Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-17-

Exhibit___

ALLOCATORS, CLASS COST OF SERVICE STUDY, REVENUE ALLOCATION AND LEAD LAG STUDY

Direct Testimony and Schedules of

GINA S. ICE

November 2, 2017

171 PU-17-398 Filed 07/11/2018 Pages: 80
Exhibit OTP-23 – Gina Ice Prefiled Direct Testimony and Schedules – Volume 2A
Otter Tail Power Company

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ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Gina S. Ice. I am employed by Otter Tail Power Company (OTP) as Rates Analyst, Regulatory Administration.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I graduated from the Carlson School of Business at the University of Minnesota, Minneapolis, Minnesota in 2005 with a Bachelor of Science degree in Accounting. I am a Certified Public Accountant (Active) in Minnesota as well as a member of the Minnesota Society of Certified Public Accountants and the American Institute of Certified Public Accountants. I started my career as an External Auditor at PricewaterhouseCoopers in 2005 in Minneapolis, Minnesota. In 2007, I joined Fairview Pharmacy Services in Minneapolis, Minnesota as a Financial Analyst. In 2010, I joined OTP as a Financial Reporting Analyst within the Accounting Department and in 2016, I started my current position as Rates Analyst, Regulatory Administration. My primary responsibilities in this position are the preparation and analysis used to determine revenue requirements associated with various state and federal cost recovery mechanisms and to develop regulatory filings associated with these cost recovery mechanisms. A copy of my resume is included as Exhibit___(GSI-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony discusses: (1) jurisdictional and class allocation factors; (2) OTP's Energy Adjustment Rider and allocators; (3) the Class Cost of Service Study and Class Revenue Responsibilities; and (4) the Lead Lag Study. My Direct Testimony also addresses several other regulatory items and compliance obligations from prior OTP rate cases.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

A. I explain the allocation factors that OTP uses in the Jurisdictional Cost of Service Study (JCOSS) and the Class Cost of Service Study (CCOSS), the use of an E8760 allocator in the CCOSS and our Energy Adjustment Rider, and our proposed class revenue responsibilities that move each customer class closer to its cost responsibility.

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

A. In Section III, I discuss jurisdictional and class allocators, including Test Year allocators. Section IV includes my discussion of OTP's CCOSS and proposed class revenue responsibilities and Section V addresses OTP's lead-lag study and cash working capital.

III. JURISDICTIONAL AND CLASS ALLOCATORS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will discuss the use of jurisdictional and class allocators. I will discuss Test Year allocators used by OTP, including the E8760 allocator.

Q. WHAT IS THE ROLE OF JURISDICTIONAL AND CLASS ALLOCATORS IN THE RATEMAKING PROCESS?

A. Jurisdictional allocators are used to allocate system costs among jurisdictions and class allocators are used to allocate jurisdictional costs among customer classes.

Q. WHY ARE JURISDICTIONAL AND CLASS ALLOCATORS NECESSARY?

A. OTP operates an integrated electrical system that serves customers across multiple jurisdictions. This integrated system design takes advantage of economies of scale to provide least cost energy solutions for all our customers. Because OTP operates as one system, costs of investment in the system and the expenses necessary to operate the system need to be allocated among the jurisdictions. Costs allocated to each jurisdiction need to be further allocated to customer classes in order to design rates.

Q. HOW DO THESE ALLOCATIONS OCCUR?

A. System costs and revenues are allocated to jurisdictions in the JCOSS described in more detail by OTP witness Mr. Tyler A. Akerman. Jurisdictional costs and revenues are allocated to customer classes in the CCOSS that I will describe in more detail.

A. Test Year JCOSS and CCOSS Allocators

Q. WHAT ALLOCATORS DID OTP USE IN ITS TEST YEAR JCOSS AND CCOSS?

A. Table 1 below identifies the main allocators used in the 2018 Test Year JCOSS and CCOSS. The OTP Cost Allocation Procedures Manual (CAPM), included as Exhibit___(GSI-1), Schedule 2, provides additional detail regarding the development of each allocator.

Table 1
JCOSS and CCOSS Allocators

Cost Function	Classification	JCOSS Allocator[1]	CCOSS Allocator[2]
Production Plant	Base Demand	E1	E1-E8760
	Peak Demand	D1	D1
	Base Energy (Wind)	E2	E2-E8760
Transmission Plant	Demand-Related	D2	D2
Distribution Plant	Demand-Related (Primary)	D3	D3
	Demand-Related (Secondary)	D4	D4
	Customer-Related (Primary)	C2	C2
	Customer-Related (Secondary)	C3	C3
	Street Lighting	C4	C4
	Area Lighting	C5	C5
	Meters	C6	C6
	Load Management	C9	C9

Q. HAS OTP CHANGED THE CAPM SINCE ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. OTP has refined the language pertaining to the classification and allocation of wind generation resources, as well as other minor clarifications and formatting updates since

[1] *See* Volume 3, Supporting Information, Schedule B-7.
[2] *See* Volume 3, Supporting Information, Schedule E-3.

OTP's last North Dakota rate case in 2008.[3] Exhibit___(GSI-1), Schedule 2, provides the content changes in red-line and clean versions.

Q. DID OTP USE THESE SAME ALLOCATORS IN ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. We used the same energy, demand and customer allocation factors outlined in the CAPM for cost allocations in this case as we did in our last North Dakota rate case except for the addition of an E8760 allocator for the CCOSS and Energy Adjustment Rider.

Q. WHY DID OTP BEGIN USING THE E8760 ALLACATOR?

A. In OTP's last North Dakota rate case, the Commission ordered OTP to use an E8760 allocator for class cost of service study development purposes and for the purposes of allocating fuel costs between classes.[4]

Q. ARE THE ALLOCATORS USED IN THE CURRENT CASE BASED ON FORECASTED INFORMATION?

A. Yes. OTP is using a forecast 2018 Test Year in this case and developed the allocation factors based on forecast information. This is a change from OTP's last North Dakota rate case where allocation factors were based on historical information, consistent with the historical Test Year used in that case. The process of developing the forecast-based allocators is described in Exhibit___(GSI-1), Schedule 3, which is a supplement to the CAPM.

Q. DOES OTP USE THE SAME ALLOCATION METHODOLOGIES ACROSS ALL OF ITS JURISDICTIONS?

A. Yes. Each of our jurisdictions has approved the same jurisdictional cost allocation methodology. We also use the same class cost allocation methodology in each of our jurisdictions, except for the use of a non-E8760 energy allocator in South Dakota.

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[3] *Otter Tail Corporation Electric Rate Increase Application*, Case No. PU-08-862 (Filed November 3, 2008).

[4] Section II. C. Page 8 of 21 Amended Settlement Agreement, Case No. PU-08-862 and PU-8-742.

B. E8760 Allocator

Q. PLEASE DISCUSS THE COMMISSION'S DIRECTIVES IN OTP'S LAST RATE CASE REGARDING THE E8760 ALLOCATOR.

A. The Commission's November 25, 2009 Order on Settlement adopted, with one modification, the October 5, 2009 Amended Settlement Agreement (the Settlement Agreement). The Settlement Agreement included the following provision:

> **C. C. Use of an E8760 Allocator.**
>
> The Parties agree that OTP should use an E8760 allocator in its next rate case for class cost of service study development purposes, and for the purposes of allocating fuel costs between classes.

I discuss the use of the E8760 allocator in the CCOSS and for purposes of allocating fuel costs below.

Q. WHAT IS AN E8760 ALLOCATOR?

A. An E8760 allocator applies a cost factor to each kilowatt hour (kWh) of energy consumed for every one of the 8,760 hours in the year to develop a weighted cost of energy factor. The E8760 allocator reflects changes in the cost of energy from hour to hour.

Q. HOW IS AN E8760 ALLOCATOR DIFFERENT FROM THE E1 AND E2 ALLOCATORS?

A. While the E8760 allocator reflects changes in the cost of energy from hour to hour, OTP's E1 and E2 allocation factors are computed based solely on energy consumed, without any consideration for the associated date and time of consumption and corresponding hourly cost of that energy. The difference between the E1 allocator and the E2 allocator is that E1 excludes residential demand control, interruptible, irrigation, and a portion of water heating and deferred sales.

Q. HOW DID OTP DEVELOP THE E1-E8760 AND E2-E8760 ALLOCATORS?

A. The class E8760 allocators were developed in five steps as follows:

Step 1: Develop Load Shapes. OTP developed class-based load shapes for each of the 8,760 hours based on load research data from 2016, the last full year of data available.

Step 2: Apply Load Shapes to Class Sales within North Dakota. The 2016 class-based load shapes were applied to total 2018 forecasted class sales for North Dakota. This resulted in a distribution of all sales within each class, across all 8,760 hours of the year for North Dakota.

Step 3: Apply Hourly Costs to Class-Based Load Shapes for North Dakota: OTP multiplied the forecasted hourly class sales by forecasted hourly 2018 MISO Day Ahead Locational Marginal Prices for the OTP load zone, which results in hourly costs by class.

Step 4: Sum Class Hourly Costs: This results in total energy costs over the 8,760 hours for each class.

Step 5: Compare Class Energy Costs to Total Energy Costs: This results in the E8760 allocators as illustrated in the example in Table 2 below.

Q. HAS OTP USED THE E1-E8760 AND E2-E8760 ALLOCATORS IN THE CCOSS?

A. Yes. Consistent with the Settlement Agreement, OTP allocated energy-related production plant costs using the E1-E8760 and E2-E8760 allocators in the CCOSS.

Q. DID OTP USE AN E8760 ALLOCATOR TO ALLOCATE FUEL COSTS IN ITS ENERGY ADJUSTMENT RIDER?

A. Yes. As required by the Settlement Agreement and the Commission's Order in OTP's last rate case, OTP has used an E8760 allocator[5] in its Energy Adjustment Rider.

Q. HOW DOES THE USE OF THE E8760 ALLOCATOR IMPACT CLASS ALLOCATIONS?

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[5] OTP was also ordered to separate its energy costs from its base rates. Section II. B. Page 8 of 21 Case No. PU-08-862 and PU-8-742 Amended Settlement Agreement. OTP witness Mr. Stuart D. Tommerdahl discusses the process of moving all fuel costs into the Energy Adjustment Rider in his Direct Testimony.

A. For illustrative purposes, Table 2 shows how the 10 customer classes are impacted using the average fuel rate[6] and applying the E2-E8760 allocator. The average fuel rate shown is based on total system costs, which is consistent with how fuel is calculated.

Table 2

Fuel Allocation	**A**	**B**	**C**
Customer Classes	**Avg Fuel $/kWh**	**E2-E8760 Allocation Ratio**	**E2-E8760 Avg Fuel $/kWh**
			(A*B)
Residential (RDC/RES)	$ 0.024587	1.0250	$ 0.025203
Farms (FAR)	$ 0.024587	0.969	$ 0.023832
General Service (TUS/GSO/GSU)	$ 0.024587	1.016	$ 0.024980
Large General Service (PLG/SLG/TLG)	$ 0.024587	0.967	$ 0.023784
Irrigation Services (IRR)	$ 0.024587	0.937	$ 0.023046
Outdoor Lighting (ALT/SLT)	$ 0.024587	0.784	$ 0.019272
OPA (OPA)	$ 0.024587	1.011	$ 0.024869
Controlled Service Water Heating (WHR)	$ 0.024587	1.035	$ 0.025455
Controlled Service Interruptible (LDF/SDF)	$ 0.024587	1.037	$ 0.025486
Controlled Service Deferred (DFL/FTD)	$ 0.024587	0.963	$ 0.023679

Q. HAS OTP PROPOSED ANY CHANGES TO THE ENERGY ADJUSTMENT RIDER?

A. Yes. As described in more detail in Mr. Tommerdahl' s Direct Testimony, OTP proposes to recover reagent and emissions allowance costs through the Energy Adjustment Rider. Table 2 above includes the costs of reagents in the average fuel rate per kWh.

Q. HOW DOES OTP PROPOSE TO USE THE E2-E8760 ALLOCATOR IN THE ENERGY ADJUSTMENT RIDER?

A. OTP proposes to allocate costs through the Energy Adjustment Rider using the E2-E8760 allocation method as a basis for cost allocation. OTP proposes to continue calculating a monthly average fuel rate and then apply the E2-E8760 allocation ratio to derive an E2-E8760 based fuel cost per kWh which is then applied to each of the 10 customer classes.

[6] OTP witness Mr. Tommerdahl Direct Testimony.

Q. WHEN DOES OTP PROPOSE TO IMPLEMENT USE OF THE E2-E8760 ALLOCATOR FOR THE ENERGY ADJUSTMENT RIDER?

A. OTP proposes to begin use of the E2-E8760 allocator for energy adjustment rider purposes when the CISOne system is implemented. As Mr. Tommerdahl describes in his Direct Testimony, CISOne is scheduled to "go-live" in the third quarter of 2018. OTP's current legacy billing system is unable to calculate a separate energy adjustment rider rate for each of the ten customer classes, which is necessary to implement use of the E8760 allocator.

IV. CCOSS AND CLASS REVENUE RESPONSIBILITIES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I explain OTP's 2018 Test Year embedded CCOSS and present OTP's proposed class revenue responsibility.

A. CCOSS

Q. HAS OTP PREPARED A CCOSS?

A. Yes. OTP prepared a CCOSS that is included in Volume 3, Supporting Information. A one-page summary of the results of the CCOSS (which is the first page of the full CCOSS) is attached as Exhibit___(GSI-1), Schedule 4.

Q. DID OTP ALSO PREPARE A MARGINAL COST STUDY?

A. Yes. OTP witness Mr. David G. Prazak discusses the elements and use of the marginal cost study in his Direct Testimony.

Q. ARE THE CCOSS AND THE MARGINAL COST STUDY USED FOR DIFFERENT PURPOSES?

A. Yes. An embedded cost study, modified to consider disproportionate rate impacts, is used to assign class revenue responsibility. The marginal cost study is then used to develop rates within each class. Marginal costs do not impact class revenue responsibility. OTP witness Mr. Prazak explains in more detail the use of marginal costs for rate design in his Direct Testimony.

Q. WHAT COSTS DOES THE CCOSS MEASURE?

A. OTP's CCOSS is an embedded cost study, meaning it measures the 2018 Test Year cost of the OTP system and all costs are fully distributed to classes.

Q. IS OTP USING THE SAME GENERAL CCOSS METHODOLOGY AS IT USED IN ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. The only differences between the CCOSS in this case and the CCOSS in OTP's last North Dakota rate case are: (1) the 2018 Test Year CCOSS is based on forecast information, including forecast allocation factors; (2) the use of the E1-E8760 and E2-E8760 factors; and (3) the addition of the Base Energy (Wind) classification of production plant. I previously discussed the development of CCOSS allocation factors in the context of the forecast 2018 Test Year in my Direct Testimony. OTP witness Mr. Akerman discusses the development of the underlying 2018 Test Year cost data.

Q. DID THE CCOSS DETERMINE THE REVENUES NEEDED TO REACH COST RESPONSIBILITY FOR EACH CUSTOMER CLASS?

A. Yes. Table 3 below shows the present revenues, the increase in revenues needed to reach cost responsibility, and the percentage of increase needed to reach cost responsibility for each of OTP's customer classes.

