Otter Tail Corporation d/b/a

Otter Tail Power Company

Before the

North Dakota Public Service Commission

Application for Authority to Increase Electric Rates in North Dakota

Case No. PU - 08 - ____

November 3, 2008

Volume 2A

Direct Testimony and Supporting Schedules

Otter Tail Power Company

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Volume 2A

Testimony and Schedules of Witnesses:

Thomas Brause

Policy

Before the North Dakota Public Service Commission
State of North 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 North Dakota

Case No. PU-08-_____
Exhibit___

POLICY

Direct Testimony and Schedules of
THOMAS R. BRAUSE

November 3, 2008

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas R. Brause, my business address is 215 South Cascade Street, Fergus Falls, Minnesota, 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 ("Otter Tail Power" or "OTP") as its Vice President Administration. My current duties include providing direction for OTP's Market Planning, Policy and Compliance, Regulatory Services, and Information Technology areas.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. After 21 years in various Information Technology roles, I became Director Human Resources, Information Technology and Safety in 1999. Since 2004, I have been Vice President Administration. My qualifications and experience are more fully described on Exhibit __ (TRB-1), Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of OTP in support of the application to the North Dakota Public Service Commission (the "Commission") for authority to increase rates.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I provide a description of OTP and a brief update on the status of plans to form a holding company structure ("Holding Company"). I also summarize the revenue needs, and rate design initiatives that OTP is proposing. Lastly, I introduce the other OTP witnesses.

Q. PLEASE SUMMARIZE OTP'S REVENUE REQUEST.

A. We are proposing an overall revenue increase of $6,084,003 or 5.14 percent based on a 2007 Historical Test Year, with known and measurable changes. This proposed increase reflects a return on equity ("ROE") of 11.25 percent and an equity ratio of 53.30 percent, and will result in an overall rate of return on investment of 8.89 percent. With this increase, a typical residential customer using 836 kWh of electricity a month would see an increase of $5.01 a month. Also with this increase, a typical commercial customer using 2,946 kWh of electricity a month would see an increase of $2.26 a month.

Q. HOW IS THE BALANCE OF YOUR TESTIMONY ORGANIZED?

A. Section II provides a description of OTP, including an update on the Company's requests for authority to form a Holding Company legal structure. In Section III, I describe the primary drivers and mitigation efforts that underlie this proposed rate increase. In Section IV, I address our rate design initiatives. In Section V, I introduce the other witnesses.

Q. WERE THE ATTACHED SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

II. DESCRIPTION OF OTP

Q. PLEASE BRIEFLY DESCRIBE OTP.

A. OTP is headquartered in Fergus Falls, Minnesota, where it began generating electricity in 1909. OTP provides electricity to 423 communities and to rural areas in the eastern two-thirds of North Dakota, western Minnesota, and northeastern South Dakota. Our 50,000 square-mile service territory, shown on Exhibit __(TRB-1), Schedule 2, is roughly the size of Wisconsin. The average

population of the communities we serve is approximately 400, and over one-half of the communities we serve have populations of fewer than 200. Only three of our communities have populations exceeding 10,000 (Jamestown, North Dakota (pop. 15,527), Fergus Falls, Minnesota (pop. 13,949) and Bemidji, Minnesota (pop. 13,074)). We operate 11 customer service centers throughout our service territory.

We operate three coal-fired base load generating plants and three peaking plants, one of each in each state where we provide service. We own five hydroelectric stations on the Otter Tail River near Fergus Falls and one on the Mississippi River near Bemidji, Minnesota.

OTP owns a total of 5,291 miles of transmission line. To help provide more reliable service at lower cost in the long term, our electric system is interconnected directly with neighboring suppliers. OTP is a member of the Midwest Reliability Organization ("MRO"), MidContinent Area Power Pool ("MAPP"), the Midwest Independent Transmission System Operator ("MISO") and Midwest Planned Reserve Sharing Group ("MPRSG"). While OTP plans to conclude its membership in MAPP and MRPSG as MISO expands its role, the goal of lowering costs by maintaining interconnection with neighboring suppliers will remain.

Q. HOW MANY CUSTOMERS DOES OTP SERVE?

A. As of year-end 2007, OTP was providing electricity and energy services to 129,311 customers: 56,936 in North Dakota, 60,664 in Minnesota, and 11,711 in South Dakota.

Q. HOW MANY PEOPLE DOES OTP EMPLOY?

A. OTP has 714 employees, including full-time, part-time, and temporary, adjusted for our share of employees at jointly owned plants.

A. OTP'S MISSION

Q. WHAT IS OTP'S MISSION?

A. OTP's mission is:

> To produce and deliver electricity as reliably, economically, and environmentally responsibly as possible to the balanced benefit of customers, shareholders, and employees and to improve the quality of life in the areas in which we do business.

Q. DOES OTP MEASURE ITS SUCCESS IN MEETING THE OBJECTIVES REFLECTED IN THAT MISSION STATEMENT?

A. Yes it does. One way we measure our success is through what we call "Key Performance Indicators" or "KPIs". These KPIs are quantifiable, bellwether components of our performance. These components are: 1) Customer Satisfaction; 2) Service Reliability; 3) Generating Plant Availability; 4) Employee Safety; and 5) Financial Performance. We regularly monitor our performance in each of these areas which provides very good indications of OTP's overall success as an electric utility and whether we are succeeding in our mission.

Q. PLEASE FURTHER EXPLAIN THESE KPI'S.

A. For each KPI, we have objective and concrete measurements of performance. This helps to ensure that we have reliable and quantifiable information from which to judge our performance.

For Customer Satisfaction, we have two types of customer satisfaction surveys, each conducted semi-annually. We have: 1) a "relationship" survey, which is a telephone survey of residential customers in our service territory; and 2) a "transactional" survey, which is a telephone survey of customers who initiated contact with OTP of a transactional nature about any issue other than paying a bill.

For the relationship survey, OTP has historically done extremely well in comparison to the top 29 Investor Owned Utilities ("IOUs"), which serve over 75

percent of all residential customers in the United States. Our second quarter 2008 results continue this trend. OTP's relationship survey score was a significant 7 points higher than the industry average (which was 73 points). The most recent transactional survey conducted with residential, commercial and industrial customers was received in the Spring of 2008. These results indicate that, overall, OTP is providing good service to customers in response to transactions, with nearly 7 in 10 rating its service level "excellent" or "very good."

For Service Reliability, we use the System Average Interruption Duration Index ("SAIDI") – This KPI measures the average minutes of interruption for a customer over the course of a year, or the "minutes per customer per year." OTP's 2007 SAIDI was 65.84 minutes -- 14 minutes lower than our KPI target of 79 minutes.

For Generating Plant Availability, we track our generating plants' Equivalent Availability. This KPI measures the availability of company-run generation plants. Equivalent Availability represents the portion of time that a generating unit is available to operate, including consideration of the lost capacity effects of partial equipment deratings when the unit was available, but at less than the full capacity. This measure is different and more refined than the traditional availability measure that represents the portion of time that a unit is capable of producing energy, regardless of its capacity level. We consistently outperform the industry average on both measures with our steam generating plants.

For Safety, we measure our Occupational Safety and Health Administration ("OSHA") Recordable Incident Rate based on the OSHA 300 Log. Our benchmarks are set using industry data provided by the Edison Electric Institute as well as OTP's own historical safety performance. We are proud to say we have consistently had incident-rate results that are less than one-half the industry average. OTP recently recognized the entire employee group for working more than one million hours without a lost work day.

For Financial Performance, we track our Net Income available for common stock. This KPI is an objective measurement of our financial

performance. OTP has a strong record of paying dividends to common stockholders.

Q. HOW ARE THESE KPI'S TRACKED AND COMMUNICATED?

A. KPIs are tracked and evaluated within each respective department; recorded and reported by the Budget/Forecast area; and, evaluated regularly by the department heads and the OTP executive group. Results are reported to all OTP employees after year-end, and periodically during the year, which helps to ensure that all employees are working to help OTP fulfill its mission. Many departments also monitor individual department performance indicators that assist OTP in working toward meeting the KPIs.

Q. OTP ALSO INCLUDES IN ITS MISSION STATEMENT A COMMITMENT TO ENVIRONMENTAL RESPONSIBILITY. PLEASE DISCUSS THAT COMMITMENT.

A. OTP takes environmental stewardship seriously. We have invested millions of dollars in environmental controls and abide by exacting federal and state environmental regulations. We've reduced sulfur dioxide and nitrogen oxides emissions by more than 25 percent since 1991. We participate in research projects through the University of North Dakota's Energy and Environmental Research Center ("EERC") to help develop cleaner, more efficient energy and environmental technologies. OTP is a partner in the EERC's Plains CO_2 Reduction Partnership, one of seven regional carbon sequestration projects across the country sponsored by the Department of Energy. To save natural resources and lower landfill use, we recycle ash byproducts from our power plants for uses such as additives for cement pipe and concrete block, and for sandblasting, road surfacing, and roofing shingles. We offer wind as an optional energy source to our customers through our Tail*Winds* program, and we are adding significant new wind generation and other renewables to our resource mix.

Q. HAS OTP ADDED SIGNIFICANT WIND GENERATION RESOURCES IN NORTH DAKOTA?

A. Yes. We are approaching 180 MWs of wind resources in North Dakota. Major projects include: 40.5 MWs in Purchased Power Agreements ("PPAs"), 40.5 MWs of utility owned generation currently in service, 48 MWs currently under construction with year end 2008 expected completion date, and 49.5 MWs planned for 2009.

B. OTP'S ORGANIZATIONAL STRUCTURE

Q. HOW IS OTP STRUCTURED?

A. OTP is an operating division of Otter Tail Corporation. OTP is not a separate legal entity, but it has been operationally separate since 2001. Otter Tail Corporation also operates several non-utility businesses as separate subsidiaries.

Q. HAS A CHANGE OF OTP'S STRUCTURE BEEN PROPOSED?

A. Yes. On October 8, 2008, the Commission issued its Order in Case No. PU-08-292 approving our request for authority to establish a Holding Company structure under which OTP would become a separate subsidiary of a newly formed Holding Company. We have also received authority to establish a holding company structure from the Federal Energy Regulatory Commission, and similar requests are pending before the Minnesota Public Utilities Commission ("MPUC") and the South Dakota Public Utilities Commission ("SDPUC"). Assuming the approvals are received and other requisite authority is obtained, we expect to complete the formation of the Holding Company structure during 2009.

III. PRIMARY DRIVERS AND MITIGATION EFFORTS REGARDING THE NEED FOR A RATE CASE INCREASE

Q. CAN YOU PLACE OTP'S PROPOSED REVENUE INCREASE IN CONTEXT?

A. Yes. Our last North Dakota rate case was in 1983, making the 5.14 percent increase equivalent to about a 0.21percent annual increase which is significantly below any measure of inflation. We serve our electric customers at rates that are among the lowest in the Midwest, which is a region that has some of the lowest rates in the nation and have done so despite our small size and the sparsely populated area we serve.

Q. HAVE YOUR BASE RATES CHANGED SINCE 1983?

A. Yes. In 1987 OTP reduced its base rates by 4.27% as the result of the lower federal income tax rate in the Tax Reform Act of 1986. This was a reduction of just over $3 million annually. The Commission also monitors and reviews regulated utilities' earnings based on their annual reports to the Commission. As a result of such reviews, OTP has either reduced its base rates or made one-time refunds to customers in seven years since its last rate case. In addition, for the five years 2001 through 2005, OTP operated under a Commission-approved Performance Based Ratemaking ("PBR") Plan. This PBR Plan called for OTP to refund to customers a share of earnings if its ROE exceeded a set level. This resulted in a refund in 2002 based on 2001 financial and performance results. The following table summarizes OTP's rate reductions in North Dakota.

History of rate reductions; refunds in ND			
Year	Amount	Percent (4)	Note
1987	$3,060,000	4.27%	(1)
1989	1,000,000	1.50%	(2)
1990	315,500	0.48%	(2)
1992	1,000,000	1.50%	(3)
1994	448,636	0.66%	(3)
1999	685,000	0.91%	(3)
1999	350,000	0.47%	(2)
2000	42,442	0.05%	(3)
2002	662,300	0.80%	(3)
(1) Reduction to base rates - TRA 86			
(2) Reduction to base rates			
(3) One-time refund			
(4) Percent of rates in effect at the time of the reduction.			

Q. WHAT ARE THE PRIMARY DRIVERS OF OTP'S NEED FOR A RATE INCREASE?

A. There are three primary drivers of our need to request a rate increase. First, since our last base rate case in 1983, operating costs, such as material, labor, pension, active medical and post-retirement medical have risen substantially. Second, we have experienced dramatic increases in fuel and purchased power costs, which currently are not being fully recovered in the Fuel Clause Adjustment ("FCA"). Third, OTP has made substantial investments in infrastructure. I will further explain each of these primary drivers.

A. OPERATING COSTS

Q. PLEASE FURTHER EXPLAIN THE INCREASES OTP HAS SEEN IN ITS OPERATING COSTS.

A. Inflation alone has added significantly to the cost of service that OTP has experienced since 1983, and there are several categories of costs that have risen at

rates well in excess of inflation in recent years. The most significant increases in operational costs are in labor and employee benefit costs. Mr. Peter Beithon will address these subjects in more detail in his testimony.

Q. WHAT HAS OTP DONE TO MANAGE AND CONTAIN THESE RISING OPERATING COSTS?

A. Because so many of these increases are related to labor and benefit costs, we have worked very hard to improve productivity and, as a result, reduce our employee count. We have, for example, instituted communications and other logistical improvements that have allowed us to reduce our employee count by approximately 16 percent since 1983. We have also reduced the number of offices that we maintain, while maintaining field personnel in those areas. These reductions have directly mitigated labor and benefit cost increases, and they have also allowed us to slow the growth of some other overhead costs, ranging from bucket trucks to personal computers. We also instituted a virtual call center in 2004 that has allowed us to better respond to customer calls with fewer customer service representatives. These reductions have been carefully implemented to avoid any adverse impact on service quality.

Q. HAVE THESE CHANGES HAD AN ADVERSE IMPACT ON SERVICE QUALITY?

A. No. Even with the changes, OTP's reliability remains very high and our customer satisfaction is recognized as one of the highest in the nation.

Q. WHAT ELSE HAS OTP DONE TO ADDRESS RISING EMPLOYEE BENEFIT COSTS?

A. We have taken steps to manage the increases in employee benefit costs. Combined with the reduction in employee count, this has helped mitigate these sharply rising costs. Mr. Peter Wasberg will address steps that we have taken to manage cost increases relating to post retirement benefits, including implementing

a soft freeze on non-union and some union pension participation, eliminating post retirement medical coverage for new non-union and some new union employees, reducing Employee Stock Ownership Plan ("ESOP") contributions, and increasing the employee-paid portion of active medical costs.

Q. HAS OTP TAKEN STEPS TO CONTROL COSTS OF OPERATING ITS PLANT AND EQUIPMENT?

A. Yes. We have developed efficient transmission, distribution and generation maintenance protocols and prudent purchasing practices to keep operating costs as low as possible. These practices and the impact they have had can be seen in our material standardization practices. Here we have partnered with suppliers to use industry-wide specifications for standard material rather than materials with specifications unique to OTP. This has led to reduced first costs and has allowed us to shorten lead times for material procurement and lower inventory levels.

B. FUEL COSTS

Q. HAVE FUEL AND PURCHASED POWER COSTS CHANGED IN RECENT YEARS?

A. Yes. Fuel and purchased power costs have seen significant increases, the most dramatic of which have occurred in the past few years.

Q. ARE THESE FUEL COST INCREASES FULLY RECOVERED THROUGH OTP'S FUEL ADJUSTMENT MECHANISM?

A. No, OTP's fuel cost increases are not fully recovered through the FCA. OTP is unlike other North Dakota utilities in that OTP currently has some tariffed retail electric rates that do not include a FCA. That is, the customers that are taking service under those tariffed rates do not have fluctuations of fuel and purchased power costs passed through to them in their monthly electric bills. They pay only the base fuel and purchased power costs that were included in OTP's base rates

set in 1983. The result is that over 12 percent of OTP's increase in total fuel and purchased power costs (since 1983) for serving North Dakota customers are not recovered through the FCA.

Q. HAS OTP MADE MANAGEMENT OF INCREASED FUEL AND PURCHASED POWER COSTS A HIGH PRIORITY?

A. Yes. We made optimizing the output of our low-cost power plants one of our highest priorities to ensure that our low-cost power plants are running at optimal efficiency and available to the greatest extent possible. As described previously, OTP treats plant availability (keeping our power plants on-line to the greatest extent possible) as a "Key Performance Indicator." We also reduced energy costs by optimizing these plants' efficiencies. In these ways, we have kept the costs of operating these plants low.

Q. WHAT ARE SOME OF THE THINGS THAT OTP HAS DONE TO IMPROVE PLANT EFFICIENCY?

A. We undertook several projects in recent years to improve plant efficiency. At our Big Stone plant, the low pressure turbine rotor and the high/intermediate pressure turbine rotor were replaced in 1996 and 2005, respectively. Each of these replacements resulted in a 2 percent efficiency improvement. And while 2 percent may not seem like a large amount, it translates to about $900,000 of fuel costs saved each year based on current fuel prices. Big Stone also switched from lignite coal to sub-bituminous coal in 1995. This not only improved plant efficiency by 5 percent, it reduced sulfur dioxide emissions, reduced fuel prices, and reduced the number of planned outage hours. In 2003, Coyote, like Big Stone, replaced its low pressure rotor and saw similar efficiency improvements. In 2007, the Advanced Hybrid Particulate Collector ("AHPC") was replaced at the Big Stone Plant. The AHPC was a research project with the Department of Energy. Since its replacement, OTP compared operating data from the June through August 2005 time period with the June through August 2008 time period.

Average load is up 40 MWs. Opacity also showed significant improvement. These are just a few examples of projects that resulted in improved efficiencies. Many other operational improvements were made in this time-frame that also had positive results.

Q. HAS OTP DONE ANYTHING ELSE TO MANAGE THE COST OF FUEL USED TO OPERATE ITS POWER PLANTS?

A. Yes. Fuel price reductions and access to competition between Powder River Basin ("PRB") mines was one of the reasons behind the fuel switch at the Big Stone Plant in 1995. Switching from steel rail cars to aluminum rail cars also reduced the delivered cost of fuel at the Big Stone Plant. Fuel price reductions were also realized at the Hoot Lake Plant when it switched from lignite to PRB fuels in the late 1980s.

We actively sought legal relief from unfair fuel and transportation costs. For example, in 1996 we and the Coyote Station co-owners took the coal supplier for the Coyote Station to arbitration over the coal price paid for that plant. We achieved a successful outcome, which has paid significant dividends in lower fuel costs. The result allowed OTP to record a $1.9 million reduction in fuel costs during 2000 (due to overcharges in coal prices from 1996 - 1999). This reduction in fuel costs was returned to electric retail customers through the FCA.

Another example of our aggressive efforts to manage delivered fuel costs is the case we and the co-owners of the Big Stone Plant brought to the Surface Transportation Board seeking relief from the high tariff rates of the Burlington Northern and Santa Fe Railroad. The challenge was a significant undertaking, lasting about 48 months and costing nearly $4.5 million dollars in legal and expert fees. While the challenge was not successful, it has been recognized by OTP's customers and others as reflecting OTP's willingness to pursue aggressively lower fuel and transportation costs for the benefit of our customers.

Q. HAS OTP TAKEN ACTION TO MANAGE ITS LOAD?

A. Yes. We significantly increased our load management capabilities. Load management allows us to lower peak demands, thereby reducing the need to purchase energy during peak times, when energy prices in the real-time energy market are often the most expensive and volatile. As of 2007, more than 30 per cent of OTP's customers participate in some form of load management.

Q. PLEASE SUMMARIZE WHAT OTP HAS DONE TO MANAGE AND CONTAIN THESE RISING COSTS?

A. All these efforts—improving the efficiency of our plants, aggressively pursuing low fuel and transportation rates, switching some plants to sub-bituminous coal, replacing the AHPC system at Big Stone Plant, and mitigating purchased power costs through load management—have helped reduce the increases to the fuel and purchased power costs.

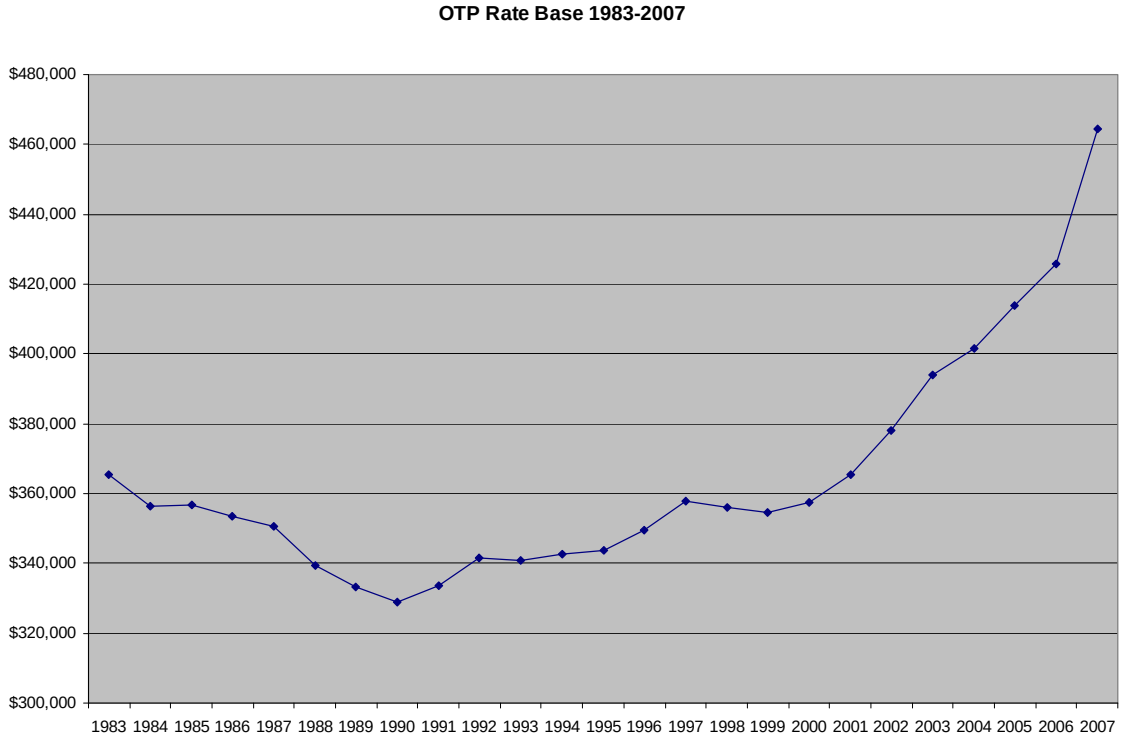
Q. HAVE OTHER FACTORS ASSISTED OTP IN DEFERRING THE NEED TO INCREASE RATES?

A. Yes. Our aggressive pursuit of opportunities to sell output from our generating plants into the wholesale energy markets (when not needed for our retail customers) has been instrumental in our ability to defer this rate increase. This has been a very important strategy for the benefit of our customers dating back to at least as early as 1986. This approach of selling wholesale generating plant output that was not needed to serve retail customers has helped to stabilize OTP's rates for the past 20 years. It is one of the reasons OTP did not request a rate increase sooner.

C. INVESTMENTS IN INFRASTRUCTURE

Q. PLEASE DESCRIBE SOME OF OTP'S INVESTMENTS IN INFRASTRUCTURE.

A. As further explained in Mr. Kyle Sem's testimony, OTP made significant investments in our transmission and power plants over the past 20 years. These infrastructure investments have resulted in an increase to our rate base. The below table shows how OTP's rate base has changed:



Q. IS OTP EXPECTING ADDITIONAL INFRASTRUCTURE INVESTMENTS IN THE FUTURE?

A. Yes. Like many other utilities, we are entering a period of unprecedented investment in infrastructure needed to reliably serve our customers. Our average investment in 2004-2006 was $30 million per year. In 2007, OTP's capital expenditures were $126 million. OTP's anticipated investments for the 5-year period of 2008 - 2012 are $880 million, an average of over $175 million per year.

Q. PLEASE DESCRIBE THESE ANTICIPATED INVESTMENTS.

A. These anticipated investments include $336 million for OTP's share of the Big Stone II project, $121 million for wind generation, and $67 million for CapX

2020 Transmission projects. Even if OTP's participation in Big Stone II were to change, a similar, if not costlier, base load generation investment would be needed. OTP has also actively pursued adding wind generation, including a significant wind generating facility near Langdon, North Dakota. OTP owns 40.5 MW, of that generating facility, at a cost of $80 million. OTP also owns 48 MW of the Ashtabula wind farm, with an anticipated cost of $121 million, and has announced plans to participate in the M-Power project by owning 49.5 MW for a total of 138 MW of wind generation located in North Dakota. OTP also has over 40 MW of wind generated PPAs located in North Dakota. In combination, these OTP investments in generation and transmission facilities are expected to reach $880 million by 2012.

Q. WHAT IS THE STATUS OF THE BIG STONE II PROJECT?

A. We have been working with the other project participants on the design and permitting for Big Stone II for several years. As of the date I am completing this testimony, several of the critical permits required for Big Stone II have been received, and two major permits are pending. The pending permits are the certificate of need for the necessary transmission lines, which is pending before the MPUC, and the air permit, which is pending before the South Dakota Department of Environment and Natural Resources. Until recently, the Big Stone II was contemplated to be a 630 MW project. Two project participants have withdrawn from ownership, although one participant has expressed interest in a power purchase arrangement. As a result, Big Stone II was reduced in size to 500 or 580 MWs.

Q. WOULD CHANGES IN BIG STONE II ELIMINATE OTP'S NEED FOR BASE LOAD CAPACITY?

A. No. Even if Big Stone II does not move forward, OTP still needs additional base load generation to reliably and economically serve our customers. If Big Stone II is not available to meet that need, an alternative base load generation resource will

be needed. It is our expectation that any alternative would have a higher levelized cost than Big Stone II, although the specific amounts and timing of investments may change.

Q. IS THIS RATE CASE IMPORTANT FOR OTP TO MEET ITS CAPITAL NEEDS FOR THESE ANTICPATED INVESTMENTS?

A. Yes. In order to complete these significant infrastructure additions, OTP will need access to unprecedented levels of debt and equity financing. It is essential that OTP be financially strong so that it can attract this capital on the most favorable terms possible. Mr. Kevin G. Moug also discusses OTP's capital needs and the importance of this case to meeting those needs.

IV. RATE DESIGN INITIATIVES

Q. IS OTP PROPOSING ANY RATE DESIGN INITIATIVES IN THIS CASE?

A. Yes. There have been dramatic changes in the industry since our last rate case and we are proposing two rate design changes that are driven by policy initiatives: 1) we propose that all usage rates be subject to the FCA; and 2) we propose that all declining block rates be eliminated.

Q. PLEASE DESCRIBE THESE PROPOSALS.

A. There are two policy-driven proposals that should be adopted.

1. *The FCA should be included in all OTP tariffs.* In an effort to better reflect the costs incurred in providing service to all our customers, we propose to apply our FCA to all our rates. As I explained earlier in my testimony, not all OTP rates are currently subject to a FCA. Recent industry discussions regarding conservation reveal that there are conservation benefits when customers receive more accurate price signals from their electricity providers so that they may make

informed decisions as to their consumption patterns. The lack of a FCA reflecting current fuel costs associated with some services means that customers taking those services have not received appropriate price signals indicating they should reduce consumption in this era of rising energy costs. Adding the FCA mechanism to these rates should improve the price signals being sent to these customers and should result in additional conservation. Mr. David Prazak more fully explains this proposal in his pre-filed Direct Testimony.

2. *Declining block rates should be eliminated.* We propose to eliminate our declining block rates. Declining block rates are usage-based rates that decrease as usage increases. Such rates are premised on the fact that rates recover both fixed and variable costs and, as usage increases, the fixed costs can be over recovered if the rate does not change (decline) with usage. Such rates, however, are disfavored because of the concern that such rates do not adequately promote conservation. Therefore, we propose eliminating our declining block rates. Mr. Prazak also more fully describes this proposal in his pre-filed Direct Testimony.

Q. HOW ARE FUEL AND PURCHASED ENERGY COSTS CURRENTLY RECOVERED IN CUSTOMER BILLS?

A. OTP's customers currently see two separate amounts on their bills that include some costs of fuel and purchased energy ("COE"). Customers' bills show a rate per kWh for each tariff under which they are billed. Included in that rate per kWh is the COE from OTP's last general rate case in 1983, sometimes referred to as the "base COE." The difference between the base COE and total COE in any given month appears in a separate charge or a credit on customers' bills, labeled as the "Energy Adjustment." Because COE is a large and volatile component of the costs included in electric rates, it may be helpful to show the COE as a single amount on customers' bills, rather than in two parts.

Q. IS OTP PROPOSING THAT CHANGE IN THIS CASE?

A. No. While we recognize the value of removing COE from the rate per kWh, combining it with the Energy Adjustment, and showing it in one line item on bills, OTP is not proposing that change in this case. We will continue to pursue the proper way to present the cost of fuel and purchased energy as one line item on customers' bills, with the goal to include such a proposal in OTP's next rate case.

V. INTRODUCTION OF WITNESSES

Q. PLEASE IDENTIFY THE WITNESSES OTP IS SPONSORING IN THIS PROCEEDING.

A. The following individuals will be sponsoring testimony in this proceeding:

- Bernadeen C. Brutlag addresses a proposed change in the jurisdictional allocation of accumulated depreciation, proposed changes in depreciation expense, the corporate allocations methodology and corporate cost allocation manual used to determine the revenue requirement, and OTP's economic development program.
- Peter J. Beithon addresses the jurisdictional cost of service study, the development of the test year operating statement with known and measurable and regulatory adjustments, the required financial schedules (developing and supporting the revenue requirement), OTP's proposed treatment of wholesale margins, the costs and benefits of belonging to MISO, the class cost of service study, and OTP's proposed class revenue allocation.
- Kyle Sem addresses the development of the test year rate base.
- Robert B. Hevert, of Concentric Energy Advisors, presents the recommendation regarding the appropriate ROE.
- Kevin G. Moug addresses capital structure, cost of debt and preferred stock and the overall cost of capital, which incorporates the ROE recommended by Mr. Hevert; a brief discussion of the proposed Holding Company; OTP's capital

investment plans; and a discussion of the sources of funding for OTP construction.

- Peter E. Wasberg addresses matters relating to employee compensation and costs.
- Hethie S. Parmesano, with NERA Economic Consulting, provides marginal cost support for our proposed rates and more specifically provides support for our proposed changes to declining block rates.
- David G. Prazak sponsors proposed rate design changes and general tariff changes and application of the FCA to all energy charges.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. As reflected in our Mission Statement, we take very seriously our responsibility to deliver electricity as reliably, economically and environmentally responsibly as possible and to improve the quality of life in the areas we serve. We have done a good job in fulfilling that mission. We wish that it were possible to continue those efforts without a rate increase, but it is not. We now require an overall revenue increase of 5.14 percent, or $6,084,003, based on the 2007 historical test year, with known and measurable changes, and including an overall rate of return of 8.89 percent. This increase is based in part on an authorized ROE of 11.25 percent and an equity ratio of 53.30 percent. OTP is also facing a growing need to invest in additional infrastructure in the next five years and will need to go to the market to raise additional capital. Consequently, we need to have reasonable earnings and a competitive ROE.

We propose to recover this revenue requirement through a rate design that reflects cost and non-cost factors as appropriate, and that reasonably encourages conservation. There have been dramatic changes in the industry since our last rate case. In recognition of those changes, we request that: 1) all usage rates be subject to the FCA; and 2) declining block rates be eliminated.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application by Otter Tail Corporation d/b/a Otter Tail Power Company, for Authority to Increase Rates for Electric Utility Service in North Dakota	))))	Case No. PU-08-____

AFFIDAVIT OF THOMAS R. BRAUSE

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Thomas R. Brause

Subscribed and sworn to before me,
this 23rd day of October, 2008.

Penny Mosher
NOTARY PUBLIC

PENNY MOSHER
Notary Public
Minnesota
My Commission Expires January 31, 2010

Mr. Thomas R. Brause
Vice President Administration
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8525

CURRENT RESPONSIBILITIES (2004 – Present)

Provide direction of Otter Tail Power Company's Market Planning, Policy and Compliance, Regulatory Services and Information Technology areas.

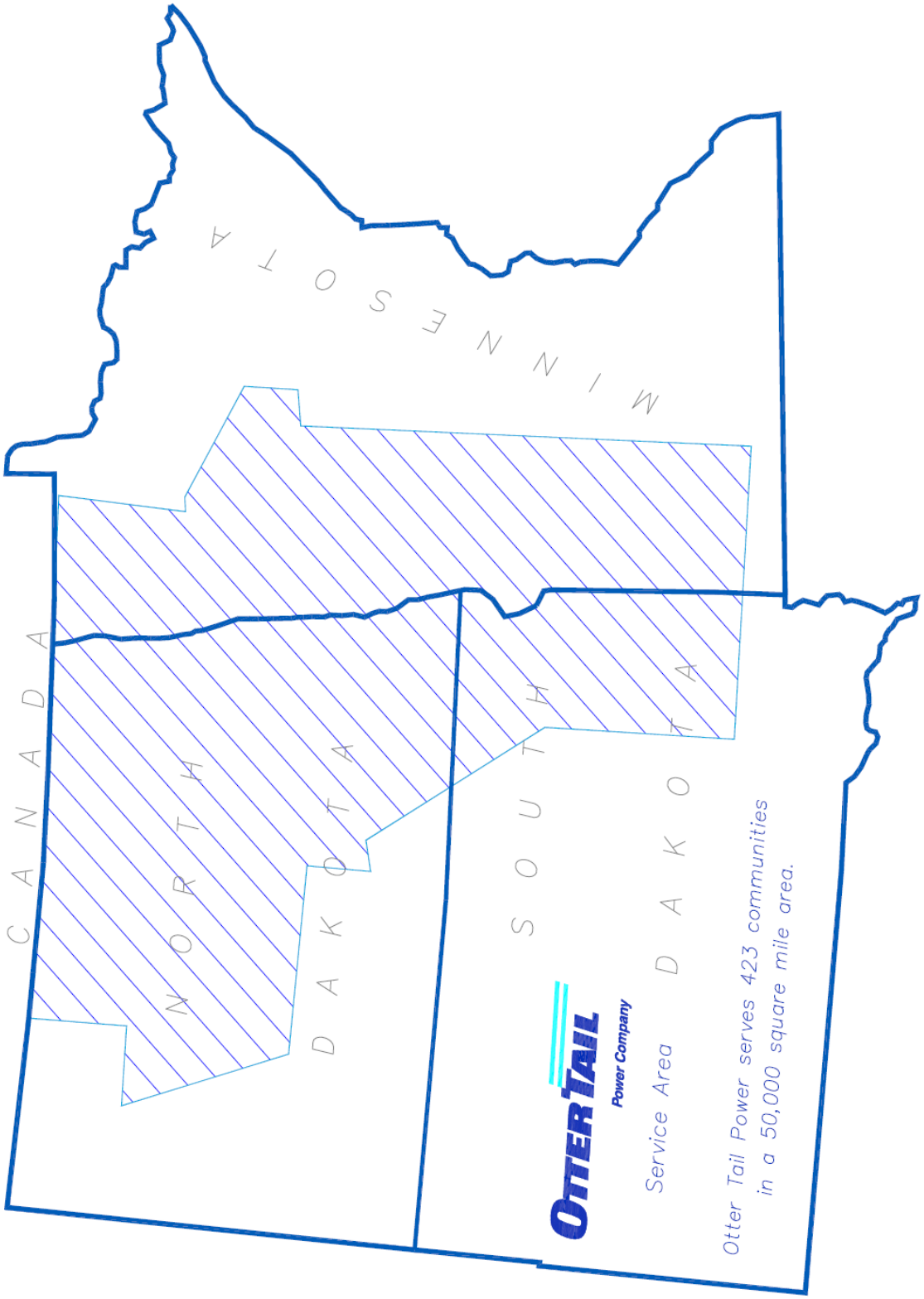
PREVIOUS POSITIONS

Otter Tail Power Company

2004 – Present	Vice President Administration
2002-2004	Director Human Resources, Information Technology and Safety
1999-2002	Director Human Resources and Information Technology
1995-1999	Director Information Services
1988-1995	Manager Information Systems
1986-1988	Supervisor Information Systems
1984-1986	Supervising Analyst, Load Management Computer Systems
1982-1984	Programmer/Analyst
1978-1982	Programmer

EDUCATION

Moorhead State University – BA, Computer Science, minor in Mathematics


MINNESOTA
CANADA
NORTH DAKOTA
SOUTH DAKOTA
OTTER TAIL
Power Company
Service Area
Otter Tail Power serves 423 communities
in a 50,000 square mile area.

Volume 2A

Testimony and Schedules of Witnesses:

Peter Beithon

Jurisdictional Cost of Service
Operating Statement
Class Cost of Service

Before the North Dakota Public Service Commission
State of North 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 North Dakota

Case No. PU-08-_____

Exhibit___

JURISDICTIONAL COST OF SERVICE, OPERATING STATEMENT, CLASS COST OF SERVICE

Direct Testimony and Exhibit of

PETER J. BEITHON

November 3, 2008

TABLE OF CONTENTS

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 $6,084,003 or 5.14%. 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) test year revenues; (ii) our proposal for addressing wholesale margins; (iii) the known and measurable adjustments to 2007 actuals to make the test year representative; (iv) expense categories not in the 2007 actuals, (iv) the recovery of Midwest Independent Transmission System Operator (MISO) costs; (vi) the proposed traditional regulatory adjustments; (vii) a customer class cost of service study; and (viii) the Company's proposal for class revenue allocations.

Q. WHAT SCHEDULES ARE YOU SPONSORING?

A. The following schedules are attached to my testimony:

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 NORTH 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 OF OPERATING STATEMENT, PROPOSED RATES TO PRESENT RATES

Exhibit ___(PJB-1), Schedule 10 CLASS COST OF SERVICE STUDY

Exhibit ___(PJB-1), Schedules 11 A & B ALLOCATION SCHEDULES AND MANUAL

Exhibit ___(PJB-1), Schedule 12 ANALYSIS OF IMPACTS OF MISO ANCILLARY SERVICES MARKET

Exhibit ___(PJB-1), Schedule 13 CAPACITY COST SAVINGS ESTIMATE FOR 2007

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 24 years ago (Case No. 10,334 had a 1983 test year), 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 with a compared to the current test year. The most significant increases driving the revenue deficiency are: a 130 percent increase in North Dakota non-fuel operating and maintenance costs, which is a 5.40 percent annual increase using a simple average over 24 years; and a 151 percent increase in North Dakota fuel and purchased power costs, a portion of which are not currently recovered through the Fuel Clause Adjustment (FCA) (as further described below). To put those increases in

perspective, inflation for the same period was 208 percent[1]. Revenues over the same period have only increased 96 percent.

II. FINANCIAL INFORMATION PROVIDED

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 appropriate ratemaking adjustments. The most recent fiscal year is the 2007 calendar year.

Q. PLEASE OUTLINE THE FINANCIAL DATA PROVIDED.

A. Following the North Dakota filing requirements where a historical test year is used, 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 same rate base components (provided by Mr. Sem) as are used in the test year, unadjusted operating income, overall rate of return, the calculation of required income, the income deficiency and revenue requirements. Separate rate base and income statement bridge schedules that identify test period adjustments are provided by Mr. Sem (rate base) and myself (operating statement). Mr. David Prazak provides the schedules showing the rate impacts from my proposed class revenue allocations and his proposed rate design.

Q. PLEASE OUTLINE THE CONCLUSIONS REACHED AS A RESULT OF YOUR 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 6.91 percent rate of return on average rate base in the test year. This is

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

significantly below the 8.89 percent 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 $6,084,003 or about 5.14 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 YOU ARE SPONSORING.

A. The financial information is broken down into nine schedules, Exhibits__(PJB-1), Schedules 1 through 9. I will discuss each schedule in more detail as we examine it.

Q. PLEASE DESCRIBE EXHIBIT__(PJB-1), SCHEDULE 1.

A. Exhibit__(PJB-1), Schedule 1 shows both Actual Year information and 2007 Test Year information. Since the request is based on test year information, I will focus on the Test Year information. Line 1 shows the Test Year average rate base of $187,173,203. Line 2 shows the total Test Year available for return, the operating income, of $12,942,144. The total available for return is at present revenue levels. Line 5 shows the overall rate of return of 6.91 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 amount OTP would be allowed to earn with the requested rate increase. Line 7 shows the required operating income of $16,639,698 which is determined by multiplying the required rate of return times the rate base. This translates into an income deficiency of $3,697,554, as 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 North Dakota, which, on an annual basis, is $6,084,003 (Line 10). The calculation of the gross revenue conversion factor is provided in Exhibit__(PJB-1), Schedule 7.

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

A. Exhibit__(PJB-1), Schedule 2 is the adjusted operating income summary of OTP, as allocated to North Dakota, for the 2007 Actual Year and the 2007 Test Year. The electric revenues consist of revenues from sales of electricity to OTP's North Dakota customers under rate schedules presently on file with the Commission. To this revenue has been added North 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 IS SHOWN ON EXHIBIT_(PJB-1), SCHEDULE 3 AND SCHEDULE 8?

A. Exhibit __(PJB-1) Schedule 3 is the ND Jurisdiction Operating Income Statement Schedule that summarizes the Actual Year 2007 total company Operating Income Statement, the Actual Year 2007 unadjusted ND Jurisdiction Operating Income Statement and reflects the adjustments made to the Actual Year to get to the proposed ND Jurisdiction Test Year Operating Income Statement. Exhibit__(PJB-1), Schedule 8 details the adjustments made on ND Jurisdiction Operating Income Statement 3

Q. IS THE DEVELOPMENT OF THE INCOME TAXES AND INCOME TAX RATES INCLUDED IN THIS FILING?

A. Yes. The computation of the federal and state income tax rates is included in Exhibit__(PJB-1), Schedule 4; Exhibit__(PJB-1), Schedule 5, is the computation of the deferred income taxes; and Exhibit__(PJB-1), Schedule 6, is the development of the federal and state income tax rates.

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, and is included in Volume 4A as part of the Work Papers. This study determines what portion of the total company costs and revenues should be recognized in determining a North Dakota revenue requirement.

Q WHY IS A JURISDICTIONAL COST OF SERVICE STUDY NECESSARY?

A. OTP serves retail customers in North Dakota, Minnesota, and South Dakota. 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 North Dakota customers.

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

A. The allocation procedures used by OTP were approved by the Commission in our last rate case, Case 10,334. Since that time we have added an energy factor that recognizes controlled service and a customer load management factor that allocates the costs of load management. We also discontinued use of the P50 transmission factor in favor of using the more appropriate D2 demand factor. The N50, N60, N70 and N90 factors have also been discontinued for allocating Construction Work in Progress (CWIP) due to use of the more appropriately matched P factors that have always been used to allocate plant in service and accumulated depreciation. I discuss these changes in more detail later in my

testimony. These allocation factors were used in the calculation of revenue requirements for all North Dakota settlements resulting from earnings reviews in the past 20 years. The current allocations also were approved in Minnesota in 1986 in MN Docket E-017/GR-86-380 and again in MN Docket E-017/GR-07-1178. For the current case, we made one additional modification to the allocation of depreciation procedures that Ms. Brutlag discusses in her testimony. This adjustment was $268,864 and is included in my Schedule 8, column H.

