Volume 2A

Testimony and Schedules of Witnesses:

Peter Beithon

Jurisdictional Cost of Service
Operating Statement
Class Cost of Service

Before the South Dakota Public Utilities Commission
State of South Dakota

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

Docket No. EL-08-_____

Exhibit___

OPERATING INCOME

Direct Testimony and Exhibit of

PETER J. BEITHON

October 31, 2008

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Peter 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 Corporation d/b/a 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. 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 financial schedules and the determination of a revenue deficiency for the test year. More specifically, I determine that OTP has a revenue deficiency of $3,883,399 or 15.30 percent. My testimony focuses on the operating income statement portion of the revenue requirement. Mr. Kyle

Sem testifies concerning the rate base component and Ms. Bernadeen Brutlag testifies on depreciation expense, the allocation of accumulated depreciation, the allocation of corporate costs, and economic development expenses. I also provide support for: (i) the test year revenues; (ii) our proposal addressing wholesale margins; (iii) the known and measurable adjustments to 2007 actuals to make the test year representative; (iv) the proposed traditional regulatory adjustments made in determining the revenue requirement; (v) a customer class cost of service study; and (vi) 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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	H-2	Cost of power and gas
	H-3	Working papers for listed expense accounts
I		Operating Revenue
J		Depreciation expense
	J-1	Expense charged other than prescribed depreciation
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	K-1	Working papers for federal income taxes
	K-2	Differences in book and tax depreciation
	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
	K-5	Working papers for claimed allowances for state income taxes
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. Kyle Sem is sponsoring Statements D, E and F; and Mr. Thomas Brause is sponsoring Statement Q.

Q: WHAT SCHEDULES ARE YOU SPONSORING?

A: I am sponsoring the following Schedules, which directly follow my testimony. I rely on these schedules to determine and support my calculation of the $3,883,399 revenue requirement.

Exhibit ___(PJB-1), Schedule 1

JURISDICTIONAL FINANCIAL SUMMARY SCHEDULE

Exhibit ___(PJB-1), Schedule 2

JURISDICTIONAL STATEMENT OF OPERATING INCOME

Exhibit ___(PJB-1), Schedule 3

TOTAL UTILITY AND SOUTH DAKOTA TEST YEAR

Exhibit ___(PJB-1), Schedule 4

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Exhibit ___(PJB-1), Schedule 5

COMPUTATION OF DEFERRED INCOME TAXES

Exhibit ___(PJB-1), Schedule 6

DEVELOPMENT OF FEDERAL AND STATE INCOME TAX RATES

Exhibit ___(PJB-1), Schedule 7

DEVELOPMENT OF GROSS REVENUE CONVERSION FACTOR

Exhibit ___(PJB-1), Schedule 8

OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Exhibit ___(PJB-1), Schedule 9

COMPARISON ON OPERATING STATEMENT OF PROPOSED RATES TO PRESENT RATES

Exhibit ___(PJB-1), Schedule 10

ALLOCATION SCHEDULES AND 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 DRIVERS OF OTP'S NEED FOR A RATE INCREASE?

A. Since OTP last set its rates 20 years ago, two primary drivers have created a need for a rate increase. The impact of these items on our revenue deficiency can be seen in Exhibit__(PJB-1), Schedule 9, which is a statement of operating income from our last rate case compared with the current test year. The most significant increases driving the revenue deficiency are: a 13 percent increase in rate base and a 120 percent increase in South Dakota non-fuel operating and maintenance costs, which is only 6 percent annually using a simple average over 20 years; and a 297 percent increase in South Dakota fuel and purchased power costs, a portion of which are not currently recovered through the Fuel Clause Adjustment (FCA) (as further described below). Revenues over the same period have only increased 118 percent. Inflation for the 20 year period was 189 percent[1].

II. FINANCIAL SCHEDULES PROVIDED AND SELECTION OF TEST YEAR

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

A. The test year period is the 2007 calendar year with known and measurable and other ratemaking adjustments. The use of the 2007 calendar year as the test year was approved by the South Dakota Public Utilities Commission in Docket EL08-013 (Order dated July 2, 2008). The most recent fiscal year is the 2007 calendar year.

Q. PLEASE OUTLINE THE FINANCIAL DATA PROVIDED.

A. Following the South Dakota Public Utilities Commission's ("Commission") rules, financial data is provided for the most recent fiscal year ("2007 Actual Year") and the test year (2007, as adjusted "2007 Test Year"). For the 2007 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). Where required by the Commission rules, the information is provided as of the beginning and the end of the test year period. Mr. Prazak provides the schedules showing the rate impacts from my proposed class revenue allocations and his proposed rate design.

[1] Ninth District Federal Reserve Bank of Minneapolis: http://woodrow.mpls.frb.fed.us/index.cfm

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

A. I determined the rate of return that OTP would earn during the 2007 Test Year at present revenue levels. My study shows that with present revenues, OTP would earn a 4.71 percent rate of return on average rate base in the Test Year. This is significantly below the 8.89% rate of return Mr. Kevin Moug identifies as needed to attract capital at reasonable cost. OTP's financial results support an increase in annual revenues of $3,883,399 or about 15.30 percent. This revenue requirement is summarized in Exhibit____PJB-1, Schedule 1 JURISDICTIONAL FINANCIAL SUMMARY SCHEDULE.

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 ten schedules. I will discuss each schedule in more detail as we examine it.

Q. PLEASE DESCRIBE EXHIBIT____(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 $60,230,800. Line 2 shows the total available for return, the operating income of $2,834,096. The total available for return is at present revenue levels. Line 5 shows the overall rate of return of 4.71 percent. This is the rate of return earned without any rate increase. Line 6 shows the required rate of return of 8.89 percent; that is, the rate of return OTP would be allowed to earn with the requested rate increase. Line 7 shows the required operating income of $5,354,518, which is determined by multiplying the required rate of return times the rate base. This translates into an income deficiency of $2,520,422 shown on Line 8. After multiplying the income deficiency by the gross revenue conversion factor (Line 9), we arrive at the revenue increase supported for South Dakota, which, on an annual basis, is $3,883,399 (Line 10). I have included the calculation of the gross revenue conversion factor 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 2007 Actual Year and the 2007 Test Year. The electric 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 operating revenues from other services provided by OTP. From the electric revenues are deducted operating expenses to arrive at net operating income before income taxes. From net operating income before income taxes is deducted total income tax expense to arrive at net operating income after income taxes.

Q. WHAT DOES EXHIBIT__(PJB-1), SCHEDULE 3, SHOW?

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 2007 Test Year (column D). Later in my testimony I discuss Schedule 8, which summarizes the individual 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 the 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 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: 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 JURISDICTIONAL COST OF SERVICE STUDY 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 Federal Energy Regulatory Commission (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 jurisdictional cost of service study. In this way, the jurisdictional cost of service study is used to determine what portion of the total costs incurred by OTP should be recovered from our South Dakota customers.

Q. HOW WAS THE SOUTH DAKOTA JURISDICTIONAL COST OF SERVICE DEVELOPED?

A. The allocation procedures used by OTP were approved in 1987 by the Commission in Case F-3691. These allocation procedures have also been approved by the Commissions in Minnesota and North Dakota. By having uniform allocation procedures in all its state jurisdictions, OTP recovers its cost of providing service across its entire territory, nor more, and no less. For the current case, street lighting and area lighting have been combined into one class, which I discuss in more detail in the class cost of service section of my testimony. We also made one modification to the allocation of depreciation procedures that Ms. Brutlag discusses in her testimony.

Q. WHAT IS THE SOURCE OF THE BASE DATA FOR THE TEST YEAR ENDING DECEMBER 31, 2007?

A. The basic data was obtained from the historical accounting records of OTP. These records are based on the Federal Energy Regulatory Commission's (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.

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 reflects that these facilities have been designed to meet peak requirements and operate as an integrated system across all jurisdictions.

Q. WAS THE ALLOCATION OF TRANSMISSION FACILITIES QUESTIONED IN OTP'S MOST RECENT MINNESOTA RATE CASE?

A. Yes. It was asserted by the Minnesota Office of Energy Security (OES), the Minnesota Chamber of Commerce, and Enbridge Pipelines that our lower voltage facilities (41.6 kV) were actually distribution facilities (or alternatively subtransmission) and should be assigned directly to states based on its location (line miles) because, they alleged, the lower voltage transmission facilities served a localized function. In that proceeding, OTP witness Mr. Timothy Rogelstad conducted a study to determine the nature of those facilities and concluded that, with the exception of 117 miles of radial lines, our 41.6 kV and 69 kV facilities are transmission facilities. The Minnesota Public Utilities Commission agreed. Consequently, we have treated our non-radial 41.6 kV lines as transmission in this proceeding. If the 41.6 kV lines were directly assigned based on location rather than allocated based on demand, our South Dakota revenue requirement would have increased by approximately $1 million or a 3.85 percent increase in addition to the 15.30 percent increase OTP is requesting.

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 is allocated on numerous factors. These cost-causative factors include primary and secondary distribution demand and customer factors. They are outlined in greater detail in OTP's cost allocation procedures for the JCOSS provided in Statement M of the required schedules.

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 2007 data for operation and maintenance expense adjusted for the items discussed on Exhibit__(PJB-1), Schedule 8. I explain below several aspects of these revenues and expenses, including the adjustments I have made.

A. TEST YEAR REVENUES

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

A. In this section of my testimony, I will first describe retail revenues. I will then describe the adjustments I made to determine the appropriate test year revenues.

Q. DEFINE RETAIL REVENUES?

A. For the purposes of rate making, 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 at the end of the test year 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 in December, are estimated using a comprehensive model. This model calculates the unbilled revenues net of the previous year's unbilled revenues, which were billed in January of 2007 for service provided in 2006. For 2007, this net calculation decreased revenues by just over $81,000.

Q. DID OTP WEATHER NORMALIZE ITS HISTORIC DATA?

A. No. South Dakota Commission practice is to not require weather normalization for electric utilities. We have also determined that such an adjustment would have had a minimal impact on the revenue requirement because the 2007 weather was extremely similar to normal.

Q. HAVE YOU MADE ANY ADJUSTMENTS TO REVENUES RELATED TO MISO DAY 2 AND IF SO WHY?

A. No. The Commission allows the pass through of MISO Day 2 costs and revenues in the fuel clause. The Commission affirmed that practice with respect to MISO

Day 2 costs in its Order in Docket. EL05-009. Therefore, changes in MISO costs and revenues are reflected in the fuel clause revenue requirement rather than through the base rate revenue requirement.

Q. HAVE YOU MADE ANY OTHER ADJUSTMENTS TO RETAIL REVENUE?

A. Yes. I have decreased South Dakota retail revenue by $13,977 to recognize billing corrections related to 2007 but made after the close of books for 2007.

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.

Q. PLEASE DESCRIBE THE REASONS FOR THE INCREASE 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 increased $2.4 million since 1986 (312 percent). There are four noteworthy sources of other electric revenue that contribute to this increase: 1) load control and dispatch revenue, 2) MISO and other revenue related to transmission tariffs, 3) integrated transmission agreement ("ITA") revenue, and 4) increased asset-based wholesale sales. Each of these revenue categories has historically been credited to the base rate revenue requirement.

Q. PLEASE DESCRIBE THE REVENUES THAT COMPRISE OTP'S LOAD CONTROL AND DISPATCH ACCOUNT.

A. There are three primary services provided by OTP that result in the revenues included in the load control and dispatch account: (1) Control Area Services Operations Tariff (CASOT) revenue (a FERC-approved tariff), (2) revenues received under scheduling and dispatch agreements, and (3) 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 the MISO and transferred functional control of its transmission facilities to MISO, it 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 that is not owned by OTP is owned by non-MISO members, OTP required a FERC-approved tariff ensuring the reliable operations of the control area that OTP operates and to provide ancillary services to these non-MISO entities. Therefore, OTP developed its FERC approved CASOT to address these control area operations and OTP's provision of ancillary services.

Q. PLEASE DESCRIBE THE OPERATIONS REQUIREMENTS OF OTP'S CASOT.

A. OTP's control area includes generators and transmission facilities that are not owned by OTP and also substantial loads that are not served by OTP. As the control area operator, OTP must coordinate with and, in emergency circumstances, have operational control over these other entities. The CASOT sets out basic operational and coordination requirements applicable both to OTP as control area operator on the one hand and load-serving entities and generators within the control area (CASOT customers) on the other. These services are recognized and prescribed by the FERC and the North American Electric Reliability Council ("NERC").

Q. WHAT ANCILLARY SERVICES DOES OTP PROVIDE TO THE ENTITIES SERVING LOAD OR OPERATING GENERATION WITHIN THE OTP CONTROL AREA?