Column B shows the total present revenue provided by each class at current rates. Column C is the difference, in dollars, between present revenues under current rates and the amount of revenue needed for a customer class to pay its fully allocated embedded cost as determined in the CCOSS. Column D is the percentage increase in revenues needed in order for the customer class to provide revenues equal to the class revenue requirement.

Table 3

Per CCOSS Including Transmission and Environmental Cost Recovery Rider Revenues			
(A)	(B)	(C)	(D)
		Class Responsibility	
Class	Present Revenues	Amount of Increase	Percent Increase
Residential	$48,209,916	$10,643,028	22.08%
Farms	2,612,688	804,687	30.80%
General Service	38,950,615	424,321	1.09%
Large General Service	43,160,710	(1,099,489)	-2.55%
Irrigation	59,083	57,369	97.10%
Lighting	2,869,144	655,804	22.86%
OPA	1,203,986	319,236	26.51%
Controlled Service Water Heating	1,085,033	535,787	49.38%
Controlled Service Interruptible	8,397,154	3,237,513	38.55%
Controlled Service Deferred	1,523,622	137,064	9.00%
	$148,071,951	$15,715,320	10.61%

Q. WHAT DOES OTP'S 2018 TEST YEAR CCOSS SHOW REGARDING CLASS COST RESPONSIBILITIES?

A. Table 4 below compares the present revenue responsibilities and cost responsibilities of OTP's customer classes as a percent of overall revenue requirement taking into account the CCOSS recommended percent of increase as seen in Table 3. OTP's 2018 Test Year CCOSS shows that the revenue responsibility of the Residential class is currently below its cost responsibility (as measured in the CCOSS). Conversely, the present revenue responsibilities of the General Service and Large General Service classes are greater than their respective cost responsibilities.

Table 4
Comparison of Present Revenue Responsibility and Cost Responsibility

(A) Class	(B) Present Revenue Responsibility	(C) Cost Responsibility	(D) Difference
Residential	32.56%	35.93%	-3.37%
Farms	1.76%	2.09%	-0.32%
General Service	26.31%	24.04%	2.26%
Large General Service	29.15%	25.68%	3.47%
Irrigation	0.04%	0.07%	-0.03%
Lighting	1.94%	2.15%	-0.21%
OPA	0.81%	0.93%	-0.12%
Controlled Service Water Heating	0.73%	0.99%	-0.26%
Controlled Service Interruptible	5.67%	7.10%	-1.43%
Controlled Service Deferred	1.03%	1.01%	0.02%

B. Class Revenue Responsibilities

Q. PLEASE SUMMARIZE HOW OTP USED THE CCOSS TO DISTRIBUTE TOTAL REVENUE REQUIREMENTS AMONG THE CLASSES OF SERVICE.

A. The CCOSS is the primary guide for setting the class revenue responsibilities. However, determining the appropriate class revenue responsibilities is not as simple as setting them to equal the results of the CCOSS. It is also necessary to consider other objectives, particularly the objective of maintaining reasonable rate continuity, and mitigating disproportionate or abrupt rate impacts. A more complete discussion of the rate design considerations applied by OTP is contained in OTP witness Mr. Prazak's Direct Testimony.

Q. WHAT IS OTP'S PROPOSAL FOR DISTRIBUTION OF REVENUE RESPONSIBILITIES?

A. Based on a consideration of all the rate design objectives, OTP proposes the distribution of revenue responsibilities contained in Table 5 below.

Table 5

As Proposed Including Transmission and Environmental Cost Recovery Rider Revenues			
(A)	(B)	(C)	(D)
		Class Responsibility	
Class	Present Revenues	Amount of Increase	Percent Increase
Residential	$48,209,916	$6,604,758	13.70%
Farms	$2,612,688	357,938	13.70%
General Service	$38,950,615	3,221,905	8.27%
Large General Service	$43,160,710	3,565,075	8.26%
Irrigation	$59,083	11,226	19.00%
Lighting	$2,869,144	372,989	13.00%
OPA	$1,203,986	156,518	13.00%
Controlled Service Water Heating	$1,085,033	148,650	13.70%
Controlled Service Interruptible	$8,397,154	1,150,410	13.70%
Controlled Service Deferred	$1,523,622	125,851	8.26%
	$148,071,951	$15,715,320	10.61%

This distribution of revenue responsibilities will result in a reasonable movement toward revenues for each class being equal to class cost responsibility without producing unreasonable bill impacts.

Q. PLEASE FURTHER EXPLAIN TABLE 5.

A. Column B shows the amount of revenues provided by each class from current rates. Column C shows the difference, in dollars, between present revenues and the amount of revenue proposed by OTP. Column D shows the percentage increase of the proposed revenues compared to present revenues.

Q. DOES OTP'S PROPOSAL MOVE ALL CLASSES CLOSER TO COST RESPONSIBILITY?

A. Yes. OTP proposes to move all classes closer to their CCOSS-indicated cost responsibilities. Table 6 below compares present revenue and cost responsibilities and OTP's proposed revenue responsibilities for all of OTP's customer classes on a percentage basis:

Table 6
Comparison of Proposed Revenue Responsibility and Cost Responsibility

(A) Class	(B) Present Revenue Responsibility	(C) Cost Responsibility from CCOSS	(D) Proposed Revenue Responsibility	(E) Difference between Present and Cost (B) - (C)	(F) Difference between Proposed and Cost (D) - (C)
Residential	32.56%	35.93%	33.47%	-3.37%	-2.47%
Farms	1.76%	2.09%	1.81%	-0.32%	-0.27%
General Service	26.31%	24.04%	25.75%	2.26%	1.71%
Large General Service	29.15%	25.68%	28.53%	3.47%	2.85%
Irrigation	0.04%	0.07%	0.04%	-0.03%	-0.03%
Lighting	1.94%	2.15%	1.98%	-0.21%	-0.17%
OPA	0.81%	0.93%	0.83%	-0.12%	-0.10%
Controlled Service Water Heating	0.73%	0.99%	0.75%	-0.26%	-0.24%
Controlled Service Interruptible	5.67%	7.10%	5.83%	-1.43%	-1.27%
Controlled Service Deferred	1.03%	1.01%	1.01%	0.02%	0.0%

Q. PLEASE PROVIDE FURTHER CONTEXT FOR OTP'S PROPOSED REVENUE RESPONSIBILITY FOR THE RESIDENTIAL CLASS.

A. As shown in Table 3, the CCOSS indicates Residential class revenues would need to increase by 22.08 percent to bring the rates for this class up to its cost level. To provide a reasonable balance of the cost of service and rate continuity objectives of rate design, OTP is proposing a moderate increase of 13.70 percent for the Residential class, as shown in Table 5.

Q. IF OTP'S RECOMMENDED REVENUE DISTRIBUTION IS ACCEPTED, WILL THERE STILL BE DIFFERENCES BETWEEN CLASS REVENUE RESPONSIBILITY AND COST RESPONSIBILITY?

A. Yes. OTP does not propose an unmoderated adherence to the results of the CCOSS. For this reason, there are still differences between OTP's proposed class revenue responsibility and cost responsibilities identified by the CCOSS. For example, OTP's recommended revenue increase of $6,604,758 for the Residential class (shown above in Table 5, Column C) moves the Residential class closer to its cost responsibility. In order to be at its full cost responsibility, the Residential class revenues would need to increase by an additional $4,038,270.

Q. HOW MUCH OF THE RECOMMENDED INCREASE IN CLASS REVENUES IS TIED TO MOVING CLASSES CLOSER TO CLASS COST RESPONSIBILITY?

A. Table 7 below identifies the portion of the change in revenue responsibility due to the change in the revenue requirement and the portion due to the movement to cost. For most classes, the recommended movement to cost is a minor component of the overall change in revenue responsibility.

Table 7
Components of Change in Class Revenue Responsibility

Class	Change in Revenue Responsibility Due to Change in Revenue Requirement	Change in Revenue Responsibility Due to Movement to Cost	Total Change in Class Revenue Responsibility
Residential	$5,116,663	$1,488,096	$6,604,758
Farms	$277,292	$80,646	$357,938
General Service	$4,133,945	($912,040)	$3,221,905
Large General Service	$4,580,775	($1,015,701)	$3,565,075
Irrigation	$6,271	$4,955	$11,226
Lighting	$304,511	$68,478	$372,989
OPA	$127,783	$28,736	$156,518
Controlled Service Water Heating	$115,158	$33,492	$148,650
Controlled Service Interruptible	$891,215	$259,195	$1,150,410
Controlled Service Deferred	$161,707	($35,855)	$125,851
Total	$15,715,320	$0	$15,715,320

Q. PLEASE SHOW THE CLASS REVENUE RESPONSIBILITIES UNDER PRESENT REVENUE AS WELL AS UNDER OTP'S PROPOSED REVENUE ALLOCATION.

A. Table 8 below identifies present revenues by class as well as the proposed class revenue responsibilities taking into account OTP's recommended percent increase for each customer class.

Table 8
Class Revenue Responsibilities

Line No.	A Class	B Present Base Revenue (1)	C Present Rider Revenue (2)	D Total Present Revenues (B+C)	E Revenue Increase - Proposed	F Class Increase % / Overall (3)	G Percent Increase (E/D)	H Total Proposed Revenues (D+E)
1	Residential	$41,965,888	$6,244,028	$48,209,916	$6,604,758	129.1%	13.70%	$54,814,675
2	Farms	$2,155,303	$457,384	$2,612,687	$357,938	129.1%	13.70%	$2,970,626
3	General Service	$33,960,007	$4,990,608	$38,950,615	$3,221,905	77.9%	8.27%	$42,172,520
4	Large General Service	$37,389,529	$5,771,181	$43,160,710	$3,565,075	77.8%	8.26%	$46,725,785
5	Irrigation	$55,745	$3,336	$59,081	$11,226	179.0%	19.00%	$70,307
6	Outdoor Lighting	$2,597,928	$271,215	$2,869,143	$372,989	122.5%	13.00%	$3,242,131
7	OPA	$1,043,696	$160,291	$1,203,986	$156,518	122.5%	13.00%	$1,360,504
8	Controlled Service Water Heating	$987,779	$97,254	$1,085,033	$148,650	129.1%	13.70%	$1,233,682
9	Controlled Service Interruptible	$7,295,962	$1,101,193	$8,397,155	$1,150,410	129.1%	13.70%	$9,547,565
10	Controlled Service Deferred	$1,337,726	$185,898	$1,523,624	$125,851	77.8%	8.26%	$1,649,475
11	Total North Dakota	$128,789,562	$19,282,388	$148,071,950	$15,715,320		10.61%	$163,787,270

(1) Present revenues include the amount currently in base for energy.
(2) Total Present Rider Revenue calculated.
(3) Proposed class increase as a percent of the total 10.61% increase.

V. LEAD LAG STUDY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will explain OTP's Lead Lag Study.

Q. WHAT IS THE PURPOSE OF THE LEAD LAG STUDY?

A. The Lead Lag Study is a widely used and accepted method for developing the Cash Working Capital (CWC) component of rate base in connection with the determination of revenue requirements. This study analyzes the lapse of time between the average day on which a utility incurs expenses to serve its customers and the average day on which cash is received from customers in payment of that service. Lead days refer to the days between incurring an expense and paying for it. Lag days refer to the days between rendering a service and receiving payment for that service.

Q. HAS OTP'S LEAD LAG STUDY BEEN UPDATED SINCE THE LAST RATE CASE?

A. Yes. OTP updated its Lead Lag Study in 2015 using data from 2014.

Q. IS THE CASH WORKING CAPITAL DETERMINATION METHODOLOGY CONSISTENT WITH OTP'S LAST RATE CASE?

A. Yes. The study and procedures used to calculate the working capital requirement are consistent with the approach and methodology filed by OTP and approved by the Commission in OTP's last North Dakota rate case. OTP reviewed the procedures used in the Lead Lag Study filed in that case and concluded no significant changes in policies or procedures had occurred and conducted the current study using those same procedures. The updated study is included in Volume 4B. The results of the updated Lead Lag Study are included in the CWC calculations provided in Volume 3, Schedule B-4, pages 1-3. OTP witness Mr. Akerman discusses the overall calculation of CWC and its inclusion in Rate Base in his Direct Testimony.

Q. HOW DO THE RESULTS OF THE UPDATED LEAD LAG STUDY COMPARE TO THE RESULTS OF THE STUDY USED IN OTP'S LAST RATE CASE?

A. The lag period has increased to 43.4 days from 38.1 days shown in OTP's last rate case in 2008, with the majority of the increase coming from collections increasing from 19.4 days in 2008 to 24.7 days in this latest study. As reflected in Volume 3, Schedule B-4, page 1 of 3, OTP does not receive cash from computer maintained billings until 43.4 days after service has been rendered. As shown on Lines 58 through 60 of Volume 3, Schedule B-4, page 1 of 3, the 43.4 days is comprised of a 15.2-day metering period lag, a 3.5-day bill processing lag, and a 24.7-day collection period lag, which was based on the total annual billings to customers divided by the average daily utility receivable balances.

Q. IS OTP AWARE OF ANY ADJUSTMENTS NEEDED IN THE CASH WORKING CAPITAL CALCULATION AS SEEN IN THE COSS?

A. Yes. As OTP neared completion of this filing, it discovered a few items that needed to be adjusted. In the calculation of the Minnesota Cash Working Capital calculation, it had incorrectly stated two expense lag days. In Volume 4A, Section 1 JCOSS, page 19-1, the Tax Collections Available – State Sales Tax should be 12.95 instead of 12.7 days. This amount comes from the Lead Lag study, page 175, line 10, column C. On page 19-1 in the

JCOSS, the expense lag days for the Tax Collections Available – Franchise Taxes should be 23.8, instead of 27.6. This amount is shown on the Lead Lag study, page 175, line 25, column C. In addition, the number of revenue lead days shown for the Cost of Energy Revenues in the calculation of the Minnesota lead days on page 18-a, line 25 should be 98.4, instead of 98.3. This amount is shown on the Lead Lag study, page 37, line 1, column C. The above-mentioned items adjust the Minnesota CWC amount and do not impact North Dakota's revenue deficiency. However, it was discovered that the CWC calculation for North Dakota inadvertently did not include franchise taxes in its calculation as evidenced on page 20-1, line 41. If OTP were to include franchise taxes in its CWC calculation with the expense lag day of 23.8, it would reduce North Dakota's revenue deficiency by $12,000. OTP will make these adjustments in its JCOSS and corresponding schedules at its earliest opportunity.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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Rates Analyst, Regulatory Administration
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8275

CURRENT RESPONSIBILITIES: (December 2015 to Present)

Preparation and financial analysis used to determine revenue requirements associated with various state and federal cost recovery mechanisms and to develop regulatory filings associated with these cost recovery mechanisms.

