Kyle Sem

Volume 2A

Direct Testimony and Supporting Schedules:

Kyle Sem

Rate Base

Before the South Dakota Public Utilities Commission
State of South Dakota

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

EL10-______

Exhibit___

RATE BASE

Direct Testimony and Schedules of

KYLE SEM

August 20, 2010

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ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is 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 "Company") as Supervisor – Revenue Requirements, Regulatory Economics Department.

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 began my career with OTP in 2006 as Rates Analyst, and accepted my current position as Supervisor – Revenue Requirements in May 2010. My primary responsibilities in this position are preparing the annual cost of service studies for the three jurisdictions where OTP provides service (South Dakota, North Dakota, and Minnesota), 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. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN ANY OTHER REGULATORY PROCEEDINGS?

A. Yes. I have filed testimony in rate case proceedings before the South Dakota Public Utilities Commission in Docket No. EL08-030, the Minnesota Public Utilities Commission, and the North Dakota Public Service Commission; I also filed testimony with the Federal Energy Regulatory Commission (FERC) related to forward-looking transmission rates.

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. I also support the rate base financial schedules provided as part of the Application. Mr. Peter J. 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 for the unadjusted 2009 Actual Year. I will then identify and explain all adjustments that are made to the 2009 Actual Year to arrive at the Test Year rate base.

Q. WHAT RATE BASE ACCOUNTING STATEMENTS, SCHEDULES AND EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring Statement D, and Schedules D-1 through D-9, as required by ARSD § § 20:10:13:54 to 20:10:13:63, Statement E and Schedules E-1 through E-3 as required by ARSD § § 20:10:13:64 to 20:10:13:67 and Statement F and Schedules F-1 through F-3 as required by ARSD § § 20:10:13:68 to 20:10:13:71. These Statements and Schedules are located in Volume 1, Tab – Required Statements. I am also sponsoring the following Exhibits, 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 South Dakota Jurisdictional Adjustments by Project.

Q. WHAT TIME PERIODS ARE SHOWN ON YOUR SCHEDULES?

A. Statement D shows in summary form the accounts of electric utility plant classified by account as of the beginning of January 1, 2009 and the end of December 31, 2009. Schedule D-1, provides this information by detail plant accounts with subtotals by functional classification, as required by ARSD § § 20:10:13:55. Schedule D-2 shows major plant additions and retirements for the test period, as required by ARSD § § 20:10:13:56. Schedule D-3 are work papers that show the monthly book balances by detailed plant account during the 12 months in the test period, each functional classification subtotal, and total plant, as required by ARSD § § 20:10:13:57. Schedules D-4, D-5, D-6 and D-8 provide the information required by ARSD § § 20:10:13:58 through ARSD § § 20:10:13:60 and ARSD § § 20:10:13:62, for the five-year period of 2005 through 2009. Schedule D-7 contains work papers on plant in service carried on the Company's books, which was not being used in rendering service, as required by ARSD § § 20:10:13:61. Statement E shows the beginning monthly balances of accumulated depreciation and amortization by function for January 1, 2009, through December 1, 2009, and the ending balance for December 31, 2009, as required by ARSD § § 20:10:13:64. Schedule E-1 shows the annual Test Year activity for accumulated depreciation and amortization as required by ARSD § § 20:10:13:65. Together, the information contained within Statements and Schedules D and E are combined to produce the net plant in service for OTP for the 2009 Test Year. Finally, Statement F and Schedule F-3 show the 2009 Test Year cash working capital calculation as required by ARSD § § 20:10:13:68 and ARSD § § 20:10:13:71. Schedule F-1 shows the monthly Test Year balances for materials and supplies, fuel stocks and prepayments while Schedule F-2 shows the same monthly information for the two years preceding the 2009 Test Year as required by § § 20:10:13:69 and ARSD § § 20:10:13:70.

Q. WHAT IS THE SOURCE OF THE 2009 ACTUAL YEAR INFORMATION?

A. The 2009 Actual Year information is taken from OTP's South Dakota jurisdictional cost of service study ("JCOSS"), which was prepared by Mr. Beithon and myself and is included in Volume 4A as part of the Work Papers. The JCOSS is based on the Company's financial information. This same financial information is used to prepare FERC Form No. 1 and the financial information for the electric utility in Otter Tail Corporation's annual report to shareholders and its SEC Form 10-K.

Q. HOW WAS THE TEST YEAR RATE BASE DEVELOPED?

A. OTP used its Actual 2009 historic year rate base calculated using 13-month averages and made adjustments for known and measurable changes along with traditional regulatory adjustments to arrive at the Test Year rate base. These adjustments were made to reflect recognized regulatory requirements and to "normalize" the actual financial information for one-time events and to reflect changes known to occur during the 24 months following the end of the Actual Year 2009 financial data, i.e., during the Projected Years 2010 and 2011.

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base consists primarily of the capital expenditures made by a utility to obtain plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation expense 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), STATEMENT D?