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) as required by North Dakota Rule 69-09-05.1-03.

Q. PLEASE EXPLAIN THE PROCESS FOR ASSIGNING OTP'S INVESTMENT IN AND EXPENSES RELATED TO ELECTRIC PLANT TO THE NORTH 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 11 B, 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 North Dakota, Minnesota, and South Dakota 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 North Dakota retail customers, it is necessary to assign or allocate the appropriate amount of the total production, transmission and distribution investment and expense to each jurisdiction.

Q. HOW WERE THE OTP ELECTRIC PRODUCTION AND TRANSMISSION SYSTEM INVESTMENT AND EXPENSE AMOUNTS ALLOCATED TO THE NORTH 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) based on their allegation that the lower voltage transmission facilities serve a localized function. OTP witness in that proceeding, Mr. Timothy Rogelstad, conducted a study, which included FERC's 7-Factor Test, 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 North Dakota revenue requirement would have increased by approximately $2.6 million or a 2.20 percent increase in addition to the 5.14 percent increase OTP is requesting.

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

A. In contrast to production and transmission allocations, which are allocated 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 with greater detail in OTP's cost allocation procedures for the JCOSS provided in Exhibit__PJB-1, Schedule 11 B and in Exhibit ___PJB-1, Schedule 10 CLASS COST OF SERVICE STUDY.

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 with the adjustments identified on Exhibit__(PJB-1), Schedule 8. I explain below several aspects of these revenues and expenses, including each of the adjustments I have made.

A. TEST YEAR REVENUES

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

A. The purpose of this section is to describe retail revenues and 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. The adjustment to calendar month is made in the Actual Year 2007 which is used for annual reporting in North Dakota. For 2007, this net calculation increased revenues by just over two hundred thousand dollars.

Q. HAVE THE 2007 ACTUAL YEAR RETAIL REVENUES BEEN ADJUSTED TO ARRIVE AT THE TEST YEAR REVENUES?

A. Yes, they have. Retail revenues have been adjusted for 1) MISO Schedules 16 and 17 revenue to comply with the settlement in Case No. 05-131 (MISO Day 2), 2), new load related to a large ethanol plant going into service in 2008, and 3) inter-year billing adjustments. These adjustments are included in my Schedule 8, providing the adjustments to the Operating Income Statement

Q. DID OTP ADJUST THE 2007 REVENUES TO REFLECT NORMAL WEATHER?

A. No. It was not necessary because 2007 was about as typical a weather year as is possible to occur. There were 8,961 heating degree days (HDD) versus 8,943 HDD in a typical year. That means that 2007 was only 0.2 percent above normal HDD. There were 482 cooling degree days (CDD) versus the annual average of 490 CDD. This equates to 98 percent of the annual average CDD. Even though we determined that making an adjustment would not be cost effective (especially for ratepayers), we did calculate the amount of the adjustment if it were to be made. When we calculated the weather normalization, the impact was a decrease in revenues of only $52,053. After applying the related fuel expense decrease, the net impact increased revenue requirements by only $3,614. A weather normalization adjustment to revenue and expense affects several aspects of revenue requirements, allocations, and rate design. Expenses are close to the revenue amount because most of the sales adjusted were heating loads on interruptible rates, which provide revenues that are close to or less than the average cost of energy. Note that we are proposing to correct this imbalance in cost recovery through our proposal to increase the controlled service rates by just over 60%.

Support for the weather normalization calculation may require an additional expert witness. Therefore, OTP has elected not to make a test year adjustment for weather normalization.

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION METHODOLOGY.

A OTP's weather normalization process was developed in cooperation with Christensen Associates of Madison, Wisconsin.

OTP's weather normalization process involves collection of more than 15 years of OTP hourly weather data, monthly revenue, and monthly kWh sales data. A statistical regression procedure is used to determine weather normalization models for each of 40 separate rate groups within each of OTP's three states.

Variables used include kWh/day, revenue/day, heating and cooling degree days/day, the number of months since January 1990, and up to 13 autoregressive terms. The results are checked for accuracy and reasonableness using graphs and reports. Weather normalized sales (kWh) and revenue are then produced on both a billing month and a calendar month basis. The revenue used does not include the fuel clause adjustment (FCA). Consequently, to include the impact of weather normalization on the FCA, weather normalized sales (kWh) are multiplied by the appropriate total cost of energy rate (which includes the FCA rate) for each of the twelve months to determine the fuel and purchased power costs. In addition, FCA revenues are calculated by multiplying the appropriate monthly FCA rate by the change in kWh due to weather normalization.

Q. HAVE YOU MADE ANY ADJUSTMENTS TO REVENUES RELATED TO MISO SCHEDULES 16 AND 17, AND IF SO WHY?

A. Yes. MISO Schedules 16 and 17 are rates charged to OTP by MISO as authorized by the FERC. They allow MISO to recover its cost of administering the Day 2 energy market. Essentially, the MISO Day 2 energy market is the process under which MISO matches its members' available generation with the demand for generation. Because Schedule 16 and 17 charges are related to the cost of acquiring generation, we and the other North Dakota utilities initially recovered these costs through our FCA pursuant to the Commission's interim order in Case No. 05-131. OTP entered into a settlement of the issues in that case that required OTP to refund Schedule 16 and 17 costs that it had recovered through the cost of energy adjustment clause (generally referred to as FCA), and defer those costs for base-rate recovery in this general rate case. Pursuant to that settlement, OTP refunded the amounts previously collected in the FCA beginning with the FCA effective on October 1, 2007. Therefore, I made an adjustment (increase to North Dakota retail revenues) of $644,731 to offset the decrease in revenues created by the refund of Schedule 16 and 17 costs for periods prior to

the 2007 Test Year. Later in my testimony I make an expense adjustment to recover the deferred MISO 16 and 17 costs.

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

A. Yes. I increased North Dakota retail revenue by $309,796 to recognize billing corrections related to 2007 but made after the close of books for 2007. These are identified in Schedule 8 as Inter-Year Billing Adjustments.

Q. WHY IS THE ADJUSTMENT FOR BILLING ADJUSTMENTS MADE AFTER BOOKS CLOSED APPROPRIATE?

A. Making the adjustment for billing adjustments is necessary to match revenues to services provided (the same as the unbilled revenue adjustment discussed earlier), and it affects the billing determinants used in rate design.

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. North Dakota other electric revenues have increased $10.1 million since 1983 (278 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 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 and 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 Schedule 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.

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 1982, and therefore they have resulted in an increase in OTP's other electric revenues since that time. $380,982 of North Dakota other revenue related to these activities was included in the test year.

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)

North Dakota's share of revenue received from MISO in 2007 was $927,299. In 2007 OTP also received MAPP transmission revenue. North Dakota's share of the MAPP revenue was $10,585. These revenues are reflected in OTP's Other Electric Revenue account, which is detailed at a system level in Volume 4A, Work Papers (Work Paper B-3).

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

A. OTP has two separate 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.

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.

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. 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: North Dakota's share of revenues received in 2007 was $1,535,611.

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 $147,987 (total system) of additional 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 near Big Stone, South Dakota. The sale of steam contributed $957,260 to North Dakota miscellaneous revenues in the 2007 Test Year (adjusted for an increase in revenue of $189,857 that became effective in 2008). I recognize this additional revenue as a revenue adjustment in my Schedule 8, Column C. The costs of coal for this customer are not part of retail fuel costs.

Q. HAVE ANY ADJUSTMENTS BEEN MADE TO REVENUE TO REFLECT THE ADDITION OF NEW LOADS THAT ARE KNOWN AND MEASURABLE?

A. Yes. A new large industrial load is expected to come on line in 2008. The estimated annual revenues for that load are $8,882,240. I recognize this additional revenue as a revenue adjustment in my Schedule 8, Column B.

B. WHOLESALE MARGINS

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 and are included in the 2007 Test Year. Item 8 of the settlement agreement in Case No. PU-05-131 stated: "Otter Tail shall address wholesale revenue margin sharing issues in its next rate case, which shall be filed no later than November 1, 2008 … In its rate case filing, Otter Tail shall either propose a mechanism to credit asset-based wholesale margins through its fuel cause, like the mechanism and percentage approved for asset-based margins for Xcel energy in its most recent Minnesota Rate Case, Docket No. E-002/GR-05-1428, or explain why such a mechanism should not be adopted. Interim rates shall be established using the same sharing mechanism proposed by Otter Tail for establishing final rates."

When OTP filed its recent Minnesota rate case (Docket E017/GR-07-1178) we proposed flowing asset-based margins through the fuel clause like Xcel Energy did in the case referenced in the settlement agreement. However, the

Minnesota Office of Energy Security (OES) and the Minnesota Office of Attorney General (OAG) opposed OTP's proposal. The OES and OAG preferred to set a revenue credit and place the risk of future decreased asset-based margins on OTP instead of its ratepayers. The Minnesota Chamber of Commerce preferred using a credit to the fuel clause adjustment. The Minnesota Public Utilities Commission (MPUC) approved a fixed credit to the base rate revenue requirement.

Q. WHY SHOULD ASSET-BASED WHOLESALE MARGINS BE CREDITED TO THE BASE RATE REVENUE REQUIREMENT RATHER THAN TO THE FCA?

A. Historically, the revenues and expenses related to asset-based transactions have been included in the base-rate retail revenue requirement calculation. The 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. This proposal is discussed in more detail later in my testimony. These 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. Because asset-based margins have been relatively consistent, we used a five-year average. More specifically, we used the average for the period 2003 through

2007. Based on this calculation, OTP recommends replacing the amount of credit in the 2007 Actual Year with a credit to the base rate revenue requirement of $4.133 million. The following chart shows the margins received in each year:

2003	3.511 million
2004	3.415 million
2005	$4.746 million
2006	$4.531 million
2007	$4.462 million

Asset-based margin activity in 2008 is on track to be similar to 2006 and 2007. I recognize this revenue adjustment of $328,687 (this is the net adjustment for revenue and expense) in my Schedule 8, Column E.

Q. DOES OTP'S PROPOSAL TO PAY 15 PERCENT OF NON-ASSET BASED MARGINS THROUGH THE FCA AFFECT RETAIL REVENUE REQUIREMENTS IN THIS CASE?

A. No. The amount of asset-based margins credited to the FCA does not affect retail revenue requirements for setting base rates because it is a credit to fuel and purchased power costs. However, OTP has made an expense adjustment related to this proposal that does have a revenue requirements impact. This adjustment is discussed in "Expense Adjustment" section of my testimony,

Q. HOW DOES OTP'S PROPOSAL TO CREDIT TO THE FCA A PORTION OF ITS NON-ASSET BASED WHOLESALE MARGINS COMPARE TO WHAT XCEL ENERGY HAS PROPOSED IN CASE NO. PU-07-776?

A. OTP is proposing the same mechanism that Xcel Energy proposed in its current rate case, Case No. PU-07-776.

Q. PLEASE EXPLAIN THE CREDITING MECHANISM THAT THE XCEL PROPOSED IN CASE NO. PU-07-776 .

A. Xcel proposed to flow a portion of its non-asset based margins through its fuel clause adjustment, subject to the additional requirement that no annual losses be passed on to customers. Since this trading activity is done by utility personnel, the purpose of this payment is to compensate retail ratepayers for an appropriate amount of labor and systems costs associated with conducting non-asset based transactions. Without non-asset based transactions, OTP's labor and system costs would still exist. OTP's proposal reduces the expenses that would otherwise be used to calculate the rates.

Q. PLEASE EXPLAIN OTP'S PROPOSAL.

A. Our proposal is the same as Xcel Energy has proposed in its current North Dakota rate case, except that our credit will result in a larger dollar credit per customer.

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.

Q. PLEASE EXPLAIN WHY OTP'S PROPOSAL RESULTS IN A LARGER CREDIT TO YOUR CUSTOMERS THAN THE ONE PROPOSED FOR XCEL.

A. OTP has generally had significantly larger non-asset based margins for its size than Xcel. Therefore, a much larger dollar amount is credited to our customers under our proposal even though the proposed percentage is the same. Based on 2007 reported actual margins, at 15 percent, Xcel Energy would provide on average an FCA credit of $0.45 per customer. For the same period, under OTP's proposed 15 percent credit, OTP customers would have received on average $5.16, or almost 11.5 times the amount credited to Xcel customers.

Table 1, below, compares the relative customer benefit under Xcel's credits ($0.45 total) and OTP's proposed credits ($5.16 total).

Table 1

	Xcel ND	OTP ND
ND Share of Non-Asset Based Sales	$260,000	$ 1,957,781
Percent proposed to share	15%	15%
Amount expected to share	$39,000	$293,667
Number of North Dakota Customers	86,209	56,936
Share per customer (annual)	$ 0.45	$ 5.16

Q. HOW DID OTP ACCOUNT FOR NON-ASSET BASED WHOLESALE MARGINS IN 2007?

A. In 2007, OTP accounted for revenues relating to non-asset related trading activities below the line. OTP also allocated below the line a portion of its wholesale trading department's labor and general costs. The allocation of these labor and general costs was based on the volume of sales. Non-asset wholesale sales as a percent of total sales (retail, asset-based wholesale, and non-asset wholesale) was calculated and applied to the labor and general costs. 45 percent of total MWH sales were from non-asset based transactions and 4.5 percent of total MWH sales were from asset based sales, To put the use of MHW volumes in perspective, there were 2.25 times as many margins from asset based sales as non-asset based sales even though the non-asset based MWH sales volumes were 7.7 times larger than the asset based sales volumes. In 2007, the amount removed from North Dakota regulated operations was $674,590. When this volumetric allocation method was initially developed several years ago, it was done because it was simple and appeared to be reasonable at that time. However, when determining rates for a number of years going forward it is critical that we utilize a method (percent of margins) that doesn't lock in a fixed amount of credit for this unregulated and risky activity that could produce widely varying levels of margins or be discontinued completely. In addition, to the extent volumes may

once have been a reasonable allocation methodology, changes in the market make volumes no longer representative of cost. In the past few years, the trend for non-asset based wholesale sales has been that overall volumes have increased while per-transaction margins have decreased. Put another way, the margins per MWH traded has continually declined. Therefore, basing the allocation of labor and general costs on sales volumes would result in an allocation to non-asset activities that it disproportionate and unreasonable.

Q. WOULD A VARIANCE TO THE COMMISSION'S FUEL CLAUSE RULES BE REQUIRED FOR YOUR MARGIN-SHARING PROPOSAL FOR NON-ASSET-BASED TRADING MARGINS?

A. No, I don't believe so. N.D. Admin. Rules 69-09-02-39, grants the Commission the authority to modify the standards for determining fuel costs and sales for good cause shown. Based on the above discussion, good cause has been shown for allowing the flow through of the non-asset based wholesale margins using the fuel clause mechanisms.

Q. WOULD A TARIFF CHANGE BE REQUIRED?

A. Yes. The Energy Adjustment Rider sponsored by Mr. Prazak has been revised to provide for the treatment of these margins through the FCA.

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 $33.5 million (a simple annual average of 5.4 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 24 years of wage increases. Our production cost increase includes cost of purchased capacity, which has increased by approximately $4.4 million since 1983, reflecting the growth in system demand caused by our customers' increasing energy requirements. The remainder of production costs (not including fuel and purchased energy) increased approximately $33.5 million or 130 percent over this period (5.4 percent annually). The transmission function has experienced significant cost increases, roughly $3.4 million since 1983 (13 percent annualized). All dollar amounts listed in this answer are North 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 NORTH 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 6 percent per year. These increases have been driven partially by increases in the cost of labor and benefits. Customer service expenses

have risen due to increased spending in the 2007 Test Year to implement new energy efficiency programs as a result of the Commission's Order in the Big Stone II Advance Determination of Prudence, Case No. PU-06-481. Other expense categories have large percentage increases but the dollar amounts are not significant.

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

A. Ms. Brutlag's 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 increasing 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 because its three diesel units are also 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 economically and environmentally) when needed. Their reliability will be especially important as a result of the need to support the intermittency of the 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. In addition, as discussed by Ms. Brutlag, OTP's

Corporate Cost Allocation Manual (CAM) is designed to prevent any cross subsidization of Otter Tail Corporation costs.

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 federal and North Dakota state 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 case.

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), Schedule 4.

Q. IS OTP INCLUDED IN CONSOLIDATED FEDERAL INCOME TAX RETURNS AND CONSOLIDATED, UNITARY TAX RETURNS IN NORTH DAKOTA?

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 and the consolidated, unitary tax return in North Dakota 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.

D. EXPENSE ADJUSTMENTS

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

A 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 SHOWING THE ADJUSTMENTS YOU MADE TO THE TEST YEAR.

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. That schedule also identifies the impact each adjustment has on the operating income statement. The known and measurable changes all occur within 12 months of the filing date of this request for rate increase, as provided in NDCC § 49-05-04.1(4). 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 North 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 North Dakota depreciation expense by $197,047 to arrive at the Test Year amount. See Column J 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 reflect a five-year average payout for incentive payments. The second change is to remove any management or key performance incentive pay amounts in excess of 25 percent of individual base pay. Combined these adjustments increases North Dakota expenses by $61,058 (Column (N), of Schedule 8).

(c) Medical, Post Retirement Medical and Pension

Q. WHAT IS FAS 106, AND HOW HAS OTP IMPLEMENTED IT?

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 recorded amount is the current period expense for future postretirement 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 postretirement 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. 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 ($1,678,516 is the North Dakota share) which will be amortized over the remaining five-year transition period, resulting in an annual amortization expense for North Dakota of $335,703.

Q. WHAT IS THE TEST YEAR FAS 106 EXPENSE?

A. The annual Test Year FAS 106 expense for North Dakota is $1,211,839, 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 North Dakota allocated FAS 106 transition obligation balance of $1,678,516 by crediting prepayments and debiting other comprehensive income. The annual expense was not affected by this change in accounting. An adjustment was made to reverse the FAS 158 prepayments balance (rate base) 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 WAS THE AMOUNT OF OTHER POST EMPLOYMENT BENEFIT (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 40.9% percent allocated to the North Dakota jurisdiction (using the labor and related expense allocator).

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 $4.6 million on a North Dakota basis.

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. OTP's position was outlined in a position paper submitted to the Commission on July 28, 1995.

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 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 cost (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 the 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, discussed 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 2 provides a comparison of the differences between the 2007 and 2008 projected expense levels on a total utility basis:

Table 2

EXPENSE CATEGORY	2007	2008	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 change in expense. Our pension costs are decreasing in 2008 as determined by our actuary Mercer and are a known and measurable change in expense. Just as our FAS 106 costs are increasing so too are our medical costs for 2008. The increase in medical costs is based on an estimate using actual costs through June 2008 and forecast amounts for the balance of 2008. Therefore, I have made a known and measurable adjustment of $125,829 to North Dakota's share of expenses to reflect the 1.9 percent net increase in these expenses. The net adjustment of $125,829 is the combination of an increase of $541,657 in Medical/Dental expense (Schedule 8, Column K), an increase of $160,038 in FAS 106 and FAS 112 (Schedule 8, Column M) benefits and a decrease of $575,861 in FAS 87/Pension costs (Schedule 8, Column L.

(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 increases in union wages and an increase in non-union wages that occurred after the 2007 Actual Year. The North Dakota Share of this adjustment is $1,317,578 (Schedule 8, Column O).

(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 2007 ACTUAL 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 that extended into December 2007 was not anticipated. I have removed the increased cost for purchased energy during December. The adjustment amounts to a decrease in North Dakota production expense of $2,949,824 (Schedule 8, Column Q).

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

A. Yes. To account for the addition of a new large load (an ethanol plant near Casselton) in North Dakota, I increased production expense for the required demand and energy costs to serve this load. The adjustment to North Dakota production expense is $3,004,397 (Schedule 8, Column B).

Q. DOES THE ADDITION OF THE NEW LARGE LOAD IN NORTH DAKOTA REQUIRE ANY OTHER ADJUSTMENTS?

A. Yes. Demand and Energy jurisdictional and class allocation factors were updated for this large load addition, as well as revenues, as discussed earlier. For this large load addition, the allocation factors for energy and demand were updated to include the impacts of this load which shifts the overall burden back to North Dakota where the revenues are. As shown on Schedule 8, Column S, the factor

change has a net impact of decreasing net operating income of $3,706,604. The net impact of increased revenue and production expense as discussed earlier was an increase to operating income of $5,877,843 (Schedule 8, Column B). In addition there are impacts on rate base which result in an increase to revenue requirements of $1,021,461. The net impact of the new large customer is $1.2 million ($5,877,843-$3,706,604-$1,021,461) positive impact before taxes or approximately a $740,000 positive impact after taxes (reduction in revenue requirements).

(2) Expense categories not included in the 2007 Actual Year

(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. The Commission has quite predictable rate case expenses passed on to the utilities. The consulting fees and outside legal fees estimates were provided by the people providing those services.

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

A. I used a three-year amortization period, which results in an annual expense of $166,667 (Schedule 8, Column W). 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 $55,383 related to legal expenses incurred to form the holding company structure (Schedule 8, Column Y). This is the annual North 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. The Commission approved this reorganization in its Order dated 10-8-2008 in Case No. PU-08-292.

(c) MISO Costs

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

A. I will discuss the nature of the test year adjustments for MISO costs I am proposing. In addition, I will provide a cost/benefit analysis of MISO's Schedule 10 (Day 1) expenses; and, in accordance with the settlement in Commission Case No. PU-05-131 July 12, 2007, I will explain that Schedule 16 and 17 (Day 2) expenses were prudently incurred, reasonable, resulted in benefits justifying recovery and were not recovered through other rates.

Q. WHAT MISO CHARGES IS OTP SEEKING TO RECOVER IN THE TEST YEAR?

A. There are three MISO charges that OTP has included in its test year. The first is the Day 1, Schedule 10, charges. The second is the deferred Day 2 Schedules 16 and 17 charges, amortized over a three year period. The third is the ongoing annual Schedule 16 and 17 charges. With respect to Day 1, approval would allow recovery of $324,217 for the North Dakota jurisdictional share of 2007 MISO Schedule 10 charges. With respect to Day 2, the North Dakota jurisdictional share for the annual amortization of deferred Schedule 16 and 17 charges in the Test Year is $309,019 and the North Dakota share of ongoing annual Schedules

16 and 17 charges for the Test Year is. $256,990 (Schedule 8, Column G). See my Schedule 8, Column F, where I show an increase to North Dakota expenses of $309,019 to amortize the deferred Schedule 16 and 17 expenses and $256,990 to include the current year Schedule 16 and 17 expenses in base rates(Schedule 8, Column G). The MISO Day 2 settlement allowed OTP to defer those costs and to seek recovery beginning with interim rates in OTP's next rate case.

MISO DAY 1 costs—Schedule 10

Q. PLEASE EXPLAIN THE PURPOSE OF THE MISO'S SCHEDULE 10 CHARGES ASSESSED TO OTP.

A. Schedule 10 is the MISO's "ISO Cost Recovery Adder." This is a FERC-approved tariff schedule administered by MISO to recover its costs for administering the ISO. These charges are assessed to all applicable transmission customers and transmission owners subject to MISO's Open Access Transmission and Energy Markets Tariff ("TEMT") for purposes of allocating MISO's administrative costs to all load under its TEMT.

Q. PLEASE PROVIDE EXAMPLES OF THE SERVICES THAT MISO PROVIDES THAT ARE INCLUDED IN THE SCHEDULE 10 ASSESSMENT.

A. MISO Schedule 10 charges recover MISO's costs associated with operating the ISO, which include MISO deferred pre-operating costs; the costs associated with building and operating the Security Center, including capital costs and operating expenses; and costs associated with administering the Tariff. There are four broad categories of services included in the MISO Schedule 10 fee including (1) tariff administration, (2) business services, (3) reliability services, and (4) other services.

Q. PLEASE PROVIDE AN EXAMPLE OF THE TARIFF ADMINISTRATION SERVICES PROVIDED BY MISO AND INCLUDED IN THE SCHEDULE 10 CHARGE.

A. Examples of the tariff administration services provided by MISO include services such as administering the TEMT, evaluating and approving transmission service requests, calculating available transfer capability ("ATC"), administration of the Open Access Same-time Information System ("OASIS") including issuing and administering security certificates, supporting the hardware and software needed for tariff administration, and archiving information.

Q. PLEASE PROVIDE AN EXAMPLE OF BUSINESS SERVICES PROVIDED BY MISO AND INCLUDED IN THE SCHEDULE 10 CHARGE.

A. The business services provided by MISO to its customers include administering billing and settlements, and dispute resolution.

Q. PLEASE PROVIDE AN EXAMPLE OF THE RELIABILITY SERVICES PROVIDED BY MISO AND INCLUDED IN THE SCHEDULE 10 CHARGE.

A. MISO provides reliability services that include system monitoring, security assessment, coordination of power system modeling, outage maintenance coordination, information exchange and sharing, and operating procedure coordination. Additionally, the reliability services include security coordination within the Midwest region as well as with neighboring regions. MISO also provides for the coordination of long-term transmission planning within the region and with neighboring regions by coordinating transmission system needs, expansion alternatives and development plans, publishing regional integrated transmission development plans, identifying and processing new transmission facilities, and developing a common set of policies to process applications and access of new generation. Also included in this subset of services included in MISO Schedule 10 RTO Administrative Adder are the congestion management services applicable to intra-regional and inter-regional scope and activities.

Q. PLEASE PROVIDE AN EXAMPLE OF THE OTHER SERVICES PROVIDED BY MISO AND INCLUDED IN THE SCHEDULE 10 CHARGE.

A. Examples of the other RTO services that MISO encompasses under its Schedule 10 ISO Cost Recovery Adder include its electronic scheduling/energy losses, operations planning, maintenance coordination and market monitoring.

Q. HOW IS THE SCHEDULE 10 CHARGE ASSESSED?

A. MISO has a formula rate schedule to recover its Schedule 10 costs. The Schedule 10 charge is comprised of two rates, a "Reserved Capacity Rate" and an "Energy Rate." The Reserved Capacity Rate is multiplied by billing units of Reserved Capacity, and the Energy Rate is multiplied by billing units of MWhs of scheduled energy. MISO determines the dollar target for recovery under the ISO Cost Recovery Adder for each month based on its budgeted costs to be recovered under Schedule 10 for that month and a true-up amount from the prior month. The true-up amount is the difference between MISO's actual costs to be recovered under Schedule 10 for the prior month and the actual amount of Schedule 10 revenue received for that prior month. As a vertically integrated transmission owner, OTP is assessed Schedule 10 on its network load and for any non-system point-to-point transmission service as a transmission customer under MISO's TEMT.

Q. DESCRIBE THE SYSTEM USE PORTION OF THE SCHEDULE 10 CHARGE.

A. MISO calculates this charge pursuant to Part II.B.2 of Schedule 10. This charge is based on the monthly peak of OTP's network load (Transmission Owner Adder Load). MISO determines its Schedule 10 charge on two components: energy and capacity. The energy portion is determined by multiplying the Energy Rate by the MWhs of energy in the billing month associated with its Transmission Owner Adder Load. The capacity portion is determined by multiplying the Capacity Rate by the Transmission Owner Adder Load in the billing month times the hours in the billing month. These two calculations (energy portion and capacity

portion) are then summed to equal the total Schedule 10 charge assessed for system use.

Q. SHOULD THE SCHEDULE 10 CHARGES OTP INCURS BE RECOVERED IN RATES?

A. Yes. As explained previously in my testimony, in 2007 Actual Year OTP received MISO transmission revenues of $927,299 (North Dakota share) which it would not have otherwise received. This amount of MISO revenue more than justifies the $324,217 of Schedule 10 charges proposed for recovery in this case. Also, as explained in detail above, MISO provides numerous tariff and other administrative services that OTP would have to self-supply if it administered its own transmission tariff. Additionally, the Schedule 10 charges are incurred pursuant to a filed FERC Tariff.

MISO Day 2 costs—Schedules 16 and 17

Q. PLEASE EXPLAIN THE ADJUSTMENT RELATED TO THE DEFERRED SCHEDULE 16 AND 17 COSTS.

A. The MISO Day 2 Settlement, item 3, allowed OTP to defer the Schedule 16 and 17 costs incurred since April 1, 2005, without interest, until interim rates take effect in this proceeding. OTP is allowed to recover the Schedule 16 and 17 costs and associated amortizations in interim rates pending the resolution of the rate case. The MISO Day 2 Settlement also requires OTP to demonstrate that the Schedule 16 and 17 costs were "prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates." I address this requirement later in my testimony. The total deferred North Dakota costs from April 2005 until June 2007 is $927,058. I made an adjustment of $309,019, to the Test Year, which reflects a three-year amortization of the accrued costs. See my Schedule 8, Column F.

Q. WHY DID YOU SELECT A THREE-YEAR AMORTIZATION PERIOD?

A. I used a three-year amortization period for two reasons. First, the MISO Day 2 settlement established a three-year amortization period starting March 1, 2009. Second a three year amortization period is consistent with our best estimate of when OTP will need to file its next rate case, as described in my testimony related to amortizing rate case expenses. The calculation of this adjustment is provided in Volume 4A, Test Year Work Paper TY-21.

Q. PLEASE DESCRIBE WHY AN ADJUSTMENT TO ADD BACK MISO DAY 2 EXPENSES INTO THE TEST YEAR PERIOD IS APPROPRIATE.

A Because we ceased recovering the Schedule 16 and 17 charges after July 2007, it is necessary to make an adjustment to annualize the amount that should be recovered in base rates. From January through June 2007 the North Dakota share of Schedules 16 and 17 charges were $150,783. These costs were reversed out and set up in a deferral account during 2007. The North Dakota share of the actual 2007 full year of charges was $256,990. Therefore the adjustment to arrive at the full amount to be included in the 2007 test year is $256,990 (Schedule 8, Column G).

Q. WAS THERE A DISCUSSION OR DOCUMENT FILED WITH THE COMMISSION AS PART OF CASE NO. PU-05-131 THAT DESCRIBES MISO SCHEDULES 16 AND 17?

A. Yes. The Settlement Agreement, Appendix A contained the following accurate description of FERC-approved MISO Schedules 16 and 17:

Schedule 16 Financial Transmission Rights Market Administration Amount

The Financial Transmission Rights Market Administration Amount, referred to as MISO Schedule 16, recovers the cost of MISO operating the FTR Markets. A flat rate administration charge is assessed per megawatt of FTR Profile Volume and per megawatt of scheduled, validated Grandfathered Agreement Financial Bilateral Transaction volume. The

charge is summed by Asset Owner (e.g., by utility) for the Operating Day. The Schedule 16 administration charge rate is subject to change based on costs incurred by Midwest ISO.

Schedule 17 Day-Ahead Market Administration Amount

The Day-Ahead Market Administration Amount in conjunction with the Real-Time Market Administration Amount, collectively referred to as MISO Schedule 17, recover the cost of MISO operating the Day-Ahead and Real-Time Energy Markets. The Day-Ahead and Real-Time Market Administration Amounts are charged separately.

The Day-Ahead Market Administration Amount consists of a charge on transactions and a charge on market participation in the Day Ahead Energy Market. The transactional charge applies to Day-Ahead Virtual Bid and Offer Schedules only. A transaction is defined as a single bid or offer by hour by Asset Owner. On an hourly basis the number of transactions are counted and multiplied by the Administration Transaction Rate and added to the hourly charge calculated for hourly market participation.

For each Asset Owner for an Operating Day, Market Settlements assesses an administration charge on the Utility's participation in the Day-Ahead Energy Market. The Asset Owner's Day-Ahead Energy Market participation volume is calculated at each Commercial Node for each hour and summed for the entire Operating Day. The resulting daily market participation volume is multiplied by the hourly Energy Markets Administration Rate. An Asset Owner's Day-Ahead hourly participation volume at a Commercial Node is based on the total energy volume into and out of the Commercial Node; in short, it is based on the summation of generation plus load volumes multiplied by the rate for Schedule 17. The

Schedule 17 administration charge rate is subject to change based on costs incurred by Midwest ISO.

Schedule 17 Real-Time Market Administration Amount

The Real-Time Market Administration Amount in conjunction with the Day-Ahead Market Administration Amount, collectively referred to as MISO Schedule 17, is designed to recover the cost of MISO operating the Day-Ahead and Real-Time Energy Markets. The Day-Ahead and Real-Time Market Administration Amounts are charged separately.

For each utility for an Operating Day, Market Settlements assesses an administration charge on the Asset Owner's participation in the Real-Time Energy Market. The Utility's Real-Time Energy Market participation volume is calculated at each Commercial Node for each hour and summed for the entire Operating Day. The resulting daily market participation volume is multiplied by the hourly Energy Markets Administration Rate. An Asset Owner's Real-Time hourly participation volume at a Commercial Node is based on the total directional energy volume, into and out of the Commercial Node; in short, it is based on the summation of generation plus load volumes, less those volumes which cleared the Day-Ahead market multiplied by the rate for Schedule 17. The Schedule 17 administration charge rate is subject to change based on costs incurred by Midwest ISO.

Q. HAS ANY UTILITY SOUGHT AND RECOVERED SCHEDULE 16 AND 17 COST?

A. In Case No. PU-07-776 Xcel Energy is seeking recovery of Schedule 16 and 17 expenses.

Q. HAVE YOU PERFORMED A COST/BENEFIT ANALYSIS ON SCHEDULES 16 AND 17 CHARGES?

A. Yes. There are significant benefits that OTP realizes from its participation in the MISO Day 2 market. Quantifying some of these benefits is relatively straight-forward. There are other benefits, but quantifying them is not always so straight-forward. Typically, the difficulty in quantifying some benefits relates to the fact that quantification would require a comparison of costs paid under MISO against what costs might have been incurred without MISO. Endeavoring to quantify benefits by comparing the road taken against the road not taken is by its very nature speculative.

Nevertheless, my analysis provides ample justification based upon the straight-forward and quantifiable benefits OTP has experienced though its participation in the MISO market. These benefits, some of which are realized by OTP largely because of OTP's unique geography and operating characteristics, are so substantial that they alone justify OTP's membership in MISO and the costs OTP has incurred under MISO Schedules 16 and 17.

Q. PLEASE DESCRIBE THESE BENEFITS.

A. The readily quantifiable benefits are in three primary areas: 1) an annual $1.9 million dollar (North Dakota share is approximately 40%) reduction in MAPP transmission service charges; 2) a reduction in the need for spinning reserves which has a value of over $1.5 million (North Dakota share is approximately 40 percent) (Exhibit __(PJB-1), Schedules 12 and 13); and 3) a much needed method of addressing OTP's obligation to supply regulation and load following services to generators in its control area, which will avoid costs to OTP of approximately $6.7 million dollars annually (North Dakota share is approximately 40 percent). These three benefits alone have a value in excess of $10 million annually. They justify the recovery of both the annual amortization of the deferred charges and the 2007 Test Year charges, which are $309,019 and $256,990, respectively.

Q. PLEASE DESCRIBE IN GREATER DETAIL EACH OF THESE BENEFITS, STARTING WITH THE REDUCTION IN MAPP TRANSMISSION SERVICE CHARGES, AND DESCRIBE HOW YOU CALCULATED THE VALUE OF THE BENEFIT.

A. OTP has been, and continues to be, capacity and energy deficit. This means that each year OTP buys firm capacity and energy to serve retail customers. At the top of my Exhibit__(PJB-1), Schedule 13, the number of MWs of capacity by month that OTP is purchasing for the calendar year 2008 is shown. Before MISO, OTP would have had to buy monthly firm transmission for capacity purchases. However, only firm transmission paths from sources that OTP felt confident would flow could be considered. The bottom part of my Exhibit__(PJB-1), Schedule 13 lists these paths and the corresponding MAPP transmission charge for monthly, firm service. By averaging these charges together, the average monthly, firm transmission charge comes to $2 per MW. Applying that charge to the number of MWs per month that OTP purchases without paying the $2, demonstrates an annual saving of $1.9 million.

Since the start of MISO, there have been no transmission charges within MISO for capacity or energy purchases. As my Exhibit__(PJB-1), Schedule 13 shows, system-wide, OTP customers have saved over $1.9 million per year in MidContinent Area Power Pool (MAPP) transmission charges for capacity purchases.

Q. PLEASE DESCRIBE HOW MISO HAS ALLOWED OTP TO REDUCE ITS NEED FOR SPINNING RESERVES AND HOW YOU CALCULATED THE VALUE OF THIS BENEFIT TO OTP.

A. On January 15, 2007, OTP's spinning reserve requirement was reduced by 5 MWs due to its participation in the MISO'S Contingency Reserve Sharing Group (the "CRSG"). The CRSG was organized and formed by MISO to bring a larger base of generation into the reserve sharing pool. The members of CRSG are comprised of both MISO and non-MISO entities. Because of the larger base of

generation, OTP's spinning reserve requirement was reduced. This means that retail customers are benefiting by having 5 more MWs of Otter Tail's base load generation available to serve retail load, or to sell into the MISO markets. Schedule 12 shows estimated 2007 savings to customers by having an additional 5 MWs available to use to meet retail load or sell into the MISO markets.

Not only did OTP see a reduction in spinning reserves, but also in non-spinning reserves. It is difficult to quantify this benefit because the non-spinning reserves are carried on a peaking unit that sees limited use. However, there is a benefit to retail customers to have more of this unit available to meet retail load when needed, or to sell into the MISO markets.

Q. PLEASE DESCRIBE HOW MISO WILL PROVIDE A METHOD TO RELIEVE OTP'S OBLIGATION TO SUPPLY REGULATION AND LOAD FOLLOWING SERVICES TO GENERATORS IN ITS CONTROL AREA, AND HOW YOU CALCULATED THE VALUE OF THIS BENEFIT TO OTP.

A. MISO is preparing to institute an Ancillary Services Market ("ASM") at which time operating reserves (spinning, non-spinning & regulation) will be supplied by MISO via the ASM. This means OTP, as the Control Area Operator in our region, will no longer be obligated to provide operating reserve services for non-OTP generators and loads within the OTP control area. This is a significant benefit to OTP retail customers because of the large amount of wind generation that is currently being planned within OTP's control area.

As of September 29, 2008, and within OTP's control area, there are 2,060 MWs of wind generation in MISO's queue with an In-Service date of October 1, 2008 or later. Of this total, OTP is planning 60 MWs. Of the remaining 2,000 MWs, even if only 10 percent actually get installed (for illustrative purposes), that would be an additional 200 MWs. OTP is planning for 5 additional MWs of regulation for each 60 MWs of wind being added. Exhibit__(PJB-1), Schedule 12 shows the net avoided cost (net of Control Area Service and Operations Tariff ("CASOT")) revenues of $6,744,612 per year.

It should be noted that the ASM market could not be implemented without an established Locational Marginal Pricing ("LMP") market. The LMP market would not exist without MISO Day 2 (and the Schedule 16 and 17 charges supporting Day 2 activities).

Q. PLEASE ALSO DESCRIBE THE LESS-EASY-TO-QUANTIFY BENEFITS OF OTP'S PARTICIPATION IN THE MISO MARKET.

A. Being a member of MISO has opened up many more opportunities for purchasing capacity and energy. Prior to MISO, OTP's list of counter parties was restricted due to available transfer capability (regional flows). With the advent of MISO, OTP experienced a noticeable decline in capacity costs. This was driven by MISO's universal deliverability that allows MISO members to deliver capacity from anywhere in the MISO footprint without a Transmission Service Request evaluation. In other words, MISO connected the natural gas-rich generation of eastern MISO with western MISO. Because of the capacity purchases OTP needs to make each month, retail customers have benefited greatly from these reduced capacity costs.

As noted earlier, during the months of December, January and February, OTP is deficit energy. Base load generation is not enough to serve retail load. Therefore, OTP buys blocks of energy. MISO opened up a much broader footprint from which OTP can purchase energy. Before MISO, OTP was restricted due to regional flows and counterparties could charge a premium because they knew they had a good path to flow the energy. Retail customers have benefited from OTP's ability to buy energy from the MISO markets.

On any given day, OTP's load may exceed base-load generation capabilities. During these times, OTP needs to purchase energy to meet retail loads. Before MISO, OTP would need to buy a "short schedule" or a block of energy over a number of hours less than the total hours of an on-peak purchase (16 hours). A large premium is typically charged to buy a short schedule because of the risk involved in selling power over the peak hours. Again, OTP could only

buy from a limited number of counter parties due to regional flows. After MISO started the LMP Market as part of Day 2, if OTP is short energy over a few peak hours due to the same reasons as described above, the energy is simply purchased from MISO in the Day Ahead or Real Time market. Although an estimate cannot be developed of the savings this has generated, OTP believes retail customers have benefited greatly from this aspect of being a MISO member.

Q. PLEASE SUMMARIZE THE COST JUSTIFICATION FOR OTP'S PARTICIPATION IN THE MISO MARKET.

A. In summary, my Exhibit_(PJB-1), Schedules 12 and 13 show system-wide estimates of quantifiable savings that customers are realizing from OTP being a MISO participant. In total, these conservative estimates exceed over $10 million ($1.9 million in savings of MAPP transmission charges, $1.5 million in savings of reserve sharing and savings of avoided control area services charges of $6.7 million) in annual savings. OTP realizes the bulk of these savings will come with the start of the ASM. But without the efforts made to date to develop Day 2, there could be no ASM. We used ten percent as the assumed amount of wind generation that will actually be installed in OTP's Control Area versus the total amount in MISO's queue. This is a conservative estimate due to the Renewable Energy Standard recently passed as law in Minnesota and the 10 percent objective passed in North Dakota. The large savings retail customers are receiving from OTP's participation in MISO make the Schedule 16 & 17 charges very reasonable.

Finally, OTP believes that MISO's Day 2 wholesale market has resulted in better transmission access, better generation optimization, lower capacity costs, and increased reliability.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATION FOR MISO COST RECOVERY.

A. OTP has presented this analysis in compliance with the Settlement in Case No. PU-05-131. This analysis shows that implementation of MISO Day 1 and Day 2 benefits OTP and its North Dakota customers. While these benefits have been offset to some extent by various costs, and while there are still implementation issues to be resolved, the overall benefits exceed costs, especially when various intangible or non-quantifiable benefits are considered. Therefore, the Commission should allow recovery of MISO costs.

(d) Storm repairs

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

A. Yes. I have added $119,992 to normalize North Dakota's 2007 Actual Year storm repair expenses to the 5-year average (Schedule 8, Column X). In 2007 storm repair expense was much lower than normal. There have been much higher expenses in individual years over the past 10 years, but the 5-year average is a more reasonable expectation for future costs as 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 ADJUSTMENTS IN HIS TESTIMONY. DID YOU MAKE ANY ADJUSTMENTS TO EXPENSES FOR THESE NEW CAPITAL PROJECTS?

A. Yes, I have included an adjustment of $479,389 to North Dakota depreciation for the Test Year to reflect the additional investment in electric plant (Schedule 8, Column I).

(f) Overhead costs for non-asset based wholesale transactions

Q. WHY ARE YOU MAKING AN ADJUSTMENT TO EXPENSES RELATED TO NON-ASSET BASED WHOLESALE TRANSACTIONS?

A. In the 2007 actual year, non-asset based revenues were accounted for entirely below the line. As I described earlier, we also imputed an amount of expenses below the line using transaction volumes as the allocator. Because volumes are no longer a reasonable basis for cost allocation, we are instead proposing to share 15 percent of the non-asset based margins with ratepayers as compensation for any possible additional costs associated with this activity. Therefore, I made an adjustment of $674,589 in expenses to return this imputed amount above the line (Schedule 8, Column P).