A. The entities located within the OTP Control Area that serve load and/or operate generation take and pay for the following services under OTP's CASOT:

Schedule 1: Scheduling, system control and dispatch service. This service is required to schedule the movement of power through, out of, within, or into a Control Area. Only the operator of the control area in which the transmission facilities used for transmission service are located can provide this service.

Schedule 2: Reactive power supply from generation sources service. This is the ancillary service that maintains transmission voltages within acceptable limits on the transmission facilities located in the OTP Control Area. Generation facilities under the control of the Control Area Operator are operated to produce (or absorb) reactive power. Thus, if this service is not already provided for under other agreements or tariffs, it must be provided for each transaction on OTP's transmission facilities located within the control area.

Schedules 3A: Load regulation and frequency response service and 3B: Generator regulation and frequency response service. Schedule 3A supplies the capacity in response to intra-hour changes in the load being served and Schedule 3B supplies the capacity necessary to provide for on-line generation utilizing Control Area capacity resources to respond to schedule ramps required to start, change, or end an inter-/intra-Control Area energy schedule. Both services are necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). These services are provided by committing on-line generation whose output is raised or lowered (predominantly through the use of Automatic Generator Control "AGC") as necessary to follow the moment-by-moment changes in load (Schedule 3A) and the moment-by-moment differences between the generator's output and the ramping energy schedule (Schedule 3B). The obligation to maintain this balance lies with the Control Area Operator and only generation equipped with and controlled by AGC may provide this service. Some of the load serving entities that serve load in the OTP Control

Area self-provide this service through Dynamic Scheduling. The remainder of this service is provided by OTP. This resulted in $ 84,873 of other revenue to South Dakota.

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

A. As I mentioned, 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. The revenues did not exist in 1986 (the test year for our last rate case), and therefore they have resulted in an increase in OTP's other electric revenues since that time.

Q. WHY DOES OTP RECEIVE MISO AND MIDCONTINENT AREA POWER POOL (MAPP) REVENUE?

A. Pursuant to the provisions for transmission services provided under the MISO's Transmission and Energy Market Tariff ("TEMT") and the MISO Transmission Owners Agreement ("TOA"), OTP receives revenues from several sources for use of its transmission system and related services that it provides related to the use of its system under the TEMT. 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 2006)

South Dakota's share of revenue received from MISO in 2007 was $206,577. In 2007 OTP also received MAPP transmission revenue. South Dakota's share of the MAPP revenue was $2,358. These revenues are part of OTP's Other Electric Revenue which is detailed at a system level in Volume 4A, Workpapers (workpaper B-3).

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 (Great River Energy and Central Power Electric Cooperative) in its control area for which OTP provides scheduling and dispatch services. These scheduling and dispatch services are transmission line switching, emergency line operations, scheduling of outages, and various related transmission scheduling and transmission dispatch services. Missouri River Energy's scheduling and dispatch is delineated in an ITA with OTP.

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 and OTP, subject to ITAs, which I discuss later in my testimony. During 2007, OTP received $154,869 (total system) in revenues for these services as compensation for services as operator of the two jointly owned generating units described in the following question and answer. These revenues are all credited to OTP's other electric revenue account.

Q: DOES OTP RECEIVE TRANSMISSION REVENUE FROM OTHER COMPANIES?

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

Q: WHAT IS AN “ITA”?

A: An ITA, or Integrated Transmission Agreement, 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 listed below was approved by FERC.

Central Power Electric Cooperative ("CPEC"). “Integrated Systems Supplement No. 7" to the Electric Service Agreement between OTP and CPEC executed on June 10, 1958, as well as the five attachments to the "Integrated Systems Supplement No. 7" occurring between December 19, 1973 and August 22, 1995. Rate Schedule No. 171; FERC Docket Nos. ER82-368, ER83-340, ER85-333, ER87-31 (GFA No. 297 pursuant to Attachment P to the MISO's TEMT)

Great River Energy ("GRE"). Integrated Transmission Agreement between Cooperative Power Association (now d/b/a GRE) and OTP dated August 25, 1967. Rate Schedule No. 154; FERC Docket Nos. ER80-135, ER83-340, ER84-299, ER85-333, ER87-433 (GFA No. 306 pursuant to Attachment P to the MISO's TEMT)

Minnkota Power Cooperative, Inc. ("MPC"). Interconnection and Transmission Service Agreement, dated July 28, 1988. Filed as part of OTP’s CASOT (FERC Docket No. ER02-912) and the GFA Settlement Proceeding (FERC Docket Nos. ER04-691-005, ER04-106-002, and EL04-104-004). This agreement is referred to a GFA No. 314 pursuant to Attachment P to the MISO's TEMT.

Missouri River Energy Services (Western Minnesota Municipal Power Agency). Integrated Transmission Agreement entered into on March 31, 1986. Filed as part of our CASOT (FERC Docket No. ER02-912) and the GFA Settlement Proceeding (FERC Docket Nos. ER04-691-005, ER04-106-002, and EL04-104-004). This agreement is referred to a GFA No. 314 and GFA No. 318 pursuant to Attachment P to the MISO's TEMT.

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 and if a utility is deficient in its investment relative to the investment by the other party, it makes deficiency payments until the investment is equalized. The deficiency payments are in essence a payment by the underinvested utility of the carrying cost of the utility that is fully invested.

Q: HOW MUCH REVENUE DID OTP RECEIVE IN 2007 AS A RESULT OF THESE ITAs?

A: South Dakota's share of revenues received in 2007 was $342,093.

Q: DOES THE OTHER ELECTRIC REVENUES ACCOUNT IN OTP'S TEST YEAR INCLUDE ASSET-BASED WHOLESALE REVENUES?

A. Yes. Those revenues were included in the 2007 Actual Year. As explained below, a representative level of asset-based wholesale revenues are included in the Test Year.

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

A. As the plant operator for Big Stone Plant and Coyote Station, OTP performs services for the other plant co-owners and therefore, OTP is compensated for these services. OTP provides services such as scheduling and operations of the plants for both the day-ahead and real-time market, acting as the meter data management agent for all co-owners of the plants, settlement reconciliation of unit dispatches and actual generation, providing accounting reports and records to the co-owners, scheduling generator outages, communicating directly with the MISO generator dispatch desk, providing and maintaining reliable communications between MISO, the plants, and the OTP control center. In 2007, this resulted in $32,968 of additional South Dakota Other Revenues.

Q. WHAT OTHER REVENUES CONTRIBUTE TO THE INCREASE IN OTHER MISCELLANEOUS REVENUE?

A. OTP supplies steam to an ethanol plant near its Big Stone Plant in Big Stone, South Dakota. The sale of steam contributed $213,252 to South Dakota miscellaneous revenues in the 2007 Test Year (adjusted for an increase of $42,295 that became effective in 2008). The costs of coal for this customer are not part of retail fuel costs. I recognize this addition in my Schedule 8, Column C.

B. WHOLESALE MARGINS

Q. HOW IS OTP PROPOSING TO TREAT WHOLESALE MARGINS?

A. Historically, the revenues and expenses related to asset-based transactions have been included in the retail revenue requirement calculation. The resulting margins are an offset to the retail revenue requirement in the determination of adequate rates. By setting a fixed revenue credit any risk of margins declining rests on OTP instead of its ratepayers. If margins increase, OTP will be able to use those margins as an offset to future inflation, delaying or reducing the need for future rate increases. In addition, OTP is proposing to pass through the fuel clause adjustment 15 percent of any margins arising from non-asset based sales. These non-asset based margins did not exist when our rates were last set and, as I discuss below, sharing them through the fuel clause reflects their small incremental cost, their highly variable nature and the fact that the margins are provided by an unregulated activity that could be discontinued at any time.

Q. HOW DID YOU DETERMINE THE APPROPRIATE AMOUNT OF ASSET BASED MARGINS TO CREDIT TO THE BASE RATE REVENUE REQUIREMENT?

A. We normalized the 2007 actual year using a five-year average because asset based margins have experienced general consistency. More specifically, we used the average for the period 2003 through 2007. Based on this calculation, OTP recommends using a normalized credit to the base rate revenue requirement of $942 thousand. The adjustment reflected in Schedule 8 includes a $56,983 increase in revenues and an increase of expenses of $131,872 for a net adjustment of $74,889. The following chart shows the margins received in each year and the volatility of these margins:

2003	$799 thousand
2004	$778 thousand
2005	$1.081 million
2006	$1.032 million
2007	$1.017 million
2008	appears to be consistent with 2005-2007

Q. WHY DO YOU PROPOSE THAT CUSTOMERS RECEIVE 15 PERCENT OF NON-ASSET-BASED MARGINS?

A. The Company proposes to bear all of the risks of non-asset-based activity, and the incremental costs of this activity are less than 15 percent. This is an unregulated, highly risky enterprise where the margins are highly variable and have shown a trend of declining. By paying a percentage of margins we cover the incremental cost of conducting this business (the same personnel who are responsible for obtaining asset-based margins also conduct our non-asset based activities). In addition, by paying a percentage of margins, the variable nature of this business (and the real possibility that the Company could exit the business in the future if the risk becomes too great) is also recognized.

C. OPERATING EXPENSE

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

A. I will first discuss those expense categories that have had the most significant impact on the need for a rate increase. I will then explain the development of certain expenses. Then I describe the adjustments to the 2007 Actual Year that have been made to reflect standard regulatory adjustments and known and measurable changes to arrive at the 2007 Test Year.

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

A. Excluding the cost of fuel and purchased energy, operation and maintenance expenses have increased by $7.5 million (a simple annual average of 6 percent My Exhibit__(PJB-1), Schedule 9 contains a listing of operation and maintenance expense increases since the last rate case by function. The majority of the increase is in our transmission, distribution and administrative and general expenses. One significant driver of these cost increases is 21 years of wage increases. Our production cost increase includes cost of purchased capacity and energy, which has increased by approximately $10.7 million since 1986, reflecting the growth in system demand caused by our customers' increasing energy requirements. The transmission function has experienced significant cost increases, roughly $712,000 since 1986 (13.7 percent annualized). All dollar amounts listed in this answer are South Dakota's share.

Q. ARE THERE OFFSETTING REVENUES THAT ARE RELATED TO THE INCREASE IN TRANSMISSION EXPENSE?

A. Yes. Much of the increase in transmission expense is offset by increases in transmission revenue that I discussed previously in my testimony related to ITA, CASOT, load control and dispatch, and MISO and MAPP revenues.

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

A. For the most part these increases reflect the long time period that has passed since OTP last increased its rates. Administrative and general expenses have increased at a simple average rate of 7.87 percent per year. These increases have been driven partially by increases in the cost of labor and benefits. Other expense categories have large percentage increases but the dollar amounts are not as significant.

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

A. Ms. Brutlag Direct Testimony details the methods used for assigning and allocating those costs in her direct testimony.

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 1981 and 1975. 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 as its three diesel units are aging. To address these issues, all of OTP's peaking units are now on a long-term maintenance plan to ensure they are available and operating at their most efficient levels (both economic and environmental) when needed. Their reliability will be especially important with the need to support the intermittency of new wind resources being built.

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 by Ms. Brutlag, OTP's Corporate Cost Allocation Manual (CAM) 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 V, increasing net income by $4,117.

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

A. OTP's income tax expenses in this proceeding were based solely on the regulated income and expenses included in the revenue requirement, using the "stand-alone" method. The stand-alone method was used to determine both state and federal income taxes. 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. This approach leads to a regulated income tax expense that is completely separated from non-regulated income tax expenses. This is the same method used in OTP's last Electric rate case EL-3691.

Q. IT APPEARS NET TAX EXPENSE ON EXHIBIT__(PJB-1), SCHEDULE 9 HAS DECREASED SINCE YOUR LAST RATE CASE. WHY WOULD TAXES DECREASE?

A. As I discuss later in my testimony, the North Dakota investment tax credits related to OTP's investment in wind generation has been allocated to South Dakota along with South Dakota's share of those investments. This creates a tax expense that is much lower than would be reflected without these tax credits.

Q. HAVE YOU PREPARED A CALCULATION OF OTP'S STAND-ALONE FEDERAL AND STATE INCOME TAX EXPENSES?

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

Q. IS OTP INCLUDED IN CONSOLIDATED FEDERAL INCOME TAX RETURNS?

A. Yes. OTP is an operating division of Otter Tail Corporation. As a division of Otter Tail Corporation, OTP is included in the consolidated federal income tax return through Otter Tail Corporation, but not as a separate entity.

Q. IS THERE A TAX SHARING AGREEMENT IN PLACE BETWEEN OTP AND OTTER TAIL CORPORATION?

A. No. Because OTP is not a separate corporation, there is no tax sharing agreement between OTP and Otter Tail Corporation.

