, Workpapers, under Other.

<u>Customer Related</u>

D650 Distribution – Meters is classified as customer.
D675 Distribution – Leased Property is classified as customer.
D700 Distribution – Street Lighting is classified as customer.

The above classifications are consistent with MP's last two retail rate cases and are also consistent with NARUC's classification.

Table 1: MP's Distribution Plant Functions by FERC Account

	FERC Account											
Function Code & Description	360	361	362	364	365	366	367	368	369	370	372	373
D100 Dist - Substations Non Bulk Delivery	X	X	X									
D123 Dist - Subs 23kv Bulk Delivery	X	X	X									
D134 Dist - Subs 34kv Bulk Delivery	X	X	X									
D146 Dist - Subs 46kv Bulk Delivery	X	X	X									
D200 Dist - Generation		X	X									
D223 Dist - Bulk Delivery Lines 23k 1/												
D234 Dist - Bulk Delivery Lines 34k 1/												
D246 Dist - Bulk Delivery Lines 46k	X	X		X	X							

D300 Dist - Overhead Lines	X			X	X							
D400 Dist - Underground Lines						X	X					
D500 Dist - Line Transformers								X				
D600 Dist - Services									X			
D650 Dist - Meters										X		
D675 Dist - Leased Property											X	
D700 Dist - Street Lighting												X

1/ Actual amounts identified in Distribution Plant Study and are included in D300, D400 and D500.

Table 2: Allocation of Distribution Plant

		Basis of Cost Allocation by Classification		
		Jurisdictional Allocation	Retail Class Allocation	
Function / Subfunction			Demand	Customer
Primary Overhead Lines		-	Class NCP	Customers
Primary Underground Lines		-	Class NCP	Customers
Secondary Overhead Lines		-	Sum NCP	Customers
Secondary Underground Lines		-	Sum NCP	Customers
Secondary OH lines transformers		-	Avg Class & Sum NCP	Customers
Secondary UG lines transformers		-	Avg Class & Sum NCP	Customers
Secondary OH services		-	Sum NCP	Customers
Secondary UG services		-	Sum NCP	Customers
Meters		Meters & cost	-	Meters & cost
Leased Property		-	-	Direct
Street Lighting		-	-	Direct
Production Demand	1/	12CP	P & A	-
Distribution Bulk Delivery	2/	NCP	Class NCP	-
Distribution Substations		-	Class NCP	-
Dist. Bulk Delivery Specific Assign	3/	Direct	-	-
Dist. Primary Delivery Specific Assign	3/	Direct	-	-

1/ Step-up transformers at generating stations booked in distribution plant are subfuctionalized as production demand.

2/ Distribution Bulk Delivery are 23, 34 and 46 kV facilities that serve FERC and retail jurisdictional customers.

3/ Specific Distribution 14 kV facilities and 23, 34, and 46 kV taps that serve FERC jurisdictional customers.

Allocation of Distribution Plant - *Jurisdictional*

Table 2 above summarizes the methodologies to allocate distribution plant to jurisdiction and customer class. Each individual line item is presented in the same order as presented in MP's CCOSS and is discussed below.

All facilities functionalized to Primary and Secondary Distribution are *only* used to serve MP's retail customers and therefore there is no allocation across jurisdictions.

Meter costs are incurred to serve customers in both MP's FERC and retail jurisdictions, thus, it is necessary to allocate those costs between jurisdictions. The allocation is based on the total meter plant balance. The meter costs are first allocated by identifying (i) the original investment meter cost (OIC) for each wholesale customer and (ii) the OIC for Large Power customers. These amounts, identified from specific plant records, are subtracted from the total meter costs.

> Total Meter Costs less OIC Meter Costs (Wholesale Customers) less OIC Meter Costs (Large Power) = Meter Costs to be allocated to Remaining Rate Classes

An average OIC is then calculated using the number of meters in each of the remaining rate classes and the meter costs in specific plant records. The remaining meter costs (miscellaneous cost) are subsequently split using a specific program run by the meter department which distributes the remainder of the costs. The costs are then totaled by jurisdiction and class to develop the meter allocator (C-12).

Leased Property and Street Lighting are lighting facilities directly assigned to MP's retail Lighting Class.

Step-up transformers at generating stations recorded in distribution plant are sub-functionalized to production demand and are allocated between jurisdictions based on the 12-month average coincident peak method following the method described above for Power Supply Production – Demand function (D-01).

Distribution Bulk Delivery plant are 23kV, 34kVand 46kV facilities that serve both FERC and retail jurisdictional customers. These facilities, sometimes referred to a subtransmission, are used to deliver power on a more localized basis to the distribution system and are functionalized and kept distinct from power supply transmission facilities. Because the loads served off the distribution bulk delivery system are more localized in nature, their diversity is less than that on the power supply transmission system. Annual maximum non-coincident demands reflect the customer loads that are considered in designing this system and are therefore used for jurisdictional cost separation. The separation is accomplished by aggregating the NCP demands of all the FERC jurisdictional customers served from the distribution bulk delivery points of output and separately aggregating such demands for all retail customers. As a result the retail jurisdictional responsibility is the retail aggregated demands divided by the total of the FERC and retail aggregated NPC demand (D-03).

Distribution Substations include substations that serve only the retail jurisdiction and therefore no allocation to the FERC jurisdiction is required.

Distribution Bulk Delivery Specific Assignment and Distribution Primary Specific Assignment are specific distribution 14kV and 23kV, 34kV and 46kV facilities that serve *only* FERC jurisdictional customers and therefore the costs are directly assigned to the FERC jurisdiction.

Allocation of Distribution Plant – *Retail Classes*

As shown in the table above, distribution facilities are allocated to retail classes based on how they are classified – that is, either with demand allocation factors (D-03 thru D-15) or customer allocation factors (C-01 thru C-15).

The customer-related costs determined for each function are allocated to the retail class primarily based on the average number of customers utilizing that function. The allocation to class of primary lines (C-01, C-03), secondary lines (C-02, C-04), transformers (C-07, C-08) and services (C-10, C-11) are all based on the number of customers served at that level of service. The analyses are based on the most recently available historical data, as well as from test year projected numbers of customers. Meter costs are allocated to class as described above (C-12).

The remaining distribution plant is classified as demand-related costs and therefore these costs are allocated using allocation factors developed to reflect the appropriate demand associated with each function. Class NCP demand refers to the situation where one retail class of customers is segregated from all others. For such a class there is one hour out of the 8,760 hours in the year when its combined load reaches a maximum point. This point is called the Class NCP (or Class Peak). Sum NCP demand differs from Class NCP demand in that the maximum demand for each of the customers within the class is determined independently. The sum of these maximum demands produces the Sum NCP (or Customer Peak) demand for such class.

The appropriate demand used for development of allocation factors varies depending on the system or functional cost being allocated. For example, since load diversity is recognized in system design and planning, it is proper to utilize a different demand in developing factors to allocate the costs associated with each system. For distribution bulk delivery (D-03), distribution substations (D-04) and primary line facilities (D-05, D-07) an intermediate amount of diversity is apparent. Because of this, Class NCP demands calculated to the appropriate level of output are reasonable to use in developing these factors. There is somewhat less diversity in loads on line transformers (D-11, D-12) and so an average of Class NCP demands and Sum NCP demands calculated to the appropriate level of output are used. Finally, the least amount of diversity exists as the Secondary Lines (D-06, D-08) and Services level (D-14, D-15) and, therefore, Sum NCP demands calculated to the appropriate level of output are used for allocating the demand-related cost of these facilities.

All of the above allocation methodologies for distribution plant are consistent with MP's last two rate cases, as well as with our last FERC rate case for the FERC jurisdictional allocations. These methods are also consistent with the methods suggested by NARUC in Chapter 6.

The development of the all jurisdictional and class allocators are detailed in Volume V, Workpapers, under Allocation Factors (AF).

General Plant: FERC accounts 390-399

General Plant is functionalized, classified and allocated following the same treatment as Intangible Plant described above.

Construction Work In Progress: FERC account 107

Steam, Hydro, Wind, Transmission, Distribution Bulk Delivery and General Plant CWIP are functionalized, classified and allocated following the same methods as described above for the corresponding plant.

The remaining Distribution Plant CWIP is first functionalized and classified based on the distribution plant ratios above, and then allocated following the same methods as described above for the corresponding plant.

This treatment is consistent with MP's last two retail rate cases and MP's last FERC rate case.

Land: FERC account 310, 330, 340, 350, 360, 389

Land – Steam, Land – Transmission, and Land – Other Distribution are functionalized and classified following the same methods as the corresponding plant and are allocated on corresponding plant in service ratios.

Land – Hydro, Land – Wind, Land – Distribution Bulk Delivery and Land – General Plant are functionalized, classified and allocated following the same methods as corresponding plant in service.

This treatment is consistent with MP's last two retail rate cases and MP's last FERC rate case.

Depreciable Plant In Service

Depreciable Plant In Service is internally calculated as functionalized, classified and allocated plant in service less corresponding land. This treatment is consistent with MP's last two retail rate cases and MP's last FERC rate case.

Accumulated Provision For Depreciation: FERC accounts 108, 110

All Accumulated Provision for Depreciation amounts are functionalized and classified following the corresponding plant in service and are allocated on corresponding depreciable plant in service ratios. This treatment is consistent with MP's last two retail rate cases and MP's last FERC rate case.

Accumulated Provision For Amortization: FERC accounts 111, 115

Accumulated Provision for Amortization amounts are functionalized, classified and allocated following labor ratios as described above under Intangible Plant. This treatment is consistent with MP's last two retail rate cases and MP's last FERC rate case.

Working Capital Requirements: FERC accounts 151, 154, 163

Fuel Inventory (a/c 151) is classified as energy and is allocated to jurisdiction using energy allocator E-01 and to class using allocator E8760. This treatment is the same as Fuel Expenses (a/c 501) discussed later, and is consistent with MP's last two retail rate cases, MP's last FERC rate case and also with NARUC Chapter 4.

Materials and Supplies (a/c 154, 163) are subfunctionalized to production, transmission and distribution on most recent calendar year amounts. Distribution is then subsequently subfunctionalized / classified on distribution plant in service ratios. All line items are allocated to jurisdiction and class following the same methods as described above for the corresponding plant. This treatment is consistent with MP's last two retail rate cases and MP's last FERC rate case.

Prepayments (a/c 165) are internally classified to demand, energy and customer and are allocated to jurisdiction and class using an internal allocator based on total depreciable plant. This treatment is consistent with MP's last two retail rate cases and MP's last FERC rate case.

Prepayment – Pension Asset are internally classified and allocated to demand, energy and customer components following total O&M labor ratios less A&G. This approach is consistent with the approach followed in MP's last two retail rate cases for other labor related A&G costs and consistent with FERC methodology approved in MP's last FERC rate case. This method is also discussed in NARUC (Chapter 8)

Prepayment - SBPC is classified to energy and is allocated to jurisdiction using energy allocator E-01 and to class using allocator E8760. This treatment is appropriate since the SBPC contract is energy related.

Cash Working Capital items are assigned to demand, energy and customer components and are allocated to jurisdiction and class using internal allocators calculated based on the corresponding or related expense. This treatment is consistent with MP's last two retail rate cases and MP's last FERC rate case.

Cash Working Capital income taxes are assigned to demand, energy and customer components and are allocated to jurisdiction and class based on total rate base.