(g) Economic Development

Q. THE COMMISSION ALLOWED OTP TO RECOVER $315,557 IN ECONOMIC DEVELOPMENT EXPENSES IN RATES AS PART OF A SETTLEMENT IN 1989. IS OTP PROPOSING SOMETHING DIFFERENT IN THIS PROCEEDING?

A. Yes. Ms. Brutlag's Direct Testimony explains OTP's economic development program and why OTP should be allowed to recover its economic development costs, as was allowed in its 1989 settlement. OTP is proposing to enhance its economic development program in North Dakota by increase the amount in base rates to $500,000 compared to the $315,000 set in 1989. Otter Tail actually spent $427,508 on economic development in 2007. Consequently, OTP made an adjustment related to economic development costs of $72,492 to bring the amount included in rates to $500,000 (Schedule 8, Column U).

(h) 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. The Direct Testimony of Ms. Brutlag discusses the change from direct assignments to allocation of depreciation in her testimony. The expense adjustment is an increase of $268,864 (Schedule 8, Column H). This is offset by

$93,635 for the change to rate base created by the change in accumulated depreciation.

(i) Corporate Allocations

Q. SCHEDULE 8, COLUMN V, HAS AN ADJUSTMENT FOR CORPORATE ALLOCATIONS. DO TESTIFY ON THIS?

A. No. Ms. Brutlag discusses the reasons for the reduction to expense of $41,833.

(j) Impact of the adjustments on allocation factors

Q. PLEASE DISCUSS THE REASON FOR THE ADJUSTMENT ON SCHEDULE 8, COLUMN Z, FOR CHANGE IN ALLOCATION FACTORS.

A. Anytime adjustments to plant and expenses are made to the cost of service study, allocations 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 Z of Schedule 8 reflects the net impact of these changes of $75,671.

(k) Energy Efficiency Programs

Q. HAVE YOU INCLUDED ANY COSTS FOR ENERGY EFFICIENCY PROGRAMS REQUIRED AS A RESULT OF THE ORDER IN CASE NO. PU-06-481?

A. Yes. I have included $1 million for energy efficiency programs (Schedule 8, Column R).

(3) <u>Traditional regulatory adjustments</u>

Q. WHAT TRADITIONAL REGULATORY ADJUSTMENTS DID YOU MAKE?

A. My Ex.__(PJB-1) Schedule 8 sets forth these adjustments, reflecting Commission policies in the following traditional areas: 1) advertising expense; 2) charitable contributions; 3) Research Expenses. I will discuss each of these adjustments below.

(a) Advertising

Q. PLEASE DESCRIBE THE ADVERTISING EXPENSE ADJUSTMENT.

A. According to the Public Service Commission's Rule 69-09-02-38, paragraph 2, any expenditure by a utility for institutional, promotional, or political advertising shall be excluded from operating expenses in the cost of service determination for ratemaking purposes. Paragraph 3 of this same rule, allows advertising expenditures which are reasonable in amount and which are not excluded under paragraph 2, to be included as operating expenses in the cost of service determination for ratemaking purposes. Allowable types of advertising include:

1. Advertising which informs electric customers how they can conserve energy or can reduce peak demand for electric energy.
2. Advertising required by law or regulations.
3. Advertising relating to service interruptions, safety measures, or emergency conditions.
4. Advertising concerning employment opportunities with an electric utility.
5. Advertising which promotes the conservation of limited resources, the use of more plentiful resources, or the use of energy efficient appliances, equipment, or services.
6. Any explanation or justification of existing or proposed rate schedules, or notifications of hearings thereon.
7. Advertising determined by the Commission to benefit customers and serve the public interest.

It was not necessary to make a test year adjustment to comply with this standard because OTP excluded $401,419 in advertising expenses from the 2007 Actual Year to comply with the Commission's Rule. The amount we've included is $143,904 from account FERC 909.

(b) Charitable Contributions

Q. PLEASE DESCRIBE OTP'S CHARITABLE GIVING PROGRAM.

A. We call our program Community Connections. Our mission for this program is to connect with our rural communities to support young minds, invest in our current and future workforce, help to create vibrant culture and strong communities, improve health and human services, and protect our natural resources. A team of five employees meets quarterly to review and grant requests according to program guidelines. In addition, each of our eleven customer service centers (six of which are located in North Dakota) has discretionary funds for smaller grants to communities within its purview.

Q. WHAT TYPES OF ACTIVITIES ARE FUNDED?

A. While Community Connections provides financial support to a broad array of activities and organizations, we focus our resources on the rural communities we serve. We designate donations for general operating support, program/project support, scholarships, and capital campaigns. Our priority funding areas are:

- education, emphasizing scholarships for line and plant workers and engineers.
- health and human services
- community enhancement, including arts and culture.
- environmental education, preservation, and conservation.

Q. WHAT TYPES OF ACTIVITIES ARE NOT FUNDED?

A. Community Connections rarely grants requests from outside our service area. And we do not fund:

- organizations without tax exempt status.
- individuals.
- lobbying, political, or fraternal groups.
- religious organizations, unless they are seeking funds in the direct interest of the entire community and not to promote a particular faith.

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

We have included 50 percent of OTP's charitable contributions benefiting the State of North Dakota in our determination of revenue requirements . The total amount included is $114,816, which is 50 percent of the North Dakota 2007 Actual Year expenses (Schedule 8, Column T). We are providing an itemized list showing the amount, recipient, and date of the 2007 donations made in North Dakota. This information included in Volume 4A, Work Papers, Adjustment TY-18.

(c) Research Expenses

Q. HAS OTP INCLUDED ANY RESEARCH EXPENSES IN ITS REQUEST?

A. No.

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 in the as Exhibit__(PJB-1), Schedule 10.

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

A. Yes, there are four differences. First the sub-classes of cooking and heat, uncontrolled water heating, and electric year around comfort have been consolidated into the residential class since separate rates for these classes were discontinued as a result of the Order in the last case. Second, the sub-classes of street and area lighting have been combined. Third, as mentioned earlier in my testimony, the class and jurisdictional allocation factors have been expanded to include an energy factor (E1) that accounts for controlled and interruptible loads and a customer factor (C9) that allocates the costs for load control equipment.

Fourth, Controlled Service has been separated into Controlled Service Interruptible and Controlled Service Deferred.

Q. PLEASE EXPLAIN THE CONSOLIDATION OF THE COOKING AND HEATING, UNCONTROLLED WATER HEATING, ELECTRIC YEAR AROUND COMFORT CLASSES INTO THE RESIDENTIAL CLASS.

A. The use of these classes in Case No. 10,334, our last rate case, was a carry over from prior rate design where these services had different rates. In Case No. 10,334, these rate differences were eliminated. To properly design residential rates the classes are more appropriately consolidated.

Q. PLEASE EXPLAIN WHY CONTROLLED SERVICE WAS SEPARATED INTO TWO DISTINCT CLASSES.

A. Controlled Service Interruptible customers are served under tariff sheets 50 (Controlled Service – Interruptible Load, 80 kW and greater) and 50.1 (Controlled Service – Interruptible Load, Less Than 80 kW Capacity). These customers can have their service curtailed by OTP at any time for the purposes stated in those tariff sheets. A common application for these tariffs is dual fuel where a customer has an electric heating source that can be controlled (shut off) at OTP's discretion. The customer also has non-electric heating source that runs when the electric heating source is controlled. Controlled Service Deferred customers are served under tariff 50.2. Typical applications for this service are heat storage systems (typically electric cable that heats a concrete floor) where, when OTP controls the heating source, the system will retain enough heat to keep the customer's space warm enough during the control period. The load shape for these two types of loads are quite different and should be separated for rate design purposes.

Q. DID OTP HAVE RATES 50, 50.1, 50.2 IN CASE NO. 10,334?

A. Yes. The reason for the change in the CCOSS classes is only to make rate design easier.

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, two separate 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, Lighting, Other Public Authorities (OPA), Controlled Water Heating, Controlled Service Interruptible, and Controlled Service Deferred.

Q. PLEASE DESCRIBE OTP'S ENERGY COST ALLOCATORS USED IN THE CCOSS.

A. The energy cost allocator used in our prior rate case has been retained and supplemented with an energy factor which excludes controlled loads. The energy allocator from the Company's previous studies (sometimes referred to as "E") has always been based on the total energy use including line losses. OTP is proposing to change the energy allocators in this case to provide for an allocator that recognizes the benefits of controlled and interruptible loads (the E allocator). Since North Dakota has a significant amount of controlled and interruptible loads, adding this allocation factor not only helps in rate design, it also allocates costs on a jurisdictional level more fairly, as these loads create less cost on the system than firm loads.

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* is included as my Exhibit___ (PJB-1), Schedule 11 B. 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 what cost items are subject to each allocator.

Q. PLEASE SUMMARIZE THE RESULTS OF THE CCOSS.

A. Table 3 below contains information from the CCOSS results, which is also shown in my Exhibit__(PJB-1), Schedule 10. It indicates the cost responsibility by class and the rate increase necessary for each class to cover its cost of service.

Table 3 Class Responsibility

		Class Responsibility	
	Current Revenues	Amount of Increase	Percent Increase
Residential	36,574,921	5,955,613	16.28%
Farms	1,601,767	339,157	21.17%
General Service	34,012,150	(2,704,468)	-7.95%
Large General Service	36,231,788	(2,389,167)	-6.59%
Irrigation	45,963	34,330	74.69%
Lighting	2,095,668	873,930	41.70%
OPA	967,569	278,381	28.77%
Controlled Service Water Heating	1,185,332	643,689	54.30%
Controlled Service Interruptible	4,744,402	2,870,712	60.51%
Controlled Service Deferred	849,617	181,827	21.40%
	118,309,177	6,084,003	5.14%

Q. PLEASE EXPLAIN TABLE 3.

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 (Exhibit___(PJB-1), Schedule 10, 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 4 below.

Table 4

Class Revenue Responsibility – Proposed increase by class

		Class Responsibility	
	Current Revenues	Amount of Increase	Percent Increase
Residential	36,574,921	2,743,119	7.50%
Farms	1,601,767	120,133	7.50%
General Service	34,012,150	321,929	0.95%
Large General Service	36,231,788	362,318	1.00%
Irrigation	45,963	4,596	10.00%
Lighting	2,095,668	523,917	25.00%
OPA	967,569	135,460	14.00%
Controlled Service Water Heating	1,185,332	118,533	10.00%
Controlled Service Interruptible	4,744,402	1,660,541	35.00%
Controlled Service Deferred	849,617	93,458	11.00%
	118,309,177	6,084,003	5.14%

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

Q. PLEASE EXPLAIN THE COMPONENTS OF TABLE 4.

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 the revenues 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 16.28 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 much more moderated increase of 7.50 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 would occur if we increased the residential class rates by the average rate increase of 5.14 percent. Therefore it is necessary to apply a rate increase to the residential class that is higher than the average increase to avoid increasing interclass cross-subsidies further than what was approved in our last rate 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.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application by Otter Tail Corporation d/b/a Otter Tail Power Company, for Authority to Increase Rates for Electric Utility Service in North Dakota	))))	Case No. PU-08-_____

AFFIDAVIT OF PETER J. BEITHON

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Peter J. Beithon

Subscribed and sworn to before me,
this 24th day of October, 2008.

NOTARY PUBLIC

WENDI A. OLSON
NOTARY PUBLIC - MINNESOTA
My Commission Expires Jan. 31, 2010

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

Case No. PU-08____
Exhibit ___(PJB-1)
Financial Information
Schedule 1

Line No.	Description	(A) 2007 Actual Year	(B) 2007 Test Year
1	Average Rate Base	$165,070,791	$187,173,203
2	Operating Income (Before AFUDC)	$11,883,263	$12,942,144
3	Allowance for Funds Used During Construction (AFUDC)	$0	$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$11,883,263	$12,942,144
5	Overall Rate of Return (Line 4 / Line 1)	7.20%	6.91%
6	Required Rate of Return	8.89%	8.89%
7	Operating Income Requirement (Line 1 x Line 6)	$14,674,793	$16,639,698
8	Income Deficiency (Line 7 - Line 4)	$2,791,530	$3,697,554
9	Gross Revenue Conversion Factor	1.645413	1.645413
10	Revenue Deficiency (Line 8 x Line 9)	$4,593,220	$6,084,003
11	Retail Related Revenues Under Present Rates		$118,309,177
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11)		5.14%

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY | **Case No. PU-08____**
Electric Utility - State of North Dakota | **Exhibit__(PJB-1)**
OPERATING INCOME SCHEDULES | **Financial Information**
JURISDICTIONAL STATEMENT OF OPERATING INCOME | **Schedule 2**

Line No.	Description	(A) 2007 Actual Year Total Utility	(B) 2007 Actual Year ND Jurisdiction	(C) 2007 Test Year Total Utility	(D) 2007 Test Year ND Jurisdiction
	OPERATING REVENUES				
1	Retail Revenue	$268,698,170	$108,472,410	$278,520,961	$118,309,177
2	Other Electric Operating Revenue	33,216,346	12,622,188	34,277,583	13,804,432
3	**TOTAL OPERATING REVENUE**	$301,914,516	$121,094,598	$312,798,544	$132,113,609
	OPERATING EXPENSES				
4	Production Expenses	$160,332,202	$62,106,875	$165,407,210	$67,714,739
5	Transmission Expenses	10,492,992	4,108,094	10,827,331	4,467,061
6	Distribution Expenses	14,686,349	6,461,701	15,280,331	6,727,802
7	Customer Accounting Expenses	10,507,260	4,545,083	10,931,905	4,728,770
8	Customer Service and Information Expenses	5,241,699	1,153,127	6,387,900	2,185,290
9	Sales Expenses	1,121,951	628,984	1,194,443	701,476
10	Administration and General Expenses	31,837,814	12,293,584	33,546,971	13,557,519
11	Charitable Contributions	111,967	0	226,783	114,816
12	Depreciation Expense	24,836,391	10,157,335	25,546,230	10,716,072
13	General Taxes	9,411,607	3,710,634	9,411,607	3,957,594
14	**TOTAL OPERATING EXPENSES**	$268,580,233	$105,165,417	$278,760,712	$114,871,140
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$33,334,283	$15,929,181	$34,037,832	$17,242,469
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	($1,136,657)	($459,510)	($1,136,657)	($476,371)
18	Deferred Income Taxes	477,922	207,151	477,922	213,186
19	Income Taxes	8,005,239	4,298,276	7,989,374	4,563,511
20	**TOTAL INCOME TAX EXPENSE**	$7,346,504	$4,045,918	$7,330,639	$4,300,326
21	**NET OPERATING INCOME**	$25,987,779	$11,883,263	$26,707,193	$12,942,143
22	Allowance for Funds Used During Construction	2,257,062	0	2,257,062	0
23	**TOTAL AVAILABLE FOR RETURN**	$28,244,841	$11,883,263	$28,964,255	$12,942,143

Note: The 2007 Actual Year is based on 2007 historic financial information that is the basis for OTP's Annual Report to the North Dakota Public Service Commission. 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 North Dakota
OPERATING INCOME SCHEDULES
TOTAL UTILITY AND NORTH DAKOTA TEST YEAR

Case No. PU-08____
Exhibit__(PJB-1)
Financial Information
Schedule 3

Line No.	Description	(A) Unadjusted Total Utility	(B) Unadjusted ND Jurisdiction	(C) Adjustments	(D) Proposed ND Jurisdiction
		2007 Test Year			
	OPERATING REVENUES				
1	Retail Revenue	$268,698,170	$108,472,410	$9,836,767	$118,309,177
2	Other Electric Operating Revenue	33,216,346	12,622,188	1,182,244	13,804,432
3	**TOTAL OPERATING REVENUE**	$301,914,516	$121,094,598	$11,019,011	$132,113,609
	OPERATING EXPENSES				
4	Production Expenses	$160,332,202	$62,106,875	$5,607,864	$67,714,739
5	Transmission Expenses	10,492,992	4,108,094	358,967	4,467,061
6	Distribution Expenses	14,686,349	6,461,701	266,101	6,727,802
7	Customer Accounting Expenses	10,507,260	4,545,083	183,687	4,728,770
8	Customer Service and Information Expenses	5,241,699	1,153,127	1,032,163	2,185,290
9	Sales Expenses	1,121,951	628,984	72,492	701,476
10	Administration and General Expenses	31,837,814	12,293,584	1,263,935	13,557,519
11	Charitable Contributions	111,967	0	114,816	114,816
12	Depreciation Expense	24,836,391	10,157,335	558,737	10,716,072
13	General Taxes	9,411,607	3,710,634	246,960	3,957,594
14	**TOTAL OPERATING EXPENSES**	$268,580,233	$105,165,417	$9,705,723	$114,871,140
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$33,334,283	$15,929,181	$1,313,288	$17,242,469
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	($1,136,657)	($459,510)	($16,862)	($476,371)
18	Deferred Income Taxes	477,922	207,151	6,035	213,186
19	Income Taxes	8,005,239	4,298,276	265,235	4,563,511
20	**TOTAL INCOME TAX EXPENSE**	$7,346,504	$4,045,918	$254,408	$4,300,326
21	**NET OPERATING INCOME**	$25,987,779	$11,883,263	$1,058,880	$12,942,143
22	Allowance for Funds Used During Construction	2,257,062	0	0	0
23	**TOTAL AVAILABLE FOR RETURN**	$28,244,841	$11,883,263	$1,058,880	$12,942,143

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

Case No. PU-08____
Exhibit__(PJB-1)
Financial Information
Schedule 4

Line No.	Description	(A) 2007 Actual Year Total Utility	(B) 2007 Actual Year ND Jurisdiction	(C) 2007 Test Year Total Utility	(D) 2007 Test Year ND Jurisdiction
	Income Before Taxes				
1	Total Operating Revenues	$301,914,516	$121,094,598	$312,798,544	$132,113,609
2	less: Total Operating Expenses	(234,332,234)	(91,297,449)	(243,802,874)	(100,197,474)
3	Book Depreciation & Amortization	(24,836,391)	(10,157,335)	(25,546,230)	(10,716,072)
4	Taxes Other Than Income	(9,411,607)	(3,710,634)	(9,411,607)	(3,957,594)
5	Interest Cost	(11,554,397)	(4,489,926)	(12,265,525)	(5,091,111)
6	**Total Before Tax Book Income**	**$21,779,887**	**$11,439,254**	**$21,772,307**	**$12,151,358**
	Tax Additions				
7	Additional Tax Depreciation				
8	Directly Assigned Schedule M Items	93,287	59,233	93,287	59,233
9	Provisions - Operating Reserves	8,598,414	3,390,023	8,598,414	3,615,645
10	Other Schedule M Items	1,606,800	633,499	1,606,800	675,662
11	**Total Tax Additions**	**$10,298,501**	**$4,082,755**	**$10,298,501**	**$4,350,540**
	Tax Deductions				
12	Additional Tax Depreciation	$2,701,294	$1,065,016	$2,701,294	$1,135,898
13	Cost to Remove	3,949,203	1,557,018	3,949,203	1,660,645
14	Accrued Vacation Pay	87,932	34,668	87,932	36,976
15	Charges - Operating Reserves	4,671,807	1,841,913	4,671,807	1,964,501
	Preferred Dividends Paid Credit	160,775	63,387	160,775	67,606
16	Other Schedule M Items	-	-	-	-
17	**Total Tax Deductions**	**$11,571,011**	**$4,562,002**	**$11,571,011**	**$4,865,626**
18	ND Adjustments to Federal Schedule M; ND Jurisdiction	-	10,845	-	11,567
19	**State Taxable Income**	**$20,507,377**	**$10,949,162**	**$20,499,797**	**$11,624,705**
20	State Income Tax Rate	6.21%	6.50%	6.11%	6.50%
21	**Total State Income Taxes & ND Incremental Tax Rate Adj ($505)**	**$1,273,318**	**$711,191**	**$1,252,992**	**$755,101**
22	**Federal Taxable Income**	**$19,234,059**	**$10,237,971**	**$19,246,805**	**$10,869,604**
23	Addback of MN Adjustments to Federal Schedule M; MN Jurisdiction		10,845		11,567
24	**Adjusted Federal Taxable Income**	**$19,234,059**	**$10,248,817**	**$19,246,805**	**$10,881,171**
25	Federal Income Tax Rate	35.00%	35.00%	35.00%	**35.00%**
26	**Total Federal Income Taxes**	**$6,731,921**	**$3,587,086**	**$6,736,382**	**$3,808,410**
27	**Total State and Federal Income Tax**	**$8,005,239**	**$4,298,277**	**$7,989,374**	**$4,563,511**

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY **Case No. PU-08____**
Electric Utility - State of North Dakota **Exhibit__(PJB-1)**
OPERATING INCOME SCHEDULES **Financial Information**
COMPUTATION OF DEFERRED INCOME TAXES **Schedule 5**

Line No.	Description	2007 Actual Year Total Utility (A)	2007 Actual Year ND Jurisdiction (B)	2007 Test Year Total Utility (C)	2007 Test Year ND Jurisdiction (D)
1	Excess Tax Over Book Depreciation	$4,006,368	$ 1,578,377	$4,006,368	$ 1,665,378
2	Excess Tax Over Book Pensions	(1,759,616)	$ (695,826)	(1,759,616)	(734,686)
3	Capitalized A & G Expenses	(456,241)	(181,261)	(456,241)	(191,410)
4	Provisions for Operating Reserves in Excess of Actual Charges	(1,513,024)	(602,046)	(1,513,024)	(635,766)
5	Other Capitalized Items	200,435	107,906	200,435	109,668
6	**TOTAL Deferred Income Taxes**	$477,922	$207,151	$477,922	$213,186

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY **Case No. PU-08____**
Electric Utility - State of North Dakota **Exhibit__(PJB-1)**
OPERATING INCOME SCHEDULES **Financial Information**
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)
S+F=	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 **Case No. PU-08____**
Electric Utility - State of North 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				32.73%
2	State Income Taxes				6.50%
3	Total Tax Percentage				39.23%
4	Operating Income %	=	100% - 39.23%	=	60.78%
5	Gross Revenue Conversion Factor	=	100.00% / 60.77%	=	1.645413

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

			KNOWN AND MEASURABLE CHANGES								
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line No.	Description	2007 Actual Year	New Large Customer	New Billing for Steam Customer	Inter-Year Billing Adjustment	Wholesale Margins Asset Based Revenue & Expense	Amortization of Deferred MISO Schedule 16 & 17 Costs	MISO Schedule 16 & 17 Costs	Depreciation Direct Assign vs Allocated	Depreciation Expense for New Plant	Update Depreciation Expense
	OPERATING REVENUES										
1	Retail Revenue	$108,472,410	$8,882,240		$309,796			$644,731			
2	Other Electric Operating Revenue	12,622,188		189,857		250,101					
3	**TOTAL OPERATING REVENUE**	$121,094,598	$8,882,240	$189,857	$309,796	$250,101	$0	$644,731	$0	$0	$0
	OPERATING EXPENSES										
4	Production Expenses	$62,106,875	$3,004,397			$578,788	$309,019	$256,990			
5	Transmission Expenses	4,108,094									
6	Distribution Expenses	6,461,701									
7	Customer Accounting Expenses	4,545,083									
8	Customer Service and Information Expenses	1,153,127									
9	Sales Expenses	628,984									
10	Administration and General Expenses	12,293,584									
11	Charitable Contributions	0									
12	Depreciation Expense	10,157,335							268,864	479,389	(197,050)
13	General Taxes	3,710,634									
14	**TOTAL OPERATING EXPENSES**	$105,165,417	$3,004,397	$0	$0	$578,788	$309,019	$256,990	$268,864	$479,389	($197,050)
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$15,929,181	$5,877,843	$189,857	$309,796	($328,687)	($309,019)	$387,741	($268,864)	($479,389)	$197,050
16	**INCOME TAX EXPENSE**										
17	Investment Tax Credit	($459,510)									
18	Deferred Income Taxes	207,151									
19	Income Taxes	4,298,276	2,305,584	74,472	121,518	(128,928)	(121,213)	152,092	(105,462)	(188,040)	77,293
20	**TOTAL INCOME TAX EXPENSE**	$4,045,918	$2,305,584	$74,472	$121,518	($128,928)	($121,213)	$152,092	($105,462)	($188,040)	$77,293
21	**NET OPERATING INCOME**	$11,883,263	$3,572,259	$115,386	$188,279	($199,760)	($187,807)	$235,650	($163,402)	($291,349)	$119,757
22	Allowance for Funds Used During Construction	0									
23	**TOTAL AVAILABLE FOR RETURN**	$11,883,263	$3,572,259	$115,386	$188,279	($199,760)	($187,807)	$235,650	($163,402)	($291,349)	$119,757

Column references to adjustment workpapers:

(B) W/P 2007 ND TY-10	(H) W/P 2007 ND TY-03	(N) W/P 2007 ND TY-12	(T) W/P 2007 ND TY-18
(C) W/P 2007 ND TY-11	(I) W/P 2007 ND TY-01	(O) W/P 2007 ND TY-12	(U) W/P 2007 ND TY-09
(D) W/P 2007 ND TY-20	(J) W/P 2007 ND TY-07 & TY-08	(P) W/P 2007 ND TY-16	(V) W/P 2007 ND TY-06
(E) W/P 2007 ND TY-15	(K) W/P 2007 ND TY-05	(Q) W/P 2007 ND TY-19	(W) W/P 2007 ND TY-04
(F) W/P 2007 ND TY-21	(L) W/P 2007 ND TY-05	(R) W/P 2007 ND TY-17	(X) W/P 2007 ND TY-14
(G) W/P 2007 ND TY-21	(M) W/P 2007 ND TY-05	(S) W/P 2007 ND TY-22	

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

KNOWN AND MEASURABLE CHANGES

Line No.	Description	(K) Employee Benefits Medical/Dental	(L) FAS 87 Pension Costs	(M) FAS 106 & 112 Benefits	(N) KPA & Utility Management Incentive	(O) Labor Expense - April & November Annual Increases	(P) Wholesale Margins Non-Asset Based Expense	(Q) Big Stone Outage Purchased Power	(R) Energy Efficiency Programs	(S) Factor Change for New Large Customer	(T) Charitable Contributions
	OPERATING REVENUES										
1	Retail Revenue										
2	Other Electric Operating Revenue									762,538	
3	**TOTAL OPERATING REVENUE**	$0	$0	$0	$0	$0	$0	$0	$0	$762,538	$0
	OPERATING EXPENSES										
4	Production Expenses	$125,279	($128,842)	$37,016	$7,010	$320,198	$674,535	($2,949,824)		$3,547,621	
5	Transmission Expenses	49,017	(50,847)	14,484	2,743	125,281				221,028	
6	Distribution Expenses	92,934	(101,519)	27,457	5,201	237,524				4,576	
7	Customer Accounting Expenses	65,274	(71,354)	19,285	3,653	166,831				0	
8	Customer Service and Information Expenses	37,387	(40,870)	11,047	640	29,212			1,000,000	0	
9	Sales Expenses									0	
10	Administration and General Expenses	171,766	(182,429)	50,749	41,811	438,532	54			427,442	
11	Charitable Contributions									0	114,816
12	Depreciation Expense									4,940	
13	General Taxes									263,535	
14	**TOTAL OPERATING EXPENSES**	$541,657	($575,861)	$160,038	$61,058	$1,317,578	$674,589	($2,949,824)	$1,000,000	$4,469,142	$114,816
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	($541,657)	$575,861	($160,038)	($61,058)	($1,317,578)	($674,589)	$2,949,824	($1,000,000)	($3,706,604)	($114,816)
16	**INCOME TAX EXPENSE**										
17	Investment Tax Credit									($16,597)	
18	Deferred Income Taxes									9,972	
19	Income Taxes	(212,465)	225,881	(62,775)	(23,950)	(516,820)	(264,608)	1,157,068	(392,250)	(1,591,538)	(45,037)
20	**TOTAL INCOME TAX EXPENSE**	($212,465)	$225,881	($62,775)	($23,950)	($516,820)	($264,608)	$1,157,068	($392,250)	($1,598,163)	($45,037)
21	**NET OPERATING INCOME**	($329,192)	$349,980	($97,263)	($37,108)	($800,758)	($409,981)	$1,792,756	($607,750)	($2,108,441)	($69,779)
22	Allowance for Funds Used During Construction										
23	**TOTAL AVAILABLE FOR RETURN**	($329,192)	$349,980	($97,263)	($37,108)	($800,758)	($409,981)	$1,792,756	($607,750)	($2,108,441)	($69,779)

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

		KNOWN AND MEASURABLE CHANGES						
		(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
Line No.	Description	Economic Development	Corporate Allocations	Amortized Rate Case Expenses	Normalized Storm Repair Expense	Holding Company Formation Costs	Changes in Allocations due to Effect of Test Year Adjustments	2007 Test Year
	OPERATING REVENUES							
1	Retail Revenue						$0	$118,309,177
2	Other Electric Operating Revenue						(20,252)	13,804,432
3	**TOTAL OPERATING REVENUE**	$0	$0	$0	$0		($20,252)	$132,113,610
	OPERATING EXPENSES							
4	Production Expenses						($174,324)	$67,714,739
5	Transmission Expenses						(2,739)	4,467,061
6	Distribution Expenses						(72)	6,727,802
7	Customer Accounting Expenses						(2)	4,728,770
8	Customer Service and Information Expenses						(5,253)	2,185,290
9	Sales Expenses	72,492					0	701,476
10	Administration and General Expenses		(41,833)	166,667	119,992	55,383	15,801	13,557,519
11	Charitable Contributions						0	114,816
12	Depreciation Expense						2,594	10,716,072
13	General Taxes						(16,575)	3,957,594
14	**TOTAL OPERATING EXPENSES**	$72,492	($41,833)	$166,667	$119,992	$55,383	($180,570)	$114,871,140
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	($72,492)	$41,833	($166,667)	($119,992)	($55,383)	$160,318	$17,242,469
16	**INCOME TAX EXPENSE**							
17	Investment Tax Credit						($265)	($476,372)
18	Deferred Income Taxes						(3,937)	213,186
19	Income Taxes	(28,435)	16,409	(65,375)	(47,067)	(21,724)	(49,395)	4,563,512
20	**TOTAL INCOME TAX EXPENSE**	($28,435)	$16,409	($65,375)	($47,067)	($21,724)	($53,597)	$4,300,326
21	**NET OPERATING INCOME**	($44,057)	$25,424	($101,292)	($72,925)	($33,659)	$213,915	$12,942,143
22	Allowance for Funds Used During Construction							0
23	**TOTAL AVAILABLE FOR RETURN**	($44,057)	$25,424	($101,292)	($72,925)	($33,659)	$213,915	$12,942,143

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY — **Case No. PU-08____**
Electric Utility - State of North Dakota — **Exhibit ___(PJB-1)**
COMPARISON OF PROPOSED TEST YEAR TO LAST RATE CASE — **Financial Information**
STATEMENT OF OPERATING INCOME — **Schedule 9**

Line No.	Description	(A) Per Order in Case 10,334	(B) General Rate Case Filing (Test Year)	(C) (C) = (B) - (A) $ Change	(D) (D) = ((C)/(A))/24 % change Simple Annual Average	Total % Change
	OPERATING REVENUES					
1	Retail	$63,789,000	$118,309,177	$54,520,177	3.56%	85%
2	Other Operating Revenue	3,654,587	13,804,432	10,149,845	11.6%	278%
3	**TOTAL OPERATING REVENUE**	$67,443,587	$132,113,609	$64,670,022	4.00%	96%
	OPERATING EXPENSES					
4	Production Expenses - Fuel and Purchased Power	$22,094,860	$55,496,973	$33,402,112	6.30%	151%
5	Production Expenses - Other	3,010,103	12,217,766	9,207,664	12.75%	306%
6	Transmission Expenses	1,055,503	4,467,061	3,411,558	13.47%	323%
7	Distribution Expenses	2,711,191	6,727,802	4,016,611	6.17%	148%
8	Customer Accounting Expenses	1,838,467	4,728,770	2,890,303	6.55%	157%
9	Customer Service & Information Expenses	451,528	2,185,290	1,733,762	16.00%	384%
10	Sales Expenses	13,879	701,476	687,597	206.43%	4954%
11	Administration & General Expenses	5,369,420	13,557,519	8,188,099	6.35%	152%
12	Charitable Contributions	0	114,816	114,816	100.00%	100%
13	Depreciation Expense	7,888,546	10,716,072	2,827,526	1.49%	36%
14	Spiritwood Amortization	0	0	0	(0.00)%	0%
15	General Taxes	3,508,728	3,957,594	448,866	0.53%	13%
16	**TOTAL OPERATING EXPENSES**	$47,942,225	$114,871,140	$66,928,915	5.82%	140%
17	**NET OPERATING INCOME BEFORE INCOME TAXES**	$19,501,362	$17,242,469	($2,258,893)	(0.48)%	-12%
	INCOME TAX EXPENSE					
18	Investment Tax Credit	$1,261,504	($476,371)	($1,737,875)	(5.74)%	-138%
19	Deferred Income Taxes	3,107,737	213,186	(2,894,551)	(3.88)%	-93%
20	Income Taxes	990,163	4,563,511	3,573,348	15.04%	361%
21	**TOTAL INCOME TAX EXPENSE**	$5,359,404	$4,300,325	($1,059,079)	(0.82)%	-20%
22	**NET OPERATING INCOME**	$14,141,958	$12,942,144	($1,199,814)	(0.35)%	-8%
23	Allowance for Funds Used During Construction					
24	**TOTAL AVAILABLE FOR RETURN**	$14,141,958	$12,942,144	($1,199,814)	(0.35)%	-8%
	Additional information					
25	**Total O & M Not Including Fuel & Purchased Power**	$25,847,365	$59,374,167	$33,526,803	5.40%	130%

Notes: Revenues reflect calendar month sales

OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

RUN = TEST YEAR
10/24/2008
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	RATE BASE		187,173,203	67,261,316	3,229,819	49,263,739	45,309,646	172,391	5,601,187	1,901,043	3,506,333	9,464,883	1,462,848
2													
3	TOTAL AVAILABLE FOR RETURN		12,942,144	2,360,006	81,008	6,023,187	5,480,044	(5,538)	(33,185)	(183)	(79,489)	(903,248)	19,542
4													
5	RATE OF RETURN EARNED		6.91%	3.51%	2.51%	12.23%	12.09%	-3.21%	-0.59%	-0.01%	-2.27%	-9.54%	1.34%
6													
7	RATE OF RETURN REQUESTED		8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%
8													
9	OPERATING INCOME REQUIRED		16,639,698	5,979,531	287,131	4,379,546	4,028,028	15,326	497,946	169,003	311,713	841,428	130,047
10													
11	TOTAL AVAILABLE FOR RETURN		12,942,144	2,360,006	81,008	6,023,187	5,480,044	(5,538)	(33,185)	(183)	(79,489)	(903,248)	19,542
12													
13	OPERATING INCOME DEFECIENCY		3,697,554	3,619,525	206,123	(1,643,641)	(1,452,016)	20,864	531,131	169,186	391,202	1,744,676	110,505
14													
15	INCREMENTAL TAXES	GRCF =	2,386,449	2,336,088	133,034	(1,060,827)	(937,150)	13,466	342,799	109,195	252,487	1,126,036	71,321
16													
17	REVENUE INCREASE REQUIRED		6,084,004	5,955,613	339,157	(2,704,468)	(2,389,167)	34,330	873,930	278,381	643,689	2,870,712	181,827
18													
19	PERCENTAGE INCREASE		5.14%	16.28%	21.17%	-7.95%	-6.59%	74.69%	41.70%	28.77%	54.30%	60.51%	21.40%
20													

Exhibit__(PJB-1)
Schedule 10
1 of 16

OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

RUN = TEST YEAR
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	ELECTRIC PLANT IN SERVICE		409,987,820	145,151,909	7,035,973	108,781,567	103,139,040	348,668	11,731,668	4,204,840	7,207,664	19,309,079	3,077,412
2													
3	ACCUMULATED DEPRECIATION		(189,745,784)	(65,842,151)	(3,229,408)	(50,777,760)	(50,059,998)	(144,702)	(5,124,486)	(1,968,096)	(3,067,378)	(8,172,774)	(1,359,030)
4													
5	NET PLANT EXCLUDING BIG STONE PLANT CAPITALIZED ITEMS		220,242,036	79,309,758	3,806,565	58,003,807	53,079,041	203,966	6,607,183	2,236,744	4,140,286	11,136,305	1,718,382
6													
7	NET CAPITALIZED ITEMS - BIG STONE PLANT		118,635	33,808	1,858	33,814	44,444	0	1,570	1,348	501	775	517
8													
9	NET ELECTRIC PLANT IN SERVICE		220,360,672	79,343,566	3,808,423	58,037,621	53,123,485	203,966	6,608,753	2,238,092	4,140,787	11,137,080	1,718,899
10													
11	PLANT HELD FOR FUTURE USE		12,871	5,168	238	3,169	1,979	21	572	119	389	1,076	140
12													
13	CONSTRUCTION WORK IN PROGRESS		2,257,935	935,970	41,161	543,583	337,745	3,710	98,371	20,726	69,820	182,144	24,705
14													
15	MATERIALS AND SUPPLIES		5,722,628	2,091,786	100,757	1,489,830	1,274,482	6,284	193,525	57,003	122,452	337,465	49,043
16													
17	FUEL STOCKS		3,072,173	865,984	47,872	871,180	1,166,335	0	41,690	34,894	13,642	16,684	13,893
18													
19	PREPAYMENTS		(13,256,872)	(4,773,299)	(229,114)	(3,491,536)	(3,195,903)	(12,271)	(397,582)	(134,643)	(249,109)	(670,005)	(103,409)
20													
21	CUSTOMER ADVANCES		(54,286)	(19,546)	(938)	(14,298)	(13,087)	(50)	(1,628)	(551)	(1,020)	(2,744)	(423)
22													
23	CASH WORKING CAPITAL		1,598,584	528,293	23,808	394,565	459,316	850	33,395	15,901	20,840	107,788	13,829
24													
25	ACCUMULATED DEFERRED INCOME TAXES		(32,540,502)	(11,716,607)	(562,387)	(8,570,374)	(7,844,707)	(30,119)	(975,910)	(330,497)	(611,467)	(1,644,605)	(253,829)
26													
27	UNAMORTIZED BALANCE - SPIRITWOOD		0	0	0	0	0	0	0	0	0	0	0
28													
29	UNAMORTIZED RATE CASE EXPENSE		0	0	0	0	0	0	0	0	0	0	0
30													
31													
32	**TOTAL AVERAGE RATE BASE**		187,173,203	67,261,316	3,229,819	49,263,739	45,309,646	172,391	5,601,187	1,901,043	3,506,333	9,464,883	1,462,848
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

RUN = TEST YEAR
10/24/08
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	**PLANT IN SERVICE**												
2	PRODUCTION PLANT												
3	A/C 101 & 106 - BASE DEMAND	E1	105,413,237	28,101,845	1,599,211	29,134,538	42,633,395	0	1,605,385	1,194,583	581,011	0	563,269
4	PEAK DEMAND	D1	48,430,531	15,739,879	810,843	14,714,929	15,000,454	0	430,643	553,578	68,753	1,004,586	106,867
5	BASE ENERGY	E1	0	0	0	0	0	0	0	0	0	0	0
6													
7	**SUBTOTAL A/C 101 & 106**		153,843,768	43,841,724	2,410,054	43,849,466	57,633,848	0	2,036,029	1,748,161	649,765	1,004,586	670,136
8													
9	A/C 114 - BASE DEMAND	E1	437,807	116,714	6,642	121,003	177,067	0	6,668	4,961	2,413	0	2,339
10	PEAK DEMAND	D1	202,575	65,837	3,392	61,550	62,744	0	1,801	2,316	288	4,202	447
11	BASE ENERGY	E1	0	0	0	0	0	0	0	0	0	0	0
12													
13	**SUBTOTAL A/C 114**		640,382	182,551	10,034	182,553	239,811	0	8,469	7,277	2,701	4,202	2,786
14													
15	**TOTAL PRODUCTION PLANT**	P10	154,484,150	44,024,274	2,420,087	44,032,019	57,873,659	0	2,044,498	1,755,437	652,466	1,008,788	672,922
16													
17													
18	TRANSMISSION PLANT												
19	A/C 101 & 106	D2	83,849,043	27,250,863	1,403,833	25,476,340	25,970,677	0	745,584	958,424	119,035	1,739,265	185,021
20	A/C 114	D2	24,048	7,815	403	7,307	7,448	0	214	275	34	499	53
21													
22	**TOTAL TRANSMISSION PLANT**		83,873,091	27,258,679	1,404,236	25,483,647	25,978,125	0	745,798	958,698	119,069	1,739,764	185,074
23													
24													
25	DISTRIBUTION PLANT												
26	PRIMARY DEMAND	D3	44,470,444	11,035,720	849,361	11,945,711	9,204,460	145,408	796,956	371,081	1,328,038	7,734,729	1,058,981
27	SECONDARY DEMAND	D4	23,731,703	5,761,354	656,241	6,441,189	3,171,600	80,023	298,099	197,270	1,572,118	4,907,636	646,174
28	PRIMARY CUSTOMER	C2	25,643,355	19,693,162	466,959	5,084,757	59,921	29,533	14,124	244,822	7,704	36,381	5,992
29	SECONDARY CUSTOMER	C3	26,434,766	20,305,004	481,467	5,240,969	58,253	30,450	14,563	252,428	7,944	37,511	6,178
30	STREETLIGHTING	C4	5,041,497	0	0	0	0	0	5,041,497	0	0	0	0
31	AREA LIGHTING	C5	2,083,462	0	0	0	0	0	2,083,462	0	0	0	0
32	METERS	C6	8,612,975	2,975,793	220,194	2,467,643	121,167	34,247	7,013	106,757	1,278,830	1,238,671	162,659
33	LOAD MANAGEMENT	C9	3,998,084	824,882	9,308	8,422	0	4,211	0	0	1,676,358	1,337,718	137,185
34													
35	**TOTAL DISTRIBUTION PLANT**	P60	140,016,287	60,595,914	2,683,530	31,188,691	12,615,401	323,872	8,255,714	1,172,358	5,870,992	15,292,646	2,017,169
36													
37													
38	GENERAL PLANT												
39	PRODUCTION	P10	10,736,423	3,059,623	168,193	3,060,161	4,022,135	0	142,090	122,000	45,345	70,109	46,767
40	TRANSMISSION	D2	4,290,841	1,394,519	71,839	1,303,711	1,329,008	0	38,154	49,046	6,091	89,004	9,468
41	DISTRIBUTION	P60	7,733,447	3,346,863	148,218	1,722,629	696,780	17,888	455,984	64,752	324,269	844,651	111,413
42	CUSTOMER ACCOUNTS	OXC	5,554,087	3,916,788	88,343	1,227,760	17,370	4,845	2,721	50,567	125,225	107,109	13,361
43	CUSTOMER SERVICE & INFO	OXI	1,525,474	823,148	22,748	324,784	244,736	656	9,526	14,717	8,600	68,333	8,226
44	LOAD MANAGEMENT	C9	59,524	12,281	139	125	0	63	0	0	24,958	19,916	2,042
45													
46	**TOTAL GENERAL PLANT**	P90	29,899,795	12,553,222	499,479	7,639,170	6,310,029	23,451	648,474	301,082	534,489	1,199,122	191,278
47													
48													
49	INTANGIBLE PLANT	P90	1,714,497	719,820	28,641	438,041	361,826	1,345	37,184	17,264	30,648	68,759	10,968
50													
51													
52	**TOTAL PLANT IN SERVICE**	EPIS	409,987,820	145,151,909	7,035,973	108,781,567	103,139,040	348,668	11,731,668	4,204,840	7,207,664	19,309,079	3,077,412
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