Q. DOES OTTER TAIL HAVE TAX SHARING AGREEMENTS WITH ITS SEPARATE SUBSIDIARIES?

A. Yes. The Tax-Sharing Agreements provide for the calculation of the income tax liabilities of each separate entity on a separate return basis. This prevents any added burden from being imposed on Otter Tail Corporation, and in turn prevents any added burden on OTP, as a division of Otter Tail Corporation. Also, under our standard operating practices, OTP's utility income tax expenses are determined as though it is a separate entity. Similarly, the regulated income tax expense of OTP in this proceeding, which is set forth on Exhibit __ (PJB-1), Schedule 4, is determined on a stand-alone basis that separates all non-regulated revenues and expenses from the calculation of the regulated tax expense of OTP. These steps assure that there is no cross-subsidization of non-regulated operations by OTP ratepayers.

These Tax-Sharing Agreements were approved most recently by the Minnesota Public Utilities Commission ("MPUC"), in Docket No. E-017/AI-07-246. The MPUC approved other Tax-Sharing Agreements that include OTP in Docket Nos. E-017/AI-92-1150, E-017/AI-93-505, E017/AI-05-131, and E017/AI-05-1394

D. EXPENSE ADJUSTMENTS

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

A In this portion of my testimony, I will identify adjustments to the expenses that are appropriate to convert the 2007 Actual Year into a representative Test Year. There are three general types of adjustments: (1) changes to make the Test Year representative, including accounting corrections, normalization of expenses, and known and measurable changes; (2) expenses not included in the 2007 Actual Year, and (3) traditional regulatory adjustments.

Q. HAVE YOU PREPARED A SCHEDULE WHICH SHOWS THE EFFECT ON THE TEST YEAR FOR EACH OF THESE ADJUSTMENTS?

A. Yes. Exhibit __ (PJB-1), Schedule 8, is a bridge schedule that includes a list of all of the adjustments made to the 2007 Actual Year in developing the Test Year. That schedule also identifies the impact that each adjustment has on the operating income statement. The known and measurable changes all occur within 24 months of the end of the Test Year (2007) for this request for rate increase. I will discuss each adjustment.

(1) Adjustments to make the test year representative

(a) Depreciation expense

Q. HOW WERE TEST YEAR DEPRECIATION EXPENSES DETERMINED?

A. As explained in Ms. Brutlag's Direct Testimony, OTP reviews the depreciation parameters for its electric plant in service annually and conducts a comprehensive study of service lives and salvage every five years. These annual reviews and the five-year study are filed for approval by the Minnesota PUC. An adjustment has been made to South Dakota depreciation expense to recognize both the change for 2008 depreciation rates and changes for 2009 indicated by a recently conducted five-year study. This adjustment reduces 2007 Actual Year South Dakota depreciation expense by $42,449 to arrive at the Test Year amount. See Column (H) of my Schedule 8. A full discussion of these adjustments is provided by Ms. Brutlag.

(b) Incentive compensation

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

A. Yes. OTP's incentive compensation programs are discussed in Mr. Peter E. Wasberg's Direct Testimony. I made one adjustment to reflect two changes. The first change is to utilize a five-year average payout reflecting the higher targeted incentive payment compared to the 2007 actual payment and the second change is the removal of management or key performance incentive pay amounts in excess of 25 percent of individual base pay. The adjustment increases South Dakota expenses by $13,551 (Column (L) of Schedule 8).

(c) Medical, Post Retirement Medical and Pension

Q. WHAT IS FAS 106?

A. Prior to the issuance of Financial Accounting Standard (FAS) 106, businesses recorded post-retirement benefit expenses other than pensions (primarily health care provided to retirees) on a pay-as-you-go basis. FAS 106, which became effective in 1993, established an accrual accounting process under which the future projected cost of Other Post Employment Benefits (OPEBs) was recognized at the time the benefits were earned. It also established a transition period of up to 30 years to recover the amounts that had not been recovered under the pay-as-you-go method but which would have been recognized under the FAS 106 accrual method.

Fundamentally, using an actuarial estimate, the annual recorded amount is the current period expense for future post-retirement benefits, such that the expense is fully recovered over the working life of the future retiree. The actuarially estimated amount is debited as expense and credited to the accumulated provision for OPEBs, creating a liability. When actual post-retirement health care costs are incurred, the liability is debited and cash is credited to pay the bill.

This methodology was modified in response to the passage of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). One component of this Act was to introduce a federal subsidy to sponsors of retiree health care benefits, which provides a benefit that is, at least actuarially, equivalent to Medicare Part D.

Q. HAS THE COMMISSION ADOPTED FAS 106 FOR RATEMAKING PURPOSES?

A. No. In Docket No. EL92-016, the Commission, in a January 26, 1993 Order, declined to adopt FAS 106 for ratemaking purposes. The Commission was concerned because the accrual method would sharply increase the annual expense and would create a mismatch of service costs and benefits by allowing amortization of past-period transition costs. The Commission was also concerned that the actuarial projections of future OPEB expenses were not sufficiently reliable to qualify as known and measurable expenses.

Q. WHAT TREATMENT IS OTP REQUESTING IN THIS RATE REQUEST?

A. OTP is requesting approval to use FAS 106 accounting for post-retirement benefits, and requests that the Commission reconsider its earlier position based on the particular facts of this case. OTP is required to comply with FAS 106 for financial reporting purposes, and the recovery of OPEB expense at the time they are recognized provides for intergenerational matching of costs and benefits. The customers who benefit from the service that results in the later payment of OPEB actual costs should be required to pay the appropriate proportionate share of those costs. With respect to the Commission's concern about matching principles related to the transition cost portion of the current expense, as explained below, to the extent the Company records a current expense that is greater than the actual cash expense, those payments are treated as ratepayer supplied capital and result in a reduction to rate base. After 15 years of accruing those rate base offsets, using pay-as-you-go accounting to set rates would actually increase OTP's revenue requirement.

Q: WHAT RECOVERY IS OTP REQUESTING IN THIS FILING?

A: OTP is requesting recovery of the current annual OPEB expense, as required by FAS 106 for reporting purposes, which includes the annual transition obligation amortization expense.

Q. DID YOU INCLUDE AN ADJUSTMENT TO REFLECT ADOPTION OF FAS 106 IN THIS PROCEEDING?

A. Yes. OTP adopted FAS 106 for financial reporting purposes in 1993. Since FAS 106 is utilized in OTP's other jurisdictions it was necessary to adjust the 2007 Actual Year to reflect the pay-as-you-go (PAYGO) method. As OTP is recommending adoption of FAS 106, it was then necessary to remove the PAYGO adjustment to the 2007 Actual Year. The removal of the adjustment for the 2007 Test Year is reflected in column U of Exhibit__(PJB-1), Schedule 8.

Q: DOES OTP'S REQUESTED TREATMENT INCREASE OR DECREASE RATES VERSUS THE PAY-AS-YOU GO METHOD IN EFFECT IN OTP'S LAST FILING IN 1987?

A: As I noted earlier, adopting FAS 106 accounting slightly reduces revenue requirements for South Dakota customers. This is in large part due to the reduction in rate base created by the accumulated recognition of OPEB expense that is more than the actual cash costs since the implementation of FAS 106 in 1993 on OTP's financial records. See the Direct Testimony of Mr. Kyle Sem for additional discussion of the rate base component

Q: IS OTP ASKING TO RECOVER THE TRANSITION OBLIGATION OVER THE PAST 15 YEARS?

A: No. Because OTP didn't file a case previously, it has already expensed the majority of the transition obligation. This previously expensed amount totals $1.1 million on a South Dakota basis.

Q. WHAT IS THE OVERALL IMPACT ON RATES OF FAS 106?

A. While pay-as-you-go payments are less than the accrual expense under FAS 106, adoption of pay-as-you go would also require that we restore rate base to what it would have been but for implementing FAS 106. The average balance of the transition obligation is an offset to prepayments for ratemaking purposes. This reduces South Dakota rate base by $1.1 million. If FAS 106 is not allowed, the resulting large increase in rate base would increase the revenue requirements under the pay-as-you-go method by $96,877. Therefore, the Commission's prior concern that the transition expense would result in an unfair matching of costs and benefits should no longer be a concern.

Using FAS 106 accrual accounting in this case provides ratepayers the benefit of the offset to prepayments that has accrued as a result of OTP's adoption of FAS 106 for financial reporting in 1993.

Q. HOW DID OTP DETERMINE THE AMOUNT OF OPEB COSTS TO RECOVER?

A. We rely on our actuary Mercer to predict future OPEB expenses for past and current employees. In 1993, the Commission was concerned that those actuarially determined costs were not sufficiently accurate to qualify as known and measurable expenses. We have had 15 years of experience in applying SFAS 106 and that experience has demonstrated that the actuarial estimates have, if anything, underestimated the future costs, not overestimated them. However, underestimated OPEB expenses are still much more accurate reflections of the actual cost of providing service than pay-as-you-go.

Q. WHAT IS THE CURRENT BALANCE FOR FAS 106 COSTS?

A. The costs are recorded and tracked in two parts -- transition costs and current accrual expenses. OTP's total utility transition cost balance as of December 31, 2007 was $3,665,800 (South Dakota's share is $350,443) which will be amortized over the remaining five-year transition period, resulting in an annual amortization expense for South Dakota is $70,089.

Q. WHAT IS THE TEST YEAR FAS 106 EXPENSE?

A. The annual test Year FAS 106 expense for South Dakota is $314,191, which includes the annual amortization expense of the transition amount noted in my answer to the previous question.

Q. HAS SIMILAR ACCOUNTING TREATMENT BEEN ADOPTED FOR OTHER RETIREMENT PROGRAMS?

A. Yes. On December 31, 2006, OTP adopted FAS 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FAS 87, 88, 106, and 132(R). As stated by the Financial Accounting Standards Board (FASB) in the summary of the statement, "This Statement improves financial reporting by requiring an employer to recognize the over funded or under funded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity… This Statement also improves financial reporting by requiring an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions."

The point most relevant to this discussion is the recognition of changes in the status of the fund as over or under funded as a component of other comprehensive income, net of tax. OTP examined the issue and determined that, FAS 71, Accounting for the Effects of Certain Types of Regulation, dictated the establishment of a regulatory asset instead of reducing retained earnings (other comprehensive income) and accumulated deferred income taxes as a result of the implementation of FAS 158.

Q. DID YOU MAKE AN ADJUSTMENT RELATED TO FAS 158?

A. Yes. At year-end 2006 when OTP recognized FAS 158, we recognized the remaining South Dakota allocated FAS 106 transition obligation balance of $373,928 by crediting prepayments and debiting other comprehensive income. The annual expense was not affected by this change in accounting. The adjustment was made to reverse this treatment to match the transition obligation amount with the annual expense for the amortization. Since this adjustment affects rate base, it is discussed by Mr. Sem in his Direct Testimony.

Q: HOW DOES OTP FUND ITS OPEB?

A: I described the accounting requirements for OPEB earlier. Because the size of our OPEB obligation is relatively small, we elected to avoid the expense of an external fund and manage our OPEB expenses internally

Q. HOW WAS THE AMOUNT OF OPEB COSTS INCLUDED IN THE TEST YEAR DETERMINED?

A. The OPEB costs included in the test year are the 2008 expenses as determined by Mercer, our actuary, with approximately 9.0% percent allocated to the South Dakota jurisdiction (using the labor and related expense allocator).

Q: WHAT IS THE STATUS OF THE PENSION ACCOUNT?

A: OTP maintains a defined benefit pension plan which requires no direct contributions from employees. The plan, with its origins going back to 1975, today covers substantially all employees of the electric utility and corporate employees. Non-union electric utility employees and corporate employees hired after September 1, 2006, are not eligible for the pension plan. OTP's policy is to fund pension costs accrued and for each of the last four years the Company has made voluntary cash contributions to the plan of $4 million annually. The pension plan has a trustee who is responsible for safekeeping of the plan's assets and also serves as a third party administrator who makes the monthly pension payments to retirees. Four investment managers are charged with investing the plan assets under guidelines established by OTP through an Investment Policy Statement. An independent actuary performs the necessary actuarial valuations required for the pension plan.

Net periodic pension costs (total system), as defined under FAS 87, are as follows:

Year	Net Periodic Pension Cost (in thousands)
2004	$1,980
2005	$4,435
2006	$5,790
2007	$4,231
2008	$2,626 (estimated)
2009	$2,700 (estimated)

A portion of the periodic pension cost is capitalized as a payroll overhead component of utility plant construction. The pension expense reduction reflects that fact that OTP discontinued the defined benefit program in 2006 for new employees.

Funded status at year-end 2007 reported fair value of plan assets of $167,508,000 and a projected benefit obligation of $186,760,000. This comparison is required for external financial reporting purposes, but in some ways is an invalid comparison. While plan assets are valued at a point in time, the projected benefit obligation looks to future periods and is escalated by assumed salary changes. Another view, perhaps more relevant, is to compare fair value of plan assets of $167,508,000 to the accumulated benefit obligations of $153,816,000 at year-end 2007. This compares two point-in-time values and supports the reduction in pension expense in 2008 that I discuss later.

