Peter Beithon

Volume 2A

Direct Testimony and Supporting Schedules:

Peter J. Beithon

Jurisdictional Cost of Service
Operating Statement
Class Cost of Service
Class Revenue Responsibility

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. EL10-_____

Exhibit___

JURISDICTIONAL COST OF SERVICE

OPERATING INCOME

CLASS COST OF SERVICE

CLASS REVENUE RESPONSIBILITY

Direct Testimony and Schedules of

PETER J. BEITHON

August 20, 2010

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ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Peter J. Beithon. My business address is 215 South Cascade Street, Fergus Falls, MN 56537.

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

A. I am employed by Otter Tail Power Company ("OTP" or the "Company") as Manager, Regulatory Economics.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS, DUTIES, AND RESPONSIBILITIES.

A. I have a Bachelor of Science Degree from the University of North Dakota with majors in accounting and marketing and a minor in natural science. I am a Certified Management Accountant (CMA) and a Certified Public Accountant (Inactive). I have worked for OTP since November of 1983, starting as a property accountant in the Accounting Department, moving to Treasury Department as the administrator of cash management, and have worked in the Regulatory Services Department since 1991, holding various positions from regulatory analyst to Supervisor, Regulatory Economics. I have held my current position of Manager, Regulatory Economics, since April 2005.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AUTHORITIES?

A. Yes. I have testified before the South Dakota Public Utilities Commission ("Commission"), the Minnesota Public Utilities Commission, the North Dakota Public Service Commission, and the Federal Energy Regulatory Commission ("FERC").

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of OTP.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports OTP's operating income financial schedules and the determination of a revenue deficiency for the test year, based on the jurisdictional cost of service study. More specifically, I determine that OTP has a revenue deficiency of $2,755,954 or 9.96 percent. My testimony focuses on the operating income statement portion of the revenue requirement (Mr. Kyle A. Sem testifies concerning the rate base components). I also provide support for the adjustments to the 2009 actual year to create the test year, including: (i) the proposed traditional regulatory adjustments; (ii) the known and measurable adjustments; and (iii) the weather normalized test year revenues. In addition, I support the customer class cost of service study and the Company's proposal for class revenue allocations.

Q. WHICH REQUIRED STATEMENTS ARE YOU SPONSORING?

A. I am sponsoring the following required statements. These Statements and supporting Schedules are required by Commission Rules (Sections 20.10.13.51 et seq.) and are located in Volume 1.

- A Balance sheet
- B Income statement
- C Earned surplus statements
- G Rate of return/Debt capital/Preferred stock capital/Common stock capital
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  - G-3 Reacquisition of bonds or preferred stock
  - G-4 Earnings per share for claimed rate of return
- H Operating and maintenance expenses
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I Operating Revenue

J Depreciation expense

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K Income taxes

- K-1 Working papers for federal income taxes
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- K-3 Working papers for consolidated federal income tax
- K-4 Working papers for an allowance for current tax greater than tax calculated at consolidated rate
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L Other taxes

- L-1 Working papers for adjusted taxes

M Overall cost of service

N Allocated cost of service

O Comparison of cost of service

P Fuel cost adjustment factor

R Purchases from affiliated companies

Mr. Sem is sponsoring Statements D, E and F; and Mr. Thomas R. Brause is sponsoring Statement Q. Mr. David G. Prazak is sponsoring the comparison of present and proposed revenues in Statement I.

Q. PLEASE LIST THE SCHEDULES YOU HAVE ATTACHED TO YOUR TESTIMONY.

A. I am also sponsoring the following Schedules, which directly follow my testimony. I rely on these schedules to determine and support my calculation of the $2,755,954 revenue deficiency. Exhibit __(PJB-1):

Schedule 1, JURISDICTIONAL FINANCIAL SUMMARY SCHEDULE

Schedule 2, JURISDICTIONAL STATEMENT OF OPERATING INCOME

Schedule 3, TOTAL UTILITY AND SOUTH DAKOTA TEST YEAR
Schedule 4, COMPUTATION OF FEDERAL AND STATE INCOME TAXES
Schedule 5, COMPUTATION OF DEFERRED INCOME TAXES
Schedule 6, DEVELOPMENT OF FEDERAL AND STATE INCOME TAX RATES
Schedule 7, DEVELOPMENT OF GROSS REVENUE CONVERSION FACTOR
Schedule 8, OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE
Schedule 9, COMPARISON OF PROPOSED RATES TO LAST RATE CASE STATEMENT OF OPERATING INCOME
Schedule 10, COST ALLOCATION PROCEDURE MANUAL FOR JURISDICTIONAL AND CLASS COST OF SERVICE STUDIES AND ALLOCATION FACTORS
Schedule 11, CORPORATE COST ALLOCATION MANUAL

Q. WERE YOUR SCHEDULES PREPARED EITHER BY YOU OR UNDER YOUR SUPERVISION?
A. Yes.

Q. ARE THERE OTHER WITNESSES YOU RELIED UPON IN DEVELOPING YOUR SCHEDULES?
A. Yes. I have relied upon and incorporated the results from the testimonies of other OTP witnesses in this proceeding.

Q. WHAT ARE THE PRIMARY FACTORS CONTRIBUTING TO OTP'S NEED FOR A RATE INCREASE?
A. As explained in the direct testimony of Mr. Brause, since OTP filed its last general rate case in 2008, three primary factors have created a need for a rate increase: (1) additional rate base investments (including the addition of the

Luverne Wind Farm) and associated depreciation expense have increased revenue requirements by $1.2 million; (2) the need to recover Big Stone II development costs creates an annual revenue requirement of $344,935; and (3) there have been significant increases in operating costs, including labor and benefit costs. Exhibit__(PJB-1), Schedule 9, is a bridge schedule comparing the operating income statement from OTP's most recent rate case (Docket No. EL08-020) and the 2009 Test Year in this case. Similarly, Schedule 5 to the direct testimony of Mr. Sem is a bridge schedule comparing the rate base from OTP's most recent rate case and the 2009 Test Year.

II. SCHEDULES PROVIDED AND SELECTION OF TEST YEAR

Q. WHAT TEST YEAR IS USED IN THE COST OF SERVICE STUDY?

A. The test year period is based on the 2009 calendar year with known and measurable and other ratemaking adjustments. The use of the 2009 calendar year as the test year was approved by the South Dakota Public Utilities Commission in Docket EL108-005 (Order dated June 16, 2010). The most recent fiscal year is the 2009 calendar year.

Q. PLEASE OUTLINE THE FINANCIAL INFORMATION PROVIDED.

A. Following the Commission's rules, financial data is provided for the most recent fiscal year ("2009 Actual Year") and the test year (2009, as adjusted "2009 Test Year"). For the 2009 Actual Year, the schedules show the actual unadjusted average rate base consisting of the rate base components provided by Mr. Sem, unadjusted operating income, overall rate of return, the calculation of required income, the income deficiency and revenue requirements. Separate rate base and income statement bridge schedules that identify test period adjustments are provided by Mr. Sem (rate base) and myself (operating statement). Mr. Prazak provides the schedules showing the rate impacts from my proposed class revenue allocations and his proposed rate design.

Q. PLEASE OUTLINE THE CONCLUSIONS REACHED AS A RESULT OF YOUR JURISDICTIONAL COST OF SERVICE STUDY?

A. I determined that at present rate levels OTP would earn a rate of return of 6.35 percent for the test year. This is significantly below the 9.13 percent rate of return Mr. Kevin G. Moug identifies as needed to attract capital at reasonable cost. OTP's financial results support an increase in annual revenues of $2,755,954, or about 9.96 percent. Of this increase, approximately $954,000 or 35 percent is from the net impacts of the addition of the Luverne wind farm, approximately $736,000 or 27 percent is from increases in employee benefits costs including pensions, approximately $345,000 or 14 percent is from the amortization of cost related to the discontinued Big Stone II project and the remainder of the increase is due to the combination of other miscellaneous items (some reductions, some increases) including the requested capital structure.

Q. PLEASE DESCRIBE THE GENERAL CONTENT OF THE FINANCIAL SCHEDULES ATTACHED TO YOUR TESTIMONY.

A. The financial information attached to my testimony is broken down into nine schedules. I will discuss each schedule in more detail as we examine it.

Q. PLEASE DESCRIBE EXIBIT__(PJB-1) SCHEDULE 1.

A. I will limit my discussion of Schedule 1 to the Test Year in column (B). Line 1 shows the average rate base of $64,406,556. Lines 2 and 4 shows the total available for return, the operating income of $4,091,636, at present revenue levels. Line 5 shows the overall current rate of return of 6.35 percent. This is the rate of return earned without any rate increase. Line 6 shows the required rate of return of 9.13 percent; that is the rate of return OTP would earn with the requested rate increase. Line 7 shows the required operating income of $5,880,319, which is determined by multiplying the required rate of return times the rate base. This translates into an income deficiency of $1,788,683 shown on Line 8. After multiplying the income deficiency by the gross revenue conversion factor (Line 9), I arrive at the revenue increase supported for South Dakota, which, on an annual basis, is $2,755,954 (Line 10). The conversion factor is calculated in Exhibit __ (PJB-1), Schedule 7.

Q. WHAT IS SHOWN ON EXHIBIT __(PJB-1), SCHEDULE 2?

A. Exhibit__(PJB-1), Schedule 2, is the operating income summary of OTP, as allocated to South Dakota, for the 2009 Actual Year and the 2009 Test Year. The retail revenues consist of revenues from sales of electricity to OTP's South Dakota customers under rate schedules presently on file with the Commission. To this revenue has been added South Dakota's allocated share of OTP's other electric operating revenues from other services provided by OTP. From the total operating revenues, operating expenses are deducted to arrive at net operating income before income taxes, from which total income tax expense is deducted to arrive at net operating income after income taxes or the amount available for return.

Q. WHAT IS SHOWN ON EXHIBIT__(PJB-1), SCHEDULE 3?

A. Schedule 3 is an operating income schedule, which reflects the Actual Year Total Utility and South Dakota. The Actual Year total adjustments by type are shown in column (C). The adjustments are combined with the Actual Year Total to arrive at the 2009 Test Year (Proposed South Dakota Jurisdiction) column (D). Later in my testimony, I discuss Schedule 8, which details the individual financial adjustments.

Q. IS THE CALCULATION OF INCOME TAXES INCLUDED IN THIS FILING?

A. Yes. The calculation of income taxes for revenue requirements is included in Exhibits__(PJB-1), Schedules 4, 5 and 6 of my Operating Income Schedules.

Q. HAS OTP PROVIDED THE SUPPORTING DOCUMENTS USED IN DEVELOPING THE TEST YEAR OPERATING INCOME?

A. Yes. Work papers supporting the test year cost of service are provided in Volumes 4A and 4B of this filing (referred to as Test Year Work Papers). In addition, Exhibit__(PJB-1), Schedule 10 provides a complete description of jurisdictional operating income and rate base allocation factors which were used to allocate operating revenue and expenses to OTP's South Dakota jurisdiction.

III. JURISDICTIONAL COST OF SERVICE STUDY

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

A. I will discuss the development of the jurisdictional cost of service study ("JCOSS") that was prepared under my direction. The JCOSS is provided in Volume 1, Statement M, as part of the Class Cost of Service Study. This study determines what portion of the total company costs and revenues should be recognized in determining a South Dakota revenue requirement.

Q. WHY IS A JCOSS NECESSARY?

A. OTP serves retail customers in South Dakota, North Dakota, and Minnesota. In addition, wholesale and wheeling service is provided to some municipal utilities, and those services are regulated by the FERC. Costs that are incurred to meet the requirements of a particular jurisdiction are directly assigned to that jurisdiction. Costs that cannot be directly assigned are allocated based upon allocation factors included in the JCOSS. In this way, the JCOSS is used to determine what portion of the total costs incurred by OTP should be recovered from our South Dakota customers.

Q. WERE ALLOCATIONS USED TO DEVELOP THE SOUTH DAKOTA JURISDICTIONAL COST OF SERVICE ?

A. Yes. The allocation procedures used by OTP were approved in 2009 by the Commission in Docket EL08-030. These allocation procedures have also been approved by the Commissions in Minnesota and North Dakota. By having uniform allocation procedures in all its jurisdictions, OTP recovers its cost of providing service across its entire territory, no more, and no less.

Q. WHAT IS THE SOURCE OF THE BASE DATA FOR THE TEST YEAR ENDING DECEMBER 31, 2009?

A. The basic data was obtained from the historical accounting records of OTP. These records are based on the FERC Uniform System of Accounts (USOA) per South Dakota Rule 20.10.13.48.