RUN = TEST YEAR
10/24/08
8:37:15 AM

LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	ACCUMULATED DEPRECIATION												
2	PRODUCTION PLANT												
3	BASE DEMAND	E1	(56,255,740)	(14,997,074)	(853,449)	(15,548,189)	(22,752,106)	0	(856,744)	(637,511)	(310,068)	0	(300,599)
4	PEAK DEMAND	D1	(31,283,645)	(10,167,156)	(523,763)	(9,505,091)	(9,689,526)	0	(278,174)	(357,583)	(44,411)	(648,911)	(69,031)
5	BASE ENERGY	E1	0	0	0	0	0	0	0	0	0	0	0
6													
7	**TOTAL PRODUCTION PLANT**		(87,539,385)	(25,164,230)	(1,377,212)	(25,053,280)	(32,441,632)	0	(1,134,917)	(995,094)	(354,479)	(648,911)	(369,630)
8													
9													
10	TRANSMISSION PLANT	D2	(31,502,500)	(10,238,284)	(527,427)	(9,571,587)	(9,757,312)	0	(280,120)	(360,084)	(44,722)	(653,451)	(69,513)
11													
12													
13	DISTRIBUTION PLANT	P60	(58,378,187)	(25,264,772)	(1,118,867)	(13,003,767)	(5,259,847)	(135,035)	(3,442,126)	(488,801)	(2,447,843)	(6,376,093)	(841,036)
14													
15													
16	GENERAL PLANT	P90	(11,844,076)	(4,972,653)	(197,856)	(3,026,071)	(2,499,564)	(9,290)	(256,877)	(119,266)	(211,725)	(475,003)	(75,770)
17													
18													
19	INTANGIBLE PLANT	P90	(481,635)	(202,211)	(8,046)	(123,054)	(101,644)	(378)	(10,446)	(4,850)	(8,610)	(19,316)	(3,081)
20													
21													
22	**TOTAL ACCUMULATED DEPRECIATION**		(189,745,784)	(65,842,151)	(3,229,408)	(50,777,760)	(50,059,998)	(144,702)	(5,124,486)	(1,968,096)	(3,067,378)	(8,172,774)	(1,359,030)
23													
24													
25	NET PLANT EXCLUDING BSP CAPITALIZED ITEMS		220,242,036	79,309,758	3,806,565	58,003,807	53,079,041	203,966	6,607,183	2,236,744	4,140,286	11,136,305	1,718,382
26													
27													
28	BSP CAPITALIZED ITEMS	P10	118,635	33,808	1,858	33,814	44,444	0	1,570	1,348	501	775	517
29													
30													
31	**TOTAL NET PLANT IN SERVICE**	NEPIS	220,360,672	79,343,566	3,808,423	58,037,621	53,123,485	203,966	6,608,753	2,238,092	4,140,787	11,137,080	1,718,899
32													
33													
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36													
37													
38													
39													
40	PLANT HELD FOR FUTURE USE												
41	PRODUCTION PLANT	P10	0	0	0	0	0	0	0	0	0	0	0
42	TRANSMISSION PLANT	D2	3,729	1,212	62	1,133	1,155	0	33	43	5	77	8
43	DISTRIBUTION PLANT	P60	9,142	3,957	175	2,036	824	21	539	77	383	999	132
44	GENERAL PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
45	INTANGIBLE PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
46													
47	**TOTAL PLANT HELD FOR FUTURE USE**		12,871	5,168	238	3,169	1,979	21	572	119	389	1,076	140
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

RUN = TEST YEAR
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	CONST WORK-IN-PROGRESS - MAJOR PROJECTS												
2	PRODUCTION PLANT	P10	0	0	0	0	0	0	0	0	0	0	0
3	TRANSMISSION PLANT	D2	0	0	0	0	0	0	0	0	0	0	0
4	DISTRIBUTION PLANT	P60	0	0	0	0	0	0	0	0	0	0	0
5	GENERAL PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
6	INTANGIBLE PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
7													
8	**TOTAL CWIP - MAJOR PROJECTS**		0	0	0	0	0	0	0	0	0	0	0
9													
10													
11	CONST WORK-IN-PROGRESS - SHORT-TERM												
12	PRODUCTION PLANT	P10	58,452	16,658	916	16,660	21,898	0	774	664	247	382	255
13	TRANSMISSION PLANT	D2	237,147	77,072	3,970	72,054	73,452	0	2,109	2,711	337	4,919	523
14	DISTRIBUTION PLANT	P60	1,419,997	614,543	27,215	316,305	127,941	3,285	83,727	11,890	59,542	155,093	20,457
15	GENERAL PLANT	P90	542,339	227,697	9,060	138,563	114,455	425	11,762	5,461	9,695	21,750	3,470
16	INTANGIBLE PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
17													
18	**TOTAL CWIP - SHORT-TERM**		2,257,935	935,970	41,161	543,583	337,745	3,710	98,371	20,726	69,820	182,144	24,705
19													
20													
21	CONST WORK-IN-PROGRESS - LONG TERM												
22	PRODUCTION PLANT	P10	0	0	0	0	0	0	0	0	0	0	0
23	TRANSMISSION PLANT	D2	0	0	0	0	0	0	0	0	0	0	0
24	DISTRIBUTION PLANT	P60	0	0	0	0	0	0	0	0	0	0	0
25	GENERAL PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
26	INTANGIBLE PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
27													
28	**TOTAL CWIP - LONG TERM**		0	0	0	0	0	0	0	0	0	0	0
29													
30													
31	**TOTAL CONSTRUCTION WORK-IN-PROGRESS**		2,257,935	935,970	41,161	543,583	337,745	3,710	98,371	20,726	69,820	182,144	24,705
32													
33													
34	MATERIALS & SUPPLIES												
35	PRODUCTION	P10	1,521,149	433,491	23,830	433,567	569,861	0	20,131	17,285	6,425	9,933	6,626
36	TRANSMISSION	D2	1,484,622	482,501	24,856	451,081	459,834	0	13,201	16,970	2,108	30,795	3,276
37	DISTRIBUTION	P60	2,716,857	1,175,795	52,071	605,181	244,787	6,284	160,193	22,748	113,920	296,736	39,141
38													
39	**TOTAL MATERIALS AND SUPPLIES**		5,722,628	2,091,786	100,757	1,489,830	1,274,482	6,284	193,525	57,003	122,452	337,465	49,043
40													
41													
42	FUEL STOCKS												
43	COAL STOCKS	E1	2,267,853	604,581	34,405	626,799	917,212	0	34,538	25,700	12,500	0	12,118
44	FUEL OIL STOCKS	D1	804,319	261,403	13,466	244,381	249,123	0	7,152	9,194	1,142	16,684	1,775
45													
46	**TOTAL FUEL STOCKS**		3,072,173	865,984	47,872	871,180	1,166,335	0	41,690	34,894	13,642	16,684	13,893
47													
48													
49	PREPAYMENTS	NEPIS	(13,256,872)	(4,773,299)	(229,114)	(3,491,536)	(3,195,903)	(12,271)	(397,582)	(134,643)	(249,109)	(670,005)	(103,409)
50													
51	CUSTOMER ADVANCES	NEPIS	(54,286)	(19,546)	(938)	(14,298)	(13,087)	(50)	(1,628)	(551)	(1,020)	(2,744)	(423)
52													
53	CASH WORKING CAPITAL	OX	1,598,584	528,293	23,808	394,565	459,316	850	33,395	15,901	20,840	107,788	13,829
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	**ACCUMULATED DEFFERED INCOME TAXES**												
2	ITEMS SD FLOWS THROUGH												
3	FEDERAL	NPMNR	(2,064,775)	(743,447)	(35,685)	(543,811)	(497,766)	(1,911)	(61,924)	(20,971)	(38,799)	(104,354)	(16,106)
4	MINNESOTA	NPISM	0	0	0	0	0	0	0	0	0	0	0
5	NORTH DAKOTA	NPISN	(390,230)	(140,507)	(6,744)	(102,777)	(94,075)	(361)	(11,703)	(3,963)	(7,333)	(19,722)	(3,044)
6													
7	**SUBTOTAL**		(2,455,005)	(883,955)	(42,429)	(646,588)	(591,841)	(2,272)	(73,627)	(24,934)	(46,132)	(124,077)	(19,150)
8													
9	ALL OTHER												
10	FEDERAL	NEPIS	(25,709,554)	(9,257,041)	(444,330)	(6,771,269)	(6,197,935)	(23,797)	(771,045)	(261,119)	(483,107)	(1,299,367)	(200,545)
11	MINNESOTA	NPISM	0	0	0	0	0	0	0	0	0	0	0
12	NORTH DAKOTA	NPISN	(4,375,944)	(1,575,612)	(75,628)	(1,152,517)	(1,054,931)	(4,050)	(131,237)	(44,444)	(82,228)	(221,161)	(34,134)
13													
14	**SUBTOTAL**		(30,085,497)	(10,832,653)	(519,958)	(7,923,785)	(7,252,866)	(27,847)	(902,283)	(305,563)	(565,335)	(1,520,528)	(234,679)
15													
16	**TOTAL ACCUMULATED DEFERRED INCOME TAXES**		(32,540,502)	(11,716,607)	(562,387)	(8,570,374)	(7,844,707)	(30,119)	(975,910)	(330,497)	(611,467)	(1,644,605)	(253,829)
17													
18													
19	UNAMORTIZED BALANCE - SPIRITWOOD PLANT	P10	0	0	0	0	0	0	0	0	0	0	0
20													
21													
22	UNAMORTIZED RATE CASE EXPENSES	R10	0	0	0	0	0	0	0	0	0	0	0
23													
24													
25													
26													
27	**TOTAL AVERAGE RATE BASE**		187,173,203	67,261,316	3,229,819	49,263,739	45,309,646	172,391	5,601,187	1,901,043	3,506,333	9,464,883	1,462,848
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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1	OPERATING REVENUES												
2	SALES OF ELECTRICITY		118,309,177	36,574,921	1,601,767	34,012,150	36,231,788	45,963	2,095,668	967,569	1,185,332	4,744,402	849,617
3	OTHER OPERATING REVENUE		13,804,432	4,233,563	206,440	3,411,099	4,173,430	7,994	262,357	136,601	191,521	1,048,161	133,267
4													
5	**TOTAL OPERATING REVENUE**		132,113,609	40,808,484	1,808,207	37,423,249	40,405,218	53,957	2,358,025	1,104,170	1,376,853	5,792,563	982,884
6													
7													
8	OPERATING EXPENSES												
9	PRODUCTION EXPENSES		67,714,739	17,992,223	943,817	16,768,827	23,737,741	21,230	879,849	679,040	682,622	5,343,526	665,864
10	TRANSMISSION EXPENSES		4,467,061	1,451,791	74,789	1,357,253	1,383,589	0	39,721	51,060	6,342	92,659	9,857
11	DISTRIBUTION EXPENSES		6,727,802	2,834,896	126,263	1,480,741	501,045	15,652	725,069	57,919	269,959	631,341	84,918
12	CUSTOMER ACCOUNTING EXPENSES		4,728,770	3,334,768	75,215	1,045,319	14,789	4,125	2,316	43,053	106,617	91,193	11,376
13	CUSTOMER SERVICE AND INFORMATION EXPENSES		2,185,290	1,179,186	32,587	465,263	350,593	939	13,646	21,082	12,320	97,889	11,784
14	SALES EXPENSES		701,476	543,831	11,270	133,740	1,513	332	320	6,705	554	2,768	443
15	ADMINISTRATIVE AND GENERAL EXPENSES		13,557,519	5,687,143	226,455	3,457,842	2,799,888	10,941	432,187	136,689	227,720	496,204	82,451
16	CHARITABLE CONTRIBUTIONS		114,816	89,013	1,845	21,890	248	54	52	1,098	91	453	72
17	DEPRECIATION EXPENSE		10,716,072	3,839,474	184,123	2,808,019	2,633,436	9,808	320,991	108,859	202,040	524,804	84,519
18	AMORTIZATION OF BIG STONE PLANT CAPITALIZED COSTS		0	0	0	0	0	0	0	0	0	0	0
19	SPIRITWOOD AMORTIZATION		0	0	0	0	0	0	0	0	0	0	0
20	GENERAL TAXES		3,957,594	1,424,980	68,398	1,042,334	954,078	3,663	118,691	40,195	74,367	200,018	30,871
21													
22	**TOTAL OPERATING EXPENSES**		114,871,140	38,377,304	1,744,762	28,581,228	32,376,918	66,745	2,532,843	1,145,700	1,582,632	7,480,855	982,155
23													
24													
25	**NET OPERATING INCOME BEFORE INCOME TAXES**		17,242,469	2,431,180	63,445	8,842,021	8,028,300	(12,787)	(174,818)	(41,531)	(205,779)	(1,688,292)	729
26													
27													
28	INCOME TAX EXPENSE												
29	INVESTMENT TAX CREDIT		(476,371)	(168,654)	(8,175)	(126,395)	(119,839)	(405)	(13,631)	(4,886)	(8,375)	(22,436)	(3,576)
30	DEFERRED INCOME TAXES		213,186	76,760	3,684	56,148	51,394	197	6,394	2,165	4,006	10,774	1,663
31	INCOME TAXES		4,563,511	163,068	(13,072)	2,889,081	2,616,701	(7,041)	(134,395)	(38,627)	(121,921)	(773,383)	(16,900)
32													
33	**TOTAL INCOME TAX EXPENSE**		4,300,325	71,174	(17,563)	2,818,834	2,548,256	(7,249)	(141,632)	(41,347)	(126,290)	(785,044)	(18,813)
34													
35													
36													
37	**NET OPERATING INCOME**		12,942,144	2,360,006	81,008	6,023,187	5,480,044	(5,538)	(33,185)	(183)	(79,489)	(903,248)	19,542
38													
39													
40	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION		0	0	0	0	0	0	0	0	0	0	0
41													
42													
43	**TOTAL AVAILABLE FOR RETURN**		12,942,144	2,360,006	81,008	6,023,187	5,480,044	(5,538)	(33,185)	(183)	(79,489)	(903,248)	19,542
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	OPERATING REVENUES												
2													
3	**SALES OF ELECTRICITY**	R10	118,309,177	36,574,921	1,601,767	34,012,150	36,231,788	45,963	2,095,668	967,569	1,185,332	4,744,402	849,617
4													
5													
6	OTHER OPERATING REVENUES												
7	SALES FOR RESALE												
8	MUNICIPALITIES & OFF SYSTEM SALES												
9	NON-ASSOCIATAED UTILITIES, CO-OPS & OPA												
10	BUY SELL TRANSACTIONS	D2	0	0	0	0	0	0	0	0	0	0	0
11	ALL OTHER TRANSACTIONS												
12	BASE DEMAND	E1	0	0	0	0	0	0	0	0	0	0	0
13	PEAK DEMAND	D1	0	0	0	0	0	0	0	0	0	0	0
14	BASE ENERGY	E2	8,508,499	2,214,519	115,241	2,035,926	2,961,262	3,214	111,508	82,974	96,869	793,092	93,894
15	PEAK ENERGY	D1	0	0	0	0	0	0	0	0	0	0	0
16													
17	**TOTAL ALL OTHER TRANSACTIONS**		8,508,499	2,214,519	115,241	2,035,926	2,961,262	3,214	111,508	82,974	96,869	793,092	93,894
18													
19	**TOTAL SALES FOR RESALE**		8,508,499	2,214,519	115,241	2,035,926	2,961,262	3,214	111,508	82,974	96,869	793,092	93,894
20													
21													
22	OTHER ELECTRIC REVENUES												
23	LATE FEES	C1	170,779	132,399	2,744	32,560	368	81	78	1,632	135	674	108
24	CONNECTION FEES	C1	89,754	69,583	1,442	17,112	194	43	41	858	71	354	57
25	RENT FROM ELECTRIC PROPERTY	NEPIS	270,804	97,506	4,680	71,323	65,284	251	8,122	2,750	5,089	13,686	2,112
26	RENT FROM ELECTRIC PROPERTY - BIG STONE	NEPIS	(8,686)	(3,128)	(150)	(2,288)	(2,094)	(8)	(261)	(88)	(163)	(439)	(68)
27	RENT FROM ELECTRIC PROPERTY - COYOTE	NEPIS	4,981	1,794	86	1,312	1,201	5	149	51	94	252	39
28	OTHER MISC ELECTRIC REVENUE	NEPIS	1,333,335	480,084	23,044	351,168	321,434	1,234	39,988	13,542	25,055	67,387	10,401
29	ITA DEFICIENCY PAYMENTS	NEPIS	1,535,611	552,916	26,539	404,443	370,198	1,421	46,054	15,596	28,856	77,610	11,978
30		NEPIS	0	0	0	0	0	0	0	0	0	0	0
31	MISCELLANEOUS SERVICES	NEPIS	14,308	5,152	247	3,768	3,449	13	429	145	269	723	112
32	WHEELING		0	0	0	0	0	0	0	0	0	0	0
33	LOAD CONTROL AND DISPATCH	NEPIS	1,875,405	675,263	32,412	493,936	452,114	1,736	56,245	19,048	35,241	94,783	14,629
34	RESIDENTIAL CONSERVATION SERVICES	C1	9,642	7,475	155	1,838	21	5	4	92	8	38	6
35													
36	**TOTAL OTHER ELECTRIC REVENUES**		5,295,933	2,019,044	91,199	1,375,172	1,212,168	4,780	150,849	53,627	94,652	255,069	39,373
37													
38	**TOTAL OTHER OPERATING REVENUES**		13,804,432	4,233,563	206,440	3,411,099	4,173,430	7,994	262,357	136,601	191,521	1,048,161	133,267
39													
40													
41	**TOTAL OPERATING REVENUES**		132,113,609	40,808,484	1,808,207	37,423,249	40,405,218	53,957	2,358,025	1,104,170	1,376,853	5,792,563	982,884
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

RUN = TEST YEAR 10/24/08 8:37:15 AM

LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	**OPERATING EXPENSES**												
2	PRODUCTION EXPENSES												
3	PROD EXPENSES EXCLUDING PURCHASED POWER												
4	BASE DEMAND	E1	4,731,771	1,261,431	71,785	1,307,786	1,913,720	0	72,062	53,622	26,080	0	25,284
5	PEAK DEMAND	D1	2,457,800	798,783	41,149	746,768	761,258	0	21,855	28,094	3,489	50,982	5,423
6	BASE ENERGY	E2	26,204,212	6,820,207	354,916	6,270,183	9,120,002	9,899	343,419	255,541	298,333	2,442,540	289,171
7	PEAK ENERGY	D1	2,597,632	844,228	43,491	789,254	804,568	0	23,098	29,692	3,688	53,882	5,732
8													
9	**TOTAL EXCLUDING PURCHASED POWER**		35,991,415	9,724,649	511,341	9,113,991	12,599,548	9,899	460,434	366,949	331,590	2,547,404	325,611
10													
11													
12	PURCHASED POWER												
13	BUY SELL TRANSACTIONS	D2	0	0	0	0	0	0	0	0	0	0	0
14	ALL OTHER TRANSACTIONS												
15	BASE DEMAND	E1	1,725,792	460,074	26,182	476,981	697,980	0	26,283	19,557	9,512	0	9,222
16	PEAK DEMAND	D1	0	0	0	0	0	0	0	0	0	0	0
17	BASE ENERGY	E2	29,997,532	7,807,500	406,294	7,177,855	10,440,213	11,331	393,132	292,534	341,520	2,796,122	331,032
18	PEAK ENERGY	D1	0	0	0	0	0	0	0	0	0	0	0
19													
20	**TOTAL ALL OTHER TRANSACTIONS**		31,723,324	8,267,574	432,476	7,654,836	11,138,193	11,331	419,415	312,091	351,032	2,796,122	340,254
21													
22	**TOTAL PURCHASED POWER**		31,723,324	8,267,574	432,476	7,654,836	11,138,193	11,331	419,415	312,091	351,032	2,796,122	340,254
23													
24	**TOTAL PRODUCTION EXPENSES**		67,714,739	17,992,223	943,817	16,768,827	23,737,741	21,230	879,849	679,040	682,622	5,343,526	665,864
25													
26													
27	TRANSMISSION EXPENSES	D2	4,467,061	1,451,791	74,789	1,357,253	1,383,589	0	39,721	51,060	6,342	92,659	9,857
28													
29													
30	DISTRIBUTION EXPENSES												
31	PRIMARY DEMAND	D3	1,905,348	472,828	36,391	511,817	394,368	6,230	34,146	15,899	56,900	331,397	45,372
32	SECONDARY DEMAND	D4	637,417	154,746	17,626	173,006	85,187	2,149	8,007	5,299	42,226	131,816	17,356
33	PRIMARY CUSTOMER	C2	1,303,643	1,001,150	23,739	258,496	3,046	1,501	718	12,446	392	1,850	305
34	SECONDARY CUSTOMER	C3	1,054,914	810,297	19,214	209,148	2,325	1,215	581	10,073	317	1,497	247
35	STREETLIGHTING	C4	659,874	0	0	0	0	0	659,874	0	0	0	0
36	AREA LIGHTING	C5	20,809	0	0	0	0	0	20,809	0	0	0	0
37	METERS	C6	1,145,797	395,874	29,293	328,274	16,119	4,556	933	14,202	170,125	164,782	21,639
38	LOAD MANAGEMENT	C9	0	0	0	0	0	0	0	0	0	0	0
39													
40	**TOTAL DISTRIBUTION**	OXD	6,727,802	2,834,896	126,263	1,480,741	501,045	15,652	725,069	57,919	269,959	631,341	84,918
41													
42													
43	CUSTOMER ACCOUNTING EXPENSES												
44	METER READING	C7	2,044,032	1,272,986	26,327	512,969	8,515	1,033	838	17,421	105,810	87,384	10,749
45	OTHER	C8	2,684,738	2,061,781	48,888	532,350	6,273	3,092	1,479	25,632	807	3,809	627
46													
47	**TOTAL CUSTOMER ACCOUNTS**	OXC	4,728,770	3,334,768	75,215	1,045,319	14,789	4,125	2,316	43,053	106,617	91,193	11,376
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

RUN = TEST YEAR 10/24/08 8:37:15 AM

LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	CUSTOMER SERVICE & INFORMATION EXPENSE												
2	CONSERVATION & PROMOTIONAL REBATES	E2	1,000,000	260,271	13,544	239,282	348,036	378	13,105	9,752	11,385	93,212	11,035
3	OTHER	C1	1,185,290	918,915	19,043	225,981	2,557	561	541	11,330	936	4,678	748
4													
5	**TOTAL CUSTOMER SERV & INFORMATION EXP**	OXI	2,185,290	1,179,186	32,587	465,263	350,593	939	13,646	21,082	12,320	97,889	11,784
6													
7													
8	SALES EXPENSES												
9	OFF-PEAK DEVELOPMENT	C1	500,000	387,633	8,033	95,328	1,079	237	228	4,780	395	1,973	316
10	OTHER	C1	201,476	156,197	3,237	38,412	435	95	92	1,926	159	795	127
11													
12	**TOTAL SALES EXPENSES**		701,476	543,831	11,270	133,740	1,513	332	320	6,705	554	2,768	443
13													
14													
15	ADMINISTRATIVE & GENERAL EXPENSES												
16	SALARIES, SUPPLIES, PENSIONS & BENEFITS												
17	PRODUCTION	OXPD	3,452,775	976,067	53,877	980,422	1,306,292	0	46,551	39,221	15,136	19,744	15,464
18	TRANSMISSION	D2	1,357,755	441,269	22,732	412,535	420,539	0	12,073	15,520	1,928	28,164	2,996
19	DISTRIBUTION	OXD	2,559,933	1,078,680	48,043	563,423	190,648	5,956	275,889	22,038	102,720	240,226	32,311
20	CUSTOMER ACCOUNTS	OXC	1,803,178	1,271,616	28,681	398,602	5,639	1,573	883	16,417	40,655	34,774	4,338
21	CUSTOMER SERVICE & INFO	C1	631,311	489,434	10,143	120,363	1,362	299	288	6,035	498	2,491	399
22													
23	**TOTAL SALARIES, SUPPLIES, PENSIONS, AND BENEFITS**		9,804,952	4,257,065	163,476	2,475,344	1,924,480	7,827	335,685	99,231	160,936	325,399	55,508
24													
25	LOAD MANAGEMENT EXPENSES	C9	0	0	0	0	0	0	0	0	0	0	0
26													
27	OUTSIDE SERVICES	NEPIS	726,210	261,481	12,551	191,266	175,071	672	21,779	7,376	13,646	36,703	5,665
28													
29	PROPERTY INSURANCE	NEPIS	529,778	190,753	9,156	139,531	127,716	490	15,888	5,381	9,955	26,775	4,132
30													
31	INJURIES & DAMAGES	NEPIS	692,354	249,291	11,966	182,349	166,909	641	20,764	7,032	13,010	34,992	5,401
32													
33	REGULATORY COMMISSION EXPENSE	R10	263,370	81,420	3,566	75,715	80,656	102	4,665	2,154	2,639	10,562	1,891
34													
35	GENERAL ADVERTISING	C1	606	470	10	116	1	0	0	6	0	2	0
36													
37	MISCELLANEOUS, RENTS, MAINTENANCE	P90	1,540,249	646,663	25,730	393,522	325,053	1,208	33,405	15,510	27,534	61,771	9,853
38													
39	**TOTAL ADMINISTRATIVE & GENERAL EXP**		13,557,519	5,687,143	226,455	3,457,842	2,799,888	10,941	432,187	136,689	227,720	496,204	82,451
40													
41													
42	CHARITABLE CONTRIBUTIONS	C1	114,816	89,013	1,845	21,890	248	54	52	1,098	91	453	72
43													
44													
45													
46	**TOTAL O & M EXPENSES**		100,197,474	33,112,849	1,492,241	24,730,875	28,789,404	53,274	2,093,161	996,646	1,306,225	6,756,033	866,765
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	**DEPRECIATION EXPENSE**												
2	PRODUCTION												
3	BASE DEMAND	E1	2,895,006	771,772	43,920	800,133	1,170,858	0	44,089	32,807	15,957	0	15,469
4	PEAK DEMAND	D1	1,185,906	385,418	19,855	360,321	367,312	0	10,545	13,555	1,684	24,599	2,617
5	BASE ENERGY	E1	0	0	0	0	0	0	0	0	0	0	0
6													
7	**TOTAL PRODUCTION**		4,080,911	1,157,190	63,775	1,160,454	1,538,170	0	54,634	46,363	17,640	24,599	18,086
8													
9													
10	TRANSMISSION	D2	1,614,258	524,632	27,027	490,469	499,986	0	14,354	18,452	2,292	33,484	3,562
11													
12													
13	DISTRIBUTION	P60	3,839,335	1,661,578	73,584	855,214	345,922	8,881	226,377	32,147	160,986	419,334	55,312
14													
15													
16	GENERAL	P90	946,193	397,252	15,806	241,745	199,684	742	20,521	9,528	16,914	37,947	6,053
17													
18													
19	INTANGIBLE	P90	235,374	98,820	3,932	60,136	49,673	185	5,105	2,370	4,208	9,440	1,506
20													
21													
22	**TOTAL DEPRECIATION EXPENSE**		10,716,072	3,839,474	184,123	2,808,019	2,633,436	9,808	320,991	108,859	202,040	524,804	84,519
23													
24													
25													
26													
27													
28													
29	BIG STONE EXPENSE OFFSETS	P10	0	0	0	0	0	0	0	0	0	0	0
30													
31													
32	SPIRITWOOD AMORTIZATION	P10	0	0	0	0	0	0	0	0	0	0	0
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	GENERAL TAXES	NEPIS	3,957,594	1,424,980	68,398	1,042,334	954,078	3,663	118,691	40,195	74,367	200,018	30,871
2													
3	NET OPERATING INCOME BEFORE TAX (NOIBT)		17,242,469	2,431,180	63,445	8,842,021	8,028,300	(12,787)	(174,818)	(41,531)	(205,779)	(1,688,292)	729
4													
5	INVESTMENT TAX CREDIT												
6	AMORTIZE PRIOR YEARS CREDIT	EPIS	(476,371)	(168,654)	(8,175)	(126,395)	(119,839)	(405)	(13,631)	(4,886)	(8,375)	(22,436)	(3,576)
7	DEBITS UTILIZED	EPIS	0	0	0	0	0	0	0	0	0	0	0
8													
9	**TOTAL INVESTMENT TAX CREDIT**		(476,371)	(168,654)	(8,175)	(126,395)	(119,839)	(405)	(13,631)	(4,886)	(8,375)	(22,436)	(3,576)
10													
11	DEFERRED INCOME TAXES												
12	ITEMS SOUTH DAKOTA FLOWS THROUGH												
13	FEDERAL	NPMNR	272,583	98,147	4,711	71,792	65,713	252	8,175	2,768	5,122	13,776	2,126
14	MINNESOTA	NPISM	0	0	0	0	0	0	0	0	0	0	0
15	NORTH DAKOTA	NPISN	53,033	19,095	917	13,968	12,785	49	1,590	539	997	2,680	414
16													
17	**SUBTOTAL**		325,616	117,242	5,628	85,759	78,498	301	9,765	3,307	6,119	16,457	2,540
18													
19	ALL OTHER												
20	FEDERAL	NEPIS	(109,492)	(39,424)	(1,892)	(28,838)	(26,396)	(101)	(3,284)	(1,112)	(2,057)	(5,534)	(854)
21	MINNESOTA	NPISM	0	0	0	0	0	0	0	0	0	0	0
22	NORTH DAKOTA	NPISN	(2,938)	(1,058)	(51)	(774)	(708)	(3)	(88)	(30)	(55)	(148)	(23)
23													
24	**SUBTOTAL**		(112,430)	(40,482)	(1,943)	(29,611)	(27,104)	(104)	(3,372)	(1,142)	(2,113)	(5,682)	(877)
25													
26	**TOTAL DEFERRED INCOME TAXES**		213,186	76,760	3,684	56,148	51,394	197	6,394	2,165	4,006	10,774	1,663
27													
28													
29	CURRENT INCOME TAXES												
30	FEDERAL INCOME TAXES		3,808,410	136,307	(10,896)	2,410,857	2,183,463	(5,876)	(112,120)	(32,224)	(101,720)	(645,285)	(14,096)
31	MINNESOTA INCOME TAXES		0	0	0	0	0	0	0	0	0	0	0
32	NORTH DAKOTA INCOME TAXES		755,101	26,761	(2,176)	478,224	433,238	(1,166)	(22,275)	(6,403)	(20,201)	(128,098)	(2,804)
33													
34	**TOTAL CURRENT INCOME TAXES**		4,563,511	163,068	(13,072)	2,889,081	2,616,701	(7,041)	(134,395)	(38,627)	(121,921)	(773,383)	(16,900)
35													
36	**TOTAL INCOME TAXES**		4,300,325	71,174	(17,563)	2,818,834	2,548,256	(7,249)	(141,632)	(41,347)	(126,290)	(785,044)	(18,813)
37													
38													
39	**NET OPERATING INCOME**		12,942,144	2,360,006	81,008	6,023,187	5,480,044	(5,538)	(33,185)	(183)	(79,489)	(903,248)	19,542
40													
41	AFDC	CWIPLT	0	0	0	0	0	0	0	0	0	0	0
42													
43	**TOTAL AVAILABLE FOR RETURN**		12,942,144	2,360,006	81,008	6,023,187	5,480,044	(5,538)	(33,185)	(183)	(79,489)	(903,248)	19,542
44													
45													
46	RATE OF RETURN ON RATE BASE		6.91%	3.51%	2.51%	12.23%	12.09%	-3.21%	-0.59%	-0.01%	-2.27%	-9.54%	1.34%
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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1	DEVELOPMENT OF FEDERAL INCOME TAX EXPENSE												
2													
3	NET OPERATING INCOME BEFORE TAX (NOIBT)		17,242,469	2,431,180	63,445	8,842,021	8,028,300	(12,787)	(174,818)	(41,531)	(205,779)	(1,688,292)	729
4	LESS: INTEREST COST		5,091,111	1,829,508	87,851	1,339,974	1,232,422	4,689	152,352	51,708	95,372	257,445	39,789
5													
6	NET INCOME BEFORE TAX		12,151,358	601,672	(24,406)	7,502,047	6,795,878	(17,476)	(327,170)	(93,239)	(301,151)	(1,945,736)	(39,060)
7													
8	FEDERAL SCHEDULE M ADJUSTMENTS:												
9	ADDITIONAL TAX DEPRECIATION	NEPIS	1,135,898	408,994	19,631	299,168	273,837	1,051	34,066	11,537	21,345	57,409	8,860
10	COST TO REMOVE	NEPIS	1,660,645	597,936	28,700	437,373	400,340	1,537	49,804	16,866	31,205	83,929	12,954
11	DIRECTLY ASSIGNED SCHEDULE M ITEMS	NEPIS	(59,233)	(21,328)	(1,024)	(15,601)	(14,280)	(55)	(1,776)	(602)	(1,113)	(2,994)	(462)
12	ACCRUED VACATION PAY	NEPIS	36,976	13,313	639	9,738	8,914	34	1,109	376	695	1,869	288
13	CHARGES - OPERATING RESERVES	NEPIS	1,964,501	707,343	33,952	517,402	473,593	1,818	58,917	19,952	36,915	99,286	15,324
14	PROVISIONS - OPERATING RESERVES	NEPIS	(3,615,645)	(1,301,857)	(62,488)	(952,273)	(871,642)	(3,347)	(108,435)	(36,722)	(67,941)	(182,736)	(28,203)
15	UNBILLED REVENUES	NEPIS	0	0	0	0	0	0	0	0	0	0	0
16	PREFERRED DIVIDENDS PAID CREDIT	NEPIS	67,606	24,342	1,168	17,806	16,298	63	2,028	687	1,270	3,417	527
17	OTHER SCHEDULE M ITEMS	NEPIS	(675,662)	(243,280)	(11,677)	(177,953)	(162,885)	(625)	(20,264)	(6,862)	(12,696)	(34,148)	(5,270)
18													
19	**SUBTOTAL FEDERAL SCHEDULE M ADJUSTMENTS**		515,086	185,463	8,902	135,661	124,175	477	15,448	5,231	9,679	26,033	4,018
20													
21	**FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES**		11,636,272	416,209	(33,308)	7,366,386	6,671,703	(17,953)	(342,618)	(98,470)	(310,830)	(1,971,769)	(43,078)
22													
23	LESS:												
24	MINNESOTA STATE INCOME TAXES		0	0	0	0	0	0	0	0	0	0	0
25	NORTH DAKOTA STATE INCOME TAXES		755,101	26,761	(2,176)	478,224	433,238	(1,166)	(22,275)	(6,403)	(20,201)	(128,098)	(2,804)
26													
27	**FEDERAL TAXABLE INCOME**		10,881,171	389,448	(31,132)	6,888,162	6,238,465	(16,787)	(320,343)	(92,067)	(290,629)	(1,843,671)	(40,274)
28	FEDERAL TAX RATE		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
29													
30	FEDERAL INCOME TAX BEFORE CREDITS		3,808,410	136,307	(10,896)	2,410,857	2,183,463	(5,876)	(112,120)	(32,224)	(101,720)	(645,285)	(14,096)
31	INVESTMENT TAX CREDIT - DEBITS UTILIZED	EPIS	0	0	0	0	0	0	0	0	0	0	0
32													
33	**FEDERAL INCOME TAXES**		3,808,410	136,307	(10,896)	2,410,857	2,183,463	(5,876)	(112,120)	(32,224)	(101,720)	(645,285)	(14,096)
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	DEVELOPMENT OF MINNESOTA STATE INCOME TAX EXPENSE												
2													
3	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		0	0	0	0	0	0	0	0	0	0	0
4													
5	MINNESOTA ADJUSTMENTS TO FEDERAL SCHEDULE M:												
6	PAYSOP ADJUSTMENT	NEPIS	0	0	0	0	0	0	0	0	0	0	0
7	CHANGE IN EXCESS TAX DEPRECIATION - MN	NEPIS	0	0	0	0	0	0	0	0	0	0	0
8	CHANGE IN ACRS - ORDINARY LOSS	NEPIS	0	0	0	0	0	0	0	0	0	0	0
9	PREFERRED DIVIDENDS PAID CREDIT	NEPIS	0	0	0	0	0	0	0	0	0	0	0
10	MISCELLANEOUS ADJUSTMENTS TO FED SCHEDULE M	NEPIS	0	0	0	0	0	0	0	0	0	0	0
11													
12	**TOTAL MINNESOTA ADJUSTMENTS TO FED SCHEDULE M**		0	0	0	0	0	0	0	0	0	0	0
13													
14	MINNESOTA TAXABLE INCOME		0	0	0	0	0	0	0	0	0	0	0
15	MINNESOTA TAX RATE		0	0	0	0	0	0	0	0	0	0	0
16													
17	**MINNESOTA INCOME TAX**		0	0	0	0	0	0	0	0	0	0	0
18													
19													
20													
21													
22													
23													
24													
25	DEVELOPMENT OF NORTH DAKOTA STATE INCOME TAX EXPENSE												
26													
27	**FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES**		11,636,272	416,209	(33,308)	7,366,386	6,671,703	(17,953)	(342,618)	(98,470)	(310,830)	(1,971,769)	(43,078)
28													
29	NORTH DAKOTA ADJUSTMENTS TO FEDERAL SCHEDULE M:												
30	CHANGE IN EXCESS TAX DEPRECIATION - ND	NEPIS	(7,783)	(2,802)	(135)	(2,050)	(1,876)	(7)	(233)	(79)	(146)	(393)	(61)
31	CHANGE IN ACRS - ORDINARY LOSS - ND	NEPIS	0	0	0	0	0	0	0	0	0	0	0
32	CHANGE IN INCOME FROM ADR PROPERTY - ND	NEPIS	0	0	0	0	0	0	0	0	0	0	0
33	MISCELLANEOUS ADJUSTMENTS TO FED SCHEDULE M	NEPIS	(3,785)	(1,363)	(65)	(997)	(912)	(4)	(113)	(38)	(71)	(191)	(30)
34			0	0	0	0	0	0	0	0	0	0	0
35	**TOTAL NORTH DAKOTA ADJUSTMENTS TO FED SCHEDULE M**		(11,567)	(4,165)	(200)	(3,047)	(2,789)	(11)	(347)	(117)	(217)	(585)	(90)
36													
37	**SUBTOTAL**		11,624,704	412,044	(33,508)	7,363,340	6,668,915	(17,964)	(342,965)	(98,588)	(311,048)	(1,972,354)	(43,168)
38	DEDUCTION OF FEDERAL INCOME TAXES		0	0	0	0	0	0	0	0	0	0	0
39													
40	**NORTH DAKOTA TAXABLE INCOME**		11,624,704	412,044	(33,508)	7,363,340	6,668,915	(17,964)	(342,965)	(98,588)	(311,048)	(1,972,354)	(43,168)
41	NORTH DAKOTA TAX RATE		6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
42													
43	**NORTH DAKOTA INCOME TAX**		755,101	26,761	(2,176)	478,224	433,238	(1,166)	(22,275)	(6,403)	(20,201)	(128,098)	(2,804)
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