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

A. The amount of the pension expense for each year is determined by our actuary Mercer. The Bank of New York Mellon (BNY Mellon) manages the pension fund with oversight from Mercer.

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

A. Yes. I am proposing known and measurable adjustments to these three expenses. Our compensation practices are more fully described in the testimony of Mr. Wasberg. The following Table 1 provides a comparison of the differences between the 2007 and 2008 expense **levels on a total utility basis**:

Table 1

EXPENSE CATEGORY	2006	2007	PERCENTAGE CHANGE
Medical	$8,304,645	$9,772,046	17.7%
FAS 106 (Post Retirement Medical)	$3,154,305	3,587,850	14%
FAS 87 Pension	4,230,508	2,626,400	-38%
Total expenses	$15,689,458	$15,986,296	1.9%

FAS 106 costs are increasing in 2008 as determined by our actuary Mercer, and are a known and measurable expense. Our pension costs are decreasing in 2008 as determined by our actuary Mercer and are a known and measurable expense. Just as our FAS 106 costs (post retirement medical benefits) are increasing, so too are our employee medical benefit costs for 2008. The increase in medical costs is based on an estimate using actual costs through June 2008 and forecasted amounts for the balance of 2008. Therefore, I made a known and measurable adjustment of $296,838 to reflect the 1.9 percent net increase in these expenses. The South Dakota share of: the medical adjustment is $140,436 (Schedule 8, Column (I)), of the FAS 106 costs is $41,495 (Column (K)), of the FAS 87/pension reduction is $153,518 (Column (J)), for a net adjustment of $28,413.

(d) Wages

Q. HAVE YOU MADE AN ADJUSTMENT ASSOCIATED WITH KNOWN AND MEASURABLE CHANGES IN WAGES?

A. Yes. I am proposing an adjustment associated with known and measurable changes in wages. More specifically, I recognize the increase in union wages and an increase in non-union wages that have occurred after the 2007 Actual Year. The South Dakota share of this adjustment is $292,474 (Column (M) of Schedule 8).

(e) Adjustments to Production Expense

Q. HAVE YOU ADJUSTED PRODUCTION EXPENSE TO REFLECT THE EXTENDED OUTAGE AT THE BIG STONE PLANT THAT OCCURRED DURING THE TEST YEAR?

A. Yes. While it is typical for Otter Tail to have an extended outage at a major generating station each year, the Big Stone outage extended into December 2007, which was not anticipated. I have removed the increased cost for purchased energy during December. The adjustment decreases South Dakota production expense by $709,964 (Column (N) of Schedule 8).

Q. DID YOU MAKE ANY OTHER ADJUSTMENTS TO PRODUCTION EXPENSE?

A. Yes. To account for the addition of a large load in North Dakota, I increased production expense by $685,736 for the required demand and energy costs to serve this load (Column (B) of Schedule 8).

Q. WHY DOES THE ADDITION OF THE NEW LARGE LOAD IN NORTH DAKOTA IMPACT SOUTH DAKOTA, AND WHAT IS THAT IMPACT?

A. Just like any other load, production and transmission expenses are allocated on a system wide basis. For example, the production expenses of a large load near Big Stone, South Dakota, are allocated to both Minnesota and North Dakota. For the North Dakota large load addition in this case, the allocation factors for energy and demand have been updated to reflect the impact of this load, which shifts the overall burden back to North Dakota to match the revenues. As shown on Schedule 8, Column (O), on page 2 of 3, the factor change reduces overall expense by $684,188. The end result is that there is little impact on South Dakota rates.

<u>(2) Expense categories not included in the 2007 Actual Year</u>

(a) Rate case expenses

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

A There were two steps. 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 the estimated consulting and outside legal fees. The consulting fees and outside legal fees estimates were provided by the people providing those services. The adjustment for the $50,000 annual rate case expense are referenced in Exhibit__(PJB-1), Schedule 8 (Column R). Workpapers showing the calculation for that adjustment are located in Volume 4A, Test Year Adjustment 2007 SD TY-04 Rate Case Expenses.

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.

(b) Holding Company Costs

Q. OTP IS IN THE PROCESS OF FORMING A HOLDING COMPANY ORGANIZATIONAL STRUCTURE. HAVE YOU INCLUDED ANY COSTS RELATED TO THE RESTRUCTURING?

A. Yes. I have included $12,338 (Column (S) of Schedule 8) related to legal expenses incurred to form the holding company structure. This is the annual South Dakota amount based on a five-year amortization of the expenses. Mr.

Moug explains why the holding company structure is beneficial to ratepayers in his direct testimony.

(c) 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 two significant wind farms to its generation fleet. The first wind farm, of which OTP owns 40.5 MW, is located near Langdon, North Dakota. The other wind farm, of which OTP owns 48 MW, is located near Ashtabula, North Dakota. While there is no fuel or purchased power expense impact quantified in the test year (the future amount of this expense is not known and measurable at this time), and those future costs will be handled through the fuel adjustment clause. However, test year production related operation and maintenance expenses related to wind generation amount to $145,484 (Column (G), Schedule 8).

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

A. Other expenses related to new wind generation include: property insurance expense increase of $22,707, property tax increase of $92,271, and depreciation expense increase of $781,845 (the balance of the $828,740 adjustment to depreciation expense in Column (G) 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 $109,168 ($1,165,016 total system). In addition, the Federal production tax credit (PTC) of, $632,460 for South Dakota ($6,749,505 total system) is included in the ITC line in Exhibit__(PJB-1), Schedule 8, column (G), line 17. The total of $741,628 on line 17 in Schedule 8 is simply the ITC and PTC added together ($109,168 + $632,460).

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 adjustment made for the North Dakota ITC is similar in impact to the way renewable energy riders in North Dakota and Minnesota flow the benefit of the North Dakota ITC to ratepayers in each of those states. The costs and credits are allocated on a kWh basis to customers in those states. This means Minnesota ratepayers receive a credit for North Dakota ITC in proportion to the plant investment to be recovered in their rates.

(d) Storm repairs

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

A. Yes. I added $26,731 to normalize South Dakota's 2007 storm repair expenses to the 5-year average (Column (T), Schedule 8). In 2007, storm repair expense was much lower than average. There have been much higher expenses in individual years over the past 10 years, but the 5-year average, which included the 2005 ice storm in northeast South Dakota, is a more reasonable expectation for future costs because the 10-year average included costs from the extensive winter storms that preceded the great flood in the Red River Valley in 1997.

(e) Depreciation expense for new electric plant in service

Q. OTP HAS A NUMBER OF CAPITAL PROJECTS IN THE TEST YEAR. MR. SEM DISCUSSES THE RATE BASE ADJUSTMENT IN HIS TESTIMONY.

Q. DID YOU MAKE ANY ADJUSTMENTS TO EXPENSES FOR THESE NEW CAPITAL PROJECTS?

A. Yes, but at an overall level (which is $828,740, Column (G), line 12, of Schedule 8), not specifically for each project. I discussed the impact of the wind generation on depreciation earlier in my testimony. South Dakota depreciation expense for the test year reflects the increased investment in plant.

(f) Economic Development

Q. IS OTP PROPOSING TO RECOVER ECONOMIC DEVELOPMENT EXPENSES IN THIS PROCEEDING?

A. Yes. Ms. Brutlag's Direct Testimony explains OTP's economic development program and why OTP should be allowed to recover 100 percent of its economic development costs. OTP is proposing to enhance its economic development program in South Dakota by including $100,000 in base rates. Otter Tail actually spent $38,078 on economic development in 2007 in South Dakota. Consequently, OTP made an adjustment related to economic development costs of $61,922 to bring the amount in rates to $100,000 (Column (P), Schedule 8).

(g) Change from Depreciation Direct Assignment to Allocation

Q. DO YOU DISCUSS THE PROPOSED CHANGE FROM THE DIRECT ASSIGNMENT OF DEPRECIATION (ACCUMULATED AND EXPENSE)?

A. No. That discussion is in the Direct Testimony of Ms. Brutlag. The expense adjustment is an increase of $115,688 (Column (F) of Schedule 8). This is more than offset by the change to rate base created by the change in accumulated depreciation.

(h) Corporate Allocations

Q. SCHEDULE 8 (COLUMN (Q)) HAS AN ADJUSTMENT FOR CORPORATE ALLOCATIONS. WHAT IS THE SOURCE FOR THIS ADJUSTMENT?

A. Ms. Brutlag discusses the reasons for the reduction to expense of $9,283 in her Direct Testimony.

(i) Impact of the adjustments on allocation factors

Q. PLEASE DISCUSS THE REASON FOR THE ADJUSTMENT ON SCHEDULE 8 (COLUMN (U)) FOR CHANGE IN ALLOCATION FACTORS.

A. Anytime adjustments to plant and expenses are made to change the 2007 Actual Year cost of service study, allocation factors (used in the allocation of plant, revenue and expenses), which are determined by balances (such as net plant in service or NEPIS) are affected. Column (W) of Schedule 8 reflects the net impact of these changes in the amount of $62,313, after tax.

(3) Traditional regulatory adjustments

(a) Advertising

Q. PLEASE DESCRIBE THE ADVERTISING EXPENSE ADJUSTMENT.

A. Advertising expenditures which are reasonable in amount 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 this criteria, OTP had excluded $82,475 in advertising expenses from its 2007 costs allocated to South Dakota. Consequently, no adjustment to the Test Year is required. Representative advertisements for which we are seeking recovery and the relative dollar values are included in Volume 4A, work paper B-14. The amount we included in the 2007 Actual Year and 2007 Test Year is $41,395.

(b) Charitable Contributions

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

A. We have not included any charitable contributions in Test Year expenses.

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. Only one, the sub-classes of street and area lighting have been consolidated.

Q. PLEASE EXPLAIN THE CONSOLIDATION OF THE STREET AND AREA LIGHTING SUB-CLASSES AND IDENTIFY THE REMAINING CLASSES.

A. OTP's CCOSS includes a number of "sub-class" categories. When preparing this CCOSS, we determined that it was more logical to combine the two lighting classes (street lighting and area lighting) at the class level as the usage characteristics of lighting are the same whether it is for street lighting or area lighting serving individuals. Consequently the two sub-class categories are not useful in developing OTP's rate structure, so the CCOSS includes only one lighting class.

Q WHAT RATE CLASSES ARE INCLUDED IN THE CCOSS?

A. In this rate case, OTP's rate structure is designed around 10 primary service classes. They are Residential, Farm, General Service, Large General Service, Irrigation, Controlled Water Heating, Controlled Service Interruptible, Other Public Authorities (OPA), Controlled Service Deferred, and Lighting.

Q. PLEASE DESCRIBE OTP'S ENERGY COST ALLOCATOR.

A. The energy cost allocator used in preparing the CCOSS in our prior rate case has been retained. The energy allocators from the Company's previous studies (some times referred to as "E1" and "E2") have always been based on the total energy use including line losses.

Q. IN THE COMPANY'S PREVIOUS RATE CASES, IT PROVIDED A JURISDICTIONAL AND CLASS COST OF SERVICE ALLOCATION MANUAL. HAS OTP PROVIDED SUCH A DOCUMENT WITH THIS FILING?

A. Yes. OTP's *Cost Allocation Procedure Manual for Jurisdictional and Class Cost of Service Studies* has been included with this filing as my Schedule 10, Exhibit___ (PJB-1). 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 which cost items each allocator is applied to.

Q. PLEASE SUMMARIZE THE RESULTS OF THE CCOSS.

A. Table 2 below contains information from the CCOSS results, which are 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 2 Class Responsibility

		Class Responsibility	
	Current Revenues	Amount of Increase	Percent Increase
Residential	7,663,869	1,557,139	20.32%
Farms	595,513	148,834	24.99%
General Service	6,540,313	206,953	3.16%
Large General Service	8,298,684	1,077,081	12.98%
Irrigation	23,906	8,157	34.12%
Lighting	525,080	137,580	26.20%
OPA	213,168	75,780	35.55%
Controlled Service Water Heating	359,535	240,845	66.99%
Controlled Service Interruptible	957,344	373,937	39.06%
Controlled Service Deferred	198,366	57,093	28.78%
	25,375,778	3,883,399	15.30%

Q. PLEASE EXPLAIN TABLE 2.

A. The Current Revenues column reports the total revenue derived from these classes at present rates. The Amount of Increase column 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. The Percent Increase column is the percentage increase for the customer class needed in order for the customer class to provide revenues equal to the revenue requirement for the class.

