EXHIBIT

OTP-8

Before the South Dakota Public Utilities Commission
State of South Dakota

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

Docket No. EL18-___

Exhibit___

MAJOR PROJECTS, TEST YEAR REVENUES, ALLOCATION FACTORS & OTHER REGULATORY MATTERS

Direct Testimony and Schedules of

STUART D. TOMMERDAHL

April 20, 2018

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Schedule 4 – Corporate Cost Allocation Manual (Redline and Clean)

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Stuart D. Tommerdahl. I am employed by Otter Tail Power Company (OTP) as Manager, Regulatory Administration.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I graduated from Moorhead State University, now Minnesota State University, Moorhead, Minnesota, in 1983 with a B.S. degree in Accounting and a minor in Economics. I am a Certified Public Accountant (Inactive) in Minnesota. From 1983 to 1992, I worked in several accounting, budgeting and financial reporting positions. In 1993, I joined OTP as Regulatory/Economic Analyst. From 1997 to 2003 I worked at Otter Tail Energy Services as Manager, Financial Planning /Analysis and subsequently Director, Financial Services.

In 2004, I returned to OTP as Manager, Risk Management. In March of 2012, I started my current position as Manager, Regulatory Administration. My primary responsibilities are to provide leadership in areas of revenue requirements analysis, pricing and rate design, tariff administration, load research, cost allocation methodologies to be used in cost of service studies, long range revenue forecasting, wholesale energy accounting, cost of energy, and unbilled revenue. A copy of my resume is included as Exhibit___(SDT-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony describes a number of revenue requirement and regulatory issues associated with this case.

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

A. My Direct Testimony focuses on the following items:

- Overview of major capital projects since our last South Dakota rate case;

- 2017 normalized retail revenues;
- Jurisdictional and class cost allocation factors;
- Fuel Adjustment Clause Rider;
- Corporate cost allocations;
- New economic development rates;
- Lead Lag Study; and
- Merricourt project step increase rates

Lastly, my Direct Testimony also addresses a few miscellaneous regulatory issues.

Q. HAVE YOU INCLUDED BOTH SOUTH DAKOTA JURISDICTIONAL AND TOTAL COMPANY AMOUNTS IN YOUR DIRECT TESTIMONY AND SCHEDULES?

A. Yes. The dollar values presented in my Direct Testimony are jurisdictionalized to South Dakota values and labeled as (OTP SD). The South Dakota jurisdictional values are also presented in combination with total company values, labeled as (OTP Total).

There are certain power plant and transmission projects where OTP is only a part owner. In those circumstances, I included each of the following: the total project costs, labeled as (Total Plant or Total Project), and the OTP ownership allocation of the project amounts, labeled as (OTP Total).

Some categories of costs include costs that fall into numerous functions, each with its own jurisdictional allocation, and therefore a straightforward calculation of a jurisdictional amount based on a single allocator is not possible. Examples of these costs include certain labor cost categories, which may include costs functionalized as generation, transmission, distribution, administration and general, with each function having its own unique jurisdictional allocation. For costs that are categorized across functions like this, the South Dakota jurisdictional dollar values have been estimated by multiplying the Total Company costs by a single blended allocator. When such an estimate has been used, the dollar values are labeled as (SD EST).

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

A. In Section III, I will discuss major capital projects OTP has completed since its last South Dakota rate case. In Section IV, I discuss the determination of 2017 normalized retail revenues. In Section V, I discuss jurisdictional and class allocation factors. In Section VI, I discuss a proposed change to OTP's Fuel Adjustment Clause Rider. Section VII includes a discussion of corporate cost allocations. In Section VIII, I discuss economic development rates. Section IX includes a discussion of the Lead Lag Study. In Section X, I discuss the Merricourt project step increase rate proposal. Section XI includes a discussion of miscellaneous issues, and Section XII includes my conclusions.

III. MAJOR CAPITAL PROJECTS SINCE LAST RATE CASE

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

A. In this section of my Direct Testimony, I will discuss major capital projects that OTP has completed since its last South Dakota rate case, including: (A) the Big Stone plant Air Quality Control System project (AQCS Project); (B) the Hoot Lake plant Mercury and Air Toxics Standards project (MATS Project); and (C) major transmission projects. I will also discuss OTP's new Customer Information System Project.

Q. WHEN WAS OTP'S LAST RATE CASE IN SOUTH DAKOTA?

A. OTP's last South Dakota rate case was filed before the South Dakota Public Utilities Commission (Commission) in 2010 and was based on a 2009 Test Year (Docket No. EL10-011).

A. Big Stone AQCS Project

Q. WHAT WILL YOU DISCUSS IN THIS SUBSECTION?

A. In this subsection of my Direct Testimony, I will explain the $0.9 million (OTP SD) of annual savings for South Dakota customers in the 2017 Test Year, which will continue for 30 years, as a result of OTP's completion of the Big Stone AQCS Project far under budget. I will also discuss the reductions in earnings for shareholders resulting from the under-budget completion of the AQCS Project.

Q. WHAT IS THE BIG STONE AQCS PROJECT?

A. The Big Stone AQCS Project is a major environmental upgrade project at the Big Stone plant that went into service on December 29, 2015. To date, it is the largest capital project ever undertaken by OTP. The AQCS Project was needed for the continued operation of the Big Stone plant. The AQCS Project reduces nitrogen oxides and sulfur dioxide emissions at our Big Stone plant by approximately 90 percent and reduces mercury emissions by approximately 80 percent. In Docket No. EL12-027, a staff report concluded that: "Based on the evaluation of Otter Tail's IRP [Integrated Resource Plan] and the analysis conducted in the ADP proceedings in North Dakota and Minnesota, the AQCS project is found to be the least cost option compared to other alternatives."[1] OTP completed the Big Stone AQCS Project substantially under budget and on time. The Big Stone AQCS Project, including the associated capital costs and OTP's completion of the project far under budget, is discussed in detail in the Direct Testimony of OTP witness Mr. Kirk A. Phinney.

Q. IS OTP PROPOSING TO CHANGE HOW BIG STONE AQCS PROJECT CAPITAL COSTS ARE RECOVERED?

A. Yes. The South Dakota jurisdictional share of the Big Stone AQCS Project capital costs currently are being recovered through OTP's South Dakota Environmental Cost Recovery Rider (ECRR), as approved in Docket No. EL14-082. OTP witness Mr. Bryce C. Haugen describes, in his Direct Testimony, OTP's proposal to move the Big Stone AQCS Project capital costs from the ECRR into base rates effective at the time OTP is proposing to implement interim rates in this case.

Q. DOES THIS PROPOSAL INCREASE COSTS TO CUSTOMERS?

A. No. Moving the Big Stone AQCS Project from the ECRR into base rates is merely a change to how the costs of the project are recovered.

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[1] Report entitled "Evaluation of Otter Tail's Air Quality Control System Project as the Least Cost Option Compared to Other Alternatives," filed January 25, 2013.

Q. DID OTP COMPLETE THE BIG STONE AQCS PROJECT AT A COST SUBSTANTIALLY BELOW BUDGET?

A. Yes. Mr. Phinney explains in his Direct Testimony that the final capital cost for the Big Stone AQCS Project is $365.5 million (Total Plant), which is $125 million below the total original project budget of $491 million (Total Plant). OTP's total company share of this savings in capital costs is $67.6 million (OTP Total), and the South Dakota jurisdictional share is $6.3 million (OTP SD).

Q. HAVE YOU DETERMINED THE SAVINGS IN THE 2017 TEST YEAR FROM COMPLETING THE BIG STONE AQCS PROJECT BELOW BUDGET?

A. Yes. I have determined that the under-budget completion of the Big Stone AQCS Project reduced the 2017 Test Year revenue deficiency and will save South Dakota customers approximately $0.9 million annually (OTP SD). This determination was based on a cost of completion of $365.5 million (Total Project) (approximately $125 million (Total Project) below budget) and reflects OTP's 53.9 percent ownership share and the South Dakota jurisdictional allocation of 9.342 percent. This savings for South Dakota customers is the result of (1) the reduction in the South Dakota jurisdictional share of the *return of capital* (depreciation) on approximately $125.5 million (Total Project) savings; plus (2) the reduction in the annual *return on capital* (earnings for investors plus tax effect) on $125.5 million (Total Project) savings. My calculation of the estimated annual savings for South Dakota customers for the 2017 Test Year is set forth on Exhibit__(SDT-1), Schedule 2.

Q. HAVE YOU ALSO DETERMINED THE CUMULATIVE SAVINGS FOR SOUTH DAKOTA CUSTOMERS OVER THE INITIAL 10 YEARS OF USE AND THE FULL 30-YEAR LIFE OF THE BIG STONE AQCS PROJECT?

A. Yes. I estimate that OTP's South Dakota customers will receive cumulative savings of approximately $8.0 million (OTP SD) over the initial 10-years of use of the Big Stone AQCS Project. I estimate that, over the 30-year life of the AQCS Project, OTP's under-budget completion of the Big Stone AQCS Project will reduce OTP's South Dakota customer costs by approximately $17.2 million (OTP SD) with a net present value of $7.8

million (OTP SD). These savings for OTP's South Dakota customers are also the result of the South Dakota jurisdictional share of the reduction in *the return of* approximately \$125.5 million (Total Project) of capital (reflected in depreciation) plus the reduction in *the return on* approximately \$125.5 million (Total Project) of capital. My calculations are also set forth on Exhibit__(SDT-1), Schedule 2.

Q. IN ADDITION TO CUSTOMER SAVINGS, DOES THE UNDER-BUDGET COMPLETION ALSO HAVE AN EFFECT ON SHAREHOLDERS?

A. Yes. While the lower investment from the under-budget completion of the Big Stone AQCS Project provides substantial savings for South Dakota customers, there is a corresponding effect on OTP shareholders in the form of reduced earnings resulting from the reduced investment.

Q. HAVE YOU DETERMINED THE REDUCED EARNINGS FOR SHAREHOLDERS IN THE 2017 TEST YEAR AND IN OTHER YEARS?

A. Yes. As a result of OTP's under budget completion of the Big Stone AQCS Project, the return to shareholders will be reduced (after OTP income taxes) by approximately:

A. \$0.3 million (OTP SD) in the 2017 Test Year;
B. \$2.9 million (OTP SD) during the first 10 years; and
C. \$5.4 million (OTP SD) over the 30-year life of the Big Stone AQCS Project.

The net present value of reduced earnings is \$2.0 million (OTP SD) over the first 10 years and \$2.7 million (OTP SD) over the 30-year life of the Big Stone AQCS Project. My calculations are set forth on Exhibit__(STD-1), Schedule 2.

Q. IS IT APPROPRIATE FOR THE COMMISSION TO CONSIDER THESE CUSTOMER SAVINGS AND LOWER EARNINGS IN SETTING OTP'S RETURN ON EQUITY?

A. Yes. OTP witness Mr. Robert B. Hevert recommends that the Commission consider OTP's under-budget completion of the Big Stone AQCS Project when setting OTP's return on equity (ROE). Considering this accomplishment in setting the ROE for OTP would help to reinforce that prudent execution of capital projects and the resulting cost savings for customers is a priority of both utilities and regulators. While OTP has always made the prudent execution of capital expenditures one of its most important business priorities, OTP believes that reinforcement of that priority in the setting of OTP's authorized ROE is appropriate in this case from a regulatory perspective.

B. Hoot Lake MATS Project

Q. WHAT WILL YOU DISCUSS IN THIS SUBSECTION?

A. In this subsection, I will discuss the Hoot Lake MATS Project, which OTP also completed under budget.

Q. WHAT IS THE HOOT LAKE MATS PROJECT?

A. The Hoot Lake MATS Project involved the upgrade of Electrostatic Precipitators and the installation of an Activated Carbon Injection system at Hoot Lake. The Hoot Lake MATS Project is designed to control mercury and particulate matter emissions at the plant. The project is described in greater detail in Mr. Phinney's Direct Testimony.

Q. DID OTP COMPLETE THE HOOT LAKE MATS PROJECT AT A COST SUBSTANTIALLY BELOW BUDGET?

A. Yes. Mr. Phinney explains in his Direct Testimony that the final capital cost for the Hoot Lake MATS Project is $7.145 million (OTP Total), which is $2.8 million (28 percent) below the total original project budget of $10 million (OTP Total).