PREVIOUS POSITIONS:

Otter Tail Power Company

2015 - Present	Rates Analyst, Regulatory Administration
2010 - 2015	Financial Analyst, Financial Reporting

Fairview Pharmacy Services, Minneapolis, MN

2007 - 2010	Financial Analyst

PricewaterhouseCoopers, Minneapolis, MN

2005 - 2007	External Auditor

EDUCATION / CERTIFICATIONS

University of Minnesota, Minneapolis, MN – B.S. in Accounting
Certified Public Accountant – Minnesota
Member of the Minnesota Society of Certified Public Accountants
Member of the American Institute of Certified Public Accountants

OTTER TAIL POWER COMPANY

Cost Allocations Procedures Manual

Revised October 2017

INTRODUCTION

The general methodology used in this procedure manual is one of functionalization and classification. Functionalization is the process by which costs are arranged according to the major utility function they serve, such as production, transmission, etc. Classification is the arrangement of costs within a function by the service characteristic to which they most closely apply or relate, to facilitate their allocation based on these service characteristics.

The major functional areas used in this procedure manual are production, transmission, distribution, customer accounting and collecting, and customer service and information. The reason for using functions other than the three major ones (production, transmission and distribution) is to provide a better base for eventual allocation of cost and to provide the flexibility necessary to handle certain cost items.

The principal service characteristics used in the classification process are: demand, energy, number of customers and number of meters. Sub-characteristics within each of these principal characteristics which allow a more precise division of cost, such as type of demand or energy, voltage level, or type of customer or meter were also used. These sub-characteristics provide added detail for a more accurate allocation of cost. The service characteristics or sub-characteristics provide the basis for determining allocation factors when allocation is necessary. Unless otherwise noted, all allocation factors described herein are used for both jurisdictional and class allocations.

The philosophy used to arrive at the service characteristics was to determine what characteristic or characteristics best describe or approximate the decisions made or factors considered when an expense is incurred or a plant investment is made. The amount of dollars to be allocated and the cost of determining or obtaining values for a service characteristic were also factors considered when determining the service characteristics to use.

There are 16 service characteristics used in this study. They consist of four demand characteristics, three energy or kilowatt-hour characteristics, and nine meter or customer characteristics. These service characteristics, which are used to develop allocation factors are:

1. GENERATION DEMAND FACTOR (D1) - this factor is determined based on contribution to Otter Tail's average annual six-hour system peak kW demand. Any loads for which Otter Tail is responsible for providing generation are included in this factor. The hours ending 9:00, 10:00, and 11:00 a.m., and 6:00, 7:00, and 8:00 p.m. were averaged to arrive at the Generation Demand Factor.
2. TRANSMISSION DEMAND FACTOR (D2) - this factor is determined based on contribution to Otter Tail's average annual six-hour transmission peak kW demand. Any loads for which Otter Tail is responsible for providing transmission service are included in this factor. The hours used are the same as those for

the Generation Demand Factor.

3. DISTRIBUTION PRIMARY DEMAND FACTOR (D3) - this factor is determined based on contributions to Otter Tail's average annual six-hour primary distribution peak kW demand minus the 0.83 kW/customer already included in the minimum system portion of the primary customer component. (See Appendix A-1.) Any loads for which Otter Tail is responsible for providing primary distribution service are included in this factor. The hours used are the same as those for the Generation Demand Factor.
4. DISTRIBUTION SECONDARY DEMAND FACTOR (D4) - this factor is determined based on non-coincident kW demands at the secondary service level minus the 3.0 kW/customer already included in the minimum system portion of the secondary customer component. (See Appendix A-1.) Only loads served at voltages less than 2400 volts are included in this factor.
5. ENERGY FACTOR (E1) - this factor is based on kilowatt-hour (kWh) sales adjusted for line losses to the generation level excluding interruptible, irrigation, and $^{14}/_{24}$ths of water heating and deferred sales.
6. ENERGY FACTOR (E2) - this factor is based on total kWh sales adjusted for line losses to the generation level. It is only used for jurisdictional allocations.
7. ENERGY FACTOR (E8760) - this factor is based on hourly energy usage, to which are applied hourly marginal costs to develop an hourly cost relationship. It is only used to allocate jurisdictional amounts to the customer classes.
8. TOTAL RETAIL CUSTOMERS FACTOR (C1) - this factor is based on the total active retail customers served in each jurisdiction.
9. TOTAL DISTRIBUTION SERVICE LOCATIONS FACTOR (C2) – a distribution service location is any point on the distribution system at which service is or can be provided including inactive and seasonal locations.
10. TOTAL SECONDARY DISTRIBUTION SERVICE LOCATIONS FACTOR (C3) - this factor includes only those distribution service locations served or which can be served at secondary voltage (below 2400 volts).
11. STREETLIGHT FACTOR (C4) - this factor is based on the weighted installed cost of the streetlights in each jurisdiction.
12. AREA LIGHT FACTOR (C5) - this factor is based on the weighted installed cost of area lights in each jurisdiction.
13. METER FACTOR (C6) - this factor is based on the weighted installed cost of meters in service.
14. METER READING FACTOR (C7) - this factor is based on total weighted meter reading time.

15. TOTAL SYSTEM SERVICE LOCATIONS FACTOR (C8) - this factor is similar to the Total Distribution Service Locations Factor, except all locations on the system at which service can be or is provided are included.
16. LOAD MANAGEMENT FACTOR (C9) - this factor is based on the total number of locations that have radio load management receivers in each jurisdiction.

The methodology for applying the various procedures and allocators to system cost values to develop jurisdictional and class or group cost values is explained in detail on the following pages.

RATE BASE COMPONENTS

PRODUCTION PLANT IN SERVICE

The plant in service within this function was classified into preliminary demand and energy categories as follows:

1. DEMAND COST - this category includes all production plant (accounts 310- 346), except that related to the Big Stone Plant unit train.
2. BASE LOAD ENERGY COST - Big Stone unit train only.

The demand category was then reclassified into Base (Energy-Related) and Peak Demand categories based on the following formulas:

$$\text{Total Current Cost} = (\text{Existing Peaking Capacity [kW]})(\text{Current Peaking Unit Cost [\$/kW]}) \\ + (\text{Existing Steam \& Hydro Capacity [kW]})(\text{Current Base Load Unit Cost [\$/kW]})$$

$$\text{Peaking Demand Factor} = \frac{(\text{Total Existing Plant Capacity})(\text{Current Peaking Unit Cost})}{\text{Total Current Cost}}$$

$$\text{Base (Energy-Related) Demand Factor} = 1 - \text{Peaking Demand Factor}$$

$$\text{\$ of Peak Demand} = (\text{Demand Cost}) \times (\text{Peaking Demand Factor})$$

$$\text{\$ of Base (Energy-Related) Demand} = (\text{Demand Cost}) \times (\text{Base Demand Factor})$$

This determination of Base and Peak Demand amounts is based on the premise that all plants are or can be used to supply system peak demands. However, base load plants (steam and hydro) are also used to supply the bulk of the energy used on the system. Therefore, the base load plants have a dual function of supplying both energy and demand. The above classification of production plant into base and peak categories recognizes this fact and assigns a portion of the base load plants to each of these functions. The underlying assumption is that the cost to supply a peak kW of demand capacity to the system is the cost of a kW of capacity from a peaking plant.

New unit costs in current year dollars were used to determine the peaking and base factors to provide an allocation method that separates costs based on present circumstances not on past circumstances. The use of current costs also eliminates any potential problems associated with the timing of plant additions, changes in load factors or changes in generation mix criteria which could lead to large short-term allocation factor variations.

The dollars in each category were then allocated based on the following:

BASE DEMAND - Energy Factor (E1)

PEAK DEMAND - Generation Demand Factor (D1)

BASE ENERGY - Energy Factor (E1)

PEAK ENERGY - Generation Demand Factor (D1)

3. Wind generation is a non-dispatchable production resource with operating characteristics different from other base load or peaking generation. The capacity factor for wind generation is determined by the Midwest Independent System Operator (MISO) as they accredit capacity based on each generation site's production. While a majority of a wind turbine's output is energy, a portion of the investment is also needed to meet the system's peak demand. The most recent MISO accreditations are used to create a weighted average for each wind farm that results in a base/peak split. Wind generation investment is allocated based on the following factors:

   BASE ENERGY - Energy Factor (E2)

   PEAK DEMAND – Generation Demand Factor (D1)

TRANSMISSION PLANT IN SERVICE

Allocated using the Transmission Demand Factor (D2).

DISTRIBUTION PLANT IN SERVICE

The plant in service within this function was classified into the following categories:

1. Primary Demand (2400 volts and above)
2. Secondary Demand (below 2400 volts)
3. Primary Customer (2400 volts and above)
4. Secondary Customer (below 2400 volts)
5. Streetlighting

6. Area Lighting
7. Meters
8. Load Management

based on the following account-by-account methodology:

ACCOUNT 360 (LAND) - classified primary demand related (substation land).

ACCOUNT 360.1 (LAND RIGHTS) - classified primary demand related.

ACCOUNT 361 (STRUCTURES AND IMPROVEMENTS) - classified primary demand related.

ACCOUNT 362 (STATION EQUIPMENT) - classified primary demand related.

ACCOUNTS 364-369.1 - classified based on minimum size system (see Appendix A-1).

ACCOUNT 370 (METERS) - direct assignment to meters characteristic.

ACCOUNT 370.1 (LOAD MANAGEMENT SWITCHES) - direct assignment to load management characteristic.

ACCOUNT 371 (INSTALLATION ON CUSTOMER'S PREMISES) - classified secondary customer related.

ACCOUNT 371.1 (RENTAL EQUIPMENT) - classified primary customer related.

ACCOUNT 371.2 (ALL OTHER PRIVATE LIGHTING) - direct assignment to area lighting.

ACCOUNT 373 (STREETLIGHTING AND SIGNAL SYSTEMS) - direct assignment to streetlighting.

The categories were then allocated based on the following:

PRIMARY DEMAND - Distribution Primary Demand Factor (D3)

SECONDARY DEMAND - Distribution Secondary Demand Factor (D4)

PRIMARY CUSTOMER - Total Distribution Service Locations Factor (C2)

SECONDARY CUSTOMER - Total Secondary Distribution Service Locations Factor (C3)

STREETLIGHTING - Streetlight Factor (C4)

AREA LIGHTING - Area Light Factor (C5)

METERS - Metering Factor (C6)

LOAD MANAGEMENT - Load Management Factor (C9)

GENERAL PLANT IN SERVICE

General Plant in Service, except Account 397.3 (Radio Load Control Equipment), was functionalized into the following categories based on the labor ratios developed from data in FERC Form No. 1, Page 354, or similar data for a forecast year.

1. Production

2. Transmission
3. Distribution
4. Customer Accounting
5. Customer Service and Information

The amounts in the production, transmission and distribution categories were then allocated using the gross plant in service ratios from the related plant in service functions. Customer Accounting and Customer Service and Information were allocated based on the expense ratios from the related expense functions. Account 397.3 directly assigned to Load Management category and allocated on the Load Management Factor (C9).

INTANGIBLE PLANT IN SERVICE

Intangible Plant in Service was allocated using the gross general plant in service ratios.

ACCUMULATED PROVISION FOR DEPRECIATION

PRODUCTION - Classification and allocation procedure is the same as that used for Production Plant in Service.

TRANSMISSION - Allocated based on gross plant in service ratios developed from the Transmission Plant in Service function.

DISTRIBUTION - Allocated based on gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - Allocated based on gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - allocated using the gross plant in service ratios developed from the Intangible Plant in Service function.

NET CAPITALIZED ITEMS - BIG STONE PLANT

Directly assigned to each jurisdiction. Allocated to classes or groups based on the gross Production Plant in Service ratio.

PLANT HELD FOR FUTURE USE

PRODUCTION - allocated using gross plant in service ratios developed from the Production Plant in Service function.

TRANSMISSION - allocated using the Transmission Demand Factor (D2).

DISTRIBUTION - allocated using gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - allocated using gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - allocated using gross plant in service ratios developed from the Intangible Plant in Service function.

CONSTRUCTION WORK IN PROGRESS (CWIP)

CWIP was separated into three parts or types: Major Projects, Short-Term, and Long-Term. The Major Projects section includes capital expenditures on which a current return is requested without an offset for Allowance For Funds Used During Construction (AFUDC). The Short-Term section are those projects with less than $10,000 cost or expected to be completed in less than 30 days. AFUDC is not accrued on short-term projects. The Long-Term section includes all other projects and AFUDC is accrued on this portion.

The CWIP of each type was functionalized as production, transmission, distribution, general, or intangible plant. The allocations are then based on the gross plant in service ratios for each individual function.

WORKING CAPITAL

MATERIALS AND SUPPLIES:

Materials and Supplies are separated into production, transmission, and distribution functions. The production portion includes materials and supplies at Big Stone and Coyote Plants as well as production repair parts. The remaining materials and supplies are split between transmission and distribution functions based on data from Page 227 of the latest FERC Form No. 1. The functional amounts are allocated on their respective gross plant in service ratios.

FUEL STOCKS:

COAL STOCKS - allocated using Energy Factor (E1).

FUEL OIL STOCKS - allocated using Generation Demand Factor (D1).

PREPAYMENTS - allocated based on total net plant in service ratios.

CUSTOMER ADVANCES - allocated based on total net plant in service ratios.

CASH WORKING CAPITAL - calculated separately for each jurisdiction. Allocated to customer class on total operating expenses for each jurisdiction (OX).

ACCUMULATED DEFERRED INCOME TAXES

Allocated using the total "net" plant in service ratios.

UNAMORTIZED BALANCE - SPIRITWOOD PLANT

Directly assigned to each jurisdiction. Allocated to customer class using the gross Production Plant in Service ratio.

UNAMORTIZED RATE CASE EXPENSE

Directly assigned to jurisdiction. Allocated to customer class on each jurisdiction's retail revenues (R10).

OPERATING REVENUES

RETAIL SALES

Directly assigned to each jurisdiction and class as billed.

WHOLESALE SALES

MUNICIPALITIES (SUPPLEMENTAL POWER ACCOUNTS 400.1-81, 400.2-81, and 400.3-81) - directly assigned to FERC jurisdiction and group as billed.

NONASSOCIATED UTILITIES, COOPERATIVES AND OTHER PUBLIC AUTHORITIES

The revenues from asset-based sales are classified as base demand, peak demand, base energy, and peak energy as follows:

1. All revenues from these sales, except those considered Participation or Peaking Power, are classified as Base Energy.
2. Demand charges for Peaking sales are classified as Peak Demand.
3. Demand charges for Participation Power sales are classified as follows:

   \$ of Peak Demand = Market price (\$/MW/Mo.) × capacity of the sale (MW)

   \$ of Base Demand = Total Demand charges − \$ of Peak Demand.
4. Energy charges for Participation Power sales are classified Base Energy.
5. Energy charges for Peaking Power sales are classified Peak Energy.

The jurisdictional allocations were then made as follows:

BASE DEMAND - Energy Factor (E1)

PEAK DEMAND - Generation Demand Factor (D1)

BASE ENERGY - Energy Factor (E2)

PEAK ENERGY - Generation Demand Factor (D1)

OTHER ELECTRIC REVENUE

ACCOUNT 450 (FORFEITED DISCOUNTS) - directly assigned to jurisdictions as collected. Allocated to classes (if required) based on Total Customers Factor (C1).

ACCOUNT 451 (CONNECTION FEES) - directly assigned to jurisdictions as collected. Allocated to classes (if required) based on Total Customers Factor (C1).