VI. CLASS REVENUE RESPONSIBILITIES

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

A. The above-described CCOSS (Statement N, Volume 1) was 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. Dave Prazak's testimony. Based on a consideration of all the rate design objectives, OTP is proposing the distribution of revenue responsibilities that are summarized in Table 3 below.

Table 3

Class Revenue Responsibility – Proposed increase by class

		Class Responsibility	
	Current Revenues	Amount of Increase	Percent Increase
Residential	7,663,869	1,149,580	15.00%
Farms	595,513	89,327	15.00%
General Service	6,540,313	819,683	12.53%
Large General Service	8,298,684	1,244,803	15.00%
Irrigation	23,906	4,064	17.00%
Lighting	525,080	105,016	20.00%
OPA	213,168	37,304	17.50%
Controlled Service Water Heating	359,535	118,646	33.00%
Controlled Service Interruptible	957,344	287,203	30.00%
Controlled Service Deferred	198,366	27,771	14.00%
	25,375,778	3,883,399	15.30%

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

Q. PLEASE EXPLAIN THE COMPONENTS OF TABLE 3.

A. The Current Revenues column reports the total current revenues from each class. The Amount of Increase column is the difference, in dollars, between Current Revenues and the amount of customer class revenue proposed by OTP. Percentage Increase is the amount of the customer class increase needed in order for the customer class to provide revenues as proposed by OTP.

Q. PLEASE ELABORATE ON OTP's PROPOSED REVENUE RESPONSIBILITY FOR THE RESIDENTIAL CLASS AND HOW IT COMPARES TO THAT ORDERED IN OTP'S LAST RATE CASE.

A. The CCOSS indicates that a 20.32 percent increase to the Residential Class would be necessary 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 more moderated increase of 15.00 percent. While the increase to the residential class is significant, it is important to recognize that final rates ordered in the last rate case left a smaller subsidy to the residential class than we are proposing in this case.

Q. HAS THE COMPANY PREPARED A COMPARISON OF PRESENT AND PROPOSED RATE REVENUES?

A. Yes. Mr. Prazak sponsors those schedules in his testimony.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULE

Docket No. EL08-______
Exhibit ___(PJB-1)
Financial Information
Schedule 1

Line No.	Description	(A) 2007 Actual Year	(B) 2007 Test Year
1	Average Rate Base	$53,592,374	$60,230,800
2	Operating Income (Before AFUDC)	$2,836,376	$2,834,096
3	Allowance for Funds Used During Construction (AFUDC)	$0	$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$2,836,376	$2,834,096
5	Overall Rate of Return (Line 4 / Line 1)	5.29%	4.71%
6	Required Rate of Return	9.15%	8.89%
7	Operating Income Requirement (Line 1 x Line 6)	$4,903,702	$5,354,518
8	Income Deficiency (Line 7 - Line 4)	$2,067,326	$2,520,422
9	Gross Revenue Conversion Factor	1.540773	1.540773
10	Revenue Deficiency (Line 8 x Line 9)	$3,185,280	$3,883,399
11	Retail Related Revenues Under Present Rates	$25,389,754	$25,375,778
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11	12.55%	15.30%

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY | **Docket No. EL08-______**
Electric Utility - State of South Dakota | **Exhibit__(PJB-1)**
OPERATING INCOME SCHEDULES | **Financial Information**
JURISDICTIONAL STATEMENT OF OPERATING INCOME | **Schedule 2**

		(A)	(B)	(C)	(D)
		2007 Actual Year		2007 Test Year	
Line No.	Description	Total Utility	SD Jurisdiction	Total Utility	SD Jurisdiction
	OPERATING REVENUES				
1	Retail Revenue	$268,698,170	$25,389,754	$278,186,026	$25,375,778
2	Other Electric Operating Revenue	33,216,346	3,305,310	34,277,583	3,174,346
3	**TOTAL OPERATING REVENUE**	$301,914,516	$28,695,065	$312,463,609	$28,550,123
	OPERATING EXPENSES				
4	Production Expenses	$162,003,159	$15,672,533	$165,594,693	$15,443,701
5	Transmission Expenses	10,492,992	971,700	10,827,331	971,158
6	Distribution Expenses	14,686,349	1,435,240	15,280,331	1,497,102
7	Customer Accounting Expenses	10,507,260	969,163	10,931,905	1,008,332
8	Customer Service and Information Expenses	5,241,699	236,920	5,387,900	243,528
9	Sales Expenses	1,121,951	79,473	1,183,873	141,395
10	Administration and General Expenses	30,165,236	2,787,503	33,602,927	3,054,404
11	Charitable Contributions	111,967	0	111,967	0
12	Depreciation Expense	25,396,909	2,276,098	33,874,064	3,177,201
13	General Taxes	9,411,607	1,012,948	10,396,607	973,916
14	**TOTAL OPERATING EXPENSES**	$269,139,129	$25,441,578	$287,191,598	$26,510,737
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$32,775,387	$3,253,487	$25,272,011	$2,039,387
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	($1,136,657)	($109,101)	($9,051,178)	($848,138)
18	Deferred Income Taxes	1,387,586	55,105	485,703	-23,796
19	Income Taxes	5,654,780	471,106	2,517,215	77,225
20	**TOTAL INCOME TAX EXPENSE**	$5,905,709	$417,111	-$6,048,260	-$794,709
21	**NET OPERATING INCOME**	$26,869,678	$2,836,376	$31,320,271	$2,834,096
22	Allowance for Funds Used During Construction	2,257,062	0	2,257,062	0
23	**TOTAL AVAILABLE FOR RETURN**	$29,126,740	$2,836,376	$33,577,333	$2,834,096

The 2007 Test Year is the 2007 Actual Year with known and measureable adjustments to arrive at the Test Year.

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME SCHEDULES
TOTAL UTILITY AND SOUTH DAKOTA TEST YEAR

Docket No. EL08-______
Exhibit__(PJB-1)
Financial Information
Schedule 3

		(A)	(B)	(C)	(D)
		2007 Test Year			
Line No.	Description	Actual Year Total Utility	Actual Year SD Jurisdiction	Adjustments	Proposed SD Jurisdiction
	OPERATING REVENUES				
1	Retail Revenue	$268,698,170	$25,389,754	($13,977)	$25,375,778
2	Other Electric Operating Revenue	33,216,346	3,305,310	(130,964)	3,174,346
3	**TOTAL OPERATING REVENUE**	$301,914,516	$28,695,065	($144,941)	$28,550,123
	OPERATING EXPENSES				
4	Production Expenses	$162,003,159	$15,672,533	($228,831)	$15,443,701
5	Transmission Expenses	10,492,992	971,700	-542	971,158
6	Distribution Expenses	14,686,349	1,435,240	61,862	1,497,102
7	Customer Accounting Expenses	10,507,260	969,163	39,168	1,008,332
8	Customer Service and Information Expenses	5,241,699	236,920	6,608	243,528
9	Sales Expenses	1,121,951	79,473	61,922	141,395
10	Administration and General Expenses	30,165,236	2,787,503	266,902	3,054,404
11	Charitable Contributions	111,967	0	0	0
12	Depreciation Expense	25,396,909	2,276,098	901,103	3,177,201
13	General Taxes	9,411,607	1,012,948	(39,032)	973,916
14	**TOTAL OPERATING EXPENSES**	$269,139,129	$25,441,578	$1,069,159	$26,510,737
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$32,775,387	$3,253,487	($1,214,100)	$2,039,387
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	($1,136,657)	($109,101)	($739,037)	($848,138)
18	Deferred Income Taxes	1,387,586	55,105	(78,902)	(23,796)
19	Income Taxes	5,654,780	471,106	(393,881)	77,225
20	**TOTAL INCOME TAX EXPENSE**	$5,905,709	$417,111	($1,211,820)	($794,709)
21	**NET OPERATING INCOME**				
22	Allowance for Funds Used During Construction	$29,126,740	$2,836,376	$0	2,834,096
23	**TOTAL AVAILABLE FOR RETURN**	$29,126,740	$2,836,376	$0	$2,834,096

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME SCHEDULES
COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Docket No. EL08-______
Exhibit__(PJB-1)
Financial Information
Schedule 4

		(A)	(B)	(C)	(D)
		2007 Actual Year		2007 Test Year	
Line No.	Description	Total Utility	SD Jurisdiction	Total Utility	SD Jurisdiction
	Income Before Taxes				
1	Total Operating Revenues	$301,914,516	$28,695,065	$312,463,609	$28,550,123
2	less: Total Operating Expenses	(234,330,613)	(22,152,531)	(242,920,927)	(22,359,619)
3	Book Depreciation & Amortization	(25,396,909)	(2,276,098)	(33,874,064)	(3,177,201)
4	Taxes Other Than Income	(9,411,607)	(1,012,948)	(10,396,607)	(973,916)
5	Interest Cost	(13,624,792)	(1,519,826)	(17,027,798)	(1,700,391)
6	**Total Before Tax Book Income**	**$19,150,595**	**$1,733,661**	**$8,244,213**	**$338,996**
	Tax Additions				
7	Additional Tax Depreciation				
8	Directly Assigned Schedule M Items	93,287	7,848	93,287	7,848
9	Provisions - Operating Reserves	4,216,383	453,799	8,598,414	805,468
10	Other Schedule M Items	1,606,800	172,936	1,606,800	150,519
11	**Total Tax Additions**	**$5,916,470**	**$634,583**	**$10,298,501**	**$963,835**
	Tax Deductions				
12	Additional Tax Depreciation	$2,682,696	$288,732	$2,682,696	$251,305
13	Cost to Remove	3,949,203	425,043	3,949,203	369,947
14	Accrued Vacation Pay	87,932	9,464	87,932	8,237
15	Charges - Operating Reserves	2,617,201	281,683	4,671,807	437,638
	Preferred Dividends Paid Credit	160,775	17,304	160,775	15,061
16	Other Schedule M Items	-	-	-	-
17	**Total Tax Deductions**	**$9,497,807**	**$1,022,226**	**$11,552,413**	**$1,082,188**
18	ND Adjustments to Federal Schedule M; ND Jurisdiction	-	-	-	-
19	**State Taxable Income**	**$15,569,258**	**$1,346,018**	**$6,990,301**	**$220,643**
20	State Income Tax Rate	2.03%	0.00%	1.55%	0.00%
21	**Total State Income Taxes & ND Incremental Tax Rate Adj ($505)**	**$316,215**	**$0**	**$108,630**	**$0**
22	**Federal Taxable Income**	**$15,253,043**	**$1,346,018**	**$6,881,671**	**$220,643**
23	Addback of MN Adjustments to Federal Schedule M; MN Jurisdiction	-	-	-	-
24	**Adjusted Federal Taxable Income**	**$15,253,043**	**$1,346,018**	**$6,881,671**	**$220,643**
25	Federal Income Tax Rate	35.00%	35.00%	35.00%	**35.00%**
26	**Total Federal Income Taxes**	**$5,338,565**	**$471,106**	**$2,408,585**	**$77,225**
27	**Total State and Federal Income Tax**	**$5,654,780**	**$471,106**	**$2,517,215**	**$77,225**

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME SCHEDULES
COMPUTATION OF DEFERRED INCOME TAXES

Docket No. EL08-______
Exhibit__(PJB-1)
Financial Information
Schedule 5

		2007 Actual Year		2007 Test Year	
Line No.	Description	Total Utility (A)	SD Jurisdiction (B)	Total Utility (C)	SD Jurisdiction (D)
1	Excess Tax Over Book Depreciation	$4,006,368	$356,574	$4,006,368	$310,353
2	Excess Tax Over Book Pensions	(1,759,616)	($159,276)	(1,759,616)	(138,630)
3	Capitalized A & G Expenses	(456,241)	($41,599)	(456,241)	(36,206)
4	Provisions for Operating Reserves in Excess of Actual Charges	(1,513,024)	($138,209)	(1,513,024)	(120,293)
5	Other Capitalized Items	1,110,099	37,615	208,216	(39,019)
6	**TOTAL Deferred Income Taxes**	$1,387,586	$55,105	$485,703	($23,796)

DEVELOPMENT OF FEDERAL AND STATE INCOME TAX RATES **Schedule 6**

Actual 2007
Proposed Test Year 2007

Let: F=Federal Income Tax = 35.00%

M=Minnesota State Income Tax Rate = 9.80%

D=North Dakota State Income Tax Rate = 6.50%

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=	6.50%	(N)
F=	32.73%	(N)
D+F=	39.23%	(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 = 39.00% (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 Corporation d/b/a OTTER TAIL POWER COMPANY | **Docket No. EL08-______**
Electric Utility - State of South Dakota | **Exhibit__(PJB-1)**
DEVELOPMENT OF GROSS REVENUE CONVERSION FACTOR | **Financial Information**
Schedule 7