Q. IS OTP PROPOSING TO CHANGE TO HOW HOOT LAKE MATS PROJECT CAPITAL COSTS ARE RECOVERED?

A. Yes. The South Dakota jurisdictional share of the Hoot Lake MATS Project capital costs currently are being recovered through the ECRR. Mr. Haugen describes OTP's proposal to move the Hoot Lake MATS Project capital costs from the ECRR into base rates effective at the time OTP is proposing to implement interim rates in this case.

Q. DOES THIS PROPOSAL INCREASE COSTS TO CUSTOMERS?

A. No. Moving the Hoot Lake MATS Project from the ECRR into base rates is merely a change to how the costs of the project are recovered.

C. Transmission Projects

Q. WHAT WILL YOU DISCUSS IN THIS SUBSECTION OF YOUR DIRECT TESTIMONY?

A. In this subsection, I will provide background information and a description of OTP's major completed transmission projects, which are included in OTP's proposal to roll transmission projects now included in OTP's Transmission Cost Recovery Rider (TCRR) into base rates. Mr. Haugen will explain that proposal in his Direct Testimony.

Q. PLEASE BRIEFLY DESCRIBE THE MAJOR TRANSMISSION PROJECTS IN WHICH OTP HAS INVESTED SINCE OTP'S LAST RATE CASE?

A. OTP has been involved with numerous transmission projects since OTP's last rate case in 2010. The most significant completed projects include: (1) the Big Stone South to Brookings multi-value project (MVP); (2) the CAPX2020 transmission projects, including Fargo to Monticello, Bemidji to Grand Rapids, and Brookings to Hampton; (3) the Casselton to Buffalo 115kV project, and (4) the Oakes Area transmission project. The Commission has reviewed and approved each of these projects for cost recovery in prior proceedings as noted in Mr. Haugen's testimony.

Q. WHAT WAS THE PURPOSE OF THE BIG STONE SOUTH TO BROOKINGS PROJECT?

A. The Big Stone South-Brookings County project is a 70-mile, 345kV transmission line built between a new Big Stone South Substation near Big Stone City, S.D., and the Brookings County Substation near Brookings, S.D. The project is one of 17 MVPSs approved by the Midcontinent Independent System Operator (MISO) in December 2011. The MVPs will help expand and enhance the region's transmission system, reduce congestion, provide access to affordable energy sources and meet public policy requirements, including renewable energy mandate. The project was placed in service in September 2017.

Q. PLEASE BRIEFLY DESCRIBE THE CAPX2020 TRANSMISSION PROJECTS.

A. The three CAPX2020 transmission projects in which OTP has invested are part of the CAPX2020 portfolio of five projects formed to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service. The total CAPX2020 portfolio involves an 800 mile, nearly $2 billion investment initiative, including four 345kV transmission lines and one 230kV line involving 11 transmission-owning utilities in South Dakota, North Dakota, Minnesota and Wisconsin. The CAPX2020 portfolio projects were approved by MISO as part of its Transmission Expansion Planning process, which identifies issues and opportunities, develops alternatives for consideration, and evaluates those alternatives to determine effective transmission solutions.

Q. PLEASE DESCRIBE OTP'S CAPX2020 PROJECTS.

A. OTP has participated in three CAPX2020 projects: (1) CAPX2020 Fargo to Monticello; (2) CAPX2020 Bemidji to Grand Rapids; and (3) CAPX2020 Brookings to Hampton. The CAPX2020 Fargo to Monticello project includes 240 miles of 345kV line running from Fargo, North Dakota to Monticello, Minnesota and associated upgrades. The project was energized April 2, 2015.

The CAPX2020 Bemidji to Grand Rapids project, which is inclusive of the Bemidji to Cass Lake segment, is a 70-mile 230kV line running from Bemidji, Minnesota to Grand Rapids, Minnesota. The project was energized September 2012.

Finally, the CAPX2020 Brookings to Hampton includes 250 miles of 345kV line running from Brookings, South Dakota to Hampton, Minnesota. The project, which connects to new renewable generation resources in southern and western Minnesota and North Dakota and South Dakota, was energized March 26, 2015.

Q. PLEASE DESCRIBE THE CASSELTON TO BUFFALO AND OAKES PROJECTS.

A. The Casselton to Buffalo project includes 16 miles of 115kV line and related modifications and replacements. The project was completed and placed in-service in November 2017. The Oakes projects includes upgrades to the transmission system around Oakes, North Dakota. This project was completed in late 2015.

Q. IS OTP NOW RECOVERING THE COST OF THESE PROJECTS IN OTP'S TCRR?

A. Yes. The South Dakota allocated portion of the costs of each of these transmission projects is included in the eight completed projects that OTP is recovering through the TCRR.

Q. WHAT IS OTP'S PROPOSAL REGARDING THOSE COMPLETED TRANSMISSION PROJECTS CURRENTLY BEING RECOVERED IN OTP'S TCRR?

A. OTP is proposing to roll the recovery of these investments out of the TCRR and into base rates at the time Otter Tail proposes interim rates to go into effect in this case. Mr. Haugen discusses the roll-in of these projects into base rates in his Direct Testimony.

D. Customer Information System

Q. WHAT WILL YOU DISCUSS IN THIS SUBSECTION OF YOUR DIRECT TESTIMONY?

A. In this subsection, I will provide background information and a description of OTP's new Customer Information System which OTP refers to internally as "CISone."

Q. IS OTP NOW IMPLEMENTING CISONE?

A. Yes. As OTP witness Mr. Bruce Gerhardson briefly describes in his Direct Testimony, OTP is implementing CISone to replace an existing legacy customer information system that OTP built internally and has been using for almost 30 years. Among other things, customer billing will be one of the key functional business operations that will transfer from the legacy system to the new CISone system. Mr. Gerhardson outlines numerous other functional improvements CISone will provide as OTP builds critical technical infrastructure to address changing needs of both customers and OTP employees. OTP's current estimated cost of the system is $15.8 million (OTP Total) / $1.5 million (OTP SD).

Q. PLEASE FURTHER DESCRIBE THE ADDITIONAL FUNCTIONALITY THAT CISONE WILL PROVIDE OTP'S CUSTOMERS AND EMPLOYEES.

A. There are many benefits that OTP customers and employees will realize once CISone is implemented. Much of this is due to the limitations of the current system due to its age. One significant source of high-level benefit will be the system's ability to "talk" to other OTP systems through interfaces, allowing data to flow in real-time rather than through overnight batches and file transfers as is currently done. This will allow information exchange at a much more rapid pace. Other benefits include:

- **Ease of new or updated rate implementation:** The existing CIS is limited due to field and capacity constraints and updating or changing rates or riders takes significant database modification. CISone will allow OTP to more easily prepare for rate/rider updates and changes, as well as provide a better process to test those changes.
- **Customer Self Service (CSS):** CISone will better support self-service and online business.
- **Mobile work management (MWM):** Mobile field workers will have access to information much more quickly, and they will have access to information that was not previously available to them in the field. "Apps" will be available through smartphones and tablets.
- **A new system will be able to support future initiatives:** CISone will support initiatives such as two-way Geographic Information System (GIS) integration, Advanced Metering Infrastructure (AMI), and Outage Management System (OMS) support.
- **Less reliance on CIS programmers and technicians:** More functions will be shifted to system end-users.
- **Improved automation:** The current CIS system is not capable of meeting current functional demands without significant manual intervention, which will not be needed with CISone.
- **Elimination of reusing of data fields:** This will minimize the risk of data corruption.

- **Easier detection and correction of billing issues**: Detection and correction will be facilitated.
- **Advanced ad-hoc reporting:** The new CIS system will come with many reports and queries that previously would have taken significant programming to develop.
- **More advanced "Checkout and Lock" features:** These features will mitigate the risk of data corruption and account errors.
- **A more robust primary/secondary failover system:** CISone is designed so that an in the event of a failure it will result in less downtime to restore.
- **Better ability to drive consistent business processes across all jurisdictions:** CISone will facilitate consistency across all jurisdictions.

Q. WHEN DOES OTP ANTICIPATE IMPLEMENTING CISONE?

A. CISone is currently scheduled to "go-live" in the 4th quarter, 2018. Implementation will only occur after CISone has been fully tested to confirm that OTP's customer billings will be accurately and correctly computed and accounted for. OTP will keep the Commission informed on the schedule during the course of this case.

Q. HOW DOES IMPLEMENTATION OF CISONE RELATE TO THE IMPLEMENATION OF FINAL RATES IN THIS RATE CASE?

A Because the implementation of the CISone system closely aligns with the timeline of this rate case and the potential implementation date of final rates, OTP is evaluating the feasibility of simultaneously implementing final rates the same month as CISone is implemented. If simultaneous implementation is not feasible, OTP is also considering implementation of final rates in the current CIS system if this case has concluded prior to CISone implementation and the Commission deems that to be the most appropriate approach.

CISone also could potentially be ready for implementation ahead of implementation of final rates. If OTP implements CISone ahead of final rates, OTP believes it would be appropriate to have a two or three month "window" between implementation of CISone and final rates for further confirmation of CISone system operation. With interim rates in effect, OTP would be open to delaying implementation of final rates as an option to best align the schedules of this case and CISone implementation. Customers would be protected and compensated for any delay by interest applied to any interim refund.

Q. IS OTP SEEKING RECOVERY OF CISONE COSTS IS THIS CASE?

A. Yes. OTP included the CISone project, including costs, in the 2017 Test Year as a known and measurable change. CISone will only be included in final rates, not in Otter Tail's proposed interim rates. The CISone system will have a ten-year depreciable life. OTP has included a Test Year adjustment to annualize the costs associated with CISone, based on this ten-year life, into the 2017 Test Year. OTP witness Mr. Tyler A. Akerman provides further detail of the normalizing adjustment in his Direct Testimony.

Q. WILL THE IMPLEMENTATION OF CISONE RESULT IN ANY CHANGES TO OTP'S CUSTOMER BILL CALCULATIONS, RATE DESIGNS, TARIFF LANGUAGE, OR OTP'S GENERAL RULES AND REGULATIONS?

A. Yes. Before filing this rate case, OTP met with Commission Staff to inform them that OTP anticipates CISone will necessitate some changes to OTP's tariffs and bills, as well as changes to the language in OTP's rate book. OTP will need Commission approval to make those changes. OTP proposes to make a separate filing sometime in the second quarter of 2018 to seek approval of the CISone tariff and bill changes. Because of the potential scenarios related to timing of the final rates and CISone, OTP and Commission Staff agreed handling these changes in a separate filing would provide greater flexibility in terms of seeking Commission approvals for CISone related changes. This flexibility is necessary should the schedule indicate CISone could be implemented ahead of the completion of this case and implementation of final rates.

Q. ARE THERE ANY RATE PROPOSALS IN THIS CASE THAT OTP WILL NOT BE ABLE TO IMPLEMENT IN OTP'S CURRENT CIS SYSTEM?

A. Yes. In this case, OTP is proposing to implement an E8760 allocation of fuel and purchased power costs recovered through the Fuel Adjustment Clause rider (also known as the Fuel Clause, FCA or Energy Adjustment). I will discuss this proposed change to OTP's Fuel Clause in greater detail later in my Direct Testimony but as a summary, implementing this E8760 allocation results in a distinct and separate Fuel Clause rate for each customer class. OTP's current legacy billing system is not able to facilitate a separate Fuel Clause rate for each class. This functionality is being designed into CISone. OTP proposes that, if final rates go into effect before CISone is implemented, the Commission allow OTP to delay the transition to a 10-class FCA rate until after CISone is implemented. In the interim, OTP proposes to charge all classes the same FCA rate. In OTP's recent Minnesota general rate case, the Minnesota Public Utilities Commission approved delaying a similar E8760 Fuel Clause rate implementation until OTP's CISone system is placed in service. A similar proposal is included in OTP's current North Dakota case. OTP is seeking consistency of the use of an E8760 allocator across all jurisdictions.