Worker Compensation Deposit: FERC account 1864-0093

The MP Regulated portion of the Worker Compensation Deposit is internally classified and allocated to demand, energy and customer components following total O&M labor ratios less A&G. This approach is consistent with the approach followed in MP's last two retail rate cases for other labor related A&G costs and consistent with FERC methodology approved in MP's last FERC rate case. This method is also discussed in NARUC (Chapter 8)

Unamortized WPPI Transmission Delivery: Account 2530-9030

Unamortized WPPI payment for transmission services are amortized over a specific 33 year schedule. This reduction to rate base is functionalized to transmission, classified as demand and allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Transmission – demand function (D-02).

Unamortized UMWI Transaction Cost: FERC account 182.3

Unamortized DC Line acquisition costs are amortized at 2.39% per year and unamortized cost to restructure the Square Butte PPA are amortized over a specific 17 year schedule. These additions to rate base are functionalized to transmission, classified as demand and allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Transmission – Demand function (D-02).

Customer Advances and Deposits: FERC account 252, 253

Ideally customer advances and deposits should be assigned to the customer classes actually making the advances. Due to the large number of historic transactions and because these transactions are recorded by FERC revenue class, they cannot be directly or readily separated into customer classes, particularly for General Service and Large Light & Power.

Because advances and deposits are made by customers requiring new service, it is reasonable to expect that the distribution of these new facilities by class would reflect the distribution of facilities to all customers in the long run. Therefore, as a proxy, Customer Advances and Deposits are functionally assigned, classified and allocated to class following Primary and Secondary Overhead Lines.

This method has been consistently and historically been used in MP's rate cases. To check or validate its reasonableness, for its 2008 rate case, MP manually reviewed over 1,000 transactions representing approximately 35% of the value of the customer advances and deposits. Based on the analysis, the comparative allocation shown in Table 3 confirms the reasonableness of the methodology.

Table 3: Customer Advances and Deposits

Allocation of Customer Deposits and Advances Based on:

Functional Assignment Per CCOSS			Actual Transactions by Revenue Class		
Residential	$	1,343,772	$	1,278,567	Residential
General Service	$	627,669	$	1,148,688	Commercial
Large Light & Power	$	492,479	$	41,187	Industrial
Large Power	$	19,685		-	-
Municipal Pumping	$	28,508	$	27,290	Municipal Pumping
Lighting	$	14,699	$	31,080	Lighting

Other Deferred Credit – Hibbard: FERC account 253000-9058/9

Other Deferred Credit – Hibbard is functionally assigned, classified and allocated following Depreciable Steam Plant – Demand. This approach is consistent with the treatment of Hibbard in rate base.

Wind Performance Deposit: FERC account 25300-9091

Wind Performance Deposit is functionally assigned, classified and allocated following Depreciable Wind Plant – Demand. This approach is consistent with the treatment of other wind plant in rate base.

Accumulated Deferred Income Taxes: FERC account 281, 282, 283, 190

Accumulated deferred income taxes are functionally assigned, classified and allocated across jurisdiction and to class using internal allocators following depreciable plant in service. Because book/tax timing differences arise from investment in plant, it is reasonable these amounts should follow plant. This treatment is consistent with MP's last two retail rate cases and MP's last FERC rate case.

INCOME STATEMENT

Sales of Electricity – Sales by Rate Class: FERC account 440-447

The Revenue function contains the sales of electricity to the Minnesota jurisdictional and non-jurisdictional classes. Actual sales are assigned to each rate class creating those sales. Since sales revenues cannot be directly classified, they remain segregated until the final allocation of the demand, energy, and customer components takes place. This, in turn, allows the model to calculate revenue and revenue requirements by classification.

Intersystem Sales: FERC account 447

Intersystem Sales are classified to demand and energy according to the details of each sale, that is, capacity sales are classified as demand, with the remaining classified as energy.

Sales classified as demand are allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Power Supply Production – Demand function (D-01).

Sales classified as energy are allocated to jurisdiction on energy (E-01) and to class on the E8760. All intersystem sales revenues are treated as revenue credits and are allocated back to MP's FERC and retail jurisdictional customers.

Sales of Electricity – Other Sales – Duel Fuel: FERC account 440-443

Duel Fuel Sales are classified to demand and energy in proportion to demand and energy charges included in the rate design. Because all duel fuel sales are to MP's retail customers, no allocation is made to FERC jurisdiction.

Sales classified as demand are allocated to class based on the P&A method described above for Power Supply Production – Demand function (D-01) and Sales classified as energy are allocated to class on the E8760.

All duel fuel sales revenues are treated as revenue credits and allocated back to MP's retail jurisdictional customers. This is consistent with the treatment of duel fuel interruptible load that is deducted from the system peak to recognize the system wide benefit of interruptible customers.

Sales of Electricity – Other Sales – LP IPS, RFPS, SBPC, Economy: FERC account 443

Sales revenue from Large Power Incremental Production Service (IPS), Replacement Firm Power Service (RFPS), Silver Bay Power Corporation (SBPC), and Economy are classified as energy and are allocated to jurisdiction on energy (E-01) and to class on the E8760.

All IPS, RFPS, SBPC and Economy sales revenues are treated a revenue credits and allocated back to MP's FERC and retail jurisdictional customers.

This method of recognizing non-firm sales and distributing the revenues associated with these customers to all of the Company's standard retail and wholesale classes of customers is consistent with Minnesota Power's last two retail rate cases.

Sales of Electricity – Other Sales – Pool Within a Pool: FERC account 443

Pool Within a Pool revenues are from a Large Power fixed charge related to RFPS or non-firm service. As with RFPS revenue, these revenues are treated as a revenue credit and are allocated back to all of the Company's standard retail and wholesale classes of customers.

These revenues are classified as demand and are allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Power Supply Production – Demand function (D-01).

Other Operating Revenue: FERC accounts 450,454, 456

There are numerous sources of Other Operating revenue in FERC accounts 450, 454 and 456. Each revenue type is reviewed and assigned to one of the following functions/classifications: Production – Demand, Production – Energy, Transmission, General Plant, Specific Retail – Distribution, and Specific Retail Energy.

Specific Retail – Distribution is then subfunctionalized and classified following distribution plant ratios.

All Other Operating revenues are treated as revenue credits and are allocated to jurisdiction and to class using the appropriate allocation factors.

All Retail Specific revenue is allocated to MP's retail customers only.

Refer to MP Exhibit___(MAP) Direct Schedule 4 for a descriptive list of Other Operating Revenue by FERC account and functional assignment.

Operation & Maintenance Expense – All

Refer to Volume V, Workpapers, Under Operating Income, for a detailed list of all O&M expenses by FERC account and classification.

<u>Operation & Maintenance Expense – Steam Production : FERC accounts 500, 502-3, 505-6, 510-514</u>

Steam O&M expenses are classified to demand and energy consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case. This treatment is similar to that shown in NARUC.

Specifically, FERC accounts 510, 512 and 513 are classified to energy, and all other expenses are classified as demand.

Fuel expense (account 501) is classified as energy and is described below.

Expenses classified as demand are allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Power Supply Production – Demand function (D-01).

Expenses classified as energy are allocated to jurisdiction on energy (E-01) and to class on the E8760.

<u>Operation & Maintenance Expense – Hydro Production: FERC accounts 535, 537-9, 541-5</u>

Hydro O&M expenses are classified to demand and energy consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case. This treatment is similar to that shown in NARUC.

Specifically, FERC accounts 543-5 are classified to energy, and all other expenses are classified as demand.

Expenses classified as demand are allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Power Supply Production – Demand function (D-01).

Expenses classified as energy are allocated to jurisdiction on energy (E-01) and to class on the E8760.

<u>Operation & Maintenance Expense – Wind Production: FERC accounts 546-554</u>

Wind O&M expenses are classified to demand consistent with the approach approved in MP's last retail rate case and consistent with that approved in MP's Renewable Resources Rider.

These expenses are allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Power Supply Production – Demand function (D-01).

Operation & Maintenance Expense – Other Power Supply: FERC accounts 556-7

Other Power Supply O&M expenses are classified to demand consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case. This treatment is similar to that shown in NARUC.

Specifically, FERC accounts 556-7 are classified as demand. These expenses are allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Power Supply Production – Demand function (D-01).

Operation & Maintenance Expense – Other Power Supply – Purchase Power: FERC accounts 555

Other Power Supply O&M expenses – Purchase Power, are classified to demand and energy according to the details of each purchase. This is consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology and that approved in MP's last FERC rate case. This treatment follows that shown in NARUC.

Expenses classified as demand are allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Power Supply Production – Demand function (D-01).

Expenses classified as energy are allocated to jurisdiction on energy (E-01) and to class on the E8760.

Operation & Maintenance Expense – Fuel: FERC accounts 501

O&M expenses – Fuel is classified to energy consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case. This treatment follows that shown in NARUC.

Expenses classified as energy are allocated to jurisdiction on energy (E-01) and to class on the E8760.

Operation & Maintenance Expense – Transmission: FERC accounts 560-3, 565- 571

O&M expenses – Transmission, are classified to demand consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case. This treatment follows NARUC.

These expenses are allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Power Supply Transmission – Demand function (D-02).

Operation & Maintenance Expense – Regional Market : FERC accounts 575

O&M expenses – Regional Transmission Expenses are classified to demand consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case. This treatment follows NARUC.

These expenses are allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for power Supply Transmission – Demand function (D-02).

<u>Operation & Maintenance Expense – Distribution</u>

Distribution O&M Expenses are functionally grouped into three groups: Meters, Distribution Bulk Delivery, and Other Distribution O&M. Following are the discussion of each of the 3 functions.

<u>Operation & Maintenance Expense – Distribution - Meters: FERC accounts 586</u>

O&M expenses – Distribution - Meters are classified as customer related consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case. This treatment follows NARUC.

These expenses are allocated to jurisdiction and class using the customer-meter allocation factor (C-12) that is based on meter counts and costs as described above and as used for meter plant.

<u>Operation & Maintenance Expense – Distribution – Bulk Delivery: FERC accounts 580-1, 583-4, 588-590, 592-4, 596-8</u>

After separating out meters expenses in FERC account 586, Distribution Bulk Delivery O&M expenses are estimated based on the ratio of distribution bulk delivery plant to total distribution plant. The functionalized expenses are then classified as demand and are allocated to jurisdiction on NCP demands and to class on Class NCP using the same allocators as described above for distribution bulk delivery plant (D-03).

This is consistent with the approach approved in MP's last three retail rate case and consistent with FERC methodology approved in MP's last FERC rate case.

<u>Operation & Maintenance Expense – Distribution – Other Distribution: FERC accounts 580, 583-4, 588-590, 592-4, 596-8</u>

After separating out meters expenses and distribution bulk delivery expenses above, the remaining Distribution O&M expenses are functionalized to Distribution Other. These expenses are then internally classified and allocated to demand and customer components following the classification and allocation of distribution plant, excluding meters and distribution bulk delivery plant.

This is consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

<u>Operation & Maintenance Expense - Customer Accounting: FERC accounts 902-4</u>

O&M Expenses – Customer Accounting are classified as customer related consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are allocated to jurisdiction and class using the Customer Account allocator (C-15). The allocator was developed using actual account expenses by work order and labor distribution. The development of this allocator is detailed in Volume V, Workpapers, under Allocation Factors (AF).