Definition: The incremental amount of gross revenue required to generate an 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%

Line		
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 Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

			KNOWN AND MEASURABLE CHANGES							
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Description	2007 Actual Year	New Large Customer	New Billing for Steam Customer	Inter-Year Billing Adjustment	Wholesale Margins Asset Based Revenue & Expense	Depreciation Direct Assign vs Allocated	Depreciation and Other Operating Expense for New Plant	Update Depreciation Expense	Employee Benefits Medical/Dental
	OPERATING REVENUES									
1	Retail Revenue	$25,389,754			($13,977)					
2	Other Electric Operating Revenue	3,305,310		42,295		56,983				
3	**TOTAL OPERATING REVENUE**	$28,695,065	$0	$42,295	($13,977)	$56,983	$0	$0	$0	$0
	OPERATING EXPENSES									
4	Production Expenses	$15,672,533	$685,736			$131,872		$145,484		$28,757
5	Transmission Expenses	971,700								10,656
6	Distribution Expenses	1,435,240								20,681
7	Customer Accounting Expenses	969,163								13,919
8	Customer Service and Information Expenses	236,920								28,306
9	Sales Expenses	79,473								
10	Administration and General Expenses	2,787,503						22,707		38,116
11	Charitable Contributions	0								
12	Depreciation Expense	2,276,098					115,688	828,740	(42,449)	
13	General Taxes	1,012,948						92,271		
14	**TOTAL OPERATING EXPENSES**	$25,441,578	$685,736	$0	$0	$131,872	$115,688	$1,089,203	($42,449)	$140,436
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$3,253,487	($685,736)	$42,295	($13,977)	($74,889)	($115,688)	($1,089,203)	$42,449	($140,436)
16	**INCOME TAX EXPENSE**									
17	Investment Tax Credit	($109,101)						(741,628)		
18	Deferred Income Taxes	55,105								
19	Income Taxes	471,106	(240,008)	14,803	(4,892)	(26,211)	(40,491)	(381,221)	14,857	(49,152)
20	**TOTAL INCOME TAX EXPENSE**	$417,111	($240,008)	$14,803	($4,892)	($26,211)	($40,491)	($1,122,849)	$14,857	($49,152)
21	**NET OPERATING INCOME**	$2,836,376	($445,728)	$27,492	($9,085)	($48,678)	($75,197)	$33,646	$27,592	($91,283)
22	Allowance for Funds Used During Construction	0								
23	**TOTAL AVAILABLE FOR RETURN**	$2,836,376	($445,728)	$27,492	($9,085)	($48,678)	($75,197)	$33,646	$27,592	($91,283)

Column references to adjustment workpapers:
(B) W/P 2007 SD TY-10
(C) W/P 2007 SD TY-11
(D) W/P 2007 SD TY-19
(E) W/P 2007 SD TY-15
(F) W/P 2007 SD TY-03
(G) W/P 2007 SD TY-01
(H) W/P 2007 SD TY-07 & TY-08
(I) W/P 2007 SD TY-05
(J) W/P 2007 SD TY-05
(K) W/P 2007 SD TY-05
(L) W/P 2007 SD TY-12
(M) W/P 2007 SD TY-12
(N) W/P 2007 SD TY-17
(O) W/P 2007 SD TY-20
(P) W/P 2007 SD TY-09
(Q) W/P 2007 SD TY-06
(R) W/P 2007 SD TY-04
(S) W/P 2007 SD TY-13
(T) W/P 2007 SD TY-14
(U) W/P 2007 SD TY-16

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

		KNOWN AND MEASURABLE CHANGES								
		(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
Line No.	Description	FAS 87 Pension Costs	FAS 106 & 112 Benefits	KPA & Utility Management Incentive	Labor Expense - April & November Annual Increases	Big Stone Outage Purchased Power	Factor Change for New Large Customer	Economic Development	Corporate Allocations	Amortized Rate Case Expenses
	OPERATING REVENUES									
1	Retail Revenue									
2	Other Electric Operating Revenue						(114,090)			
3	**TOTAL OPERATING REVENUE**	$0	$0	$0	$0	$0	($114,090)	$0	$0	$0
	OPERATING EXPENSES									
4	Production Expenses	($31,436)	$8,498	$1,609	$73,499	($709,964)	($562,885)			
5	Transmission Expenses	(11,649)	3,150	596	27,237		(30,531)			
6	Distribution Expenses	(22,606)	6,110	1,157	52,854		3,666			
7	Customer Accounting Expenses	(15,215)	4,112	779	35,574		0			
8	Customer Service and Information Expenses	(30,943)	8,363	131	6,002		0			
9	Sales Expenses						0	61,922		
10	Administration and General Expenses	(41,668)	11,261	9,279	97,308		(57,310)		(9,283)	50,000
11	Charitable Contributions						0			
12	Depreciation Expense						(882)			
13	General Taxes						(36,246)			
14	**TOTAL OPERATING EXPENSES**	($153,518)	$41,495	$13,551	$292,474	($709,964)	($684,188)	$61,922	($9,283)	$50,000
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$153,518	($41,495)	($13,551)	($292,474)	$709,964	$570,098	($61,922)	$9,283	($50,000)
16	**INCOME TAX EXPENSE**									
17	Investment Tax Credit						$2,352			
18	Deferred Income Taxes						(1,972)			
19	Income Taxes	53,731	(14,523)	(4,743)	(102,366)	248,488	222,324	(21,673)	3,249	(17,500)
20	**TOTAL INCOME TAX EXPENSE**	$53,731	($14,523)	($4,743)	($102,366)	$248,488	$222,704	($21,673)	$3,249	($17,500)
21	**NET OPERATING INCOME**	$99,787	($26,972)	($8,808)	($190,108)	$461,477	$347,393	($40,249)	$6,034	($32,500)
22	Allowance for Funds Used During Construction									
23	**TOTAL AVAILABLE FOR RETURN**	$99,787	($26,972)	($8,808)	($190,108)	$461,477	$347,393	($40,249)	$6,034	($32,500)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

		KNOWN AND MEASURABLE CHANGES					
		(S)	(T)	(U)	(V)	(W)	(X)
Line No.	Description	Holding Company Formation Costs	Normalized Storm Repair Expense	Convert Post Retirement Medical from Pay as you Go to FAS 106	Remove Minor Affiliate Transactions	Changes in Allocations due to Effect of Test Year Adjustments	2007 Test Year
	OPERATING REVENUES						
1	Retail Revenue					$0	$25,375,778
2	Other Electric Operating Revenue					(116,151)	3,174,346
3	**TOTAL OPERATING REVENUE**		$0			($116,151)	$28,550,125
	OPERATING EXPENSES						
4	Production Expenses					($2)	$15,443,701
5	Transmission Expenses					(2)	971,157
6	Distribution Expenses					1	1,497,103
7	Customer Accounting Expenses					(1)	1,008,332
8	Customer Service and Information Expenses					(5,251)	243,527
9	Sales Expenses					0	141,395
10	Administration and General Expenses	12,338	26,731	156,267	(6,334)	(42,511)	3,054,404
11	Charitable Contributions						0
12	Depreciation Expense					6	3,177,201
13	General Taxes					(95,057)	973,917
14	**TOTAL OPERATING EXPENSES**	$12,338	$26,731	$156,267	($6,334)	($142,817)	$26,510,737
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	($12,338)	($26,731)	($156,267)	$6,334	$26,667	$2,039,388
16	**INCOME TAX EXPENSE**						
17	Investment Tax Credit					$239	($848,137)
18	Deferred Income Taxes			(71,759)		(5,171)	(23,796)
19	Income Taxes	(4,318)	(9,356)	(131,002)	2,217	93,912	77,231
20	**TOTAL INCOME TAX EXPENSE**	($4,318)	($9,356)	($202,761)	$2,217	$88,980	($794,702)
21	**NET OPERATING INCOME**	($8,020)	($17,375)	$46,494	$4,117	($62,313)	$2,834,090
22	Allowance for Funds Used During Construction						0
23	**TOTAL AVAILABLE FOR RETURN**	($8,020)	($17,375)	$46,494	$4,117	($62,313)	$2,834,090

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY — **Docket EL08-______**
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**

Line No.	Description	(A) Per Order in Docket F-3691	(B) General Rate Case Filing (Test Year)	(C) (C) = (B) - (A) $ Change	(D) (D) = ((C)/(A))/20 % change Simple Annual Average	Total % change
	OPERATING REVENUES					
1	Retail	$12,331,596	$25,375,778	$13,044,182	5.29%	106%
2	Other Operating Revenue	769,817	3,174,346	2,404,529	15.6%	312%
3	**TOTAL OPERATING REVENUE**	$13,101,413	$28,550,123	$15,448,710	5.90%	118%
	OPERATING EXPENSES					
4	Production Expenses - Fuel and Purchased Power	$3,187,671	$12,644,537	$9,456,866	14.83%	297%
5	Production Expenses - Other	1,550,345	2,799,164	1,248,819	4.03%	81%
6	Transmission Expenses	259,153	971,158	712,005	13.74%	275%
7	Distribution Expenses	627,754	1,497,102	869,348	6.92%	138%
8	Customer Accounting Expenses	420,274	1,008,332	588,058	7.00%	140%
9	Customer Service & Information Expenses	74,829	243,528	168,699	11.27%	225%
10	Sales Expenses	84,427	141,395	56,968	3.37%	67%
11	Administration & General Expenses	1,187,030	3,054,404	1,867,374	7.87%	157%
12	Charitable Contributions	0	0	0	100.00%	
13	Depreciation Expense	1,373,263	3,177,201	1,803,938	6.57%	131%
14	Spiritwood Amortization	46,952	0	(46,952)	0.00%	-100%
15	General Taxes	682,861	973,916	291,055	2.13%	43%
16	**TOTAL OPERATING EXPENSES**	$9,494,559	$26,510,737	$17,016,178	8.96%	179%
17	**NET OPERATING INCOME BEFORE INCOME TAXES**	$3,606,854	$2,039,387	($1,567,467)	(2.17)%	-43%
	INCOME TAX EXPENSE					
18	Investment Tax Credit	($98,171)	($848,138)	($749,967)	(38.20)%	764%
19	Deferred Income Taxes	295,176	(23,796)	(318,972)	(5.40)%	-108%
20	Income Taxes	600,734	77,225	(523,509)	(4.36)%	-87%
21	**TOTAL INCOME TAX EXPENSE**	$797,739	($794,709)	($1,592,448)	(9.98)%	-200%
22	**NET OPERATING INCOME**	$2,809,115	$2,834,096	$24,981	0.04%	1%
23	Allowance for Funds Used During Construction					
24	**TOTAL AVAILABLE FOR RETURN**	$2,809,115	$2,834,096	$24,981	0.04%	1%
	Additional information					
25	**Total O & M Not Including Fuel & Purchased Power**	$6,306,888	$13,866,199	$7,559,312	5.99%	120%

Notes: Revenues reflect calendar month sales

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
SUMMARY OF RATE BASE JURISDICTIONAL ALLOCATION FACTORS

Financial Information

The allocation factors on this page were used to determine South Dakota jurisdictional rate base amounts for all of the years presented in these schedules. Accounts not on this page have been directly assigned to jurisdictions. Descriptions under the Allocation Factor column with a / means the first method was used in historic actual and projected, the method after the / is used in the test year.

The following allocation factors are used to compute South Dakota jurisdictional amounts for Plant-in-Service, Accumulated Depreciation, Accumulated Deferred Income Tax and Construction Work in Progress.

For a full description of each allocation factor, see OTP's *Cost Allocation Procedure Manual for Jurisdictional and Class Cost of Service Studies* , Peter Beithon's testimony, Exhibit ___(PJB-1), Schedule 2.