Q. HAS OTP PROVIDED SEPARATE RATE SCHEDULES TO REFLECT EACH OF THESE SCENARIOS?

A. Yes. In Volume 3, a proposed version of Section 13.01 is provided that would be applicable to the application of the E8760 allocation to the Fuel Clause once CISone is placed into service. In this version, each customer class's specific Energy Adjustment Factor Ratio (EAF Ratio) is included. A second proposed version of Section 13.01 is provided that would be applicable in the event final rates in this case are implemented ahead of the implementation of CISone. In this version, each customer class's specific EAF Ratio is set to 1.000. In this instance, all customers would be charged the same FCA rate as I noted above.

IV. 2017 NORMALIZED RETAIL REVENUES

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

A. This section describes how 2017 South Dakota normalized retail revenues were determined. First, I will describe how 2017 South Dakota actual retail revenues were established. I will then describe the adjustments made to determine total 2017 normalized retail revenues for the 2017 Test Year.

A. 2017 Actual Retail Revenues

Q. PLEASE DEFINE RETAIL REVENUES.

A. For the purposes of ratemaking, retail revenues are the total retail revenues (billed and unbilled) on a calendar month basis, plus or minus the adjustments I discuss below. In other words, the calendar month revenue includes revenue for the billed sales and estimated revenue for electricity that has been delivered to customers, but not yet billed. This includes revenues collected through base rates as well as revenues applicable to OTP's various cost recovery riders.

Q. WHAT DO YOU MEAN BY "REVENUES ON A CALENDAR MONTH BASIS"?

A. Calendar month revenues are determined by making an adjustment for unbilled revenues to billing month retail revenues. Billing month revenues do not coincide with the calendar month, as they are billed on cycles (20 cycles in a month for OTP). Total 2017 billed revenues for the South Dakota retail jurisdiction were $33,113,281.

To have retail revenues match to the calendar year for which expenses are incurred, the incremental amount of revenues that have not been billed at the end of the year for each of the 20 billing cycles are estimated using a comprehensive model. This model calculates the unbilled revenues for 2017 that were billed in January 2018, net of the December 2016 unbilled revenues that were billed in January of 2017. For 2017, the unbilled revenue calculation increased South Dakota retail revenues by $108,870.

In addition, total billed revenues are also adjusted by the amount of any over or under collection balance attributable to OTP's cost recovery riders to reflect the actual calendar year revenue requirement within that rider. The total amount of these adjustments was a decrease to South Dakota retail revenue of ($292,279). OTP's total South Dakota retail revenues for 2017 before any normalizing adjustments were $32,929,872.

B. Weather Normalization

Q. HAVE ACTUAL 2017 SOUTH DAKOTA RETAIL REVENUES BEEN WEATHER ADJUSTED TO ARRIVE AT THE 2017 TEST YEAR REVENUES?

A. Yes, actual 2017 South Dakota retail revenues have been weather normalized as described below.

Q. WHAT IS THE PURPOSE OF WEATHER NORMALIZING HISTORIC DATA?

A. If OTP were using a projected test year based on a budget, a weather normalization adjustment would not be necessary, since budgets assume normal weather. However, in a test year based on historic data, the historic sales data needs to be adjusted to produce retail revenue and variable costs that are representative of the effects of "normal" weather.

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION METHODOLOGY USED BY OTP.

A. OTP's weather normalization process utilizes a similar methodology to what was used in OTP's last South Dakota general rate case. For 2017, the weather normalization adjustment results in an increase to South Dakota base revenues of $202,124. The weather normalization adjustment also results in increased fuel expenses and associated FCA revenues of approximately $133,229 for South Dakota. The combination of these adjustments is shown as Test Year Adjustment TY-05 in Schedule 10 to Mr. Akerman's Direct Testimony.

OTP's weather normalization process utilizes the current year plus the prior 20 years of OTP hourly weather data, monthly revenue, and monthly kWh data. A statistical regression procedure is used to determine weather normalization models for each of 40 different rate groups within each of OTP's three states. Variables used include: (i) kWh/day; (ii) heating and cooling degree days; (iii) the number of months since January 1997; and (iv) up to 13 autoregressive terms. The results are checked for accuracy and reasonableness using graphs and reports. Weather normalized kWh sales are then priced on current rates using a calendar month basis. The resulting revenue amounts do not include FCA revenues.

Consequently, to include the impact of weather normalization on the FCA, weather normalized kWh sales are multiplied by the appropriate total cost of energy rate for each of the twelve months to determine the fuel and purchased power costs. As noted above, total FCA fuel and purchased power costs and associated FCA revenues for South Dakota are $133,229.

Q. DOES WEATHER NORMALIZATION RESULT IN AN ADJUSTMENT TO UNBILLED REVENUES FOR THE 2017 TEST YEAR?

A. Yes, but not separately. As stated in the previous question, weather normalization is computed on a calendar month basis, which includes unbilled sales.

C. Billing Adjustments

Q. DO THE 2017 TEST YEAR SALES REFLECT ANY BILLING ADJUSTMENTS?

A. Yes. During 2017 OTP made minor bill adjustments attributable to time periods prior to 2017. There have also been billing adjustments made in early 2018 that were attributable to 2017.

Test Year Adjustment TY-06 in Schedule 10 to Mr. Akerman's Direct Testimony moves the revenues and associated estimated fuel costs to the proper year. These adjustments increase 2017 South Dakota revenues by $4,325, and associated fuel costs by $2,179.

D. Total 2017 Normalized Retail Revenues

Q. WHAT ARE THE TOTAL NORMALIZED SOUTH DAKOTA RETAIL REVENUES FOR 2017?

A. Table 1 below summarizes OTP's total 2017 normalized South Dakota retail revenues.

Table 1

Total 2017 SD Normalized Retail Revenue Summary

Revenue Component	SD Total
Billed Revenues	$33,113,281
Unbilled Revenue	$108,870
Rider Revenue Adjustments	$(292,279)
Total 2017 Retail Revenue	**$32,929,872**
Weather Normalization Adjustments (Base + Fuel)	$335,353
Billing Adjustments	$4,325
Total 2017 Normalized Retail Revenue	**$33,269,550**

Mr. Haugen provides further detail in his Direct Testimony as to OTP's proposed class revenue responsibilities.

V. 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 ARE THE ROLES 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 to design rates.

Q. HOW DO THESE ALLOCATIONS OCCUR?

A. System costs and revenues are allocated to jurisdictions in the Jurisdictional Cost of Service Study (JCOSS) described in more detail by Mr. Akerman. Jurisdictional costs and revenues are allocated to customer classes in the Class Cost of Service Study (CCOSS) described by Mr. Haugen.

A. Test Year JCOSS and CCOSS Allocators

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

A. Table 2 below identifies the main allocators used in the 2017 Test Year JCOSS and CCOSS. The OTP Cost Allocation Procedures Manual (CAPM), included as Exhibit__(SDT-1), Schedule 3, provides additional detail regarding the development of each allocator.

Table 2

JCOSS and CCOSS Allocators

Cost Function	Classification	JCOSS Allocator[2]	CCOSS Allocator[3]
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

[2] *See* Volume 4A, Section C, Supporting Information, Schedule B-7.
[3] *See* Volume 4A, Section C, Supporting Information, Schedule E-3.

Q. HAS OTP CHANGED THE CAPM SINCE ITS LAST SOUTH 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 OTP's last South Dakota rate case in 2010. Exhibit (SDT-1), Schedule 3, provides the content changes in red-line and clean versions.

Q. DID OTP USE THESE SAME ALLOCATORS IN ITS LAST SOUTH 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 South Dakota rate case except for the addition of an E8760 allocator for the CCOSS and Fuel Clause Adjustment Rider.

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

A. Yes. OTP is using a historic 2017 Test Year in this case and developed the allocation factors based on 2017 actual information, adjusted for the known and measurable changes I discussed earlier. This is consistent with the historical Test Year used in OTP's last South Dakota rate case. The process of developing the allocators is described in 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. OTP's proposal to implement the E8760 allocator for class cost of service allocations is also consistent with what has been approved or proposed in OTP's other jurisdictions as well.

B. E8760 Allocator

Q. WHAT IS AN E8760 ALLOCATOR?

A. An E8760 allocator applies a cost factor to each 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 South Dakota. The 2016 class-based load shapes were applied to 2017 class sales for South Dakota. This resulted in a distribution of all sales within each class, across all 8,760 hours of the year for South Dakota.

Step 3: Apply Hourly Costs to Class-Based Load Shapes for South Dakota: OTP multiplied the actual hourly class sales by hourly 2017 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, which are shown in Table 3 below.

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

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

VI. FUEL ADJUSTMENT CLAUSE RIDER

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

A. In this section of my Direct Testimony, I will discuss a proposed change to the name of the Fuel Adjustment Clause Rider, Electric Rate Schedule 13.01, and the use of the E8760 allocator I just discussed, in that rider. I will also discuss removal of any reference to non-asset-based trading from that rate schedule.

Q. IS OTP PROPOSING A NEW NAME FOR THE FUEL ADJUSTMENT CLAUSE RIDER?

A. Yes. OTP proposes to change the name of Electric Rate Schedule 13.01 from the Fuel Adjustment Clause Rider to the Energy Adjustment Rider to be consistent with the naming conventions of the comparable riders in OTP's other jurisdictions. I will use that proposed term throughout the rest of my testimony.

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

A. Yes. OTP proposes to use an E8760 allocator in its Energy Adjustment Rider.

Q. WHAT IS THE RATIONALE FOR COMPUTING AND USING AN E8760 ALLOCATOR FOR ENERGY ADJUSTMENT RIDER?

A. Energy usage can vary significantly between customer classes over the course of a day, week, month or year. At the same time, costs to provide that energy also vary each day, week, month or year. The E8760 allocator takes into account when energy is used and the associated cost of that energy and creates an appropriate weighting of the overall cost each class is accountable for. As a result, the E8760 allocator yields a distinct and separate Energy Adjustment Rider rate for each customer class that more accurately reflects the cost causation responsibility of that class for energy costs.

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

A. For illustrative purposes, Table 3 below shows how the 10 customer classes are impacted using the average fuel rate 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 and as summarized in Volume 1, Statement P.

Table 3

Fuel Allocation	**A**	**B**	**C**
Customer Classes	**Avg Fuel $/kWh**	**E2-E8760 Allocation Ratio**	**E2-E8760 Avg Fuel $/kWh**
			(A*B)
Residential (RDC/RES)	$ 0.026153	1.0240	$ 0.026779
Farms (FAR)	$ 0.026153	1.017	$ 0.026587
General Service (TUS/GSO/GSU)	$ 0.026153	1.031	$ 0.026975
Large General Service (PLG/SLG/TLG)	$ 0.026153	0.981	$ 0.025661
Irrigation Services (IRR)	$ 0.026153	0.912	$ 0.023838
Outdoor Lighting (ALT/SLT)	$ 0.026153	0.808	$ 0.021140
OPA (OPA)	$ 0.026153	1.007	$ 0.026327
Controlled Service Water Heating (WHR)	$ 0.026153	1.038	$ 0.027154
Controlled Service Interruptible (LDF/SDF)	$ 0.026153	1.013	$ 0.026484
Controlled Service Deferred (DFL/FTD)	$ 0.026153	0.946	$ 0.024739

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.

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 at the time final rates go into effect, provided the CISone system is in service. As described earlier in my testimony, CISone is scheduled to "go-live" in the 4th 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. Therefore, implementation would need to be delayed until CISone is in service.

Q. IS OTP PROPOSING A MODIFICATION TO THE ENERGY ADJUSTMENT RIDER RELATED TO NON-ASSET BASED TRADING?

A. Yes. OTP is proposing to remove Paragraph 13 of Electric Rate Schedule 13.01, as OTP is currently no longer involved in non-asset-based trading. I discuss this change to non-asset-based trading later in my testimony.

VII. CORPORATE COST ALLOCATIONS

Q. WHAT WILL YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will explain how corporate costs that are incurred by Otter Tail Corporation in connection with the services provided by Otter Tail Corporation for the operation of OTP are handled in the 2017 Test Year.