ACCOUNT 456.5 (WHEELING) - directly assigned to FERC groups as collected.

ACCOUNT 456.7 (RESIDENTIAL CONSERVATION SERVICE) - directly assigned to jurisdictions. Allocated to classes based on E8760 (Energy Factor).

ALL OTHER ACCOUNTS - allocated using total net plant in service ratios.

EXPENSE COMPONENTS

PRODUCTION EXPENSES

The expenses within this function, except those in Account 555, were classified into PRELIMINARY demand and energy categories as follows:

1. STEAM AND HYDRO (SH) DEMAND - this category includes all expenses in Accounts 500, 502-511, 535-543, and 556.
2. INTERNAL COMBUSTION (IC) DEMAND - this category includes all expenses in Accounts 546-554, except Account 547.
3. BASE ENERGY - includes Accounts 501, 512, 513, 514, 544, and 545.
4. PEAK ENERGY - includes Account 547.

The two demand categories (SH and IC) were then reclassified into BASE and PEAK Demand categories using the same methodology and formulas applied to those categories in Production Plant in Service.

The expenses in Account 555 (Purchased Power) are classified into base and peak demand and energy based on the following:

A. All expenses, except those for purchases labeled Participation or Peaking Power, were classified as Base Energy.
B. Demand charges for Peaking Power were classified as Peak Demand.
C. Demand Charges for Participation Power (including co-generators and shared customers) were classified as follows:

$$\begin{aligned}\$\text{ of Peak Demand} &= \text{MAPP Schedule H (peaking) rate (\$/MW/Mo.)} \\ &\quad \times \text{capacity of the purchase (MW)} \\ &\quad \times \text{number of months purchased.}\end{aligned}$$

$$\$\text{ of Base Demand} = \text{Total Demand Charges} - \$\text{ of Peak Demand.}$$

D. Energy charges for Participation Power were classified as Base Energy.
E. Energy charges for Peaking Power were classified as Peak Energy.

The jurisdictional allocations were then made as follows:

BASE DEMAND - Energy Factor (E1)

PEAK DEMAND - Generation Demand Factor (D1)

BASE ENERGY - Energy Factor (E2)

PEAK ENERGY - Generation Demand Factor (D1)

TRANSMISSION EXPENSES

Allocated using the Transmission Demand Factor (D2).

DISTRIBUTION EXPENSES

The expenses within this function were classified into the following categories:

1. Primary Demand (2400 volts and above)
2. Secondary Demand (below 2400 volts)
3. Primary Customer (2400 volts and above)
4. Secondary Customer (below 2400 volts)
5. Streetlights
6. Area Lights
7. Meters
8. Load Management

Based on the following account-by-account methodology:

OPERATION

ACCOUNT 580 (SUPERVISION AND ENGINEERING) - classified based on classification of Accounts 582-588.

ACCOUNT 582 (STATION EXPENSE) - classified based on classification of related plant in service Account 362.

ACCOUNT 583 (OVERHEAD LINE EXPENSE) - classified based on the classification of related plant in service Accounts 364, 365, 368 and 369.

ACCOUNT 584 (UNDERGROUND LINE EXPENSE) - classified based on the classification of related plant in service Accounts 366, 367, and 369.1.

ACCOUNT 585 (STREETLIGHTING EXPENSE) - classified directly as streetlighting.

ACCOUNTS 586.1-586.5 & 586.9 (METER EXPENSES) - classified directly as meters.

ACCOUNTS 586.6-586.7 (METER EXPENSES) - classified directly as load management.

ACCOUNT 587 (CUSTOMER INSTALLATION EXPENSE) - classified secondary customer.

ACCOUNT 588 (MISCELLANEOUS EXPENSE) - classified based on classification of Accounts 582-587.

ACCOUNT 589 (RENTS) - classified based on classification of related plant in service Account 364.

MAINTENANCE

ACCOUNT 590 (SUPERVISION AND ENGINEERING) - classified based on classification of Accounts 592-596.

ACCOUNT 592 (STATION EQUIPMENT) - classified based on classification of related plant in service Account 362.

ACCOUNT 593 (OVERHEAD LINES) - classified based on classification of related plant in service Accounts 364, 365, and 369.

ACCOUNT 594 (UNDERGROUND LINES) - classified based on classification of related plant in service Accounts 366, 367, and 369.1.

ACCOUNT 595 (LINE TRANSFORMERS) - classified based on classification of related plant in service Account 368.

ACCOUNT 596 (STREETLIGHTING) - classified directly to streetlighting.

ACCOUNTS 597.1-597.2 (METERS) - classified directly to meters.

ACCOUNT 597.3 (METERS) - classified directly to load management.

ACCOUNT 598 (MISCELLANEOUS DISTRIBUTION PLANT) - classified based on classification of Accounts 592-597.

Each category was then allocated based on the following:

PRIMARY DEMAND - Distribution Primary Demand Factor (D3).

SECONDARY DEMAND - Distribution Secondary Demand Factor (D4).

PRIMARY CUSTOMER - Total Distribution Service Locations Factor (C2).

SECONDARY CUSTOMER - Total Secondary Distribution Service Locations Factor (C3).

STREETLIGHTING - Streetlight Factor (C4).

AREA LIGHTING - Area Light Factor (C5).

METERS - Meter Factor (C6).

LOAD MANAGEMENT - Load Management Factor (C9).

CUSTOMER ACCOUNTING AND COLLECTING EXPENSES

Expenses in this function were classified into two categories:

1. Meter Reading

2. Other Expenses

as specified by the following:

ACCOUNT 901 (SUPERVISION) - classified based on classification of Accounts 902-905.

ACCOUNT 902 (METER READING EXPENSE) - classified meter reading.

ACCOUNT 903 (CUSTOMER RECORDS AND COLLECTIONS) - classified other expense.

ACCOUNT 904 (UNCOLLECTIBLE ACCOUNTS) - classified other expense.

ACCOUNT 905 (MISCELLANEOUS CUSTOMER ACCOUNTING EXPENSES) - classified other expense.

The METER READING category was allocated using the Meter Reading Factor (C7) and the OTHER EXPENSES category using the Total System Service Locations Factor (C8).

CUSTOMER SERVICE AND INFORMATION EXPENSES

Conservation related programs and promotional rebates are directly assigned to jurisdiction and then allocated to class based on E8760 (Energy Factor). All other Customer Service and Information Expenses are allocated based on Total Customer Factor (C1).

SALES EXPENSES

Economic Development is directly assigned to jurisdiction and then allocated to class based on Total Customer Factor (C1). Account 913, Advertising, is assigned below the line. All other Sales Expenses are allocated based on Total Customer Factor (C1).

ADMINISTRATIVE AND GENERAL EXPENSES

ACCOUNTS 920 (SALARIES), 921 (SUPPLIES, ETC.), AND 926 (PENSIONS AND BENEFITS) - these accounts functionalized as: Production, Transmission, Distribution, Customer Accounting or Customer Service, based on FERC labor ratios (FERC Form No. 1, Page 354, or comparable data for a forecast year). Functional categories were then allocated using the expense ratios from the related expense functions, except that in the Production category the energy-related expenses and buy/sell transactions were not included in the ratios. (Energy-related expenses and buy/sell transactions are excluded because they are mainly purchased fuel which requires a minimum of company labor.)

ACCOUNT 923 (OUTSIDE SERVICES) - allocated based on total net plant in service ratios.

ACCOUNTS 924 (PROPERTY INSURANCE) and 925 (INJURIES & DAMAGES) - were allocated based on the total net plant in service ratios.

ACCOUNTS 928 (REGULATORY COMMISSION EXPENSES) - directly assigned to each jurisdiction. Allocated to classes or groups based on total electric revenues from each class or group.

ACCOUNT 930.1 (GENERAL ADVERTISING) -- The majority of this account is assigned below the line. Any remaining amount is allocated based on Total Customers Factor (C1).

ACCOUNTS 930.2 (MISCELLANEOUS), 931 (RENTS), and 935.1-935.5 & 935.9 (MAINTENANCE) - allocated based on the gross general plant in service ratios.

ACCOUNT 935.6 (MAINTENANCE) - directly assigned to load management and allocated on (C9).

DEPRECIATION EXPENSES

PRODUCTION - Classification and allocation procedure is the same as that used for Production Plant in Service.

TRANSMISSION - Allocated based on gross plant in service ratios developed from the Transmission Plant in Service function.

DISTRIBUTION - Allocated based on gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - Allocated based on gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - Allocated using the gross plant in service ratios developed from the Intangible Plant in Service function.

BIG STONE PLANT CAPITALIZED ITEMS EXPENSES

Directly assigned to each jurisdiction. Allocated to classes or groups based on the gross Production Plant in Service ratio.

OTHER EXPENSE - SPIRITWOOD AMORTIZATION

Directly assigned to each jurisdiction. Allocated to customer class using the gross Production Plant in Service ratio.

GENERAL TAXES

Allocated using total net plant in service ratios.

DEFERRED INCOME TAXES

Allocated using total net plant in service ratios.

INVESTMENT TAX CREDIT

Allocated using total gross plant in service ratios.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

Allocated based on long-term construction work in progress ratios.

INCOME TAXES

Income taxes are calculated for each jurisdiction separately.

APPENDIX A-1

DETERMINATION OF THE DEMAND & CUSTOMER COMPONENTS OF THE DISTRIBUTION SYSTEM

The customer component of the distribution system, that portion which varies with the number of customers, was determined by applying the minimum size system method. This method involves determining the minimum size unit currently being installed and using the average installed book cost of that unit to determine the customer component. However, our accounting system is such that, except for Account 368 (transformers), the only average installed book cost available is for all the units in an account regardless of size. To circumvent this problem, the following procedures were used:

1. The Electric Distribution (ED) Department specified what the minimum size unit for each account is and then provided information as to the type and quantity of material included in this unit and the amount of labor necessary to install it.
2. For each account that a customer component is required, the average age of the account was determined by using results of the recently completed depreciation study. This age is then subtracted from the study year to determine in what year the average unit was installed.
3. The average installed cost of the minimum size unit for the year indicated above was then determined. This was done by developing material, labor, transportation, and payroll costs for the year this unit was installed and applying them to the information supplied in No. 1, above.

The following pages describe how the dollars in each account were assigned to the various categories of cost using the data developed above and other figures from the various accounts.

Symbol Legend:

PSL = Poles for Streetlights

DSL = Dollars allocated to Streetlighting

DAL = Dollars allocated to Area Lighting

DPCC = Dollars allocated to Primary Customer Category

DPDC = Dollars allocated to Primary Demand Category

DSCC = Dollars allocated to Secondary Customer Category

DSDC = Dollars allocated to Secondary Demand Category

UPD = Units of Primary Distribution

USD = Units of Secondary Distribution

<u>Account 364 (Poles):</u> (All poles considered primary)

A. Average age of a pole.

B. Minimum size pole.

C. Installed cost of the minimum size pole of the age in "A."

D. Number of streetlights on separate poles. (Based on sample survey by Engineering Services.)

E. Number of area lights on separate poles. (Based on sample survey by Engineering Services.)

F. Number of poles in Account 364.

G. Total dollars in Account 364.

<u>Dollar Allocations for Account 364</u>

To Streetlighting $= D \times C^* = DSL$

To Area Lighting $= E \times C^* = DAL$

Customer Component $= (F - D - E) \times C = DPCC$

Demand Component $= DSL - DAL - DPCC = DPDC$

*Cost of a minimum size pole was used because most streetlights are mounted on minimum size poles and those that are on larger poles are mounted on poles that do not have the usual framing (crossarms, etc.).

<u>Account 365 (Overhead Conductor and Devices):</u>

I. Primary

A. Average age of primary conductor.

B. Minimum size primary unit.

C. Average installed cost of a minimum size primary unit of the age in "A."

D. Average number of poles in a minimum size unit of primary conductor. (Estimated by ED Department.)

E. Total dollars in Account 365 considered primary (see note).

F. Total number of poles used for primary distribution. (Number of poles in Account 364 - Number of poles allocated to streetlighting and area lighting.)

Number of units of primary distribution $= UPD = \frac{F}{D1}$

Dollar Allocations for Account 365 Primary

Customer Component = C × UPD = DPCC

Demand Component = E − DPCC = DPDC

NOTE: All bare copper, aluminum, ACSR and iron wire are primary. 30% of WP copper, 80% of WP aluminum and 50% of the steel wire are primary. (Estimated by ED Department - exact percentages very difficult to determine.) All miscellaneous conductor and other equipment are primary.

II. Secondary

A. Average age of secondary conductor.

B. Minimum size secondary unit.

C. Average installed cost of a minimum size unit of the age in "A."

D. Number of units of secondary conductor (see note).

E. Total dollars in Account 365 considered secondary. (All conductor not primary - see primary section.)

F. Dollar value of duplex conductor in Account 365. (Duplex assumed to be used entirely for street and area lights.)

G. Percent of total number of lighting units (street and area lights) that are streetlights.

Dollar Allocations for Account 365 Secondary

To Streetlighting = F × G = DSL

To Area Lighting = F − DSL = DAL

Customer Component = C × D = DSCC

Demand Component = E − F − DSCC = DSDC

NOTE: Estimated by ED Department based on 250' of secondary for each five urban residential cottages, and urban commercial customers, 3,360' of secondary per unit.

Account 366 (Underground Conduit):

The percentages developed from the allocation of Account 367 will be applied to this account.

Account 367 (Underground Conductor and Devices):

I. Primary

A. Average age of primary unit.

B. Minimum size primary unit.

C. Average installed cost of a minimum size primary unit of the age in "A."

D. Number of feet of conductor in the minimum size primary unit.

E. Total dollars in Account 367 considered primary. (All conductor rated 5 kV and above, and all nonconductor items are considered primary.)

F. Total number of feet of primary conductor in Account 367.

$$\text{Number of units of primary distribution} = \text{UPD} = \frac{\text{F}}{\text{D2}}$$

<u>Dollar Allocations for Account 367 Primary</u>

$$\text{Customer Component} = \text{C} \times \text{UPD} = \text{DPCC}$$

$$\text{Demand Component} = \text{E} - \text{DPCC} = \text{DPDC}$$

II. Secondary

A. Average age of secondary unit.

B. Minimum size of secondary unit.

C. Average installed cost of a minimum size secondary unit of the age in "A."

D. Number of feet of conductor in the minimum size secondary unit.

E. Total dollars in Account 367 considered secondary. (All conductor rated 600 volts or less is secondary.)

F. Total number of feet of secondary conductor in Account 367 (see note).

G. Dollar value of duplex conductor in Account 367 (duplex conductor is assumed to be used entirely for street and area lights).

H. Percent of total number of lighting units (street and area lights) that is streetlights.

$$\text{Number of units of secondary distribution} = \text{USD} = \frac{\text{F}}{\text{D3}}$$

<u>Dollar Allocations for Account 367 Secondary</u>

$$\text{To Streetlighting} = \text{G} \times \text{H} = \text{DSL}$$

$$\text{To Area Lighting} = \text{G} - \text{DSL} = \text{DAL}$$

$$\text{Customer Component} = \text{C} \times \text{USD} = \text{DSCC}$$

Demand Component $= E - G - DSCC = DSDC$

NOTE: Includes all quadruplex and triplex cable and 1/3 of 600 volt single wire. (Duplex is for lighting only.)