Line No.	Description	Allocation Basis
	RATE BASE COMPONENT	ALLOCATION FACTOR
1	Electric Plant in Service	
2	Production Plant	
3	Base Demand	kwh Sales Factor (E1)
4	Peak Demand	Generation Demand Factor (D1)
5	Base Energy	kwh Sales Factor (E1)
6	Transmission Plant	Transmission Demand Factor (D2)
7	Distribution Plant	
8	Primary Demand	Distribution Primary Demand Factor (D3)
9	Secondary Demand	Distribution Secondary Demand Factor (D4)
10	Primary Customer	Total Retail Service Locations Factor (C2)
11	Secondary Customer	Total Secondary Retail Service Location Factor (C3)
12	Street Lighting	Streetlight Factor (C4)
13	Area Lighting	Area Light Factor (C5)
14	Meters	Meter Factor (C6)
15	Load Management	Load Management Factor (C9)
16	Rental Equipment	Direct Assignment (North Dakota only)
17	General Plant	
18	Production	Gross Production Plant in Service Ratio (P10)
19	Transmission	Gross Transmission Plant in Service Ratio (P50)
20	Distribution	Gross Distribution Plant in Service Ratio (P60)
21	Customer Accounts	Customer Accounts Expense Ratio (OXC)
22	Customer Service & Info.	Customer Service & Info, Expense Ratio (OXI)
23	Load Management	Load Management Factor (C9)
24	Intangible Plant	
25	Production	Gross Production Plant in Service Ratio (P10)
26	Transmission	Gross Transmission Plant in Service Ratio (P50)
27	Distribution	Gross Distribution Plant in Service Ratio (P60)
28	General	Gross General Plant in Service Ratio (P90)
29	Accumulated Provision for Depreciation	
30	Production Plant	
31	Base Demand	Direct Assignment/kwh Sales Factor (E1)
32	Peak Demand	Direct Assignment/Generation Demand Factor (D1) Base Energy
33	Base Energy	Direct Assignment/kwh Sales Factor (E1)
34	Transmission Plant	Direct Assignment/Transmission Demand Factor (D2)
35	Distribution Plant	Direct Assignment/Gross Distribution Plant in Service Ratio (P60)
36	General Plant	Direct Assignment/Gross General Plant in Service Ratio (P90)
37	Intangible Plant	Gross General Plant in Service Ratio (P90)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
SUMMARY OF RATE BASE JURISDICTIONAL ALLOCATION FACTORS

Line No.	RATE BASE COMPONENT	ALLOCATION FACTOR
1	Electric Plant Held for Future Use	
2	Production Plant	
3	Base Demand	kwh Sales Factor (E1)
4	Peak Demand	Generation Demand Factor (D1)
5	Base Energy	kwh Sales Factor (E1)
6	Transmission Plant	Transmission Demand Factor (D2)
7	Distribution Plant	
8	Primary Demand	Distribution Primary Demand Factor (D3)
9	Secondary Demand	Distribution Secondary Demand Factor (D4)
10	Primary Customer	Total Retail Service Locations Factor (C2)
11	Secondary Customer	Total Secondary Retail Service Location Factor (C3)
12	Streetlighting	Streetlight Factor (C4)
13	Area Lighting	Area Light Factor (C5)
14	Meters	Metering Factor (C6)
15	General Plant	
16	Production	Gross Production Plant in Service Ratio (P10)
17	Transmission	Transmission Demand Factor (D2)
18	Distribution	Gross Distribution Plant in Service Ratio (P60)
19	Customer Accounts	Customer Accounts Expense Ratio (OXC)
20	Customer Service & Info.	Customer Service & Info, Expense Ratio (OXI)
21	Intangible Plant	
22	Production	Gross Production Plant in Service Ratio (P10)
23	Transmission	Gross Transmission Plant in Service Ratio (P50)
24	Distribution	Gross Distribution Plant in Service Ratio (P60)
25	General	Gross General Plant in Service Ratio (P90)
26	Unamortized Balance -	
27	Spiritwood Plant	Gross Production Plant in Service Ratio (P10)
28	Construction Work in Progress — Short Term	
29	Production Plant	
30	Base Demand	kwh Sales Factor (E1)
31	Peak Demand	Generation Demand Factor (D1)
32	Base Energy	kwh Sales Factor (E1)
33	Transmission Plant	Transmission Demand Factor (D2)
34	Distribution Plant	Gross Distribution Plant in Service Ratio (P60)
35	General Plant	Gross General Plant in Service Ratio (P90)
36	Intangible Plant	Gross General Plant in Service Ratio (P90)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
SUMMARY OF RATE BASE JURISDICTIONAL ALLOCATION FACTORS

Line No.	RATE BASE COMPONENT	ALLOCATION FACTOR
1	Construction Work in Progress — Other	
2	Production Plant	
3	Base Demand	kwh Sales Factor (E1)
4	Peak Demand	Generation Demand Factor (D1)
5	Base Energy	kwh Sales Factor (E1)
6	Transmission Plant	Transmission Demand Factor (D2)
7	Distribution Plant	Gross Distribution Plant in Service Ratio (P60)
8	General Plant	Gross General Plant in Service Ratio (P90)
9	Intangible Plant	Gross General Plant in Service Ratio (P90)
10	Materials and Supplies	
11	Diesel Parts and Supplies	Generation Demand Factor (D1)
12	Big Stone and Coyote Plants	
13	Base Demand	kwh Sales Factor (E1)
14	Peak Demand	Generation Demand Factor (D1)
15	All Other	
16	Transmission	Transmission Demand Factor (D2)
17	Distribution	Gross Distribution Plant in Service Ratio (P60)
18	Fuel Stocks	
19	Coal Stocks	kwh Sales Factor (El)
20	Fuel Oil Stocks	Generation Demand Factor (D1)
21	Prepayments	Total Net Plant in Service Ratio (NEPIS)
22	Cash Working Capital	Separately Calculated by Jurisdiction
23	Accumulated Deferred Income Taxes	
24	Items South Dakota flows through:	
25	Federal	Total Net Plant in Service Ratio (NEPIS)
26	excluding South Dakota (NPMNR)	
27	Minnesota	Total Net Plant in Service — MN Ratio (NPISM)
28	North Dakota	Total Net Plant in Service — ND Ratio (NPISN)
29	All Other:	
30	Federal	Total Net Plant in Service Ratio (NEPIS)
31	Minnesota	Total Net Plant in Service — MN Ratio (NPISM)
32	North Dakota	Total Net Plant in Service — ND Ratio (NPISN)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ALLOCATION FACTORS

The allocation factors on this page were used to determine South Dakota jurisdictional rate base amounts for all of the years presented in these schedules. Accounts not on this page have been directly assigned to jurisdictions. Descriptions under the Allocation Factor column with a / means the first method was used in historic actual and projected, the method after the / is used in the test year.

The following allocation factors are used to compute South Dakota jurisdictional amounts for Expenses as listed below. For a full description of each allocation factor, see OTP's *Cost Allocation Procedure Manual for Jurisdictional and Class Cost of Service Studies* , Peter Beithon's testimony, Exhibit ___(PJB-1), Schedule 2.

Line No.	Description	Allocation Basis
	ELEMENT OF OPERATING INCOME	
1	Operating Revenues	
2	Sales of Electricity	Direct Assignment
3	Other Operating Revenues	
4	Asset Based Sales	kwh Sales Factor (E2)
5	Municipalities	Direct Assignment (FERC only)
6	Other Electric Revenue	
7	Residential Conservation Services	Direct Assignment
8	Forfeited Discounts	Direct Assignment
9	Connection Fees	Direct Assignment
10	Wheeling	Direct Assignment (FERC only)
11	Income - Rent	Total Net Plant in Service Ratio (NEPIS)
12	Integrated Transmission Agreements	Total Net Plant in Service Ratio (NEPIS)
13	Load Control and Dispatch (also MISO Trans Rev.)	Total Net Plant in Service Ratio (NEPIS)
14	All Other	Total Net Plant in Service Ratio (NEPIS)
15	Loan Pool Interest	Directly assigned to Jurisdiction
16	Operating Expenses	
17	Production Expenses	
18	Asset-based Sales	kwh Sales Factor (E2)
19	Production and Purchase Expenses	
20	Base Demand	kwh Sales Factor (E1)
21	Peak Demand	Generation Demand Factor (D1)
22	Base Energy	kwh Sales Factor (E2)
23	Peak Energy	Generation Demand Factor (D1)
24	Transmission Expenses	Transmission Demand Factor (D2)
25	Distribution Expenses	
26	Primary Demand	Distribution Primary Demand Factor (D3)
27	Secondary Demand	Distribution Secondary Demand Factor (D4)
28	Primary Custaaer	Total Retail Service Locations Factor (C2)
29	Secondary Customer	Total Secondary Retail Service Locations Factor (C3)
30	Streetlighting	Streetlight Factor (C4)
31	Area Lighting	Area Light Factor (C5)
32	Meters	Meter Factor (C6)
33	Load Management Expenses	Load Management Factor (C9)
34	Customer Accounts Expenses	
35	Meter Reading	Meter Reading Factor (C7)
36	Other	Total System Serv0 Locations Factor (C8)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ALLOCATION FACTORS

Line No.	Description	Allocation Basis
	ELEMENT OF OPERATING INCOME	ALLOCATION FACTOR
1	Operating Expenses - continued	
2	Customer Service & Informational	
3	Expenses	
4	Conservation & Promotional Rebates	Direct Assignment then 1/2 E1 and 1/2 D1
5	All Other	Total Retail Customers Factor (C1)
6		
6	Sales Expenses	
7	Off-Peak Development	Direct Assignment
8	All Other	Total Retail Customers Factor (C1)
9	Administrative and General Expenses	
10	A & G Salaries, Office Supplies &	
11	Exp., & Employee Pensions & Benefits	
12	Production	Production Expense Ratio (Excl. Energy
13		Related) (OXPD)
14	Transmission	Transmission Expense Ratio (D2)
15	Distribution	Distribution Expense Ratio (OXD)
16	Customer Accounts	Customer Accounts Expense Ratio (OXC)
17	Customer Service & Informational	Customer Service & Informational Expense (C1)
18		Ratio (OXI)
19	Load Management Expenses	Load Management Factor (C9)
20	Outside Services	Total Net Plant in Service Ratio (NEPIS)
21	Property Insurance	Total Net Plant in Service Ratio (NEPIS)
22	Injuries and Damages	Total Net Plant in Service Ratio (NEPIS)
23		
24	Regulatory Commission Expenses	Direct Assignment
25	General Advertising	Total Retail Customers Factor (C1)
26	Miscellaneous General Expenses, Rents	
27	and Maintenance of General Plant	General Plant in Service Ratio (P90)
28	Charitable Contributions	Direct Assignment
29	Depreciation Expenses	
30	Production	
31	Base Demand	Direct Assignment/kwh Sales Factor (E1) Test Year
32	Peak Demand	Direct Assignment/Generation Demand Factor (D1) test year
33	Base Energy	Direct Assignment/kwh Sales Factor (E1) Test Year
34	Transmission	Direct Assignment/Transmission Demand Factor (D2) test year
35	Distribution	Direct Assignment/P60 test year
36	General	Direct Assignment/General Plant in Service Ratio (P90) Test year
37	Intangible	General Plant in Service Ratio (P90)
38	General Taxes	Total Net Plant in Service Ratio (NEPIS)
39	Other Expense	Gross Production Plant in Service Ratio (P10)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ALLOCATION FACTORS

Line No.	Description	Allocation Basis
	ELEMENT OF OPERATING INCOME	ALLOCATION FACTOR
1	Operating Expenses - continued	
2	Investment Tax Credit	
3	Amortization of Prior Years' Credits	Total Gross Plant in Service Ratio (EPIS)
4	Debits Utilized	Federal Income Taxes Before Credits
5		(FITBC)
6	Adjustments	Total Gross Plant in Service Ratio (EPIS)
6		
7	Deferred Income Tax Expense	
8	Items South Dakota flows through:	
	Federal	Total Net Plant in Service Ratio
9		excluding South Dakota (NPMNR)
10	Minnesota	Total Net Plant in Service - MN Ratio
11		(NPISM)
12	North Dakota	Total Net Plant in Service - ND Ratio
13		(NPISN)
14		
15	All Other:	
16	Federal	Total Net Plant in Service Ratio (NEPIS)
17	Minnesota	Total Net Plant in Service - MN Ratio
18		(NPISM)
19	North Dakota	Total Net Plant in Service - ND Ratio
20		(NPISN)
21		
22	Income Taxes	
23	Federal Income Taxes	Separately Calculated by Jurisdiction
24	Minnesota Income Taxes	State Income Tax Factor (ROOM)
25	North Dakota Income Taxes	State Income Tax Factor (ROON)
26		
27	Allowance for Funds Used	
	During Construction	Other Construction Work in Progress Ratio
28		(CWIP Accruing AFDC) (CWIPO)
29	NOTE: See Schedule B-6 for the values for the allocation factors	