A. Exhibit ___(KAS-1), Statement D, Cost of Plant, summarizes the South Dakota electric utility plant balances as of the end of December 31, 2008, the book additions and reductions to rate base during 2009, together with the book balances as of the end of December 31, 2009. Adjustments made to the 2009 Actual Year book balances and the total cost of plant are shown in Columns (H) and (I). I will separately discuss each of those adjustments later in my testimony. 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 SOUTH 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, Docket No. EL08-030, with a Test Year ending December 31, 2007 ("2007 Test Year") to the Test Year rate base included in this filing. The requested increase in rate base is approximately $3.8 million. 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 a 13-month average based on monthly balances from December 2008 through December 2009. Use of a 13-month average for net electric plant in service was approved in OTP's most recent South Dakota electric rate case; therefore, we used a 13-month average balance in this filing as well.

Q. WHAT DO THE LINE ITEMS ON STATEMENT D AND SCHEDULE D-1 DESCRIBE?

A. These are the components of OTP's utility plant in service. Statement D lists the functional plant balances as of December 31, 2008, the 2009 Test Year activity and ends with the 2009 Test Year plant balances by FERC account. Schedule D-1 provides the same information by FERC account as well as by plant account. The electric plant in service is based upon the original cost of property from the books and records of OTP as allocated to the South Dakota jurisdiction.

Q. PLEASE EXPLAIN EXHIBIT__(KAS-1), STATEMENT E AND SCHEDULE E-1.

A. As I mentioned previously, Statement E shows the beginning monthly balances of accumulated depreciation and amortization by function for January 1, 2009, through December 1, 2009, and the ending balances for December 31, 2009, and ends with the 2009 Test Year. Schedule E-1 shows the annual Test Year activity for accumulated depreciation and amortization including: beginning balances, annual depreciation or amortization expense, retirements, salvage, ending book balances, Test Year adjustment amounts, and the ending 2009 Test Year balances by function. Schedule E-2 states that there has been no change in depreciation methods or procedures since the period covered by the last annual report on FERC Form 1 for 2009. Schedule E-3 states that each FERC account is assigned to a particular functional group resulting in no allocation of overall accounts.

Q. PLEASE EXPLAIN EXHIBIT__(KAS-1), STATEMENT F AND SCHEDULES F-1 THROUGH F-3.

A. As mentioned previously, Statement F and Schedule F-3 show the 2009 Test Year cash working capital calculation. Schedule F-1 shows the monthly Test Year balances for materials and supplies, fuel stocks and prepayments while Schedule F-2 shows the same monthly information for the two years preceding the Test Year. Both F-1 and F-2 show 13-month average calculations for the rate base items listed above, which is the method used in this filing and is consistent with what was approved in OTP's previous rate case.

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

A. There has been a significant addition to plant in service since our last general rate case for new wind investment called the Luverne Wind Energy Center. I will discuss this project 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, information technologies, transmission, distribution, 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.

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

A. The responsibility for allocating capital spending resides in the Asset Management area of the Company, and specifically in Delivery Planning. In carrying out this function, a Capital Allocation Review Team assists in 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, Finance, 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 January 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 March. The projects are then reviewed and prioritized by the Capital Budget Team. During this step, projects are approved, partially funded or denied. The budget is then submitted to the Utility's Executive Team for review and approval by June 1 of each year. The final approval of the capital budget is made by the Otter Tail Corporation 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 the normal timeline for capital allocation, the project is reviewed by the Capital Budget Team similar to the regular process. The request is then 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 spending 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 prioritize the remaining projects.

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

A. One of the key components used in prioritizing capital spending is replacement plans. Over the past eight 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 currently spread replacement over five years. That way, we are continually replacing the PC's, rather than replacing them 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. EARLIER YOU MENTIONED THE ADDITION OF THE LUVERNE WIND ENERGY CENTER AS A SIGNIFICANT NEW ELECTRIC PLANT INVESTMENT SINCE OTP'S LAST RATE CASE. WILL YOU PLEASE DESCRIBE THE LUVERNE WIND PROJECT?

A. The Luverne Wind Project is a wind generation project located in Steele County, North Dakota, approximately six miles north of Luverne, North Dakota. The Luverne Project is located in the Lake Ashtabula area, but it is separate from the Ashtabula wind generation project completed in 2008. The Luverne Project is part of a larger wind energy generation center called the Luverne Wind Energy Center. The Luverne Wind Energy Center became commercially operational in September 2009 and consists of a total of 113 General Electric wind turbines, each of which has a nameplate capacity of 1.5 MW (for an aggregate of 169.5 MW nameplate capacity). The Luverne Wind Energy Center was jointly developed by Otter Tail and NextEra. By jointly working with NextEra, Otter Tail has gained efficiencies of scope and scale and benefited from NextEra's experience in such projects. OTP's ownership comprises approximately 29 percent of the capacity of the Luverne Wind Energy Center, consisting of 33 wind turbines with an aggregate nameplate capacity of 49.5 MW, tower foundations, operational equipment, electric collection circuit lines, project substation, approximately 13 miles of 230 kilovolt line, and real property interests. NextEra, through its subsidiary Ashtabula Wind II, LLC, developed and owns the remaining 71 percent of the Luverne Wind Energy Center.