Q. PLEASE DESCRIBE THE OWNERSHIP STRUCTURE OF OTP AND OTTER TAIL CORPORATION.

A. OTP is a wholly owned subsidiary of Otter Tail Corporation. In 2008, Otter Tail Corporation filed a petition with the Commission seeking approval to form a new holding company through restructuring, with the purpose of establishing OTP as a separate, subsidiary corporation. The Commission approved the request on October 30, 2008, and as of July 1, 2009, OTP became a separate legal entity, instead of an operating division, which OTP had been prior to the formation of Otter Tail Corporation.

Q. WHAT SERVICES DOES OTTER TAIL CORPORATION PROVIDE TO OTP?

A. Otter Tail Corporation provides the following services to OTP: financial reporting, tax planning and reporting, treasury, financial planning, corporate communications, internal audit, benefits plans, safety and risk management, shareholder services and investor relations, aviation and executive management services.

Q. ARE THESE SERVICES GOVERNED BY ANY AGREEMENTS?

A. Yes. At the time of the restructuring, OTP entered into three agreements with Otter Tail Corporation: (i) an Administrative Services Agreement that describes how services are provided from Otter Tail Corporation to OTP and how costs for such services are assigned and allocated to OTP; (ii) a Tax Sharing Agreement that describes how tax obligations and benefits are to be allocated; and (iii) a Cash Management Agreement that describes how cash management services can be provided by Otter Tail Corporation to OTP. Currently, no cash management services are being provided by Otter Tail Corporation to OTP.

Q. HOW ARE OTP TAXES COMPUTED UNDER THE TAX SHARING AGREEMENT?

A. OTP computes its taxes on a standalone basis, exclusive of Otter Tail Corporation. The determination of taxes on a standalone basis means that OTP incurs the same taxes as if it was a separate corporation and does not incur any taxes for Otter Tail Corporation or for the business of other subsidiaries of Otter Tail Corporation. All tax decisions for OTP are based on strategies beneficial to its ratepayers. All tax calculations included in the 2017 Test Year are based only on OTP financial performance. The tax calculations included in this Test Year are detailed in Volume 4A, Supporting Information, Schedule C-7.

Q. HOW DO THE SERVICES PERFORMED BY OTTER TAIL CORPORATION COMPARE WITH THE SERVICES PERFORMED BY SUBSIDIARY SERVICE COMPANIES OF SOME OTHER UTILITY HOLDING COMPANIES?

A. The services performed for OTP by Otter Tail Corporation are less extensive than service performed by other holding company service company subsidiaries, such as Xcel Energy's corporate services unit. Otter Tail Corporation does not process OTP's invoices or customers' bills; it does not perform billing for OTP; it does not manage OTP's human resources (HR), information technologies (IT), or procurement. Rather, OTP directly provides its own accounting, bill and invoice processing, IT, HR, supply chain, engineering, rates and regulation, payroll, marketing and sales, fuel and energy procurement, and customer service.

Q. HOW DID YOU ARRIVE AT THE APPROPRIATE LEVEL OF OTTER TAIL CORPORATION EXPENSES TO INCLUDE IN THE TEST YEAR?

A. Under the Administrative Services Agreement, the costs of corporate functions are allocated using the allocation methodology and specific allocation factors described in the Corporate Cost Allocation Manual (CAM), included as Exhibit__(SDT-1), Schedule 4. Allocation factors were applied to actual 2017 corporate expenses, adjusted for certain corporate expenses which have either been capped or disallowed in prior Commission Orders. Both redline, and clean copies of the 2017 CAM are provided in Schedule 4.

Q. HOW WERE THE COST ALLOCATION METHODOLOGIES DEVELOPED?

A. The following goals were considered when the corporate cost allocation methodology was developed:

1) The result should fully allocate costs;

2) Costs are directly assigned where possible;

3) If direct assignment is not possible, an indirect allocation will be made if there is a cost causative link to another cost category for which direct assignment is used;

4) When neither direct nor indirect cost causation can be found, a representative general allocator is used;

5) The result is equitable for customers and shareholders;

6) The methodology is easy to administer – no additional studies or data gathering is needed; and

7) The allocators have components that are based on verifiable public information, to the extent possible.

Q. PLEASE EXPLAIN THE ALLOCATION PROCESS IN MORE DETAIL.

A. Otter Tail Corporation costs can be charged to OTP or to Otter Tail Corporation's non-utility operations. The allocation process uses three steps. First, all labor and other costs that are appropriate for direct assignment to OTP or non-utility operations are identified and directly assigned. Members of the Corporate Group use timesheets to directly assign labor. Invoices and other costs are directly assigned as appropriate. In the 2017 Test Year, approximately 42 percent of all Otter Tail Corporation costs were allocated to OTP or non-utility operations using direct assignment.

Second, indirect allocators are used for certain functions. Indirect allocators are used where an indirect-cost causative linkage to another cost category or group of cost categories exists. About 17 percent of corporate costs were allocated to OTP or non-utility operations using indirect allocators.

The remaining 41 percent of corporate costs are not appropriate for either direct assignment or indirect allocation. These costs are allocated to OTP or non-utility operations using the general allocator that is composed of revenues, assets and labor dollars, equally weighted.

Q. HOW MUCH OF THE TOTAL OTTER TAIL CORPORATION COST IS ALLOCATED TO OTP IN THE 2017 TEST YEAR?

A. Table 4, below, shows the allocation of Otter Tail Corporation costs for the 2017 Test Year.

Table 4

Otter Tail Corporation Cost Allocation

	Otter Tail Corporation 2017 Costs		SD Share
Allocated to OTP	$10,294,461[4]	51.5%	$859,751[5]
Allocated to Non-Utility	$9,694,759	47.9%	
Total Corporate Costs	$19,989,220	100.0%	

[4] OTP Allocation before any adjustments $10,294,461
Net billings and accruals to Otter Tail Corporation ($17,769)
Total Net Corporate Costs to OTP (Before Incentive Cap) $10,276,692 (Volume 1 Statement H-4 Line 37)

[5] Volume 1 Statement H-4, Line 47 SD Share.

Q. DOES THE ALLOCATION IN TABLE 4 REFLECT THE COMMISSION'S DECISIONS ON INCENTIVE COMPENSATION?

A. Yes. The Otter Tail Corporation costs allocated to OTP in the 2017 Test Year reflect the Commission's decisions regarding bonuses and incentive compensation in determining the South Dakota share. Specifically, Otter Tail Corporation executives' bonuses and incentive compensation are capped at 25 percent of base salary, as reflected in Volume 4A, Section B, workpaper B-16. Statement H-4 shows the adjustment made to calculate the South Dakota amount.

Q. ARE THE COSTS REFLECTED IN TABLE 4 REASONABLE AND APPROPRIATE FOR INCLUSION IN THE 2017 TEST YEAR?

A. Yes. All costs have been allocated in a manner consistent with prior cases. The Otter Tail Corporation costs reflected in Table 4 are reasonable and appropriate for inclusion in the 2017 Test Year. Approximately 70 percent of operating and net income for Otter Tail Corporation is derived from OTP,[6] yet as Table 4 above reflects, only 51.5 percent of Corporate costs are allocated to OTP.

VIII. ECONOMIC DEVELOPMENT RATES

Q. WHAT TOPICS WILL YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will discuss two new economic development rates being proposed by OTP.

Q. DOES OTP'S CURRENT RATE STRUCTURE SUPPORT ECONOMIC DEVELOPMENT?

A. Yes. As Mr. Gerhardson points out in his Direct Testimony, OTP has the 4th lowest blended rate for all customers in the United States, and the second lowest of any investor-

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[6] Derived from page 5 of Otter Tail Corporation's 2017 Annual Report to Shareholders. Operating Income for OTP was $90 million; Otter Tail Corporation operating income was $126 million. Similarly, OTP accounted for $49 million of Otter Tail Corporation's total net income of $72 million.

owned utility in South Dakota. High energy use entities that may be considering locating or expanding in South Dakota will give careful consideration to low rates in evaluating their options, including locating in areas in South Dakota that OTP serves. OTP's high customer satisfaction and reliable service are additional supporting factors that helps OTP attract new load.

Q. IS OTP PROPOSING ANY NEW RATES IN THIS CASE THAT WOULD SUPPORT FURTHER ECONOMIC DEVELOPMENT IN SOUTH DAKOTA?

A. Yes. In this case, OTP is proposing two new rate offerings: a new Economic Development Rider-Large General Service (EDR) rate; and a new Super Large General Service (Super LGS) rate offering. In order to expand OTP's "tool-box" of rate offerings to help attract new business, OTP has designed these two rate offerings to enhance OTP's potential to attract business to South Dakota. Both rate mechanisms would allow OTP to compute customer-specific rate quotes in the form of a discount, using a formulaic approach that insures that a proposed discount will still yield benefits to all other customers should the customer take service from OTP. OTP witness Mr. David Prazak provides the details associated with these new rate offerings in his Direct Testimony, along with proposed rate schedules for each.

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC DEVELOPMENT-LARGE GENERAL SERVICE RIDER RATE.

A. The mechanism calculates a proposed rate discount off OTP's Large General Service Rider rate. OTP could potentially offer a discount for up to a five-year period with this rider. OTP has developed a model to price the potential discount while ensuring that the potential customer will at least pay the annual incremental (marginal) costs to serve them. This helps ensure net benefits are realized by all other customers through the addition of the load.

Q. PLEASE BRIEFLY DESCRIBE THE SUPER LGS RATE.

A. The Super LGS rate is intended for very large, high load factor customers such as a data processing facility or a large agricultural processing facility that might have a connected load of 25 MWs or more and run at a very high capacity level (at least 80 percent load factor). Following a similar approach as the EDR rate, a rate would be computed based on a customer's specific operating profile and would be set at a level which still provides benefits to other customers. Unlike the EDR rate, the Super LGS rate could continue beyond a five-year period.

Q. PLEASE EXPLAIN FURTHER HOW THESE RATES BENEFIT OTHER CUSTOMERS.

A. The computation of these rates takes into account the marginal costs OTP would incur to serve these customers. Because these marginal costs are covered under both rate offerings, the incremental margins over and above the marginal costs helps cover OTP's fixed costs of service. Other customers realize the benefit of these new customers in at least two ways. First, in the near term (for example when a rider filing such as the TCRR is made), the costs being recovered within the rider would be spread over a greater number of KWs or kWhs, reducing the effective rate that all customers would pay. Second, adding new load that contributes incremental margin to OTP could help delay the need for future rate cases. When rates are reset in the next rate case, again, the costs would be spread over a greater number of KWs and kWhs keeping rates lower than without these customers.

Q. ARE THERE OTHER BENEFITS IF THESE RATES ARE SUCCESSFUL IN ATTRACTING NEW BUSINESS TO OTP AREAS IN SOUTH DAKOTA?

A. Yes. For example, attracting a large agricultural processing facility or data processing facility would certainly bring with it new employment opportunities; potentially attract more people to the communities OTP serves; provide further economic activity to existing or potentially new additional businesses providing products and services to the area; increase the state's tax base that would drive increased property, sales, and income taxes for the state.

Q. HOW WOULD YOU SUMMARIZE OTP'S NEED FOR ECONOMIC DEVELOPMENT RATES?

A. The sustainability of the small towns OTP serves across rural South Dakota is critical for OTP's long-term success and its commitment to provide low cost, safe, reliable energy to all customers. A declining customer base results in OTP costs being spread over fewer customers, resulting in an increasing effect on future rates. OTP, its customers, and the state of South Dakota all benefit when economic development efforts facilitate the attraction and development of new business and the expansion or retention of existing business. OTP's design of the economic development rates discussed above assure benefits are realized to all parties involved.

IX. 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 South 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 4A, Section C, 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 38.9 days shown in OTP's last rate case in 2010, with the majority of the increase coming from collections increasing from 20.07 days in 2010 to 24.7 days in this latest study. As reflected in Volume 4A, Section C, 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 4A, Section C, 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.

X. MERRICOURT WIND PROJECT STEP INCREASE RATE PROPOSAL

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR TESTIMONY?