<u>Operation & Maintenance Expense - Customer Accounting Credit Cards</u>

O&M Expenses – Customer Accounting Credit Cards are classified as customer related consistent with the above primary account. These expenses are allocated only to Minnesota jurisdiction reflecting the design of the proposal to benefit the Residential and General Services classes and are allocated to those two classes.

These expenses are allocated to jurisdiction and class using the Customer Account allocator (C-18). The allocator was developed using actual account expenses by work order and labor distribution. The development of this allocator is detailed in Volume V, Workpapers, under Allocation Factors (AF).

<u>Operation & Maintenance Expense - Customer Service & Information: FERC accounts 907-10</u>

O&M Expenses – Customer Service and Information are classified as customer related consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are allocated to jurisdiction and class using the Customer Service allocator (C-17). The allocator was developed using actual account expenses by work order and labor distribution. The development of this allocator is detailed in Volume V, Workpapers, under Allocation Factors (AF).

<u>Operation & Maintenance Expense – Conservation Improvement Program: FERC accounts 907-10</u>

O&M Expenses – Conservation Improvement Program (CIP) are classified as energy consistent with the approach approved in MP's last three retail rate cases.

In the 2008 rate case MP revised the Conservation Cost Recovery Charge ("CCRC") methodology so that it excludes the test year energy sales for exempt Large Power customers and thus more accurately reflects the test year retail sales subject to the CCRC. To reflect this change MP changed the allocation of CIP expenses from the E8760 allocator to the CCRC allocator that allocates CIP expenses to retail rate classes based on each class's MWh of energy subject to the CCRC.

<u>Operation & Maintenance Expense - Sales: FERC accounts 913</u>

O&M Expenses – Sales are classified as customer related consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are allocated to class using the Customer Sales allocator (C-16). The allocator was developed using actual account expenses by work order and labor distribution. The development of this allocator is detailed in Volume V, Workpapers, under Allocation Factors (AF).

<u>Operation & Maintenance Expense – Property Insurance: FERC accounts 924</u>

O&M Expenses – Property Insurance are internally classified and allocated to demand, energy and customer components consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are classified and allocated following utility plant in service ratios.

<u>Operation & Maintenance Expense – Regulatory Expenses - Misc: FERC accounts 928</u>

O&M Expenses – Regulatory Expenses - Miscellaneous are internally classified and allocated to demand, energy and customer components consistent with the approach approved in MP's last three retail rate case and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are classified and allocated following utility plant in service ratios.

<u>Operation & Maintenance Expense – Regulatory Expenses - MISO: FERC accounts 928</u>

O&M Expenses – Regulatory Expenses - MISO are functionalized to Demand – Transmission and are allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Power Supply Transmission – Demand function (D-02).

This treatment is consistent with the approach approved in MP's last two retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

<u>Operation & Maintenance Expense – Advertising: FERC accounts 930.1</u>

O&M Expenses – Advertising are internally classified and allocated to demand, energy and customer components consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are classified and allocated to jurisdiction and class following total O&M labor ratios less A&G.

Operation & Maintenance Expense – Franchise Requirements: FERC accounts 927

O&M Expenses – Franchise Requirements are internally classified and allocated to demand, energy and customer components consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are classified and allocated to class following retail sales.

Operation & Maintenance Expense – Rate Case Expenses (Retail): FERC accounts 928

O&M Expenses – Rate Case Expenses (Retail) are internally classified and allocated to demand, energy and customer components consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are classified and allocated to retail classes on total retail rate base.

Operation & Maintenance Expense – General Plant: FERC accounts 935

O&M Expenses – General Plant are internally classified and allocated to demand, energy and customer components consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are classified and allocated to jurisdiction and class following total O&M labor ratios less A&G.

Operation & Maintenance Expense – General Plant – Other A&G: FERC accounts 920.1, 923, 925-6, 930.2

O&M Expenses – General Plant – Other A&G are internally classified and allocated to demand, energy and customer components consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are classified and allocated to jurisdiction and class following total O&M labor ratios less A&G.

Operation & Maintenance Expense – Interest on Customer Deposits: FERC account 43100.1002

O&M Expenses – Interest on Customer Deposits are internally classified and allocated to demand and customer components consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are classified and allocated to class following Customer Advances discussed above.

Operation & Maintenance Expense – Charitable Contributions: FERC account 426.1

O&M Expenses – Donations are internally classified and allocated to demand, energy and customer components consistent with the approach approved in MP's last three retail rate cases and consistent with FERC methodology approved in MP's last FERC rate case.

These expenses are classified and allocated to jurisdiction and class following total O&M labor ratios less A&G.

Operation & Maintenance Expense – Labor Only

O&M Expenses – Labor Only are the labor expenses included in the total O&M expenses above. The labor only expenses are broken out to allow labor ratios and allocators to be internally developed in the CCOSS model. Apart from using the resulting labor ratios and allocators to functionally assign certain CCOSS rate base and income statement components, the labor only expenses are not otherwise utilized in the CCOSS model.

The labor only expense are internally functionalized, classified and allocated to demand, energy and customer components following the treatment of O&M expenses discussed above.
This treatment is consistent with the approach approved in MP's last three retail rate cases and is consistent with FERC methodology approved in MP's last FERC rate case.

For further information on the internally developed labor ratios and allocators, refer to description of internally developed allocators below.

Depreciation Expense: FERC account 403

Depreciation expenses are functionalized, classified and allocated following the corresponding depreciable plant in service.

This treatment is consistent with MP's last two retail rate cases and MP's last FERC rate case.

Amortization Expense: FERC accounts 406, 407.3, 411.1

UMWI amortization expense and ARO Accretion are functionalized, classified and allocated following production demand. ARO accretion is excluded in Interim and General rates by MPUC Order.

2010 and 2016 Rate Case Amortization are functionalized, classified and allocated following total retail rate base.

CEC TG5 Amortization is functionalized, classified and allocated following production demand. Medicare Part D Amortization is internally functionalized, classified and allocated following corresponding labor only expense ratios.

Amortization Expense of Intangible Plant is functionalized, classified and allocated following the treatment of General and Intangible Plant.

Deferred Strom Expense Cost Amortization is internally functionalized, classified and allocated following corresponding retail labor only expense ratios.

Intangible Plant Amortization is internally functionalized, classified and allocated following General and Intangible Plant. This treatment is consistent with the approach approved in MP's last two retail rate cases and are consistent with FERC methodology approved in MP's last FERC rate case.

Property Taxes: FERC account 408.1

Property taxes are internally functionalized, classified and allocated following corresponding plant in service ratios.

This treatment are consistent with the approach approved in MP's last three retail rate cases and are consistent with FERC methodology approved in MP's last FERC rate case.

Payroll Taxes: FERC account 408.1

Payroll taxes for Power Supply, Transmission & Distribution and Administration are internally functionalized, classified and allocated following corresponding labor only expense ratios.

Payroll taxes for Customer Accounting, Customer Service and Information and Sales are classified and allocated following the same treatment as the corresponding O&M expenses.

These treatments are consistent with the approach approved in MP's last three retail rate cases and are consistent with FERC methodology approved in MP's last FERC rate case.

Air Quality Emission Expense and MN Wind Production Tax: FERC account 408.1

Air Quality Emission expense and MN Wind Production Tax are functionalized to production, classified as energy, and are allocated to jurisdiction on energy (E-01) and to class on the E8760.

This treatment is consistent with the approach approved in MP's last two retail rate cases.

Additions and Deductions to Income for Tax: FERC accounts – various

The numerous additions and deductions to income for tax are functionally assigned and allocated to jurisdiction and class primarily with internal allocators and ratios that best reflect cost causation for each item.

These treatments are consistent with the approach approved in MP's last three retail rate cases and are consistent with FERC methodology approved in MP's last FERC rate case.

The amount "Deduction to Income for Tax – Interest on Long Term Debt" is a part of what is termed Interest Synchronization. In the CCOSS the interest on long term debt is internally calculated in the model for the total company; the calculation is the weighted costs of long term debt multiplied by the total company average rate base in the model. The resulting amount is then classified and allocated to jurisdiction and class using an internal allocator developed on total average rate base ratios.

This treatment is consistent with the approach approved in MP's last three retail rate cases and is consistent with FERC methodology approved in MP's last FERC rate case.

State Income Tax

The NOL Reclass to Deferred Tax Benefit and the State Depreciation Modification adjustments are internally functionalized, classified and allocated following plant in service ratios.

When the CCOSS is run, the revenue requirements for each function, sub-function and classification component by class and jurisdiction are calculated by what is sometimes called the "Reverse or Backwards Revenue Requirement" calculation. The basic formula is shown below:

Reverse Revenue Requirement Calculation

1		Cost of Service Revenue Requirements
2	=	Rate of Return (Current Authorized or Proposed)
3	x	Rate Base
4	+	Total Operation & Maintenance Expense
5	+	Depreciation and Amortization Expense
6	+	Taxes Other than Income Taxes
7	=	Operating Income Before Income Taxes
8	+/-	Additions/Deduction for Tax
9	+	CCOSS calculation of State and Federal Income Taxes
10	+	Provision for Deferred Income Taxes – Net
11	+	Investment Tax Credit
12	-	Investment Tax Credit Feedback
13	-	AFDUC
14	-	Total Other Operating Revenue
15	-	Total Other Sales Revenue
16	-	Total Inter System Sales Revenue

The above calculation illustrates that when the CCOSS is run, the required revenues to be at "cost" are calculated based on the same rate of return (either current authorized or proposed) for each function, sub-function, component, class, and jurisdiction. The CCOSS calculates and assigns income taxes by class based on the adjusted net taxable income of each function, sub-function, component, and jurisdiction as determined soley by the CCOSS. As shown above, present rate revenues are not in the backwards revenue requirements formula; therefore, the CCOSS calculates and assigns income taxes by class based on the adjusted net taxable income by class as determined by the CCOSS.

Minnesota state tax income tax is calculated at the statutory tax rate of 9.8% multiplied by the state net taxable income.

Federal Income Tax

Minnesota state tax income tax deduction is calculated as described above. The NOL Reclass to Deferred Tax Benefit are internally functionalized, classified and allocated following plant in service ratios. Federal income tax is calculated at the statutory tax rate of 35% multiplied by the federal net taxable income. When the CCOSS is run, the CCOSS calculates and assigns income taxes by class based on the adjusted net taxable income by function, sub-function, and classification component by class and jurisdiction class as determined by the CCOSS as described above.

Federal production tax credit is deducted from the federal income tax calculated above to arrive at the total federal income tax. The federal production tax credit is allocated to jurisdiction based on the 12-month average coincident peak method and to class based on the P&A method described above for Power Supply Production – Demand function.

Provision for Deferred Income Tax: FERC accounts 410.1, 411.1

Provision for Deferred Income Tax are functionalized by plant and then classified and allocated to jurisdiction and class following corresponding depreciable plant in service ratios.

This treatment is consistent with the approach approved in MP's last three retail rate cases and is consistent with FERC methodology approved in MP's last FERC rate case.

Investment Tax Credit, Current and Feedback: FERC account 411.4

Investment tax credits are functionalized by plant and then classified and allocated to jurisdiction and class following corresponding depreciable plant in service ratios.

This treatment is consistent with the approach approved in MP's last three retail rate cases and is consistent with FERC methodology approved in MP's last FERC rate case.