Q. WHY DID OTP INVEST IN THIS WIND PROJECT?

A. The Luverne Wind Project, along with earlier investments in the Langdon and Ashtabula Wind Energy Projects, completes development of 160 MW of wind generation that was shown in OTP's 2006 - 2010 Integrated Resource Plan to be part of a least-cost plan for fulfilling OTP's need for additional capacity and energy resources. These wind investments were made because they were economic alternatives. They also help OTP meet renewable energy objectives and standards in the states we serve.

Q. WHAT GENERAL OBSERVATION DO YOU HAVE AS YOU COMPARE NET PLANT IN SERVICE IN 2007, THE PRIOR TEST YEAR, WITH THE 2009 TEST YEAR?

A. As shown on my Schedule 5, OTP's South Dakota net electric plant in service grew by approximately $11.3 million, or about 16.6 percent when comparing the final approved Test Year net plant in service in Docket No. EL08-030. That equates to an approximate 5.5 percent annual increase (over a three year period when the 2010 known and measureable plant additions are factored in). Net transmission and distribution plant increased 15.7 percent and 11.1 percent, respectively, slightly lower than the overall average increase, while investment in production plant increased by 21.6 percent. The increase in production plant is driven mainly by the new wind investment addition previously discussed. OTP has made transmission and distribution investments to meet customer needs and enhance system reliability and has been replacing outdated equipment at the generating plants to reduce the risk of untimely, costly and extended outages. The more significant additions will be discussed later in my testimony.

1. Plant Additions and Retirements

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

A. Yes. I made several adjustments related to projects that either went into service during 2009 or will go into service by December 31, 2010 (the known and measurable adjustment period selected for plant additions in this filing). As a result, I will describe the adjustments for 2009 and 2010 based on the in-service year because plant adjustments that went into service during 2009 are adjusted differently than those that will go into service in 2010. The detailed calculations for the adjustments to plant in service can be found on work paper series SD TY-01, in Volume 4A, Tab – Test Year Workpapers.

Q. PLEASE BRIEFLY DESCRIBE THE ADJUSTMENTS.

A. First, I made adjustments for nine capital projects that went into service before the end of 2009 that were included in Long-Term Construction Work in Progress (“CWIP”) on December 31, 2008 (see the discussion on CWIP later in my testimony), and two projects that were both started and completed during 2009. The projects in Long-Term CWIP on December 31, 2008, included (i) two production-related projects at the Coyote Power Plant; (ii) an upgrade to the boiler controls for Units #2 and #3 at the Hoot Lake Power Plant; and (iii) six transmission-related projects. The two projects that were started and completed during 2009 were (i) a production-related project at the Hoot Lake Plant and (ii) a transmission project to help serve the new Casselton ethanol plant. Because rate base for plant in service is based on a 13-month average of month-end balances during the Test Year, this adjustment annualizes these projects so that the entire amount is included in rate base rather than only a portion, which would be the result when averaging is used. Since the Test Year presents costs that are the basis for future rates taking effect in 2011, it is appropriate to include a full year of investment in rate base for these projects because they went into service during the Test Year. My total adjustment to annualize 2009 additions that were either part of CWIP on December 31, 2008 and completed in 2009, or were started and completed during 2009 is $13,879,625. South Dakota's share of this adjustment is $1,371,100 (see 2009 Test Year adjustment work paper SD TY-01 located in Volume 4A for more detail on the Total Company and South Dakota jurisdictional calculations). Later in my testimony I will discuss the associated adjustments, including adjusting to reflect a full-year of accumulated depreciation.

Q. PLEASE TELL US MORE ABOUT EACH OF THE ADJUSTMENTS TO PLANT IN SERVICE YOU LISTED, BEGINNING WITH THE TWO COYOTE PLANT PROJECTS.

A. The first project that I would like to discuss that was completed at Coyote is the replacement of the existing High Pressure (HP)/Intermediate Pressure (IP) turbine rotor with the installation of a redesigned HP/IP steam turbine and stationary components on the main turbine/generator. The purpose of the project was to improve the efficiency of the HP/IP turbine through the enhanced design of the steam flow path. The improved turbine design will allow the electric generator to provide more electrical output per pound of steam by more efficiently transferring the energy in the steam to the electric generator. Because of the dramatic improvements in rotor and turbine blade design that have occurred since the turbines initially went into service 20 years ago, Coyote Plant can produce an additional 17 megawatts of power with the same steam flow while also maintaining the same level of heat input. The turbine replacement occurred to obtain this increase in efficiency and not because of any operation or maintenance problems.

Q. PLEASE DESCRIBE THE SECOND COYOTE PLANT PROJECT?

A. The second project completed at Coyote was the replacement of reheat outlet tubing. By 2009, the Coyote Plant's boiler had been in service for 28 years. The normal life expectancy in the utility industry for tubing like that used in Coyote which has a service condition that approaches 1,000^{o} F is around 25 years. As a result, it was necessary to replace the reheat outlet tubing to reduce the risk of future failures and to maintain unit reliability. The existing reheat outlet pendants were replaced with all new material, spacers, and shielding. The new pendants have upgraded material to reduce the possibility of damage from overheating while also providing for enhanced heat transfer.