A. In this section of my Direct Testimony, I will discuss OTP's proposal to include the 150 MW Merricourt Wind (Merricourt) project into base rates through the use of a step increase rate upon completion of the project. Mr. Akerman addresses the financial adjustments associated with the Merricourt project to determine the increased jurisdictional revenue requirement. Mr. Haugen addresses the associated class revenue requirement impacts and Mr. Prazak addresses the updates to rates attributable to the Merricourt project.

Q. WHEN IS THE MERRICOURT PROJECT SCHEDULED TO BE PLACED IN SERVICE?

A. The Merricourt project is scheduled to be completed and in-service at the end of 2019.

Q. WHY IS OTP PROPOSING A STEP INCREASE RATE FOR THE MERRICOURT PROJECT?

A. The Merricourt project is the largest single wind energy project in which OTP has invested in to date, with an estimated total cost of approximately $271 million (OTP Total), $25 million (OTP SD). Because of the size of the project and the absence of any other recovery mechanism such as a rider to recover the cost project, OTP believes developing a step increase rate in this case would be the most cost-effective and efficient approach to request recovery.

Q. ARE THERE ANY OTHER RATE IMPACTS BEYOND COST RECOVERY THAT WILL OCCUR DUE TO THE MERRICOURT PROJECT?

A. Yes. When Merricourt is placed in service, the energy output from Merricourt will be generated at zero fuel cost and will displace other costs such as purchased power costs, which flow through the Energy Adjustment Rider. An updated Statement P that reflects the estimated reduction in purchased power costs is included in Volume 4A, Section 5. The estimated average base fuel rate, calculated on a system basis, drops from $0.026153 to $0.022996 per kWh.

Q. IF A STEP INCREASE RATE WAS NOT APPROVED IN THIS CASE, HOW WOULD OTP SEEK FUTURE RECOVERY OF THIS PROJECT?

A. OTP would need to file another rate case to request recovery of the Merricourt project costs. OTP's current assumption that final rates in this case will become effective January 1, 2019, and the Merricourt project is scheduled to be completed and in-service just one year later. As Mr. Gerhardson discusses, OTP believes it would be in the best interest of all stakeholders to avoid the significant cost of another rate case, not long after the conclusion of this case, to incorporate this project into base rates.

Q. ARE THERE OTHER MAJOR OTP INVESTMENTS THAT ARE GOING TO DRIVE FUTURE RATE CASES?

A. Yes. OTP is also developing its Astoria Station (Astoria) project, an approximately $165 million simple cycle gas generating station to be located near Astoria, South Dakota, which is currently scheduled to be completed in 2021. OTP anticipates that it will need to file a rate case in the 2021 timeframe to request recovery of the Astoria project, as well as incorporate then-completed transmission projects, such as the Big Stone South to Ellendale project, currently under construction, into base rates. The step increase proposal in this case will allow OTP to bridge the gap between this case and the potential 2021 case.

Q. WHEN DOES OTP PROPOSE THE STEP INCREASE RATES TO INCLUDE THE MERRICOURT PROJECT WOULD TAKE EFFECT?

A. OTP proposes that the step increase rates would become effective January 1, 2020.

XI. MISCELLANEOUS ITEMS

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

A. In this section of my Direct Testimony, I will discuss: 1) non-asset-based trading; 2) rate case expenses; and 3) holding company formation expenses.

A. Non-Asset Based Trading

Q. DOES THE 2017 TEST YEAR INCLUDE ANY COSTS RELATED TO NON-ASSET BASED TRADING ACTIVITIES?

A. No. OTP ceased all non-asset-based trading activities as of December 31, 2014. Thus, there are no new non-asset-based trading costs or revenues in the 2017 Test Year.

Q. WHY DID OTP MAKE THE BUSINESS DECISION TO CEASE NON-ASSET BASED TRADING ACTIVITIES?

A. OTP conducted a financial analysis on its non-asset-based trading business in the winter and spring of 2014. The analysis showed historically declining margins and reduced profits in the future. Based on this analysis, OTP ultimately concluded that it should exit the non-asset-based trading business.

Q. DOES OTP HAVE ANY REMAINING NON-ASSET BASED TRADING POSITIONS?

A. No. The last new non-asset-based trades occurred on December 31, 2014. A small number of non-asset-based positions carried into the 2015 calendar year, but they were completely liquidated by June 1, 2015. As of that date, OTP had no non-asset-based trading positions.

B. Rate Case Expenses

Q. WHAT IS THE ESTIMATED RATE CASE EXPENSE FOR THIS CASE?

A. We estimate the rate case expenses associated with this case to be $550,000 (OTP SD). This expense includes administrative costs, the charges to be expected from the Commission and outside consulting and legal fees.

Q. HOW DID YOU DEVELOP THIS ESTIMATE?

A. Administrative costs and Commission charges are estimated based on fees assessed in other South Dakota rate cases. Consulting fees and outside legal fees estimates were based on information from service providers. The details are reflected in work paper TY-09 in Volume 4A, Workpapers.

Q. WHAT IS THE AMOUNT OF RATE CASE EXPENSE INCLUDED IN THE 2017 TEST YEAR?

A. The 2017 Test Year annual rate case expense is $183,333 (OTP SD).

Q. WHAT AMORTIZATION PERIOD DID YOU USE?

A. We used a three-year amortization period. Because the rate case expense is a one-time expense, it would be inappropriate to treat those expenses as recurring expenses. Therefore, it is appropriate to amortize those expenses over the period of time expected before OTP's next rate case. Based on what we know today, we believe OTP will likely file its next rate case in three years.

C. Holding Company Formation Expenses

Q. DOES THE 2017 TEST YEAR INCLUDE ANY ADJUSTMENT FOR AMORTIZATION OF HOLDING COMPANY COSTS?

A. No. In Docket, EL08-025, the Commission approved OTP's request to form a holding company. OTP began amortizing holding company costs following its rate case in Docket EL08-030 and updated the amortization to three years following OTP's last general in Docket EL-10-011. There are no holding company formation expenses included in the 2017 Test Year.

XII. CONCLUSION

Q. WHAT ARE YOUR CONCLUSIONS?

A. My Direct Testimony supports the conclusions that:

- OTP has effectively managed its major capital projects which has resulted in very substantial customer savings;
- The 2017 Test Year South Dakota retail revenues are reasonable and appropriate for ratemaking;
- OTP's jurisdictional and class allocations are reasonable for establishing rates in this case;
- OTP's proposed revisions to its Fuel Clause Rider are reasonable;
- OTP's corporate cost allocations meet Commission requirements and are appropriate;
- OTP's proposal rates for economic development are reasonable and appropriate;

- OTP's proposal for step increase rates for the Merricourt project will help delay the need for another rate case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Mr. Stuart D. Tommerdahl, CPA (Inactive)
Manager, Regulatory Administration
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8279

CURRENT RESPONSIBILITIES: (March 2012 to Present)

Provide leadership in revenue requirements analysis, pricing and rate design, tariff administration, load research, allocation methodologies for cost of service studies, long range revenue forecasting, wholesale energy accounting, cost of energy, and unbilled revenue.

PREVIOUS POSITIONS:

Otter Tail Power Company

2012 - Present	Manager, Regulatory Administration
2004 – 2012	Manager, Risk Management
2003 - 2004	Business Analyst

Otter Tail Energy Services

1998-2003	Director, Financial Services
1997-1998	Manager, Financial Planning/Analysis

Otter Tail Power Company

1997 – 1997	Senior Regulatory/Economic Analyst
1993 – 1997	Regulatory/Economic Analyst

Great Plains Software, Fargo, ND

1986 - 1993	Budget & Financial Reporting Manager
1984 – 1986	Inventory Accountant / Purchasing

Twin Valley-Ulen Telephone Co., Twin Valley, MN

1983 – 1984	Accountant

EDUCATIONAL / CERTIFICATIONS

Moorhead State University-Moorhead, B.S. Accounting, Minor in Economics.
Certified Public Accountant (Inactive)

Otter Tail Power Company

Estimated Project Savings Impacts on Revenue Requirements (Customer Savings) and Earnings (Reduced Shareholder Return) of the Big Stone Air Quality Control System

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
										Customer Impact			Shareholder Impact			
Line No.	Yr	Original cost Total Project	Final Cost Total Project	Project Savings (1)	OTP Total share @ 53.9%	OTP SD share %	OTP SD Rate Base Balance (30 Year Life)	OTP SD Total Annual Avoided Depreciation	OTP SD Total Annual Avoided Return Revenue Requirement (Column F x 9.42% Rate Base Revenue Requirement Factor) (4)	OTP SD Total Annual Avoided Revenue Requirements (Column G + Column H)	OTP SD Avoided Revenue Requirement	OTP SD NPV Avoided Revenue Requirement (5)	OTP SD Available for Return (Column F x 5.47% Equity Return Factor) (6)	OTP SD 30 Years Avoided Available for Return	OTP SD NPV Avoided Available for Return (4)	Notes
1	2015	**$491,000,000**	**$365,513,806**	**$125,486,194**	**$67,637,059**	**9.341629%**	**$6,318,403**	**$210,613**	**$595,194**	**$805,807**			**$345,568**			
2	2016						$6,107,790	$210,613	$687,737	$898,351			$334,049			
3	**2017 Test Year**						$5,897,176	$210,613	$664,022	**$874,635**			**$322,530**			**Test Year**
4	2018						$5,686,563	$210,613	$640,307	$850,920			$311,012			
5	2019						$5,475,949	$210,613	$616,592	$827,205			$299,493			
6	2020						$5,265,336	$210,613	$592,877	$803,490			$287,974			
7	2021						$5,054,723	$210,613	$569,162	$779,775			$276,455			
8	2022						$4,844,109	$210,613	$545,447	$756,060			$264,936			
9	2023						$4,633,496	$210,613	$521,732	$732,345			$253,417			
10	2024						$4,422,882	$210,613	$498,017	$708,630	**$8,037,219**	**$5,473,181**	$241,898	**$2,937,331**	**$2,023,050**	**Initial 10 Years**
11	2025						$4,212,269	$210,613	$474,301	$684,915			$230,379			
12	2026						$4,001,655	$210,613	$450,586	$661,200			$218,860			
13	2027						$3,791,042	$210,613	$426,871	$637,485			$207,341			
14	2028						$3,580,428	$210,613	$403,156	$613,770			$195,822			
15	2029						$3,369,815	$210,613	$379,441	$590,055			$184,303			
16	2030						$3,159,202	$210,613	$355,726	$566,340			$172,784			
17	2031						$2,948,588	$210,613	$332,011	$542,624			$161,265			
18	2032						$2,737,975	$210,613	$308,296	$518,909			$149,746			
19	2033						$2,527,361	$210,613	$284,581	$495,194			$138,227			
20	2034						$2,316,748	$210,613	$260,866	$471,479			$126,708			
21	2035						$2,106,134	$210,613	$237,151	$447,764			$115,189			
22	2036						$1,895,521	$210,613	$213,436	$424,049			$103,671			
23	2037						$1,684,908	$210,613	$189,721	$400,334			$92,152			
24	2038						$1,474,294	$210,613	$166,006	$376,619			$80,633			
25	2039						$1,263,681	$210,613	$142,290	$352,904			$69,114			
26	2040						$1,053,067	$210,613	$118,575	$329,189			$57,595			
27	2041						$842,454	$210,613	$94,860	$305,474			$46,076			
28	2042						$631,840	$210,613	$71,145	$281,759			$34,557			
29	2043						$421,227	$210,613	$47,430	$258,044			$23,038			
30	2044						$210,613	$210,613	$23,715	$234,329			$11,519			
31	**Total**							**$6,318,403**	**$10,911,250**		**$17,229,654**	**$7,843,928**		**$5,356,309**	**$2,706,167**	**Life of Project**

32

	Steam production plant jurisdictional allocator		Base / Peak %
33	**Steam production plant jurisdictional allocator**		**Base / Peak %**
34	E1	9.364273% (2)	81.510000% (3)
35	D1	9.241806% (2)	18.490000% (3)
36	SD Jurisdictional Share %		**9.341629%**