RUN = TEST YEAR
10/24/08
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LINE NO	ITEM	ALLOCATION FACTOR	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	MWH CONSUMPTION AT GENERATORS - PARTIAL	E1	1,621,989	432,402	24,607	448,292	655,998	0	24,702	18,381	8,940	0	8,667
2	PERCENTAGE		100.00000%	26.65874%	1.51709%	27.63841%	40.44406%	0.00000%	1.52294%	1.13324%	0.55117%	0.00000%	0.53434%
3													
4	MWH CONSUMPTION AT GENERATORS - TOTAL	E2	1,884,859	490,575	25,529	451,012	655,998	712	24,702	18,381	21,459	175,691	20,800
5	PERCENTAGE		100.00000%	26.02714%	1.35442%	23.92815%	34.80357%	0.03777%	1.31055%	0.97519%	1.13849%	9.32117%	1.10353%
6													
7	GENERATION DEMAND FACTOR	D1	259,222	84,247	4,340	78,761	80,289	0	2,305	2,963	368	5,377	572
8	PERCENTAGE		100.00000%	32.49991%	1.67424%	30.38358%	30.97313%	0.00000%	0.88920%	1.14303%	0.14196%	2.07428%	0.22066%
9													
10	TRANSMISSION DEMAND FACTOR	D2	259,222	84,247	4,340	78,761	80,289	0	2,305	2,963	368	5,377	572
11	PERCENTAGE		100.00000%	32.49991%	1.67424%	30.38358%	30.97313%	0.00000%	0.88920%	1.14303%	0.14196%	2.07428%	0.22066%
12													
13	DISTRIBUTION - PRIMARY DEMAND FACTOR	D3	335,193	83,181	6,402	90,040	69,378	1,096	6,007	2,797	10,010	58,300	7,982
14	PERCENTAGE		100.00000%	24.81585%	1.90994%	26.86214%	20.69793%	0.32698%	1.79210%	0.83444%	2.98634%	17.39296%	2.38131%
15													
16	DISTRIBUTION - SECONDARY DEMAND FACTOR	D4	459,669	111,594	12,711	124,762	61,432	1,550	5,774	3,821	30,451	95,058	12,516
17	PERCENTAGE		100.00000%	24.27703%	2.76525%	27.14170%	13.36440%	0.33720%	1.25612%	0.83125%	6.62455%	20.67966%	2.72283%
18													
19	CUSTOMER OR METER FACTORS												
20	TOTAL RETAIL CUSTOMERS	C1	57,014	44,201	916	10,870	123	27	26	545	45	225	36
21	PERCENTAGE		100.00000%	77.52657%	1.60662%	19.06549%	0.21574%	0.04736%	0.04560%	0.95591%	0.07893%	0.39464%	0.06314%
22													
23	RETAIL SERVICE LOCATIONS	C2	59,913	46,011	1,091	11,880	140	69	33	572	18	85	14
24	PERCENTAGE		100.00000%	76.79635%	1.82097%	19.82875%	0.23367%	0.11517%	0.05508%	0.95472%	0.03004%	0.14187%	0.02337%
25													
26	SECONDARY SERVICE LOCATIONS	C3	59,901	46,011	1,091	11,876	132	69	33	572	18	85	14
27	PERCENTAGE		100.00000%	76.81174%	1.82134%	19.82605%	0.22036%	0.11519%	0.05509%	0.95491%	0.03005%	0.14190%	0.02337%
28													
29	STREET LIGHTING FACTOR	C4	1,760,035	0	0	0	0	0	1,760,035	0	0	0	0
30	PERCENTAGE		100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%
31													
32	AREA LIGHTING FACTOR	C5	1,716,671	0	0	0	0	0	1,716,671	0	0	0	0
33	PERCENTAGE		100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%
34													
35	METER FACTOR	C6	12,850,789	4,439,962	328,536	3,681,789	180,785	51,098	10,464	159,285	1,908,048	1,848,130	242,692
36	PERCENTAGE		100.00000%	34.55011%	2.55654%	28.65030%	1.40680%	0.39763%	0.08143%	1.23950%	14.84771%	14.38145%	1.88854%
37													
38	METER READING FACTOR	C7	73,215	45,597	943	18,374	305	37	30	624	3,790	3,130	385
39	PERCENTAGE		100.00000%	62.27822%	1.28799%	25.09595%	0.41658%	0.05054%	0.04098%	0.85228%	5.17653%	4.27508%	0.52585%
40													
41	SYSTEM SERVICE LOCATIONS	C8	59,913	46,011	1,091	11,880	140	69	33	572	18	85	14
42	PERCENTAGE		100.00000%	76.79635%	1.82097%	19.82875%	0.23367%	0.11517%	0.05508%	0.95472%	0.03004%	0.14187%	0.02337%
43													
44	LOAD MANAGEMENT FACTOR	C9	18,040	3,722	42	38	0	19	0	0	7,564	6,036	619
45	PERCENTAGE		100.00000%	20.63193%	0.23282%	0.21064%	0.00000%	0.10532%	0.00000%	0.00000%	41.92905%	33.45898%	3.43126%
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOCATION FACTOR	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
0													
1	GROSS PLANT IN SERVICE												
2	PRODUCTION PLANT	P10	154,484,150	44,024,274	2,420,087	44,032,019	57,873,659	0	2,044,498	1,755,437	652,466	1,008,788	672,922
3	PERCENTAGE		100.00000%	28.49760%	1.56656%	28.50261%	37.46252%	0.00000%	1.32344%	1.13632%	0.42235%	0.65300%	0.43559%
4													
5	DISTRIBUTION PLANT	P60	140,016,287	60,595,914	2,683,530	31,188,691	12,615,401	323,872	8,255,714	1,172,358	5,870,992	15,292,646	2,017,169
6	PERCENTAGE		100.00000%	43.27776%	1.91658%	22.27504%	9.00995%	0.23131%	5.89625%	0.83730%	4.19308%	10.92205%	1.44067%
7													
8	GENERAL PLANT	P90	29,899,795	12,553,222	499,479	7,639,170	6,310,029	23,451	648,474	301,082	534,489	1,199,122	191,278
9	PERCENTAGE		100.0000%	41.9843%	1.6705%	25.5492%	21.1039%	0.0784%	2.16882%	1.00697%	1.78760%	4.01047%	0.63973%
10													
11													
12	ELECTRIC PLANT IN SERVICE	EPIS	409,987,820	145,151,909	7,035,973	108,781,567	103,139,040	348,668	11,731,668	4,204,840	7,207,664	19,309,079	3,077,412
13	PERCENTAGE		100.00000%	35.40396%	1.71614%	26.53288%	25.15661%	0.08504%	2.86147%	1.02560%	1.75802%	4.70967%	0.75061%
14													
15	**NET ELECTRIC PLANT IN SERVICE**	NEPIS	220,360,672	79,343,566	3,808,423	58,037,621	53,123,485	203,966	6,608,753	2,238,092	4,140,787	11,137,080	1,718,899
16	PERCENTAGE		100.00000%	36.00623%	1.72827%	26.33756%	24.10752%	0.09256%	2.99906%	1.01565%	1.87910%	5.05402%	0.78004%
17													
18	OPERATION AND MAINTENANCE EXPENSE												
19	PRODUCTION EXPENSE (EXCL ENERGY)	OXPD	8,915,363	2,520,288	139,116	2,531,535	3,372,958	0	120,200	101,273	39,082	50,982	39,929
20	PERCENTAGE		100.00000%	28.26904%	1.56041%	28.39520%	37.83310%	0.00000%	1.34823%	1.13594%	0.43836%	0.57184%	0.44787%
21													
22	DISTRIBUTION EXPENSE	OXD	6,727,802	2,834,896	126,263	1,480,741	501,045	15,652	725,069	57,919	269,959	631,341	84,918
23	PERCENTAGE		100.00000%	42.13703%	1.87673%	22.00928%	7.44737%	0.23264%	10.77720%	0.86089%	4.01259%	9.38406%	1.26220%
24													
25	CUSTOMER ACCOUNTS EXPENSE	OXC	4,728,770	3,334,768	75,215	1,045,319	14,789	4,125	2,316	43,053	106,617	91,193	11,376
26	PERCENTAGE		100.00000%	70.52083%	1.59059%	22.10552%	0.31274%	0.08723%	0.04898%	0.91044%	2.25464%	1.92847%	0.24057%
27													
28	CUSTOMER SERVICE & INFORMATION EXPENSE	OXI	2,185,290	1,179,186	32,587	465,263	350,593	939	13,646	21,082	12,320	97,889	11,784
29	PERCENTAGE		100.00000%	53.96016%	1.49122%	21.29067%	16.04331%	0.04297%	0.62445%	0.96473%	0.56379%	4.47947%	0.53923%
30													
31	OTHER DEFERRED INCOME TAX FACTOR												
32	MINNESOTA	NPISM	0	0	0	0	0	0	0	0	0	0	0
33	PERCENTAGE		0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
34													
35	NORTH DAKOTA	NPISN	220,360,672	79,343,566	3,808,423	58,037,621	53,123,485	203,966	6,608,753	2,238,092	4,140,787	11,137,080	1,718,899
36	PERCENTAGE		100.00000%	36.00623%	1.72827%	26.33756%	24.10752%	0.09256%	2.99906%	1.01565%	1.87910%	5.05402%	0.78004%
37													
38	EXCLUDING SOUTH DAKOTA	NPMNR	220,360,672	79,343,566	3,808,423	58,037,621	53,123,485	203,966	6,608,753	2,238,092	4,140,787	11,137,080	1,718,899
39	PERCENTAGE		100.00000%	36.00623%	1.72827%	26.33756%	24.10752%	0.09256%	2.99906%	1.01565%	1.87910%	5.05402%	0.78004%
40													
41	LONG-TERM CWIP RATIO (W/AFDC)	CWIPLT	0	0	0	0	0	0	0	0	0	0	0
42	PERCENTAGE		0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
43													
44	REVENUE	R10	118,309,177	36,574,921	1,601,767	34,012,150	36,231,788	45,963	2,095,668	967,569	1,185,332	4,744,402	849,617
45	PERCENTAGE		100.00000%	30.91469%	1.35388%	28.74853%	30.62466%	0.03885%	1.77135%	0.81783%	1.00189%	4.01017%	0.71813%
46													
47	LABOR AND RELATED EXPENSE	LRE	40,581,805	17,008,071	674,425	10,337,953	8,422,861	31,657	1,333,139	411,076	662,040	1,460,268	240,314
48	PERCENTAGE		100.00000%	41.91058%	1.66189%	25.47436%	20.75526%	0.07801%	3.28507%	1.01296%	1.63137%	3.59833%	0.59217%
49													
50	TOTAL O & M EXPENSE	OX	100,197,474	33,112,849	1,492,241	24,730,875	28,789,404	53,274	2,093,161	996,646	1,306,225	6,756,033	866,765
51	PERCENTAGE		100.00000%	33.04759%	1.48930%	24.68213%	28.73266%	0.05317%	2.08904%	0.99468%	1.30365%	6.74272%	0.86506%
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The allocation factors on this page were used to determine North Dakoata 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 North 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 11 B (manual).

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)

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)

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)

The allocation factors on this page were used to determine North 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 North 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 11 B (manual).

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)

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)

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-11 A, pages 7 and 8 for the allocation factor values

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

Case No. PU-08____
Exhibit__(PJB-1)
Financial Information
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Allocators - Demand, Energy and Customer

LINE NO	ITEM	FACTOR	Actual Year 2007 TOTAL UTILITY	Actual Year 2007 NORTH DAKOTA	Actual Year 2007 ALL OTHER	Test Year 2007 TOTAL UTILITY	Test Year 2007 NORTH DAKOTA	Test Year 2007 ALL OTHER
1	MWH CONSUMPTION AT GENERATORS - PARTIAL	E1	3,918,074	1,457,625	2,460,449	4,082,438	1,621,989	2,460,449
2	PERCENTAGE		100.000000%	37.202590%	62.797410%	100.000000%	39.730897%	60.269103%
4	MWH CONSUMPTION AT GENERATORS - TOTAL	E2	4,430,839	1,720,495	2,710,344	4,595,203	1,884,859	2,710,344
5	PERCENTAGE		100.000000%	38.830005%	61.169995%	100.000000%	41.017975%	58.982025%
6	GENERATION DEMAND FACTOR	D1	598,234	236,559	361,675	622,316	259,222	363,094
7	PERCENTAGE		100.000000%	39.542883%	60.457117%	100.000000%	41.654420%	58.345580%
8	TRANSMISSION DEMAND FACTOR	D2	604,225	236,559	367,666	628,307	259,222	369,085
9	PERCENTAGE		100.000000%	39.150834%	60.849166%	100.000000%	41.257266%	58.742734%
10	DISTRIBUTION - PRIMARY DEMAND FACTOR	D3	757,342	332,687	424,655	761,059	335,193	425,866
11	PERCENTAGE		100.000000%	43.928211%	56.071789%	100.000000%	44.042944%	55.957056%
12	DISTRIBUTION - SECONDARY DEMAND FACTOR	D4	998,227	459,319	538,908	999,305	459,669	539,636
13	PERCENTAGE		100.000000%	46.013482%	53.986518%	100.000000%	45.998869%	54.001131%
14	CUSTOMER OR METER FACTORS							
15	TOTAL RETAIL CUSTOMERS	C1	129,675	57,014	72,661	129,675	57,014	72,661
16	PERCENTAGE		100.000000%	43.966840%	56.033160%	100.000000%	43.966840%	56.033160%
17	RETAIL SERVICE LOCATIONS	C2	135,857	59,913	75,944	135,857	59,913	75,944
18	PERCENTAGE		100.000000%	44.100046%	55.899954%	100.000000%	44.100046%	55.899954%
19	SECONDARY SERVICE LOCATIONS	C3	135,784	59,901	75,883	135,784	59,901	75,883
20	PERCENTAGE		100.000000%	44.114918%	55.885082%	100.000000%	44.114918%	55.885082%
21	STREET LIGHTING FACTOR	C4	4,185,546	1,760,035	2,425,511	4,185,546	1,760,035	2,425,511
22	PERCENTAGE		100.000000%	42.050308%	57.949692%	100.000000%	42.050308%	57.949692%
23	AREA LIGHTING FACTOR	C5	3,688,552	1,716,671	1,971,881	3,688,552	1,716,671	1,971,881
24	PERCENTAGE		100.000000%	46.540512%	53.459488%	100.000000%	46.540512%	53.459488%
25	METER FACTOR	C6	29,240,646	12,850,789	16,389,857	29,240,646	12,850,789	16,389,857
26	PERCENTAGE		100.000000%	43.948376%	56.051624%	100.000000%	43.948376%	56.051624%
27	METER READING FACTOR	C7	173,474	73,215	100,259	173,474	73,215	100,259
28	PERCENTAGE		100.000000%	42.205172%	57.794828%	100.000000%	42.205172%	57.794828%
29	SYSTEM SERVICE LOCATIONS	C8	135,879	59,913	75,966	135,879	59,913	75,966
30	PERCENTAGE		100.000000%	44.092906%	55.907094%	100.000000%	44.092906%	55.907094%
31	LOAD MANAGEMENT FACTOR	C9	40,923	18,040	22,883	40,923	18,040	22,883
32	PERCENTAGE		100.000000%	44.082790%	55.917210%	100.000000%	44.082790%	55.917210%

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME JURISDICITONAL
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Allocators - General Plant, Operation and Maintenance Expense and Taxes

LINE NO	ITEM	FACTOR	Actual Year 2007 TOTAL UTILITY	Actual Year 2007 NORTH DAKOTA	Actual Year 2007 ALL OTHER	Test Year 2007 TOTAL UTILITY	Test Year 2007 NORTH DAKOTA	Test Year 2007 ALL OTHER
1	PRODUCTION PLANT	P10	366,910,631	139,125,650	227,784,981	383,173,741	154,484,150	228,689,591
2	PERCENTAGE		100.000000%	37.918130%	62.081870%	100.000000%	40.316998%	59.683002%
3	DISTRIBUTION PLANT	P60	315,099,950	139,614,140	175,485,810	315,766,511	140,016,287	175,750,224
4	PERCENTAGE		100.000000%	44.307890%	55.692110%	100.000000%	44.341715%	55.658285%
38	GENERAL PLANT	P90	70,354,613	27,876,579	42,478,034	71,904,846	29,899,795	42,005,051
39	PERCENTAGE		100.000000%	39.622959%	60.377041%	100.000000%	41.582448%	58.417552%
40	ELECTRIC PLANT IN SERVICE	EPIS	946,761,213	382,741,667	564,019,546	978,261,122	409,987,820	568,273,302
41	PERCENTAGE		100.000000%	40.426420%	59.573580%	100.000000%	41.909855%	58.090145%
42	NET ELECTRIC PLANT IN SERVICE	NEPIS	493,280,843	194,481,610	298,799,233	524,042,632	220,360,672	303,681,961
43	PERCENTAGE		100.000000%	39.426143%	60.573857%	100.000000%	42.050142%	57.949858%
44	OPERATION AND MAINTENANCE EXPENSE							
45	PRODUCTION EXPENSE (EXCL ENERGY)	OXPD	19,229,459	7,272,217	11,957,242	22,153,706	8,915,363	13,238,343
46	PERCENTAGE		100.000000%	37.818105%	62.181895%	100.000000%	40.243211%	59.756789%
47	DISTRIBUTION EXPENSE	OXD	14,686,349	6,461,701	8,224,648	15,280,331	6,727,802	8,552,529
48	PERCENTAGE		100.000000%	43.998008%	56.001992%	100.000000%	44.029165%	55.970835%
49	CUSTOMER ACCOUNTS EXPENSE	OXC	10,507,260	4,545,083	5,962,177	10,931,905	4,728,770	6,203,135
50	PERCENTAGE		100.000000%	43.256597%	56.743403%	100.000000%	43.256597%	56.743403%
51	CUSTOMER SERVICE & INFORMATION EXPENSE	OXI	5,241,699	1,153,127	4,088,572	6,387,900	2,185,290	4,202,610
52	PERCENTAGE		100.000000%	21.999105%	78.000895%	100.000000%	34.209830%	65.790170%
53	OTHER DEFERRED INCOME TAX FACTOR							
54	MINNESOTA	NPISM	244,543,074	-	244,543,074	253,639,255	-	253,639,255
55	PERCENTAGE		100.000000%	0.000000%	100.000000%	100.000000%	0.000000%	100.000000%
56	NORTH DAKOTA	NPISN	195,226,513	194,481,610	744,903	221,150,321	220,360,672	789,649
57	PERCENTAGE		100.000000%	99.618442%	0.381558%	100.000000%	99.642936%	0.357064%
58	EXCLUDING SOUTH DAKOTA	NPMNR	439,799,457	194,481,610	245,317,847	474,821,241	220,360,672	254,460,569
59	PERCENTAGE		100.000000%	44.220521%	55.779479%	100.000000%	46.409186%	53.590814%
60	LONG-TERM CWIP RATIO (W/AFDC)	CWIPLT	20,811,434	-	20,811,434	16,819,347	-	16,819,347
61	PERCENTAGE		100.000000%	0.000000%	100.000000%	100.000000%	0.000000%	100.000000%
62	REVENUE	R10	268,698,170	108,472,410	160,225,760	278,520,961	118,309,177	160,211,783
63	PERCENTAGE		100.000000%	40.369612%	59.630388%	100.000000%	42.477657%	57.522343%
64	LABOR AND RELATED EXPENSE	LRE	91,995,573	35,833,806	56,161,767	99,128,145	40,581,805	58,546,340
65	PERCENTAGE		100.000000%	38.951663%	61.048337%	100.000000%	40.938732%	59.061268%

COST ALLOCATION PROCEDURE MANUAL

FOR

JURISDICTIONAL AND CLASS

COST OF SERVICE STUDIES

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)

OTHER ELECTRIC REVENUE

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

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

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

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

Dollar Allocations for Account 364

To Streetlighting = D x C* = DSL

To Area Lighting = E x C* = DAL

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

Demand Component = DSL - DAL - DPCC = DPDC

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

Account 365 (Overhead Conductor and Devices):

I. Primary

A. Average age of primary conductor.

B. Minimum size primary unit.

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

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

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

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

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

Dollar Allocations for Account 365 Primary

Customer Component = C x UPD = DPCC

Demand Component = E - DPCC = DPDC

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

II. Secondary

A. Average age of secondary conductor.

B. Minimum size secondary unit.

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

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

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

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

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

Dollar Allocations for Account 365 Secondary

To Streetlighting = F x G = DSL

To Area Lighting = F - DSL = DAL

Customer Component = C x D = DSCC

Demand Component = E - F - DSCC = DSDC

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

Account 366 (Underground Conduit):

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

Account 367 (Underground Conductor and Devices):

I. Primary

A. Average age of primary unit.

B. Minimum size primary unit.

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

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

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

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

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

Dollar Allocations for Account 367 Primary

Customer Component = C x UPD = DPCC

Demand Component = E - DPCC = DPDC

II. Secondary

A. Average age of secondary unit.

B. Minimum size of secondary unit.

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

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

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

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

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

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

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

Dollar Allocations for Account 367 Secondary

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.)

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

A. Average installed cost of minimum size 2400 V. overhead unit.*

B. Average installed cost of minimum size 7200 V. overhead unit.*

C. Average installed cost of minimum size 14400 V. overhead unit.*

D. Average installed cost of minimum size 2400 V. underground unit.*

E. Average installed cost of minimum size 7200 V. underground unit.*

F. Number of 2400 V. overhead units in the account.

G. Number of 7200 V. overhead units in the account.

H. Number of 14400 V. overhead units in the account.

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

I. Number of 2400 V. underground units in the account.

J. Number of 7200 V. underground units in the account.

K. Total dollar value of Account 368.

Dollar Allocations for Account 368

Customer Component = (A 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

MISO Contingency Reserve Sharing Group

Effective Date: 1/15/2007
Reduction in Reserves: 5 MWs

Annual Savings: $1,574,610 (365 Days x 24 hrs x 5 MWs x $35.95)
The margin reflects the average YTD thru 8/31/07
DA price over Otter Tail's Base Load generation cost

MISO ANCILLARY SERVICES MARKET

Projected New Wind Generation in OTP's Control Area: (2000 MWs of Wind Generation in the Queue for OTP's Control Area x 10% (assumed will actually be built) plus the 60 MWs Otter Tail is planning)		260
Estimated Additional MWs of Regulation Needed: (Planning on 5 MWs of Regulation for Every 60 MWs Added)		22
Margin on DA Price over Otter Tail's Base Load Generation Cost:	$	35.95
Estimated Annual Cost To Retail Customers After June 1, 2008: (365 Days x 24 hrs x 22 MWs x $35.95) The savings reflects the average YTD thru 8/31/07DA price over Otter Tail's Base Load generation cost	$	6,928,284
Less: Annual Control Area Service and Operations Tariff Revenue:	$	183,672
Net Estimated Avoided Annual Cost to Retail Customers After June 1, 2008:		$6,744,612

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY **Case No. PU-08____**
Electric Utility - State of Minnesota **Exhibit ___(PJB-1)**
CAPACITY COST SAVINGS ESTIMATE FOR 2007 **Financial Information**
Schedule 13

CAPACITY PURCHASES FOR 2007

	MWS	AVOIDED FIRM MAPP TRANSMISSION CHARGES
JANUARY	137	$204,201
FEBRUARY	137	$184,440
MARCH	112	$166,938
APRIL	112	$161,553
MAY	60	$89,431
JUNE	101	$150,543
JULY	101	$150,543
AUGUST	101	$150,543
SEPTEMBER	76	$113,280
OCTOBER	76	$113,280
NOVEMBER	131	$195,258
DECEMBER	152	$226,559
TOTAL MAPP TRANSMISSION CHARGES		**$1,906,568**

SOURCE	DESTINATION	MAPP RATE
Basin (Laramie River)	OTP	$2.9734
Dairyland Power Coop.	OTP	$2.4087
Great River Energy	OTP	$1.0428
Heartland Cons.Pwr.Dist.	OTP	$3.1960
HutchinsonUtilitiesComm	OTP	$1.5507
Montana-Dakota Util. Co.	OTP	$0.7591
MidAmerican Energy Co.	OTP	$2.5612
Manitoba Hydro Elect. Bd.	OTP	$1.2813
Minnesota Power	OTP	$1.1526
Missouri River Energy Services	OTP	$2.2711
Northern States Power Co.	OTP	$1.6878
Omaha Public Power Dist.	OTP	$3.1017
So. Minn. Mun. Power	OTP	$1.7472
SaskPower	OTP	$2.5197
Western Area Pwr. Admin.	OTP	$2.3473
Wisconsin Pub. Pwr. Inc.	OTP	$1.4536
	AVERAGE PER MW	$2.0034

Volume 2A

Testimony and Schedules of Witnesses:

Kyle Sem

Rate Base

Before the North Dakota Public Service Commission
State of North 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 North Dakota

Case No. PU-08-____

Exhibit___

RATE BASE

Direct Testimony and Exhibit of

KYLE SEM

November 3, 2008

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kyle A. Sem, and my address is 215 South Cascade Street, Fergus Falls, Minnesota 56537.

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

A. I am employed by Otter Tail Power Company ("OTP" or the "Utility") as Rates Analyst, Regulatory Services.

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

A. I graduated magna cum laude from Mankato State University, now Minnesota State University, Mankato, Minnesota, in 1998 with a B.S. degree in Accounting. I am a Certified Public Accountant in Minnesota as well as a member of the Minnesota Society of Certified Public Accountants and the American Institute of Certified Public Accountants. I have been employed by OTP since 2006 as Rates Analyst. My primary responsibilities in this position are preparing the annual cost of service studies for the three jurisdictions where OTP provides service (North Dakota, Minnesota, and South Dakota), preparing the Lead Lag Study and providing other regulatory and financial analyses.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of OTP.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will explain the development of the rate base proposed for use in setting rates in this proceeding. Mr. Peter Beithon uses the results of my testimony in preparing the overall financial schedules for the rate case.

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

A. Yes.

II. RATE BASE COMPONENTS AND OVERVIEW

Q. HOW WILL YOU PRESENT YOUR TESTIMONY ON RATE BASE?

A. I will discuss each component of rate base. For each component, I will provide any needed background information and explain the information included in the unadjusted 2007 Actual Year data. I will then identify and explain any adjustments that are made to the 2007 Actual Year to arrive at the 2007 Test Year.

Q. WHAT RATE BASE ACCOUNTING SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring the following rate base schedules, which are attached to my testimony:

1) Exhibit ___ (KAS-1), Schedule 1 – Rate Base Summary;
2) Exhibit ___ (KAS-1), Schedule 2 – Rate Base Components;
3) Exhibit ___ (KAS-1), Schedule 3 – Cash Working Capital;
4) Exhibit ___ (KAS-1), Schedule 4 – Rate Base Adjustments;
5) Exhibit ___ (KAS-1), Schedule 5 – Rate Base Comparison;
6) Exhibit ___ (KAS-1), Schedule 6 -- Total Company and North Dakota Jurisdictional.

Q. WHAT TIME PERIODS ARE SHOWN ON YOUR SCHEDULES?

A. My schedules show information for two time periods: 1) unadjusted 2007 Actual Year, and 2) 2007 Actual Year 2007 with traditional regulatory and

known and measurable adjustments to produce the 2007 Test Year upon which our change in rates is based.

Q. WHAT IS THE SOURCE OF THE 2007 ACTUAL YEAR INFORMATION?

A. The 2007 Actual Year information is taken from OTP's North Dakota jurisdictional cost of service study ("JCOSS"), which is the basis for reporting the earned regulated returns included in OTP's Annual Report to the North Dakota Public Service Commission ("Commission"). The JCOSS is based on the Utility's financial information. This same financial information is used to prepare FERC Form No. 1 and the Utility section of Otter Tail Corporation's annual report to shareholders.

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base consists primarily of the capital expenditures made by a utility to secure plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital (e.g. accumulated deferred income tax).

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE TEST YEAR RATE BASE.

A. The test year rate base is generally comprised of the following major items which will be described in further detail later in my testimony:

- Net utility plant
- Construction work in progress
- Cash working capital items
- Accumulated deferred income taxes

Q. PLEASE BEGIN BY EXPLAINING EXHIBIT ___(KAS-1), SCHEDULES 1 THROUGH 4.

A. Exhibit ___(KAS-1), Schedule 1, Rate Base Summary, summarizes the North Dakota total company electric utility rate base for each of the two time periods under discussion (2007 Actual Year and 2007 Test Year). Schedule 2 provides the total company amounts for rate base and the amounts allocated to North Dakota, for both time periods. Schedule 3 is provided for the 2007 Actual and Test Year as supporting information for the cash working capital calculation in Columns (B) and (C), line 10, of Schedule 1. Schedule 4 is a bridge schedule showing the adjustments made to the 2007 Actual Year data to develop the Test Year. A full discussion of the jurisdictional allocation methodology is contained in the testimony of Mr. Beithon.

Q. HAVE YOU COMPARED THE TEST YEAR RATE BASE TO THE RATE BASE APPROVED IN THE MOST RECENT NORTH DAKOTA ELECTRIC RATE CASE ORDER?

A. Yes. Exhibit__(KAS-1), Schedule 5, included with my testimony provides a comparison of the rate base approved in the most recent rate case with a Test Year ending December 31, 1983 ("1983 Projected Test Year") to the 2007 Test Year rate base. As I discuss the rate base components, I will, as appropriate, review significant changes from the last rate case.

A. NET UTILITY PLANT

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

A. Net utility plant represents OTP's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation.

Q. PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT INVESTMENT IN THIS CASE.

A. The net utility plant is included in rate base at depreciated original cost, reflecting the simple average of balances at the beginning and end of the test year. OTP's most recent North Dakota electric rate case also used a simple average for net electric plant in service.

Q. WHAT DO THE LINE ITEMS 1 THROUGH 3 ON SCHEDULE 1 DESCRIBE?

A. These are the components of OTP's net utility plant in service. It consists of electric plant in service, less the accumulated depreciation, arriving at net electric plant in service. The electric plant in service is based upon the original cost of property from the books and records of OTP as allocated to the North Dakota jurisdiction.

Q. PLEASE DESCRIBE THE MORE SIGNIFICANT CHANGES IN ELECTRIC PLANT SINCE OTP'S LAST GENERAL RATE CASE.

A. There have been thousands of units of property added and retired since our last general rate case in 1983. I will discuss six significant items from that time period. They are:

1) Generation:
   a) addition of a combustion turbine peaking plant at Solway, Minnesota;
   b) addition of a diesel generator at OTP's system operations center in Fergus Falls; and the
   c) retirement of Unit #1 of OTP's Hoot Lake generating plant at Fergus Falls
2) Transmission:
   a) Alexandria to Henning 115 kV line;
   b) Oslo to Thief River Falls 115 kV line; and the;
   c) Harvey, North Dakota, to the US-Canadian border north of Rolette, North Dakota 230 kV line.

I will discuss each of these changes in greater detail later in my testimony.

Q. WHAT ARE OTP'S OBJECTIVES WITH REGARD TO CAPITAL SPENDING?

A. OTP has four primary objectives when determining its capital spending:

1) Increase the capability of the system (Plants, IT, T&D, etc.) to accommodate growth;
2) Replace aging facilities through an orderly plan to maintain reliability and customer satisfaction;
3) Invest in new technology to reduce or eliminate future expenses; and
4) Improve Key Performance Indicators (KPIs). KPIs are internal targets set by management for customer satisfaction, service reliability, generation plant availability, safety and financial performance, as Mr. Brause explains in his testimony.

Q. HOW DOES OTP ALLOCATE ITS CAPITAL BUDGET BETWEEN COMPETING ELIGIBLE PROJECTS?

A. The accountability for allocating capital spending resides in the Asset Management area of the Utility, and specifically in Delivery Planning. In carrying out this function, a Capital Allocation Review Team assists in the development of the allocation of capital. This team is made up of a representative from each functional area of the company. Functional areas include Asset Management, Supply, Customer Service, IT, Administration, and Business Planning.

Q. HOW DOES THE CAPITAL ALLOCATION PROCESS WORK?

A. Capital allocation and prioritization is an on-going process. The formal process starts in April of each year with the request for capital projects and the submittal of project applications. The deadline for submitting project applications is typically the middle of June. The projects are then reviewed and prioritized by the Capital Allocation Review Team. During this step, projects are approved,

partially funded or denied. The budget is then submitted to the Utility Executive Team for review and approval in early September. The final approval of the capital budget is made by the Board of Directors in December.

Q. WHAT HAPPENS AS UNEXPECTED REQUESTS FOR CAPITAL PROJECTS OCCUR OUTSIDE OF THE NORMAL PROCESS?

A. If a request for capital funds comes outside of the normal timeline for capital allocation, the project is reviewed by the Capital Allocation Review Team similar to the regular process. However, the request is compared to other projects that have already been approved. If the new request is of a higher priority, then a lower priority project is delayed to fit the new project into the capital spending plan for the year.

Q. DO ALL PROJECT APPLICATIONS FOR CAPITAL GET APPROVED?

A. No. During any given year, requests for capital spending exceed the target levels. As a result, prioritization of capital projects is used.

Q. WHAT IS PRIORITIZATION?

A. In simple terms, it is the ranking of capital projects in order of importance from highest to lowest.

Q. HOW DOES OTP PRIORITIZE ITS CAPITAL SPENDING?

A. The first step in prioritization is categorizing the projects. Each year there are many "must do" projects. These include the projects required for connecting new customers, or projects that are necessary to meet compliance requirements, which might, for example, include installing new emission control systems on power plants. Upon providing sufficient justification, these projects are moved to "approved" status in the budget process. We then take the remaining projects and prioritize them.

Q. WHAT IS OTP'S REPLACEMENT PLAN FOR ITS AGING FACILITIES?

A. One of the key components that we use in prioritizing capital spending is replacement plans. Over the past five years, OTP has developed replacement plans for various assets. For example, we have a significant amount of underground distribution cable that is over 30 years old. Each year, we set aside a certain dollar amount for replacing such cable. The replacement projects that get funded are prioritized based on their performance characteristics (e.g. number of times the cable has failed), age, etc. Another example of a replacement plan is the computers that are used by employees. The IT department has developed criteria for when a PC is replaced. This is a predictable pattern, and rather than replace all of the PC's in one year, we spread replacement over five years. That way, we are continually replacing the PC's, rather than replacing all in one year. The purpose of the replacement plans is to "levelize" the capital spending required so that we do not end up with large expenditures occurring in single years. Not only does this levelize the capital dollars, but it also utilizes our workforce in an efficient manner.

Q. NOW LET'S DISCUSS THE SPECIFIC PROJECTS REFERRED TO EARLIER. PLEASE DESCRIBE THE SOLWAY COMBUSTION TURBINE.

A. The Solway combustion turbine (CT) is a dual-fueled General Electric LM6000 simple cycle combustion turbine. It went into operation in May 2003. It is normally operated on interruptible natural gas, but can switch over to fuel oil operation if the gas supply is curtailed. The unit has a nameplate rating of 44,500 kW, but the monthly ratings vary from approximately 41,900 kW in the peak summer month to 48,800 kW in the peak winter month. The LM6000 engine is the same engine as on a Boeing 747 aircraft, and is one of the most efficient simple-cycle CT's available. The site is equipped with a 1,250 kW diesel generator to provide black start capability (i.e., in the event of a wide area outage, the diesel unit can be started to provide power to start the Solway CT). The unit can then pick up load in the surrounding area, including most of the

load in Bemidji. The diesel is capable of synchronizing with the electric grid and serving retail customers, and is accredited by Mid-Continent Area Power Pool (MAPP).

Q. WHY DID OTP INSTALL THE SOLWAY CT?

A. The need for additional peaking capacity was identified in OTP's 1999 Integrated Resource Plan ("IRP"), a copy of which was filed with the North Dakota Commission for informational purposes, where OTP proposed adding a gas-fired CT, to begin operation after May 1, 2002, with 44,000 kW name plate winter peaking capacity. The Minnesota Public Utilities Commission approved OTP's IRP in its ORDER ACCEPTING 1999 INTEGRATED RESOURCE PLAN, VARYING THE NEXT RESOURCE PLAN FILING DATE, ORDERING CONTINUING DISCUSSIONS AND A STUDY OF A GREEN PRICING PROGRAM BY JULY 1, 2001, Docket No. E017/RP-99-909, dated March 14, 2000. After receiving that authorization, OTP executed on its approved IRP and built the Solway CT. The North Dakota PSC was also informed of the completed construction of the Solway CT on page 15 of the 2003 North Dakota 10-Year Plan.

OTP decided to construct a peaking facility rather than purchase power because wholesale capacity prices at the time were escalating rapidly. The Company had made a conscious decision in the late 1980's and early 1990's to purchase wholesale capacity in lieu of building generating resources, as long as those purchases could be made at an economic cost. In fact, OTP went from 1981, when Coyote Station came on-line, until 2003 without building a generating facility, other than the Fergus Falls Control Center diesel generator that I previously mentioned, and discuss in greater detail later. The resource plan filing also indicated that the Company planned to issue an RFP for peaking capacity in the later part of 1999 and would continue to pursue economic purchases of peaking capacity. However, if such capacity was unavailable or uneconomic, OTP would need to construct a combustion turbine no earlier than May 1, 2002.

Q. WHAT WERE THE SPECIFIC RESULTS OF THE PEAKING CAPACITY RFP?

A. OTP received ten proposals of which two were for year-round capacity and eight were for seasonal capacity. The two for year-round capacity would have required us to pay for capacity that OTP did not need. Four of the proposals were from inside of MAPP and the others were from areas outside of MAPP. Those located outside of the MAPP service area would have had higher delivery costs. The capacity prices ranged from $5/kW-month up to $10/kW-month. The $5/kW-month cost was close to the estimated revenue requirements of constructing a simple cycle combustion turbine at the time. Consequently, the higher priced offers were not cost justified. Most of the proposals had energy priced at the daily wholesale market price (subjecting us to the variability of the market, with the only benefit being an assured supply), and had other requirements such as a 16-hour minimum scheduling requirement (completely unacceptable for a peaking facility, which needs to be dispatchable on 45 minutes notice) or a minimum monthly capacity factor, which would have increased energy costs.

Q. WERE THERE OTHER SPECIFIC CONSIDERATIONS IN EVALUATING THE RESULTS OF THE PEAKING CAPACITY RFP?

A. Yes, then existing transmission limitations played a key role in deciding that OTP could not rely on the wholesale market to meet its needs. In particular, we had consummated a three-year purchase power agreement (PPA) with Minnesota Power for the 2000 – 2002 summer seasons. However, we were unable to get direct firm transmission service from Minnesota Power for the 2000 summer season. Consequently, OTP was only able to receive accreditation of the transaction from MAPP by offsetting another agreement that OTP had in place with Northern States Power (NSP) at the time. In essence, the Minnesota Power capacity was delivered to NSP to satisfy an equivalent OTP obligation to

NSP. OTP was able to then keep the capacity it had planned to supply to NSP. A similar situation developed in the 2001 summer season. Firm transmission service was unavailable. Minnesota Power was finally able to rearrange its resources to deliver part of the capacity from a facility in North Dakota and part of the capacity from a facility located in Wisconsin, rather than from its own facilities. What caused great concern at OTP was the fact that almost all of the proposals received by OTP in response to the RFP would have been impacted by the same transmission constraint.

Minnesota Power is located fairly close to OTP and yet we were being impacted by a transmission constraint located some distance away. And because the constraint was on facilities owned by others some distance from the OTP system, OTP could not take measures to mitigate the constraint. The constraint created the potential for OTP to be restricted in its ability to purchase capacity from the wholesale marketplace and created the potential for OTP to be subject to the pricing practices of just a couple of suppliers, from whom OTP could find access to purchase capacity. The transmission constraint, combined with the increasing wholesale capacity cost, provided the impetus for moving ahead with construction of a combustion turbine.

Q. BESIDES MEETING PEAK CAPACITY AND ENERGY NEEDS ARE THERE OTHER BENEFITS ASSOCIATED WITH THE CONSTRUCTION OF THE SOLWAY CT?

A. Yes. The construction of the Solway CT allowed OTP to delay transmission investments. In selecting the site for the unit, the availability of local transmission facilities was taken into consideration. The Solway site near Bemidji, Minnesota, had existing adequate transmission and a high-pressure natural gas pipeline. In addition, at the time, OTP was facing transmission issues in the Bemidji area under certain transmission contingency situations. Under heavy loading conditions, the Bemidji area could suffer voltage problems if certain transmission facilities experienced an outage. By adding generation in

that area, the existing transmission was adequate to serve that load, allowing transmission upgrades to be delayed for several years, so this was an important additional benefit to the facility.

Q. WHAT WAS THE DOLLAR AMOUNT ADDED TO ELECTRIC PLANT IN SERVICE FOR THE SOLWAY CT GENERATOR?

A. The Solway CT generator represented a net addition of $27.5 million, of which approximately $11.1 million is allocated to North Dakota.

Q. TURNING TO THE NEXT ITEM YOU LISTED – ADDITION OF THE DIESEL GENERATOR AT OTP'S SYSTEM OPERATIONS CONTROL CENTER IN FERGUS FALLS – PLEASE DESCRIBE THIS UNIT AND ITS PURPOSE.

A. This unit is a 2,000 kW nameplate rated diesel fuel powered generator located in Fergus Falls, Minnesota. The primary purpose of the unit is to provide emergency backup service to the OTP System Operations control center, but the generator is also capable of synchronizing with the electric grid and can be used to provide energy to serve retail load. It is accredited in the MAPP and counts toward OTP's MAPP Reserve Capacity obligation.

Q. WHY DID OTP INSTALL THE FERGUS FALLS CONTROL CENTER DIESEL GENERATOR?

A. In 1995 OTP developed a new System Operations control center, which is staffed around the clock to manage all generation and transmission facilities within the control area. The National Electric Reliability Council (NERC) standards required a backup power supply to ensure that the control center always has electric service to maintain operation of computers, communications systems, and system control.

Q. WHAT IS THE DOLLAR AMOUNT ADDED TO ELECTRIC PLANT IN SERVICE FOR THIS DIESEL GENERATOR?

A. This diesel generator represented a net addition of $600,000, of which approximately $242,000 is allocated to North Dakota.

Q. PLEASE DISCUSS THE NEXT SIGNIFICANT CHANGE IN GENERATION, THE RETIREMENT OF UNIT #1 OF THE HOOT LAKE GENERATING PLANT.

A. The Hoot Lake generating plant, consisting of remaining Units #2 and #3, and a small hydroelectric plant, is located on the Otter Tail River at Fergus Falls. Hoot Lake #1 was a 1948 vintage coal-fired steam unit with a nameplate rating of about 7,500 kW that was retired December 31, 2005. The retirement came about because of a number of operational, efficiency, and environmental issues that were going to have to be addressed. Consequently, the Company proposed retirement of Hoot Lake #1 in its 2003 IRP, a copy of which was sent to the North Dakota PSC for informational purposes. The Minnesota Commission approved the Company's 2003 IRP in its ORDER ACCEPTING 2003 INTEGRATED RESOURCE PLAN, VARYING THE NEXT RESOURCE PLAN FILING DATE, AND REQUIRING INTERIM FILING, Docket No. E-017/RP-02-1168, dated May 29, 2003 The North Dakota PSC was informed of the retirement of Unit #1 in OTP's 2008 ND 10-Year Plan on page 23.

Q. WHAT WERE THE OPERATIONAL ISSUES?

A. Probably the most significant operational issue was the water requirements for cooling the unit to condense the steam back into water. The Hoot Lake Plant contained three steam units with a rather unique operational situation for cooling. In the early 1900's, OTP diverted part of the Otter Tail River to create a new lake that was named Hoot Lake. A channel was dredged to allow water to flow from Hoot Lake into a slough area that then became Wright Lake. Wright Lake is at an elevation located above the steam units, so water could be gravity

fed into the steam units for cooling, avoiding the expense and reduced net output caused by having to pump cooling water. Hoot Lake units #2 and #3 were also equipped with cooling towers, which were only needed when insufficient water was available from Wright Lake or when downstream river temperatures reached the limit allowed under the plant's permits. OTP also has several hydroelectric facilities located on the Otter Tail River. During the late 1980's, OTP was ordered to obtain licenses for these facilities from the Federal Energy Regulatory Commission (FERC). These units had existed prior to FERC and had never been licensed. As a result of the licensing process, which took several years, the terms of the license require OTP to divert less water from the Otter Tail River. This reduced the amount of water available to the steam plant. During most of the 1990's this was not a concern as most of the time the Hoot Lake units were not heavily loaded. But as wholesale market prices increased, the Hoot Lake units were called on more and more. This resulted in units # 2 and # 3 being put on cooling towers more frequently, and the consequent parasitic losses of running the cooling towers reduced the output from Hoot Lake #1. At peak times, the 7,500 kW output of the unit was reduced by the 2,000-3,000 kW required for the additional cooling needed for the other two units.

Q. WHAT WERE THE EFFICIENCY ISSUES THAT CONTRIBUTED TO THE DECISION TO RETIRE HOOT LAKE #1?

A. Over time, the seals on the steam turbine had degraded and the efficiency of the steam turbine was approximately 50 percent worse than its original design performance. Too much steam was bypassing the turbine blades and not doing productive work. The steam turbine was in need of an overhaul. It would have been possible to continue operation without overhauling the steam turbine, but this raised the cost and increased emissions per MWh of output. Also, the operating permit for the unit restricted the maximum amount of steam flow that

was allowed. Without a turbine overhaul, the net output of the unit would decline as less and less of the steam was being productively used.

Q. WHAT WERE THE ENVIRONMENTAL ISSUES?

A. The Hoot Lake #1 unit was equipped with a fabric filter for particulate control. The condition of the fabric filter system had deteriorated over time, partially due to the limited operation that the unit was experiencing. If it had not been retired, the facility would have required additional significant investment to maintain ongoing compliance with operating permit emission requirements.

Q. PLEASE SUMMARIZE THE BASIS FOR THE DECISION TO RETIRE THE HOOT LAKE #1 UNIT?

A: In combination, these various issues made it uneconomic to continue operating the unit. The costs to repair and/or maintain some of the existing equipment and the negative impact to the Hoot Lake #2 and #3 units due to the water issues I described, and the limited operation of this unit, made it more cost-effective to retire the unit.

Q. IN YOUR EARLIER SUMMARY, YOU LISTED THREE TRANSMISSION LINES. WOULD YOU PLEASE RECAP THOSE FOR US?

A. Yes. Since the last rate case in 1983, OTP has constructed three major transmission lines. (1) The Alexandria to Henning 115 kV transmission line was constructed in the mid-1990's and was a joint project with Great River Energy and Missouri River Energy Services. (2) OTP constructed approximately 50 miles of 115 kV transmission line between Oslo, Minnesota, and Thief River Falls. This project was completed in 1999. (3) The construction of a 100-mile 230 kV transmission line from Harvey, North Dakota, to Glenboro, Manitoba, of which OTP owns 40 miles.

Q. WHAT WAS THE SINGLE LARGEST TRANSMISSION RATE BASE ADDITION SINCE THE LAST RATE CASE?

A. OTP's largest transmission rate base addition was the third project identified above -- the Harvey – Glenboro project. This project was jointly sponsored by OTP, Xcel Energy and Manitoba Hydro. It was a 160-mile 230 kV transmission line that originated in central North Dakota and terminated in southwestern Manitoba, with major substation additions or expansions at Harvey, Balta, Rugby, North Dakota, and Glenboro, Manitoba. This project was placed into service in the fall of 2002. This project was approved by the North Dakota Public Service Commission in Case No. PU-401-99-586.