Allowance for Funds Used During Construction: FERC account 4191.1, 432

Allowance for Funds Used During Construction (ADFUDC) are functionalized by plant and then classified and allocated to jurisdiction and class following the treatment of the corresponding construction work in progress.

This treatment is consistent with the approach approved in MP's last three retail rate cases and is consistent with FERC methodology approved in MP's last FERC rate case.

INTERNALLY DEVELOPED ALLOCATION FACTORS

There are two basic type of allocators used in the CCOSS: Externally Developed allocators that are developed using data external to the CCOSS model, and Internally Developed allocators that are automatically calculated based on data internal to the CCOSS model.

The externally developed allocators have been described above and are detailed in Volume IV, Workpapers, under Allocation Factors (AF). Internally developed allocators are ratios based on one or more revenue, expense or rate base items that have been allocated to jurisdiction and class within the CCOSS using one or more other allocators.

Table 5 Internally Developed Allocators, outlines the development, calculations, and sources of the values of the internally developed allocators from MP's CCOSS. The internally developed allocators (ratios) and their respective "ALLOC" codes are at MP Exhibit ___ (SJS), Schedule C-1, Pages 41-46. These ratios are calculated based on the values which are summarized and found at MP Exhibit ___ (SJS), Schedule C-1, Pages 37-40. These values are taken from various lines within the CCOSS and represent one or more revenue, expense or rate base items that have been allocated to jurisdiction and class within the CCOSS using one or more other allocators.

An example is described below to illustrate the development, calculation, source and use of an internally developed allocator.

On Line 5 of Table 5 is the internally developed allocator "DISTRIBUTION PLANT," identified by the allocation code "DISTPLT."

Columns 1, 2 and 3 indicate how the internally developed allocator is calculated – it shows the calculations and results.

Columns 4, 5, and 6 show the values used in the calculation.

Columns 7 and 8 reference the starting page number and line number in MP Exhibit ___ (SJS), Direct Schedule C-1 (CCOSS) showing the source location of the values used in the calculations.

The source of the values used to calculate "DISTPLT" can be found at MP Exhibit ___ (SJS), Direct Schedule C-1, page 5, line 44, the rate base item "TOTAL DISTRIBUTION PLANT." As can be seen, this is the sum of all distribution plant that has been allocated to jurisdiction and class based on the various "externally developed" distribution plant allocation factors.

The internally developed allocator “DISTPLT” is used to allocate distribution plant property taxes to jurisdiction and class as shown at MP Exhibit ___ (SJS), Direct Schedule C-1, line 26, pages 23-24.

Table 4 Summary of Functionalization, Classification and Allocation in MP's CCOSS

	Functionalization and Classification of Rate Base and Income Statement Accounts 1/	FERC Account or MP's Function Code	Note	Classification: Demand	Classification: Energy	Classification: Customer	Basis of Jurisdictional Cost Allocation	Basis of Retail Class Cost Allocation	Internal (I) or External (E) Allocator	Name / Number of External Allocator	Allocation Code Used in CCOSS
	RATE BASE										
1	ELECTRIC PLANT IN SERVICE (PIS)										
2	INTANGIBLE PLANT										
3	PRODUCTION - ENERGY	301-303		-	X	-	Total O&M Labor less A&G - Energy		(I)	-	LABLAGE
4	OTHER	301-303		X	-	X	Total O&M Labor less A&G - Other		(I)	-	LABLAGO
5	TANGIBLE PLANT										
6	STEAM										
7	PRODUCTION - DEMAND	311-317		X	-	-	12 CP	P & A	(E)	D-01	DPROD
8	AFUDC CONTRA (FERC)			X	-	-	12 CP	P & A	(E)	D-01	DPRODR
9	AFUDC CONTRA (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
10	HYDRO										
11	PRODUCTION - DEMAND	331-337		X	-	-	12 CP	P & A	(E)	D-01	DPROD
12	PRODUCTION - ENERGY	B200	2/	-	X	-	E-01	E8760	(E)	E8760	EPROD
13	AFUDC CONTRA (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
14	WIND PRODUCTION - DEMAND	341-347		X	-	-	12 CP	P & A	(E)	D-01	DPROD
15	AFUDC CONTRA (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
16	TRANSMISSION										
17	PRODUCTION - DEMAND	C200	3/	X	-	-	12 CP	P & A	(E)	D-01	DPROD
18	TRANSMISSION	352-359		X	-	-	12 CP	P & A	(E)	D-02	DTRAN
19	AFUDC CONTRA (FERC)			X	-	-	12 CP	P & A	(E)	D-02	DTRANR
20	AFUDC CONTRA (RETAIL)			X	-	-	12 CP	P & A	(E)	D-02	DTRANJ
21	DISTRIBUTION	361-368	4/								
22	PRIMARY										
23	OVERHEAD LINES - DEMAND	D300		X	-	-	-	Class NCP	(E)	D-05	DDISTPOL
24	OVERHEAD LINES - CUST	D300		-	-	X	-	Customers	(E)	C-01	CDISTPOL
25	UNGRD LINES - DEMAND	D400		X	-	-	-	Class NCP	(E)	D-07	DDISTPUL
26	UNGRD LINES - CUST	D400		-	-	X	-	Customers	(E)	C-03	CDISTPUL
27	SECONDARY										
28	OVHD LINES - DEMAND	D300		X	-	-	-	Sum NCP	(E)	D-06	DDISTSOL
29	OVHD LINES - CUST	D300		-	-	X	-	Customers	(E)	C-02	CDISTSOL
30	UNGRD LINES - DEMAND	D400		X	-	-	-	Sum NCP	(E)	D-08	DDISTSUL
31	UNGRD LINES - CUST	D400		-	-	X	-	Customers	(E)	C-04	CDISTSUL
32	OVHD LINE TRANSFRM - DEM	D500		X	-	-	-	Avg Class & Sum NCP	(E)	D-11	DDISTSOT
33	OVHD LINE TRANSFRMS - CUST	D500		-	-	X	-	Customers	(E)	C-07	CDISTSOT
34	UNGRD LINE TRANSFRMS - DEM	D500		X	-	-	-	Avg Class & Sum NCP	(E)	D-12	DDISTSUT
35	UNGRD LINE TRANSFRMS - CUST	D500		-	-	X	-	Customers	(E)	C-08	CDISTSUT
36	OVHD SERVICES - DEMAND	369		X	-	-	-	Sum NCP	(E)	D-14	DDISTSOS
37	OVERHEAD SERVICES - CUST	369		-	-	X	-	Customers	(E)	C-10	CDISTSOS
38	UNGRD SERVICES - DEM	369		X	-	-	-	Sum NCP	(E)	D-15	DDISTSUS
39	UNGRD SERVICES - CUST	369		-	-	X	-	Customers	(E)	C-11	CDISTSUS
40	METERS	370		-	-	X	Meter counts & cost		(E)	C-12	CMETERS
41	LEASED PROPERTY	372		-	-	X	-	Direct	(E)	C-14	CDISTSLP
42	STREET LIGHTING	373		-	-	X	-	Direct	(E)	-	CLIGHT
43	PRODUCTION - DEMAND	D200	5/	X	-	-	12 CP	P & A	(E)	D-01	DPROD
44	DISTRIBUTION BULK DELIVERY		6/	X	-	-	NCP	Class NCP	(E)	D-03	DSUB46
45	DISTRIBUTION SUBSTATIONS	D100		X	-	-	-	Class NCP	(E)	D-04	DDISPSUB
46	DIST BULK DEL SPECIFIC ASSIGN		7/	X	-	-	Direct	-	(E)	-	DSUBSATP

Table 4 Summary of Functionalization, Classification and Allocation in MP's CCOSS

	Functionalization and Classification of Rate Base and Income Statement Accounts 1/	FERC Account or MP's Function Code	Note	Classification: Demand	Classification: Energy	Classification: Customer	Basis of Jurisdictional Cost Allocation	Basis of Retail Class Cost Allocation	Internal (I) or External (E) Allocator	Name / Number of External Allocator	Allocation Code Used in CCOSS
47	DIST PRIMARY SPECIFIC ASSIGN	D100		X	-	-	Direct	-	(E)	-	DDPSADP
48	GENERAL PLANT										
49	PRODUCTION - ENERGY	390-399		-	X	-	Total O&M Labor less A&G - Energy		(I)	-	LABLAGE
50	OTHER	390-399		X	-	X	Total O&M Labor less A&G - Other		(I)	-	LABLAGO
51											
52	CONSTRUCTION WORK IN PROGRESS	107									
53	STEAM PRODUCTION DEMAND	107		X	-	-	12 CP	P & A	(E)	D-01	DPROD
54	AFUDC CONTRA (FERC)			X	-	-	12 CP	P & A	(E)	D-01	DPRODR
55	AFUDC CONTRA (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
56	HYDRO										
57	PRODUCTION - DEMAND	107		X	-	-	12 CP	P & A	(E)	D-01	DPROD
58	PRODUCTION - ENERGY	107		-	X	-	E-01	E8760	(E)	E8760	EPROD
59	AFUDC CONTRA (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
60	WIND	107		X	-	-	12 CP	P & A	(E)	D-01	DPROD
61	AFUDC CONTRA (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
62	TRANSMISSION	107		X	-	-	12 CP	P & A	(E)	D-02	DTRAN
63	AFUDC CONTRA (FERC)			X	-	-	12 CP	P & A	(E)	D-02	DTRANR
64	AFUDC CONTRA (RETAIL)			X	-	-	12 CP	P & A	(E)	D-02	DTRANJ
65	DISTRIBUTION										
66	DIST BULK DELIVERY	107		X	-	-	NCP	Class NCP	(E)	D-03	DSUB46
67	DIST SUBSTATIONS	107		X	-	-	-	Class NCP	(E)	D-04	DDISPSUB
68	PRI OVERHEAD LINES - DEMAND	107		X	-	-	-	Class NCP	(E)	D-05	DDISTPOL
69	PRI OVERHEAD LINES - CUST	107		-	-	X		Customers	(E)	C-01	CDISTPOL
70	PRI UNGRD LINES - DEMAND	107		X	-	-	-	Class NCP	(E)	D-07	DDISTPUL
71	PRI UNGRD LINES - CUST	107		-	-	X		Customers	(E)	C-03	CDISTPUL
72	SEC OVHD LINES - DEMAND	107		X	-	-	-	Sum NCP	(E)	D-06	DDISTSOL
73	SEC OVHD LINES - CUST	107		-	-	X		Customers	(E)	C-02	CDISTSOL
74	SEC UNGRD LINES - DEMAND	107		X	-	-	-	Sum NCP	(E)	D-08	DDISTSUL
75	SEC UNGRD LINES - CUST	107		-	-	X		Customers	(E)	C-04	CDISTSUL
76	METERS	107		-	-	X	Meter counts & cost		(E)	C-12	CMETERS
77	GENERAL PLANT										
78	PRODUCTION - ENERGY	107		-	X	-	Total O&M Labor less A&G Energy		(I)	-	LABLAGE
79	OTHER	107		X	-	X	Total O&M Labor less A&G Other		(I)	-	LABLAGO
80	LAND										
81	STEAM PRODUCTION	310		X	-	-	Steam PIS		(I)	-	STMPLT
82	HYDRO PRODUCTION										
83	PRODUCTION - DEMAND	330		X	-	-	12 CP	P & A	(E)	D-01	DPROD
84	PRODUCTION - ENERGY	330		-	X	-	E-01	E8760	(E)	E8760	EPROD
85	WIND PRODUCTION	340		X	-	-	12 CP	P & A	(E)	D-01	DPROD
86	TRANSMISSION	350		X	-	-	Transmission PIS		(I)	-	TRANPLTO
87	DISTRIBUTION										
88	DIST BULK DELIVERY	360		X	-	-	NCP	Class NCP	(E)	D-03	DSUB46
89	OTHER DISTRIBUTION	360		X	-	X	Other Distribution PIS		(I)	-	DISTPLTO
90	GENERAL										
91	PRODUCTION - ENERGY	389		-	X	-	Total O&M Labor less A&G - Energy		(I)	-	LABLAGE
92	OTHER	389		X	-	X	Total O&M Labor less A&G - Other		(I)	-	LABLAGO
93											
94	DEPRECIABLE PLANT IN SERVICE		8/								
95	STEAM PRODUCTION	-		X	-	-	Plant in Service less Land		-	-	-
96	HYDRO PRODUCTION	-									
97	PRODUCTION - DEMAND	-		X	-	-	Plant in Service less Land		-	-	-
98	PRODUCTION - ENERGY	-		-	X	-	Plant in Service less Land		-	-	-
99	WIND PRODUCTION	-		X	-	-	Plant in Service less Land		-	-	-
100	TRANSMISSION	-		X	-	-	Plant in Service less Land		-	-	-
101	DISTRIBUTION	-									
102	DIST BULK DELIVERY	-		X	-	-	Plant in Service less Land		-	-	-
103	OTHER DISTRIBUTION	-		X	-	X	Plant in Service less Land		-	-	-