Q. PLEASE EXPLAIN THE PROCESS FOR ASSIGNING OTP'S INVESTMENT IN AND EXPENSES RELATED TO ELECTRIC PLANT TO THE SOUTH DAKOTA JURISDICTION.

A. Plant investments are accounted for in the manner prescribed by the FERC Uniform System of Accounts. Detailed records are maintained on a functional basis (i.e. Production, Transmission, Distribution, etc.). These functional amounts are directly assigned to the appropriate jurisdiction or allocated based on principles of cost causation, as outlined in my Exhibit ____(PBJ-1), Schedule 10, OTP's *Cost Allocation Procedure Manual for Jurisdictional and Class Cost of Service Studies*.

Q. PLEASE EXPLAIN THE NEED FOR JURISDICTIONALLY ALLOCATING THE INVESTMENT IN AND EXPENSES RELATED TO PRODUCTION AND TRANSMISSION FACILITIES.

A. OTP's production and transmission system is designed, built, and operated to provide an integrated source of electricity shared by OTP's electric customers in

South Dakota, North Dakota, and Minnesota, as well as a few wholesale customers with rates regulated by FERC. To determine the level of investment and expense associated with the provision of electric service to South Dakota retail customers, it is necessary to assign or allocate the appropriate amount of the total production and transmission investment and expense to each jurisdiction.

Q. HOW WERE THE OTP ELECTRIC PRODUCTION AND TRANSMISSION SYSTEM INVESTMENT AND EXPENSE AMOUNTS ALLOCATED TO THE SOUTH DAKOTA JURISDICTION IN THIS CASE?

A. We based these allocations upon each jurisdiction's coincident peak demand for electricity. It is reasonable to use coincident peak demand as a basis for allocation because production (generation) and transmission facilities are designed to meet OTP's total peak requirements, inclusive of all its jurisdictions. Our peak demand is determined through load research, which analyzes data gathered from recorders installed at specific locations in our service area. The number and location of these recorders are determined by statistical sampling techniques. The load research data collected is used to determine the system peak demands for each class of customer and then is used as the basis for calculating demand allocation factors, which are used in the jurisdictional and class cost of service studies. This approach reflects that these facilities have been designed to meet peak requirements and operate as an integrated system across all jurisdictions.

Q. SINCE THE LAST RATE CASE, HAS THE COMPANY CONDUCTED STUDIES TO DETERMINE THE PROPER CLASSIFICATION OF ITS TRANSMISSION FACILITIES?

A. Yes. The use of Boundary Guidelines[1] developed by the Minnesota Public Utilities Commission to determine the appropriate classification of transmission

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[1] Order Adopting Boundary Guidelines For Distinguishing Transmission From Generation and Distribution Assets, Docket No. E999/CI-99-1261, July 26, 2000.

facilities between generation, distribution and transmission is discussed by Mr. Sem in his Direct Testimony. OTP conducted studies based on these Boundary Guidelines and the resulting income statement adjustment is reflected on Exhibit__(PJB-1), Schedule 8, column (D). The rate base adjustments resulting from these studies are discussed by Mr. Sem in his testimony.

Q. HOW WERE THE COSTS OF DISTRIBUTION INVESTMENT AND EXPENSE ALLOCATED TO THE SOUTH DAKOTA JURISDICTION?

A. In contrast to production and transmission allocations, which are based on very few factors, distribution investment and expense are allocated on numerous factors. These cost-causative factors include primary and secondary distribution demand and several customer factors. These factors are outlined in greater detail in OTP's cost allocation procedures for the JCOSS provided in Statement M of the required schedules and in Schedule 10 attached to my testimony.

IV. DEVELOPMENT OF THE OPERATING STATEMENT

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE MAIN AREAS OF INCOME AND EXPENSE REFLECTED IN THE OPERATING STATEMENT.

A. The operating statement is developed using actual 2009 data for revenues and operation and maintenance expense, adjusted for the items shown on Exhibit __(PJB-1), Schedule 8. I explain below several aspects of these revenues and expenses, including the adjustments I made to develop a fair and representative test year operating income statement.

A. TEST YEAR REVENUES

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

A. This section describes how revenues were determined for purposes of calculating the base rate revenue requirement. I will first describe the retail revenues used to establish the base rate revenue requirement. I will then describe the adjustments I made to determine the appropriate test year revenues.

1. Retail Revenues

Q. 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.

Q. WHAT DO YOU MEAN BY CALENDAR MONTH?

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). To have retail revenues match to the calendar year for which expenses are incurred, the incremental amount of revenues, which 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 2009, which were billed in January 2010, net of the December 2008 unbilled revenues, which were billed in January of 2009. For 2009, this calculation increased revenues by just under $103,000.

a. Weather Normalization

Q. HAVE THE ACTUAL 2009 RETAIL REVENUES BEEN WEATHER ADJUSTED TO ARRIVE AT THE TEST YEAR REVENUES?

A. Yes, 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 need 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 was developed in cooperation with Christensen Associates Energy Consulting, LLC of Madison, Wisconsin. The weather normalization adjustment results in a deduction to South Dakota revenues of $64,029. The weather normalization adjustment also results in decreased fuel expenses of approximately $36,134 for South Dakota. This adjustment is provided on Exhibit__(PJB-1), Schedule 8, column (F).

OTP's weather normalization process involves collection of more than 19 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 1990; and (iv) up to 13 autoregressive terms. The results are checked for accuracy and reasonableness using graphs and reports. Weather normalized sales (kWh) are then priced on current rates using a calendar month basis. The resulting revenue amounts do not include fuel clause adjustment ("FCA") revenues.

Consequently, to include the impact of weather normalization on the FCA, weather normalized sales (kWh) are multiplied by the appropriate total cost of energy rate for each of the twelve months to determine the fuel and purchased power costs. In addition, FCA revenues are calculated by multiplying the appropriate monthly FCA rate by the change in kWh due to weather normalization.

Q. DOES WEATHER NORMALIZATION RESULT IN AN ADJUSTMENT TO UNBILLED REVENUES FOR THE 2009 TEST YEAR?

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

b. Normalization of Test Year Retail Revenues

Q. OTP IMPLEMENTED NEW RATES IN JULY OF 2009. DID YOU NORMALIZE THE REVENUES IN THE TEST YEAR?

A. Yes. As shown in Exhibit__(PJB-1), Schedule 8, column (G), OTP has normalized Test Year Retail Revenues. The details of this normalization are shown in Test Year Adjustment TY-07 which in contained in Volume 4A, Work Papers. The normalization takes into account the fact current rates were implemented in July of 2009, interim rates were in place starting with service provided on and after May 1, 2009, and the base cost of energy was changed starting with current rates in July 2009. This adjustment also: (i) removes Energy Efficiency Partnership ("EEP") revenues; (ii) removes billing corrections related to prior periods; and (iii) includes billing adjustments related to 2009 that occurred in 2010. In simple terms, OTP recalculated the revenue for the period from January 2009 through June 2009 applying current rates and recalculated the FCA for 2009.

2. Other Electric Revenue

Q. DO RETAIL SALES REPRESENT THE ONLY SOURCE OF REVENUES TO OTP DURING THE TEST YEAR?

A. No. As discussed in detail below, other electric revenues are included as well. These include items such as asset-based wholesale margins, integrated transmission agreement (“ITA”) payments, Midwest Independent Transmission System Operation (“MISO”) transmission related revenues, revenue from sales to a steam customer of the Big Stone generating plant, load control and dispatch revenues, control area services operations tariff (“CASOT”) revenues, and specific tariff charges including service activation fees, reconnection fees, and others.

Q. PLEASE DESCRIBE THE REASONS FOR THE DECREASE IN OTHER ELECTRIC REVENUE SINCE OTP’S LAST GENERAL RATE CASE.

A. As shown on Exhibit __(PJB-1), Schedule 9, South Dakota other electric revenues have decreased $923,687 since 2007 (29 percent). The decrease is largely due to the reduction in asset-based wholesale margins from $1,876,923 in the 2007 Test Year to $1,000,424 in the 2009 Test Year.

a. Asset-Based Wholesale Margins

Q. IS OTP PROPOSING ANY CHANGES REGARDING THE TREATMENT OF ASSET-BASED WHOLESALE MARGINS?

A. No. OTP is proposing to continue the current Asset-Based Wholesale Margins process, which provides a credit of 85 percent of the 2009 Test Year margins to the retail cost of service, calculated using 2009 margins, with any change to that margin to be reflected in the FCA on an annual basis and distributed equally each month over the ensuing twelve months. Flowing through the changes in the margins directly to customers through the FCA as they are realized, on an annual basis, ensures that neither ratepayers nor the Company are disadvantaged by a non-representative margin included in base rates. This current method has been in place only since mid-2009, and no detriments to the method have been identified.

Therefore, I recommend continued use of this equitable and administratively simple method for applying asset-based margins.

Q. IS OTP PROPOSING ANY CHANGES TO THE TREATMENT OF NON-ASSET BASED WHOLESALE MARGINS?

A. No. The settlement in OTP's last rate case provides that 25 percent of non-asset based margins (but not less than $0), be flowed through OTP's FCA, as calculated at the end of each calendar year and passed through in 12 equal monthly amounts. This non-asset based margin sharing mechanism should be continued.

Q. HOW IS OTP PROPOSING TO TREAT MISO ANCILLARY SERVICES MARKET COSTS AND REVENUES?

A. While OTP's ultimate proposal is that all (100 percent) ancillary service market ("ASM") costs and revenues (margins) should be passed through the fuel clause, OTP has included the revenues and costs as a base rate revenue credit in this filing. Passing ASM costs and revenues through the FCA will better match how these costs are incurred. Since the ASM market is still relatively new and not completely predictable, passing the revenues and costs through the FCA is more logical than using a set revenue credit based on just the first year of operation of the ASM market. If the Commission agrees, OTP will remove the revenue credit from final base revenue requirements and modify the FCA tariff to include ASM revenues and expenses within the fuel clause mechanism.

In the first year of ASM, OTP had approximately $28,000 in ASM revenues net of expenses, which has been included in the test year revenue requirements.

b. Control Area Services Operations Tariff (CASOT)

Q. PLEASE DESCRIBE OTP'S LOAD CONTROL AND DISPATCH REVENUES.

A. There are three primary services provided by OTP that result in the revenues included in the load control and dispatch account. (i) Control Area Services Operations Tariff (CASOT) revenue (a FERC-approved tariff); (ii) transmission revenue (includes MISO, Midcontinent Area Power Pool ("MAPP") and ITAs) and (iii) revenues received as the plant operator for OTP's two jointly owned generating plants, Big Stone and Coyote.

Q. PLEASE DESCRIBE THE PURPOSE OF OTP'S CASOT.

A. Effective February 1, 2002, when OTP became a transmission-owning member of MISO and transferred functional control of its transmission facilities to MISO, OTP terminated its Open Access Transmission Tariff ("OATT") and became a customer under the MISO OATT. Because a large percentage of the load, generation, and transmission in the OTP Control Area did not join MISO, OTP has a FERC-approved tariff authorizing OTP to provide reliable operations of the control area and authorizing OTP to provide ancillary services to these non-MISO entities.

Q. HOW IS OTP COMPENSATED FOR THE PROVISION OF THESE CASOT SERVICES?

A. OTP is compensated for the costs of providing these services pursuant to the CASOT, which was approved by FERC in Docket No. ER-02-912-00. The revenues collected pursuant to the CASOT are accounted for as other electric revenues.

Q. HAS THE MISO ANCILLARY SERVICES MARKET AFFECTED CASOT REVENUE?

A. Yes. Revenue under Schedule 3 of the CASOT has been eliminated from utilities that were previously taking Schedule 3 service and can now participate in the MISO ASM. This resulted in a $39,899 reduction in South Dakota allocated revenues since OTP's last general rate case. I discussed OTP's proposal for recognizing the MISO ASM costs and revenues along with OTP's proposal for asset-base wholesale margins earlier in my testimony.

c. Transmission Revenue (includes MISO, MAPP & ITAs)

Q. WHY DOES OTP RECEIVE MISO AND MAPP REVENUE?

A. Pursuant to MISO's Transmission and Energy Market Tariff ("TEMT") and the MISO Transmission Owners Agreement, OTP receives revenues from several sources for use of its transmission system and related services that it provides. These sources of revenue include.

a) Schedule 1 - Scheduling, System Control & Dispatch
b) Schedule 2 - Reactive Supply & Voltage Control
c) Schedule 7 - Firm Transmission Service
d) Schedule 8 - Non-Firm Transmission Service
e) Schedule 9 - Network Integrated Transmission Service
f) Schedule 11 - Pass Through Revenue
g) Schedule 14 – Regional Through And Out (RTOR)
h) Schedule 21 - PJM SECA (ended March 2009)

OTP received $356,013 in transmission related revenue on a South Dakota jurisdictional basis from MISO in 2009. OTP also received just over $6,177 from MAPP on a South Dakota jurisdictional basis in 2009 miscellaneous transmission related revenues. These revenues are included in OTP's Other Electric Revenue account.