Q. WHAT WAS OTP'S INVESTMENT IN THE HARVEY-GLENBORO TRANSMISSION PROJECT?

A. OTP invested $9.7 million in this project. We own the transmission line between Harvey-Balta and Rugby as well as the substation at Rugby. Of this amount, approximately $4 million was allocated to the North Dakota jurisdiction.

Q. WHY DID OTP MAKE THE HARVEY-GLENBORO ADDITION?

A. As part of a regional transmission planning process, the Harvey-Glenboro project was identified as a transmission project that provided multiple benefits. From OTP's perspective, the benefits were related to improved reliability in north-central North Dakota and the reduction of generation curtailments during multiple outages of transmission facilities.

Q. HOW DOES THIS TRANSMISSION LINE BENEFIT OTP'S CUSTOMERS?

A. Transmission is regional. This transmission line is located in North Dakota and supports the transmission grid in this region. A few examples include:

a) When transmission lines are out of service, it is not uncommon to have to reduce generation to ensure safe loading limits on the remaining

transmission system. The addition of the Harvey-Glenboro line reduced the amount of generation that would need to be reduced to ensure safe loading limits. Some of this generation is used to serve North Dakota customers.

b) This line increased the amount of power that can be transferred from Manitoba to the United States. This additional power transfer can be used to serve North Dakota customers.

c) This line supports voltages in the Red River Valley on both sides of the river. Without this line, we would have had to build the Bemidji - Boswell and Fargo - Monticello transmission projects earlier. These lines are part of the CAPX 2020 transmission plan and are in the planning and permitting stages at this time.

Q. WAS THE HARVEY-GLENBORO PROJECT ENDORSED BY REGIONAL RELIABILITY ENTITIES?

A. Yes, it was. The project was endorsed by the Red River Valley Sub-regional planning group as well as the Mid-Continent Area Power Pool.

Q. WHAT GENERAL OBSERVATION DO YOU HAVE AS YOU COMPARE NET PLANT IN SERVICE IN 1983 WITH 2007?

A. OTP's North Dakota net electric plant in service grew by approximately $38 million, or about 21 percent, during these 24 years. (See my Exhibit__(KAS-1), Schedule 5.) In 1983, our two largest baseload steam plants were much newer, and one might expect that because of depreciation, net production plant in service could be smaller today than it was in 1983. In fact, net production plant in service is smaller today by $35.5 million, but growth in transmission and distribution facilities have more than offset that decline. OTP has made transmission and distribution investments to meet customer needs and enhance our reliability that more than offset the depreciation of net production plant.

Q. ARE YOU PROPOSING ANY KNOWN AND MEASURABLE ADJUSTMENTS TO PLANT IN SERVICE TO DEVELOP THE TEST YEAR?

A. Yes. I made several adjustments related to projects that either went into service during 2007 or will go into service by October 31, 2009 (within 12 months of this filing). I will describe these adjustments in segments as plant adjustments that went into service during 2007 are adjusted differently than those that will go into service after 2007. The detailed calculations for the adjustments to plant in service can be found on work paper series TY-01, in Volume 4A, Tab – 2007 Test Year Work Papers. First, I made adjustments for four capital projects that went into service before the end of 2007 that were included in Long-Term Construction Work in Progress ("CWIP") on December 31, 2006 (see the discussion on CWIP later in my testimony), and three projects that were both started and completed during 2007. The projects in Long-Term CWIP on December 31, 2006, included (i) the final installations of the new load management ("LM") equipment replacing an old LM system; (ii) a Power Network Analysis Applications software package; (iii) a production-related project at the Big Stone Plant, and (iv) a production-related project at the Hoot Lake Plant. The three projects that were started and completed during 2007 were production-related projects, all located at the Big Stone Plant. Because rate base for plant in service is based on a simple average of the beginning and ending balances during the Test Year, this adjustment annualizes these projects so that the entire amount is included in rate base rather than only half, which would be the result if the simple average is used. It is appropriate to include a full year of investment in rate base for these projects because they occurred during the historical 2007 Test Year, and rates will not be affected as a result of this proceeding until January 2009, long after these projects became fully operational. My total adjustment to annualize 2007 additions that were either part of CWIP on December 31, 2006, or were started and completed during 2007 is $9,319,534 (See Exhibit (KAS-1), Schedule 6). ND's share of this

adjustment is $3,783,616 (See Exhibit (KAS-1), Schedule 6). As I will discuss later in my testimony, I have not included any of the investment related to wind projects in my Test Year adjustments.

Q. PLEASE TELL US MORE ABOUT EACH OF THE ADJUSTMENTS TO PLANT IN SERVICE YOU LISTED, BEGINNING WITH THE NEW LOAD MANAGEMENT EQUIPMENT.

A. OTP first began LM with use of time clocks on water heaters in the 1940's in order to reduce our load during the morning peak hours and then again in the evening peak hours as customers returned home from work. This was in response to large load growth after the war. Then in the late 1970's a pilot radio LM system was installed in two small towns in our service territory. This resulted in the installation of the Regency Radio Load Management system in the early 1980's. At first, we replaced time clock meters on the water heaters and then moved to installing LM radios to control dual fuel electric heating systems. Since then, we have added more controlled service tariffs to give our customers more choices to respond to available technology.

Over the years, we expanded the system with additional towers to improve the radio signal to towns on the edge of our coverage and found additional suppliers for radio receivers.

Q. WHY DID OTP MAKE THE INVESTMENT IN LM IN 2007?

A. The old LM system was 22 years old and a typical system has a life of 15 years. We had done all that was practical to extend the life of that system, but ran out of options. Finding replacement components and parts was becoming very difficult. The old system was becoming less reliable as time went on. Improved technology in newer systems allows more flexibility for controlling electric load. For example, each radio receiver in our new system is individually addressable. We can reprogram many functions over the airwaves and can initiate control for a specific radio if required. We have found this to be a great

help in trouble shooting at customers' premises. Another feature we needed was the ability to cycle summer cooling load. While OTP is a winter peaking utility, our summer load is approaching the winter peak, so summer load control is becoming more important to us. Overall we identified a need for a more flexible and dependable system to manage a robust portfolio of controlled service rates, and this new system meets those needs.

Q. WHAT IS THE POWER NETWORK ANALYSIS APPLICATIONS SOFTWARE?

A. The Power Network Analysis Applications (PNAA) software provides real-time power flow, state estimator and contingency analysis capabilities. The software enhances the Power System Operator's (PSO) and transmission operations engineer's ability to reliably operate the transmission system in real-time. Additionally, the PNAA tools provide "what if" analysis capabilities that allow the engineers and PSO's to complete offline studies to enhance the short-term and long-term operation of the transmission system.

Q. PLEASE LIST THE PRODUCTION RELATED PROJECTS AT BIG STONE PLANT.

A. The four production-related projects are: (i) a brine concentrator lined sludge pond expansion; (ii) a condenser retube; (iii) an Advanced Hybrid Particulate Controller (AHPC) replacement and (iv) a generator rewind.

Q. PLEASE TELL US MORE ABOUT EACH OF THE BIG STONE PROJECTS, BEGINNING WITH THE BRINE CONCENTRATOR LINED SLUDGE POND EXPANSION.

A. The original brine concentrator sludge pond was a clay lined pond designed to hold the concentrated waste stream from the plant's brine concentrator (water distillery). In the early 1990's we partitioned an area approximately 1.5 acres and lined that area with a high density polyethylene (HDPE) liner to prevent

possible leakage from the pond. This storage area worked well for a time, but as the plant's overall water balance continued to degrade, the brine concentrator needed to operate nearly the entire year, producing more waste water than could be stored in the small pond. In 2007, an additional 8 acres of pond was lined with HDPE to store additional waste from the brine concentrator.

Q. PLEASE DESCRIBE THE CONDENSER RETUBE PROJECT.

A. The original condenser tubes were primarily admiralty brass material, with certain areas tubed with stainless steel. Admiralty brass, when clean, has a better heat transfer rate than stainless steel. In 1998, the condenser was retubed with original style material due to failing brass tubes. The failure mechanism appeared to be a manufacturing flaw that eventually resulted in tube leaks. In the last nine years, the cooling pond water chemistry became more aggressive toward the brass tubes, causing corrosion and erosion. The tubes were also becoming fouled but could not be cleaned because of concerns about causing additional leaks. However, the stainless steel tubes were remaining clean and were not leaking. We retubed the entire condenser with stainless steel tubes during 2007. The tubes will now remain clean thereby increasing plant efficiency. The retube also allowed us to rebuild the circulating water pumps in 2007, restoring full circulating water flow, also improving unit efficiency. The condenser is the largest heat exchanger in the plant, and any improvements are important.

Q. WILL YOU PLEASE DESCRIBE THE AHPC REPLACEMENT PROJECT THAT WAS COMPLETED?

A. Yes. Big Stone Plant installed the experimental AHPC in 2002 to replace our failing electrostatic precipitator (ESP). The AHPC was designed to have the benefits of both an ESP and a bag house, greatly reducing emissions of fine particulate (dust). The project was partially funded by the National Energy Technology Lab's Power Plant Improvement Initiative. However, we realized

the AHPC was not meeting design expectations almost immediately. Problems included premature bag failures (expensive and time consuming to replace), and due to very high pressure drops, plant output was limited to some degree almost continually. At times, these derates were 75 MW or more. In 2005, efforts were made to add additional bags using more AHPC technology, but again, this effort failed. In 2007, the AHPC was replaced with a standard pulse-jet baghouse. The baghouse uses no ESP components, and greatly increased the number of bags, thus reducing pressure drop. Results in 2008 have been very good, with minimal operating limitations, and no failing bags.

Q. PLEASE DESCRIBE THE FOURTH AND FINAL BIG STONE PLANT PROJECT ADDED IN 2007, THE GENERATOR REWIND.

A. In 2005, the Big Stone Plant failed a transposition test, an electrical test (pass/fail) that gives an indication of the condition of the electrical insulation of the non-rotating coils of the generator. At that time, our insurance carrier recommended a full stator rewind, typical for a generator the age of Big Stone (30 years of age). We continued to monitor and inspect the generator until we could budget for a rewind during a future outage (scheduled for 2010). In 2006, an inspection revealed a burned strand in an end-winding of the generator. This was repaired to allow operation, but we immediately made plans to rewind the generator in the fall of 2007. The benefits of this project are improved reliability and availability. OTP contracted with Alstom to rewind the generator, but Alstom fell significantly behind schedule. As a result, OTP terminated their contract in September 2007 and hired Siemens to rewind the generator and that was completed in late fall 2007.

Q. PLEASE DESCRIBE THE PROJECT AT HOOT LAKE PLANT THAT WAS ADDED IN 2007.

A. The capital project costs added during 2007 at the Hoot Lake Plant were related to Voluntary Investigation and Clean-up (VIC) work on several old ash landfill

sites. Hoot Lake has four ash landfill sites located on the property that were built and placed in service before the Minnesota Pollution Control Agency (MPCA) had regulations and required permits regarding ash dumping in landfill areas. Over time the MPCA and OTP have identified environmental concerns with respect to these ash landfill sites. The approach that OTP employs to address the environmental concerns is VIC. VIC allows OTP to work together with the MPCA to research and find measures that can be used to clean-up and control the environmental issues at these sites.

Q. HAVE YOU MADE OTHER ADJUSTMENTS RELATED TO THE PLANT ADDITIONS THAT WERE PLACED IN SERVICE DURING 2007?

A. Yes. Because of the adjustment I made to include a full year of investment in rate base for the 2007 plant additions, I also made an adjustment to annualize accumulated depreciation as well as an adjustment to the operating statement to include a full year's depreciation expense on all of the 2007 plant additions. The total adjustment to accumulated depreciation related to projects that were placed into service during 2007 is an increase of $667,795 (See Exhibit (KAS-1), Schedule 6). The North Dakota share of this adjustment is $272,738 (See Exhibit (KAS-1), Schedule 6). As I mentioned, an operating statement adjustment is also needed to normalize the amount of depreciation expense that was taken during 2007 to reflect a full or normal year. The adjustment amount totaled $639,513 with the North Dakota share being approximately $259,000. Since the additions are treated as if they had been made at the start of the year, matching also justifies including a year of accumulated depreciation offset.

Q. YOU MENTIONED SEVERAL ADJUSTMENTS RELATED TO PLANT IN SERVICE THAT YOU WERE GOING TO DESCRIBE. PLEASE DISCUSS THEM.

A. I have two other adjustments related to plant in service that I need to discuss. The next adjustment is related to projects that were on-going during 2007 and

are scheduled to be completed by October 31, 2009 (within 12 months of the date of the filing of this rate case). This adjustment is similar to the adjustment I just described for projects that were completed in 2007. Any current capital outlay for the projects resided in Long-term CWIP at the end of 2007. There are six projects included in this adjustment: a General Office building addition; two Production-related projects at Hoot Lake Plant; a Production-related addition at Coyote Plant; and two Transmission projects. The adjustment needed to annualize plant in service is to add the full budgeted costs of each project while also removing any amounts included in Long-term CWIP at the end of 2007. Each of the adjustments qualify as known and measurable adjustments, justifying removing them from the status of incomplete projects in 2007 and treating them as completed projects. The adjustment amount to increase plant in service is $13,479,075 (See Exhibit (KAS-1), Schedule 6). The North Dakota share of this adjustment is $5,502,472 (See Exhibit (KAS-1), Schedule 6).

Q. WHAT GENERAL OFFICE BUILDING ADDITION WAS STARTED IN 2007 THAT WILL BE COMPLETED BY OCTOBER 31, 2009?

A. During 2007, construction began on an addition to the Hi-Tech Building, part of OTP's General Office complex. This addition will be used to house the Print and Mail Services department which is currently located in the lower-level of the General Office. The addition will allow for more equipment and shelving space for Print and Mail Services as well as more office space in the General Office building. The addition will be completed during 2008.

Q. WHAT PROJECTS AT THE HOOT LAKE PLANT WERE STARTED DURING 2007 AND ARE EXPECTED TO BE COMPLETED BY OCTOBER 31, 2009?

A. The two production-related capital projects at Hoot Lake that were started during 2007 were the upgrade of the burner on Unit #2 as well as the replacement of superheater tubes on Unit #2.

The burner upgrade on Unit #2 was the result of Environmental Protection Agency regulations that required our Nitrogen Oxide ("NOx") emission levels to be lowered to 0.15 pounds per million Btu by 2009. Current NOx emissions at Hoot Lake Unit #2 were averaging 0.430 pounds per million Btu at the time of the environmental regulation change and upgrades were needed in order to lower the NOx to the required level. Another contributing factor for the burner upgrade was the fact that the existing burners were past their estimated life span and were in need of replacement. The burner modifications and replacement satisfied both issues of lowering NOx levels and the need to replace equipment beyond its life expectancy.

The replacement of superheater tubes on Unit #2 was due to the failure of the existing low temperature superheater tubes over the last three years, which caused unplanned outages on the unit. The old tubes were well past their life expectancy and Hoot Lake mechanics had made several weld repairs to these tubes. As a result, metal thickness and metal fatigue were becoming an issue. Based on potential generation losses and plant safety, the decision was made to replace them.

Q. PLEASE DESCRIBE THE PRODUCTION-RELATED ADDITION AT THE COYOTE PLANT.

A. The addition at the Coyote Plant was the purchase of a spare Generator Step-Up Transformer (GSU). The GSU is a large transformer that takes the 22,000 volt electricity coming off the generator and steps it up to 345,000 volts before it is sent down the transmission lines to customers. The purchase of a spare was initiated due to the long lead-time in procuring a replacement GSU, up to two years, and the fact that the existing unit was over 25 years old. The age of the existing unit led to reliability concerns and the risk of not having a spare was too great should the existing unit fail. If a failure had occurred, and a spare was not available, the unit would not be able to generate electricity and would likely

have been off-line for a year or more while we waited for a replacement unit to arrive.

Q. PLEASE BRIEFLY DESCRIBE THE TWO TRANSMISSION RELATED PROJECTS THAT WERE STARTED BUT NOT COMPLETED BY THE END OF 2007.

A. The first transmission project is related to additions at the substation in Hensel, North Dakota. Prior to the addition of the LWEC, customers in northeastern North Dakota were served by long radial transmission lines. Customers in the Langdon area were served by a 115 kV radial line from Devils Lake and customers in the Hensel area were served by a 115 kV radial line from Drayton. Load growth in northeastern North Dakota was indicating that a new transmission source would be needed in the future to continue serving customers in this area reliably. One transmission solution that was contemplated was a new 115 kV line from the Langdon Substation to the Hensel Substation to "loop" the Langdon and Hensel substations together via a large 115 kV loop from Drayton to Devils Lake.

When the interconnection studies for the LWEC were performed for the 159 MW wind generating facility, a new 115 kV line from Langdon to Hensel was studied to determine if this line (along with the existing 115 kV line from Langdon to Devils Lake) provided adequate transmission outlet for the new wind farm. Interconnection studies did indeed indicate that a new 35-mile 115 kV line was necessary for sufficient transmission capacity for the LWEC. Therefore, the new Langdon - Hensel 115 kV line was accelerated for the Langdon Wind Energy Center project and energized as part of the project in December of 2007. Thus, this new line served the dual purpose of providing an adequate outlet for the LWEC, and it also improved transmission reliability in the Langdon area.

As part of the Langdon - Hensel 115 kV line addition, substation modifications were necessary at the Hensel substation to integrate the new 115

kV line into the bulk transmission system. The substation additions involved adding new 115 kV circuit breakers as well as protective relaying additions. In addition, coordinated planning efforts between Minnkota Power Cooperative and OTP indicated that a new 115/69/41.6 kV transformer at the Hensel substation is needed as a result of load growth in the Hensel area causing loading concerns on the existing transformer. The transformer addition at the Hensel substation is expected to take place during the winter of 2008-2009.

Q. WILL YOU NOW BRIEFLY DESCRIBE THE OTHER TRANSMISSION RELATED PROJECT THAT WAS STARTED BUT NOT COMPLETED BY THE END OF 2007?

A. Yes. Load growth in the area between Appleton and Canby has caused electrical facilities in this area to exceed allowable capacity. During peak load times, the transformer at the Canby substation becomes overloaded during critical contingency situations. The only practical alternative that was identified by OTP was to upgrade the existing 41.6 kV line between Appleton and Canby to 115 kV. For ease of construction, improved reliability, and lower overall cost, it was determined that the entire 42 miles of upgraded line would occur in a single timeframe. Upgrading the line will result in a positive economic impact in the form of reduced system losses. OTP submitted a Certificate of Need ("CON") application and a Route Permit application to the Minnesota Public Utilities Commission on September 7, 2006. The CON and Route Permit were approved on April 18, 2007. Construction of the upgrade began in late April 2007 and the line is expected to be energized at 115 kV by May 2009.

Q. IS THERE A RELATED ADJUSTMENT TO ACCUMULATED DEPRECIATION AND DEPRECIATION EXPENSE FOR THE GROUP OF PROJECTS JUST DESCRIBED?

A. Yes. An adjustment is needed to both accumulated depreciation and depreciation expense. Because the projects added to plant are not projected to go into service

until after 2007, there is no current year depreciation expense or accumulated depreciation included in the 2007 Actual Year. Therefore, an adjustment is needed to normalize a full year's worth of projected depreciation expense as well as an off-setting amount to annualize accumulated depreciation. As I explained earlier, these adjustments are appropriate to match depreciation and the accumulated depreciation offset to the annualized rate base addition. The adjustment amount to increase accumulated depreciation and depreciation expense is $360,844 (See Exhibit (KAS-1), Schedule 6). The North Dakota share of this adjustment is $147,254 (See Exhibit (KAS-1), Schedule 6).

Q. DO YOU HAVE ANY OTHER PLANT IN SERVICE ADDITIONS TO DISCUSS?

A. Yes. I have one final adjustment for projects that are scheduled to be started after December 31, 2007 and completed before October 31, 2009. There are two projects included in this adjustment; 1) a Production project at Hoot Lake Plant; and 2) a Transmission project related to the new Casselton Ethanol Plant. The total rate base adjustment for these projects is an increase of $8,701,300 (See Exhibit (KAS-1), Schedule 6). The North Dakota share of this adjustment is $3,575,133 (See Exhibit (KAS-1), Schedule 6). As with the other plant additions there are matching adjustments needed to annualize accumulated depreciation and normalize depreciation expense to reflect a full or normal year of rate base treatment. There is no current year depreciation expense or accumulated depreciation amounts included in the 2007 Actual Year. Therefore, the adjustment needed will be the same for depreciation expense and accumulated depreciation. (See Exhibit __ (PJB-1) Schedule 8, Column I.) The total adjustment being made is $173,921 (See Exhibit (KAS-1), Schedule 6). The North Dakota share is $71,755 (See Exhibit (KAS-1), Schedule 6).

Q. PLEASE BRIEFLY DESCRIBE THE PRODUCTION PROJECT AT HOOT LAKE.

A. The production project at Hoot Lake Plant is the replacement of superheater tubes on Unit #3. The low temperature and high temperature superheat tubes on Unit #3 are well past their life expectancy. As with the old tubes on Unit #2 that I discussed earler, Unit #3 has seen several forced and unplanned outages due to tube leaks. Over the last few years, Hoot Lake mechanics have made a number of weld repairs in these boiler sections related to the leaks and the threat of generation losses and tube failures was becoming too great to ignore. As a result, the decision was made to replace the old tubes.

Q. PLEASE TELL US MORE ABOUT THE TRANSMISSION PROJECT RELATED TO THE NEW CASSELTON ETHANOL PLANT.

A. A new ethanol plant near Casselton, North Dakota, will be served by OTP and is expected to be in-service in October 2008. The ethanol plant has informed OTP that they have plans to double their electrical demand within 2 to 3 years after initial start-up. In order to provide reliable service to the ethanol plant, Otter Tail is constructing a new 115 kV line from Mapleton to Casselton. The new 115 kV line will be double circuited with an existing 41.6 kV line to minimize the impacts. In 2009, it is expected that the new 115 kV line to Casselton will be extended further west to the Buffalo substation to complete a 115 kV loop between the Sheyenne Substation and the Buffalo Substation. As part of this project, substation modifications will occur at Buffalo, Mapleton, and Casselton.

Q. IS OTP REQUESTING COST RECOVERY FOR ANY INVESTMENTS IN WIND GENERATION IN THIS CASE?

A. No. OTP is the owner of a portion of a large wind farm near Langdon, North Dakota, that went into commercial operation in late 2007 and early 2008. The cost recovery for this wind investment is accomplished through the Renewable Resource Cost Recovery Rider approved by the Commission on May 21, 2008. All costs and Rider revenues are tracked separately and no portion of the plant investment, expenses, or revenue is included in the test year used in this case to

set base rates. Cost recovery on the Langdon Project and additional wind investments are included in the annual filing of OTP's Renewable Resource Rider rate made on August 29, 2008. No costs included for recovery through the Rider are included in the test year for this general rate case.

Q. PLEASE SUMMARIZE THE TOTAL ADJUSTMENTS TO PLANT-IN-SERVICE RELATED TO NEW PROJECT ADDITIONS.

A. The total adjustments to gross plant related to new projects being added in the Test Year is $31,499,909. The North Dakota share of this amount is $12,861,223. The total of all adjustments to accumulated depreciation related to new projects is $1,202,558. The North Dakota share is $491,747. These adjustments result in a net increase to Total Company and North Dakota plant-in-service of $30,297,348 and $12,369,475, respectively (See Exhibit__(KAS-1), Schedule 6 for more detail related to the above totals). The total adjustment to the Operating Statement is found on Exhibit __ (PJB-1) Schedule 8, Column I, line 12, $479,389.

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO PLANT IN SERVICE BESIDES THOSE JUST DESCRIBED RELATED TO NEW ADDITIONS?

A. Yes. There is a change in the calculated energy and demand allocation factor percentages as a result of the new load related to the addition of the Casselton Ethanol Plant in North Dakota. The factors are adjusted to accurately reflect the jurisdictional sales that are generated, including the new load, in relation to the total sales of the system. Therefore, the new load increases the North Dakota amount of allocated net plant by approximately $13,812,000 (see Exhibit__(KAS-1), Schedule 4, Column G).

Q. THE OTHER MAJOR COMPONENT TO NET PLANT IN SERVICE IS ACCUMULATED DEPRECIATION. ARE YOU PROPOSING ANY

CHANGES IN HOW ACCUMULATED DEPRECIATION IS DETERMINED?

A. Yes. OTP is proposing two changes related to accumulated depreciation in addition to those related to matching new plant in service discussed above. These additional changes are fully discussed in the testimony of Ms. Bernadeen Brutlag.

Q. PLEASE SUMMARIZE THE PROPOSED ADJUSTMENTS RELATED TO PLANT IN SERVICE DESCRIBED ABOVE.

A. The North Dakota share of the proposed adjustments I have described as well as the adjustments related to accumulated depreciation described in Ms. Brutlag's testimony (see Exhibit (KAS-1), Schedule 4) are an increase to plant in service of approximately $27,246,000 and an increase in accumulated depreciation of approximately $1,367,000. As I mentioned previously, the adjustments were made to normalize the Test Year for projects that will be in service on or before October 31, 2009 and to recognize the shift in energy and demand allocation percentages related to the new load coming on line in 2008.

B. CONSTRUCTION WORK IN PROGRESS

Q. PLEASE EXPLAIN THE ITEM CALLED CONSTRUCTION WORK IN PROGRESS.

A. Construction Work in Progress ("CWIP") consists of two parts: short-term and other construction activities. Short-term CWIP applies to small rebuilds, heavying up of lines and similar types of activity which benefits existing customers. These are construction projects which cost less than $10,000 and require less than 30 days to complete, as set forth in North Dakota Rule 69-09-05.1-05. AFUDC is not added to the short-term CWIP. The Commission ruled in our preceding cases that it is proper to include short-term CWIP in rate base, which we have also done in this case. Long-term CWIP has not been allowed to

be included in rate base in the past and has been excluded in the 2007 Test Year calculation as well.

Q. DOES OTP CALCULATE ALLOWANCE FOR FUNDS DURING CONSTRUCTION ("AFUDC") ON ITS LONG-TERM CWIP?

A. Yes. OTP develops a rate for AFUDC based on FERC Order No. 561 and FERC Electric Plant Instruction 3 (17), 18 C.F.R. Ch. 1, Pt 101. These FERC accounting instructions generally provide that AFUDC rates are developed using the cost of short-term debt to the extent it supports the long-term CWIP, followed by the cost of other components of the utility's capital structure. Mr. Kevin Moug in his Direct Testimony discusses the Utility's capitalization in more detail.

C. CASH WORKING CAPITAL ITEMS

Q. PLEASE EXPLAIN WHAT YOU HAVE INCLUDED WITH REGARD TO WORKING CAPITAL?

A. The working capital items of fuel stocks, materials and supplies and prepayments are included and discussed below.

Q. PLEASE DISCUSS WORKING CAPITAL BEGINNING WITH MATERIALS AND SUPPLIES ON LINE 23 OF SCHEDULE 2.

A. Work paper series, A-3, found under the tab, Workpapers A-D in Volume 4A, supports Line 23 of my Schedule 2 and summarizes the materials and supplies inventory by month and shows the calculation of the total utility amount for the 2007 Actual Year. The accounting records provide the materials and supplies inventory at the generating plants, central stores, and at various locations throughout OTP's service territory. The dollar amount used to calculate revenue requirements is based on 13-month average balances. The only adjustment to materials and supplies in the Test Year is to reflect the change in energy and

demand allocation percentages related to the new load previously discussed. The North Dakota portion of this adjustment is approximately $168,000.

Q. PLEASE EXPLAIN FUEL STOCKS, LINE 24 OF SCHEDULE 2?

A. Work paper series, A-8, found under the tab, Workpapers A-D in Volume 4A, supports Line 24 of my Schedule 2 and presents the 13-month average inventory balances for fuel stocks. Fuel stocks include coal stockpiles and fuel oil for the peaking plants. This schedule shows the calculation of the amount for the total utility for the 2007 Actual Year. As with materials and supplies, the only adjustment to fuel stocks in the Test Year is related to the change in energy and demand allocation percentages. The North Dakota share of this adjustment is approximately $185,000.

Q. HOW IS THE 13-MONTH AVERAGE BALANCE FOR FUEL STOCKS DETERMINED?

A. Primarily, these balances are summarized directly from the Company's general ledger.

Q. WOULD YOU PLEASE DESCRIBE THE PREPAYMENTS SHOWN ON LINE 25 OF YOUR SCHEDULE 2?

A. My Schedule 2, Line 25 represents Prepayments that are included in rate base. Work paper series, A-4, found under the tab, Workpapers A-D in Volume 4A, shows the calculation of Prepayments for the total utility for the 2007 Actual Year. The content of this line item has changed since the last rate case. In that case, Prepayments included only prepaid insurance expense. In this current case, three separate items are grouped together under the line item of Prepayments. The three items are 1) prepaid insurance, 2) post-retirement benefits liability, and 3) post-employment benefits liability. The amounts for each item are developed using a 13-month average.

Q. PLEASE EXPLAIN THE TWO NEW ITEMS, BEGINNING WITH POST-RETIREMENT BENEFITS LIABILITY.

A. In December 1990, the Financial Accounting Standards Board (FASB) issued statement no. 106, Employers' Accounting for Post-retirement Benefits Other Than Pensions, effective for fiscal years beginning after December 15, 1992. Prior to this pronouncement, these benefits had been accounted for as actual costs were incurred (sometimes referred to as pay as you go). Financial Accounting Standard (FAS) No. 106 changed to an accrual method, which recognized future liability in current expense. Because future liability is now recognized along with current cash costs, the annual expense is larger. OTP adopted accrual accounting for post-retirement benefits in 1993. Since the amount collected in rates is currently larger than OTP pays out in cash benefits each year we have reduced rate base by the cumulative difference between the accrual amount collected in rates and the cash amount actually paid out. This rate base reduction recognizes the availability of customers' cash and essentially pays customers our authorized rate of return for the benefit of having the use of that cash the same as we pay our shareholders for their investments. Additional discussion of post-retirement benefits expense appears in the testimony of Mr. Beithon.

Q. IS THE ITEM OF POST-EMPLOYMENT BENEFIT LIABILITY SIMILAR?

A. Yes. The accounting change occurred in 1994 under FAS no. 112, Employers' Accounting for Post-Employment Benefits, issued in 1992, effective for fiscal years beginning after December 15, 1993. While FAS no. 106 applied to post-*retirement* benefits, FAS no. 112 is concerned with post-*employment* benefits. OTP's practice is to adopt changes in Generally Accepted Accounting Principles (GAAP) as they occur and implement each as they pertain to a regulated utility. In this case, FAS no. 112 is a similar accounting change to FAS no. 106 and OTP accounts for it in a similar manner. That is, rate base is reduced for the

amount of the cumulative liability, which represents cash collected in rates but not yet paid out in cash expenses.

Q. ARE THERE KNOWN AND MEASURABLE RATE BASE ADJUSTMENTS FOR THE ABOVE THREE ITEMS IN THE 2007 TEST YEAR?

A. Yes. There is an adjustment to FAS 106, Post-retirement Benefits that Mr. Beithon addresses in his testimony (See Exhibit__(KAS-1), Schedule 4, Column C). There also is a similar adjustment to the one affecting materials and supplies and fuel stocks related to the change in energy and demand allocation percentages associated with a new Large Customer. The North Dakota share of this adjustment is approximately ($995,000) (See Exhibit__(KAS-1), Schedule 4, column G). The total amount of Test Year adjustments to prepayments in North Dakota, including the piece related to FAS 106 described by Mr. Beithon, is approximately $747,000.

Q. PLEASE FINISH YOUR DISCUSSION OF THE WORKING CAPITAL PORTION OF RATE BASE BY DISCUSSING YOUR SCHEDULE 2, LINE 27, CASH WORKING CAPITAL.

A. This item represents a determination of cash working capital requirements for operation, maintenance, and other expenses and is supported by my Schedule 3, pages 1 – 3.

Q. HOW WERE SUCH CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

A. A lead-lag study was performed by OTP based on calendar 2005 financial data. The results of that study are summarized on Schedule 3, pages 1 – 3. This study analyzes the lapse of time between the average day on which the Company incurs expenses to serve its customers and the average day on which cash is received from customers in payment of that service. As reflected on my Schedule 3, page 1, line 61, on average, OTP does not receive cash from its

customers until 38.1 days after service has been rendered. As shown on Lines 58 through 60 of Schedule 3, page 1 of 3, the 38.1 days is comprised of a 15.2 day metering period lag, a 3.5 day bill processing lag, and a 19.4 day collection period lag, which was based on the total annual billings to customers divided by the average daily utility receivable balances.

Q. PLEASE EXPLAIN OTHER COMPONENTS OF THE LEAD-LAG STUDY?

A. Page 1 of Schedule 3 calculates the revenue lead days for total utility and North Dakota. Pages 2 and 3 of Schedule 3, calculate and compare the lag, or in some cases lead, days associated with certain payments to suppliers and employees. The net lead or lag period (revenue lag minus expense lead) for various items is shown in Column (F), the Net Revenue Lag Dollars.

Q. WOULD YOU PLEASE EXPLAIN HOW SCHEDULE 3 DETERMINES THE CASH WORKING CAPITAL REQUIREMENT?

A. Column (A) on page 2 of Schedule 3 presents the expenses incurred during the 2007 actual year, for OTP's North Dakota electric jurisdiction. Column (B) is a determination of the daily expenses, i.e., the total annual expenses divided by 365 days. Column (C) presents the expense lag days as determined by the lead-lag study. Column (D) then subtracts the expense lag days from the revenue lead days to develop the net revenue lag dollars (the total cash requirement) in Column (E). Page 3 of Schedule 3 presents the same information for the 2007 test year.

Q. IS THERE A KNOWN AND MEASURABLE TEST YEAR ADJUSTMENT FOR CASH WORKING CAPITAL?

A. Yes. Cash working capital is embedded in the class cost of service model. Any change to components of revenue requirements in the model changes the cash working capital amount. The adjustment for the 2007 Test Year reduces cash working capital by $3,212,811 and represents the cumulative affect of all of the

adjustments made to the 2007 Actual Year to arrive at the 2007 Test Year (See Exhibit__(KAS-1), Schedule 4).

Q. WHY DOES THE CASH WORKING CAPITAL BALANCE GO DOWN IN THE TEST YEAR FROM THE ACTUAL 2007 YEAR?

A. Two of the biggest drivers of the timing of cash working capital are energy costs and property taxes. The actual 2007 cash working capital amount recognized the lag in collecting changes in cost of energy through the fuel clause adjustment. The test year, however, assumes that the current base cost of energy is now in base rates and the lag at that point in time has been reduced. The other item affecting cash working capital, property taxes, reduces cash needs. This occurs because under accrual accounting property taxes are recognized as an expense and collected in rates during the year when the assessment is determined, more than 12 months before the cash payment is due. Test year property taxes are $3,640,599 and lead days are 316.5. Net lead days for property taxes are 279.0. (Line 6, Columns (A), (C) and (D) on page 3 of Schedule 3.)

Q. IS THE CASH WORKING CAPITAL DETERMINATION METHODOLOGY CONSISTENT WITH OTP'S LAST ELECTRIC RATE PROCEEDING BEFORE THE COMMISSION?

A. No. OTP utilized the formula approach in its last North Dakota electric rate case. However, in the Order to Case No. 10,334, the Commission noted that the formula method had become dated and there was concern that this method was providing more working capital than actually required. As a result, a North Dakota staff witness was appointed to perform a lead-lag study to the North Dakota jurisdiction to determine the reasonableness of OTP's cash working capital requirements as calculated in that case using the formula method. Based upon the results of that study, the staff witness concluded the formula approach had not provided an accurate representation of the company's cash working

capital requirements. The Commission agreed with the conclusion reached by the staff witness and made an adjustment to eliminate cash working capital from the rate base calculation. As a result, OTP has calculated cash working capital for the 2007 Test Year using a lead-lag study to be consistent with the Commission's decision in the Order in Case No. 10,334.

D. ACCUMULATED DEFERRED INCOME TAXES

Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES ("ADIT").

A. Accumulated deferred income taxes are created by inter-period differences between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference is the extent to which accelerated tax depreciation generally exceeds straight-line book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts.

Q. WHY ARE ACCUMULATED DEFERRED INCOME TAXES DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

A. To the extent deferred income taxes have been allowed for recovery in rates, they represent a non-investor source of funds. Accordingly, the average projected ADIT balance is deducted in arriving at total rate base to recognize such funds are available for the utility's use between the time they are collected in rates and ultimately remitted to the respective taxing authorities.

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED IN THE TEST YEAR RATE BASE?

A. As shown on Schedule 1, line 11, $32,540,502 was deducted. This amount reflects a simple average of the beginning and ending test year ADIT balances

as well as an adjustment in the Test Year to reflect the impacts of the changes in energy and demand allocation percentages. The North Dakota portion of this impact is approximately ($1,845,000) (see my Schedule 4, Column G).

III. CONCLUSION

Q. WHAT IS THE AVERAGE ORIGINAL COST RATE BASE FOR THE NORTH DAKOTA JURISDICTION AS DEVELOPED ON SCHEDULE 1?

A. The average original cost rate base for the North Dakota jurisdiction for the 2007 actual year and the 2007 test year is $165,070,792 and $187,173,203, respectively.

Q. WHAT IS SHOWN ON SCHEDULE 2?

A. Schedule 2 shows average electric plant in service, average accumulated depreciation, and net average electric plant in service in detail by function and all remaining rate base components in total for the entire system and the North Dakota jurisdiction. This schedule provides the detail underlying the information in the summary Schedule 1. Schedule 3 provides additional detail regarding the cash working capital calculation shown on line 27 of Schedule 2.

Q. WHAT IS SCHEDULE 4?

A. This schedule lists the adjustments made to determine the proposed test year rate base.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON RATE BASE FOR THE 2007 TEST YEAR?

A. Schedule 4 shows the 2007 actual year, a summary of proposed adjustments, and the 2007 test year rate base of $187,173,203.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application by Otter Tail Corporation d/b/a Otter Tail Power Company, for Authority to Increase Rates for Electric Utility Service in North Dakota	))))	Case No. PU-08-____

AFFIDAVIT OF KYLE SEM

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Kyle Sem

Subscribed and sworn to before me,
this 23rd day of October, 2008.