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104	GENERAL	-									
105	PRODUCTION - ENERGY	-		-	X	-	Plant in Service less Land		-	-	-
106	OTHER	-		X	-	X	Plant in Service less Land		-	-	-
107											
108	ACCUMULATED PROVISION FOR DEPREC										
109	STEAM PRODUCTION	108, 110		X	-	-	Depreciable Steam PIS		(I)	-	DSTMPLT
110	CONTRA ADJUSTMENT (FERC)			X	-	-	12 CP	P & A	(E)	D-01	DPRODR
111	CONTRA ADJUSTMENT (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
112	HYDRO PRODUCTION										
113	PRODUCTION - DEMAND	108, 110		X	-	-	Depreciable Hydo PIS (D)		(I)	-	DHYDPLTO
114	PRODUCTION - ENERGY	108, 110		-	X	-	Depreciable Hydo PIS (E)		(I)	-	DHYDPLTE
115	CONTRA ADJUSTMENT (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
116	WIND PRODUCTION	108, 110		X	-	-	Depreciable Wind PIS		(I)	-	DWINDPLT
117	CONTRA ADJUSTMENT (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
118	TRANSMISSION	108, 110		X	-	-	Depreciable Trans PIS		(I)	-	DTRNPLTO
119	CONTRA ADJUSTMENT (FERC)			X	-	-	12 CP	P & A	(E)	D-02	DTRANR
120	CONTRA ADJUSTMENT (RETAIL)			X	-	-	12 CP	P & A	(E)	D-02	DTRANJ
121	DISTRIBUTION										
122	DIST BULK DELVERY	108, 110		X	-	-	Depreciable Dist Bulk Del PIS		(I)	-	DDISPLTS
123	OTHER DISTRIBUTION	108, 110		X	-	X	Depreciable Other Dist PIS		(I)	-	DDISPLTO
124	GENERAL										
125	PRODUCTION - ENERGY	108, 110		-	X	-	Depreciable General PIS (E)		(I)	-	DGENPLTE
126	OTHER	108, 110		X	-	X	Depreciable General PIS (O)		(I)	-	DGENPLTO
127	ACCUMULATED PROVISION FOR AMORT										
128	INTANGIBLE PLANT										
129	PRODUCTION - ENERGY	111, 115		-	X	-	Total O&M Labor less A&G - Energy		(I)	-	LABLAGE
130	OTHER	111, 115		X	-	X	Total O&M Labor less A&G - Other		(I)	-	LABLAGO
131											
132	WORKING CAPITAL REQUIREMENTS										
133	FUEL INVENTORY	151		-	X	-	E-01	E8760	(E)	E8760	EPROD
134	MATERIALS & SUPPLIES	154, 163	9/								
135	PRODUCTION - DEMAND	154, 163		X	-	-	12 CP	P & A	(E)	D-01	DPROD
136	TRANSMISSION	154, 163		X	-	-	12 CP	P & A	(E)	D-02	DTRAN
137	DIST BULK DELIVERY	154, 163		X	-	-	NCP	Class NCP	(E)	D-03	DSUB46
138	DIST SUBSTATIONS	154, 163		X	-	-	-	Class NCP	(E)	D-04	DDISPSUB
139	PRI OVERHEAD LINES - DEMAND	154, 163		X	-	-	-	Class NCP	(E)	D-05	DDISTPOL
140	PRI OVERHEAD LINES - CUST	154, 163		-	-	X	-	Customers	(E)	C-01	CDISTPOL
141	PRI UNGRD LINES - DEMAND	154, 163		X	-	-	-	Class NCP	(E)	D-07	DDISTPUL
142	PRI UNGRD LINES - CUST	154, 163		-	-	X	-	Customers	(E)	C-03	CDISTPUL
143	SEC OVHD LINES - DEMAND	154, 163		X	-	-	-	Sum NCP	(E)	D-06	DDISTSOL
144	SEC OVHD LINES - CUST	154, 163		-	-	X	-	Customers	(E)	C-02	CDISTSOL
145	SEC UNGRD LINES - DEMAND	154, 163		X	-	-	-	Sum NCP	(E)	D-08	DDISTSUL
146	SEC UNGRD LINES - CUST	154, 163		-	-	X	-	Customers	(E)	C-04	CDISTSUL
147	OVHD LINE TRANSFRM - DEM	154, 163		X	-	-	-	Avg Class & Sum NCP	(E)	D-11	DDISTSOT
148	OVHD LINE TRANSFRMS - CUST	154, 163		-	-	X	-	Customers	(E)	C-07	CDISTSOT
149	UNGRD LINE TRANSFRMS - DEM	154, 163		X	-	-	-	Avg Class & Sum NCP	(E)	D-12	DDISTSUT
150	UNGRD LINE TRANSFRMS - CUST	154, 163		-	-	X	-	Customers	(E)	C-08	CDISTSUT
151	METERS	154, 163		-	-	X	Meter counts & cost		(E)	C-12	CMETERS
152	STREET LIGHTING	154, 163		-	-	X	-	Direct	(E)	-	CLIGHT
153	PREPAYMENTS	165		X	X	X	Total Depreciable Plant		(I)	-	TOTDPLT
154	PREPAYMENTS - PENSION ASSET			X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
155	PREPAYMENTS - OPEB			X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
156	PREPAYMENTS - SBPC CONTRACT			-	X	-	E-01	E8760	(E)	E8760	EPROD
157	CASH WORKING CAPITAL	-	10/								
158	O&M EXPENSES	-									
159	FUEL	-		-	X	-	Fuel Expense		(I)	-	FUELEXP
160	PURCHASED POWER	-		X	X	-	Total Purchased Power Exp		(I)	-	PPWREXP

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161	PAYROLL	-		X	X	X	Total O&M Labor		(I)	-	LABOR
162	OTHER O&M	-		X	X	X	Total O&M Less Pur Pwr, Fuel, Labor		(I)	-	OMLPPFL
163	PROPERTY TAXES	-		X	X	X	Total Propert Taxes		(I)	-	PROPTAX
164	PAYROLL TAXES	-		X	X	X	Total O&M Labor		(I)	-	LABOR
165	ENVIRONMENTAL	-		-	X	-	E-01	E8760	(E)	E8760	EPROD
166	INCOME TAXES	-		X	X	X	Total Income Taxes		(I)	-	TOTRB
167	INCOME TAXES (INCREASE)	-		X	X	X	Total Income Taxes		(I)	-	TOTRBR
168	PAYROLL TAXES WITHHELD	-		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
169	SALES TAX COLLECTIONS	-		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
170											
171	ASSET RETIREMENT OBLIGATION (2300+18230)	230		X	-	-	12 CP	P & A	(E)	D-01	DPROD
172	OPEN										
173	WORKERS COMP DEPOSIT			X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
174	UNAMORT WPPI TRANSM AMORT	a/c 2530-9030		X	-	-	12 CP	P & A	(E)	D-02	DTRAN
175	UNAMORT UMWI TRANSACTION COST	182.3-3003		X	-	-	12 CP	P & A	(E)	D-02	DTRAN
176											
177	CUSTOMER ADVANCES										
178	PRIMARY OVHD LINES - DEM	252		X	-	-	-	Class NCP	(E)	D-05	DDISTPOL
179	PRIMARY OVHD LINES - CUST	252		-	-	X	-	Customers	(E)	C-01	CDISTPOL
180	SECONDARY OVHD LINES - DEM	252		X	-	-	-	Sum NCP	(E)	D-06	DDISTSOL
181	SECONDARY OVHD LINES - CUST	252		-	-	X	-	Customers	(E)	C-02	CDISTSOL
182											
183	CUSTOMER DEPOSITS	235		X	-	X	Total Customer Advances		(I)	-	CUSTADV
184											
185	OTHER DEFERRED CREDITS - HIBBARD			X	-	-	Depreciable Steam PIS		(I)	-	DSTMPLT
186	WIND PERFORMANCE DEPOSIT			X	-	-	Depreciable Wind PIS		(I)	-	DWINDPLT
187											
188	SPECIFIED DEFERRED CREDITS										
189	ACCUMULATED DEFERRED INCOME TAXES										
190	ACCOUNTS 281, 282, 283										
191	STEAM	281-3		X	-	-	Depreciable Steam PIS		(I)	-	DSTMPLT
192	HYDRO	281-3		X	X	-	Total Depreciable Hydo PIS		(I)	-	DHYDPLT
193	WIND	281-3		X	-	-	Depreciable Wind PIS		(I)	-	DWINDPLT
194	TRANSMISSION	281-3		X	-	-	Depreciable Trans PIS		(I)	-	DTRANPLT
195	DISTRIBUTION	281-3		X	-	X	Total Depreciable Dist PIS		(I)	-	DDISTPLT
196	GENERAL	281-3		X	X	X	Total Depreciable General PIS		(I)	-	DGENPLT
197											
198	SPECIFIED DEFERRED DEBITS										
199	ACCUMULATED DEFERRED INCOME TAXES										
200	ACCOUNT 190										
201	STEAM	190		X	-	-	Depreciable Steam PIS		(I)	-	DSTMPLT
202	HYDRO	190		X	X	-	Total Depreciable Hydo PIS		(I)	-	DHYDPLT
203	WIND	190		X	-	-	Depreciable Wind PIS		(I)	-	DWINDPLT
204	TRANSMISSION	190		X	-	-	Depreciable Trans PIS		(I)	-	DTRANPLT
205	DISTRIBUTION	190		X	-	X	Total Depreciable Dist PIS		(I)	-	DDISTPLT
206	GENERAL	190		X	X	X	Total Depreciable General PIS		(I)	-	DGENPLT
207											

Table 4 Summary of Functionalization, Classification and Allocation in MP's CCOSS