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME JURISDICTIONAL
ALLOCATION FACTOR AMOUNTS

Allocators - Demand, Energy and Customer

			Actual Year 2007			Test Year 2007		
LINE NO	ITEM	FACTOR	TOTAL UTILITY	SOUTH DAKOTA	ALL OTHER	TOTAL UTILITY	SOUTH DAKOTA	ALL OTHER
1	MWH CONSUMPTION AT GENERATORS - PARTIAL	E1	3,918,074	382,540	3,535,534	4,082,438	382,540	3,699,898
2	PERCENTAGE		100.000000%	9.763471%	90.236529%	100.000000%	9.370380%	90.629620%
4	MWH CONSUMPTION AT GENERATORS - TOTAL	E2	4,430,839	429,450	4,001,389	4,595,203	429,450	4,165,753
5	PERCENTAGE		100.000000%	9.692295%	90.307705%	100.000000%	9.345615%	90.654385%
6	GENERATION DEMAND FACTOR	D1	598,234	55,954	542,280	622,316	56,356	565,960
7	PERCENTAGE		100.000000%	9.353195%	90.646805%	100.000000%	9.055845%	90.944155%
8	TRANSMISSION DEMAND FACTOR	D2	604,225	55,954	548,271	628,307	56,356	571,951
9	PERCENTAGE		100.000000%	9.260463%	90.739537%	100.000000%	8.969502%	91.030498%
10	DISTRIBUTION - PRIMARY DEMAND FACTOR	D3	757,342	77,778	679,564	761,059	78,710	682,349
11	PERCENTAGE		100.000000%	10.269858%	89.730142%	100.000000%	10.342161%	89.657839%
12	DISTRIBUTION - SECONDARY DEMAND FACTOR	D4	998,227	106,359	891,868	999,305	106,969	892,336
13	PERCENTAGE		100.000000%	10.654791%	89.345209%	100.000000%	10.704340%	89.295660%
14	CUSTOMER OR METER FACTORS							
15	TOTAL RETAIL CUSTOMERS	C1	129,675	11,714	117,961	129,675	11,714	117,961
16	PERCENTAGE		100.000000%	9.033353%	90.966647%	100.000000%	9.033353%	90.966647%
17	RETAIL SERVICE LOCATIONS	C2	135,857	12,381	123,476	135,857	12,381	123,476
18	PERCENTAGE		100.000000%	9.113259%	90.886741%	100.000000%	9.113259%	90.886741%
19	SECONDARY SERVICE LOCATIONS	C3	135,784	12,372	123,412	135,784	12,372	123,412
20	PERCENTAGE		100.000000%	9.111530%	90.888470%	100.000000%	9.111530%	90.888470%
21	STREET LIGHTING FACTOR	C4	4,185,546	445,084	3,740,462	4,185,546	445,084	3,740,462
22	PERCENTAGE		100.000000%	10.633834%	89.366166%	100.000000%	10.633834%	89.366166%
23	AREA LIGHTING FACTOR	C5	3,688,552	350,046	3,338,506	3,688,552	350,046	3,338,506
24	PERCENTAGE		100.000000%	9.490065%	90.509935%	100.000000%	9.490065%	90.509935%
25	METER FACTOR	C6	29,240,646	2,724,953	26,515,693	29,240,646	2,724,953	26,515,693
26	PERCENTAGE		100.000000%	9.319059%	90.680941%	100.000000%	9.319059%	90.680941%
27	METER READING FACTOR	C7	173,474	16,245	157,229	173,474	16,245	157,229
28	PERCENTAGE		100.000000%	9.364516%	90.635484%	100.000000%	9.364516%	90.635484%
29	SYSTEM SERVICE LOCATIONS	C8	135,879	12,381	123,498	135,879	12,381	123,498
30	PERCENTAGE		100.000000%	9.111783%	90.888217%	100.000000%	9.111783%	90.888217%
31	LOAD MANAGEMENT FACTOR	C9	40,923	4,108	36,815	40,923	4,108	36,815
32	PERCENTAGE		100.000000%	10.038365%	89.961635%	100.000000%	10.038365%	89.961635%

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME JURISDICITONAL
ALLOCATION FACTOR AMOUNTS

Allocators - General Plant, Operation and Maintenance Expense and Taxes

			Actual Year 2007			Test Year 2007		
LINE NO	ITEM	FACTOR	TOTAL UTILITY	SOUTH DAKOTA	ALL OTHER	TOTAL UTILITY	SOUTH DAKOTA	ALL OTHER
1	PRODUCTION PLANT	P10	401,831,692	38,732,905	363,098,787	579,764,145	53,785,604	525,978,541
2	PERCENTAGE		100.000000%	9.639087%	90.360913%	100.000000%	9.277153%	90.722847%
3	DISTRIBUTION PLANT	P60	321,276,855	31,604,543	289,672,312	321,943,416	31,772,252	290,171,164
4	PERCENTAGE		100.000000%	9.837168%	90.162832%	100.000000%	9.868893%	90.131107%
38	GENERAL PLANT	P90	72,566,818	6,708,612	65,858,207	74,117,051	6,727,735	67,389,316
39	PERCENTAGE		100.000000%	9.244737%	90.755263%	100.000000%	9.077176%	90.922824%
40	ELECTRIC PLANT IN SERVICE	EPIS	994,969,974	95,500,987	899,468,987	1,188,139,226	111,334,200	1,076,805,026
41	PERCENTAGE		100.000000%	9.598379%	90.401621%	100.000000%	9.370467%	90.629533%
42	NET ELECTRIC PLANT IN SERVICE	NEPIS	533,455,831	57,414,560	476,041,271	718,119,647	67,270,827	650,848,820
43	PERCENTAGE		100.000000%	10.762758%	89.237242%	100.000000%	9.367635%	90.632365%
44	OPERATION AND MAINTENANCE EXPENSE							
45	PRODUCTION EXPENSE (EXCL ENERGY)	OXPD	20,900,416	2,017,585	18,882,831	23,721,095	2,202,812	21,518,283
46	PERCENTAGE		100.000000%	9.653324%	90.346676%	100.000000%	9.286300%	90.713700%
47	DISTRIBUTION EXPENSE	OXD	14,686,349	1,435,240	13,251,109	15,280,331	1,497,102	13,783,229
48	PERCENTAGE		100.000000%	9.772613%	90.227387%	100.000000%	9.797576%	90.202424%
49	CUSTOMER ACCOUNTS EXPENSE	OXC	10,507,260	969,163	9,538,096	10,931,905	1,008,332	9,923,573
50	PERCENTAGE		100.000000%	9.223750%	90.776250%	100.000000%	9.223750%	90.776250%
51	CUSTOMER SERVICE & INFORMATION EXPENSE	OXI	5,241,699	236,920	5,004,780	5,387,900	243,528	5,144,373
52	PERCENTAGE		100.000000%	4.519899%	95.480101%	100.000000%	4.519899%	95.480101%
53	OTHER DEFERRED INCOME TAX FACTOR							
54	MINNESOTA	NPISM	265,407,315	-	265,407,315	351,606,212	-	351,606,212
55	PERCENTAGE		100.000000%	0.000000%	100.000000%	100.000000%	0.000000%	100.000000%
56	NORTH DAKOTA	NPISN	210,604,309	-	210,604,309	299,207,468	-	299,207,468
57	PERCENTAGE		100.000000%	0.000000%	100.000000%	100.000000%	0.000000%	100.000000%
58	EXCLUDING SOUTH DAKOTA	NPMNR	476,041,271	-	476,041,271	650,848,820	-	650,848,820
59	PERCENTAGE		100.000000%	0.000000%	100.000000%	100.000000%	0.000000%	100.000000%
60	LONG-TERM CWIP RATIO (W/AFDC)	CWIPLT	20,811,434	-	20,811,434	13,710,392	-	13,710,392
61	PERCENTAGE		100.000000%	0.000000%	100.000000%	100.000000%	0.000000%	100.000000%
62	REVENUE	R10	268,698,170	25,389,754	243,308,416	275,712,789	25,375,778	250,337,012
63	PERCENTAGE		100.000000%	9.449173%	90.550827%	100.000000%	9.203700%	90.796300%
64	LABOR AND RELATED EXPENSE	LRE	91,993,952	8,418,110	83,575,842	99,751,489	8,977,335	90,774,154
65	PERCENTAGE		100.000000%	9.150721%	90.849279%	100.000000%	8.999700%	91.000300%

OX

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 characteristic, 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 .83 kW/customer already included in the minimum system portion of the primary customer component. (See Appendix A-1.) Any loads for which Otter Tail is responsible for providing primary distribution service are included in this factor. The hours used are the same as those for the Generation Demand Factor.

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

5. ENERGY FACTOR (E1) - this factor is based on kilowatt-hour (kWh) sales adjusted for line losses to the generation level excluding interruptible irrigation and 14/24'ths of water heating and deferred sales.

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

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 that related to the Big Stone Plant unit train. 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 =

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

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)

TRANSMISSION PLANT IN SERVICE

Allocated using the Transmission Demand Factor (D2).

DISTRIBUTION PLANT IN SERVICE

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

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

based on the following account-by-account methodology:

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

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

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

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

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

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

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

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

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

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

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

The categories were then allocated based on the following:

PRIMARY DEMAND - Distribution Primary Demand Factor (D3)

SECONDARY DEMAND - Distribution Secondary Demand Factor (D4)

PRIMARY CUSTOMER - Total Distribution Service Locations Factor (C2)

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

STREETLIGHTING - Streetlight Factor (C4)

AREA LIGHTING - Area Light Factor (C5)

METERS - Metering Factor (C6)

LOAD MANAGEMENT - Load Management Factor (C9)

GENERAL PLANT IN SERVICE

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

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

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

INTANGIBLE PLANT IN SERVICE

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

ACCUMULATED PROVISION FOR DEPRECIATION

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

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

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

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

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

NET CAPITALIZED ITEMS - BIG STONE PLANT

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

PLANT HELD FOR FUTURE USE

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

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

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

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

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

CONSTRUCTION WORK IN PROGRESS (CWIP)

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

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

WORKING CAPITAL

MATERIALS AND SUPPLIES:

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

FUEL STOCKS:

COAL STOCKS - allocated using Energy Factor (E1).

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

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

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

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

ACCUMULATED DEFERRED INCOME TAXES

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

UNAMORTIZED BALANCE - SPIRITWOOD PLANT

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

UNAMORTIZED RATE CASE EXPENSE

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

OPERATING REVENUES

RETAIL SALES

Directly assigned to each jurisdiction and class as billed.

SALES FOR RESALE

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

NONASSOCIATED UTILITIES, COOPERATIVES AND OTHER PUBLIC AUTHORITIES

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

The revenues from the remaining portion are classified as base demand, peak demand, base energy, and peak energy as follows:

1. All revenues from these sales, except those considered Participation or Peaking Power, are classified as Base Energy.

2. Demand charges for Peaking sales are classified as Peak Demand.

3. Demand charges for Participation Power sales are classified as follows:

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

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

4. Energy charges for Participation Power sales are classified Base Energy.

5. Energy charges for Peaking Power sales are classified Peak Energy.

The jurisdictional allocations were then made as follows:

BASE DEMAND - Energy Factor (E1)

PEAK DEMAND - Generation Demand Factor (D1)

BASE ENERGY - Energy Factor (E2)

PEAK ENERGY - Generation Demand Factor (D1)

<u>OTHER ELECTRIC REVENUE</u>

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

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

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

ACCOUNT 456.7 (RESIDENTIAL CONSERVATION SERVICE) - directly assigned to jurisdictions. Allocated to classes based on Total Customers Factor (C1).

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 as follows:

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

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

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

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

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

$ 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.

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

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

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

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

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

MAINTENANCE

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

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

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

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

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

ACCOUNT 596 (STREETLIGHTING) - classified directly to streetlighting.

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

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

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

Each category was then allocated based on the following:

PRIMARY DEMAND - Distribution Primary Demand Factor (D3).

SECONDARY DEMAND - Distribution Secondary Demand Factor (D4).

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

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

STREETLIGHTING - Streetlight Factor (C4).

AREA LIGHTING - Area Light Factor (C5).

METERS - Meter Factor (C6).

LOAD MANAGEMENT - Load Management Factor (C9).

CUSTOMER ACCOUNTING AND COLLECTING EXPENSES

Expenses in this function were classified into two categories:

1. Meter Reading

2. Other Expenses

as specified by the following:

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

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

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

ACCOUNT 904 (UNCOLLECTIBLE ACCOUNTS) - classified other expense.

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

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

CUSTOMER SERVICE AND INFORMATION EXPENSES

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

SALES EXPENSES

Off-Peak Development and New Load Development are directly assigned to jurisdiction and then allocated to class based on Total Customer Factor (C1). All other Sales Expenses are allocated based on Total Customer Factor (C1).

ADMINISTRATIVE AND GENERAL EXPENSES

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

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

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

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

ACCOUNT 930.1 (GENERAL ADVERTISING) - allocated based on Total Customers Factor (C1).

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

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

DEPRECIATION EXPENSES

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

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

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

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

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

BIG STONE PLANT CAPITALIZED ITEMS EXPENSES

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

OTHER EXPENSE - SPIRITWOOD AMORTIZATION

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

GENERAL TAXES

Allocated using total net plant in service ratios.

DEFERRED INCOME TAXES

Allocated using total net plant in service ratios.

INVESTMENT TAX CREDIT

Allocated using total gross plant in service ratios.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFDC)

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.

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

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.).

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

I. Primary

A. Average age of primary conductor.

B. Minimum size primary unit.

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

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

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

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

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

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

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.

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

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