NOTARY PUBLIC

WENDI A. OLSON
NOTARY PUBLIC - MINNESOTA
My Commission Expires Jan. 31, 2010

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY **Case No. PU-08____**
Electric Utility - State of North Dakota **Exhibit ___ (KAS-1)**
RATE BASE SCHEDULES **Financial Information**
RATE BASE SUMMARY **Schedule 1**

Line No.	(A) Description	(B) 2007 Actual Year	(C) 2007 Test Year
1	Electric Plant in Service	$382,860,302	$410,106,455
2	Less: Accumulated Depreciation	(188,378,692)	(189,745,784)
3	Net Electric Plant in Service	$194,481,610	$220,360,671
	Other Rate Base Components:		
4	Plant Held for Future Use	$12,674	$12,871
5	Construction Work in Progress	2,215,710	2,257,935
6	Materials and Supplies	5,554,248	$5,722,628
7	Fuel Stocks	2,887,084	3,072,173
8	Prepayments	(14,003,394)	(13,256,872)
9	Customer Advances	(50,899)	(54,286)
10	Cash Working Capital	4,811,395	1,598,584
11	Accumulated Deferred Income Taxes	(30,837,636)	(32,540,502)
12	Unamortized Balance - Spiritwood	0	0
13	TOTAL	$165,070,792	$187,173,203

Note: The 2007 Actual Year is based on 2007 historic financial information that is the basis for OTP's Annual Report to the North Dakota Public Service Commission. 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 **Case No. PU-08____**
Electric Utility - State of North Dakota **Exhibit ___ (KAS-1)**
RATE BASE SCHEDULES **Financial Information**
RATE BASE COMPONENTS **Schedule 2**

		2007 Test Year					
		Total Utility			North Dakota Jurisdiction		
Line No.	Description	(A) 2007 Actual Year	(B) Adjustments	(C) 2007 Test Year	(D) 2007 Actual Year	(E) Adjustments	(F) = (D) + (E) 2007 Test Year
	Utility Plant in Service:						
1	Production	$366,910,631	$16,263,110	$383,173,741	$139,125,650	$15,358,500	$154,484,150
2	Transmission	190,660,998	12,631,899	203,292,897	74,645,372	9,227,719	83,873,091
3	Distribution	315,099,950	666,561	315,766,511	139,614,140	402,147	140,016,287
4	General	70,354,613	1,550,233	71,904,846	27,876,579	2,023,216	29,899,795
5	Intangible	3,735,021	388,106	4,123,127	1,479,926	234,571	1,714,497
6	**TOTAL Utility Plant in Service**	$946,761,213	$31,499,909	$978,261,122	$382,741,667	$27,246,153	$409,987,820
	Accumulated Depreciation						
7	Production	($215,818,786)	($875,956)	($216,694,742)	($86,189,731)	($1,349,654)	($87,539,385)
8	Transmission	(76,391,323)	35,076	(76,356,247)	(30,696,441)	(806,059)	(31,502,500)
9	Distribution	(131,748,913)	93,682	(131,655,231)	(59,315,268)	937,081	(58,378,187)
10	General	(28,647,675)	164,320	(28,483,355)	(11,779,824)	(64,252)	(11,844,076)
11	Intangible	(1,003,024)	(155,242)	(1,158,266)	(397,428)	(84,207)	(481,635)
12	**TOTAL Accumulated Depreciation**	($453,609,721)	($738,120)	($454,347,841)	($188,378,692)	($1,367,091)	($189,745,783)
13	**NET Utility Plant in Service**						
14	Production	$151,091,845	$15,387,154	$166,478,999	$52,935,919	$14,008,846	$66,944,765
15	Transmission	114,269,675	12,666,975	126,936,650	43,948,931	8,421,660	52,370,591
16	Distribution	183,351,037	760,243	184,111,280	80,298,872	1,339,228	81,638,100
17	General	41,706,938	1,714,553	43,421,491	16,096,755	1,958,964	18,055,719
18	Intangible	2,731,997	232,864	2,964,861	1,082,498	150,364	1,232,862
19	**NET Utility Plant in Service**	$493,151,492	$30,761,789	$523,913,281	$194,362,975	$25,879,062	$220,242,037
20	Big Stone Plant capitalized items	$129,351	$0	$129,351	$118,635	$0	$118,635
21	Utility Plant Held for Future Use	29,656	0	29,656	$12,674	$197	$12,871
22	Construction Work in Progress	26,037,862	(3,992,087)	22,045,775	2,215,710	42,225	2,257,935
23	Materials and Supplies	13,498,511	0	13,498,511	5,554,248	168,380	5,722,628
24	Fuel Stocks	7,638,969	0	7,638,969	2,887,084	185,089	3,072,173
25	Prepayments	(35,518,043)	3,991,701	(31,526,342)	(14,003,394)	746,522	(13,256,872)
26	Customer Advances	(129,099)	0	(129,099)	(50,899)	(3,387)	(54,286)
27	Cash Working Capital*	10,112,418	(6,266,879)	3,845,539	4,811,395	(3,212,811)	1,598,584
28	Accumulated Deferred Income Taxes	(79,531,881)	0	(79,531,881)	(30,837,636)	(1,702,866)	(32,540,502)
29	**Total Average Rate Base**	$435,419,236	$24,494,524	$459,913,760	$165,070,792	$22,102,411	$187,173,203

* Detailed on Schedule 3, pages 1-3

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY **Case No. PU-08____**
Electric Utility - State of North Dakota **Exhibit ___ (KAS-1)**
RATE BASE SCHEDULES **Financial Information**
CASH WORKING CAPITAL **Schedule 3, page 1 of 3**

LINE NO	ITEM	2007 ACTUAL YEAR TOTAL UTILITY	2007 ACTUAL YEAR NORTH DAKOTA	2007 TEST YEAR TOTAL UTILITY	2007 TEST YEAR NORTH DAKOTA
1	CASH WORKING CAPITAL CALCULATION - REVENUE LEAD DAYS				
2					
3	REVENUES				
4	COMPUTER MAINTAINED BILLINGS	210,328,769	83,927,881	256,380,509	108,807,866
5	MANUALLY MAINTAINED BILLINGS	18,869,929	7,529,703	23,001,523	9,761,844
6	COST OF ENERGY REVENUES	40,397,002	17,275,360	0	0
7	SALES FOR RESALE	20,308,582	7,817,881	20,954,774	8,508,499
8	RENT FROM ELECTRIC PROPERTY	644,002	253,905	644,002	270,804
9	OTHER MISC ELECTRIC REVENUE	2,719,318	1,072,122	3,170,821	1,333,335
10	ITA DEFICIENCY PAYMENTS	3,651,858	1,439,787	3,651,858	1,535,611
11	WHEELING	433,023	0	433,023	0
12	LOAD CONTROL AND DISPATCH	4,459,926	1,758,377	4,459,926	1,875,405
13	RENT FROM ELECTRIC PROPERTY - BIG STONE	(20,657)	(8,144)	(20,657)	(8,686)
14	RENT FROM ELECTRIC PROPERTY - COYOTE	11,846	4,670	11,846	4,981
15	PROFIT ON MATERIALS AND SUPPLIES	0	0	0	0
16	MISCELLANEOUS SERVICES	34,025	13,415	34,025	14,308
17	RESIDENTIAL CONSERVATION SERVICES	76,895	9,642	76,895	9,642
18					
19	**TOTAL REVENUES**	$301,914,516	$121,094,598	$312,798,545	$132,113,610
20					
21	REVENUE LEAD DAYS FROM SERVICE TO COLLECTION				
22	COMPUTER MAINTAINED BILLINGS	N/A	38.1	N/A	38.1
23	MANUALLY MAINTAINED BILLINGS	N/A	43.1	N/A	43.1
24	COST OF ENERGY REVENUES	N/A	127.8	N/A	127.8
25	SALES FOR RESALE	N/A	25.4	N/A	25.4
26	RENT FROM ELECTRIC PROPERTY	N/A	(86.4)	N/A	(86.4)
27	OTHER MISC ELECTRIC REVENUE	N/A	35.0	N/A	35.0
28	ITA DEFICIENCY PAYMENTS	N/A	53.2	N/A	53.2
29	WHEELING	N/A	37.8	N/A	37.8
30	LOAD CONTROL AND DISPATCH	N/A	33.6	N/A	33.6
31	RENT FROM ELECTRIC PROPERTY - BIG STONE	N/A	50.2	N/A	37.5
32	RENT FROM ELECTRIC PROPERTY - COYOTE	N/A	50.2	N/A	37.5
33	PROFIT ON MATERIALS AND SUPPLIES	N/A	50.2	N/A	37.5
34	MISCELLANEOUS SERVICES	N/A	50.2	N/A	37.5
35	RESIDENTIAL CONSERVATION SERVICES	N/A	50.2	N/A	37.5
36					
37	REVENUE DOLLAR DAYS (REVENUES X REVENUE LEAD DAYS)				
38	COMPUTER MAINTAINED BILLINGS	$8,013,526,084	$3,197,652,252	$9,768,097,403	$4,145,579,712
39	MANUALLY MAINTAINED BILLINGS	813,293,929	324,530,193	991,365,628	420,735,489
40	COST OF ENERGY REVENUES	4,522,367,678	2,207,790,984	0	0
41	SALES FOR RESALE	515,837,988	198,574,177	532,251,260	216,115,872
42	RENT FROM ELECTRIC PROPERTY	(55,641,744)	(21,937,394)	(55,641,744)	(23,397,433)
43	OTHER MISC ELECTRIC REVENUE	95,176,121	37,524,273	110,978,726	46,666,712
44	ITA DEFICIENCY PAYMENTS	194,278,846	76,596,655	194,278,846	81,694,531
45	WHEELING	16,368,267	0	16,368,267	0
46	LOAD CONTROL AND DISPATCH	149,853,514	59,081,460	149,853,514	63,013,615
47	RENT FROM ELECTRIC PROPERTY - BIG STONE	(975,857)	(408,836)	(773,099)	(325,731)
48	RENT FROM ELECTRIC PROPERTY - COYOTE	559,610	234,449	443,338	186,792
49	PROFIT ON MATERIALS AND SUPPLIES	0	0	0	0
50	MISCELLANEOUS SERVICES	1,607,399	673,420	1,273,423	536,534
51	RESIDENTIAL CONSERVATION SERVICES	3,493,444	484,038	2,876,820	361,582
52					
53	**TOTAL DOLLAR DAYS**	$14,269,745,278	$6,080,795,672	$11,711,372,380	$4,951,167,674
54					
55	**AVG REVENUE LEAD DAYS (TOTAL REV DOLLAR DAYS / TOTAL REV)**	47.3	**50.2**	37.4	**37.5**
56					
57	**Calculation of Days from Service to Collection**				
58	Service Period to Date Meter is Read	(365 / 12 / 2)	15.2		
59	Read Date to Date Billing is Prepared		3.5		
60	Billing Date to Date collection is Received		19.4		
61	Total		38.1		

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
CASH WORKING CAPITAL
Calculation applying lead-lag factors

Case No. PU-08____
Exhibit ___ (KAS-1)
Financial Information
Schedule 3, page 2 of 3

		2007 ACTUAL YEAR					
		NORTH DAKOTA JURISDICTION					TOTAL UTILITY
		(A)	(B)	(C)	(D)	(E)	(F)
LINE NO	ITEM	Operating Expense	Expense/day at 365 day/year	Expense Lag Days	Lead Days of 50.2 Over Expense Lag Days	Net Revenue Lag Dollars	Net Revenue Lag Dollars
1	FUEL - COAL	$20,630,427	$56,522	16.0	34.2	$1,933,043	$4,539,859
2	FUEL - OIL	2,734,977	7,493	8.9	41.3	309,465	769,416
3	PURCHASED POWER	29,584,804	81,054	32.8	17.4	1,410,344	3,009,070
4	LABOR AND ASSOC PAYROLL EXPENSE	23,406,198	64,127	13.9	36.3	2,327,795	5,473,464
5	ALL OTHER O&M EXPENSE	14,941,042	40,934	19.4	30.8	1,260,778	2,848,979
6	PROPERTY TAX (EXCL COAL CONV TAX)	3,413,419	9,352	318.6	(268.4)	(2,509,666)	(6,435,658)
7	COAL CONVERSION TAXES	297,214	814	318.6	(268.4)	(218,522)	(560,368)
8	FEDERAL INCOME TAXES	3,587,086	9,828	43.9	6.3	61,914	75,874
9	STATE INCOME TAXES	711,191	1,948	73.0	(22.8)	(44,425)	(7,069)
10	INCREMENTAL FEDERAL INCOME TAXES	0	0	43.9	6.3	0	0
11	INCREMENTAL STATE INCOME TAXES	0	0	73.0	(22.8)	0	0
12	BANK BALANCES		0			3,706	9,400
13	SPECIAL DEPOSITS		0			311,106	789,085
14	WORKING FUNDS		0			8,941	22,679
15	TAX COLLECTIONS AVAILABLE						
16	FICA WITHHOLDING	(1,557,673)	(4,268)	0.0		0	0
17	FEDERAL WITHHOLDING	(2,656,824)	(7,279)	0.0		0	0
18	STATE WITHHOLDING- MN	0	0	1.9		0	(8,512)
19	STATE WITHHOLDING- ND	(256,507)	(703)	61.1		(42,939)	(42,939)
20	STATE SALES TAX	(2,020)	(6)	26.1		(144)	(301,193)
21	FRANCHISE TAXES	0	0	0.0		0	(69,670)
22							
23	**TOTAL CASH WORKING CAPITAL REQUIREMENT**					**4,811,395**	$10,112,418

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY **Case No. PU-08____**
Electric Utility - State of North Dakota **Exhibit ___ (KAS-1)**
RATE BASE SCHEDULES **Financial Information**
CASH WORKING CAPITAL **Schedule 3, page 3 of 3**
Calculation applying lead-lag factors

		2007 TEST YEAR					
		NORTH DAKOTA JURISDICTION					TOTAL UTILITY
		(A)	(B)	(C)	(D)	(E)	(F)
LINE NO	ITEM	Operating Expense	Expense/day at 365 day/year	Expense Lag Days	Lead Days of 37.5 Over Expense Lag Days	Net Revenue Lag Dollars	Net Revenue Lag Dollars
1	FUEL - COAL	$21,792,898	$59,707	16.0	21.5	$1,283,691	$3,120,532
2	FUEL - OIL	2,920,848	8,002	8.9	28.6	228,866	574,755
3	PURCHASED POWER	31,723,324	86,913	32.8	4.7	408,492	984,423
4	LABOR AND ASSOC PAYROLL EXPENSE	24,600,235	67,398	13.9	23.6	1,590,591	3,872,547
5	ALL OTHER O&M EXPENSE	19,160,169	52,494	19.4	18.1	950,134	2,259,605
6	PROPERTY TAX (EXCL COAL CONV TAX)	3,640,599	9,974	316.5	(279.0)	(2,782,877)	(6,619,750)
7	COAL CONVERSION TAXES	316,995	868	316.5	(279.0)	(242,312)	(576,397)
8	FEDERAL INCOME TAXES	3,100,192	8,494	43.9	(6.4)	(66,778)	(118,751)
9	STATE INCOME TAXES	614,431	1,683	73.0	(35.5)	(73,441)	(50,276)
10	INCREMENTAL FEDERAL INCOME TAXES	0	0	43.9	(6.4)	0	0
11	INCREMENTAL STATE INCOME TAXES	0	0	73.0	(35.5)	0	0
12	BANK BALANCES		0			3,953	9,400
13	SPECIAL DEPOSITS		0			331,811	789,085
14	WORKING FUNDS		0			9,537	22,679
15	TAX COLLECTIONS AVAILABLE						
16	FICA WITHHOLDING	(1,637,135)	(4,485)	0.0		0	0
17	FEDERAL WITHHOLDING	(2,792,358)	(7,650)	0.0		0	0
18	STATE WITHHOLDING- MN	0	0	1.9		(42,939)	(8,512)
19	STATE WITHHOLDING- ND	(256,507)	(703)	61.1		(144)	(42,939)
20	STATE SALES TAX	(2,020)	(6)	26.1		0	(301,193)
21	FRANCHISE TAXES	0	0	0.0		0	(69,670)
22							
23	**TOTAL CASH WORKING CAPITAL REQUIREMENT**					**1,598,584**	$3,845,539

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENTS
2007 Actual Year versus 2007 Test Year

Case No. PU-08____
Exhibit ___ (KAS-1)
Financial Information
Schedule 4

Line No.	Description	(A) 2007 Actual Year	(B) Annualize Plant in Service	(C) Prepayments	(D) Depreciation Direct Assignment to Allocated	(E) Depreciation to Reflect 2008 Rates	(F) Depreciation to Reflect 2009 Rates	(G) Factor Change for New Large Customer	(H) Changes in Allocations due to Effect of Test Year Adjustments	(I) Income Statement Adjustments Affecting CWC	(J) 2007 Test Year
	Utility Plant in Service:										
1	Production	$139,125,650	$6,549,415					$8,809,086	-$1		$154,484,150
2	Transmission	74,645,372	5,211,576					4,016,143			83,873,091
3	Distribution	139,614,140	293,839					108,308			140,016,287
4	General	27,876,579	645,009					845,988	532,219		29,899,795
5	Intangible	1,479,926	161,384					44,912	28,275		1,714,497
6	**TOTAL Utility Plant in Service**	$382,741,667	$12,861,223	$0	$0	$0	$0	$13,824,437	$560,493	$0	$409,987,820
	Accumulated Depreciation										
7	Production	($86,189,731)	($264,149)		($996,931)	($53,056)	($35,518)				($87,539,385)
8	Transmission	(30,696,441)	(115,397)		(820,531)	21,320	108,549				(31,502,500)
9	Distribution	(59,315,268)	(19,306)		895,541	17,247	43,599				(58,378,187)
10	General	(11,779,824)	(28,341)		(131,336)	2,394	92,515		516		(11,844,076)
11	Intangible	(397,428)	(64,553)					(12,061)	(7,593)		(481,635)
12	**TOTAL Accumulated Depreciation**	($188,378,692)	($491,746)	$0	($1,053,257)	($12,095)	$209,145	($12,061)	($7,077)	$0	($189,745,783)
13	**NET Utility Plant in Service**										
14	Production	$52,935,919	$6,285,266	$0	($996,931)	($53,056)	($35,518)	$8,809,086		$0	$66,944,765
15	Transmission	43,948,931	5,096,179	0	(820,531)	21,320	108,549	4,016,143		0	52,370,591
16	Distribution	80,298,872	274,533	0	895,541	17,247	43,599	108,308		0	81,638,100
17	General	16,096,755	616,668	0	(131,336)	2,394	92,515	845,988		0	18,055,719
18	Intangible	1,082,498	96,831	0	0	0	0	32,851		0	1,232,862
19	**NET Utility Plant in Service**	$194,362,975	$12,369,477	$0	($1,053,257)	($12,095)	$209,145	$13,812,376	$0	$0	$220,242,037
20	Big Stone Plant capitalized items	$118,635									118,635
21	Utility Plant Held for Future Use	12,674						197			12,871
22	Construction Work in Progress	2,215,710						32,372	9,853		2,257,935
23	Materials and Supplies	5,554,248						168,489	(109)		5,722,628
24	Fuel Stocks	2,887,084						185,089			3,072,173
25	Prepayments	(14,003,394)		1,678,516				(994,542)	62,548		(13,256,872)
26	Customer Advances	(50,899)						(3,615)	228		(54,286)
27	Cash Working Capital	4,811,395						134,322		(3,347,133)	1,598,584
28	Accumulated Deferred Income Taxes	(30,837,636)						(1,844,693)	141,827		(32,540,502)
29	**Total Average Rate Base**	$165,070,792	$12,369,477	$1,678,516	($1,053,257)	($12,095)	$209,145	$11,489,995	$214,347	($3,347,133)	$187,173,203

Column references to adjustment workpapers:
(B) W/P 2007 ND TY-01
(C) W/P 2007 ND TY-02
(D) W/P 2007 ND TY-03
(E) W/P 2007 ND TY-07
(F) W/P 2007 ND TY-08

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY | **Case No. PU-08____**
Electric Utility - State of North Dakota | **Exhibit ___ (KAS-1)**
COMPARISON OF RATE BASE COMPONENTS | **Financial Information**
MOST RECENT RATE CASE WITH CURRENT PROPOSED TEST YEAR | **Schedule 5**

Line No.	Description	(A) Per Order in Case No. 10,334	(B) 2007 Test Year	(C) (C) = (B) - (A) $ Change
1	Electric Plant in Service	$237,538,231	$410,106,455	$172,568,224
2	Less: Accumulated Depreciation	(54,804,859)	(189,745,784)	(134,940,925)
3	Net Electric Plant in Service	$182,733,372	$220,360,671	$37,627,299
	Other Rate Base Components:			
4	Plant Held for Future Use	$25,020	$12,871	($12,149)
5	Construction Work in Progress	3,830,422	2,257,935	(1,572,487)
6	Materials and Supplies	2,657,294	5,722,628	3,065,334
7	Fuel Stocks	2,866,086	3,072,173	206,087
8	Prepayments	0	(13,256,872)	(13,256,872)
9	Customer Advances	0	(54,286)	(54,286)
10	Cash Working Capital	0	1,598,584	1,598,584
11	Accumulated Deferred Income Taxes	(17,932,448)	(32,540,502)	(14,608,054)
12	Unamortized Balance - Spiritwood	0	0	0
13	TOTAL	$174,179,746	$187,173,203	$12,993,456

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
Test Year Plant-in-Service Adjustments for Additions by Project
Total Company and North Dakota Jurisdiction

Case No. PU-08____
Exhibit ___ (KAS-1)
Financial Information
Schedule 6

Line No.	(A) Project Description	(B) Total Company Gross Plant	(C) Total Company Accumulated Depreciation	(D) Total Company Net Plant	(E) North Dakota Gross Plant	(F) North Dakota Accumulated Depreciation	(G) North Dakota Net Plant
	Projects Placed-in-Service During 2007						
1	Load Management Replacement	$666,561	($43,539)	$623,022	$293,839	($19,306)	$274,533
2	Power Network Analysis Applications Software	388,106	(155,242)	232,864	161,384	(64,553)	96,831
3	Brine Concentrator at Big Stone Plant	378,588	(25,777)	352,811	152,463	(10,381)	142,083
4	VIC Site Work at Hoot Lake Plant	400,911	(24,271)	376,640	161,453	(9,774)	151,679
5	Condenser Retube at Big Stone Plant	939,924	(63,996)	875,928	378,522	(25,772)	352,750
6	AHPC Replacement at Big Stone Plant	4,215,731	(196,349)	4,019,382	1,697,742	(79,073)	1,618,669
7	Generator Rewind at Big Stone Plant	2,329,712	(158,621)	2,171,091	938,212	(63,879)	874,333
8	**Total Adjustments for Projects Placed-in-Service During 2007**	$9,319,534	($667,795)	$8,651,738	$3,783,616	($272,738)	$3,510,878
	Projects Started in 2007 and Placed-in-Service During 2008-2009						
9	Hi-Tech Addition	$1,550,233	($68,156)	$1,482,077	$645,009	($28,341)	$616,668
10	Burner #2 Upgrade at Hoot Lake Plant	2,438,723	(87,477)	2,351,246	982,113	(35,228)	946,884
11	Replacement of Superheater Tubes on Unit #2 at Hoot Lake	1,450,479	(52,029)	1,398,450	584,131	(20,953)	563,178
12	Generator Step-Up at Coyote Plant	2,609,041	(47,401)	2,561,640	1,050,703	(19,089)	1,031,613
13	Hensel Substation	2,390,381	(51,831)	2,338,550	986,206	(21,384)	964,822
14	Appleton/Canby Transmission Line	3,040,218	(53,950)	2,986,268	1,254,311	(22,258)	1,232,053
15	**Total Adjustments for Projects Started in 2007 and Placed-in-Service During 2008-2009**	$13,479,075	($360,844)	$13,118,231	$5,502,472	($147,254)	$5,355,219
	Projects Started and Placed-in-Service During 2008-2009						
16	Replacement of Superheater Tubes on Unit #3 at Hoot Lake	$1,500,000	$0	$1,500,000	$604,074	$0	$604,074
17	Casselton Ethanol Plant	7,201,300	(173,921)	7,027,379	2,971,059	(71,755)	2,899,304
18	**Total Adjustments for Projects Started and Placed-in-Service During 2008-2009**	$8,701,300	($173,921)	$8,527,379	$3,575,133	($71,755)	$3,503,378
19	**Total Plant-in-Service Adjustments for 2007 Test Year**	$31,499,909	($1,202,558)	$30,297,348	$12,861,223	($491,747)	$12,369,475

Note: The Schedule above is a summary of the adjustments calculated within Work Paper TY-01 found in Volume 4A, Tab - 2007 Test Year Work Papers.

Volume 2A

Testimony and Schedules of Witnesses:

Bernadeen Brutlag

Depreciation Allocation
Depreciation Expense
Corporate Allocations
Economic Development

Before the North Dakota Public Service Commission
State of North 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 North Dakota

Case No. PU-08-_____

Exhibit___

DEPRECIATION ALLOCATION, DEPRECIATION EXPENSE, CORPORATE ALLOCATIONS & ECONOMIC DEVELOPMENT

Direct Testimony and Exhibit of

BERNADEEN BRUTLAG

November 3, 2008

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bernadeen C. Brutlag, 215 South Cascade Street, Fergus Falls, Minnesota 56537.

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

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

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

A. I graduated summa cum laude from Moorhead State University, now Minnesota State University, Moorhead, Minnesota, in 1984 with a B.S. degree in Accounting. I am also a Certified Public Accountant (inactive) in Minnesota. I am a member of the Minnesota Society of Certified Public Accountants and the Institute of Management Accountants. I have been employed by OTP since 1984. From 1984 until 1989 I was Depreciation Analyst, responsible for conducting and obtaining approval for the results of depreciation studies. From 1989 until 1993, I was Senior Regulatory Analyst. My primary responsibilities in this position were preparing annual cost of service studies for the three state jurisdictions where OTP provides service (North Dakota, Minnesota, and South Dakota), and other regulatory and financial analyses. In 1993, I was named Manager of Regulatory Analysis and Compliance. Since 1998, I have been Manager, Regulatory Services, with responsibility for the Utility's revenue requirements, rate administration, regulatory compliance, rate design, load research, and overall regulatory policy.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of OTP.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony has four parts. First, I explain a proposed change in allocation method for accumulated depreciation and depreciation expense. Second, I will discuss adjustments to depreciation expense and accumulated depreciation for known changes in depreciation rates occurring after the 2007 Actual Year. Third, I will explain the corporate allocations used in this proceeding. Finally, I will discuss the Company's economic development program. Mr. Peter Beithon will use the results of my testimony in preparing the overall financial schedules for the rate case.

II. ALLOCATION OF DEPRECIATION

Q. IS OTP PROPOSING A CHANGE IN THE JURISDICTIONAL ALLOCATION OF DEPRECIATION?

A. Yes.

Q. PLEASE SUMMARIZE THE PROPOSED CHANGE.

A. Since OTP's last rate case, for reasons that I will explain, Accumulated Depreciation and Depreciation Expense have been directly assigned to each jurisdiction which OTP serves. I am proposing to allocate both of these items using the same allocation factors used for allocating Electric Plant in Service.

Q. WHY WERE THESE TWO ITEMS PREVIOUSLY DIRECTLY ASSIGNED TO JURISDICTIONS?

A. The property owned by OTP serves all jurisdictions and the allocation of property depends upon usage levels of the customers in the various regulatory jurisdictions served by the Utility. OTP's service territory is contiguous,

covering parts of the three states in which we provide service. Operating characteristics affecting Utility property are similar throughout OTP's service territory. Property accounting rules and functions performed by the property are uniform throughout the system. Nevertheless, for a period of time in the past there existed a significant difference in accounting for allowed depreciation expense (recovery of capital), the primary component of accumulated depreciation reserves, among the three jurisdictions served by the Company. During the prior period, each jurisdiction allowed depreciation expense based upon significantly different depreciation parameters. In 1983, the Company adopted an extensive depreciation accounting process that determined the depreciation expense to be assigned to each jurisdiction according to the then allowed depreciation procedures.

Q. ARE THERE STILL DIFFERENCES IN ALLOWED DEPRECIATION RATES AMONG JURISDICTIONS?

A. There are no longer differences in the salvage and remaining lives used to calculate depreciation rates. The North Dakota Public Service Commission ("Commission") in Docket PU-401-88-374 by Orders dated December 20, 1988, and June 23, 1992, adopted the same parameters that Minnesota uses to develop annual depreciation rates. Changes in remaining lives and salvage approved by Minnesota in annual depreciation filings were also approved for use in North Dakota at the same time.[1] Therefore, since 1989, all of OTP's depreciation expense has been calculated using identical parameters for both North Dakota and Minnesota.

Q. SHOULD NORTH DAKOTA CONTINUE TO RELY ON THE MINNESOTA DEPRECIATION ORDERS?

[1] The December 20, 1988, Order required the Minnesota depreciation Orders to be approved by the North Dakota Commission prior to implementation. This approval requirement was later modified in Amended Order dated June 23, 1992, to require annual Minnesota Orders to be filed but approval by the North Dakota Commission was no longer required.

A. Yes. This process has served both the Commission and OTP well. As stated in the June 23, 1992 Order: "The purpose was to reduce Otter Tail Power Company's regulatory and accounting burden, not add to it. Accordingly, the requirements of the previous [December 20, 1988] order requiring the Commission to review and approve the Minnesota rates are redundant and unnecessary."

Minnesota Statutes § 216B.11 and Minnesota Rules 7825.0600 through 7825.0900 gives authority to the Minnesota Public Utilities Commission to review and approve proper and adequate rates and methods for depreciation used by regulated electric utilities in that state. These Rules require utilities to review their depreciable rates annually and conduct depreciation studies at least every five years. As I mentioned earlier, OTP's electric generating and delivery system is fully integrated and has similar characteristics throughout its service territory. OTP conducts its annual depreciation reviews and the five-year depreciation studies on the property and equipment in its entire system. Therefore, it is reasonable and in fact desirable to use consistent depreciation parameters and methods in all three states covered by OTP's service territory. By using a single set of depreciation parameters for our contiguous, fully integrated system, OTP's regulatory and accounting costs are lower and the Commission and its Staff may use their resources for more significant matters.

Q. WHY WAS THE DIRECT ASSIGNMENT OF ACCUMULATED DEPRECIATION AND DEPRECIATION EXPENSE MAINTAINED EVEN AFTER MINNESOTA AND NORTH DAKOTA ADOPTED IDENTICAL DEPRECIATION COMPONENTS?

A. Prior to North Dakota's adoption of the Minnesota approved depreciation components, North Dakota had allowed substantially higher decommissioning rates and shorter depreciable lives on some property. It was, therefore, necessary to maintain jurisdictional direct assignments to recognize the fact that

North Dakota customers had, at that time, provided more decommissioning funds on common assets than Minnesota customers.

Q. WHY ARE YOU PROPOSING TO ELIMINATE DIRECT ASSIGNMENT?

A. For nearly 20 years, the depreciation parameters have been identical for both North Dakota and Minnesota. Over time, the remaining life formula used by both states narrowed the differences created by the different depreciation parameters allowed long ago. While OTP has monitored the relationship of directly assigned reserves to allocated Electric Plant in Service and made periodic adjustments to these jurisdictional amounts, over time, it is more difficult or nearly impossible to identify how much of the jurisdictional difference is because of past regulatory decisions and how much is caused by customer changes among the jurisdictions. I believe any difference in jurisdictional Accumulated Depreciation that may remain is too small to have a material impact on rates. Further, allocating accumulated depreciation and depreciation expense using the same allocation factors as Electric Plant in Service is appropriate and removes administrative requirements to monitor and account for directly assigned amounts.

Q. WHY SHOULD THE SAME ALLOCATION FACTORS USED FOR ELECTRIC PLANT IN SERVICE BE USED FOR ALLOCATING ACCUMULATED DEPRECIATION AND DEPRECIATION EXPENSE?

A. Depreciation expense and accumulated depreciation are the cost of returning the investment in Electric Plant in Service to the shareholders. Accumulated depreciation is the amount of Electric Plant in Service paid over the life of the assets. Therefore, the jurisdictional factors used to allocate Electric Plant in Service and the associated depreciation and accumulated depreciation expense should all be the same. This change was also requested by OTP and approved in our most recent Minnesota rate case, Docket No. E017/GR-07-1178. If we do

not use the same allocation factors for all three states, we will not be able to recover our revenue requirement.

Q WHAT IMPACT DOES THIS CHANGE HAVE ON THE REVENUE REQUIREMENT?

A. Since North Dakota's regulatory decisions resulted in its jurisdictional accumulated depreciation being higher, the proposal to change to an allocation method will slightly increase revenue requirements for North Dakota.

Q. WHAT IS THE AMOUNT OF THE ADJUSTMENT IN THE TEST YEAR FOR THIS CHANGE?

A. The Test Year adjustment includes an increase in North Dakota Accumulated Depreciation of $1,053,257 (which acts to decrease rate base and, therefore, the revenue requirement) and an increase in North Dakota depreciation expense of $268,864.

III. DEPRECIATION RATES

Q. HAVE YOU MADE OTHER ADJUSTMENTS RELATED TO DEPRECIATION?

A. Yes. I am proposing a total net depreciation expense reduction of $197,047 to reflect changes in depreciation rates that occurred after the end of the 2007 Actual Year.

Q. WHAT IS THE FIRST COMPONENT OF THAT ADJUSTMENT?

A. As I discussed in Section II above, depreciation parameters used to calculate depreciation rates are reviewed and approved each year by the Minnesota Public Utilities Commission and filed with the North Dakota Commission. I have adjusted the 2007 Test Year depreciation expense and accumulated depreciation

to reflect the Minnesota Public Utilities Commission approved depreciation parameters for use in 2008. That adjustment resulted in an increase in North Dakota depreciation expense and accumulated depreciation of $12,095.

Q. DID YOU MAKE AN ADDITIONAL ADJUSTMENT?

A. Yes. I made an adjustment that reduces depreciation expenses by $209,142 to reflect changes proposed by OTP in our five-year depreciation study filed with the Minnesota Public Utilities Commission on August 29, 2008. While that five-year study has not been approved, we expect it to be approved and because the changes lower our revenue requirement, it is appropriate that these proposals be reflected in our North Dakota rates. If these proposed parameters are changed by the Minnesota Public Utilities Commission before rates are approved in this proceeding, we request that the actually approved depreciation parameters be used in the rate setting process. Table 1 below shows the proposed changes in depreciation expense by function.

	Depreciation expense change
Production	$35,518
Transmission	(108,549)
Distribution	(43,596)
General	(92,515)
Total	($209,142)

Table 1

Q. PLEASE EXPLAIN THE $35,518 PRODUCTION ADJUSTMENT.

A. The primary component of this adjustment is driven by our proposal in the five-year depreciation study to extend the retirement date for OTP's three steam generating plants. The retirement date for Hoot Lake Plant Units 1 and 2 was extended two years to 2019, Big Stone Plant retirement date is now 2024, four years longer than its previous retirement date, and the retirement date for Coyote Station was also extended by four years to 2029.

Q. WHY HAVE THE EXPECTED RETIREMENT DATES FOR THESE THREE PLANTS CHANGED?

A. These plants provide low cost power for our retail customers; therefore, it is highly desirable to keep these plants in operation. In order to do that, however, it has been necessary to make capital investments in these plants. OTP witness Mr. Kyle Sem discusses several of these investments. Those investments have allowed the lives of these plants to be extended.

Q. IS THERE AN OFFSETTING ADJUSTMENT YOU ARE PROPOSING?

A. Yes. Along with setting new retirement dates for these three plants, OTP conducted a new decommissioning study as part of the five-year depreciation filing. This study showed an increase in expected decommissioning costs. Table 2 below shows the current composite depreciation rates (2008) for each plant, along with the new rates (2009) that include both the later retirement dates and the updated decommissioning costs.

Composite depreciation rates	Big Stone	Hoot Lake	Coyote
2008	2.89%	3.01%	2.44%
2009 under the five year study	3.18%	3.01%	2.19%
Net impact on annual expense (total system)	$392,848	$403	($377,940)

Table 2

The table also shows that, while longer lives and increased estimated demolition costs are significant, the net result of the changes on depreciation expense for the three plants as a group is very small – a total system amount of $15,311 and $6,278 for North Dakota.

Q. WHAT OTHER ADJUSTMENTS CAUSED THE TOTAL PRODUCTION EXPENSE TO INCREASE BY $35,518?

A. In addition to the three steam plants, the Production function includes several small hydro-electric dams and peaking units. The depreciation expense change

for all of these units combined makes up the remaining $29,240 for a total increase of $35,518.

Q. WHAT FACTORS CHANGED THE DEPRECIATION EXPENSE FOR TRANSMISSION PLANT?

A. I am proposing a reduction in depreciation expense for transmission of $108,549. The statistical analysis used in the five-year study showed that substation equipment is lasting longer than previously expected. This is the most significant cause for the reduction of depreciation expense for transmission.

Q. WHAT DID THE STATISTICAL ANALYSIS SHOW FOR DISTRIBUTION PLANT?

A. The analysis resulted in only a small reduction in depreciation expense for the distribution function ($43,596). Within the function were offsetting changes, such as an increase in removal costs for overhead lines that increased expense, higher salvage value for line transformers that reduced expense, a longer life and lower removal costs for underground services that reduced expense, and a shorter life for load management switches that increased expense.

Q. WHAT CAUSED THE $92,515 REDUCTION IN EXPENSE FOR GENERAL PLANT?

A. The reduction in depreciation expense is primarily caused by our proposal to extend the retirement date for our General Office building by ten years.

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. The proposed adjustments to 2007 Actual Year depreciation expense are an increase in expense for 2008 of $12,095 and a decrease in expense of $209,142 based on the five-year depreciation study recently completed, for a net Test Year

reduction from 2007 actual depreciation expense of $197,047. Corresponding adjustments are made to accumulated depreciation.

Q. FINALLY, ARE THERE OTHER ADJUSTMENTS TO DEPRECIATION EXPENSE IN THIS CASE?

A. Yes. OTP witness Kyle Sem discusses several Test Year adjustments to electric plant in service, which have related adjustments to depreciation expense and accumulated depreciation. OTP witness Peter Beithon will incorporate the results of all of these adjustments into total revenue requirements.

IV. CORPORATE ALLOCATIONS

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

A. Mr. Thomas Brause briefly discussed the legal and operational structure of Otter Tail Corporation ("the Otter Tail Corporate Group" or "Corporate") and the pending reorganization to a holding company in his Direct Testimony. I discuss in more detail the functions of the Corporate Group and of the Utility, which does business as Otter Tail Power Company. I also describe the function of the Corporate Group and the proposed method for allocating corporate costs. I also sponsor the Corporate Cost Allocation Manual ("CAM"), a copy of which is included as Exhibit __ (BCB-1), Schedule 1.

Q. HOW ARE OTTER TAIL CORPORATION AND OTP STRUCTURED AT PRESENT?

A. The Utility is the same legal entity as Otter Tail Corporation. However, Otter Tail Corporation is organized and operates in many ways like a holding company even though it is not yet a holding company; and OTP operates like a subsidiary of Otter Tail Corporation, even though it is not yet a subsidiary.

Q. AFTER THE HOLDING COMPANY ORGANIZATIONAL STRUCTURE HAS BEEN FORMED, HOW, IF AT ALL, WOULD THAT AFFECT THE COST ALLOCATIONS AND MORE BROADLY THE REVENUE REQUIREMENT IN THIS PROCEEDING?

A. When Otter Tail Corporation becomes a holding company, the cost allocations and revenue requirements proposed in this case will remain the same. This is because Otter Tail Corporation and OTP operate as though there were a holding company structure today.

Q. WHAT FUNCTION DOES THE CORPORATE GROUP PERFORM FOR THE UTILITY?

A. Otter Tail's Corporate Group provides a corporate management function for the Utility, as well as for the unregulated subsidiaries that are part of Varistar (the parent company for the corporation's unregulated subsidiaries). The functions performed by the Corporate Group include:

- Pay corporate taxes and associated returns
- External financial reporting – filing of 10-Qs and 10-Ks
- Corporate accounting – reoccurring journal entries for things like dividends, interest expense, Board of Director expenses, amortization of financing costs
- Shareholder services
- Investor relations – meeting with rating agencies and equity analysts
- Corporate communications – all corporate-related communications including the production of the annual report
- Internal audit
- Corporate financing – debt and equity financings
- Determine executive compensation and benefits
- All legal-related functions
- Oversight of insurance and enterprise risk management

Q. HOW DOES THE CORPORATE GROUP COMPARE IN SIZE TO THE ENTIRE CORPORATION?

A. Otter Tail's Corporate Group is a small part of the total corporation. The Corporate Group has 53 employees out of a total of 4,300 employees for the entire corporation, including all subsidiaries, or about 1.2 percent of the total employees. Expenses of the Corporate Group in 2007 were $21.2 million while total consolidated corporation operating revenues were $1.2 billion dollars, and total consolidated corporation operating expenses were $1.1 billion. Thus, Corporate Group expense is less than 2 percent of either operating revenue or operating expense.

Q. CAN YOU CONTRAST THE FUNCTION OF OTTER TAIL CORPORATION CORPORATE GROUP WITH A SERVICES SUBSIDIARY RESIDING IN SOME UTILITY HOLDING COMPANIES?

A. Yes. Otter Tail's Corporate Group is not a services entity like the corporate services unit in Xcel Energy (Xcel Energy Services Inc.), for example. Otter Tail's Corporate Group does not process the Utility's invoices, customers' bills, nor does it do billing for the Utility. It does not manage the Utility's HR, IT, procurement, nor provide services other than management services to the Utility. OTP contains within its own operating unit functions such as accounting, bill and invoice processing, IT, HR, supply chain, engineering, rates and regulation, payroll, marketing and sales, fuel and energy procurement, and customer service.

Q. HOW ARE THE COSTS OF THESE CORPORATE FUNCTIONS ALLOCATED TO OTP?

A. Costs of the corporate functions are allocated to the Utility using the allocation methodology described in the CAM. The allocations in the CAM are updated

annually based on the most recent historic year available and applied to the next 12 months.

Q. HOW WERE THE COST ALLOCATION METHODOLOGIES DEVELOPED?

A. In developing its corporate allocation methodology, OTP considered the following goals:

1) The result should be fully allocated costing;

2) Costs are directly assigned where possible;

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

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

5) The result is equitable for customers and shareholders;

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

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

Q. PLEASE EXPLAIN THE ALLOCATION PROCESS IN MORE DETAIL.

A. Corporate costs can be charged to Varistar, charged to OTP, or kept at Corporate. The allocation process uses three steps. First, all labor and other costs that can be directly assigned to Varistar, Corporate Group, or OTP are identified. Members of the Corporate Group use timesheets to assign labor. Invoices and other costs are assigned as appropriate. In the 2007 Actual Year, 54 percent of all corporate costs were directly assigned to one of the three entities. Second, indirect allocators are used for certain functions. Indirect allocators are used where an indirect-cost causative linkage to another cost category or group of cost categories exists for which direct assignment or

allocation is available. In the 2007 Actual Year about 17 percent of corporate costs were indirectly allocated. The remaining corporate costs (29 per cent in the 2007 Actual Year) do not have an identifiable direct or indirect relationship to Varistar, Corporate Group, or OTP. Those costs are allocated using a General Allocator, which is composed of revenues, assets, and labor dollars, equally weighted.

Q. HOW MUCH OF THE TOTAL CORPORATE COSTS WERE PAID BY OTP IN 2007?

A. In the 2007 Actual Year, OTP was charged 31 percent of total corporate costs. Table 3 shows how corporate costs were charged in 2007.

CORPORATE COSTS	ACTUAL YEAR 2007	
Allocated to OTP	$6,599,861	31.07%
Allocated to Varistar	11,210,723	52.79%
Kept at Corporate	3,427,232	16.14%
Total 2006 Corporate Costs	$21,237,816	100.00%

Table 3

Q. HAVE YOU MADE AN ADJUSTMENT TO THE ACTUAL 2007 CORPORATE COSTS TO ARRIVE AT THE 2007 TEST YEAR?

A. Yes, I made two adjustments related to Corporate labor and labor related costs. First, I increased Corporate Group costs allocated to OTP by $216,426 to reflect the increases of salaries and wages that occurred after the end of the Actual Year 2007. I also reduced the Utility portion of Corporate costs related to cash bonuses of the Corporate executive management by $315,784. This adjustment was made to Corporate labor costs allocated to OTP to be consistent with the proposed 25 percent cap on individual incentives as discussed by Mr. Peter Wasberg. These two offsetting adjustments result in a net decrease of $99,358 from actual 2007 corporate costs. North Dakota's share of this adjustment is a reduction of $41,833.

Q. WHAT PERCENT OF TOTAL CORPORATE CHARGES IS CHARGED TO OTP IN THE TEST YEAR, AS REDUCED BY $41,833?

A. In the 2007 Test Year, as adjusted, OTP is charged 30.6 percent of total corporate costs.

Q. PLEASE DESCRIBE THE GENERAL ALLOCATOR PROPOSED BY OTP.

A. The General Allocator used to allocate Corporate Group costs, not otherwise directly assigned or indirectly allocated, using three equally weighted components: revenues, assets, and labor dollars.

Q. PLEASE DESCRIBE THE COMPONENTS OF THE PROPOSED GENERAL ALLOCATOR, BEGINNING WITH REVENUES AND ASSETS.

A. The source and items included in these two components are shown on Appendix A to the CAM (my Exhibit ___ (BCB-1), Schedule 1). The revenues included are from continuing operations of the total corporation and OTP. The assets included are those reported in the business segment section of the 2007 Annual Report to Shareholders.

Q. BEFORE YOU DISCUSS THE LABOR DOLLARS COMPONENT, WHY WEREN'T EMPLOYEE FULL-TIME EQUIVALENTS USED INSTEAD?

A. I explained earlier the goals that OTP believes important. Besides the obvious goal that the resulting allocation must be equitable, the components used in the allocator should be auditable, relatively easy to obtain, and not create unnecessary additional administrative work. In order to calculate full time equivalents (FTEs), labor hours would need to be gathered from each subsidiary. That is not data currently gathered. Otter Tail Corporation operates as a very decentralized organization. Each of the 11 subsidiaries (and their subsidiaries) operates quite independently, keeping its own accounting and payroll system. Gathering this data from the diverse systems, and finding a way to ensure that the data is complete and accurate, would be a challenge, difficult to verify and

time-consuming. In addition, some of the non-utility subsidiaries have operations that experience seasonal fluctuations that would interfere with the consistent application of this component of the General Allocator.

Q. WHY NOT USE EMPLOYEE COUNT?

A. Employee counts are available, but OTP proposes instead using labor dollars as a component of the General Allocator. We do so for several reasons. First of all, we can reliably obtain labor dollar data easily without additional administrative work – it is data already being collected for reporting purposes. A second advantage is that it is part of the accounting information used in external financial reporting and, therefore, subject to review and audit. As mentioned above, each of Otter Tail Corporation's subsidiaries uses its own accounting systems. The Corporate Group performs the consolidation process needed for external financial reporting. This process results in consistent accounting data used to complete external financial statements. The accounting data includes labor costs. A third advantage of using labor dollars is that each subsidiary's labor dollars have a better relationship to the costs of Corporate management than do FTEs or employee count. Labor costs are an important part of manufacturing and construction companies, as well as the Utility. Efficient management of labor dollars, while primarily done at the subsidiary level, is a concern of overall Corporate management to ensure the financial success of each company. Therefore, the relationship of labor dollars to Corporate management is a third advantage for using labor dollars.

Q. WHAT TYPES OF COSTS ARE INCLUDED IN ARRIVING AT LABOR DOLLARS?

A. The following types of accounts for each subsidiary are included in the definition of labor dollars: labor (direct and indirect), salaries, sales commissions, management bonuses, payroll taxes and employee benefits. Some items like management bonuses and payroll taxes need to be included because

some subsidiaries include those in labor and some report them separately. The goal is to have consistent costs for each subsidiary in order to calculate an appropriate ratio.