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208	**INCOME STATEMENT**										
209	ELECTRIC OPERATING REVENUES										
210	SALES OF ELECTRICITY										
211	SALES BY RATE CLASS	440-447		X	X	X	Actual	Actual	-	-	-
212	INTERSYSTEM SALES DEMAND	447		X	-	-	12 CP	P & A	(E)	D-01	DPROD
213	INTERSYSTEM SALES ENERGY	447		-	X	-	E-01	E8760	(E)	E8760	EPROD
214	OTHER SALES										
215	DUAL FUEL DEMAND	440-443		X	-	-	-	P & A	(E)	D-01 (Retail)	DPRODJ
216	DUAL FUEL ENERGY	440-443		-	X	-	-	E8760	(E)	E8760	EPRODR
217	LP IPS, RFPS, SBPC - ENERGY	443		-	X	-	E-01	E8760	(E)	E8760	EPROD
218	ECONOMY ENERGY	443		-	X	-	E-01	E8760	(E)	E8760	EPROD
219	POOL WITHIN A POOL	443		X	-	-	12 CP	P & A	(E)	D-01	DPROD
220	OTHER OPERATING REVENUE										
221	A/C 4561, 4564, 4569 PROD - DEMAND	456		X	-	-	12 CP	P & A	(E)	D-01	DPROD
222	A/C 4569 PRODUCTION - ENERGY	456		-	X	-	E-01	E8760	(E)	E8760	EPROD
223	A/C 454, 4562, 4569 - TRANSMISSION	454, 456		X	-	-	12 CP	P & A	(E)	D-02	DTRAN
224	A/C 4569 - GENERAL PLANT	456		X	X	X	General Plant		(I)	-	GENPLT
225	A/C 4569 - RETAIL - ENERGY	456		-	X	-	-	E8760	(E)	E8760	EPRODR
226	A/C 450-4569 RETAIL - DISTRIBUTION	450, 456									
227	PRI OVHD LINES - DEMAND	450, 456		X	-	-	-	Class NCP	(E)	D-05	DDISTPOL
228	PRI OVHD LINES - CUSTOMER	450, 456		-	-	X	-	Customers	(E)	C-01	CDISTPOL
229	SEC OVHD LINES - DEMAND	450, 456		X	-	-	-	Sum NCP	(E)	D-06	DDISTSOL
230	SEC OVHD LINES - CUSTOMER	450, 456		-	-	X	-	Customers	(E)	C-02	CDISTSOL
231	OVHD LINE TRANSFRM - DEM	450, 456		X	-	-	-	Avg Class & Sum NCP	(E)	D-11	DDISTSOT
232	OVHD LINE TRANSFRMS - CUST	450, 456		-	-	X	-	Customers	(E)	C-07	CDISTSOT
233	UNGRD LINE TRANSFRMS - DEM	450, 456		X	-	-	-	Avg Class & Sum NCP	(E)	D-12	DDISTSUT
234	UNGRD LINE TRANSFRMS - CUST	450, 456		-	-	X	-	Customers	(E)	C-08	CDISTSUT
235											
236	OPERATION & MAINTENANCE EXPENSE										
237	STEAM PRODUCTION										
238	DEMAND	500, 502-6, 511, 514		X	-	-	12 CP	P & A	(E)	D-01	DPROD
239	ENERGY	510, 512-3		-	X	-	E-01	E8760	(E)	E8760	EPROD
240	HYDRO PRODUCTION										
241	DEMAND	535, 537-9, 541-2		X	-	-	12 CP	P & A	(E)	D-01	DPROD
242	ENERGY	543-5		-	X	-	E-01	E8760	(E)	E8760	EPROD
243	WIND PRODUCTION	546, 551		X	-	-	12 CP	P & A	(E)	D-01	DPROD
244	OTHER POWER SUPPLY										
245	PRODUCTION DEMAND	556-7		X	-	-	12 CP	P & A	(E)	D-01	DPROD
246	PURCHASED POWER										
247	DEMAND	555		X	-	-	12 CP	P & A	(E)	D-01	DPROD
248	ENERGY	555		-	X	-	E-01	E8760	(E)	E8760	EPROD
249	FUEL	501		-	X	-	E-01	E8760	(E)	E8760	EPROD
250	TRANSMISSION	560-1, 563, 565, 567-9, 570-1		X	-	-	Transmission PIS		(I)	-	TRANPLT
251	REGIONAL TRANSM AND MARKET	575		X	-	-	12 CP	P & A	(E)	D-02	DTRAN
252	DISTRIBUTION										
253	METERS	586		-	-	X	Meter counts & cost		(E)	C-12	CMETERS
254	BULK DELIVERY	580, 583-4, 588-590, 592-4,		X	-	-	NCP	Class NCP	(E)	D-03	DSUB46
255	OTHER DISTRIBUTION	596-8		X	-	X	Dist PIS, Excl Meters & Dist BD		(I)	-	DISTPLMS
256	CUSTOMER ACCOUNTING	902-4		-	-	X	Expenses & Labor ratios		(E)	C-15	CACCTS
257	CUSTOMER ACCOUNTING CREDIT CARDS			-	-	X	Expenses & Labor ratios		(E)	C-18	CACCTS
258	CUSTOMER SERVICE & INFORMATION	907-10		-	-	X	Expenses & Labor ratios		(E)	C-17	CUSTSERV
259	CONSERV IMPROVE PROG - ENERGY	907-10		-	X	-	-	CCRC MWh	(E)	CCRC	CIPEXPE
260	SALES	913		-	-	X	-	Exp & Labor ratios	(E)	C-16	CSALES
261	ADMINISTRATIVE & GENERAL										
262	PROPERTY INSURANCE	924		X	X	X	Utility Plant In Service		(I)	-	PLANT
263	REGULATORY EXPENSES - MISC	928		X	X	X	Utility Plant In Service		(I)	-	PLANT
264	REGULATORY EXPENSES - MIS0	928		X	-	-	12 CP	P & A	(E)	D-02	DTRAN

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265	ADVERTISING	930.1		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
266	FRANCHISE REQUIREMENTS	927		X	X	X	-	Retail Sales	(I)	-	RSALESJ
267	RATE CASE EXPENSE (FERC)										
268	RATE CASE EXPENSE (RETAIL)	928		X	X	X	-	Retail rate base	(I)	-	TOTRBR
269	GENERAL PLANT	935		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
270	OTHER ADMIN & GENERAL	920-1, 923, 925-6, 930.2		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
271	CUSTOMER DEPOSITS - INTEREST- RETAIL	431		X	-	X	-	Cust Deposits	(I)	-	CUSTDEP
272	CHARITABLE CONTRIBUTIONS	426.1		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
273	CUSTOMER DEPOSITS - INTEREST- FERC	431		X	X	X	Total Rate Base - FERC		(I)	-	TOTRBF
274											
275	OPERATION & MAINTENCE - LABOR ONLY										
276	STEAM PRODUCTION										
277	DEMAND	500, 502, 506		X	-	-	12 CP	P & A	(E)	D-01	DPROD
278	ENERGY	510, 512-3		-	X	-	E-01	E8760	(E)	E8760	EPROD
279	HYDRO PRODUCTION										
280	DEMAND	535, 539		X	-	-	12 CP	P & A	(E)	D-01	DPROD
281	ENERGY	541		-	X	-	E-01	E8760	(E)	E8760	EPROD
282	WIND PRODUCTION	551		X	-	-	12 CP	P & A	(E)	D-01	DPROD
283	OTHER POWER SUPPLY	556-7		X	-	-	Other Power Supply Expense				OPSEXP
284	FUEL	501		-	X	-	E-01	E8760	(E)	E8760	EPROD
285	TRANSMISSION	560, 561.1-.2, 561.5-7, 563,		X	-	-	Transmission Expense		(I)	-	TRANEXP
286	DISTRIBUTION										
287	METERS	586		-	-	X					CMETERS
288	BULK DELIVERY	580, 583, 584, 588, 590, 593,		X	-	-	NCP	Class NCP	(E)	D-03	DSUB46
289	OTHER DISTRIBUTION	594, 595, 598		X	-	X	Dist PIS, Excl Meters & Dist BD		(I)	-	DISTPLMS
290	CUSTOMER ACCOUNTING	901-5		-	-	X	Expenses & Labor ratios		(E)	C-15	CACCTS
291	CUSTOMER SERVICE & INFORMATION	907-910		-	-	X	Expenses & Labor ratios		(E)	C-17	CUSTSERV
292	SALES	913		-	-	X	-	Exp & Labor ratios	(E)	C-16	CSALES
293	ADMINISTRATIVE & GENERAL										
294	PRODUCTION ENERGY - GP MAINT	920, 924-6, 928, 930.1-.2, 935		-	X	-	Total O&M Labor less A&G - Energy		(I)	-	LABLAGE
295	OTHER A&G			X	-	X	Total O&M Labor less A&G - Other		(I)	-	LABLAGO
296											
297	DEPRECIATION EXPENSE										
298	STEAM	403		X	-	-	Depreciable Steam PIS		(I)	-	DSTMPLT
299	CONTRA ADJUSTMENT (FERC)			X	-	-	12 CP	P & A	(E)	D-01	DPRODR
300	CONTRA ADJUSTMENT (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
301	HYDRO	403		X	X	-	Total Depreciable Hydo PIS		(I)	-	DHYDPLT
302	CONTRA ADJUSTMENT (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
303	WIND	403		X	-	-	Depreciable Wind PIS		(I)	-	DWINDPLT
304	CONTRA ADJUSTMENT (RETAIL)			X	-	-	12 CP	P & A	(E)	D-01	DPRODJ
305	TRANSMISSION	403		X	-	-	Depreciable Trans PIS		(I)	-	DTRANPLT
306	CONTRA ADJUSTMENT (FERC)			X	-	-	12 CP	P & A	(E)	D-02	DTRANR
307	CONTRA ADJUSTMENT (RETAIL)			X	-	-	12 CP	P & A	(E)	D-02	DTRANJ
308	DISTRIBUTION	403		X	-	X	Total Depreciable Dist PIS		(I)	-	DDISTPLT
309	GENERAL	403		X	X	X	Total Depreciable General PIS		(I)	-	DGENPLT
310											
311	AMORTIZATION EXPENSE										
312	UMWI (406, 407.3) AND ACCRETION (411.1)	406, 407.3, 411.1		X	-	-	12 CP	-	(E)	D-01 FERC	DPRODR
313	2010 and 2016 RATE CASE AMORTIZATION			X	X	X	Total Average Rate Base Retail		(I)	-	TOTRBR
314	CEC TG5 AMORTIZATION			X	-	-	12 CP	P & A	(E)	D-01	DPROD
315	MEDICARE PART D AMORTIZATION			X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
316	DEF STORM COST AMORTIZATION			X	-	X	O&M Distribution Labor Retail		(I)	-	LABORDISJ
317	INTANGIBLE PLANT	403.1, 404		X	X	X	General Plant		(I)	-	GENPLT
318											
319	PROPERTY TAXES										
320	STEAM	408.1		X	-	-	Steam PIS		(I)	-	STMPLT
321	HYDRO	408.1		X	X	-	Total Hydo PIS		(I)	-	HYDPLT