Q. PLEASE DESCRIBE THE PURPOSE OF OTP'S SCHEDULING AND DISPATCH AGREEMENTS AND THE ASSOCIATED REVENUES.

A. OTP has two agreements with transmission-owning, load-serving entities in its control area for which OTP provides scheduling and dispatch services (Great River Energy and Central Power Electric Cooperative). These scheduling and dispatch services are transmission line switching, emergency line operations, scheduling of outages, and various related transmission scheduling and transmission dispatch services.

Q. HOW IS OTP COMPENSATED FOR THESE SERVICES?

A. The scheduling and dispatch services provided for under these scheduling and dispatch agreements are charged based on OTP's costs associated with system control and dispatching, including operating, maintenance, and fixed costs. Great River Energy, and Central Power Electric Cooperative each pay their pro rata share of the system control and dispatching, operating, and maintenance expenses based on the respective joint use facilities owned by each party. During 2009, OTP received $12,957 (South Dakota jurisdiction) in Other Electric Revenues for these services.

Q. DOES OTP RECEIVE TRANSMISSION REVENUE FROM OTHER COMPANIES?

A. Yes. In addition to MISO revenue, OTP receives transmission revenue from other utilities. OTP receives the majority of its revenue from our neighboring utilities with which we have ITAs for joint use of defined transmission systems.

Q. WHAT IS AN ITA?

A. An ITA is an agreement to use a transmission system that is planned and constructed to serve the load of two or more utilities. OTP has four ITAs, one each with Great River Energy, Minnkota Power Cooperative, Central Power Electric Cooperative, and Missouri River Energy Services. One of the objectives of each ITA is to make sure each utility shares in the costs of the transmission system proportionate to usage. Each of the four agreements was approved by FERC.

Q. WHAT MECHANISM DO THE ITAs USE TO BALANCE INVESTMENTS IN THE SHARED TRANSMISSION SYSTEM?

A. The proportion of investment to usage of the system is determined each year for each of the ITAs. If a utility is deficient in its investment based on its usage of the facility when compared to the other party's investment and usage, it makes deficiency payments until the investment is equalized. The deficiency payments are, in essence, payments by the underinvested utility of the carrying cost of the utility that is more than fully invested.

Q. HOW MUCH REVENUE DID OTP RECEIVE IN 2009 AS A RESULT OF THESE ITAs?

A. OTP received $356,013 in 2009 (South Dakota jurisdiction).

d. Generating Plant Operator

Q. PLEASE DESCRIBE THE COMPENSATION OTP RECEIVES AS THE PLANT OPERATOR FOR THE TWO JOINTLY OWNED GENERATING UNITS, BIG STONE AND COYOTE.

A. OTP operates the Big Stone Plant and Coyote Station on behalf of itself and its partners. As the plant operator, OTP provides services for which it is compensated by its partners. The services include: scheduling and operations of the plants for both the day-ahead and real-time market; acting as the meter data management agent for all partners of the plants; settlement reconciliation of unit dispatches and actual generation; providing accounting reports and records to the partners; scheduling generator outages; communicating directly with the MISO generator dispatch desk; and providing and maintaining reliable communications between MISO, the plants, and the OTP control center. In 2009, this resulted in $33,220 (South Dakota jurisdiction) of additional revenues, reflected in the Other Electric Revenue account.

Q. WHAT OTHER REVENUES ARE INCLUDED IN THE OTHER ELECTRIC REVENUE CATEGORY?

A. OTP supplies steam to an ethanol plant near its Big Stone Plant in Big Stone, South Dakota. This contributed $214,506 to South Dakota Other Electric Revenues in 2009. The costs of coal for this customer are not part of retail fuel costs.

e. Energy Efficiency Partnership

Q. HOW HAS OTP TREATED THE EEP REVENUES AND EXPENSES IN THE TEST YEAR?

A. OTP has not included the revenues or expenses in the 2009 actual year or the 2009 test year because the EEP costs are recovered through the separate EEP rider.

B. OPERATING EXPENSE

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

A. This section of my testimony discusses operating expenses. I will first discuss in general terms the overall change in expenses since the last rate case. I then describe the adjustments to the 2009 actual year that have been made to reflect standard regulatory adjustments and known and measurable changes to arrive at the 2009 test year.

Q. WHAT IS THE AMOUNT OF CHANGE IN OPERATION AND MAINTENANCE COSTS SINCE THE LAST RATE CASE?

A. There has been a 8.8 percent increase in operating costs not including fuel, purchased power, depreciation and general taxes, which, using a simple average over two years, is 4.4 percent annually. Exhibit__(PJB-1), Schedule 9 contains a listing of expense changes by function since the last rate case. Total operating expense including fuel, purchased power, depreciation and general taxes has increased only 2 percent. This 1 percent annual average system-wide increase includes the known and measureable adjustments for increased costs for labor, and employee benefits (medical/dental) occurring in 2010.

Q. WHAT IS THE EXPLANATION FOR THIS LEVEL OF EXPENSES?

A. As explained in the direct testimony of Mr. Brause, OTP made drastic cuts to its budgets in response to deteriorating economic conditions and the resulting revenue deficiencies. OTP did not give any non-union salary increases in 2009. OTP also restricted travel and training and other expenditures and was able to reduce total system expenses by more than three percent below 2008 levels. These level of expense reductions were driven by the economy and cannot be sustained on an ongoing basis and still provide safe, reliable service.

Q. WHAT IS INCLUDED IN PRODUCTION EXPENSE?

A. The most significant production expense is fuel and purchased power. Production expense also includes maintenance costs of OTP's generation plants. A combination of plant age and growing energy needs has increased maintenance costs. OTP's two largest base load generating plants went into operation in 1975 and 1981. A third base load plant is even older. OTP expects its peaking units to have a higher level of maintenance costs for the foreseeable future, because its three diesel units are aging. To address these issues, all of OTP's peaking units are on a heightened long-term maintenance plan to ensure they are available and operating at their most efficient levels when needed. Their reliability is especially important with the need to support the variability of new wind resources. Because of the recent reduction in fuel and purchased energy costs, overall production expense has actually decreased by 9 percent since the last rate case.

Q. HOW HAVE ADMINISTRATIVE AND GENERAL AND CUSTOMER SERVICE EXPENSES CHANGED SINCE OTP'S LAST SOUTH DAKOTA RATE CASE?

A. In total, the Administrative and General (A&G) expenses have increased $540,299 (18 percent, 9.25 percent annualized). These increases have been driven mostly by increases in the pension costs and partially due to labor increases and other benefits. Customer Service and Customer Accounting Costs combined have risen $17,325 (1 percent, 0.5 percent annualized).

Q. ARE THERE ADJUSTMENTS TO ACTUAL 2009 EXPENSES THAT YOU DEVELOPED TO ARRIVE AT THE TEST YEAR AMOUNTS?

A. Yes. As discussed by Mr. Brause and earlier in my testimony, expenses for 2009 were abnormally low. OTP's budgets for 2010 and 2011 indicate a more normal level for some expenses. My adjustments reflect the level of expenses that OTP incurs to provide reliable electric service to its retail customers.

Q. HAVE YOU PREPARED A SCHEDULE SHOWING THE ADJUSTMENTS YOU MADE TO ARRIVE AT THE TEST YEAR.

A. Yes. Exhibit __ (PJB-1), Schedule 8, is an operating income bridge schedule that includes a list of all of the income statement adjustments made to the 2009 actual year in developing the test year including: (i) the revenue adjustments I previously discussed; (ii) the effect on operating income because of the rate base adjustments supported by Mr. Sem in his direct testimony; (iii) additional known and measurable expense changes; and (iv) the traditional regulatory expense adjustments. That schedule also identifies the impact each adjustment has on the operating income statement. I will discuss each adjustment.

1. Wind Generation Costs

Q. HOW DOES THE ADDITION OF WIND GENERATION AFFECT PRODUCTION EXPENSE?

A. As is discussed in the Direct Testimony of Mr. Kyle Sem, OTP has added a significant wind farm to its generation fleet since its last rate case. This wind project is located near Luverne, North Dakota. Additional energy available from OTP's wind generation reduces our need to purchase energy in the MISO market. The exact future cost savings are not a known and measureable change for this test year because Luverne has not been on line long enough to predict its average capacity factor. However, any future cost savings will be reflected in the FCA. Test year production related operation and maintenance expenses associated with wind generation amount to $140,515 (Exhibit__(PJB-1), Schedule 8, Line 4, Columns (U) and (V)). Column (U) removes all 2009 Actual Year wind related costs and column (V) inserts the normalized wind related expenses. This is done to include a full year of expenses for the Luverne wind farm in the test year.

Q. WHAT OTHER EXPENSES ARE AFFECTED BY THE ADDITION OF NEW WIND GENERATION?

A. Other expenses related to new wind generation include: property insurance expense increase of $10,033, property tax increase of $77,225, and depreciation expense increase of $192,233 (the $46,353 adjustment to depreciation expense in Column (B) relates to non-wind new plant additions).

Q. HOW ARE INCOME TAXES IMPACTED BY THE ADDITION OF WIND GENERATION?

A. North Dakota law allows an investment tax credit (“ITC”) on wind generation in that state. The ITC is based on a percentage of the investment for each of the first five years it is in place. For ratemaking purposes, we have normalized the ITC over the entire 25-year life of the investment. We have allocated to South Dakota a share of this tax credit in the same proportion that the wind generation is allocated to South Dakota. The South Dakota share of the North Dakota ITC is $853,260. In addition, the Federal production tax credit (“PTC”) from the

Langdon and Ashtabula Wind Projects of $1,178,440 is included in the ITC line in Exhibit__(PJB-1), Schedule 8, column (V), line 18.

Q. SOUTH DAKOTA DOESN'T HAVE CORPORATE INCOME TAX. WHY IS IT APPROPRIATE TO FLOW A NORTH DAKOTA TAX CREDIT TO SOUTH DAKOTA CUSTOMERS?

A. The North Dakota ITC is directly related to the investment in wind generation. As an economic source of generation for all customers, wind investments are allocated to state jurisdictions based on allocation principles similar to other generation. It is appropriate that a tax credit directly related to the investment should be allocated to the state jurisdictions in the same proportion as the investment.

2. Capacity Costs

Q. HAVE YOU MADE AN ADJUSTMENT FOR CAPACITY COSTS?

A. Yes. As a result of the economic downturn and lower electricity needs in the market, low cost capacity has become available. OTP has entered into agreements to purchase capacity for the next four years at prices lower than were incurred in 2009. The resulting expense reduction of $62,145 is reflected in Exhibit__(PJB-1), Schedule 8, column (R), line 4.

3. Big Stone II Expenses

Q. DID OTP REQUEST AND RECEIVE APPROVAL TO DEFER THE BIG STONE II COSTS UNTIL ITS NEXT RATE CASE?

A. Yes, OTP requested such an accounting deferral in Docket No. EL09-024. The Commission approved our request in its Order dated February 11, 2010.

Q. WHAT IS OTP'S PROPOSAL FOR RECOVERY OF BIG STONE II COSTS?

A. Mr. Brause's testimony explains why OTP should be allowed to recover the expenses associated with the development of the Big Stone II project. OTP is proposing to amortize the costs over five years with rate base treatment for the unamortized balance.

Q. WHY IS IT APPROPRIATE TO AMORTIZE THESE COSTS OVER FIVE YEARS?

A. OTP incurred these costs over the period of early 2005 through late 2009, a period of five years. OTP's proposal matches the period of amortization of the costs with the amount of time over which the costs were incurred.

Q. WHAT IS THE IMPACT OF THE BIG STONE II COST RECOVERY ON THE OPERATING STATEMENT?

A. The impact is $252,663, as shown on Exhibit__(PJB-1), Schedule 8, column (C), line 12. The overall impact on the revenue requirement, including the return on the unamortized balance, is $344,935.

Q. WHY IS IT APPROPRIATE TO EARN A RETURN ON THE UNAMORTIZED BALANCE?

A. The total cost is approximately $12.7 million. The South Dakota jurisdictional share of these costs for the test year is 9.84 percent or $1.2 million dollars. For costs that are recovered over time, the lack of a return is effectively a disallowance of a portion of the investment. For OTP, the Big Stone II development costs are too significant an investment to go unrecovered for such an extended time period without a return on that investment. If utilities are not allowed to fully recover reasonable costs incurred in the pursuit of projects that are in the interests of their ratepayers, such under-recoveries will have a chilling effect on utilities pursuing any projects other than those which have no potential controversy.