Q. PLEASE DESCRIBE THE UPGRADES TO UNITS #2 AND #3 AT THE HOOT LAKE PLANT.

A. The Hoot Lake project completed during 2009 was the upgrade of the Honeywell Boiler Control Systems used to operate Units #2 and #3. The project replaced the antiquated Honeywell High Performance Process Manager (HPPM) processors with updated HPPM processors. The project also converted the operator interface from the old TDC3000 touch screens to new Experion Stations. The boiler control system was updated to provide for more efficient control loops, which results in fewer boiler swings, more stable operation, and increased plant efficiency.

Q. EARLIER YOU MENTIONED THE ADDITION OF SIX TRANSMISSION-RELATED PROJECTS THAT WERE IN CWIP AT THE BEGINNING OF 2009 AND WENT INTO SERVICE DURING 2009. PLEASE DESCRIBE EACH OF THOSE PROJECTS.

A. The first transmission project that I will discuss is the Cass Lake Reactive Support project which includes two new 115 kV, 15 MVAR capacitor banks. The capacitor banks each have a 115 kV circuit breaker on them along with protective relays and controls. The capacitor banks are required to support the voltage at the Cass Lake substation during the loss of certain transmission system elements. They are also needed to keep voltages within acceptable tolerances during these loss events. The project was completed as a result of voltage concerns that were identified by planning studies that looked at potential load growth in the area.

Q. WHAT IS THE SECOND TRANSMISSION PROJECT THAT YOU WOULD LIKE TO DISCUSS?

A. The second transmission project included in the Test Year Adjustments is the Ladish 115 kV Ring Bus Project that was completed during 2009. This project was completed in order to upgrade service to the Cargill Malting Plant near Spiritwood, North Dakota. Cargill was previously served by two 41.6-12.5 kV transformers and a 115-41.6 kV transformer. Based on customer projections of load increases in the future, OTP separated the 115 kV bus, installing two new 115-12.5 kV transformers for the local loads and a separate 115-41.6 kV transformer for remote loads. This project was completed in conjunction with Great River Energy's (GRE's) Spiritwood project and as a result these changes will improve service to Cargill as well as allow for any future load that may develop. While GRE provides steam to Cargill from its Spiritwood plant, OTP provides all of Cargill's electric energy needs.

Q. IS THERE AN ADDITIONAL TRANSMISSION PROJECT RELATED TO THE LADISH SUBSTATION?

A. Yes. The second transmission project related to the Ladish Substation work that was completed during 2009 was a MISO interconnection project related to GRE's Spiritwood project (mentioned previously) that included improvements to OTP's existing transmission system. The MISO interconnection study determined that the 115 kV bus at OTP's Spiritwood site should be a ring bus configuration. Previously, there were no breakers or other devices on the 115 kV bus at Ladish as it was purely a load serving bus. Based on the MISO process, it was determined that the addition of breakers and building a ring bus at Spiritwood not only benefits generation, but also the transmission system. The addition included three 115 kV breakers, the associated switches, buswork, dead-end structures, foundations, line relaying, controls, control house, and other equipment. The MISO interconnection requires the interconnection customer (GRE) to pay for 50 percent of the cost of the project while OTP remains the sole owner of the facilities. The capitalized amounts included in the Test Year are OTP's share of the project costs net of GRE's contribution.

Q. PLEASE DISCUSS THE NEXT TRANSMISSION PROJECT INCLUDED IN THE TEST YEAR ADJUSTMENTS.

A. The next transmission project that I would like to discuss is the Crookston 115 kV Substation Rebuild. This is a renovation project to improve the Crookston substation that included replacing several footings that were heaving out of the ground, installation of new protection and control equipment on the transmission lines, transformers and other station equipment and the addition of new 41.6 kV tie breakers to separate the two transformers so they can be switched independently. These renovations will improve service to all loads in the Crookston area and allow for more flexible operation.

Q. PLEASE DESCRIBE THE NEXT TRANSMISSION PROJECT?

A. The fifth transmission project included in the Test Year adjustments is the Dawson/Louisburg Junction 115 kV Substation Uprate. These substations required voltage upgrades along with the 115 kV conversion of the Appleton-Canby transmission line that I discuss later. The transmission line upgrade was required to serve load growth in the region and provide improved transmission outlet for the Big Stone Generating Plant.

Q. PLEASE DISCUSS THE FINAL TRANSMISSION-RELATED PROJECT THAT WAS INCLUDED IN CWIP AT THE END OF 2008 AND COMPLETED DURING 2009?

A. The sixth and final transmission project that was in CWIP at the end of 2008 and completed during 2009 is the Appleton-Canby Transmission Line Upgrade from 41.6 kV to 115 kV. The upgrade was needed because load growth in the Appleton-Canby area had caused the transformer at the Canby substation to be overloaded during critical contingency situations. The upgrade of the existing 41.6 kV line to 115 kV remedied these concerns.