Q. ARE HEAD COUNTS USED FOR ANY PURPOSE IN THE ALLOCATION PROCESS?

A. Yes, an employee-ratio based on head-count is used in two indirect allocators – human resources (HR) and risk management (RM). Employee count is appropriate for these two indirect allocators because the costs to which these allocators are being applied tend to be tied to how many employees are involved. Employee count is also more appropriate in those two applications than the alternative of using labor dollars because of the specific costs to which the allocators are applied. The cost of administering HR benefit costs, for instance, relates more to the number of employees than to the compensation of individual groups of employees. The employee ratio is not used alone in the two indirect allocators and a relatively small proportion of Corporate Group dollars are allocated on these indirect allocators. Therefore, these components of the indirect allocators remain appropriate. However, OTP is less inclined to use employee count in the General Allocator because, as I explained, the number of employees in the regulated and unregulated parts of the business has little relationship to general corporate management.

Q. IN SUMMARY, WHY IS THE GENERAL ALLOCATOR PROPOSED BY OTP APPROPRIATE?

A. The non-utility subsidiaries of Otter Tail Corporation are almost completely unrelated to the electric utility business. They are also quite diverse in business characteristics. OTP's proposed General Allocator is broadly based, stable, and verifiable. Using a General Allocator comprised of revenue, assets, and labor dollars has the advantage of being comprehensive and balances the characteristics of Otter Tail Corporation's varied lines of business. Some

subsidiaries have significant assets, while others have few assets; some are high revenue, low margin businesses, while others are low revenues but high margins; and some are more labor intensive businesses. Using these three components (revenues, assets, and labor), recognizes this diversity.

Q. USING THE ALLOCATION METHOD AND FACTORS SUGGESTED, IS OTP PAYING MORE THAN ITS FAIR SHARE OF CORPORATE MANAGEMENT COSTS?

A. No. It is paying an appropriate share of corporate costs. As can be seen in the business segment section of the 2007 annual report to shareholders, the Utility had 56 percent of the consolidated corporation's assets, 46 percent of the consolidated corporation's income before income taxes, but paid just over 30 percent of the corporate management costs. This comparison indicates that the Utility is not paying more than its equitable share of corporate costs.

V. ECONOMIC DEVELOPMENT

Q. PLEASE DESCRIBE THE PURPOSE OF THIS PORTION OF YOUR TESTIMONY.

A. This portion of my testimony supports our request to continue OTP's North Dakota economic development program, and in fact increase the amount spent on that program.

Q. PLEASE PROVIDE SOME BACKGROUND FOR OTP'S NORTH DAKOTA ECONOMIC DEVELOPMENT PROGRAM.

A. As the result of a settlement following an earnings review, the North Dakota Commission issued two Orders dated December 20, 1988, and March 7, 1989, in Case No. PU-401-88-374. These Orders set up a plan in which OTP would spend a minimum of $315,557 annually on economic development activities in

its North Dakota service territory. Economic development costs of $315,557 have been included in OTP's rates since that time. Since the North Dakota program's inception, OTP has actually spent, on average, well over half a million dollars annually. The plan includes guidelines for the type of expenditures made. The four types of expenditures and the target expenditure amounts for each component are as follows:

PURPOSE	AMOUNT
Community matching grants	$160,000
Labor dedicated to economic development	100,000
Loan pool loss provision	35,000
Miscellaneous economic development expense	20,557
Total	$315,557

Table 4

OTP may spend more or less than the guideline for any category in any given year, but its spending over time is to approximate the guidelines for each category. As noted, in actuality, we have significantly exceeded those expenditure guidelines.

Q. WHAT IMPACT HAS OTP HAD WITH ITS ECONOMIC DEVELOPMENT EFFORTS IN NORTH DAKOTA?

A. Beginning in 1989 and through 2007, OTP has assisted in creating 6,222 jobs and assisted in saving an additional 1,069 jobs in North Dakota. In 2007, OTP worked with 53 cities in North Dakota that requested assistance. The projects covered a wide variety of business development projects. In 2007, these efforts helped create 451 jobs.

Q. HOW ELSE DO COMMUNITIES BENEFIT FROM YOUR ECONOMIC DEVELOPMENT EFFORTS?

A. By creating opportunities and slowing out-migration from our rural communities we also helped these communities stabilize their tax base and maintain the

number of students they have in their schools. Our efforts also helped to ensure that community members have access to health care services and that their children have the same educational opportunities as those who live in larger communities. Our efforts helped communities utilize their infrastructure and utility resources more effectively. While these impacts might be difficult to quantify, they are indeed real to the inhabitants of these small towns. For many of our communities, the issues associated with out-migration and lack of opportunity have been among their greatest concerns for the past few decades. Because our customers are so significantly impacted by these issues, we have emphasized these concerns in our mission statement. As Mr. Brause explained, our mission includes a commitment to improve the quality of life in the communities we serve. The economic development program costs included in our Test Year will help fulfill this mission.

Q. HOW MUCH HAS OTP ACTUALLY SPENT ON ECONOMIC DEVELOPMENT SINCE 1989?

A. From 1989 through 2007, OTP has spent over $9.7 million on economic development in North Dakota. Exhibit ___ (BCB-1), Schedule 2, attached to my testimony shows OTP's spending each year for each of the four categories in the Commission's spending guidelines. During this time period, OTP has, on average, spent just over $500,000 annually.

Q. WHAT AMOUNT OF ECONOMIC DEVELOPMENT EXPENSE IS OTP REQUESTING IN THIS CASE?

A. OTP is requesting that $500,000 be included in it rates for economic development activity in OTP's North Dakota service territory.

The guideline amounts proposed for rate recovery are as follows:

PURPOSE	AMOUNT
Community matching grants	$230,000
Labor dedicated to economic development	200,000
Loan pool loss provision	10,000
Miscellaneous economic development expenses	60,000
Total	$500,000

Table 5

The proposed revised guidelines for spending categories are very close to the 18-year averages shown on Exhibit ___ (BCB-1), Schedule 2.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application by Otter Tail Corporation d/b/a Otter Tail Power Company, for Authority to Increase Rates for Electric Utility Service in North Dakota	))))	Case No. PU-08-_____

AFFIDAVIT OF BERNADEEN BRUTLAG

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Bernadeen Brutlag

Subscribed and sworn to before me,
this 27th day of October, 2008.

NOTARY PUBLIC

JENNIFER M. WINNINGHAM-FLODEN
NOTARY PUBLIC - MINNESOTA
My Commission Expires Jan. 31, 2013

Corporate Cost Allocation Manual

Last Update: February 2008

I. INTRODUCTION

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

Otter Tail Power Company (the largest operating company of Otter Tail Corporation) serves retail electric customers in three jurisdictions including Minnesota, North and South Dakota and is governed by the rules and regulations in each jurisdiction. As a regulated utility, Otter Tail Power is allowed to recover prudent and reasonable costs for services it receives from Corporate, and reflects the cost of these services in its revenue requirements for setting rates.

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

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

II. METHODOLOGY

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

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

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

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

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

III. ALLOCATION FACTORS

Indirect Allocation Factors:

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

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

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

D. Internal Audit Factor: This factor is based on the previous year ending December 31 ratio where the numerator is the total hours spent auditing electric operations and the denominator is the sum of hours auditing electric and non-electric operations. Non-

electric operations do not include hours spent auditing Corporate-related matters. See Appendix A

General Allocation Factor:

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

IV. CLARIFICATION ON CERTAIN COSTS

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

A. Labor: Each employee at Corporate tracks their time on a daily basis. Attached as Appendix B are samples of time-sheets for typical corporate employees. Percentages are used instead of hours to track time between Corporate, Utility, and Non-utility activities. The time designated Utility is directly assigned to Otter Tail Power. The percentage of time being recorded in the Corporate column is allocated based on the employee's position and will use one of the allocation factors discussed above in Section III.

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

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

D. Stock Option Expense: Under FAS 123(R) companies are required to record the value of stock options over the period in which the options vest. These expenses are allocated to Otter Tail Power based on the number of options granted to employees in this company.

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

F. Executive Stock Incentive Plan: Under FAS 123(R) companies are required to record the value of incentive stock, awarded based on the performance of the company's stock price, over the time period used to evaluate performance. Otter Tail Corporation provides incentive stock to the corporate officers as part of their overall compensation package. The costs associated with this plan are not allocated.

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

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

I. Meetings: Costs associated with periodic meetings that involve personnel from across the operating companies such as quarterly leadership meetings, quarterly accounting and HR meetings are allocated based on the number of people attending from each company, versus the total number of people in attendance.

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

K. Aviation Services: Corporate provides air service for the operating companies of Otter Tail Corporation. There are two aircrafts available for use. One is owned by Otter Tail Power Company (the King Air), the other is owned by Varistar Corporation (the Citation). To help recover the variable costs associated with flying these two aircraft, corporate charges $650/hr for the King Air and $920/hr for the Citation.[1]

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

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

V. DESCRIPTION AND ALLOCATION OF SERVICES PROVIDED

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

A. Corporate Overheads

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

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

B. Executive Management Services

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

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

C. Board of Directors

Description: Represents charges for board of director fees, restricted stock, travel and other expenses associated with attending Board meetings.

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

D. Corporate Development

Description: Represents charges for the Platform Leaders and their staff that have oversight responsibilities with the non-electric operating companies, identifying and researching acquisition candidates, due diligence on acquisition targets, and integrating recently acquired companies into Otter Tail Corporation.

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

E. Administrative Services

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

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

F. Information Technology

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

Allocation Factor: License and maintenance fees comprise a large portion of the non-labor costs. As much as possible, these costs are directly assigned based on the number of user licenses utilizing the software by operating company. All costs not directly assigned are allocated on the IT Factor including labor classified as Corporate.

G. Corporate Accounting

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

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

H. Internal Audit

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

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

I. Financial Planning and Sourcing

Description: Represents charges for supporting financial analysis and budgeting at the operating company and corporate level, communicating with both debt and equity analysts, maintaining Otter Tail Corporation's capital structure, monitoring and accessing capital markets and other services as identified by the Chief Financial Officer. Charges also represent services related to sourcing, procurement, vendor relationships, and developing strategies to leverage the consolidated buying power of Otter Tail Corporation as a whole.

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

J. Corporate Communications

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

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

K. Shareholder Services

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

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

L. Human Resources

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

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

M. Legal Affairs

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

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

N. Risk Management

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

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

VI. CONCLUSION

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

Appendix A

Computation of Allocation Factors for 2008

General Allocation Factor

REVENUES	2007	
Electric Retail Revenue	276,894	
Electric Wholes Revenue	20,345	
Other Operating Revenues	20,625	
Non-Asset Based Power Pool Sales	62,214	
Total Electric Revenues	380,078	
Total Consolidated Revenues continuing operations	1,295,806	
Ratio	**29%**	**29%**
Revenue Ratio		

TOTAL ASSETS		
Assets - Electric Operations	813,565	
Consolidated Assets	1,454,754	
Asset Ratio	**56%**	**56%**

TOTAL LABOR DOLLARS		
Labor Dollars - Electric Operations	61,773	
Consolidated Labor Dollars	258,497	
Labor Dollars - Ratio	**24%**	**24%**

2008 General Allocation Factor	**36%**

IT Factor

	2007	Factor
Labor Allocated to OTP	1,960	
Total Corporate Labor	5,309	
2008 IT Factor		**37%**

HR Factor

Benefit Costs	Electric Operations	Consolidated Operations	Factor
Benefits Costs - Cost of Goods Sold	0	7,662	
Benefits Costs - Overhead (Indirect)	0	9,846	
Benefits Costs - Sales	0	537	
Benefits Costs - R&D	0	0	
Benefits Costs - A&G	736	4,568	
Benefits Loaded Through Labor	24,522	24,522	
Subtotal	25,258	47,135	
Benefit Ratio		**54%**	
Employee Ratio		**17%**	
2008 HR Factor			**35%**

Appendix A

Computation of Allocation Factors for 2008

RM Factor	**2007**	**Factor**
Employee Ratio		
Employees - Electric Operations	714	
Consolidated Temp & Full-Time Employees	4,300	
Employee Ratio	**17%**	
Insurance Premium Ratio		
Insurance Premiums Paid by OTP	2,125	
Sum of all Insurance Premiums Paid	10,386	
Insurance Ratio	**20%**	
2008 RM Factor		**19%**

Internal Audit Factor	**2007**	**Factor**
Electric Auditing Hours	2,712	
Non-Electric Hours	3,808	
2008 Internal Audit Factor		**42%**

Reset Time Sheet

OTTER TAIL CORPORATE TIME SHEET

FOR WAGE HOUR EXEMPT EMPLOYEES

Pay Period Starting Date 2/16/2007

Employee: 1 **Department:** Financial Planning & Sourcing

Employee ID: xxxx **Manager:** xxxxx

OTTER TAIL CORPORATION

Paid Time Off Reporting

Day	Date	Pay Code	Hrs not worked
Fri	2/16		
Sat	2/17		
Sun	2/18		
Mon	2/19		
Tue	2/20		
Wed	2/21		
Thu	2/22		
Fri	2/23		
Sat	2/24		
Sun	2/25		
Mon	2/26		
Tue	2/27		
Wed	2/28		
		Totals	**0**

Time Allocation (Allocate PTO, HOL, FLT, etc. 100% to Corp)

Corp	Utility						Not Electric	Total	Company/Project
	Regulated	Not Regulated	BSP II - OTP	BSP	BSP II	Coyote			
0%	0%	0%	0%	0%	0%	0%	0%	0%	

Pay Code	Total Hours
EXC - Excused Absence Paid	0
FLT - Floating Holiday	0
FNL - Funeral/Maternity	0
HOL - Holiday	0
JUR - Jury Duty	0
LST - Unpaid Absence	0
PTO - Paid Time Off	0
SCK - Accrued Sick Leave	0
STD - Short Term Disability	0
VAC - Accrued Vacation	0
Total	**0**

Allocation		Accounting	% of Time
Corp	OTP	060-7100-499	0%
	Non-electric	060-7100-299	0%
Utility	Regulated	060-7100-460	0%
	Not Regulated	060-7100-402	0%
	BSP II - OTP	060-7100-494	0%
	BSP	060-7100-497	0%
	BSP II	060-7100-496	0%
	Coyote	060-7100-498	0%
Non-electric		060-7100-200	0%
Total			0%

Allocation Factor	General	Ratio
OTP		38%
Non-electric		62%

Error Legend

Monthly Allocation does not equal 100%

Employee signature Date

This is a true and accurate report of my time.

Manager signature Date

Timesheet Version: 2007 Exempt timesheet v2.0

Reset Time Sheet

OTTER TAIL CORPORATE TIME SHEET

FOR NON WAGE HOUR EXEMPT EMPLOYEES

Pay Period Start Date: 1/1/2007

Employee: 1
Employee ID: xxxx

Department: Corporate Accounting
Manager: xxxxxxxx

OTTER TAIL CORPORATION

Paid Time Off Reporting

Carry Forward Hours - Paid in Prior Period

Day	Date	Pay Code	Hrs worked	Hrs not worked	Addn'l Reg Hrs	OT Hrs worked
Mon	1/1					
Tue	1/2					
Wed	1/3					
Thu	1/4					
Fri	1/5					
Sat	1/6					
		Week 1 Subtotal	0	0	0	0
Sun	1/7					
Mon	1/8					
Tue	1/9					
Wed	1/10					
Thu	1/11					
Fri	1/12					
Sat	1/13					
		Week 2 Subtotal	0	0	0	0
Sun	1/14					
Mon	1/15					
		Week 3 Subtotal	0	0	0	0
		Pay Period Total	0	0	0	0

Time Allocation (Allocate PTO, HOL, FLT, etc. 100% to Corp)

Corp	Utility: Regulated	Utility: NOT Regulated	Utility: BSP II - OTP	Utility: BSP	Utility: BSP II	Utility: Coyote	Not Electric	Total	Company/Project
-	-	-	-	-	-	-	-	-	

Pay Code				
EXC - Excused Absence Paid				
FLT - Floating Holiday				
FNL - Funeral/Maternity				
HOL - Holiday				
JUR - Jury Duty				
LST - Unpaid Absence				
PTO - Paid Time Off				
SCK - Accrued Sick Leave				
STD - Short Term Disability				
VAC - Accrued Vacation				
OVT - Overtime				
STE - Straight Time Extra				
REG - Regular Work Time				
Total	0	0	0	0

Allocation		Accounting	% of Time
Corp	OTP	050-7100-499	-
	Non-electric	050-7100-299	-
Utility	Regulated	050-7100-450	-
	Not Regulated	050-7100-402	-
	BSP II - OTP	050-7100-494	-
	BSP	050-7100-497	-
	BSP II	050-7100-496	-
	Coyote	050-7100-498	-
Non-electric		050-7100-200	-
Total			0%

Allocation Factor	General	Ratio
OTP		38%
Non-electric		62%

Error Legend

Monthly time allocation does not equal 100%

Employee signature — Date
This is a true and accurate report of my time.

Manager signature — Date

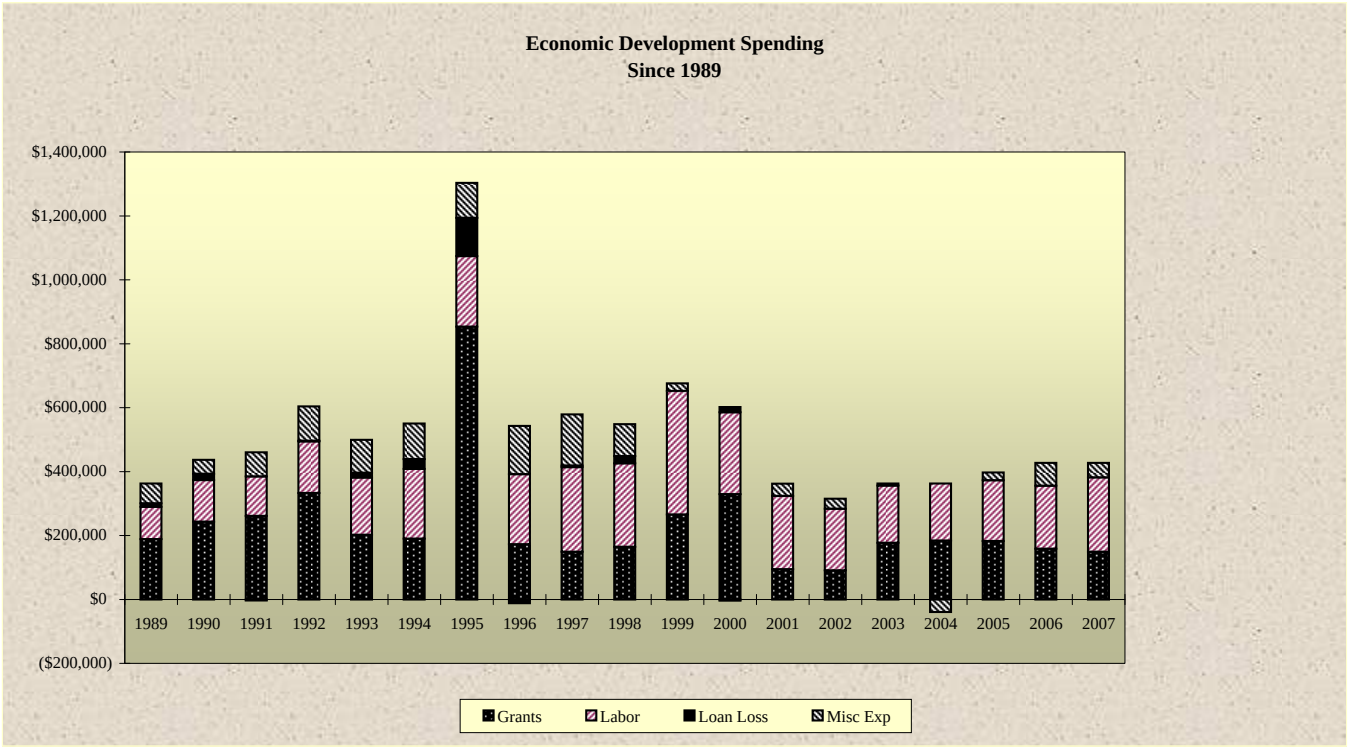
Timesheet Version: 2007 Non-exempt timesheet v2.0

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
History of ND Economic Development Expenditures Since 1989

Case No. PU-08____
Exhibit ___ (BCB-1)
Schedule 2

	Grants	Assigned Labor	Loan Loss	Misc Exp	Total		Cumulative Total
1989	$188,520	$101,239	$11,000	$61,879	$362,638		$362,638
1990	242,900	130,533	19,427	43,972	436,832		799,470
1991	261,100	123,771	(3,924)	75,620	456,567		1,256,037
1992	332,550	162,007	1,890	107,726	604,173		1,860,210
1993	201,952	179,227	14,954	103,481	499,614		2,359,824
1994	190,000	218,068	30,800	111,498	550,366		2,910,189
1995	853,175	220,771	120,013	109,421	1,303,380	*	4,213,569
1996	172,700	218,816	(12,413)	151,577	530,680		4,744,249
1997	148,800	264,768	5,286	160,222	579,076		5,323,325
1998	164,529	261,466	22,163	100,292	548,450		5,871,775
1999	265,476	386,431	0	24,264	676,170		6,547,946
2000	329,181	256,511	16,466	(4,391)	597,767		7,145,712
2001	94,262	229,560	0	38,140	361,962		7,507,675
2002	90,665	192,924	0	31,325	314,914		7,822,589
2003	177,200	179,058	0	6,276	362,534		8,185,122
2004	183,750	178,786	0	(39,761)	322,774		8,507,897
2005	182,250	190,289	0	24,950	397,489		8,905,385
2006	158,325	197,473	0	71,563	427,361		9,332,746
2007	149,000	232,535	0	45,973	427,508		9,760,254
Totals	$4,386,336	$3,924,231	$225,662	$1,224,026	$9,760,254		
Average	**$230,860**	**$206,538**	**$11,877**	**$64,422**	**$513,698**		
Amount from 1989 Order	$160,000	$100,000	$35,000	$20,557	$315,557		

* includes commitment to NDSBIC for $300,000



Volume 2A

Testimony and Schedules of Witnesses:

Kevin Moug

Financial Soundness
Capital Structure
Cost of Capital

Before the North Dakota Public Service Commission

State of North 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 North Dakota

Case No. PU-08-_____

Exhibit___

FINANCIAL SOUNDNESS, CAPITAL STRUCTURE AND COST OF CAPITAL

Direct Testimony and Schedules of
Kevin G. Moug

November 3, 2008

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin G. Moug. My business address is 4334 18th Avenue SW, Suite 200, Fargo ND 58103.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Chief Financial Officer of Otter Tail Corporation ("OTC"). Otter Tail Power Company ("OTP") is currently an operating division of OTC.

Q. WHO ARE YOU TESTIFYING FOR?

A. I am testifying on behalf of OTP.

Q. HAVE YOU INCLUDED A DESCRIPTION OF YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?

A. Yes, a description of my educational and employment experience is included as Exhibit___(KGM-1), Schedule 1.

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

Yes.

II. PURPOSE OF TESTIMONY

Q. WHAT ARE THE PURPOSES OF YOUR DIRECT TESTIMONY?

A. The purposes of my Direct Testimony are to discuss financial issues that have important implications for the overall financial soundness of OTP and our ability to complete OTP's substantial investment plans. I will address the capital structure and associated cost of financing for OTP's electric utility operations. I will also discuss the relationship between the substantial investment plans of OTP and its financial

soundness, including a discussion of the impact of decisions by the North Dakota Public Service Commission (the "Commission") on those plans.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND YOUR RECOMMENDATIONS TO THE COMMISSION.

A. OTP recommends an overall cost of capital of 8.89 percent. This cost of capital is based on: (i) OTP's thirteen month average divisional capital structure for 2007, consisting of 40.3 percent long term debt, 2.8 percent short term debt, 3.6 percent preferred stock, and 53.3 percent common equity; and (ii) OTP's costs of long-term debt, short-term debt, and preferred stock; and (iii) an 11.25 percent return on equity ("ROE"), which is explained in the Direct Testimony of Mr. Robert B. Hevert. Exhibit___ (KGM-1). Schedule 2, and the following table, provide a summary of OTP's capital structure and the costs of the components of its proposed capital structure.

	Amount	Percentage of Total Capitalization	Cost of Capital	Weighted Cost of Capital
Long-Term Debt	$173,571,466	40.3%	6.33%	2.55%
Short-Term Debt	12,154,247	2.8%	5.85%	0.16%
Long-Term and Short-Term Debt	$185,725,713	43.1%	6.30%	2.72%
Preferred Stock	15,500,000	3.6%	4.75%	0.17%
Common Equity	229,633,133	53.3%	11.25%	6.00%
Total Capitalization	$430,858,846	100.0%		8.89%

The use of OTP's divisional capital structure and recommended ROE provides the foundation for OTP's financial soundness and for the accomplishment of its investment objectives. The proposed capital structure will also remain appropriate for ratemaking purposes in the event that a holding company structure is formed, as we have proposed in Case No PU-08-292 and as the Commission has approved in the October 8, 2008 Order in that Case.

Q. HOW IS THE BALANCE OF YOUR TESTIMONY ORGANIZED?

A. First, I will explain our recommended capital structure, including costs of debt and preferred stock, and discuss how that capital structure relates to OTC. Second, I will discuss the financial requirements needed to accomplish OTP's overall investment plan, and the importance of maintaining OTP's financial soundness to the accomplishment of that investment plan. I will also address the funds used to finance construction activities, as directed in the May 24, 2006 Order in Case No. PU-05-256. Third, I will address the formation of a holding company, including an explanation of why our proposed capital structure and cost of capital remain appropriate for this rate case.

Q. HAS OTP PROVIDED SCHEDULES OF THE ACTUAL AND PROPOSED 2007 AVERAGE CAPITAL STRUCTURES AND COSTS OF CAPITAL?

A. Yes. Exhibit___(KGM-1), Schedule 2, attached to my testimony is a summary of the capital structures in this case. Details and supporting calculations are included with the work papers for the cost of service studies in Volume 4A.

III. CAPITAL STRUCTURE AND COST OF DEBT

Q. PLEASE SUMMARIZE OTP'S CAPITAL STRUCTURE AND COSTS.

A. OTP is currently a separate operating division of OTC and was throughout the 2007 test year. OTP's electric utility operations and investments are financed with a combination of long-term debt, short-term debt, preferred stock and common equity, which comprise OTP's capital structure. OTP's 2007 Test Year capital structure is set forth on Exhibit___(KGM-1), Schedule 2, and reflects the amount and costs of the capital used to finance the investments and operations of OTP. OTP's cost of capital is based on its separate 2007 average divisional capital structure, consisting of 40.3 percent long-term debt, 2.8 percent short-term debt, 3.6 percent preferred stock, and 53.3 percent common equity. It is also based on OTP's costs of long-term debt, short-term debt, and preferred stock, and an 11.25 percent ROE.

Long-Term Debt

Q. WHAT IS THE AMOUNT AND COST OF OTP'S LONG-TERM DEBT IN THE PROPOSED CAPITAL STRUCTURE?

A. The amount of OTP's long-term debt in the capital structure is $173.6 million and the cost of long-term debt is 6.33 percent, as shown on Exhibit___(KGM-1), Schedule 2.

Q. HOW WERE THE AMOUNT AND THE COST OF OTP'S LONG-TERM DEBT CALCULATED?

A. The amount and cost of OTP's long-term debt were calculated on the basis of the 13-month average beginning December 31, 2006 and ending December 31, 2007.

Q. HOW IS LONG-TERM DEBT ASSIGNED TO OTP?

A. The portfolio of long-term debt that has been assigned to OTP reflects application of several factors. Some debt has been issued expressly for utility purposes and may have restrictions that limit usage to utility purposes. Other debt issued by OTC is not related to utility operations and is, accordingly, excluded from the OTP-utility long term debt portfolio. Debt is assigned to OTP-utility in the year in which it is issued by OTC and remains assigned to OTP thereafter.

Q. HOW DOES OTP'S COST OF LONG-TERM DEBT COMPARE TO OTHER NORTH DAKOTA UTILITIES?

A. OTP's cost of debt has historically been the lowest of investor owned utilities in North Dakota, as shown in this table:

	2003	**2004**	**2005**	**2006**	**2007**
OTP	**6.310%**	**6.300%**	**6.360%**	**6.330%**	**6.330%**
Xcel-ND-gas	7.874%	7.321%	6.970%	6.830%	6.830%
Xcel-ND-electric	7.750%	7.330%	6.970%	6.830%	6.830%
MDU-ND-electric	8.780%	8.624%	8.712%	7.983%	7.311%
MDU-ND-gas	8.780%	8.624%	8.713%	7.983%	7.311%
Source: Annual reports					

Short-Term Debt

Q. WHAT ARE OTP'S SHORT-TERM DEBT AND ASSOCIATED COSTS?

A. The short-term debt of $12.2 million and cost of 5.85 percent were based on the average of daily outstanding balances for the 2007 Actual Year

Preferred Stock

Q. IS THERE A COMPONENT OF PREFERRED STOCK IN OTP'S CAPITAL STRUCTURE?

A. Yes. OTP's capital structure includes $15.5 million of Preferred Stock at a cost of 4.75 percent.

Common Equity

Q. HOW WAS THE AMOUNT AND PERCENTAGE OF OTP'S TEST YEAR COMMON EQUITY DETERMINED?

A. The $229.6 million and 53.3 percent of OTP's common equity were based on a 13-month average from December 31, 2006 through December 31, 2007.

Q. ARE COSTS INCURRED IN CONNECTION WITH ISSUING COMMON STOCK?

A. Yes. When common stock is issued to the public, the corporation issuing the stock incurs costs in the process of issuance, including underwriter discounts, audit, legal, printing and listing fees and other expenses of issuance. When these issuance costs (also known as "flotation costs") are incurred, they reduce the net proceeds received by the corporation issuing the stock. Flotation costs are not an "expense" and they are not reflected in the annual income statement of the issuing corporation. When newly issued equity is allocated to OTP, the portion of the issuance costs related to that equity is allocated to OTP.

Q. HAS COMMON STOCK BEEN RECENTLY ISSUED?

A. Yes. The Company completed a $155 million common stock offering in September 2008.A portion of the net proceeds from the equity offering were used to finance the construction of the Ashtabula Wind Center in Barnes County, North Dakota. This is a regulated rate base investment in which OTP will own 32 wind turbines rated at 1.5 megawatts each.

Q. IS IT PROBABLE THAT ADDITIONAL COMMON STOCK WILL BE ISSUED IN CONNECTION WITH OTP'S INVESTMENT PLANS?

A. Yes. As further explained by Mr. Brause, OTP's investment plans show that the substantial increases in investments that began in the 2007 test year will continue for the next five years. These investment plans will substantially increase the need for equity at OTP, and make a further common equity issuance probable.

Q. PLEASE BRIEFLY DESCRIBE THE OWNERS OF OTC'S COMMON STOCK.

A. Our ownership mix consists of 57 percent individual investors and 43 percent institutional investors. By contrast, according to Edison Electric Institute ("EEI"), the average for other electric utilities ownership mix is 34 percent individual investors and 66 percent institutional investors. Based on information about our registered common stock owners, we know we have a substantial concentration of common stock owners in North Dakota (13 percent), Minnesota (44 percent), and South Dakota (3 percent). While these percentages do not reflect the distribution of total share ownership, we do conclude that we have a concentration of individual ("retail") ownership among persons who are within our service region and that we are, in a significant sense, locally owned.

Capital Structure

Q. DOES OTP MAINTAIN A SEPARATE DIVISIONAL CAPITAL STRUCTURE?

A. Yes.

Q. WHEN WAS OTP'S DIVISIONAL CAPITAL STRUCTURE ESTABLISHED?

A. OTP's separate divisional capital structure was established in 1997, and it has been maintained on a separate basis since that time.

Q. DOES OTC SUPPLY CAPITAL TO OTP?

A. Yes. As a division of OTC, OTP receives all of its capital through OTC. OTP's capital structure reflects the capital that has been used to fund the operations and investments in OTP's electric utility operations.

Q. IS OTP'S DIVISIONAL CAPITAL STRUCTURE APPROPRIATE FOR THE CALCULATION OF OTP'S RATE OF RETURN?

A. Yes. The OTP capital structure is appropriate for several reasons:

1. The OTP divisional capital structure reflects the capital that has provided financing for OTP's electric utility operations and properties;
2. The OTP divisional capital structure is supported by the need for capital resources to fulfill OTP's substantial investment plans for its electric utility operations; and
3 The OTP capital structure is similar to the capital structures of other electric generation and distribution companies, as Mr. Hevert explains in his Direct Testimony.

Q. WHAT FACTORS DOES OTP'S CAPITAL STRUCTURE REFLECT?

A. The OTP capital structure reflects the combination of several factors, including: (i) the common equity, debt, and preferred stock, that had been used to finance the OTP electric utility operations; (ii) OTP earnings and capital contributions by OTC, which increase the common equity of OTP; (iii) the funding of dividends on preferred stock and a portion of the dividends on common equity, which decreases the common equity of OTP; and (iv) the goal of maintaining a capital structure for OTP that is appropriate for an electric utility.

Q. IS THE OTP CAPITAL STRUCTURE USED IN THE MANAGEMENT OF OTP?

A. Yes. The OTP capital structure provides the foundation for evaluation of the financial performance of OTP and is used for management of OTP.

Q. HOW DOES OTP'S TEST YEAR COMMON EQUITY RATIO COMPARE TO OTHER ELECTRIC UTILITIES?

A. As Mr. Hevert explains, OTP's proposed equity ratio is appropriate in relation to the equity ratios of his comparable companies.

IV. INVESTMENT PLANS AND FUTURE CAPITAL REQUIREMENTS

Q. PLEASE DESCRIBE OTP'S ANTICIPATED CAPITAL EXPENDITURES.

A. As Mr. Brause explains, the investment plans for OTP have increased dramatically. Investments were approximately $25 million in 2004, $30 million in 2005, and $35 million in 2006, an average of $30 million per year. In contrast, in 2007 OTP invested $126 million, including our investment in the Langdon Wind Project. As noted in our September 24, 2008 Prospectus Supplement, we also expect to invest approximately $121 in the Ashtabula Wind Center. As reflected in OTC's June 30, 2008 Form 10-Q, it is anticipated that investments for OTP for the 5-year period of 2008-2012 will be approximately $880 million, which would be an average of over $175 million per year. These investments include approximately $336 million for Big Stone II, $121 million of the Ashtabula Wind Center, and $67 million for CapX 2020 transmission projects. As explained by Mr. Brause, even if OTP's participation in Big Stone II changes, a similar, if not costlier, base load generation investment will be required.

Q. WILL THE AUTHORIZED ROE AND CAPITAL STRUCTURE IN THIS PROCEEDING HAVE AN IMPACT ON THE ABILITY OF OTP TO ACHIEVE ITS INVESTMENT PLANS?

A. Yes. The ROE and capital structure authorized in this proceeding will have a substantial impact on our ability to carry out OTP's 5-year investment plan in two important ways. First, the ROE and capital structure will have a direct impact on the

level of earnings authorized by the Commission. That level of earnings will, in turn, directly impact our ability to fund capital investment with internally generated funds. Second, the ROE and capital structure authorized in this proceeding will have a significant effect on the perceptions of investors. These perceptions will have a substantial impact on both the availability and the cost of the capital needed to carry out OTP's investment plans. Investors are very aware of a utility's regulatory environment and the authorized ROE and capital structure are significant elements of that regulatory environment. The reaction of investors is likely to be heightened by the combination of: (i) the fact that OTP has not requested a general rate increase since 1983; and (ii) the scale of the OTP investment plan, particularly in contrast to its historic investment levels.

Q. HAS THE COMMISSION REQUESTED THAT OTP ADDRESS THE FINANCING OF ITS INVESTMENT AND CONSTRUCTION ACTIVIES?

A. Yes. In the May 24, 2006 Order in Case No. PU-05-256, the Commission stated:

> [I]n its next rate case proceeding, Otter Tail will prove due diligence for choosing the types of funding sources it uses to construct assets. For instance, Otter Tail must show why funding construction activities with long-term debt and equity is preferable to using lower cost short-term debt.

Q. WHAT IS OTP'S APPROACH TO FUNDING CONSTRUCTION ACTIVITIES?

A. OTP's approach for funding large capital projects is as follows: As a project begins, OTP will use internally generated cash flows along with short term credit facilities to make progress payments related to the capital project. OTP maintains a $170 million line of credit (which is subject to renewal on July 30, 2011) to support working capital needs and other capital requirements for its utility operations. This credit facility has a feature whereby the line can be increased to $250 million during the term of the agreement. Capital projects are typically financed with short term credit facilities or construction revolvers until such time as the short-term borrowings are large enough to justify a permanent financing. Once the short-term borrowings have been built up on the credit facilities, a company will typically issue debt and equity in order to match a long-term asset with long-term financing, and to maintain its targeted capital

structure. The common stock issuance in September 2008 is an example of this approach.

Q. IS IT APPROPRIATE TO INCLUDE THE COST OF THE LONG-TERM DEBT AND COMMON EQUITY IN THE CARRYING COSTS OF A CONSTRUCTION PROJECT?

A. Yes. It is appropriate for two reasons. First, cash is fungible, and construction activities are financed by all sources of cash, which includes existing long-term debt, common equity, and short-term borrowing. Cash from all sources is used even if the short-term borrowing is the last source of cash added, as construction activities occur. It is unrealistic to assign only short-term debt to construction activities in this context. Second, the availability of short-term debt is directly dependent on the existence of long-term debt and common equity. Since short-term debt would not be available at all without the financial support of the long-term debt and common equity, failing to include a part of the cost of that long-term debt and common equity would be a distortion of the real costs of construction.

Q. WHAT ARE OTC'S CURRENT SENIOR UNSECURED CREDIT RATINGS?

A. Moody's Investors Services maintains an A3 rating, with a negative outlook. This rating was just reaffirmed by Moody's in September 2008. Standard and Poor's ("S&P) maintains a BBB- rating, with a stable outlook. This rating was issued in September 2008 as well. The previous rating by S&P was BBB+, with a negative outlook.

Q. WHY DID S&P INITIATE A DOWNGRADE OF OTC'S SENIOR UNSECURED CREDIT RATING?

A. OTC's credit profile reflects the combination of its regulated electric utility business and the non-electric businesses. The non-electric businesses are considered to have higher risk, given the unregulated nature of these businesses. The lowering of the S&P rating relates to OTC's growing non-electric businesses which are considered to have a higher degree of earnings and cash flow volatility than OTP. Also, S&P

believes these businesses will be under greater pressure given current economic conditions. Another factor noted by S&P is the large construction program being undertaken by OTP. The financial effect of OTP's construction program will ultimately depend on external financing and the level of regulatory support during and after construction. S&P has concerns that cost overruns or construction delays could result in declining financial measures. In fact, our plan to form a holding company was undertaken, in large part, to enable OTP to obtain separate (and higher) debt ratings than OTC. We anticipate that, after the formation of a holding company, OTP will have the ability to obtain such separate credit ratings and believe that those ratings may be higher than OTC's debt ratings.

Q. DOES THIS DOWNGRADE IMPACT THE NORTH DAKOTA RATE CASE?

A. No. The requested cost of capital and regulated return on equity are not impacted by this downgrade. The costs of long term debt, short term debt, and preferred stock are based on embedded, historical costs, not on current debt ratings. Thus, there is no effect on those costs. The ROE is forward looking and based on a comparable group, not on OTP or OTC specifically. Thus, there is no effect on the ROE.

V. FORMATION OF HOLDING COMPANY

Q. HAS OTC COMPLETED THE FORMATION OF THE HOLDING COMPANY?

A. No. OTC has not yet obtained all necessary regulatory approvals, and the formation of the holding company would not occur prior to April 1, 2009 in any event.

Q IS THE IMPLEMENTATION OF A HOLDING COMPANY CONSISENT WITH OTC'S AND OTP'S LONG-RUN FINANCIAL STRATEGIES?

A. Yes. OTC has had a long run financial strategy of enhancing the financial separation of OTP from the unregulated operations of OTC. In fact, that strategy has been a primary financial objective of OTC that began with the establishment of a separate divisional capital structure in 1997, was expanded with the separation of the corporate group in 2001, and is being completed with the formation of the holding company.

Q. DOES THE COMMISSION NEED TO DETERMINE THE CAPITAL STRUCTURE OF A NEW OTP SUBSIDIARY IN THIS PROCEEDING?

A. No. This proceeding is concerned with the appropriate capital structure and cost of capital for ratemaking based on the 2007 test year. The OTP capital structure that is implemented after formation of the holding company will remain subject to Commission review and oversight, and OTC and OTP will provide full information regarding the capital structures for OTP and any new holding company.

VI. CONCLUSION

Q. CAN YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. Yes. I recommend the Commission approve a capital structure consisting of 53.3 percent equity, an ROE of 11.25 percent and an overall rate of return of 8.89 percent.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application by Otter Tail Corporation d/b/a Otter Tail Power Company, for Authority to Increase Rates for Electric Utility Service in North Dakota	))))	Case No. PU-08-____

AFFIDAVIT OF KEVIN G. MOUG

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Kevin Moug
Kevin G. Moug

Subscribed and sworn to before me,
this 23rd day of October, 2008.

Jacquelyn Rogness
Jacquelyn Rogness

NOTARY PUBLIC
State of North Dakota

My Commission expires January 10, 2012.

JACQUELYN ROGNESS
Notary Public
State of North Dakota
My Commission Expires Jan. 10, 2012

KEVIN G. MOUG

EMPLOYMENT

2001-PRESENT Otter Tail Corporation — Fargo, ND
Chief Financial Officer

1996-PRESENT Varistar Corporation — Fargo, ND
Chief Financial Officer & Treasurer

1993-1996 Advance Dental Management — Mondovi, WI
Chief Financial Officer

1981-1993 Deloitte & Touche — Minneapolis, MN
Senior Manager – Middle Market Practice

EDUCATION

- Bachelor of Science in Business Administration — University of North Dakota

INDUSTRY CERTIFICATIONS

- Certified Public Accountant

PROFESSIONAL AFFILIATIONS

- American Institute of Certified Public Accountants — Member
- Financial Executive International — Member
- US Bank Advisory Board — Board Member
- Minn-Kota Chapter of American Red Cross — Board of Directors
- Innovis Health — Board of Directors

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota

Case No. PU-08____
Exhibit___(KGM-1)
Financial Information
Schedule 2

RATE OF RETURN COST OF CAPITAL SCHEDULE

	(A)	(B)	(C)	(D)
Capitalization:	Amount	Percent of Total Capitalization	Cost of Capital	Weighted Cost of Capital
2007 ACTUAL YEAR				
Long-Term Debt	$173,571,466	40.3%	6.33%	2.55%
Short-Term Debt	12,154,247	2.8%	5.85%	0.17%
Long-Term and Short-Term Debt	$185,725,713	43.1%	6.30%	2.72%
Preferred Stock	15,500,000	3.6%	4.75%	0.17%
Common Equity	229,633,133	53.3%	8.08%	4.31%
Total Capitalization	$430,858,846	100.0%		7.19%
2007 TEST YEAR				
Long-Term Debt	$173,571,466	40.3%	6.33%	2.55%
Short-Term Debt	12,154,247	2.8%	5.85%	0.16%
Long-Term and Short-Term Debt	$185,725,713	43.1%	6.30%	2.72%
Preferred Stock	15,500,000	3.6%	4.75%	0.17%
Common Equity	229,633,133	53.3%	11.25%	6.00%
Total Capitalization	$430,858,846	100.0%		8.89%

All are based on 13-month average balances.

Details in JCOSS W/P D-1 through D-3