Q. DID OTP HAVE A REASONABLE BASIS TO PURSUE BIG STONE II?

A. Yes. Mr. Brause in his Direct Testimony explains why OTP pursued the Big Stone II project and why it ultimately withdrew from the project.

4. Medical, Post Retirement Medical and Pension

Q. HAVE YOU MADE ADJUSTMENTS ASSOCIATED WITH MEDICAL, POST RETIREMENT MEDICAL AND PENSION EXPENSES?

A. Yes. I am proposing known and measurable adjustments to these three expenses. These adjustments are provided on Exhibit__(PJB-1), Schedule 8, column (J) (Employee Benefits Medical/Dental) with an increase in expense of $120,095; column (K) (FAS 87 Pension Costs) with an increase in expense of $391,419; and column (L) (FAS 106 and 112) with an increase in expense of $81,748. Our compensation practices are more fully described in the testimony of Mr. Wasberg. Table 1 provides a comparison of the differences between the 2009 and known and measurable changes through 2011 South Dakota expense levels.

Table 1

Expense category	2009	2011	Percentage change
Medical	813,801	933,896	14.76%
FAS 112 (Post Employment Medical)	11,817	26,636	125.40%
FAS 106 (Post Retirement Medical)	283,150	350,079	23.64%
FAS 87 Pension	238,725	630,144	163.96%
Total expenses	$1,347,493	$1,940,755	44.03%

Q. PLEASE EXPLAIN THE INCREASE IN MEDICAL COSTS.

A. The increase in medical costs is a known and measureable change that is based on a forecast for 2011 that is prepared by our actuary, Mercer. That increase in medical costs is consistent with history. OTP's medical costs increased 17 percent in 2006, were fairly flat in 2007 (for the reasons described in the direct testimony of Mr. Pete Wasberg), and increased 12 percent in 2008.

Q. PLEASE EXPLAIN OTP'S COSTS UNDER FINANCIAL ACCOUNTING STANDARDS BOARD STATEMENT NO. 106 ("FAS 106")?

A. OTP's FAS 106 costs are recorded and tracked in two parts -- transition costs and current accrual expenses. OTP's remaining transition cost balance on a South Dakota jurisdictional basis as of December 31, 2009 was $215,011. The annual FAS 106 (employee post-retirement medical) expense is $350,079, which includes the $71,670 annual amortization of the transition amount, with approximately 9 percent (using the labor and related expense allocator) allocated to the South Dakota jurisdiction.

Q. HOW WERE OTP'S COSTS UNDER FINANCIAL ACCOUNTING STANDARDS BOARD STATEMENT NO. 112 ("FAS 112") DETERMINED?

A. The FAS 112 employee post-employment costs included in the test year are also 2011 expenses, based on information from our actuary.

Q. HOW WAS THE PENSION EXPENSE INCLUDED IN THE TEST YEAR DETERMINED?

A. OTP's test year pension expenses were based on the net period pension cost determined under Financial Accounting Standards Board Statement No. 87 ("FAS 87"). The amount of the pension expense for each year is also determined by our actuary Mercer. As shown on Exhibit__(PJB-1), Schedule 8, column (K), pension expenses are increase by $391,419 for 2011. The pension increase is the result of the performance of the overall market in which the pension assets are invested. Mr. Wasberg discusses these expense increases further in this testimony.

Q. WILL OTP PROVIDE UPDATED ACTUARIAL INFORMATION?

A. Yes. OTP will supply updated actuarial studies for medical, FAS 106, and FAS 87 Pension costs when they become available in the fourth quarter of 2010.

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU INCLUDED BECAUSE OF THE PASSAGE OF THE PATIENT PROTECTION AND AFFORDABLE CARE ACT.

A. In Actual Year 2009, the Internal Revenue Code allowed companies to exclude the subsidy provided by Medicare Part D from income and provided tax-deductibility for retiree drug costs defrayed by the tax-free subsidy. As a result, OTP recorded negative deferred tax expense and accumulated a deferred tax asset in anticipation of future tax deductions. The negative expense reduced OTP's cost of service and the deferred tax asset was added to rate base. During the set-up period in advance of the actual expense, current income taxes are higher. When the future deductions occur, current taxes will be lowered and an offsetting deferred tax expense will occur. As deductions occur, the accumulated deferred tax asset balance reverses.

Q. WHY HAVE YOU INCLUDED AN ADJUSTMENT RELATED TO THIS LEGISLATION?

A. With the recent passage of health care reform legislation, the favorable tax treatment accorded Medicare Part D prescription drug subsidies has been reduced. Beginning in 2013, the Company will no longer be able to deduct retiree drug costs to the extent of the subsidy. As a result, the tax benefits provided ratepayers in the form of negative deferred tax expense will not reverse.

Q. IS THE HEALTH CARE REFORM LEGISLATION A TEST YEAR EVENT?

A. Yes, it is. This legislation was passed in 2010 and pursuant to FAS 109 needs to be reflected immediately.

Q. WHAT DO YOU RECOMMEND?

A. Given that the tax law change has eliminated this future deduction, it is appropriate to: (i) remove the negative deferred tax expense and associated rate base impacts from the test year; and (ii) expense the beginning deferred tax asset balance that was built up through the recording of negative deferred tax expenses in anticipation of a future deduction.

Q. WHAT SPECIFIC ADJUSTMENTS ARE YOU PROPOSING?

A. OTP is proposing two adjustments. First, I have proposed the removal of the $81,172 of deferred tax expense included in Actual Year 2009. Second, this increased expense has a corresponding average rate base reduction of $247,171

5. Wages

Q. HAVE YOU MADE ANY ADJUSTMENTS ASSOCIATED WITH WAGES?

A. Yes. I am proposing three adjustments associated with changes in wages. As explained by Mr. Wasberg, we have entered into a new labor union contract with the International Brotherhood of Electrical Workers (IBEW) that includes a 2.0 percent increase effective November 1, 2009, and have an existing contract for Coyote Plant that calls for 4.0 percent increases, including increases effective September 1, 2009 and 2010. I have annualized the increases effective November 1 and September 1, 2009, and reflected a part year for the increase effective September 1, 2010. For non-union employees, I have included wage increases averaging 3.0 percent that are taking effect in April 2010, after no increases in 2009. I have also included a 3 percent adjustment for management wages effective April 2010, after no increases in 2009. The impact of using a 5 percent wage increase for executive management instead of the 3 percent used for the non-union wage increase is $12,411 on a South Dakota basis. The total amount of the all adjustments to wages is $188,086 (South Dakota share), which is reflected on Exhibit__(PJB-1), Schedule 8, column H.

6. Incentive Compensation

Q. HAVE YOU MADE ANY ADJUSTMENTS WITH RESPECT TO INCENTIVE COMPENSATION?

A. Yes. OTP's incentive compensation programs are discussed in Mr. Wasberg's direct testimony. I made one adjustment to reflect a reduction in the general employee annual incentive plan ("KPA") by $45,103, which is included in Exhibit__(PJB-1), Schedule 8, column (I). The adjustment is made to reflect the 5-year average of 3 percent payout. The removal of any incentive pay amounts in excess of 25 percent of individual base pay is now an actual year adjustment (it was $22,350) consistent with the settlement in our last rate case. Therefore, no test year adjustment is needed.

7. Tree Trimming and Vegetation Maintenance

Q. WHY HAVE YOU PROPOSED AN ADJUSTMENT FOR TREE TRIMMING AND VEGETATION MAINTENANCE?

A. In 2009, tree trimming expenditures were significantly below 2007 and 2008 actual expenditures. The 2010 budget is below, but close to, the actual expenditures for 2007 and 2008 and is at the level expected to be incurred in the future. Tree trimming is budgeted to increase by $42,519 in 2011, and a corresponding increase is proposed, and included on Exhibit__(PJB-1), Schedule 8, column (P).

8. Storm Repairs

Q. HAVE YOU MADE ANY ADJUSTMENTS TO STORM REPAIR EXPENSE?

A. Yes. I have added $21,433 to 2009 actual year storm repair expenses as shown on Exhibit__(PJB-1), Schedule 8, column (Q). This adjustment brings this expense up to the five-year average amount. The 2009 actual year storm repair expense was much lower than average, and therefore not representative of the normal cost of this activity.

9. Economic Development

Q. WHAT IS OTP'S PROPOSAL REGARDING ECONOMIC DEVELOPMENT COSTS?

A. OTP continues to participate in economic development activities in the towns it serves in South Dakota. Therefore, OTP proposes to include in rates 2009 South Dakota economic development expenses of $21,254 (compared to the amount in Docket EL08-030 of $19,039).

10. Corporate Allocations

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

A. In this section of my testimony, I describe the method for allocating corporate costs and discuss the functions the Corporate Group performs for OTP. The Corporate Cost Allocation Manual ("CCAM") is included as Exhibit __ (PJB-1), Schedule 11.

Q. HOW ARE OTTER TAIL CORPORATION AND OTP STRUCTURED?

A. As of July 1, 2009, a holding company was formed and OTP became a separate legal entity instead of an operating division. OTP is a wholly owned subsidiary of Otter Tail Corporation. At the time of the reorganization, 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 could be provided by Otter Tail Corporation. I will describe how the administrative services agreement and tax sharing agreement are administered. Currently, no cash management services are being provided by Otter Tail Corporation to OTP.

Q. CAN YOU CONTRAST THE FUNCTION OF OTTER TAIL CORPORATION WITH THE FUNCTION OF SERVICES SUBSIDIARIES, WHICH HAVE BEEN CREATED BY SOME UTILITY HOLDING COMPANIES?

A. Yes. For example, Otter Tail Corporation is not like the corporate services unit in Xcel Energy (Xcel Energy Services Inc.). Otter Tail Corporation does not: process the utility's invoices or customers' bills; do billing for the utility; manage the utility's human resources ("HR"); provide information technologies ("IT"); or provide procurement services. 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 ARE THE COSTS OF THE CORPORATE FUNCTIONS PROVIDED BY OTTER TAIL CORPORATION ALLOCATED TO OTP?

A. Pursuant to the terms of the administrative services agreement, the costs of the corporate functions are allocated using the allocation methodology and specific allocation factors described in the CCAM. The allocation factors in the CCAM are updated annually based on the most recent historic year available and applied to the next 12 months.

Q. HOW WERE THE COST ALLOCATION METHODOLOGIES IN THE CCAM DEVELOPED?

A. The CCAM describes the functions performed by the Corporate Group and the way that the costs for those functions are allocated to OTP. The allocation methods follow cost causative principles when available. When cost causation is not easily determined, OTP allocates those costs 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.

Q. PLEASE EXPLAIN THE ALLOCATION PROCESS IN MORE DETAIL.

A. Corporate 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 assigned. Members of the Corporate Group use timesheets to directly assign labor. Invoices and other costs are directly assigned as appropriate. In the 2009 actual year, 53 percent of all corporate costs were distributed 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 16 percent of corporate costs were allocated using indirect allocators. The remaining 31 percent of corporate costs are not appropriate for either direct assignment or indirect allocation. Those costs are allocated using the general allocator described in my previous answer.

Q. HOW MUCH OF THE TOTAL OTTER TAIL CORPORATION COSTS WAS ALLOCATED TO OTP IN 2009?

A. Table 2, below, shows the allocation of Otter Tail Corporation (OTC) costs in 2009.

Table 2

OTC COSTS	ACTUAL YEAR 2009	
Allocated to OTP	$5,402,585	25.63%
Allocated to non-utility	$15,679,990	74.37%
Total 2009 OTC Costs	$21,082,575	100.00%

11. Holding Company Formation Expenses

Q. ARE THE AMORTIZED EXPENSES OF FORMING A HOLDING COMPANY STRUCTURE INCLUDED IN THE TEST YEAR?

A. Yes. The Company's proposal to form a holding company was approved by the Commission by its Order dated November 13, 2008, in Docket No. EL08-025. In our last rate case, Docket EL08-030, the Commission authorized recovery of $31,250. That rate case was filed before the reorganization was complete. In this case, OTP is proposing to amortize over a five-year period additional formation costs incurred since the amount approved in Docket EL08-030 . The amount of $3,075 included in the test year for Holding Company formation is South Dakota's share of the annual amortization of those additional costs allocated to OTP. This adjustment is provided on Exhibit__(PJB-1), Schedule 8, column (M).