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322	WIND	408.1		X	-	-	Wind PIS		(I)	-	WINDPLT
323	TRANSMISSION	408.1		X	-	-	Transmission PIS		(I)	-	TRANPLT
324	DISTRIBUTION	408.1		X	-	X	Total Distribution PIS		(I)	-	DISTPLT
325	GENERAL PLANT	408.1		X	X	X	Total General PIS		(I)	-	GENPLT
326											
327	PAYROLL TAXES										
328	STEAM	408.1		X	X	-	O&M Steam Labor		(I)	-	LABORST
329	HYDRO	408.1		X	X	-	O&M Hydro Labor		(I)	-	LABORHY
330	WIND	408.1		X	X	-	O&M Wind Labor		(I)	-	LABORWI
331	TRANSMISSION	408.1		X	-	-	Other Power Supply Expense		(I)	-	TRANEXP
332	DISTRIBUTION	408.1		X	-	X	O&M Distribution Labor		(I)	-	LABORDIS
333	CUSTOMER ACCOUNTING	408.1		-	-	X	Expenses & Customer count		(E)	C-15	CACCTS
334	CUSTOMER SERVICE & INFO	408.1		-	-	X	Labor ratios		(E)	C-17	CUSTSERV
335	SALES	408.1		-	-	X	-	Labor ratios	(E)	C-16	CSALES
336	ADMIN & GEN	408.1		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
337											
338	AIR QUALITY EMISSION - PROD ENERGY	408.1		-	X	-	E-01	E8760	(E)	E8760	EPROD
339	MINNESOTA WIND/SOLAR PRODUCTION TAX	408.1		-	X	-	E-01	E8760	(E)	E8760	EPROD
340											
341	ADDITIONS TO INCOME FOR TAX										
342	CAPITALIZED INTEREST	various		X	X	X	Utility Plant In Service		(I)	-	PLANT
343	CONTRIBUTION IN AID OF CONSTRUCT	various		X	-	-	-	Sum NCP	(E)	D-06	DDISTSOL
344	ARO AMORT	various		X	-	-	Steam Plant		(I)	-	STMPLT
345	ESOP 75M - PERM DIFFERENCE	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
346	ND ITC REGULATORY LIABILIY	various		X	-	-	Wind PIS		(I)	-	WINDPLT
347	CONSERVATION IMPROV PROJ	various		-	X	-	-	CCRC MWh	(E)	CCRC	CIPEXPE
348	PERFORMANCE SHARES	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
349	RETAIL RATE CASE EXPENSE	various		X	X	X	Total Rate Base - Retail		(I)	-	TOTRBR
350	POLITICAL ACTIVITIES	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
351	RESTRICTED STOCK	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
352	DUES	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
353	MEALS AND ENTERTAINMENT	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
354	BOND ISSUE COSTS (NCL)	various		X	X	X	Total Rate Base		(I)	-	TOTRB
355	DEFERRED COMP	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
356	CAPITALIZED OVERHEADS	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
357											
358	DEDUCTIONS TO INCOME FOR TAX										
359	FUEL CLAUSE ADJUSMENT	various		-	X	-	E-01	E8760	(E)	E8760	EPROD
360	RETIREMENTS	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
361	OPEB FAS 106 OPERATING	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
362	BOSWELL TRANSMISSION AMORT	various		X	-	-	12 CP	P & A	(E)	D-02	DTRAN
363	EPA NOV	various		X	-	-	Steam Plant		(I)	-	STMPLT
364	RSOP	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
365	PENSION EXPENSE	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
366	ESOP 75M - TEMPORARY DIFFERENCE	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
367	COST TO RETIRE	various		X	X	X	Utility Plant In Service		(I)	-	PLANT
368	SECTION 174	various		X	X	X	Total O&M Labor less A&G		(I)	-	LABLAG
369	DEPRECIATION TAX OVER BOOK	various		X	X	X	Utility Plant In Service		(I)	-	PLANT
370	INT LONG TERM DEBT (INT SYNC)		11/	X	X	X	Total Average Rate Base		(I)	-	TOTRB
371											
372	INCOME TAXES										
373	STATE INCOME TAX										
374	ADJ NET INCOME	-		X	X	X	CCOSS CALCULATION		-	-	-
375	NOL RECLASS TO DEF TAX BENFIT	-		X	X	X	Utility Plant In Service		(I)	-	PLANT
376	STATE DEPREC MODIFICATION	-		X	X	X	Utility Plant In Service		(I)	-	PLANT
377	STATE NET TAX INC	-		X	X	X	CCOSS CALCULATION				
378	STATE TAX AT 9.8 PERCENT	-		X	X	X	CCOSS CALCULATION				

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379	CORRECTION TO PRIOR YEARS			X	X	X	Utility Plant In Service		(I)	-	PLANT
380	STATE MINIMUM TAX			X	X	X	Utility Plant In Service		(I)	-	PLANT
381											
382	FEDERAL INCOME TAX										
383	ADJ NET INCOME	-		X	X	X	CCOSS CALCULATION		-	-	-
384	STATE TAX DEDUCTION	-		X	X	X	Calculated Above		-	-	-
385	NOL CARRYFORWARD UTILIZED	-		X	X	X	Utility Plant In Service		(I)	-	PLANT
386	FED NET TAX INC	-		X	X	X	CCOSS CALCULATION		-	-	-
387	FED TAX AT 35 PERCENT	-		X	X	X	CCOSS CALCULATION			-	
388	FED PRODUCTION TAX CREDIT	4091-1000		X	-	-	12 CP	P & A	(E)	D-01	DPROD
389	CORRECTION TO PRIOR YEARS			X	X	X	Utility Plant In Service		(I)	-	PLANT
390											
391	PROVISION FOR DEFERRED INCOME TAX										
392	ACCOUNT 410.1										
393	STEAM	410.1		X	-	-	Depreciable Steam PIS		(I)	-	DSTMPLT
394	HYDRO	410.1		X	X	-	Total Depreciable Hydo PIS		(I)	-	DHYDPLT
395	WIND	410.1		X	-	-	Depreciable Wind PIS		(I)	-	DWINDPLT
396	TRANSMISSION	410.1		X	-	-	Depreciable Trans PIS		(I)	-	DTRANPLT
397	DISTRIBUTION	410.1		X	-	X	Total Depreciable Dist PIS		(I)	-	DDISTPLT
398	GENERAL	410.1		X	X	X	Total Depreciable General PIS		(I)	-	DGENPLT
399											
400	PROVISION FOR DEFERRED INCOME TAX - CREDIT										
401	ACCOUNT 411.1										
402	STEAM	411.1		X	-	-	Depreciable Steam PIS		(I)	-	DSTMPLT
403	HYDRO	411.1		X	X	-	Total Depreciable Hydo PIS		(I)	-	DHYDPLT
404	WIND	411.1		X	-	-	Depreciable Wind PIS		(I)	-	DWINDPLT
405	TRANSMISSION	411.1		X	-	-	Depreciable Trans PIS		(I)	-	DTRANPLT
406	DISTRIBUTION	411.1		X	-	X	Total Depreciable Dist PIS		(I)	-	DDISTPLT
407	GENERAL	411.1		X	X	X	Total Depreciable General PIS		(I)	-	DGENPLT
408											
409	INVESTMENT TAX CREDIT:CURRENT										
410	ACCOUNT 411.4										
411	STEAM	411.4		-	-	-	Depreciable Steam PIS		(I)	-	DSTMPLT
412	HYDRO	411.4		-	-	-	Total Depreciable Hydo PIS		(I)	-	DHYDPLT
413	WIND	411.4		X	-	-	Depreciable Wind PIS		(I)	-	DWINDPLT
414	TRANSMISSION	411.4		-	-	-	Depreciable Trans PIS		(I)	-	DTRANPLT
415	DISTRIBUTION	411.4		-	-	-	Total Depreciable Dist PIS		(I)	-	DDISTPLT
416	GENERAL	411.4		-	-	-	Total Depreciable General PIS		(I)	-	DGENPLT
417											
418	INVESTMENT TAX CREDIT:FEEDBACK										
419	ACCOUNT 411.4										
420	STEAM	411.4		X	-	-	Depreciable Steam PIS		(I)	-	DSTMPLT
421	HYDRO	411.4		X	X	-	Total Depreciable Hydo PIS		(I)	-	DHYDPLT
422	WIND	411.4		X	-	-	Depreciable Wind PIS		(I)	-	DWINDPLT
423	TRANSMISSION	411.4		X	-	-	Depreciable Trans PIS		(I)	-	DTRANPLT
424	DISTRIBUTION	411.4		X	-	X	Total Depreciable Dist PIS		(I)	-	DDISTPLT
425	GENERAL	411.4		-	-	-	Total Depreciable General PIS		(I)	-	DGENPLT
426											
427	ALLOWANCE FUNDS DURING CONSTRUCTION										
428	STEAM	419.1, 432		X	-	-	12 CP	P & A	(E)	D-01	DPROD
429	HYDRO	419.1, 432		X	-	-	12 CP	P & A	(E)	D-01	DPROD
430	WIND	419.1, 432		X	-	-	12 CP	P & A	(E)	D-01	DPROD
431	TRANSMISSION	419.1, 432		X	-	-	12 CP	P & A	(E)	D-02	DTRAN
432	DISTRIBUTION	419.1, 432		X	-	X	Total CWIP Distribution		(I)	-	CWIPP
433	GENERAL	419.1, 432		X	X	X	Total CWIP General Plant		(I)	-	CWIPLP

Table 4 Summary of Functionalization, Classification and Allocation in MP's CCOSS

Functionalization and Classification of Rate Base and Income Statement Accounts 1/	FERC Account or MP's Function Code	Note	Classification: Demand	Classification: Energy	Classification: Customer	Basis of Jurisdictional Cost Allocation	Basis of Retail Class Cost Allocation	Internal (I) or External (E) Allocator	Name / Number of External Allocator	Allocation Code Used in CCOSS

Notes:

1/ All items are presented in the same order as in MP's COSS Exhibits B-1 to B-3, C-1, and C-1(IR) to C-4 (IR).
2/ All regulated Hydro projects and assets at reservoir facilities only are subfunctionalized as production energy, remaining plant is demand.
3/ Step-up transformers at generating stations booked in transmission plant are subfuctionalized as production demand.
4/ Refer to MP's COSS Guide for description of tratment of distribution plant.
5/ Step-up transformers at generating stations booked in distribution plant are subfuctionalized as production demand.
6/ Distribution Bulk Delivery are 23, 34 and 46 kV facilities that serve FERC and retail jurisdictional customers.
7/ Specific Distribution 14 kV facilities and 23, 34, and 46 kV taps that serve FERC jurisdictional customers.
8/ Calculated: Plant In Service less land.
9/ Subfunctionalized to PT&D on most recent calender year actual amounts. Distribution subsequently subfunctionalized/classifed on PIS ratios.
10/ Calculated -- refer to Working Capital workpapers.
11/ Calculated as part of interest syncronization. Average rate base multiplied by cost of longterm debt.