37

38 (1) Phinney Direct Table 1, Page 10
39 (2) JCOSS Page 15-1
40 (3) Workpaper C-1 (Base/Peak Split)
41 (4) Rate Base Revenue Requirement Factor 9.42% Pg 2 of 2
42 (5) Net Present Value (NPV) computed using ROR Discount Rate **7.96%** Pg 2 of 2
43 (6) Rate Base Equity Return Factor reflects the after-tax earnings 5.47% Pg 2 of 2

OTTER TAIL POWER COMPANY
Revenue Requirement Factor Calculation
To be used when estimating revenue requirement on rate baseamount changes

Amounts rounded to 4 decimal places =

Line	Description	SD				
1	**Effective Tax Rate**	21.0000%				
2	**SDPUC Special Hearing Fund Assessment**	0.0015				
3	**Capital Structure**	Rate	Ratio	Cost	Weighted Debt Cost	
4	LT Debt	5.3000%	46.90%	2.4900%	5.30%	
5	ST Debt	0.0000%	0.00%	0.0000%		
6	Common Equity	10.3000%	53.10%	5.4692%		
7	Required Rate of Return			7.9592%		
8	Equity Return Tax RR (5.41% Equity X Tax Effect 1.61) - 5.41% Equity)			1.4608%		
9	**Rate Base Revenue Requirement Factor**			9.4200%		
10						
11						
12	Tax Effect 1 / (1 - Tax Rate)	1.267724	Gross Up of Equity %	6.93%		
13			Equity %	5.47%		
14			Difference	1.46%		
15						
16	**PROOF - EXAMPLE**		Total		Debt	Equity
17	Rate Base		**$ 10,000**		$ 4,690	$ 5,310
18						
19	Revenue Requirement	9.42%	**$ 942**			
20	Interest on Debt (Weighted Debt Cost X Debt Amt)		$ 249			
21	Taxable Income		$ 693			
22	Taxes	21.1500%	$ 146.66			
23	Return on Rate Base		$ 795	7.95% ROR		
24	Available for Return (Equity 5.41% X RB)		$ 547	10.30% ROE		
25						
26	**Equity Return**					
27	Revenue		$ 942			
28	Interest Expense		$ 249			
29	Taxes		$ 147			
30	Available for Return		$ 547			
31	Equity		$ 5,310			
32	ROE (Line 30/Line 31)		10.30%			
33						
34						

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 ~~except wind generation~~ (accounts 310-~~347~~ 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 ~~typical~~ capacity factor for wind generation is ~~still being~~ determined~~. While~~ by the ~~Midwest~~ Midcontinent Independent ~~Transmission~~ System Operator (MISO) ~~continues to evaluate the~~ as they accredit capacity ~~factor~~based on each generation site's production. While a majority of a wind~~, its current~~ 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 ~~capacity credit is 8 percent. Therefore, wind~~farm that results in a base/peak split. Wind generation investment is allocated ~~as 92 percent BASE ENERGY (E2) and 8 percent PEAK DEMAND (D1).~~ 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).

<u>DISTRIBUTION PLANT IN SERVICE</u>

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:

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

$ of Base Demand = Total Demand Charges − $ 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.

~~ACCOUNT~~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.

~~ACCOUNT~~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 ~~E2~~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

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

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

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

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

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

*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.)

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

<u>Dollar Allocations for Account 365 Primary</u>

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

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

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.

<u>Dollar Allocations for Account 365 Secondary</u>

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

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

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

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

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.

<u>Account 366 (Underground Conduit):</u>

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.

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

Dollar Allocations for Account 367 Primary

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

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

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.

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

Dollar Allocations for Account 367 Secondary

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

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

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

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

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

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

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

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

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.

<u>Dollar Allocations for Account 369</u>

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

Demand Component $= F - DSCC = DSDC$

<u>Account 369.1 (Underground Services):</u> (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.

<u>Dollar Allocations for Account 369.1</u>

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 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 Midcontinent 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:

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

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

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>

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

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

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

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

*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.)

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

Dollar Allocations for Account 365 Primary

Customer Component $= C \times UPD = DPCC$

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 $= F \times G = DSL$

To Area Lighting $= F - DSL = DAL$

Customer Component $= C \times D = DSCC$

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>

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

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

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

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

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>

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

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

<u>Account 369 (Overhead Services):</u> (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.

<u>Dollar Allocations for Account 369</u>

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

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

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

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

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

Corporate Cost Allocation Manual

Last Update: February ~~2010~~2017

I. INTRODUCTION

The corporate entity ("Corporate") of Otter Tail Corporation provides services to the operating companies that comprise the Corporation. One of three things can occur with costs from Corporate services: 1) allocated to Otter Tail Power Company; 2) allocated to Varistar Inc., or 3) not allocated and remain at Corporate. The purpose of this manual is to detail how costs are being allocated to Otter Tail Power Company.

Otter Tail Power Company (the largest operating company of Otter Tail Corporation) serves retail electric customers in three jurisdictions including Minnesota, North and South Dakota and is governed by the rules and regulations in each jurisdiction. As a regulated utility, Otter Tail Power is allowed to recover prudent and reasonable costs for services it receives from Corporate, and reflects the cost of these services in its revenue requirements for setting rates. Costs allocated from Corporate are based on allocation factors that are calculated annually. In Minnesota, a different allocation method for the general allocator has been ordered for regulated reporting; however, this change in percentage is adjusted by Otter Tail Power Company so all costs billed from Corporate are at the same rate, regardless of jurisdiction.

The services provided by Corporate include financial reporting, tax planning and reporting, treasury and cash management, financial planning, internal audit, human resource and labor expertise, benefit plans, corporate communications, safety and risk management, shareholder services and investor relations, ~~sourcing,~~ aviation and executive management services (CEO, COO, CFO and General Counsel). These services are distinct from and do not duplicate similar services in Otter Tail Power Company. See Section V below for additional information of Corporate services. To support these services, there are specific corporate costs associated with administration and information technology ("IT") that also need to be allocated.

The remainder of this document is devoted to explaining the services being provided and the methodology and allocation factors used to allocate Corporate service costs to Otter Tail Power Company.

II. METHODOLOGY

Corporate identifies costs in three categories: 1) directly assignable costs, 2) indirect costs that are allocated on a department or functional allocation factor, and 3) general costs that are allocated using a general allocation factor.

Directly assignable costs are those costs where the purpose behind the costs can be attributed to a specific operating company. For example, consulting fees to help with a project related to an individual operating company would be directly assigned to that operating company.

Indirect costs have an identifiable cost causation related to another activity or factor. For example, costs for an employee in the Risk Management department of Corporate to attend a seminar on safety would be allocated using a functional allocation factor such as number of employees.

General costs are those costs that cannot be directly assigned or where cost-causation cannot be identified. Examples would include postage, local telephone and communication service costs, time spent preparing the annual report and other SEC filings, preparing to meet with rating agencies, working with and tracking shareholder matters. These types of costs will be allocated on a general allocation factor discussed below.

Allocation factors are updated annually in February with the most recent calendar year's data. The updated allocation factors are then implemented and utilized for all Corporate Costs in February and remain unchanged for 12 months. ~~Current year factors are applied to corporate billings to the utility in first month following availability of final, audited financial information required for some factors.~~

III. ALLOCATION FACTORS

Indirect Allocation Factors:

A. IT Factor: This factor is based on the previous year ending December 31 ratio of corporate labor assigned to Otter Tail Power where the numerator is the total Corporate labor (not including bonuses) assigned to Otter Tail Power and the denominator is the total of all Corporate labor (not including bonuses). See Appendix A.

B. HR Factor: This factor is based on the average of the previous year ending December 31 ratio of employees, and the previous year ending December 31 ratio of benefit expenses. For the employee ratio the numerator is ~~both~~ full ~~and part~~-time employees in electric operations and the denominator is the total number of full ~~and part~~-time employees for all of Otter Tail Corporation. For the benefit ratio, the numerator is total benefit costs (including benefit costs cleared through the payroll loading rate) from electric operations, and the denominator is consolidated benefit costs for all of Otter Tail Corporation (including benefit costs cleared through the payroll loading rate~~) excluding benefit costs for Corporate employees.~~). The specific consolidated corporate accounts that will be used to calculate this ratio (including Otter Tail Power benefit costs cleared through payroll loading) are accounts C5030, C5230, C6030, C6530, C7030. See Appendix A.

C. RM Factor: This risk-management factor is the average of the previous year ending December 31 ratio of employees, and the ~~previous~~current year ratio of insurance premiums paid. For the employee ratio the numerator is ~~both~~ full ~~and part~~-time employees in electric operations and the denominator is the total number of full ~~and part~~-time employees for all of Otter Tail Corporation. For the insurance premium ratio, the numerator is the total premiums paid by Otter Tail Power and the denominator is the sum of insurance premiums paid by all operating companies. See Appendix A.

D. Internal Audit Factor: This factor is based on the previous year ending December 31 ratio where the numerator is the total hours spent auditing electric operations and the denominator is the sum of hours auditing electric and non-electric operations. Non-electric operations do not include hours spent auditing Corporate-related matters. See Appendix A.

General Allocation Factor:

This factor is based on a three-factor formula that is comprised of the average ratio of Total Assets, Total Revenues and Total Labor Dollars for the most recent calendar year. The specific consolidated corporate accounts that will be used to calculate the Total Labor Dollars ratio are C5010, C5020, C5030, C5210, C5220, C5230, C6010, C6015, C6020, C6030, C6510, C6520, C6530, C7010, C7020 and C7030. Appendix A shows the computation of this factor based on prior-year audited numbers and shows the source for the information to calculate each ratio.[1]

IV. CLARIFICATION ON CERTAIN COSTS

There are certain costs that need to be discussed in further detail to gain an understanding of exactly how they are being allocated, or in some instances, not being allocated. This section will list each of these costs individually and provide background and instruction on how each is handled for allocation purposes.

A. Labor: Employees at Corporate track their time on a daily basis. Percentages are used to track time between Corporate, Otter Tail Power Company, and Varistar activities. The time designated Otter Tail Power is directly assigned to the power company. The percentage of time being recorded in the Corporate column is allocated based on the

[1] The Minnesota Public Utilities Commission (PUC) has ordered in Otter Tail Power Company's last rate case (Docket No. E017/GR-07-1178), that the General Allocator calculation method must comply with the PUC's orders in Docket E,G999/CI-90-1008. That docket established a general allocator based on the ratio of regulated to unregulated expenses, excluding fuel, purchased power, and purchased cost of goods sold.

employee's position and will use one of the allocation factors discussed above in Section III.

B. Bonuses and Benefits: Cash bonuses are allocated based on each employee's labor ratio from the previous year. An employee's labor ratio reflects both directly assigned and allocated labor. Bonuses are accrued and allocated during the current year, and a true-up is made in the following year after the exact bonus amount is determined and the employee's actual labor ratio from the previous year is available. Benefit costs are allocated on each employee's labor ratio from the most recent 30-day pay period.

C. Contributions~~, Employee Stock Purchase Plan and Deferred Compensation Expense: The costs associated with these three items~~: The contributions made by Otter Tail Corporation are not allocated to Otter Tail Power. Each operating company makes its own contributions and those contributions made from a corporation perspective are typically not allocated. ~~Costs for the stock purchase plan and deferred compensation plan are kept at Corporate and not allocated.~~

D. Employee Stock Purchase Plan and Deferred Compensation Expense: The costs associated with the Employee Stock Purchase Plan are allocated based on the ratio of Otter Tail Power employee stock purchases to the total of the most recent stock purchase and Deferred Compensation expense is allocated to Otter Tail Power based on the general allocator.

~~D.~~E. Stock Option Expense: Under ~~FAS 123(R)~~Accounting Standard Codification (ASC) Topic 718 companies are required to record the value of stock options over the period in which the options vest. These expenses are allocated to Otter Tail Power based on the number of options granted to employees in this company. No stock options were granted in 2016 and none are expected to be granted to employees in 2017.

~~E.~~F. Restricted Stock and Restricted Stock Units: Under ~~FAS 123(R)~~ASC Topic 718 companies are required to record the value of restricted stock and restricted stock units over the period in which the shares vest. Restricted stock and restricted stock unit expense on shares granted to Otter Tail Power employees are directly assigned to Otter Tail Power. ~~No~~The portion of restricted stock or restricted stock units granted to Corporate employees and the Board of Directors is allocated to Otter Tail Power Company based on the general allocator.