Account 368 (Transformers): (All transformers classified secondary)

A. Average installed cost of minimum size 2400 V. overhead unit.*
B. Average installed cost of minimum size 7200 V. overhead unit.*
C. Average installed cost of minimum size 14400 V. overhead unit.*
D. Average installed cost of minimum size 2400 V. underground unit.*
E. Average installed cost of minimum size 7200 V. underground unit.*
F. Number of 2400 V. overhead units in the account.
G. Number of 7200 V. overhead units in the account.
H. Number of 14400 V. overhead units in the account.

*Overhead unit cost includes cost of appropriate cutout and arrester.

I. Number of 2400 V. underground units in the account.
J. Number of 7200 V. underground units in the account.
K. Total dollar value of Account 368.

Dollar Allocations for Account 368

Customer Component $= (A \times F) + (B \times G) + (C \times H) + (D \times I) + (E \times J) = DSCC$

Demand Component $= K - DSCC = DSDC$

Account 369 (Overhead Services): (All services classified secondary)

A. Average age of a service.
B. Minimum size of a service.
C. Average installed cost of a minimum size service of the age in "A."
D. Total number of 3 and 4 services.
E. Dollar value of two-wire services (two-wire services are considered all customer component).
F. Total dollar value of Account 369.

Dollar Allocations for Account 369

Customer Component $= (C \times D) + E = DSCC$

Demand Component $= F - DSCC = DSDC$

Account 369.1 (Underground Services): (All services classified secondary)

A. Average age of an underground service.

B. Minimum size of an underground service.

C. Average installed cost of a minimum size three-wire service of the age in "A."

D. Total number of services in Account 369.1.

E. Total dollar value of Account 369.1.

Dollar Allocations for Account 369.1

Customer Component $= (C \times D) = DSCC$

Demand Component $= E - DSCC = DSDC$

OTTER TAIL POWER COMPANY

Cost Allocations Procedures Manual

Revised October 2017

INTRODUCTION

The general methodology used in this procedure manual is one of functionalization and classification. Functionalization is the process by which costs are arranged according to the major utility function they serve, such as production, transmission, etc. Classification is the arrangement of costs within a function by the service characteristic to which they most closely apply or relate, to facilitate their allocation based on these service characteristics.

The major functional areas used in this procedure manual are production, transmission, distribution, customer accounting and collecting, and customer service and information. The reason for using functions other than the three major ones (production, transmission and distribution) is to provide a better base for eventual allocation of cost and to provide the flexibility necessary to handle certain cost items.

The principal service characteristics used in the classification process are: demand, energy, number of customers and number of meters. Sub-characteristics within each of these principal characteristics which allow a more precise division of cost, such as type of demand or energy, voltage level, or type of customer or meter were also used. These sub-characteristics provide added detail for a more accurate allocation of cost. The service characteristics or sub-characteristics provide the basis for determining allocation factors when allocation is necessary. Unless otherwise noted, all allocation factors described herein are used for both jurisdictional and class allocations.

The philosophy used to arrive at the service characteristics was to determine what characteristic or characteristics best describe or approximate the decisions made or factors considered when an expense is incurred or a plant investment is made. The amount of dollars to be allocated and the cost of determining or obtaining values for a service characteristic were also factors considered when determining the service characteristics to use.

There are ~~15~~16 service characteristics used in this study. They consist of four demand characteristics, ~~two~~three energy or kilowatt-hour characteristics, and nine meter or customer characteristics. These service characteristics, which are used to develop allocation factors are:

1. GENERATION DEMAND FACTOR (D1) - this factor is determined based on contribution to Otter Tail's average annual six-hour system peak kW demand. Any loads for which Otter Tail is responsible for providing generation are included in this factor. The hours ending 9:00, 10:00, and 11:00 a.m., and 6:00, 7:00, and 8:00 p.m. were averaged to arrive at the Generation Demand Factor.
2. TRANSMISSION DEMAND FACTOR (D2) - this factor is determined based on contribution to Otter Tail's average annual six-hour transmission peak kW demand. Any loads for which Otter Tail is responsible for providing transmission service are included in this factor. The hours used are the same as those for

the Generation Demand Factor.

3. DISTRIBUTION PRIMARY DEMAND FACTOR (D3) - this factor is determined based on contributions to Otter Tail's average annual six-hour primary distribution peak kW demand minus the 0.83 kW/customer already included in the minimum system portion of the primary customer component. (See Appendix A-1.) Any loads for which Otter Tail is responsible for providing primary distribution service are included in this factor. The hours used are the same as those for the Generation Demand Factor.
4. DISTRIBUTION SECONDARY DEMAND FACTOR (D4) - this factor is determined based on non-coincident kW demands at the secondary service level minus the 3.0 kW/customer already included in the minimum system portion of the secondary customer component. (See Appendix A-1.) Only loads served at voltages less than 2400 volts are included in this factor.
5. ENERGY FACTOR (E1) - this factor is based on kilowatt-hour (kWh) sales adjusted for line losses to the generation level excluding interruptible, irrigation, and $^{14}/_{24}$ths of water heating and deferred sales.
6. ENERGY FACTOR (E2) - this factor is based on total kWh sales adjusted for line losses to the generation level. It is only used for jurisdictional allocations.
7. ENERGY FACTOR (E8760) - this factor is based on hourly energy usage, to which are applied hourly marginal costs to develop an hourly cost relationship. It is only used to allocate jurisdictional amounts to the customer classes.

~~7.~~8. TOTAL RETAIL CUSTOMERS FACTOR (C1) - this factor is based on the total active retail customers served in each jurisdiction.

~~8.~~9. TOTAL DISTRIBUTION SERVICE LOCATIONS FACTOR (C2) – a distribution service location is any point on the distribution system at which service is or can be provided including inactive and seasonal locations.

~~9.~~10. TOTAL SECONDARY DISTRIBUTION SERVICE LOCATIONS FACTOR (C3) - this factor includes only those distribution service locations served or which can be served at secondary voltage (below 2400 volts).

~~10.~~11. STREETLIGHT FACTOR (C4) - this factor is based on the weighted installed cost of the streetlights in each jurisdiction.

~~11.~~12. AREA LIGHT FACTOR (C5) - this factor is based on the weighted installed cost of area lights in each jurisdiction.

~~12.~~13. METER FACTOR (C6) - this factor is based on the weighted installed cost of meters in service.

~~13.~~14. METER READING FACTOR (C7) - this factor is based on total weighted meter reading time.

~~14.~~15. TOTAL SYSTEM SERVICE LOCATIONS FACTOR (C8) - this factor is similar to the Total Distribution Service Locations Factor, except all locations on the system at which service can be or is provided are included.

~~15.~~16. LOAD MANAGEMENT FACTOR (C9) - this factor is based on the total number of locations that have radio load management receivers in each jurisdiction.

The methodology for applying the various procedures and allocators to system cost values to develop jurisdictional and class or group cost values is explained in detail on the following pages.

RATE BASE COMPONENTS

PRODUCTION PLANT IN SERVICE

The plant in service within this function was classified into preliminary demand and energy categories as follows:

1. DEMAND COST - this category includes all production plant (accounts 310- 346), except that related to the Big Stone Plant unit train.
2. BASE LOAD ENERGY COST - Big Stone unit train only.

The demand category was then reclassified into Base (Energy-Related) and Peak Demand categories based on the following formulas:

$$\text{Total Current Cost} = (\text{Existing Peaking Capacity [kW]})(\text{Current Peaking Unit Cost [\$/kW]}) + (\text{Existing Steam \& Hydro Capacity [kW]})(\text{Current Base Load Unit Cost [\$/kW]})$$

$$\text{Peaking Demand Factor} = \frac{(\text{Total Existing Plant Capacity})(\text{Current Peaking Unit Cost})}{\text{Total Current Cost}}$$

$$\text{Base (Energy-Related) Demand Factor} = 1 - \text{Peaking Demand Factor}$$

$$\text{\$ of Peak Demand} = (\text{Demand Cost}) \times (\text{Peaking Demand Factor})$$

$$\text{\$ of Base (Energy-Related) Demand} = (\text{Demand Cost}) \times (\text{Base Demand Factor})$$

This determination of Base and Peak Demand amounts is based on the premise that all plants are or can be used to supply system peak demands. However, base load plants (steam and hydro) are also used to supply the bulk of the energy used on the system. Therefore, the base load plants have a dual function of supplying both energy and demand. The above classification of production plant into base and peak categories recognizes this fact and assigns a portion of the base load plants to each of these functions. The underlying assumption is that the cost to supply a peak kW of demand capacity to the system is the cost of a kW of capacity from a peaking plant.

New unit costs in current year dollars were used to determine the peaking and base factors to provide an allocation method that separates costs based on present circumstances not on past circumstances. The use of current costs also eliminates any potential problems associated with the timing of plant additions, changes in load factors or changes in generation mix criteria which could lead to large short-term allocation factor variations.

The dollars in each category were then allocated based on the following:

BASE DEMAND - Energy Factor (E1)

PEAK DEMAND - Generation Demand Factor (D1)

BASE ENERGY - Energy Factor (E1)

PEAK ENERGY - Generation Demand Factor (D1)

3. Wind generation is a non-dispatchable production resource with operating characteristics different from other base load or peaking generation. The capacity factor for wind generation is determined by the Midwest Independent System Operator (MISO) as they accredit capacity based on each generation site's production. While a majority of a wind turbine's output is energy, a portion of the investment is also needed to meet the system's peak demand. The most recent MISO accreditations are used to create a weighted average for each wind farm that results in a base/peak split. Wind generation investment is allocated based on the following factors:

BASE ENERGY - Energy Factor (E2)

PEAK DEMAND – Generation Demand Factor (D1)

TRANSMISSION PLANT IN SERVICE

Allocated using the Transmission Demand Factor (D2).

DISTRIBUTION PLANT IN SERVICE

The plant in service within this function was classified into the following categories:

1. Primary Demand (2400 volts and above)
2. Secondary Demand (below 2400 volts)
3. Primary Customer (2400 volts and above)
4. Secondary Customer (below 2400 volts)

5. Streetlighting
6. Area Lighting
7. Meters
8. Load Management

based on the following account-by-account methodology:

ACCOUNT 360 (LAND) - classified primary demand related (substation land).

ACCOUNT 360.1 (LAND RIGHTS) - classified primary demand related.

ACCOUNT 361 (STRUCTURES AND IMPROVEMENTS) - classified primary demand related.

ACCOUNT 362 (STATION EQUIPMENT) - classified primary demand related.

ACCOUNTS 364-369.1 - classified based on minimum size system (see Appendix A-1).

ACCOUNT 370 (METERS) - direct assignment to meters characteristic.

ACCOUNT 370.1 (LOAD MANAGEMENT SWITCHES) - direct assignment to load management characteristic.

ACCOUNT 371 (INSTALLATION ON CUSTOMER'S PREMISES) - classified secondary customer related.

ACCOUNT 371.1 (RENTAL EQUIPMENT) - classified primary customer related.

ACCOUNT 371.2 (ALL OTHER PRIVATE LIGHTING) - direct assignment to area lighting.

ACCOUNT 373 (STREETLIGHTING AND SIGNAL SYSTEMS) - direct assignment to streetlighting.

The categories were then allocated based on the following:

PRIMARY DEMAND - Distribution Primary Demand Factor (D3)

SECONDARY DEMAND - Distribution Secondary Demand Factor (D4)

PRIMARY CUSTOMER - Total Distribution Service Locations Factor (C2)

SECONDARY CUSTOMER - Total Secondary Distribution Service Locations Factor (C3)

STREETLIGHTING - Streetlight Factor (C4)

AREA LIGHTING - Area Light Factor (C5)

METERS - Metering Factor (C6)

LOAD MANAGEMENT - Load Management Factor (C9)

GENERAL PLANT IN SERVICE

General Plant in Service, except Account 397.3 (Radio Load Control Equipment), was functionalized into the following categories based on the labor ratios developed from data in FERC Form No. 1, Page 354, or similar data for a forecast year.

1. Production
2. Transmission
3. Distribution
4. Customer Accounting
5. Customer Service and Information

The amounts in the production, transmission and distribution categories were then allocated using the gross plant in service ratios from the related plant in service functions. Customer Accounting and Customer Service and Information were allocated based on the expense ratios from the related expense functions. Account 397.3 directly assigned to Load Management category and allocated on the Load Management Factor (C9).

INTANGIBLE PLANT IN SERVICE

Intangible Plant in Service was allocated using the gross general plant in service ratios.

ACCUMULATED PROVISION FOR DEPRECIATION

PRODUCTION - Classification and allocation procedure is the same as that used for Production Plant in Service.

TRANSMISSION - Allocated ~~to classes or groups~~ based on gross plant in service ratios developed from the Transmission Plant in Service function.

DISTRIBUTION - Allocated ~~to classes or groups~~ based on gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - Allocated ~~to classes or groups~~ based on gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - allocated using the gross plant in service ratios developed from the Intangible Plant in Service function.

NET CAPITALIZED ITEMS - BIG STONE PLANT

Directly assigned to each jurisdiction. Allocated to classes or groups based on the gross Production Plant in Service ratio.

PLANT HELD FOR FUTURE USE

PRODUCTION - allocated using gross plant in service ratios developed from the Production Plant in Service function.

TRANSMISSION - allocated using the Transmission Demand Factor (D2).

DISTRIBUTION - allocated using gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - allocated using gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - allocated using gross plant in service ratios developed from the Intangible Plant in Service function.

CONSTRUCTION WORK IN PROGRESS (CWIP)

CWIP was separated into three parts or types: Major Projects, Short-Term, and Long-Term. The Major Projects section includes capital expenditures on which a current return is requested without an offset for Allowance For Funds Used During Construction (AFUDC). The Short-Term section are those projects with less than $10,000 cost or expected to be completed in less than 30 days. AFUDC is not accrued on short-term projects. The Long-Term section includes all other projects and AFUDC is accrued on this portion.

The CWIP of each type was functionalized as production, transmission, distribution, general, or intangible plant. The allocations are then based on the gross plant in service ratios for each individual function.

WORKING CAPITAL

MATERIALS AND SUPPLIES:

Materials and Supplies are separated into production, transmission, and distribution functions. The production portion includes materials and supplies at Big Stone and Coyote Plants as well as production repair parts. The remaining materials and supplies are split between transmission and distribution functions based on data from Page 227 of the latest FERC Form No. 1. The functional amounts are allocated on their respective gross plant in service ratios.

FUEL STOCKS:

COAL STOCKS - allocated using Energy Factor (E1).

FUEL OIL STOCKS - allocated using Generation Demand Factor (D1).

PREPAYMENTS - allocated based on total net plant in service ratios.

CUSTOMER ADVANCES - allocated based on total net plant in service ratios.

CASH WORKING CAPITAL - calculated separately for each jurisdiction. Allocated to customer class on total operating expenses for each jurisdiction (OX).

ACCUMULATED DEFERRED INCOME TAXES

Allocated using the total "net" plant in service ratios.

UNAMORTIZED BALANCE - SPIRITWOOD PLANT

Directly assigned to each jurisdiction. Allocated to customer class using the gross Production Plant in Service ratio.