Q. PLEASE DISCUSS THE TWO PROJECTS THAT WERE BOTH STARTED AND COMPLETED DURING 2009?

A. The first project was the Replacement of the Superheater Tubes on Unit #3 at the Hoot Lake Generating Plant. In the last 4 to 5 years, the majority of the outages on Unit #3 have related to leaks in the Primary and Secondary Superheater Tubes. Thielsch Engineering conducted a life assessment and indicated the tubes had exceeded their life expectancy. As a result, unless the tubes were replaced, the number of outages at Hoot Lake would continue to increase, resulting in loss of generation and increased safety risk. In addition, the tubes were nearing the point that repairs could not be made and there was the potential risk that the unit would need to be shut down completely in an emergency situation until tubes could be replaced. This could result in higher costs for replacement power if the outage occurred at a time of high market prices. There were two components to this project, the Low Temperature Superheat (Primary Superheat) section and the High Temperature Superheat (Secondary Superheat) section. A decision to replace both sections at one time was made based on labor costs for installation, material price, and scheduling. Replacing both sections at the same time resulted in substantially less labor for installation and lower material costs. Engineering costs and development of the design were also lower as efficiencies were achieved in these areas by simultaneously planning and completing the work for both sections.

Q. PLEASE DESCRIBE THE OTHER PROJECT THAT WAS BOTH STARTED AND COMPLETED DURING 2009.

A. The other project that was included in the 2009 Test Year Adjustments that was both started and completed during the year is a transmission project related to the construction of a 115 kV substation located near the Casselton Ethanol Plant near Casselton, North Dakota. The substation was built for the purpose of serving the plant, which produces 120 million gallons of ethanol per year. No substation previously existed at this site. Two 24 MVA transformers were installed to provide duplicative service to the plant; i.e., if one transformer were to fail, the plant would remain in operation. A 115 kV, four breaker ring bus was constructed in order to accommodate the incoming line, the two transformers, and a future line extending to the Buffalo 345 kV substation. Six 15 kV circuit breakers were installed on the low side of the transformer to accommodate the distribution feeders.

Q. HAVE YOU MADE OTHER ADJUSTMENTS RELATED TO THE PLANT ADDITIONS THAT WERE PLACED IN SERVICE DURING 2009?

A. Yes. Because of the adjustment to include a full year of investment in rate base for the 2009 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 2009 plant additions. In addition, any amounts related to the projects that were in long-term CWIP at the beginning of 2009 were removed as well as any associated Allowance for Funds Used During Construction ("AFUDC") that was accrued during the year.

Since the additions are treated as if they had been made at the start of the year, matching also requires including a year of accumulated depreciation. The total increase to accumulated depreciation related to projects that were placed into service during 2009 is an increase of $473,039. The South Dakota share of this adjustment is $46,877 (see 2009 Test Year adjustment work paper SD TY-01 located in Volume 4A for more detail on the Total Company and South Dakota jurisdictional calculations). As I mentioned, an operating statement adjustment is also needed to normalize the amount of depreciation expense that was taken during 2009 to reflect a full or normal year. The expense adjustment amount totaled $426,625 with the South Dakota share being $42,267 (see see 2009 Test Year adjustment work paper SD TY-01 located in Volume 4A for more detail on the Total Company and South Dakota jurisdictional calculations). Finally, because some of the projects were included in long-term CWIP at the beginning of 2009, I removed $9,086,395 related to amounts included in the 2009 13-month average calculation. Again, matching principles require a corresponding reduction to any AFUDC accrued during the year on these specific projects. The amount being removed is $461,224. South Dakota does not allow recovery of long-term CWIP or require AFUDC as a revenue credit. Therefore, there is no overall impact to rate base or the operating statement on a South Dakota basis for either of these adjustments.

Q. YOU MENTIONED INCLUDING 2010 PLANT ADDITIONS TO PLANT IN SERVICE. PLEASE DESCRIBE THESE ADJUSTMENTS.

A. In addition to the adjustments mentioned previously, I made two other adjustments related to plant in service. The first is related to a project that was on-going during 2009 and is scheduled to be completed by December 31, 2010 (known and measurable change period). This adjustment is similar to the adjustment I just described for projects that were completed in 2009. Any current capital outlay for the projects resided in long-term CWIP at the end of 2009. This adjustment is for the construction of a new substation in Fergus Falls, Minnesota. The adjustment needed to annualize plant in service adds the full budgeted cost of the project to plant in service, removes any amounts included in long-term CWIP at the end of 2009, and removes any associated plant retirements. This adjustment qualifies as a known and measurable change, justifying removal from the status of incomplete projects in 2009 and including them in completed projects for the Test Year. The adjustment amount to increase plant in service for the addition is $550,000. The South Dakota share of this adjustment is $59,474. The adjustment amount to decrease plant in service for the associated retirement of the old substation is ($75,229). The South Dakota share is ($8,135). Please refer to Test Year adjustment work paper 2009 SD TY-01 located in Volume 4A for more detail on the Total Company and South Dakota jurisdictional calculations related to the plant additions and retirements discussed above.