~~F.~~G. Executive Stock ~~Incentive~~Performance Award Plan: Under ~~FAS 123(R)~~ASC Topic 718 companies are required to record the value of incentive stock, awarded based on the performance of the company's stock price, over the time period used to evaluate performance. Otter Tail Corporation provides incentive stock to the corporate officers as part of their overall compensation package. The costs associated with this plan are ~~not allocated.~~ allocated based on the prior year time allocations for each executive. In addition when performance shares are awarded to Otter Tail Power's president the cost related to his award is directly assigned to Otter Tail Power.

~~G.~~H. Bank Charges: Corporate serves as the "Bank" for operating companies and therefore incurs the various fees associated with the accounts maintained by the operating companies. ~~Each operating company~~Otter Tail Power is directly charged for ~~their~~its respective fees and the fees associated with Corporate's accounts are allocated using the General Allocation Factor.

~~H.~~I. External Audit Fees: Otter Tail Corporation currently retains an independent registered public accounting firm to audit its financial reports and records. Each year this firm provides to Otter Tail Corporation a Client Service Plan that outlines the number of hours it has assigned to audit electric and non-electric operations. Fees from the firm are allocated based on the ratio of assigned hours for electric versus total audit hours on consolidated operations. -The hours assigned to corporate are allocated using the general allocator.

~~I.~~J. Meetings: Costs associated with periodic meetings that involve personnel from across the operating companies such as ~~quarterly~~ leadership meetings, quarterly accounting and HR meetings are not allocated.

K. Training and Development: Costs associated with training and development are direct charged where possible but otherwise allocated using the appropriate indirect allocator or the general allocator.

~~J.~~L. Travel and meals: With the exception of travel-related expense related to operations of Otter Tail Power's jointly owned generation plants~~,~~, or if corporate employees are working specifically forOtter Tail Power, corporate travel expense is not allocated.

~~K.~~M. Aviation Services: Corporate provides air service for the operating companies of Otter Tail Corporation. There ~~are two aircrafts~~is one aircraft available for use~~. One is~~ which is the King Air. The King Air is owned by Otter Tail Power Company ~~(the King Air), the other is owned by Varistar Corporation (the Encore).~~. To help recover the variable costs associated with flying ~~these two~~this aircraft, corporate charges hourly rates which are reviewed periodically.[2] (See Appendix B for hourly rates)

Because the King Air is owned by Otter Tail Power, at the end of each quarter the costs associated with the King Air that have not been recovered through the hourly rate are charged to Otter Tail Power. For example, the costs not cleared for the quarter total \$9,000. Otter Tail Power has recorded depreciation expense for the quarter of \$1,000 which is added to the \$9,000 of un-cleared costs for a total of \$10,000. The \$10,000 is

[2] The aviation charge rates may be changed during the year to reflect changes in variable costs (i.e., aviation fuel).

multiplied by the non-utility usage factor (the percentage of hours flown for operating companies other than Otter Tail Power) and for our example we'll say it's 52%. Otter Tail Power will then be charged $3,800 ($9,000 less $5,200 ($10,000 x 52%)) to reflect the utility-portion of costs not cleared on the King Air.

V. DESCRIPTION AND ALLOCATION OF SERVICES PROVIDED

Further detail is discussed below on the services provided by Corporate. Each service shown below is directly related to an individual cost center at Corporate. For each service a description is provided along with the primary allocation factor that is used to allocate associated costs. Again, costs that can be directly assigned to the various operating companies are directly assigned. Indirect costs are allocated using one of the factors discussed in Section III.

A. Corporate Overheads

Description: Represents charges for ~~succession planning and developing leadership at the operating companies,~~ bank charges, building lease and depreciation expense.

~~Allocation Factor: Costs associated with succession planning and developing leaders at the various operating companies are not allocated but kept at Corporate. All other~~Allocation Factor: All costs not directly assigned are allocated on the General Allocation Factor.

B. Executive Management Services

Description: Represents charges for Otter Tail Corporation's executive management team ~~comprised of the four Officers,~~ and Contributions.

Allocation Factor: Contributions are not allocated and all other costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

C. Board of Directors

Description: Represents charges for board of director fees, restricted stock, travel and other expenses associated with attending Board meetings or related to being a board member.

Allocation Factor: Fees and restricted stock expense are allocated on the General Allocation Factor. Otter Tail Power is not allocated any costs associated with ~~restricted stock granted to directors or~~ travel related expenses.

D. Corporate Development

Description: Represents charges for the Corporate Development staff that are responsible for identifying and researching acquisition candidates, due diligence on acquisition targets, and integrating recently acquired companies into Otter Tail Corporation.

Allocation Factor: All costs are currently being directly assigned to Varistar Corporation but if Otter Tail Power uses these services for an acquisition, the associated costs would be directly billed to Otter Tail Power.

E. Platform Leadership

Description: Represents charges for the Platform Leaders and their staff that have oversight responsibilities with the non-electric operating companies.

Allocation Factor: All costs are currently being directly assigned to Varistar Corporation.

F. Administrative Services

Description: Represents charges for providing administrative support to all the other services, office supplies~~, cell phones~~ and office equipment leases.

Allocation Factor: All costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

G. Information Technology

Description: Represents charges for supporting corporate computers, networks, land-based phones and T1 lines, internet, software and other various pieces of hardware. In addition, consulting services are provided as requested to the various operating companies.

Allocation Factor: License and maintenance fees comprise a large portion of the non-labor costs. As much as possible, these costs are directly assigned based on the number of user licenses utilizing the software by each operating company. All costs not directly assigned are allocated on the IT Factor including labor classified as Corporate. The corporate VP of Information Technology is a shared position with Otter Tail Power Company. The specific costs for this position are directly assigned to Otter Tail Power as appropriate.

H. Corporate Accounting

Description: Represents charges for maintaining financial records, statements and systems, SEC filings, tax accounting and filings, cash management and consulting with various operating companies on an as-needed basis.

Allocation Factor: External audit fees are allocated as discussed in Section IV. Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

I. Internal Audit

Description: Represents charges for reviewing internal controls and conducting operation audits at the various companies within Otter Tail Corporation.

Allocation Factor: Costs not directly assigned are allocated on the Internal Audit Factor including labor classified as Corporate.

J. Financial Planning

Description: Represents charges for supporting financial analysis and budgeting at the operating company and corporate level.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

K. Treasury

Description: Represents charges for communicating with both debt and equity analysts, maintaining Otter Tail Corporation's capital structure, monitoring and accessing capital markets and other services as identified by the Chief Financial Officer.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

L. Corporate Communications

Description: Represents charges for corporate communications including press releases, advertising and branding and annual report preparation. Another service provided is coordinating and tracking contributions made on behalf of Corporate.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

M. Shareholder Services

Description: Represents charges for maintaining shareholder records, communicating with investors at various fairs, coordinating transfer agents and planning the annual shareholder meeting.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

N. Human Resources/Leadership Development

Description: Represents charges for establishing and maintaining policies related to employment and benefits of corporate employees and executive compensation, searches for candidates for upper-level management positions on behalf of operating companies, organizing and facilitating leadership training, organizing and aiding in the administration of company benefit programs.

Allocation Factor: Costs not directly assigned are allocated on the HR Factor including labor classified as Corporate. In case of leadership and employee development training, costs are allocated based on employees in attendance at training sessions, if possible and otherwise allocated using the HR allocator.

O. Legal Affairs

Description: Represents charges for legal services related to employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other various legal matters.

Allocation Factor: ~~All~~Most costs associated with legal services are directly assigned~~. All~~ but if costs cannot be directly charged, the general allocator is used. Typically, labor costs for all corporate lawyers other than the General Counsel are ~~directly~~generally assigned to ~~one operating company, or a group of operating~~the Varistar companies~~.~~ ~~Three~~ as Otter Tail Power employs their own attorneys, however, there are times when corporate lawyers ~~are currently~~perform work for Otter Tail Power which would be assigned ~~to Otter Tail Power and two lawyers are assigned to non-electric companies.~~ as such.

P. Risk Management

Description: Represents charges for assisting operating companies with assessment and management of risks, identifying and implementing loss control strategies to minimize the frequency and financial consequences of accidental losses, assisting operating companies in post loss claim management, overseeing Otter Tail Corporation's consolidated insurance program, and identifying and documenting the environmental conditions during the process of acquiring a new company.

Allocation Factor: Costs not directly assigned are allocated on the RM Factor including labor classified as Corporate.

~~**Q. Sourcing**~~

~~Description: Charges represent services related to sourcing, procurement, vendor relationships, and developing strategies to leverage the consolidated buying power of Otter Tail Corporation as a whole.~~

~~Allocation Factor: Sourcing-related costs are directly assigned in most instances. Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.~~

VI. CONCLUSION

As circumstances arise, such as adding a new service that will be provided by Corporate, appropriate changes will be made to the manual. Appendix A will be updated annually in February when the prior-year audited records are available and Appendix B will be updated as Aviation Rates are changed.

OTTERTAIL CORPORATION

Corporate Cost Allocation Manual

Last Update: February 2017

I. INTRODUCTION

The corporate entity ("Corporate") of Otter Tail Corporation provides services to the operating companies that comprise the Corporation. One of three things can occur with costs from Corporate services: 1) allocated to Otter Tail Power Company; 2) allocated to Varistar Inc., or 3) not allocated and remain at Corporate. The purpose of this manual is to detail how costs are being allocated to Otter Tail Power Company.

Otter Tail Power Company (the largest operating company of Otter Tail Corporation) serves retail electric customers in three jurisdictions including Minnesota, North and South Dakota and is governed by the rules and regulations in each jurisdiction. As a regulated utility, Otter Tail Power is allowed to recover prudent and reasonable costs for services it receives from Corporate, and reflects the cost of these services in its revenue requirements for setting rates. Costs allocated from Corporate are based on allocation factors that are calculated annually. In Minnesota, a different allocation method for the general allocator has been ordered for regulated reporting; however, this change in percentage is adjusted by Otter Tail Power Company so all costs billed from Corporate are at the same rate, regardless of jurisdiction.

The services provided by Corporate include financial reporting, tax planning and reporting, treasury and cash management, financial planning, internal audit, human resource and labor expertise, benefit plans, corporate communications, safety and risk management, shareholder services and investor relations, aviation and executive management services (CEO, COO, CFO and General Counsel). These services are distinct from and do not duplicate similar services in Otter Tail Power Company. See Section V below for additional information of Corporate services. To support these services, there are specific corporate costs associated with administration and information technology ("IT") that also need to be allocated.

The remainder of this document is devoted to explaining the services being provided and the methodology and allocation factors used to allocate Corporate service costs to Otter Tail Power Company.

II. METHODOLOGY

Corporate identifies costs in three categories: 1) directly assignable costs, 2) indirect costs that are allocated on a department or functional allocation factor, and 3) general costs that are allocated using a general allocation factor.

Directly assignable costs are those costs where the purpose behind the costs can be attributed to a specific operating company. For example, consulting fees to help with a project related to an individual operating company would be directly assigned to that operating company.

Indirect costs have an identifiable cost causation related to another activity or factor. For example, costs for an employee in the Risk Management department of Corporate to attend a seminar on safety would be allocated using a functional allocation factor such as number of employees.

General costs are those costs that cannot be directly assigned or where cost-causation cannot be identified. Examples would include postage, local telephone and communication service costs, time spent preparing the annual report and other SEC filings, preparing to meet with rating agencies, working with and tracking shareholder matters. These types of costs will be allocated on a general allocation factor discussed below.

Allocation factors are updated annually in February with the most recent calendar year's data. The updated allocation factors are then implemented and utilized for all Corporate Costs in February and remain unchanged for 12 months.

III. ALLOCATION FACTORS

Indirect Allocation Factors:

A. IT Factor: This factor is based on the previous year ending December 31 ratio of corporate labor assigned to Otter Tail Power where the numerator is the total Corporate labor (not including bonuses) assigned to Otter Tail Power and the denominator is the total of all Corporate labor (not including bonuses). See Appendix A.