UNAMORTIZED RATE CASE EXPENSE

Directly assigned to jurisdiction. Allocated to customer class on each jurisdiction's retail revenues (R10).

OPERATING REVENUES

RETAIL SALES

Directly assigned to each jurisdiction and class as billed.

WHOLESALE SALES ~~FOR RESALE~~

MUNICIPALITIES (SUPPLEMENTAL POWER ACCOUNTS 400.1-81, 400.2-81, and 400.3-81) - directly assigned to FERC jurisdiction and group as billed.

NONASSOCIATED UTILITIES, COOPERATIVES AND

OTHER PUBLIC AUTHORITIES

~~These sales are split between those that represent buy/sell transactions and those that are sales from OTP generation based on a percentage provided by System Operations Department.~~ The revenues from ~~the buy/sell portion are allocated on the Transmission Demand Factor (D2) since it is our transmission system that makes these transactions possible.~~

~~The revenues from the remaining portion are~~ asset-based sales are classified as base demand, peak demand, base energy, and peak energy as follows:

1. All revenues from these sales, except those considered Participation or Peaking Power, are classified as Base Energy.
2. Demand charges for Peaking sales are classified as Peak Demand.
3. Demand charges for Participation Power sales are classified as follows:

~~$ of Peak Demand = MAPP Schedule H (peaking) rate ($/MW/Mo.) x capacity of the sale (MW) x number of months of the sale.~~

~~$ of Base Demand = Total Demand charges - $ of Peak Demand.~~

~~4.~~ ______$ of Peak Demand = Market price ($/MW/Mo.) × capacity of the sale (MW)

______$ of Base Demand = Total Demand charges − $ of Peak Demand.

4. Energy charges for Participation Power sales are classified Base Energy.
5. Energy charges for Peaking Power sales are classified Peak Energy.

The jurisdictional allocations were then made as follows:

BASE DEMAND - Energy Factor (E1)

PEAK DEMAND - Generation Demand Factor (D1)

BASE ENERGY - Energy Factor (E2)

PEAK ENERGY - Generation Demand Factor (D1)

<u>OTHER ELECTRIC REVENUE</u>

ACCOUNT 450 (FORFEITED DISCOUNTS) - directly assigned to jurisdictions as collected. Allocated to classes (if required) based on Total Customers Factor (C1).

ACCOUNT 451 (CONNECTION FEES) - directly assigned to jurisdictions as collected. Allocated to classes (if required) based on Total Customers Factor (C1).

ACCOUNT 456.5 (WHEELING) - directly assigned to FERC groups as collected.

ACCOUNT 456.7 (RESIDENTIAL CONSERVATION SERVICE) - directly assigned to jurisdictions. Allocated to classes based on ~~Total Customers~~<u>E8760 (Energy</u> Factor~~(C1)~~).

ALL OTHER ACCOUNTS - allocated using total net plant in service ratios.

<u>EXPENSE COMPONENTS</u>

<u>PRODUCTION EXPENSES</u>

The expenses within this function, except those in Account 555, were classified into PRELIMINARY demand and energy categories as follows:

1. STEAM AND HYDRO (SH) DEMAND - this category includes all expenses in Accounts 500, 502-511, 535-543, and 556.
2. INTERNAL COMBUSTION (IC) DEMAND - this category includes all expenses in Accounts 546-554, except Account 547.
3. BASE ENERGY - includes Accounts 501, 512, 513, 514, 544, and 545.
4. PEAK ENERGY - includes Account 547.

The two demand categories (SH and IC) were then reclassified into BASE and PEAK Demand categories using the same methodology and formulas applied to those categories in Production Plant in Service.

The expenses in Account 555 (Purchased Power) are classified ~~as follows:~~

~~1. Account 555.2 (cost of non-contractual sales) expenses are split between those that represent buy/sell transactions and those that are for OTP's system use based on a percentage provided by System Operations Department. The expenses from the buy/sell portion are allocated on the Transmission Demand Factor (D2) since it is our transmission system that makes these transactions possible.~~

~~2. All remaining expenses in A/C 555 are classified~~ into base and peak demand and energy based on the following:

A. All expenses, except those for purchases labeled Participation or Peaking Power, were classified as Base Energy.

B. Demand charges for Peaking Power were classified as Peak Demand.

C. Demand Charges for Participation Power (including co-generators and shared customers) were classified as follows:

$$\begin{aligned}\$ \text{ of Peak Demand} &= \text{MAPP Schedule H (peaking) rate (\$/MW/Mo.)}\\ &\quad \times \text{capacity of the purchase (MW)}\\ &\quad \times \text{number of months purchased.}\end{aligned}$$

$$\$ \text{ of Base Demand} = \text{Total Demand Charges} - \$ \text{ of Peak Demand.}$$

D. Energy charges for Participation Power were classified as Base Energy.

E. Energy charges for Peaking Power were classified as Peak Energy.

The jurisdictional allocations were then made as follows:

BASE DEMAND - Energy Factor (E1)

PEAK DEMAND - Generation Demand Factor (D1)

BASE ENERGY - Energy Factor (E2)

PEAK ENERGY - Generation Demand Factor (D1)

TRANSMISSION EXPENSES

Allocated using the Transmission Demand Factor (D2).

DISTRIBUTION EXPENSES

The expenses within this function were classified into the following categories:

1. Primary Demand (2400 volts and above)
2. Secondary Demand (below 2400 volts)

3. Primary Customer (2400 volts and above)
4. Secondary Customer (below 2400 volts)
5. Streetlights
6. Area Lights
7. Meters
8. Load Management

Based on the following account-by-account methodology:

OPERATION

ACCOUNT 580 (SUPERVISION AND ENGINEERING) - classified based on classification of Accounts 582-588.

ACCOUNT 582 (STATION EXPENSE) - classified based on classification of related plant in service Account 362.

ACCOUNT 583 (OVERHEAD LINE EXPENSE) - classified based on the classification of related plant in service Accounts 364, 365, 368 and 369.

ACCOUNT 584 (UNDERGROUND LINE EXPENSE) - classified based on the classification of related plant in service Accounts 366, 367, and 369.1.

ACCOUNT 585 (STREETLIGHTING EXPENSE) - classified directly as streetlighting.

ACCOUNTS 586.1-586.5 & 586.9 (METER EXPENSES) - classified directly as meters.

ACCOUNTS 586.6-586.7 (METER EXPENSES) - classified directly as load management.

ACCOUNT 587 (CUSTOMER INSTALLATION EXPENSE) - classified secondary customer.

ACCOUNT 588 (MISCELLANEOUS EXPENSE) - classified based on classification of Accounts 582-587.

ACCOUNT 589 (RENTS) - classified based on classification of related plant in service Account 364.

MAINTENANCE

ACCOUNT 590 (SUPERVISION AND ENGINEERING) - classified based on classification of Accounts 592-596.

ACCOUNT 592 (STATION EQUIPMENT) - classified based on classification of related plant in service Account 362.

ACCOUNT 593 (OVERHEAD LINES) - classified based on classification of related plant in service Accounts 364, 365, and 369.

ACCOUNT 594 (UNDERGROUND LINES) - classified based on classification of related plant in service Accounts 366, 367, and 369.1.

ACCOUNT 595 (LINE TRANSFORMERS) - classified based on classification of related plant in service

Account 368.

ACCOUNT 596 (STREETLIGHTING) - classified directly to streetlighting.

ACCOUNTS 597.1-597.2 (METERS) - classified directly to meters.

ACCOUNT 597.3 (METERS) - classified directly to load management.

ACCOUNT 598 (MISCELLANEOUS DISTRIBUTION PLANT) - classified based on classification of Accounts 592-597.

Each category was then allocated based on the following:

PRIMARY DEMAND - Distribution Primary Demand Factor (D3).

SECONDARY DEMAND - Distribution Secondary Demand Factor (D4).

PRIMARY CUSTOMER - Total Distribution Service Locations Factor (C2).

SECONDARY CUSTOMER - Total Secondary Distribution Service Locations Factor (C3).

STREETLIGHTING - Streetlight Factor (C4).

AREA LIGHTING - Area Light Factor (C5).

METERS - Meter Factor (C6).

LOAD MANAGEMENT - Load Management Factor (C9).

CUSTOMER ACCOUNTING AND COLLECTING EXPENSES

Expenses in this function were classified into two categories:

1. Meter Reading
2. Other Expenses

as specified by the following:

ACCOUNT 901 (SUPERVISION) - classified based on classification of Accounts 902-905.

ACCOUNT 902 (METER READING EXPENSE) - classified meter reading.

ACCOUNT 903 (CUSTOMER RECORDS AND COLLECTIONS) - classified other expense.

ACCOUNT 904 (UNCOLLECTIBLE ACCOUNTS) - classified other expense.

ACCOUNT 905 (MISCELLANEOUS CUSTOMER ACCOUNTING EXPENSES) - classified other expense.

The METER READING category was allocated using the Meter Reading Factor (C7) and the OTHER EXPENSES category using the Total System Service Locations Factor (C8).

CUSTOMER SERVICE AND INFORMATION EXPENSES

Conservation related programs and promotional rebates are directly assigned to jurisdiction and then allocated to class based on ~~Total Customer~~E8760 (Energy Factor~~(C1).~~). All other Customer Service and Information Expenses are allocated based on Total Customer Factor (C1).

SALES EXPENSES

~~Off Peak~~Economic Development ~~and New Load Development are~~is directly assigned to jurisdiction and then allocated to class based on Total Customer Factor (C1). Account 913, Advertising, is assigned below the line. All other Sales Expenses are allocated based on Total Customer Factor (C1).

ADMINISTRATIVE AND GENERAL EXPENSES

ACCOUNTS 920 (SALARIES), 921 (SUPPLIES, ETC.), AND 926 (PENSIONS AND BENEFITS) - these accounts functionalized as: Production, Transmission, Distribution, Customer Accounting or Customer Service, based on FERC labor ratios (FERC Form No. 1, Page 354, or comparable data for a forecast year). Functional categories were then allocated using the expense ratios from the related expense functions, except that in the Production category the energy-related expenses and buy/sell transactions were not included in the ratios. (Energy-related expenses and buy/sell transactions are excluded because they are mainly purchased fuel which requires a minimum of company labor.)

ACCOUNT 923 (OUTSIDE SERVICES) - allocated based on total net plant in service ratios.

ACCOUNTS 924 (PROPERTY INSURANCE) and 925 (INJURIES & DAMAGES) - were allocated based on the total net plant in service ratios.

ACCOUNTS 928 (REGULATORY COMMISSION EXPENSES) - directly assigned to each jurisdiction. Allocated to classes or groups based on total electric revenues from each class or group.

ACCOUNT 930.1 (GENERAL ADVERTISING) -– The majority of this account is assigned below the line. Any remaining amount is allocated based on Total Customers Factor (C1).

ACCOUNTS 930.2 (MISCELLANEOUS), 931 (RENTS), and 935.1-935.5 & 935.9 (MAINTENANCE) - allocated based on the gross general plant in service ratios.

ACCOUNT 935.6 (MAINTENANCE) - directly assigned to load management and allocated on (C9).

DEPRECIATION EXPENSES

PRODUCTION - Classification and allocation procedure is the same as that used for Production Plant in Service.

TRANSMISSION - Allocated ~~to classes or groups~~ based on gross plant in service ratios developed from the Transmission Plant in Service function.

DISTRIBUTION - Allocated ~~to classes or groups~~ based on gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - Allocated ~~to classes or groups~~ based on gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - Allocated using the gross plant in service ratios developed from the Intangible Plant in Service function.

BIG STONE PLANT CAPITALIZED ITEMS EXPENSES

Directly assigned to each jurisdiction. Allocated to classes or groups based on the gross Production Plant in Service ratio.

OTHER EXPENSE - SPIRITWOOD AMORTIZATION

Directly assigned to each jurisdiction. Allocated to customer class using the gross Production Plant in Service ratio.

GENERAL TAXES

Allocated using total net plant in service ratios.

DEFERRED INCOME TAXES

Allocated using total net plant in service ratios.

INVESTMENT TAX CREDIT

Allocated using total gross plant in service ratios.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (~~AFDC~~AFUDC)

Allocated based on long-term construction work in progress ratios.

INCOME TAXES

Income taxes are calculated for each jurisdiction separately.

APPENDIX A-1

DETERMINATION OF THE DEMAND & CUSTOMER COMPONENTS OF THE DISTRIBUTION SYSTEM

The customer component of the distribution system, that portion which varies with the number of customers, was determined by applying the minimum size system method. This method involves determining the minimum size unit currently being installed and using the average installed book cost of that unit to determine the customer component. However, our accounting system is such that, except for Account 368 (transformers), the only average installed book cost available is for all the units in an account regardless of size. To circumvent this problem, the following procedures were used:

1. The Electric Distribution (ED) Department specified what the minimum size unit for each account is and then provided information as to the type and quantity of material included in this unit and the amount of labor necessary to install it.
2. For each account that a customer component is required, the average age of the account was determined by using results of the recently completed depreciation study. This age is then subtracted from the study year to determine in what year the average unit was installed.
3. The average installed cost of the minimum size unit for the year indicated above was then determined. This was done by developing material, labor, transportation, and payroll costs for the year this unit was installed and applying them to the information supplied in No. 1, above.

The following pages describe how the dollars in each account were assigned to the various categories of cost using the data developed above and other figures from the various accounts.

Symbol Legend:

PSL = Poles for Streetlights

DSL = Dollars allocated to Streetlighting

DAL = Dollars allocated to Area Lighting

DPCC = Dollars allocated to Primary Customer Category

DPDC = Dollars allocated to Primary Demand Category

DSCC = Dollars allocated to Secondary Customer Category

DSDC = Dollars allocated to Secondary Demand Category

UPD = Units of Primary Distribution

USD = Units of Secondary Distribution

Account 364 (Poles): (All poles considered primary)

A. Average age of a pole.
B. Minimum size pole.
C. Installed cost of the minimum size pole of the age in "A."
D. Number of streetlights on separate poles. (Based on sample survey by Engineering Services.)
E. Number of area lights on separate poles. (Based on sample survey by Engineering Services.)
F. Number of poles in Account 364.
G. Total dollars in Account 364.

Dollar Allocations for Account 364

To Streetlighting $= \mathrm{D} \times \mathrm{C}^* = \mathrm{DSL}$

To Area Lighting $= \mathrm{E} \times \mathrm{C}^* = \mathrm{DAL}$

Customer Component $= (\mathrm{F} - \mathrm{D} - \mathrm{E}) \times \mathrm{C} = \mathrm{DPCC}$

Demand Component $= \mathrm{DSL} - \mathrm{DAL} - \mathrm{DPCC} = \mathrm{DPDC}$

*Cost of a minimum size pole was used because most streetlights are mounted on minimum size poles and those that are on larger poles are mounted on poles that do not have the usual framing (crossarms, etc.).

Account 365 (Overhead Conductor and Devices):

I. Primary

A. Average age of primary conductor.
B. Minimum size primary unit.
C. Average installed cost of a minimum size primary unit of the age in "A."
D. Average number of poles in a minimum size unit of primary conductor. (Estimated by ED Department.)
E. Total dollars in Account 365 considered primary (see note).
F. Total number of poles used for primary distribution. (Number of poles in Account 364 - Number of poles allocated to streetlighting and area lighting.)