Q. PLEASE DISCUSS THE NEW FERGUS FALLS SUBSTATION CONSTRUCTION THAT WILL BE COMPLETED DURING 2010?

A. The substation is being built to provide capacity for future demand growth in Fergus Falls, to provide back-up service should either of the existing substations have to be removed temporarily from service (e.g., maintenance), and to eliminate voltage problems in certain areas. While the substation is entirely new, an old substation at an alternate location will be retired. That sub is known as the South Cascade Sub. All retired equipment has been removed from rate base as I discussed earlier.

Q. IS THERE A RELATED ADJUSTMENT TO ACCUMULATED DEPRECIATION AND DEPRECIATION EXPENSE FOR THE PROJECT 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 2009, there is no current year depreciation expense or accumulated depreciation included in the 2009 Actual Year. Therefore, an adjustment is needed to normalize a full year's 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 expense and the accumulated depreciation offset to the annualized rate base addition. The adjustment amount to increase accumulated depreciation and depreciation expense is $13,060. The South Dakota share of this adjustment is $1,292. In addition, as mentioned earlier, there was a substation retirement associated with this addition and with that retirement an adjustment is needed to remove the accumulated depreciation. The adjustment on a system-wide basis is a reduction of ($29,793). The South Dakota share is ($2,948).

Q. ARE THERE ANY OTHER ADJUSTMENTS TO MAKE RELATED TO THIS PROJECT?

A. Yes. Since this project was initiated during 2009, any costs incurred have been accumulated in long-term CWIP. As a result, an adjustment is needed to remove the CWIP amount along with any associated AFUDC that was accrued on this particular project during 2009. The adjustment needed to remove the long-term CWIP is ($13,376) and the adjustment to remove AFUDC is ($850). As mentioned previously, South Dakota does not allow recovery of long-term CWIP or require AFUDC as a revenue credit. Therefore, there is no overall impact to rate base or the operating statement on a South Dakota basis for either of these adjustments.

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, 2009 and completed before December 31, 2010. There is one transmission and one production-related project included in this adjustment: 1) installation of two Capacitor Banks at the Gwinner, North Dakota Substation; and 2) a Hot End Basket replacement project at the Big Stone Plant. The total rate base adjustment for these projects is an increase of $1,314,200. The South Dakota share of this adjustment is $130,809. 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 2009 Actual Year. Therefore, the adjustment needed will be the same for depreciation expense and accumulated depreciation. The total adjustment being made is $28,063. The South Dakota share is $2,793.

Q. PLEASE BRIEFLY DESCRIBE THESE TWO PROJECTS BEGINNING WITH THE GWINNER CAPACITOR BANK PROJECT.

A. The Gwinner Capacitor Bank project includes the addition of two new 115 kV, 6 MVAR capacitor banks at the Gwinner substation near Gwinner, North Dakota. The capacitor banks each have a 115 kV circuit breaker on them along with protective relays and controls. The project requires expansion of the fenced in area, the expansion of the existing control house as well as installation of new Supervisory Control And Data Acquisition (SCADA) control and communications equipment required to maintain the voltage levels at the Gwinner substation during loss of certain system elements. Without this addition, the voltage at the Gwinner substation falls below acceptable tolerances during certain contingencies.

Q. PLEASE EXPLAIN THE FINAL PROJECT YOU ARE INCLUDING IN THE TEST YEAR ADJUSTMENTS FOR 2010 PLANT ADDITIONS?

A. The final adjustment for plant additions is the replacement of Air Pre-Heater (APH) Hot End Air Baskets ("Air Heater Baskets") at the Big Stone Plant. An air heater is basically a heat exchanger that recovers energy from the boiler combustion exhaust gas and transfers it to the incoming combustion air. They are small (3 to 4 cu. ft.) elements that are made out of corrugated steel plates housed in a frame and weigh between 1,000 and 2,000 pounds each. Each air heater (there are two) holds 480 Air Heater Baskets. Air Heater Baskets typically have a 5 to 10-year service life. The existing baskets were installed in 2002 and will be eight years old in 2010, nearing the end of their useful life. The baskets were last inspected in 2008 and showed signs of cracking and thinning leading to the decision to replace them.

Q. ARE THERE ANY OTHER ADJUSTMENTS RELATED TO THE PROJECTS THAT WILL BE STARTED AND COMPLETED DURING 2010 THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. As mentioned in the description of the Hot End Air Baskets project, the existing baskets are nearing the end of their useful life and will be replaced. As a result, an adjustment is necessary to remove the associated equipment that will be retired. The total adjustment amount is ($294,307). The South Dakota amount of the retired plant is ($29,294). In addition to the plant adjustment there also needs to be a corresponding adjustment to remove the accumulated depreciation that pertains to the retired plant. The adjustment to remove the accumulated depreciation totals ($50,727) of which the South Dakota amount is ($5,049).