12. Rate Case Expenses

Q. HOW DID YOU DETERMINE THE AMOUNT OF RATE CASE EXPENSE TO INCLUDE IN THE TEST YEAR?

A. There were two components. First, it was necessary to estimate the amount of rate case expense. Second, it was necessary to determine a reasonable amortization period.

Q. WHAT PROCESS DID YOU USE TO ESTIMATE RATE CASE EXPENSES?

A. We included South Dakota's statutory filing fee of $100,000 and added estimates for consulting and outside legal fees, based on information from service providers and our experience in our last rate case. The details are reflected in workpaper TY-11 in Volume 4A, Work Papers.

Q. WHAT AMORTIZATION PERIOD DID YOU USE, AND WHY?

A. I 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. We project that, due to our investment plans, we will need to file a rate case in three years.

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

A. $75,000, which is included in Exhibit __ (PJB-1), Schedule 8, column (N).

13. Depreciation Expense

Q. HOW WERE TEST YEAR DEPRECIATION EXPENSES DETERMINED?

A. OTP is required to file an annual review of its depreciation rates in Minnesota and a comprehensive study of the lives and salvage parameters of its property every five years. When the depreciation filing is approved, OTP uses the depreciation parameters to calculate total system depreciation expense. It is appropriate to use the same depreciation parameters for all jurisdictions that OTP serves because our facilities operate as one integrated system across our entire service territory. The depreciation expense included in the 2009 actual year does not reflect the depreciation rates effective January 1, 2010, certified by the Minnesota Public Utilities Commission in Docket No. E-017/D-09-1019. To reflect the known and measurable change in depreciation rates in effect for the 12 months following the end of the 2009 actual year, an adjustment in the amount of $66,786 has been made to arrive at the South Dakota test year depreciation expense. This adjustment is shown in Exhibit __ (PJB-1), Schedule 8, column (E).

Q. WHAT OTHER ADJUSTMENTS DID YOU MAKE TO THE TEST YEAR DEPRECIATION AND AMORTIZATION EXPENSE?

A. The remaining adjustments are related to the plant in service adjustments described in the direct testimony of Mr. Sem. There is a depreciation expense adjustment of $46,353 related to normalized plant in service (see Exhibit __ (PJB-1), Schedule 8, column (B)), an adjustment of $252,663 related to the Recovery of the Big Stone II costs (see Exhibit __ (PJB-1), Schedule 8, column (C)), and an adjustment of $306 (see Exhibit __ (PJB-1), Schedule 8, column (D)); related to the transmission and distribution plant reclassification described by Mr. Sem; and a depreciation adjustment of $192,233, before tax, (see Exhibit __ (PJB-1), Schedule 8, columns (U) and (V)) relate to normalizing the expenses for the addition of the Luverne wind farm.

14. Transmission Rider Adjustment

Q. HAVE YOU MADE ANY ADJUSTMENTS TO OFFSET REVENUES THAT WILL BE COLLECTED THROUGH OTP'S TRANSMISSION RIDER?

A. Yes. I reduced production expense by $13,427, the amount of MISO Schedule 26 costs so they can be included in the OTP's soon to be filed transmission rider. This adjustment is provide on Exhibit __ (PJB-1), Schedule 8, column (S).

15. Income Taxes

Q. HOW WERE OTP'S INCOME TAX EXPENSES DETERMINED?

A. OTP's income tax expenses were based on the "stand-alone" method. The stand-alone method determines the jurisdictional regulated income tax expenses based solely on regulated jurisdictional income and expenses (separate from all other income and expenses), normalized by using straight-line depreciation to determine current income tax expenses and accelerated income tax depreciation to determine deferred income taxes (which are treated as a reduction to rate base). The stand-alone method was used in OTP's last general rate case (Docket No. EL08-030), and has been consistently used by the Commission in utility rate cases. The current income tax expense reflected in the revenue requirement is ($2,126,193).

Q. HAVE YOU PREPARED A SCHEDULE SHOWING THE CALCULATION OF OTP'S STAND-ALONE FEDERAL INCOME TAX EXPENSES?

A. Yes. The calculation of OTP's federal income tax expenses for this proceeding is shown on Exhibit__(PJB-1), Schedules 4, 5 and 6.

Q. WHY DID OTP HAVE AN INCOME TAX LOSS IN 2009?

A. OTP's income tax loss was resulted from two primary sources. (i) income tax depreciation provisions that were available for renewable energy projects, such as OTP's wind projects at Langdon, Ashtabula, and Luverne, including 50 percent depreciation for the projects and accelerated depreciation, as well as PTCs; and (ii) the recognition on the 2009 OTP federal income tax return of a reclassification of costs from capital to current expense accounts for the years 2001 through 2009.

Q. PLEASE EXPLAIN THE DEPRECIATION PROVISIONS AND PTCs, AND THEIR EFFECT ON OTP'S 2009 FEDERAL INCOME TAX RETURN.

A. The 50 percent bonus depreciation referred to above allowed a company to deduct up to 50 percent of the cost of an asset in the year it is placed in service. This provision applied to OTP's Luverne Wind Farm, which had a cost of approximately $105 million. The 50 percent depreciation allowed is different from typical accelerated depreciation, but both create large deductions for current income taxes (reducing current taxes), which are normalized through deferred income taxes for both financial and rate setting purposes. PTCs are tax credits which are based on the actual production (generation) of OTP's renewable generation. Due to the large investment in wind projects, OTP has large deductions and credits recognized in current taxes in 2009 and expects to have net operating losses for tax purposes through 2011.

Q. DO OTP CUSTOMERS BENEFIT FROM THE DEPRECIATION AND PTCs RELATED TO OTP'S RENEWABLE GENERATING RESOURCES?

A. Yes. OTP's customers benefit through the reduction in rate base resulting from deferred income taxes (which reflects both the 50 percent first year depreciation and typical accelerated depreciation), the PTCs, and the North Dakota investment tax credits built into the revenue requirements.

Q. PLEASE EXPLAIN THE TAX RECLASSIFICATION OF COSTS FROM 2001 THROUGH 2009.

A. In 2009, OTP recognized Capitalized to Repair Basis Adjustments for the years 2001-2009 under Internal Revenue Service Code, Section 481(a). The result was a one-time deduction of $42,618,532 for Federal current income taxes which was recognized on OTP's 2009 income tax return. The Section 481(a) adjustment also resulted in an offset to deferred taxes with a net effect of reducing the company-wide test year cost of service by $822,571.

Q. DOES OTP HAVE A TAX SHARING AGREEMENT WITH ITS PARENT?

A. Yes. The OTP Tax-Sharing Agreement provides for the calculation of OTP's income tax liability on a separate return basis, and the payment by OTP of its income tax liabilities and the receipt by OTP of the value of income tax losses in the context of the consolidated income tax filings by Otter Tail Corporation. This approach prevents any subsidization by OTP or any added burden being imposed on OTP, and allows OTP to receive the tax savings that arise from OTP tax losses in the year in which the loss is reflected on OTP's income tax return. OTP has received a payment for the income tax savings arising from its 2009 income tax losses from the income tax refund received in the second quarter, 2010.

16. Affiliate Transactions

Q. HAVE TRANSACTIONS WITH SUBSIDIARIES RESULTED IN CROSS SUBSIDIZATION OF THE AFFILIATED SUBSIDIARIES BY OTP RATEPAYERS?

A. No. OTP has prevented any cross subsidization by providing services to the subsidiaries at fully allocated costs and by procuring services at no more than reasonable market prices. As discussed earlier in my testimony, OTP's CCAM is designed to prevent any cross subsidization of Otter Tail Corporation costs. In addition, to avoid any possible concern, I made an adjustment removing all affiliated transactions from the test year, Exhibit____(PJB-1), Schedule 8, Column (T), increasing net income by $2,468.

17. Changes in allocations due to adjustments.

Q. PLEASE EXPLAIN THE REASON FOR THE ADJUSTMENT FOR CHANGES IN ALLOCATIONS DUE TO THE ADJUSTMENTS.

A. The adjustments to the 2009 Actual Year included in Exhibit __ (PJB-1), Schedule 8 also cause minor changes in the allocators used in determining the South Dakota jurisdictional cost of service. These changes result in an increase in allocated expenses of $1,139. Column (W) of Schedule 8 provides the calculation of this adjustment.

C. TRADITIONAL REGULATORY ADJUSTMENTS

1. Advertising

Q. PLEASE DESCRIBE ADVERTISING EXPENSE.

A. Advertising expenditures that are reasonable in amount and purpose are included as operating expenses in the cost of service determination for ratemaking purposes. The types of advertising included are those designed to encourage energy conservation, promote safety, inform and educate consumers on the utility's financial services, disseminate information on a utility's corporate affairs to its owners. It was not necessary to make a test year adjustment because we already account for advertising costs using these criteria. OTP had excluded $54,784 in advertising expenses from its 2009 costs allocated to South Dakota. The relative dollar values are included in Volume 4A, work paper B-14. The amount we included in the 2009 Actual Year and 2009 Test Year is $11,120.

2. Charitable Contributions

Q. WHAT HAVE YOU INCLUDED IN THE TEST YEAR FOR CHARITABLE CONTRIBUTIONS?

A. We have not included any charitable contributions in the South Dakota Test Year expenses as shown on page 2 of work paper B-6 found the Volume 4A, Work Papers.

V. CLASS COST OF SERVICE STUDY

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

A. The purpose of this section of my testimony is to support the embedded class cost of service study ("CCOSS"). OTP has prepared a CCOSS, which is included with the summary of the results of the CCOSS provided in Statement N, Volume 1.

Q. ARE THERE DIFFERENCES BETWEEN THIS CCOSS AND THE CCOSS OTP FILED IN ITS LAST GENERAL RATE CASE?

A. No. The definition of revenue classes and the allocation methods are consistent with those in OTP's last rate case.

Q. HAS OTP PERFORMED A NEW AVERAGE ENERGY LOSS STUDY?

A. Yes. OTP's engineering staff performed a new average loss study, which OTP has applied to its energy allocators. The average loss study determines the losses at various voltage levels in order apply the appropriate loss levels to the individual components of energy allocation factors. When applied to the E2 (all energy) allocator, the average losses calculate to 7.64 percent. However, it is important to remember the impact of the average loss study on allocation factors is not the direct percent, but rather, the proportion among the allocation factors.

Q. HAS OTP SUPPLIED AN EMBEDDED CLASS COST OF SERVICE STUDY AS WELL AS A MARGINAL COST STUDY?

A. Yes. OTP's class cost of service study was an embedded cost study in its last general rate case and is an embedded cost study in this case. However, OTP does not design rates based on the embedded cost study. Instead, we use marginal costs once the embedded class cost of service study and the revenue allocation process are completed. The revenue allocation process includes judgment to mitigate rate shock that would result if class revenue requirements were based solely on cost. The marginal cost study and rate design are covered in the direct testimony of Mr. Prazak.

Q. HAS OTP PROVIDED A JURISDICTIONAL AND CLASS COST OF SERVICE ALLOCATION MANUAL WITH THIS FILING?

A. Yes. OTP's *Cost Allocation Procedure Manual for Jurisdictional and Class Cost of Service Studies* is included as Schedule 10, Exhibit___ (PJB-1) to my testimony. It provides a useful primer on the processes of cost functionalization, classification, and allocation. These basic processes are common to all embedded cost studies. This manual also describes how each of OTP's cost allocators was developed and explains how each allocator is applied.

VI. CLASS REVENUE RESPONSIBILITIES

Q. PLEASE SUMMARIZE THE RESULTS OF THE CCOSS.

A. Table 3 below contains information from the CCOSS results, which is also shown in Statement N, of Volume 1. It indicates the cost responsibility by class and the rate increase necessary for each class to cover its cost of service.

Table 3

Class Responsibility

(A)	(B)	(C)	(D)
	Class Responsibility		
Class	Current Revenues	Amount of Increase	Percent Increase
Residential	$8,579,300	$1,496,208	17.44%
Farms	594,499	228,602	38.45%
General Service	6,301,645	(248,724)	-3.95%
Large General Service	9,807,499	223,587	2.28%
Irrigation	19,773	3,104	15.70%
Lighting	602,119	123,408	20.50%
OPA	235,278	73,934	31.42%
Controlled Service Water Heating	413,540	198,376	47.97%
Controlled Service Interruptible	831,818	557,401	67.01%
Controlled Service Deferred	286,907	100,059	34.87%
	$27,672,377	$2,755,955	9.96%

Q. PLEASE EXPLAIN TABLE 3.

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

Q. HOW IS OTP PROPOSING TO DISTRIBUTE THE TOTAL REVENUE REQUIREMENTS AMONG THE CLASSES OF SERVICE?

A. The CCOSS is the primary guide for setting the class revenue responsibilities. However, determining the appropriate class revenue responsibilities is not as simple as setting them to equal the results of the CCOSS. It is also necessary to consider other objectives, particularly the objective of maintaining reasonable rate continuity, and mitigating rate shock. A more complete discussion of the rate design considerations applied by OTP is contained in Mr. Prazak's testimony. Based on a consideration of all the rate design objectives, OTP proposes the distribution of revenue responsibilities contained in Table 4 below.