Table 5 CCOSS Internally Developed Allocators

	ALLOC	Used in CCOSS	INTERNALLY DEVELOPED ALLOCATORS TOTAL COMPANY (1=2+3)	FERC JURIS (2=5/4)	TOTAL RETAIL (3=6/4)	VALUES OF INTERNALLY DEVELOPED ALLOCATORS TOTAL COMPANY (4=5+6)	FERC JURIS (5)	TOTAL RETAIL (6 = Sum Retail)	SOURCE OF VALUES MP Exhibit__(SJS) SCHEDULE C-1 STARTING PAGE # (7)	LINE # (8)
INTERNALLY DEVELOPED										
1 STEAM PLANT	STMPLT	Yes	1.000000	0.163334	0.836666	1,633,253,637	266,765,745	1,366,487,892	5	7
2 TOTAL HYDRO PLANT	HYDPLT	Yes	1.000000	0.163454	0.836546	191,826,651	31,354,767	160,471,884	5	11
3 TOTAL WIND PLANT	WINDPLT	Yes	1.000000	0.167722	0.832278	813,590,974	136,456,809	677,134,165	5	14
4 TRANSMISSION PLANT	TRANPLT	Yes	1.000000	0.178357	0.821643	734,432,792	130,990,899	603,441,893	5	19
5 DISTRIBUTION PLANT	DISTPLT	Yes	1.000000	0.041257	0.958743	579,238,286	23,897,560	555,340,726	5	44
6 GENERAL PLANT	GENPLT	Yes	1.000000	0.134722	0.865278	199,089,557	26,821,828	172,267,729	7	3
7 DISTRIBUTION PLANT EXCL DIST BD	DISTPLTO	Yes	1.000000	0.005950	0.994050	488,953,458	2,909,189	486,044,269	5	44-40
8 DISTRIB PLT EXCL METERS & DIST BD	DISTPLMS	Yes	1.000000	0.004854	0.995146	432,976,217	2,101,839	430,874,378	7	44-40-36
9 UTILITY PLANT LESS CWIP & PLANT HELD	PLANT	Yes	1.000000	0.148202	0.851798	4,228,439,582	626,662,271	3,601,777,311	7	4
10 TOTAL CWIP DISTRIBUTION	CWIPP	Yes	1.000000	0.002173	0.997827	1,567,900	3,407	1,564,493	7	33
11 TOTAL CWIP GENERAL PLANT	CWIPLP	Yes	1.000000	0.134722	0.865278	5,552,393	748,032	4,804,361	7	36
12 TOTAL UTILITY PLANT	TOTPLT	No	1.000000	0.148214	0.851786	4,254,073,024	630,512,192	3,623,560,832	7	38
13 DEPRECIABLE STEAM PRODUCTION	DSTMPLT	Yes	1.000000	0.163334	0.836666	1,624,950,988	265,409,641	1,359,541,347	9	15
14 DEPRECIABLE HYDRO PROD - DEMAND	DHYDPLTO	Yes	1.000000	0.163461	0.836539	170,378,628	27,850,306	142,528,322	9	16
15 DEPRECIABLE HYDRO PROD - ENERGY	DHYDPLTE	Yes	1.000000	0.163450	0.836550	18,079,585	2,955,108	15,124,477	9	17
16 DEPRECIABLE HYDRO PRODUCTION	DHYDPLT	Yes	1.000000	0.163460	0.836540	188,458,213	30,805,414	157,652,799	9	16+17
17 DEPRECIABLE TRANSM - OTHER TRANSM	DTRNPLTO	Yes	1.000000	0.178357	0.821643	720,113,402	128,436,942	591,676,460	9	19
18 DEPRECIABLE WIND PRODUCTION	DWINDPLT	Yes	1.000000	0.167730	0.832270	812,109,126	136,215,193	675,893,933	9	18
19 TOTAL DEPRECIABLE TRANSMISSION	DTRANPLT	Yes	1.000000	0.178357	0.821643	720,113,402	128,436,942	591,676,460	9	19
20 DEPRECIABLE DISTRIB - BULK DEL	DDISPLTS	Yes	1.000000	0.232468	0.767532	89,838,414	20,884,594	68,953,819	9	20
21 DEPRECIABLE DISTRIB - OTHER DISTRIB	DDISPLTO	Yes	1.000000	0.005950	0.994050	486,535,821	2,894,804	483,641,017	9	21
22 TOTAL DEPRECIABLE DISTRIBUTION	DDISTPLT	Yes	1.000000	0.041257	0.958743	576,374,235	23,779,399	552,594,836	9	20+21
23 DEPRECIABLE GENERAL - ENERGY	DGENPLTE	Yes	1.000000	0.163450	0.836550	46,335,824	7,573,590	38,762,233	9	22
24 DEPRECIABLE GENERAL - OTHER	DGENPLTO	Yes	1.000000	0.125894	0.874106	150,777,435	18,981,986	131,795,449	9	23
25 TOTAL DEPRECIABLE GENERAL	DGENPLT	Yes	1.000000	0.134722	0.865278	197,113,259	26,555,577	170,557,682	9	22+23
26 DEPRECIABLE PLANT HELD	DHELDPLT	Yes	-	-	-	0	0	0	9	24
27 TOTAL DEPRECIABLE PLANT	TOTDPLT	Yes	1.000000	0.148382	0.851618	4,119,119,223	611,202,165	3,507,917,058	9	25
28 TOTAL NET PLANT INCL CWIP	TOTNETPI	No	1.000000	0.150959	0.849041	2,788,321,147	420,922,559	2,367,398,588	11	21
29 TOTAL CUSTOMER ADVANCES	CUSTADV	Yes	1.000000	0.000000	1.000000	1,790,064	0	1,790,064	15	5
30 TOTAL CUSTOMER DEPOSITS	CUSTDEP	Yes	1.000000	0.000000	1.000000	240,131	0	240,131	15	6
31 TOTAL AVERAGE RATE BASE	TOTRB	Yes	1.000000	0.151174	0.848826	2,448,082,174	370,085,386	2,077,996,788	15	24
32 TOTAL AVERAGE RATE BASE - RETAIL	TOTRBR	No	1.000000	0.000000	1.000000	2,077,996,788	0	2,077,996,788	15	24
33 TOTAL AVERAGE RATE BASE - FERC	TOTRBF	No	1.000000	1.000000	0.000000	370,085,386	370,085,386	0	15	24
34 CONSERV IMPROVE PROJECT RETAIL	CIPEXP	Yes	1.000000	0.000000	1.000000	10,572,625	0	10,572,625	19	23
35 SALES BY RATE CLASS (FERC)	RSALESR	Yes	1.000000	1.000000	0.000000	116,126,178	116,126,178	0	17	1
36 SALES BY RATE CLASS (RETAIL)	RSALESJ	Yes	1.000000	0.000000	1.000000	596,503,879	0	596,503,879	17	1
37 OTHER POWER SUPPLY EXPENSE	OPSEXP	Yes	1.000000	0.163050	0.836950	2,205,104	359,542	1,845,562	19	8
38 TOTAL PURCHASED POWER	PPWREXP	Yes	1.000000	0.163353	0.836647	234,226,672	38,261,615	195,965,057	19	18
39 FUEL	FUELEXP	Yes	1.000000	0.163450	0.836550	137,912,510	22,541,800	115,370,710	19	12
40 TRANSMISSION EXPENSE	TRANEXP	Yes	1.000000	0.180140	0.819860	57,240,371	10,311,280	46,929,091	19	13+14
41 TOTAL O & M LESS PUR PWR, FUEL, LABOR	OMLPPFL	Yes	1.000000	0.137141	0.862859	165,256,174	22,663,387	142,592,787	19	38-11-12 less L21 p 21
42 TOTAL O&M STEAM LABOR	LABORST	Yes	1.000000	0.163237	0.836763	26,376,841	4,305,670	22,071,171	21	3
43 TOTAL O&M HYDRO LABOR	LABORHY	Yes	1.000000	0.163222	0.836778	4,344,869	709,179	3,635,690	21	6
44 TOTAL O&M WIND LABOR	LABORWI	Yes	1.000000	0.163050	0.836950	589,218	96,072	493,146	21	7
45 TOTAL O&M DISTRIBUTION LABOR	LABORDIS	Yes	1.000000	0.038259	0.961741	11,929,252	456,406	11,472,846	21	14
46 TOTAL O&M DISTRIBUTION LABOR RETAIL	LABORDISJ	Yes	1.000000	0.000000	1.000000	11,472,846	0	11,472,846	21	14
47 TOTAL O&M LABOR LESS A&G - ENERGY	LABLAGE	Yes	1.000000	0.163450	0.836550	14,186,714	2,318,818	11,867,896	21	2+5+9
48 TOTAL O&M LABOR LESS A&G - OTHER	LABLAGO	Yes	1.000000	0.125894	0.874106	46,163,771	5,811,745	40,352,026	21	18-6-5-9
49 TOTAL OPER & MAINT LABOR LESS A&G	LABLAG	Yes	1.000000	0.134722	0.865278	60,350,485	8,130,564	52,219,921	21	18
50 TOTAL OPERATION & MAINT LABOR	LABOR	Yes	1.000000	0.134722	0.865278	82,621,827	11,131,013	71,490,814	21	21
51 TOTAL DEPRECIATION EXPENSE	DEPEXP	No	1.000000	0.145134	0.854866	117,908,514	17,112,537	100,795,977	23	28
52 TOTAL PROPERTY TAXES	PROPTAX	Yes	1.000000	0.139452	0.860548	41,728,246	5,819,070	35,909,176		

Summary of Marginal Energy Cost Study

Commission Order Point 22 from Minnesota Power's last rate case states "In its next rate case filing, the Company shall provide a marginal energy cost study." [1] The purpose of a marginal cost study is to focus on determining the cost the utility incurs in order to provide the next unit of service.

Analysis Approach and Results

With the recent decrease in demand from Minnesota Power's Large Power customers projected to continue through the study period of 2016 through 2020 and the delay in new customer growth, Minnesota Power is projecting a surplus of energy and capacity in the near term.

Due to the projected excess energy, Minnesota Power made the assumption that the marginal energy cost should be based on the cost of energy from an existing unit in the power supply. Typically, Laskin Energy Center (LEC) has a higher energy cost than other dispatchable resources in Minnesota Power's power supply. For purposes of this study, LEC is assumed to be the marginal generating unit available to serve incremental load above Minnesota Power's current customer load outlooks. The marginal energy cost was calculated for each year in the study period using the formula below.

$$Marginal\ Energy\ Cost = \frac{Laskin\ Heat\ Rate \times Laskin\ Fuel \times (1 + 0.5 \times Transmission\ Losses)}{10}$$

To take into consideration the cost of losses between the generator and customer demand, the marginal energy cost was adjusted for 50% of line losses[2]. The projected marginal energy cost for the study period are shown below. The marginal energy cost is expected to increase over the study period due to the projected increase in the price of natural gas, which is the fuel used at LEC.

Projected Marginal Energy Cost (¢/kWh)

	2016	**2017**	**2018**	**2019**	**2020**
Marginal Energy Cost Unadjusted	3.58	3.91	4.34	4.67	4.82
Marginal Energy Cost Adjusted for Transmission Losses	3.77	4.12	4.57	4.92	5.07

Assumptions and Outlooks

The key assumptions that Minnesota Power utilized in this study are as follow:.

Natural gas forecast assumptions:

- Natural gas at Henry Hub: $2.41/MMBtu in 2016 to $3.37/MMBtu in 2020
- Natural gas supply prices reflect the projected spot market at Henry Hub. In addition, a regional delivery charge of [TRADE SECRET DATA EXCISED] was assumed.

[1] Minnesota Power Docket E-015/GR-09-1151
[2] Minn. Rule 7835.0600, subp. 4 and Minnesota Public Utilities Commission-approved environmental externalities. Fifty percent of the line losses are 5.2472%.