Q. PLEASE SUMMARIZE THE TOTAL ADJUSTMENTS TO PLANT IN SERVICE RELATED TO THE NEW PROJECT ADDITIONS YOU JUST DESCRIBED.

A. The total adjustments to gross plant related to new projects being added (excluding wind) net of associated retirements in the Test Year is $15,374,289. The South Dakota share of this amount is $1,523,954. The total of all adjustments to accumulated depreciation related to new projects and associated retirements is $433,642. The South Dakota share is $42,965. These adjustments result in a net increase to Total Company and South Dakota plant in service of $14,940,647 and $1,480,989, respectively. In addition to the gross plant and accumulated depreciation adjustments, there is a corresponding removal adjustment to long-term CWIP for any projects that were in CWIP at the end of 2008 and completed during 2009 or in CWIP at the end of 2009 and projected to go in service during 2010. The total adjustment to long-term CWIP is a reduction of ($9,099,771). The South Dakota share is $0. Please refer to Exhibit__(KAS-1) Schedule 4, column B for a summary of the adjustments to plant in service discussed above. Exhibit__(PJB-1), Schedule 8, provides the corresponding adjustments to the Operating Statement associated with these rate base adjustments. The total adjustment to the Operating Statement is a $467,748 increase to depreciation expense and a ($462,074) decrease in AFUDC. The South Dakota share of these adjustments is an increase of $46,353 in depreciation expense and no impact related to AFUDC, respectively.

Q. EARLIER YOU MENTIONED THE NEW WIND INVESTMENT SINCE OTP'S LAST RATE CASE. PLEASE DISCUSS OTP'S REQUEST FOR COST RECOVERY IN THIS CASE RELATED TO INVESTMENTS IN WIND GENERATION?

A. In addition to the new wind investment discussed earlier, OTP is the owner of 27 turbines with a nameplate rating of 40.5 megawatts, which are part of a large wind farm near Langdon in Cavalier County, North Dakota, the Langdon Wind Energy Center (LWEC), that went into commercial operation in late 2007 and early 2008. OTP also owns 48-megawatt's of the Ashtabula Wind Energy Project (AWC) that became operational at the end of 2008. Cost recovery for LWEC and AWC was included in OTP's last South Dakota rate case. However, the costs associated with all three wind projects are tracked and recovered separately from base rates in both North Dakota and Minnesota. In South Dakota, all of these costs are proposed to be recovered in base rates. The adjustments to rate base that I have used and explain below isolate the wind-related components of rate base and allow for consistent treatment and recovery across jurisdictions.

Q. WHAT TEST YEAR ADJUSTMENTS WERE MADE TO INCLUDE WIND-RELATED COSTS IN THIS FILING?

A. First, an adjustment was made to remove all 2009 Actual Year costs related to wind in order to start with a "clean" rate base and operating statement, which also allowed for more transparency related to the adjustments being made to bring wind in. The adjustment represents a full year of costs for LWEC and AWC and partial year costs for Luverne. That adjustment removed $219,794,670 in plant in service, $7,398,039 in accumulated depreciation, $10,193,423 in CWIP, $556,313 in materials and supplies and $61,214,614 in accumulated deferred income tax (ADIT) liability (a reduction to rate base) costs on a system-wide basis. The South Dakota share of the adjustment was a reduction of $21,245,007 to plant in service, $715,083 to accumulated depreciation, there was no impact to rate base related to CWIP due to South Dakota's regulatory treatment as discussed previously, a $54,735 decrease in materials and supplies and a $5,437,370 decrease in ADIT liabilities. These adjustments are summarized on Exhibit__(KAS-1) Schedule 4, column J. A summary of these adjustments can be found on work paper series SD TY-18, in Volume 4A, Tab – Test Year Workpapers.

Next, an adjustment to include the 2010 projected wind-related costs on the three projects was made. This adjustment resulted in an increase of $267,526,913 in plant in service, $22,486,859 in accumulated depreciation, $727,335 in materials and supplies and $87,001,046 in ADIT liabilities on a system-wide basis. The South Dakota share was an increase of $25,858,731 to plant, $2,173,544 to accumulated depreciation, $71,562 in materials and supplies and $7,192,893 in ADIT liabilities. These adjustments are summarized on Exhibit__(KAS-1) Schedule 4, column K. A summary of these adjustments can be found on work paper series SD TY-19, in Volume 4A, Tab – Test Year Workpapers. Increases in net plant related to Luverne due to a partial year of in-service time in the 2009 Actual Year offset any reductions associated with increased levels of accumulated depreciation for the LWEC and AWC.

Q. PLEASE SUMMARIZE THE TEST YEAR ADJUSTMENTS RELATED TO WIND THAT WERE MADE IN THIS FILING.

A. The net change in plant in service and accumulated depreciation related to the wind adjustments was an increase of $47,732,243 and $15,088,820, respectively, on a system-wide basis. The South Dakota share of the net change is an increase to plant of $4,613,724 and an increase in accumulated depreciation of $1,458,462. In addition, the net change on a system-wide basis in materials and supplies and ADIT liabilities (a reduction to rate base) was an increase of $171,022 and $25,786,432, respectively. The South Dakota share of these changes was an increase to materials and supplies of $16,827 and an increase in ADIT liabilities of $1,755,523. There were also a number of adjustments to the operating statement that can be found on work paper series SD TY-18 and SD TY-19, referenced above, that will be addressed in Mr. Beithon's testimony.