~~Number of units of primary distribution = UPD =~~ $\cancel{\frac{F}{D} - 1}$

$$\text{Number of units of primary distribution} = \text{UPD} = \frac{\text{F}}{\text{D1}}$$

Dollar Allocations for Account 365 Primary

Customer Component $= \text{C} \times \text{UPD} = \text{DPCC}$

Demand Component $= \text{E} - \text{DPCC} = \text{DPDC}$

NOTE: All bare copper, aluminum, ACSR and iron wire are primary. 30% of WP copper, 80% of WP aluminum and 50% of the steel wire are primary. (Estimated by ED Department - exact percentages very difficult to determine.) All miscellaneous conductor and other equipment are primary.

II. Secondary

A. Average age of secondary conductor.
B. Minimum size secondary unit.
C. Average installed cost of a minimum size unit of the age in "A."
D. Number of units of secondary conductor (see note).
E. Total dollars in Account 365 considered secondary. (All conductor not primary - see primary section.)
F. Dollar value of duplex conductor in Account 365. (Duplex assumed to be used entirely for street and area lights.)
G. Percent of total number of lighting units (street and area lights) that are streetlights.

Dollar Allocations for Account 365 Secondary

To Streetlighting $= \text{F} \times \text{G} = \text{DSL}$

To Area Lighting $= \text{F} - \text{DSL} = \text{DAL}$

Customer Component $= \text{C} \times \text{D} = \text{DSCC}$

Demand Component $= \text{E} - \text{F} - \text{DSCC} = \text{DSDC}$

NOTE: Estimated by ED Department based on 250' of secondary for each five urban residential cottages, and urban commercial customers, 3,360' of secondary per unit.

Account 366 (Underground Conduit):

The percentages developed from the allocation of Account 367 will be applied to this account.

Account 367 (Underground Conductor and Devices):

I. Primary

A. Average age of primary unit.

B. Minimum size primary unit.

C. Average installed cost of a minimum size primary unit of the age in "A."

D. Number of feet of conductor in the minimum size primary unit.

E. Total dollars in Account 367 considered primary. (All conductor rated 5 kV and above, and all nonconductor items are considered primary.)

F. Total number of feet of primary conductor in Account 367.

~~Number of units of primary distribution = UPD =~~ $\cancel{\frac{F}{D}2}$

$$\text{Number of units of primary distribution} = \text{UPD} = \frac{\text{F}}{\text{D2}}$$

Dollar Allocations for Account 367 Primary

Customer Component = C × UPD = DPCC

Demand Component = E − DPCC = DPDC

II. Secondary

A. Average age of secondary unit.

B. Minimum size of secondary unit.

C. Average installed cost of a minimum size secondary unit of the age in "A."

D. Number of feet of conductor in the minimum size secondary unit.

E. Total dollars in Account 367 considered secondary. (All conductor rated 600 volts or less is secondary.)

F. Total number of feet of secondary conductor in Account 367 (see note).

G. Dollar value of duplex conductor in Account 367 (duplex conductor is assumed to be used entirely for street and area lights).

H. Percent of total number of lighting units (street and area lights) that is streetlights.

~~Number of units of secondary distribution = USD = $\frac{F}{D}$3~~

Number of units of secondary distribution $= \text{USD} = \frac{\text{F}}{\text{D3}}$

<u>Dollar Allocations for Account 367 Secondary</u>

To Streetlighting $= \text{G} \times \text{H} = \text{DSL}$

To Area Lighting $= \text{G} - \text{DSL} = \text{DAL}$

Customer Component $= \text{C} \times \text{USD} = \text{DSCC}$

Demand Component $= \text{E} - \text{G} - \text{DSCC} = \text{DSDC}$

NOTE: Includes all quadruplex and triplex cable and 1/3 of 600 volt single wire. (Duplex is for lighting only.)

<u>Account 368 (Transformers):</u> (All transformers classified secondary)

A. Average installed cost of minimum size 2400 V. overhead unit.*
B. Average installed cost of minimum size 7200 V. overhead unit.*
C. Average installed cost of minimum size 14400 V. overhead unit.*
D. Average installed cost of minimum size 2400 V. underground unit.*
E. Average installed cost of minimum size 7200 V. underground unit.*
F. Number of 2400 V. overhead units in the account.
G. Number of 7200 V. overhead units in the account.
H. Number of 14400 V. overhead units in the account.

*Overhead unit cost includes cost of appropriate cutout and arrester.

I. Number of 2400 V. underground units in the account.
J. Number of 7200 V. underground units in the account.
K. Total dollar value of Account 368.

<u>Dollar Allocations for Account 368</u>

Customer Component $= (\text{A} \times \text{F}) + (\text{B} \times \text{G}) + (\text{C} \times \text{H}) + (\text{D} \times \text{I}) + (\text{E} \times \text{J}) = \text{DSCC}$

Demand Component $= \text{K} - \text{DSCC} = \text{DSDC}$

Account 369 (Overhead Services): (All services classified secondary)

A. Average age of a service.
B. Minimum size of a service.
C. Average installed cost of a minimum size service of the age in "A."
D. Total number of 3 and 4 services.
E. Dollar value of two-wire services (two-wire services are considered all customer component).
F. Total dollar value of Account 369.

Dollar Allocations for Account 369

Customer Component $= (C \times D) + E = DSCC$

Demand Component $= F - DSCC = DSDC$

Account 369.1 (Underground Services): (All services classified secondary)

A. Average age of an underground service.
B. Minimum size of an underground service.
C. Average installed cost of a minimum size three-wire service of the age in "A."
D. Total number of services in Account 369.1.
E. Total dollar value of Account 369.1.

Dollar Allocations for Account 369.1

Customer Component $= (C \times D) = DSCC$

Demand Component $= E - DSCC = DSDC$

Forecast Cost Allocation Factors Manual

Supplement to Otter Tail Power Company's Cost Allocation Procedure Manual

This Supplement describes the general processes used to develop forecasted demand, energy and customer cost allocation factors outlined in Otter Tail Power Company's Cost Allocation Procedures Manual.

Introduction:

Otter Tail Power Company ("OTP") operates as a single electrical system to serve customers in three states (Regulatory jurisdictions) – Minnesota, North Dakota, and South Dakota. OTP is subject to the statutes, rules and regulations that dictate the operation of a publicly owned electric utility within each state. Rates are state specific and subject to approval by the respective state's regulatory Commission.

OTP generally accounts for its costs (investment and expense) on a system basis. To determine a particular state's share of its cost of service, the company applies allocation factors to its system costs to further assign those costs to each jurisdiction. The current process OTP uses to allocate its costs is documented in OTP's Cost Allocation Procedure Manual ("CAPM").

Historically, OTP's general rate cases were based on cost of service studies that were developed using a historic test year. The associated cost allocation factors were based on historical information using a single annual coincident peak ("1 CP") for OTP's system. The current CAPM has been previously approved by each state, in OTP's most recent rate case within each state. Maintaining a consistent cost allocation process between jurisdictions is important. Using the same cost allocation methodology in all jurisdictions helps minimize the potential for material over or under-recovery of costs across jurisdictions that might occur if different cost allocation methodologies were used in each state.

In future rate cases, OTP will be using a forecast test year in Minnesota and North Dakota. This supplement to Otter Tail's Cost Allocation Procedures Manual, describes in general terms, the methodologies used to compute the forecast cost allocation factors to be used in a forecast test year.

Summary of Cost Allocation Factors:

OTP has 16 different demand, energy and customer allocation factors that are used to allocate costs within the jurisdictional cost of service study. As noted earlier, these same factors are used across all three jurisdictions OTP serves. Below is a summary of the 16 allocation factors as outlined in the CAPM:

1. <u>GENERATION DEMAND FACTOR (D1)</u>
2. <u>TRANSMISSION DEMAND FACTOR (D2)</u>
3. <u>DISTRIBUTION PRIMARY DEMAND FACTOR (D3)</u>
4. <u>DISTRIBUTION SECONDARY DEMAND FACTOR (D4)</u>
5. <u>ENERGY FACTOR (E1)</u>
6. <u>ENERGY FACTOR (E2)</u>
7. <u>ENERGY FACTOR (E8760)</u> (Class allocations only – MN & ND)
8. <u>TOTAL RETAIL CUSTOMERS FACTOR (C1)</u>
9. <u>TOTAL DISTRIBUTION SERVICE LOCATIONS FACTOR (C2</u>
10. <u>TOTAL SECONDARY DISTRIBUTION SERVICE LOCATIONS FACTOR (C3)</u>
11. <u>STREETLIGHT FACTOR (C4)</u>

12. <u>AREA LIGHT FACTOR (C5)</u>
13. <u>METER FACTOR (C6)</u>
14. <u>METER READING FACTOR (C7)</u>
15. <u>TOTAL SYSTEM SERVICE LOCATIONS FACTOR (C8)</u>
16. <u>LOAD MANAGEMENT FACTOR (C9)</u>

The rest of this document describes each allocation factor, (as described in the current CAPM) and the related methodology used to develop the forecast of that factor. In some explanations contained below related to the computations of D and E factors, references are made to manually forecasted customers. In some jurisdictions, certain customers are manually forecasted, exclusive from forecasts developed for all other customers. In most cases, these customers are forecasted separately due to size or certain operational characteristics. When the explanation specifically refers to manually forecasted customers, the explanation will specifically state "manually forecasted customers". All other references to forecasted data will refer to all other customers exclusive of the manually forecasted ones.

Forecast Allocation Factors Methodology:

1. **<u>GENERATION DEMAND FACTOR (D1)</u>** - This factor is determined based on contribution to Otter Tail's average annual six-hour system peak kW demand. Any loads for which Otter Tail is responsible for providing generation are included in this factor. The hours ending 9:00, 10:00, and 11:00 a.m., and 6:00, 7:00, and 8:00 p.m. were averaged to arrive at the Generation Demand Factor.

   Forecast Methodology for D1: The Forecasted D1 factors are computed using a 4 step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

   a. Compute customers demand
   b. Compute manually forecasted customers demand
   c. Compute FERC demand
   d. Compute total forecasted D1 Factors

   a. <u>Compute customers demand</u>: First, the historical allocation factors are re-computed excluding the manually forecasted customers. Next, annual Generation Demand (D1) and the Energy at the generation level (E2) factors are compiled in a spreadsheet, for the last five years. A Demand/Energy ratio is then computed for each customer class and state for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2 excluding the manually forecasted customers) to compute the Forecasted Generation Demand (Forecasted D1).

b. <u>Compute manually forecasted customers demand</u>: Manually forecasted customers demand is determined. In some cases, a fixed baseline demand agreed on by OTP and the customer is the level of demand used for those customers in the forecast.

c. <u>Compute FERC demand</u>: The FERC D1 factors are calculated by computing the average historical five year D1 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.

d. <u>Compute total forecasted D1 Factors</u>: The manually forecasted demand is added to the corresponding forecasted demand for all other customers. Total demand by class is combined within each jurisdiction to determine each jurisdiction's total demand. Total system demand is the sum of the jurisdictional demands. The jurisdictional Generation Demand (D1) allocator is based on each jurisdiction's share of the total system demand.

2. **<u>TRANSMISSION DEMAND FACTOR (D2)</u>** - this factor is determined based on contribution to Otter Tail's average annual six-hour transmission peak kW demand. Any loads for which Otter Tail is responsible for providing transmission service are included in this factor. The hours used are the same as those for the Generation Demand Factor.

Forecast Methodology for D2: The Forecasted D2 factors are computed using a 4 step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

a. Compute forecasted customers demand
b. Compute manually forecasted customer Demand
c. Compute FERC demand
d. Compute total forecasted D2 Factors

a. <u>Compute forecasted customers demand</u>: First, the historical allocation factors for the previous five years are re-computed excluding the manually forecasted customers. Next, the annual transmission Demand (D2) and the Energy at the generation level (E2) are compiled in a spreadsheet, for the last five years. A Demand/Energy ratio is then computed for each customer class and jurisdiction for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2 excluding the manually forecasted customers), to compute the non-manually Forecasted Transmission Demand (Forecasted D2).

b. Compute manually forecasted customer Demand: Manually forecasted customers demand is determined. In some cases, a fixed baseline demand agreed on by OTP and the customer is the level of demand used for those customers in the forecast.

c. Compute FERC demand: The FERC D2 factors are calculated by computing the average historical five year D2 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.

d. Compute total forecasted D2 Factors: The manually forecasted demand is added to the corresponding demand from all other customers. Total demand by class is combined within each jurisdiction to determine each jurisdiction's total demand. Total system demand is the sum of the jurisdictional demands. The jurisdictional demand (D2) allocator is based on the jurisdiction's share of the total system demand.

3. **DISTRIBUTION PRIMARY DEMAND FACTOR (D3)** - this factor is determined based on contributions to Otter Tail's average annual six-hour primary distribution peak kW demand minus the 0.83 kW/customer already included in the minimum system portion of the primary customer component. (See Appendix A-1.) Any loads for which Otter Tail is responsible for providing primary distribution service are included in this factor. The hours used are the same as those for the Generation Demand Factor.

Forecast Methodology for D3: The Forecasted D3 factors are computed using a 3 step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

a. Compute non-FERC demand
b. Compute the FERC demand
c. Compute total forecasted D3 Factors

a. Compute non-FERC demand: First, historical allocation factors for the previous five years are re-computed. Next, each year's Distribution Primary Demand (D3) and the Energy at the generation level (E2) are compiled in a spreadsheet, for the previous five years, and a Demand/Energy ratio is computed for each class and jurisdiction for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2) to compute the

Distribution Primary Demand (Forecasted D3).

b. Compute the FERC demand: The FERC D3 factors are calculated by computing the average historical five year D3 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.

c. Compute total forecasted D3 Factors: The non-FERC forecasted demand is added to the corresponding FERC forecasted demand. The entire system is summed up by class and the jurisdictional total is divided by the total system to get the Forecasted Distribution Primary Demand (D3) allocation factor.

4. **DISTRIBUTION SECONDARY DEMAND FACTOR (D4)** - this factor is determined based on non-coincident kW demands at the secondary service level minus the 3.0 kW/customer already included in the minimum system portion of the secondary customer component. (See Appendix A-1.) Only loads served at voltages less than 2400 volts are included in this factor.

Forecast Methodology for D4: The Forecasted D4 factors are computed using a 3 step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

a. Compute non-FERC demand
b. Compute the FERC demand
c. Compute total forecasted D4 Factors

a. Compute non-FERC demand: The historical allocation factors are re-computed for the prior five year's Distribution Secondary Demand (D4) and the Energy at the generation level (E2) factors. These factors are compiled in a spreadsheet and a Demand/Energy ratio is computed for each class and state for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2) to compute the non-manually forecast Distribution Secondary Demand factor. (Forecasted D4).

b. Compute the FERC demand: The FERC D4 factors are calculated by finding the average historical five year D4 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.

c. Compute total forecasted D4 Factors: The non-FERC forecasted demand is added to the corresponding FERC demand. The entire system is summed up by class and the jurisdictional total is divided by the total system to get the Forecasted Distribution Secondary Demand (D4) allocation factor.