Table 4

Class Revenue Responsibility – Proposed increase by class

(A)	(B)	(C)	(D)
	Class Responsibility		
Class	Current Revenues	Amount of Increase	Percent Increase
Residential	$8,579,300	$1,072,412	12.50%
Farms	594,499	89,175	15.00%
General Service	6,301,645	478,522	7.59%
Large General Service	9,807,499	744,389	7.59%
Irrigation	19,773	2,966	15.00%
Lighting	602,119	60,212	10.00%
OPA	235,278	35,292	15.00%
Controlled Service Water Heating	413,540	66,166	16.00%
Controlled Service Interruptible	831,818	158,045	19.00%
Controlled Service Deferred	286,907	48,774	17.00%
	$27,672,377	$2,755,954	9.96%

This distribution of revenue responsibilities results in a reasonable movement toward full cost recovery by class without producing unreasonable bill impacts.

Q. PLEASE EXPLAIN TABLE 4.

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

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

A. The CCOSS indicates that a 17.44 percent increase to the Residential Class would be needed to bring the rates for this class up to its cost level. To provide a reasonable balance of the cost of service and rate continuity objectives of rate design, OTP is proposing a moderated increase of 12.50 percent. While the increase to the Residential Class is significant, it is important to recognize that final rates ordered in OTP's last rate case left some room to go before rates matched CCOSS. Therefore, it is necessary to apply a rate increase to the Residential Class that is higher than the average increase to reasonably mitigate existing interclass cross-subsidies.

Q. HOW DO MARGINAL COSTS RELATE TO REVENUE ALLOCATIONS?

A. As explained above, an embedded cost study, modified to consider disproportionate rate impacts, is used to assign class revenue responsibility. Marginal costs are then used to develop rates within each class. Marginal costs do not impact class revenue responsibility. Mr. Prazak explains in more detail the use of marginal costs for rate design in his testimony.

Q. HOW DOES THE MARGINAL COST METHOD USED IN RATE DESIGN COMPARE WITH THE REVENUE ALLOCATION PROPOSED BY OTP?

A. The class revenue responsibility proposed by OTP is about 91 percent of marginal costs as indicated in Table 5.

Table 5

Proposed Revenue as a Percent of Marginal Costs

CCOSS Class	Proposed Revenue as Percent of Marginal Cost
Residential	93%
Farms	69%
General Service	101%
Large General Service	74%
Irrigation	86%
Lighting	N/A
OPA	77%
Controlled Service Water Heating	88%
Controlled Service Interruptible	77%
Controlled Service Deferred Load	96%
	91%

A calculation was not made for Lighting. Lighting rates were set using the proposed lighting class increase of 15 percent because it includes numerous fixtures, for which the cost was updated in our previous rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULE

Docket No. EL10-______
Exhibit ___(PJB-1)
Financial Information
Schedule 1

Line No.	Description	(A) 2009 Actual Year	(B) 2009 Test Year
1	Average Rate Base	$62,922,312	$64,406,556
2	Operating Income (Before AFUDC)	$5,568,902	$4,091,636
3	Allowance for Funds Used During Construction (AFUDC)	$0	$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$5,568,902	$4,091,636
5	Overall Rate of Return (Line 4 / Line 1)	8.85%	6.35%
6	Required Rate of Return	8.18%	9.13%
7	Operating Income Requirement (Line 1 x Line 6)	$5,147,045	$5,880,319
8	Income Deficiency (Line 7 - Line 4)	($421,857)	$1,788,683
9	Gross Revenue Conversion Factor	1.540773	1.540773
10	Revenue Deficiency (Line 8 x Line 9)	($649,986)	$2,755,954
11	Retail Related Revenues Under Present Rates	$27,634,807	$27,672,377
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11)	-2.35%	9.96%

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME SCHEDULES
JURISDICTIONAL STATEMENT OF OPERATING INCOME

Docket No. EL10-______
Exhibit__(PJB-1)
Financial Information
Schedule 2

		(A)	(B)	(C)	(D)
		2009 Actual Year		2009 Test Year	
Line No.	Description	Total Utility	SD Jurisdiction	Total Utility	SD Jurisdiction
	OPERATING REVENUES				
1	Retail Revenue	$288,387,480	$27,634,807	$275,143,628	$27,672,377
2	Other Electric Operating Revenue	23,723,640	2,279,962	23,723,640	2,280,393
3	**TOTAL OPERATING REVENUE**	$312,111,120	$29,914,769	$298,867,268	$29,952,770
	OPERATING EXPENSES				
4	Production Expenses	$138,946,818	$13,473,421	$141,192,060	$13,698,261
5	Transmission Expenses	10,686,696	1,048,976	11,688,244	1,147,285
6	Distribution Expenses	14,334,019	1,397,735	15,689,632	1,529,964
7	Customer Accounting Expenses	11,149,593	969,935	12,058,572	1,049,010
8	Customer Service and Information Expenses	4,939,950	186,556	5,225,951	211,061
9	Sales Expenses	878,227	51,229	878,227	51,229
10	Administration and General Expenses	32,468,730	3,105,795	35,466,679	3,461,663
11	Charitable Contributions	93,665	0	93,665	0
12	Depreciation Expense	36,158,445	3,550,318	41,824,544	4,109,295
13	General Taxes	8,845,653	867,475	9,632,831	945,024
14	**TOTAL OPERATING EXPENSES**	$258,501,796	$24,651,439	$273,750,405	$26,202,791
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$53,609,324	$5,263,330	$25,116,863	$3,749,979
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	($9,310,969)	($915,852)	($10,077,892)	($991,042)
18	Deferred Income Taxes	49,196,013	3,953,396	36,853,943	2,775,578
19	Income Taxes	(36,898,709)	(3,343,116)	(29,143,340)	(2,126,193)
20	**TOTAL INCOME TAX EXPENSE**	$2,986,335	(305,572)	(2,367,288)	(341,656)
21	**NET OPERATING INCOME**	$50,622,989	$5,568,902	$27,484,152	$4,091,636
22	Allowance for Funds Used During Construction	4,216,005	0	3,258,459	0
23	**TOTAL AVAILABLE FOR RETURN**	$54,838,994	$5,568,902	$30,742,610	$4,091,636

The 2009 Test Year is the 2009 Actual Year with known and measureable adjustments to arrive at the Test Year.

OTTER TAIL POWER COMPANY | **Docket No. EL10-______**
Electric Utility - State of South Dakota | **Exhibit__(PJB-1)**
OPERATING INCOME SCHEDULES | **Financial Information**
TOTAL UTILITY AND SOUTH DAKOTA TEST YEAR | **Schedule 3**

		(A)	(B)	(C)	(D)
		2009 Test Year			
Line No.	Description	Actual Year Total Utility	Actual Year SD Jurisdiction	Adjustments	Proposed SD Jurisdiction
	OPERATING REVENUES				
1	Retail Revenue	$288,387,480	$27,634,807	$37,570	$27,672,377
2	Other Electric Operating Revenue	23,723,640	2,279,962	431	2,280,393
3	**TOTAL OPERATING REVENUE**	$312,111,120	$29,914,769	$38,001	$29,952,770
	OPERATING EXPENSES				
4	Production Expenses	$138,946,818	$13,473,421	$224,840	$13,698,261
5	Transmission Expenses	10,686,696	1,048,976	98,309	1,147,285
6	Distribution Expenses	14,334,019	1,397,735	132,229	1,529,964
7	Customer Accounting Expenses	11,149,593	969,935	79,075	1,049,010
8	Customer Service and Information Expenses	4,939,950	186,556	24,505	211,061
9	Sales Expenses	878,227	51,229	0	51,229
10	Administration and General Expenses	32,468,730	3,105,795	355,868	3,461,663
11	Charitable Contributions	93,665	0	0	0
12	Depreciation Expense	36,158,445	3,550,318	558,977	4,109,295
13	General Taxes	8,845,653	867,475	77,549	945,024
14	**TOTAL OPERATING EXPENSES**	$258,501,795	$24,651,439	$1,551,352	$26,202,791
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$53,609,325	$5,263,330	($1,513,351)	$3,749,979
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	($9,310,969)	($915,852)	($75,190)	($991,042)
18	Deferred Income Taxes	49,196,013	3,953,396	(1,177,818)	2,775,578
19	Income Taxes	(36,898,709)	(3,343,116)	1,216,923	(2,126,193)
20	**TOTAL INCOME TAX EXPENSE**	$2,986,335	($305,572)	($36,085)	($341,656)
21	**NET OPERATING INCOME**	$50,622,990	$5,568,902	($1,477,266)	$4,091,636
22	Allowance for Funds Used During Construction	4,216,005	0	0	0
23	**TOTAL AVAILABLE FOR RETURN**	$54,838,994	$5,568,902	($1,477,266)	$4,091,636

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME SCHEDULES
COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Docket No. EL10-______
Exhibit__(PJB-1)
Financial Information
Schedule 4

		(A)	(B)	(C)	(D)
		2009 Actual Year		2009 Test Year	
Line No.	Description	Total Utility	SD Jurisdiction	Total Utility	SD Jurisdiction
	Income Before Taxes				
1	Total Operating Revenues	$312,111,120	$29,914,769	$298,867,268	$29,952,770
2	less: Total Operating Expenses	(213,497,697)	(20,233,646)	(222,293,029)	(21,148,472)
3	Book Depreciation & Amortization	(36,158,445)	(3,550,318)	(41,824,544)	(4,109,295)
4	Taxes Other Than Income	(8,845,653)	(867,475)	(9,632,831)	(945,024)
5	Interest Cost	(19,559,234)	(2,073,277)	(19,607,883)	(2,094,071)
6	**Total Before Tax Book Income**	**$34,050,091**	**$3,190,053**	**$5,508,981**	**$1,655,908**
	Tax Additions				
7	Additional Tax Depreciation				
8	Directly Assigned Schedule M Items	186,954	8,404	186,954	8,404
9	Provisions - Operating Reserves	7,629,629	748,222	7,629,629	748,501
10	Other Schedule M Items	-	-	-	-
11	**Total Tax Additions**	**$7,816,583**	**$756,626**	**$7,816,583**	**$756,905**
	Tax Deductions				
12	Additional Tax Depreciation	$87,767,748	$8,607,205	$36,932,813	$3,623,274
13	Cost to Remove	3,029,927	297,139	3,029,927	297,249
14	Accrued Vacation Pay	73,953	7,252	73,953	7,255
15	Charges - Operating Reserves	4,161,474	408,107	4,161,474	408,259
	Preferred Dividends Paid Credit	-	-	-	-
16	Other Schedule M Items	42,610,619	4,178,737	42,318,293	4,151,613
17	**Total Tax Deductions**	**$137,643,721**	**$13,498,440**	**$86,516,460**	**$8,487,650**
18	ND Adjustments to Federal Schedule M; ND Jurisdiction	-	-	-	-
19	**State Taxable Income**	**($95,777,047)**	**($9,551,761)**	**($73,190,896)**	**($6,074,837)**
20	State Income Tax Rate	5.42%	0.00%	7.41%	0.00%
21	**Total State Income Taxes & ND Incremental Tax Rate Adj ($505)**	**($5,194,989)**	**$0**	**($5,425,425)**	**$0**
22	**Federal Taxable Income**	**($90,582,058)**	**($9,551,761)**	**($67,765,472)**	**($6,074,837)**
23	Addback of MN Adjustments to Federal Schedule M; MN Jurisdiction	-	-	-	-
24	**Adjusted Federal Taxable Income**	**($90,582,058)**	**($9,551,761)**	**($67,765,472)**	**($6,074,837)**
25	Federal Income Tax Rate	35.00%	35.00%	35.00%	**35.00%**
26	**Total Federal Income Taxes**	**($31,703,720)**	**($3,343,116)**	**($23,717,915)**	**($2,126,193)**
27	**Total State and Federal Income Tax**	**($36,898,709)**	**($3,343,116)**	**($29,143,340)**	**($2,126,193)**