B. HR Factor: This factor is based on the average of the previous year ending December 31 ratio of employees, and the previous year ending December 31 ratio of benefit expenses. For the employee ratio the numerator is full -time employees in electric operations and the denominator is the total number of full -time employees for all of Otter Tail Corporation. For the benefit ratio, the numerator is total benefit costs (including benefit costs cleared through the payroll loading rate) from electric operations, and the denominator is consolidated benefit costs for all of Otter Tail Corporation (including benefit costs cleared through the payroll loading rate). The specific consolidated corporate accounts that will be used to calculate this ratio (including Otter Tail Power benefit costs cleared through payroll loading) are accounts C5030, C5230, C6030, C6530, C7030. See Appendix A.

C. RM Factor: This risk-management factor is the average of the previous year ending December 31 ratio of employees, and the current year ratio of insurance premiums paid. For the employee ratio the numerator is full -time employees in electric operations and the denominator is the total number of full -time employees for all of Otter Tail Corporation. For the insurance premium ratio, the numerator is the total premiums paid by Otter Tail Power and the denominator is the sum of insurance premiums paid by all operating companies. See Appendix A.

D. Internal Audit Factor: This factor is based on the previous year ending December 31 ratio where the numerator is the total hours spent auditing electric operations and the denominator is the sum of hours auditing electric and non-electric operations. Non-electric operations do not include hours spent auditing Corporate-related matters. See Appendix A.

General Allocation Factor:

This factor is based on a three-factor formula that is comprised of the average ratio of Total Assets, Total Revenues and Total Labor Dollars for the most recent calendar year. The specific consolidated corporate accounts that will be used to calculate the Total Labor Dollars ratio are C5010, C5020, C5030, C5210, C5220, C5230, C6010, C6015, C6020, C6030, C6510, C6520, C6530, C7010, C7020 and C7030. Appendix A shows the computation of this factor based on prior-year audited numbers and shows the source for the information to calculate each ratio.[1]

IV. CLARIFICATION ON CERTAIN COSTS

There are certain costs that need to be discussed in further detail to gain an understanding of exactly how they are being allocated, or in some instances, not being allocated. This section will list each of these costs individually and provide background and instruction on how each is handled for allocation purposes.

A. Labor: Employees at Corporate track their time on a daily basis. Percentages are used to track time between Corporate, Otter Tail Power Company, and Varistar activities. The time designated Otter Tail Power is directly assigned to the power company. The percentage of time being recorded in the Corporate column is allocated based on the employee's position and will use one of the allocation factors discussed above in Section III.

B. Bonuses and Benefits: Cash bonuses are allocated based on each employee's labor ratio from the previous year. An employee's labor ratio reflects both directly assigned and allocated labor. Bonuses are accrued and allocated during the current year, and a true-up is made in the following year after the exact bonus amount is determined and the employee's actual labor ratio from the previous year is available. Benefit costs are allocated on each employee's labor ratio from the most recent 30-day pay period.

[1] The Minnesota Public Utilities Commission (PUC) has ordered in Otter Tail Power Company's last rate case (Docket No. E017/GR-07-1178), that the General Allocator calculation method must comply with the PUC's orders in Docket E,G999/CI-90-1008. That docket established a general allocator based on the ratio of regulated to unregulated expenses, excluding fuel, purchased power, and purchased cost of goods sold.

C. Contributions: The contributions made by Otter Tail Corporation are not allocated to Otter Tail Power. Each operating company makes its own contributions and those contributions made from a corporation perspective are typically not allocated.

D. Employee Stock Purchase Plan and Deferred Compensation Expense: The costs associated with the Employee Stock Purchase Plan are allocated based on the ratio of Otter Tail Power employee stock purchases to the total of the most recent stock purchase and Deferred Compensation expense is allocated to Otter Tail Power based on the general allocator.

E. Stock Option Expense: Under Accounting Standard Codification (ASC) Topic 718 companies are required to record the value of stock options over the period in which the options vest. These expenses are allocated to Otter Tail Power based on the number of options granted to employees in this company. No stock options were granted in 2016 and none are expected to be granted to employees in 2017.

F. Restricted Stock and Restricted Stock Units: Under ASC Topic 718 companies are required to record the value of restricted stock and restricted stock units over the period in which the shares vest. Restricted stock and restricted stock unit expense on shares granted to Otter Tail Power employees are directly assigned to Otter Tail Power. The portion of restricted stock or restricted stock units granted to Corporate employees and the Board of Directors is allocated to Otter Tail Power Company based on the general allocator.

G. Executive Stock Performance Award Plan: Under ASC Topic 718 companies are required to record the value of incentive stock, awarded based on the performance of the company's stock price, over the time period used to evaluate performance. Otter Tail Corporation provides incentive stock to the corporate officers as part of their overall compensation package. The costs associated with this plan are allocated based on the prior year time allocations for each executive. In addition when performance shares are awarded to Otter Tail Power's president the cost related to his award is directly assigned to Otter Tail Power.

H. Bank Charges: Corporate serves as the "Bank" for operating companies and therefore incurs the various fees associated with the accounts maintained by the operating companies. Otter Tail Power is directly charged for its respective fees and the fees associated with Corporate's accounts are allocated using the General Allocation Factor.

I. External Audit Fees: Otter Tail Corporation currently retains an independent registered public accounting firm to audit its financial reports and records. Each year this firm provides to Otter Tail Corporation a Client Service Plan that outlines the number of hours it has assigned to audit electric and non-electric operations. Fees from the firm are allocated based on the ratio of assigned hours for electric versus total audit hours on consolidated operations. The hours assigned to corporate are allocated using the general allocator.

J. Meetings: Costs associated with periodic meetings that involve personnel from across the operating companies such as leadership meetings, quarterly accounting and HR meetings are not allocated.

K. Training and Development: Costs associated with training and development are direct charged where possible but otherwise allocated using the appropriate indirect allocator or the general allocator.

L. Travel and meals: With the exception of travel-related expense related to operations of Otter Tail Power's jointly owned generation plants or if corporate employees are working specifically forOtter Tail Power, corporate travel expense is not allocated.

M. Aviation Services: Corporate provides air service for the operating companies of Otter Tail Corporation. There is one aircraft available for use which is the King Air. The King Air is owned by Otter Tail Power Company. To help recover the variable costs associated with flying this aircraft, corporate charges hourly rates which are reviewed periodically.[2] (See Appendix B for hourly rates)

Because the King Air is owned by Otter Tail Power, at the end of each quarter the costs associated with the King Air that have not been recovered through the hourly rate are charged to Otter Tail Power. For example, the costs not cleared for the quarter total \$9,000. Otter Tail Power has recorded depreciation expense for the quarter of \$1,000 which is added to the \$9,000 of un-cleared costs for a total of \$10,000. The \$10,000 is multiplied by the non-utility usage factor (the percentage of hours flown for operating companies other than Otter Tail Power) and for our example we'll say it's 52%. Otter Tail Power will then be charged \$3,800 (\$9,000 less \$5,200 (\$10,000 x 52%)) to reflect the utility-portion of costs not cleared on the King Air.

V. DESCRIPTION AND ALLOCATION OF SERVICES PROVIDED

Further detail is discussed below on the services provided by Corporate. Each service shown below is directly related to an individual cost center at Corporate. For each service a description is provided along with the primary allocation factor that is used to allocate associated costs. Again, costs that can be directly assigned to the various operating companies are directly assigned. Indirect costs are allocated using one of the factors discussed in Section III.

A. Corporate Overheads

[2] The aviation charge rates may be changed during the year to reflect changes in variable costs (i.e., aviation fuel).

Description: Represents charges for bank charges, building lease and depreciation expense.

Allocation Factor: All costs not directly assigned are allocated on the General Allocation Factor.

B. Executive Management Services

Description: Represents charges for Otter Tail Corporation's executive management team and Contributions.

Allocation Factor: Contributions are not allocated and all other costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

C. Board of Directors

Description: Represents charges for board of director fees, restricted stock, travel and other expenses associated with attending Board meetings or related to being a board member.

Allocation Factor: Fees and restricted stock expense are allocated on the General Allocation Factor. Otter Tail Power is not allocated any costs associated with travel related expenses.

D. Corporate Development

Description: Represents charges for the Corporate Development staff that are responsible for identifying and researching acquisition candidates, due diligence on acquisition targets, and integrating recently acquired companies into Otter Tail Corporation.

Allocation Factor: All costs are currently being directly assigned to Varistar Corporation but if Otter Tail Power uses these services for an acquisition, the associated costs would be directly billed to Otter Tail Power.

E. Platform Leadership

Description: Represents charges for the Platform Leaders and their staff that have oversight responsibilities with the non-electric operating companies.

Allocation Factor: All costs are currently being directly assigned to Varistar Corporation.

F. Administrative Services

Description: Represents charges for providing administrative support to all the other services, office supplies and office equipment leases.

Allocation Factor: All costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

G. Information Technology

Description: Represents charges for supporting corporate computers, networks, land-based phones and T1 lines, internet, software and other various pieces of hardware. In addition, consulting services are provided as requested to the various operating companies.

Allocation Factor: License and maintenance fees comprise a large portion of the non-labor costs. As much as possible, these costs are directly assigned based on the number of user licenses utilizing the software by each operating company. All costs not directly assigned are allocated on the IT Factor including labor classified as Corporate. The corporate VP of Information Technology is a shared position with Otter Tail Power Company. The specific costs for this position are directly assigned to Otter Tail Power as appropriate.

H. Corporate Accounting

Description: Represents charges for maintaining financial records, statements and systems, SEC filings, tax accounting and filings, cash management and consulting with various operating companies on an as-needed basis.

Allocation Factor: External audit fees are allocated as discussed in Section IV. Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

I. Internal Audit

Description: Represents charges for reviewing internal controls and conducting operation audits at the various companies within Otter Tail Corporation.

Allocation Factor: Costs not directly assigned are allocated on the Internal Audit Factor including labor classified as Corporate.

J. Financial Planning

Description: Represents charges for supporting financial analysis and budgeting at the operating company and corporate level.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

K. Treasury

Description: Represents charges for communicating with both debt and equity analysts, maintaining Otter Tail Corporation's capital structure, monitoring and accessing capital markets and other services as identified by the Chief Financial Officer.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

L. Corporate Communications

Description: Represents charges for corporate communications including press releases, advertising and branding and annual report preparation. Another service provided is coordinating and tracking contributions made on behalf of Corporate.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

M. Shareholder Services

Description: Represents charges for maintaining shareholder records, communicating with investors at various fairs, coordinating transfer agents and planning the annual shareholder meeting.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

N. Human Resources/Leadership Development

Description: Represents charges for establishing and maintaining policies related to employment and benefits of corporate employees and executive compensation, searches for candidates for upper-level management positions on behalf of operating companies, organizing and facilitating leadership training, organizing and aiding in the administration of company benefit programs.

Allocation Factor: Costs not directly assigned are allocated on the HR Factor including labor classified as Corporate. In case of leadership and employee development training, costs are allocated based on employees in attendance at training sessions, if possible and otherwise allocated using the HR allocator.

O. Legal Affairs

Description: Represents charges for legal services related to employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other various legal matters.

Allocation Factor: Most costs associated with legal services are directly assigned but if costs cannot be directly charged, the general allocator is used. Typically, labor costs for all corporate lawyers other than the General Counsel are generally assigned to the Varistar companies as Otter Tail Power employs their own attorneys, however, there are times when corporate lawyers perform work for Otter Tail Power which would be assigned as such.

P. Risk Management

Description: Represents charges for assisting operating companies with assessment and management of risks, identifying and implementing loss control strategies to minimize the frequency and financial consequences of accidental losses, assisting operating companies in post loss claim management, overseeing Otter Tail Corporation's consolidated insurance program, and identifying and documenting the environmental conditions during the process of acquiring a new company.

Allocation Factor: Costs not directly assigned are allocated on the RM Factor including labor classified as Corporate.

VI. CONCLUSION

As circumstances arise, such as adding a new service that will be provided by Corporate, appropriate changes will be made to the manual. Appendix A will be updated annually in February when the prior-year audited records are available and Appendix B will be updated as Aviation Rates are changed.