5. **<u>ENERGY FACTOR (E1)</u>** - this factor is based on kilowatt-hour (kWh) sales adjusted for line losses to the generation level excluding interruptible, irrigation, and $^{14}/_{24}$ths of water heating and deferred sales.

Forecast Methodology for E1: The Forecasted E1 factors are computed using a 4 step process:

a. Compute Energy at the meter level
b. Compute Energy at the generation level excluding interruptible, irrigation, and $^{14}/_{24}$ths of water heating and deferred sales
c. Compute FERC Energy
d. Compute total forecasted E1 Factors

a. <u>Compute Energy at the meter level</u>: The annual kWh Sales forecast at the rate group level is the initial dataset for developing this factor. Where applicable, the kWh energy forecast from manually forecasted customers are added to the appropriate rate group to calculate total energy sales at the meter by rate group.

b. <u>Compute Energy at the generation level excluding interruptible, irrigation, and $^{14}/_{24}$ths of water heating and deferred sales</u>: The meter level kWh energy forecast at the rate group level above is converted to MWhs. The forecast amounts are then multiplied by the loss factor applicable for each respective rate group level forecast to arrive at the generation level energy forecast for each state. Interruptible and irrigation rates are excluded, and water heating and deferred rates energy is multiplied by $^{10}/_{24}$ths (excluding $^{14}/_{24}$ths).

c. <u>Compute FERC Energy</u>: The FERC E1 Energy is calculated by summing up the 3 states E1 total for each forecasted year and multiplying that by the 5 year average of the historical FERC E1 factors.

d. <u>Compute total forecasted E1 Factors</u>: The generation level energy less interruptible, irrigation, and $^{14}/_{24}$ths of water heating and deferred energy is then summed by class (manually forecasted customers are summed with their appropriate class) and state for each year to reach the system level energy. Then each jurisdictional total is divided by the system total to get the forecasted Energy Factor (E1).

6. **<u>ENERGY FACTOR (E2)</u>** - this factor is based on total kWh sales adjusted for line losses to the generation level. It is only used for jurisdictional allocations.

   Forecast Methodology for E2: The Forecasted E2 factors are computed using a 4 step process:

   a. Compute Energy at the meter level
   b. Compute Energy at the generation level
   c. Compute FERC Energy
   d. Compute total forecasted E2 Factors

   a. <u>Compute Energy at the meter level</u>: The annual kWh Sales forecast at the rate group level is the initial dataset for developing this factor. Where applicable, the kWh energy forecast from manually forecasted customers are added to the appropriate rate group to calculate total energy sales at the meter by rate group.
   b. <u>Compute Energy at the generation level</u>: The meter level kWh energy forecast at the rate group level above is converted to MWhs. The forecast amounts are then multiplied by the loss factor applicable for each respective rate group level forecast to arrive at the generation level energy forecast for each state.
   c. <u>Compute FERC Energy</u>: The FERC E2 Energy is calculated by summing up the 3 states E2 total for each forecasted year and multiplying the state energy forecasts by the 5 year average of the historical FERC E2 factors.
   d. <u>Compute total forecasted E2 Factors</u>: The generation level energy forecast by rate group is then summed to a class level, state level and system level (manually forecasted customers are added to the appropriate class and state) for each year. Each jurisdictional total is divided by the system total to get the respective jurisdictional Energy Factors (E2).

7. **<u>ENERGY FACTOR (E8760)</u>** - This factor is based on hourly energy usage, to which are applied hourly marginal costs to develop an hourly cost relationship. **<u>This factor is only used to allocate jurisdictional amounts to the customer classes in Minnesota and North Dakota.</u>**

   General Note on E8760 Factors: The E8760[1] factors are developed in a manner upon which

[1] In a leap year, calculations would be made using 8784 hours.

marginal energy prices are applied to energy usage which is comparable to the energy usage levels that included in the determination of the E1 and E2 factors. For example, the E8760 factor which replaces the E1 factor, excludes similar controllable or interruptible loads and irrigation, like the E1 factor does. As a result, there are two E8760 factors that are developed; one that mirrors the energy usage of all customers reflected in the E1 factor and one that mirrors the energy usage and customers reflected in the E2 factor. The two factors are identified as E1-E8760 and E2-E8760.

Forecast Methodology for E1-E8760: Forecasted E1-E8760 allocation factors are developed using a 4 step process.

a. Develop customer load profiles
b. Apply load profiles to forecast sales and scale to generation levels
c. Apply hourly energy costs to forecasted hourly sales
d. Compute E1-E8760 factor excluding controllable load and irrigation

a. <u>Develop customer load profiles:</u> Annual hourly kWh load survey data[2] is gathered for each customer load research group (which includes manually forecast customer data). Based on the annual hourly load research data, hourly "profiles" are developed by customer group as the basis to shape forecasted kWhs across all 8760 hours of the forecast year. Multiple profiles are developed based on applicable customer types.

b. <u>Apply load profiles to forecast sales and scale to generation levels:</u> Each month's hourly load shape developed in step a. is applied to the corresponding monthly kWh sales forecast for the respective customer group to distribute those sales across the hours of the month. This process applied to all twelve months of the year yields the distribution of the forecasted sales across all 8760 hours of the year. Within this step of the process, the forecast kWh sales are also calibrated to account for losses, which vary depending on customer type and service voltage level. The end result of this step is forecasted generation level kWh sales by customer class for all 8760 hours of the year.

c. <u>Apply hourly energy costs to hourly energy sales:</u> Forecasted hourly marginal energy costs are multiplied against the forecasted hourly kWh sales developed in the prior step to compute total annual marginal revenues.

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[2] OTP's load research by customer type is conducted on a system basis.

d. Compute E8760 Factors: excluding Controllable load and irrigation: To compute the E1-E8760 allocation factors, the marginal energy costs computed in step c. are aggregated to the class level. The class's marginal energy revenues are divided by the total jurisdictional marginal energy revenues to determine each class's allocation factor (percentage). The resultant set of factors (percentages) are converted back to equivalent kWhs by class and used in place of the E2 factor cost allocation in the class cost of service study. Customers who are excluded from the calculation of the E1 factors are excluded from the calculation of the E1-E8760 factors (interruptible, irrigation, and 14/24 ths of water heating and deferred sales).

Forecast Methodology for E2-E8760: Forecasted E2-8760 allocation factors are developed using a 4 step process.

a. Develop customer load profiles
b. Apply load profiles to forecast sales and scale to generation levels
c. Apply hourly energy costs to forecasted hourly sales
d. Compute E2-E8760 Factor

a. Develop customer load profiles: Annual hourly kWh load survey data[3] is gathered for each customer load research group (which includes manually forecast customer data). Based on the annual hourly load research data, hourly "profiles" are developed by customer group upon which to use to shape forecasted kWhs across all 8760 hours of the forecast year. Multiple profiles are developed based on applicable customer types.

b. Apply load profiles to forecast sales and scale to generation levels: Each month's hourly load shape developed in step a. is applied to the corresponding monthly kWh sales forecast for the respective customer group to distribute those sales across the hours of the month. This process applied to all twelve months of the year yields the distribution of the forecasted sales across all 8760 hours of the year. Within this step of the process, the forecast kWh sales are also calibrated to account for losses, which vary depending on customer type and service voltage level. The end result of this step is forecasted generation level kWh sales by customer class for all 8760 hours of the year.

[3] OTP's load research by customer type is conducted on a system basis.

c. Apply hourly energy costs to hourly energy sales: Forecasted hourly marginal energy costs are multiplied against the forecasted hourly kWh sales developed in the prior step to compute total annual marginal revenues.

d. Compute E8760 Factors: To compute the E2-E8760 allocation factors, the marginal energy costs computed in step c. are aggregated to the class level. The class's marginal energy revenues are divided by the total jurisdictional marginal energy revenues to determine each class's allocation factor (percentage). The resultant set of factors (percentages) are converted back to equivalent kWhs by class and used in place of the E2 factor cost allocation in the class cost of service study.

8. **TOTAL RETAIL CUSTOMERS FACTOR (C1)** - this factor is based on the total active retail customers served in each jurisdiction.

Forecast Methodology for C1: The Forecasted C1 factors are computed using a 4 step process:

a. Compute historical C1 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Compute Forecasted C1 factors

a. Compute historical C1 values: The historical C1 factors are computed.
b. Compute Class Growth factor: Customer growth Factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.
c. Compute the FERC values: Remain the same as the most recent historical year.
d. Compute Forecasted C1 factors: To compute forecasted C1 values for each year, the prior year's C1 values are multiplied by the growth factor. The C1 values are summed by state/FERC and system. Each jurisdictional total is divided by the system total to yield the forecasted C1 Factor.

9. **TOTAL DISTRIBUTION SERVICE LOCATIONS FACTOR (C2)** – a distribution service location is any point on the distribution system at which service is or can be provided including inactive and seasonal locations.

Forecast Methodology for C2: The Forecasted C2 factors are computed using a 4 step process:

a. Compute historical C2 values

b. Compute Class Growth factor

c. Compute the FERC values

d. Compute Forecasted C2 factors

a. Compute historical C2 values: The historical C2 factors are computed.

b. Compute Class Growth factor: Customer growth factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.

c. Compute the FERC values: Remain the same as the most recent historical year

d. Compute Forecasted C2 factors: To compute forecasted C2 values for each year, the prior year's C2 values are multiplied by the growth factor. The C2 values are summed by jurisdiction and system. Each jurisdictional total is divided by the system total to yield the jurisdictional forecasted C2 factor.

10. **TOTAL SECONDARY DISTRIBUTION SERVICE LOCATIONS FACTOR (C3)** - this factor includes only those distribution service locations served or which can be served at secondary voltage (below 2400 volts).

Forecast Methodology for C3: The Forecasted C3 factors are computed using a 4 step process:

a. Compute historical C3 values

b. Compute Class Growth factor

c. Compute the FERC values

d. Compute Forecasted C3 factors

a. Compute historical C3 values: The historical C3 factors are computed.

b. Compute Class Growth factor: Customer growth factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.

c. Compute the FERC values: Remain the same as the most recent historical year.

d. Compute Forecasted C3 factors: To get the Forecasted C3 values for each year, the prior year's C3 values are multiplied by the growth factor. The C3 values are summed by jurisdiction and system. Then each jurisdictional total is divided by the system total to yield the forecasted C3 factor.

11. **STREETLIGHT FACTOR (C4)** - this factor is based on the weighted installed cost of the streetlights in

each jurisdiction.

Forecast Methodology for C4: The most recent historical C4 factor is used as the forecasted C4 factor with no change.

12. **AREA LIGHT FACTOR (C5)** - this factor is based on the weighted installed cost of area lights in each jurisdiction.

Forecast Methodology for C5: The most recent historical C5 factor is used as the forecasted C5 factor with no change.

13. **METER FACTOR (C6)** - this factor is based on the weighted installed cost of meters in service.

Forecast Methodology for C6: The most recent historical C6 factor is used as the forecasted C6 factor with no change.

14. **METER READING FACTOR (C7)** - this factor is based on total weighted meter reading time.

Forecast Methodology for C7: The Forecasted C7 factors are computed using a 4 step process:

a. Compute historical C7 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Combine historical values and growth factor and computes Forecasted C7 factors

a. Compute historical C7 values: The historical C7 factors are computed.
b. Compute Class Growth factor: Customer growth Factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.
c. Compute the FERC values: Remain the same as the most recent historical year
d. Compute Forecasted C7 factors: To compute the Forecasted C7 values for each year, the prior year's C7 values are multiplied by the growth factor. The C7 values are summed by jurisdiction and system. Then each jurisdictional total is divided by the system total to yield the Forecasted C7 Factor.

e.

15. **<u>TOTAL SYSTEM SERVICE LOCATIONS FACTOR (C8)</u>** - this factor is similar to the Total Distribution Service Locations Factor, except all locations on the system at which service can be or is provided are included.

Forecast Methodology for C8: The Forecasted C8 factors are computed using a 4 step process:

a. Compute historical C8 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Combine historical values and growth factor and computes Forecasted C8 factors

a. <u>Compute historical C8 values</u>: The historical C8 factors are computed.
b. <u>Compute Class Growth factor</u>: Customer growth Factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.
c. <u>Compute the FERC values</u>: Remain the same as the most recent historical year.
d. <u>Compute Forecasted C8 factors</u>: To compute the Forecasted C8 values for each year, the prior year's C8 values are multiplied by the growth factor. The C8 values are summed by jurisdiction and system. Then each jurisdictional total is divided by the system total to yield the forecasted C8 factor.

16. **<u>LOAD MANAGEMENT FACTOR (C9)</u>** - this factor is based on the total number of locations that have radio load management receivers in each jurisdiction.

Forecast Methodology for C9: The Forecasted C9 factors are computed using a 4 step process:

a. Compute historical C9 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Compute Forecasted C9 factors

a. <u>Compute historical C9 values</u>: The historical C9 factors are computed.
b. <u>Compute Class Growth factor</u>: Customer growth Factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.

c. Compute the FERC values: Remain the same as the most recent historical year.

d. Compute Forecasted C9 factors: To compute the forecasted C9 values for each year, the prior year's C9 values are multiplied by the growth factor. The C9 values are summed by jurisdiction and system. Then each jurisdiction is divided by the system total to yield the forecasted C9 factor.

NORTH DAKOTA

OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
North Dakota Budget YEAR 2018 - Simple Average

LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	RATE BASE		354,191,795	125,874,811	8,479,201	88,428,075	90,600,482	313,267	8,217,318	3,262,553	3,755,746	22,051,030	3,209,311
2													
3	TOTAL AVAILABLE FOR RETURN		18,454,393	3,412,418	175,289	6,783,796	7,904,724	(10,715)	247,020	61,466	(33,919)	(256,217)	170,530
4													
5	RATE OF RETURN EARNED		5.21%	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
6													
7	RATE OF RETURN REQUESTED		7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%
8													
9	OPERATING INCOME REQUIRED		28,229,086	10,032,222	675,792	7,047,718	7,220,858	24,967	654,920	260,026	299,333	1,757,467	255,782
10													
11	TOTAL AVAILABLE FOR RETURN		18,454,393	3,412,418	175,289	6,783,796	7,904,724	(10,715)	247,020	61,466	(33,919)	(256,217)	170,530
12													
13	OPERATING INCOME DEFECIENCY		9,774,693	6,619,804	500,503	263,921	(683,866)	35,683	407,900	198,560	333,252	2,013,684	85,252
14													
15	INCREMENTAL TAXES	GRCF =	5,940,627	4,023,224	304,184	160,400	(415,623)	21,686	247,904	120,676	202,536	1,223,828	51,812
16													
17	REVENUE INCREASE REQUIRED		15,715,320	10,643,028	804,687	424,321	(1,099,489)	57,369	655,804	319,236	535,787	3,237,513	137,064
18													
19	PERCENTAGE INCREASE		10.61%	22.08%	30.80%	1.09%	-2.55%	97.10%	22.86%	26.51%	49.38%	38.55%	9.00%
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25	RETURN ON EQUITY		5.05%	0.29%	-0.94%	9.74%	11.74%	-11.39%	0.85%	-1.29%	-6.60%	-7.09%	5.24%
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