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME SCHEDULES
COMPUTATION OF DEFERRED INCOME TAXES

Docket No. EL10-______
Exhibit__(PJB-1)
Financial Information
Schedule 5

Line No.	Description	2009 Actual Year Total Utility (A)	2009 Actual Year SD Jurisdiction (B)	2009 Test Year Total Utility (C)	2009 Test Year SD Jurisdiction (D)
1	Excess Tax Over Book Depreciation	$36,150,274	2,986,280	$22,980,804	$2,254,519
2	Excess Tax Over Book Pensions	(1,191,258)	(98,189)	(1,191,258)	(116,868)
3	Capitalized A & G Expenses	(413,026)	(33,184)	(413,026)	(40,520)
4	Provisions for Operating Reserves in Excess of Actual Charges	(1,295,734)	(104,247)	(1,295,734)	(127,117)
5	Other Capitalized Items	15,945,757	1,202,736	16,773,157	805,563
6	**TOTAL Deferred Income Taxes**	$49,196,013	$3,953,396	$36,853,943	$2,775,578

OTTER TAIL POWER COMPANY | **Docket No. EL10-______**
Electric Utility - State of South Dakota | **Exhibit__(PJB-1)**
OPERATING INCOME SCHEDULES | **Financial Information**
DEVELOPMENT OF FEDERAL AND STATE INCOME TAX RATES | **Schedule 6**

Actual 2009
Proposed Test Year 2009

Let: Description

M=Minnesota State Income Tax Rate = 9.80%

D=North Dakota State Income Tax Rate = 6.40%

S=South Dakota Income Tax Rate = 0%

N=Net Income After Interest Deductions but Before Income Taxes

Jurisdictional:

Only Minnesota and Federal Income Taxes

M=	9.80%	(N)
F=	31.57%	(N)
M+F=	41.37%	(N)

Only North Dakota and Federal Income Taxes

D=	6.40%	(N)
F=	32.76%	(N)
D+F=	39.16%	(N)

Only South Dakota and Federal Income Taxes

S=	0.00%	(N)
F=	35.00%	(N)
Preferre	35.00%	(N)

Composite: Combined Minnesota, North Dakota, South Dakota and Federal Income Taxes.
M + D + S + F = 39.40% (N)

Notes:
1 Investment tax credits and surtax credits are ignored.
2 State income taxes are deductible from federal taxable income.
3 Net income is defined at each jurisdictional level.
4 Composite income tax rates are determined by the Income Tax Department based upon apportionment laws (unitary and nonunitary) for each state involved.

OTTER TAIL POWER COMPANY | **Docket No. EL10-______**
Electric Utility - State of South Dakota | **Exhibit__(PJB-1)**
DEVELOPMENT OF GROSS REVENUE CONVERSION FACTOR | **Financial Information**
Schedule 7

Definition: Description
additional dollar of operating income. Gross earnings fees included.

Line No.	Description	% of Incremental Gross Revenues
1	Federal Income Taxes	35.00%
2	State Income Taxes	0.00%
3	Total Tax Percentage	35.00%

4 SD GROSS REVENUE CONVERSION FACTOR:
5 (INCLUDING RECOGNITION OF SD SPECIAL HEARING FUND ASSESSMENT)

6 WHERE "X" = GROSS REVENUE DEFICIENCY
7 "Y" = CONVERSION FACTOR
8 .0015 = SDPUC SPECIAL HEARING FUND ASSESSMENT
9 35.00% = FEDERAL TAX RATE

10 X = [X - .0015X - [(X - .0015X) * .34]] * Y
11 X = [.9985X - (.9985X * .34)] * Y
12 X = (.9985X - .33949X) * Y
13 X = .65901XY
14 1 = .65901Y
15 Gross Revenue Conversion Factor **Y = 1.540773**

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Docket No. EL10-____
Exhibit__(PJB-1)
Financial Information
Schedule 8

			KNOWN AND MEASURABLE CHANGES						
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Description	2009 Actual Year	Depreciation Expense for Current and Future Plant	BSP II Amortization and Removal of AFUCD	Transmission Plant Transfer Adjustment	Update Depreciation Expense	Weather Normalization	Retail Revenue Nomalization	Labor Expense - April & November Annual Increases
	OPERATING REVENUES								
1	Retail Revenue	$27,634,807					($64,029)	$101,599	
2	Other Electric Operating Revenue	2,279,962							
3	**TOTAL OPERATING REVENUE**	$29,914,769	$0	$0	$0	$0	($64,029)	$101,599	$0
	OPERATING EXPENSES								
4	Production Expenses	$13,473,421					($36,134)		$48,518
5	Transmission Expenses	1,048,976							18,317
6	Distribution Expenses	1,397,735							32,326
7	Customer Accounting Expenses	969,935							20,618
8	Customer Service and Information Expenses	186,556							6,991
9	Sales Expenses	51,229							
10	Administration and General Expenses	3,105,795							61,314
11	Charitable Contributions	0							
12	Depreciation Expense	3,550,318	46,353	252,663	306	66,786			
13	General Taxes	867,475							
14	**TOTAL OPERATING EXPENSES**	$24,651,439	$46,353	$252,663	$306	$66,786	($36,134)	$0	$188,086
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$5,263,330	($46,353)	($252,663)	($306)	($66,786)	($27,895)	$101,599	($188,086)
16	**INCOME TAX EXPENSE**								
17	Investment Tax Credit	($915,852)							
18	Deferred Income Taxes	3,953,396							
19	Income Taxes	(3,343,116)	(16,223)	(88,432)	(107)	(23,375)	(9,763)	35,560	(65,830)
20	**TOTAL INCOME TAX EXPENSE**	($305,572)	($16,223)	($88,432)	($107)	($23,375)	($9,763)	$35,560	($65,830)
21	**NET OPERATING INCOME**	$5,568,902	($30,129)	($164,231)	($199)	($43,411)	($18,132)	$66,039	($122,256)
22	Allowance for Funds Used During Construction	0							
23	**TOTAL AVAILABLE FOR RETURN**	$5,568,902	($30,129)	($164,231)	($199)	($43,411)	($18,132)	$66,039	($122,256)

Column references to adjustment workpapers:

(B) W/P 2009 SD TY-01
(C) W/P 2009 SD TY-02
(D) W/P 2009 SD TY-03
(E) W/P 2009 SD TY-04
(F) W/P 2009 SD TY-06
(G) W/P 2009 SD TY-07
(H) W/P 2009 SD TY-08
(I) W/P 2009 SD TY-08
(J) W/P 2009 SD TY-09
(K) W/P 2009 SD TY-09
(L) W/P 2009 SD TY-09
(M) W/P 2009 SD TY-10
(N) W/P 2009 SD TY-11
(O) W/P 2009 SD TY-12
(P) W/P 2009 SD TY-13
(Q) W/P 2009 SD TY-14
(R) W/P 2009 SD TY-15
(S) W/P 2009 SD TY-16
(T) W/P 2009 SD TY-17
(U) W/P 2009 SD TY-18
(V) W/P 2009 SD TY-19

		KNOWN AND MEASURABLE CHANGES							
		(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
Line No.	Description	KPA & Utility Management Incentive	Employee Benefits Medical/Dental	FAS 87 Pension Costs	FAS 106 & 112 Benefits	Holding Company Formation Costs	Amortized Rate Case Expenses	Patient Protection and Affordable Care Act	Vegetation Maintenance Cycles
	OPERATING REVENUES								
1	Retail Revenue							$0	
2	Other Electric Operating Revenue								
3	**TOTAL OPERATING REVENUE**		$0	$0	$0		$0	$0	$0
	OPERATING EXPENSES								
4	Production Expenses	($11,634)	$29,499	$96,142	$20,080				
5	Transmission Expenses	(4,392)	12,044	39,254	8,198				38,316
6	Distribution Expenses	(7,752)	20,941	68,253	14,254				4,205
7	Customer Accounting Expenses	(4,944)	12,835	41,830	8,737				
8	Customer Service and Information Expenses	(1,676)	3,884	12,660	2,644				
9	Sales Expenses								
10	Administration and General Expenses	(14,704)	40,892	133,279	27,835	3,075	75,000		
11	Charitable Contributions								
12	Depreciation Expense								
13	General Taxes								
14	**TOTAL OPERATING EXPENSES**	($45,103)	$120,095	$391,419	$81,748	$3,075	$75,000	$0	$42,519
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$45,103	($120,095)	($391,419)	($81,748)	($3,075)	($75,000)	$0	($42,519)
16	**INCOME TAX EXPENSE**								
17	Investment Tax Credit								
18	Deferred Income Taxes							81,172	
19	Income Taxes	15,786	(42,033)	(136,997)	(28,612)	(1,076)	(26,250)	0	(14,882)
20	**TOTAL INCOME TAX EXPENSE**	$15,786	($42,033)	($136,997)	($28,612)	($1,076)	($26,250)	$81,172	($14,882)
21	**NET OPERATING INCOME**	$29,317	($78,062)	($254,422)	($53,136)	($1,999)	($48,750)	($81,172)	($27,637)
22	Allowance for Funds Used During Construction								
23	**TOTAL AVAILABLE FOR RETURN**	$29,317	($78,062)	($254,422)	($53,136)	($1,999)	($48,750)	($81,172)	($27,637)

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Docket No. EL10-____
Exhibit__(PJB-1)
Financial Information
Schedule 8

		KNOWN AND MEASURABLE CHANGES							
		(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
Line No.	Description	Normalized Storm Repair Expense	Reduction in Capacity Costs	Schedule 26 Expenses Collected in Transmission Rider	Remove Minor Affiliate Transactions	Wind Removal	Wind In	Changes in Allocations due to Effect of Test Year Adjustments	2009 Test Year
	OPERATING REVENUES								
1	Retail Revenue								$27,672,377
2	Other Electric Operating Revenue							431	2,280,393
3	**TOTAL OPERATING REVENUE**	$0	$0	$0	$0	$0	$0	$431	$29,952,770
	OPERATING EXPENSES								
4	Production Expenses		($62,145)			($124,085)	$264,600		$13,698,261
5	Transmission Expenses			(13,427)					1,147,285
6	Distribution Expenses								1,529,964
7	Customer Accounting Expenses								1,049,010
8	Customer Service and Information Expenses								211,061
9	Sales Expenses								51,229
10	Administration and General Expenses	21,433			(2,468)	(28,228)	38,261	179	3,461,663
11	Charitable Contributions								0
12	Depreciation Expense					(825,622)	1,017,855	636	4,109,295
13	General Taxes					(63,480)	140,705	324	945,024
14	**TOTAL OPERATING EXPENSES**	$21,433	($62,145)	($13,427)	($2,468)	($1,041,415)	$1,461,421	$1,139	$26,202,791
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	($21,433)	$62,145	$13,427	$2,468	$1,041,415	($1,461,421)	($708)	$3,749,979
16	**INCOME TAX EXPENSE**								
17	Investment Tax Credit					$777,842	($853,260)	$228	($991,042)
18	Deferred Income Taxes					(2,438,900)	1,178,440	1,470	2,775,578
19	Income Taxes	(7,502)	21,751	4,699	864	3,149,052	(1,553,920)	4,212	(2,126,193)
20	**TOTAL INCOME TAX EXPENSE**	($7,502)	$21,751	$4,699	$864	$1,487,994	($1,228,740)	$5,910	($341,656)
21	**NET OPERATING INCOME**	($13,931)	$40,394	$8,727	$1,604	($446,579)	($232,681)	($6,618)	$4,091,636
22	Allowance for Funds Used During Construction								0
23	**TOTAL AVAILABLE FOR RETURN**	($13,931)	$40,394	$8,727	$1,604	($446,579)	($232,681)	($6,618)	$4,091,636

OTTER TAIL POWER COMPANY **Docket EL10-______**
Electric Utility - State of South Dakota **Exhibit ___(PJB-1)**
COMPARISON OF PROPOSED RATES TO LAST RATE CASE **Financial Information**
STATEMENT OF OPERATING INCOME **Schedule 9**

		(A)	(B)	(C)	(D)	
				(C) = (B) - (A)	(D) = ((C)/(A))/2	
Line No.	Description	Per Order in Docket EL08-030	General Rate Case Filing (2009 Test Year)	$ Change	% change Simple Annual Average	Total % change
	OPERATING REVENUES					
1	Retail	$24,921,439	$27,672,377	$2,750,938	5.52%	11.0%
2	Other Operating Revenue	3,204,080	2,280,393	(923,687)	-14.4%	-28.8%
3	**TOTAL OPERATING REVENUE**	$28,125,519	$29,952,770	$1,827,251	3.25%	6.5%
	OPERATING EXPENSES					
4	Production Expenses - Fuel and Purchased Power	$12,066,220	$11,005,647	($1,060,573)	-4.39%	-8.8%
5	Production Expenses - Other	2,628,392	2,689,614	61,222	1.16%	2.3%
6	Transmission Expenses	987,141	1,147,285	160,144	8.11%	16.2%
7	Distribution Expenses	1,432,248	1,529,964	97,716	3.41%	6.8%
8	Customer Accounting Expenses	1,000,533	1,049,010	48,477	2.42%	4.8%
9	Customer Service & Information Expenses	242,213	211,061	(31,152)	-6.43%	-12.9%
10	Sales Expenses	60,434	51,229	(9,205)	-7.62%	-15.2%
11	Administration & General Expenses	2,921,364	3,461,663	540,299	9.25%	18.5%
12	Other	45,000	0	(45,000)	100.00%	
13	Depreciation Expense	3,240,798	4,109,295	868,497	13.40%	26.8%
14	General Taxes	1,035,497	945,024	(90,473)	-4.37%	-8.7%
15	**TOTAL OPERATING EXPENSES**	$25,659,839	$26,199,791	$539,952	1.05%	2.1%
16	**NET OPERATING INCOME BEFORE INCOME TAXES**	$2,465,680	$3,752,979	$1,287,299	-(26.10)%	52.2%
	INCOME TAX EXPENSE					
18	Investment Tax Credit	($868,360)	($991,042)	($122,682)	(7.06)%	14.1%
19	Deferred Income Taxes	(24,413)	2,775,578	2,799,991	(5734.63)%	-11469.3%
20	Income Taxes	246,537	(2,126,193)	(2,372,730)	(481.21)%	-962.4%
21	**TOTAL INCOME TAX EXPENSE**	($646,236)	($341,657)	$304,579	(23.57)%	-47.1%
22	**NET OPERATING INCOME**	$3,111,917	$4,094,636	$982,719	15.79%	31.6%
23	Allowance for Funds Used During Construction					
24	**TOTAL AVAILABLE FOR RETURN**	$3,111,917	$4,094,636	$982,719	15.79%	31.6%
	Additional information					
25	**Total O & M Not Including Fuel & Purchased Power, Depreciation or General Taxes**	$9,317,324	$10,139,825	$822,501	4.41%	8.8%

Notes: Revenues reflect calendar month sales

COST ALLOCATION PROCEDURE MANUAL

FOR

JURISDICTIONAL AND CLASS

COST OF SERVICE STUDIES

OTTER TAIL POWER COMPANY

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. Subcharacteristics 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 subcharacteristics provide added detail for a more accurate allocation of cost. The service characteristics or subcharacteristics provide the basis for determining allocation factors when allocation is necessary.

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 service characteristics used in this study. They consist of four demand characteristics, two 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 14/24ths of water heating and deferred sales.

Deleted: '

6. ENERGY FACTOR (E2) - this factor is based on total kWh sales adjusted for line losses to the generation level.

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

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

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

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

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

14. 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. 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), except that related to the Big Stone Plant unit train.

Deleted: Accounts 310-346.

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:

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

Peaking Demand Factor =

(Total Existing Plant Capacity)(Current Peaking Unit Cost)

Total Current Cost

Base (Energy-Related) Demand Factor = 1 - Peaking Demand Factor

$ of Peak Demand = (Demand Cost) x (Peaking Demand Factor)

$ of Base (Energy-Related) Demand = (Demand Cost) x (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 the Midwest Independent Transmission System Operator (MISO) continues to evaluate the capacity factor of wind, its current wind capacity credit is 8 percent. Therefore, wind generation investment is allocated as 92 percent BASE ENERGY (E2) and 8 percent PEAK DEMAND (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.

Deleted: to classes or groups

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

Deleted: to classes or groups

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

Deleted: to classes or groups

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

Deleted: SALES FOR RESALE

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

NONASSOCIATED UTILITIES, COOPERATIVES AND

OTHER PUBLIC AUTHORITIES

The revenues from 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.) x capacity of the sale (MW) x number of months of the sale.

   $ 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

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

Deleted: asset-based sales

Deleted: the remaining portion

Deleted: APP Schedule H (peaking) rate

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 E2 (Energy Factor).

Deleted: 50% E1

Deleted: and 50% D1 (Generation Demand)

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:

Deleted: as follows: ¶
1. Account 555.2 (cost of non-contractual sales) expenses are split between those that represent buy/sell transactions and those that are for OTP's system use based on a percentage provided by System Operations Department. The expenses from the buy/sell portion are allocated on the Transmission Demand Factor (D2) since it is our transmission system that makes these transactions possible.¶
2. All remaining expenses in A/C 555 are classified

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:

$ of Peak Demand = MAPP Schedule H (peaking) rate ($/MW/Mo.)

x capacity of the purchase (MW) x number of months purchased.

$ 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 586 (METER EXPENSES) - classified directly as meters.

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

Deleted: S

Deleted: .1-586.5 & 586.9

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

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.

<u>MAINTENANCE</u>

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 597 (METERS) - classified directly to meters.

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

Deleted: S

Deleted: .1-597.2

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

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 (Energy Factor). All other Customer Service and Information Expenses are allocated based on Total Customer Factor (C1).

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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).

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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) and 931 (RENTS) - 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.

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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

To Streetlighting = D x C* = DSL

To Area Lighting = E x C* = DAL

Customer Component = (F - D - E) x C = DPCC

Demand Component = DSL - DAL - DPCC = DPDC

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

Account 365 (Overhead Conductor and Devices):

I. Primary

A. Average age of primary conductor.

B. Minimum size primary unit.

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

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

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

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

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

Dollar Allocations for Account 365 Primary

Customer Component = C x 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 x G = DSL

To Area Lighting = F - DSL = DAL

Customer Component = C x 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.

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

Dollar Allocations for Account 367 Primary

Customer Component = C x UPD = DPCC

Demand Component = E - DPCC = DPDC

II. Secondary

A. Average age of secondary unit.

B. Minimum size of secondary unit.

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

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

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

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

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

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

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

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

To Streetlighting = G x H = DSL

To Area Lighting = G - DSL = DAL

Customer Component = C x USD = DSCC

Demand Component = E - G - DSCC = DSDC

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

<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.

Dollar Allocations for Account 368

Customer Component = (A x F) + (B x G) + (C x H) + (D x I) + (E x J)

= DSCC

Demand Component = K - DSCC = DSDC

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

A. Average age of a service.

B. Minimum size of a service.

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

D. Total number of 3 and 4 services.

E. Dollar value of two-wire services (two-wire services are considered all customer component).

F. Total dollar value of Account 369.

Dollar Allocations for Account 369

Customer Component = (C x D) + E = DSCC

Demand Component = F - DSCC = DSDC

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

A. Average age of an underground service.

B. Minimum size of an underground service.

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

D. Total number of services in Account 369.1.

E. Total dollar value of Account 369.1.

Dollar Allocations for Account 369.1

Customer Component = C x D = DSCC

Demand Component = E - DSCC = DSDC

Corporate Cost Allocation Manual

Last Update: February 2010~~2007~~

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 with the most recent calendar year's data 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 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 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, Employee Stock Purchase Plan and Deferred Compensation Expense: The costs associated with these three items 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. Stock Option Expense: Under FAS 123(R) 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.

E. Restricted Stock and Restricted Stock Units: Under FAS 123(R) 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 portion of restricted stock or restricted stock units granted to Corporate employees and the Board of Directors is allocated to Otter Tail Power Company.

F. Executive Stock Incentive Plan: Under FAS 123(R) 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.

G. 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 is directly charged for their respective fees and the fees associated with Corporate's accounts are allocated using the General Allocation Factor.

H. 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.

I. 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.~~allocated based on the number of people attending from each company, versus the total number of people in attendance.~~

J. Travel and meals: With the exception of travel-related expense related to operations of Otter Tail Power's jointly owned generation plants, travel expense is not allocated.

K. Aviation Services: Corporate provides air service for the operating companies of Otter Tail Corporation. There are two aircrafts available for use. One 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 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

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 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.

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

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.

Allocation Factor: Fees 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.

~~F.~~D. Corporate Development

Description: Represents charges for the Corporate Development~~Platform Leaders and their~~ staff that are responsible for~~have oversight responsibilities with the non-electric operating companies,~~ 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.

~~G.~~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.

~~H.~~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.

~~I.~~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.

~~M.~~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.

~~N.~~J. Financial Planning ~~and Sourcing~~

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. ~~Charges also~~

~~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.

~~O.~~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.

~~P.~~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.

~~Q.~~N. Human Resources

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.

~~R.~~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 costs associated with legal services are directly assigned. All lawyers other than the General Counsel are directly assigned to one operating company, or a group of operating companies. Three lawyers are currently assigned to Otter Tail Power and two lawyers are~~a fourth is~~ assigned to non-electric companies.

~~S.~~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. ~~.~~

Appendix A

Computation of Allocation Factors for 2010

General Allocation Factor

	2009		Ref#
REVENUES			
Electric Retail Revenue	282,116		(1)
Electric Wholes Revenue	12,579		(2)
Other Operating Revenues	16,546		(3)
Non-Asset Based Power Pool Sales	33,474		(4)
Total Electric Revenues	344,715		(5)
Total Consolidated Revenues continuing operations	1,069,804		(6)
Ratio	**32%**	**32%**	
Revenue Ratio			
TOTAL ASSETS			
Assets - Electric Operations	1,119,822		(7)
Consolidated Assets	1,754,678		(8)
Asset Ratio	**64%**	**64%**	
TOTAL LABOR DOLLARS			
Labor Dollars - Electric Operations	64,317		(9)
Consolidated Labor Dollars	252,009		(10)
Labor Dollars - Ratio	**26%**	**26%**	(11)
2010 General Allocation Factor		**41%**	

IT Factor

	2009	Factor	
Labor Allocated to OTP	2,080		(12)
Total Corporate Labor	6,212		(13)
2010 IT Factor		**33%**	

HR Factor

Benefit Costs	**Electric Operations**	**Consolidated Operations**	**Factor**	
Benefits Costs - Cost of Goods Sold	0	6,052		(14)
Benefits Costs - Overhead (Indirect)	0	9,884		(15)
Benefits Costs - Sales	0	652		(16)
Benefits Costs - R&D	0	78		(17)
Benefits Costs - A&G	3,084	7,269		(18)
Benefits Loaded Through Labor	25,688	25,688		(19)
Subtotal	28,772	49,623		
Benefit Ratio		**58%**		
Employee Ratio		**20%**		(20)
2010 HR Factor			**39%**	

Appendix A

Computation of Allocation Factors for 2010

RM Factor

	2009	Factor	
Employee Ratio			
Employees - Electric Operations	723		(21)
Consolidated Temp & Full-Time Employees	3,684		(22)
Employee Ratio	**20%**		
Insurance Premium Ratio			
Insurance Premiums Paid by OTP	2,727		(23)
Sum of all Insurance Premiums Paid	11,361		(24)
Insurance Ratio	**24%**		
2010 RM Factor		**22%**	

Internal Audit Factor

	2009	Factor	
Electric Auditing Hours	2,926		(25)
Non-Electric Hours	4,366		(26)
2010 Internal Audit Factor		**40%**	

Appendix A

Sources of information for Allocation Factors

Ref#

(1)	(C4040),(C4090)
(2)	(C4050)
(3)	(C4990)
(4)	(C4130)
(5)	See Sheet 2 for reconciliation to footnote 2, segment information of Annual Report
(6)	(C4010,C4020,C4030,C4040,C4050,C4090,C4990,C4130 less revenue from disc ops)
(7)	From Footnote 2, Segment Information of Annual Report
(8)	From Footnote 2, Segment Information of Annual Report
(9)	(C7010, C7020, C7030) - Otter Tail Power Only
(10)	(C5010, C5020, C5030, C5210, C5220, C5230, C6010, C6015, C6020, C6030, C6510, C6520, C6530, C7010, C7020, C7030)
(11)	Labor dollars include salaries, direct labor, indirect labor, payroll taxes, benefits and sales commissions. Management bonuses are not inlcuded.
(12)	OTC account 7100, tasks 400-499,
(13)	OTC account 7100 all tasks
(14)	C5030
(15)	C5230
(16)	C6030
(17)	C6530
(18)	C7030, excluding corporate employee benefits costs
(19)	Per Daryl Evavold of OTP less payroll taxes
(20)	From Below

Appendix A

Sources of information for Allocation Factors

(21) Per Annual Report - Highlights of the Year
(22) Per Annual Report - Highlights of the Year

(23) Per Risk Management Director
(24) Per Risk Management Director

(25) From IA 2009 Time Tracking Report
(26) From IA 2009 Time Tracking Report

Appendix B

OTTERTAIL CORPORATION

Aviation Charge Rates as of February 2010:

Encore	$	1,250.00	per hour
King Air	$	850.00	per hour