Q. WHAT IS THE NET RESULT OF ALL OF THE PLANT IN SERVICE ADJUSTMENTS TO RATE BASE, INCLUDING ADJUSTMENTS MADE FOR WIND?

A. The overall change in average rate base related to the Test Year adjustments associated with new plant in service discussed above, including adjustments to include wind, is an increase of $2,897,554 when compared with rate base in the 2009 Actual Year.

2. Big Stone II Cost Recovery

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO RATE BASE BESIDES THOSE JUST DESCRIBED RELATED TO NEW ADDITIONS?

A. Yes. We made two other adjustments related to gross plant: 1) Recovery of Big Stone II Costs; and 2) the Reclassification of Plant between Generation, Transmission and Distribution.

Q. PLEASE BEGIN BY DISCUSSING THE ADJUSTMENT TO RECOVER COSTS RELATED TO BIG STONE II?

A. As discussed in the testimony of Mr. Thomas R. Brause, OTP withdrew from the Big Stone II project in September 2009. On December 14, 2009, OTP filed a petition in Docket No. EL09-024 requesting authority to use deferred accounting until its next rate case for costs incurred during its participation in the Big Stone II Project. The petition was conditionally approved by the Commission (please refer to the Order in Docket No. EL09-024 for a description of the conditions) on February 3, 2010. OTP is proposing, in this general rate case, to amortize the costs associated with Big Stone II over five years matching the length in time the costs were incurred and accumulated. Any unamortized balance would be included in rate base until fully amortized. The total system amount that OTP is asking to recover is $12,692,127. The adjustment that I made to the Test Year includes the unamortized balance of Big Stone II costs in rate base, which is an increase to rate base of $10,153,702. That is equal to the total amount referred to above minus a full year's amortization expense. The South Dakota share of this adjustment is $1,010,651. This adjustment is provided on Exhibit__(KAS-1) Schedule 4, column C. The adjustment to include the full year of amortization expense is $2,538,425, of which the South Dakota share is $252,663.

Q. WHY HAS A FULL YEAR OF AMORTIZATION EXPENSE BEEN SUBTRACTED?

A. An adjustment to the operating statement is being made to recognize a full year of amortization expense. Therefore, the amount of rate base being included in the Test Year has been reduced by the accumulated amortization for a full year.

Q. ARE THERE ANY OTHER ADJUSTMENTS TO RATE BASE OR OPERATING INCOME RELATED TO BIG STONE II?

A. As mentioned previously, OTP withdrew from the Big Stone II Project in September 2009. Up until that time all costs related to the project were accumulating within the monthly long-term CWIP balances. As a result, an adjustment is needed to remove that amount along with the associated AFUDC that has been accrued during 2009. The adjustment to long-term CWIP is a reduction of ($8,181,810). The corresponding adjustment to remove the associated AFUDC is a reduction of ($495,472). Since South Dakota does not allow long-term CWIP in rate base or require AFUDC as a revenue credit to the operating statement these adjustments do not have any impact on a jurisdictional basis. Please refer to the testimony of Mr. Brause for further discussion related to the Big Stone II project. Workpaper series SD TY-02, located in Volume 4A, Tab – 2009 Test Year Workpapers, shows the details of these adjustments. Please also refer to the testimony of Mr. Beithon as he addresses the revenue requirement impacts associated with these adjustments.

3. Reclassification of Transmission Plant

Q. PLEASE CONTINUE BY DISCUSSING THE PLANT RECLASSIFICATION ADJUSTMENT.

A. OTP was ordered in its last Minnesota general rate case, Docket No. E-017/GR-07-1178, to conduct and submit at least 30 days in advance of filing its next Minnesota rate case (OTP filed a general rate case in Minnesota on April 2, 2010) a Boundary Guideline Study ("Study") to determine what, if any, assets should be reclassified from transmission to distribution or production-related plant.[1] During the course of the Study, it was determined that there were adjustments needed to reclassify plant from the transmission function to both distribution and production. In addition, it was discovered that there were some plant assets that were misclassified as distribution that needed to be reclassified to transmission. As the Study was being conducted, transfers of assets occurred at two times: 1) 4th Quarter 2009; and 2) 1st Quarter 2010. There were additional reclassifications as a result of an earlier study conducted during OTP's last Minnesota rate case (Docket E-017/GR-07-1178), which were made in 2008. As a result, plant was properly included in the correct function during the most recent Actual Year for the earlier 2008 reclassification and no further adjustment was needed in this filing.

[1] The Boundary Guidelines were adopted by the Minnesota Public Utilities Commission Order Adopting Boundary Guidelines for Distinguishing Transmission from Generation and Distribution Assets, E999/CI-99-1261, July 26, 2000.

As a result of the reclassifications that occurred in 2009 and 2010, an adjustment is needed to annualize the transfer within each function based on a 13-month average calculation. The adjustment had no overall impact on gross plant from a system-wide standpoint. The changes do, however, impact the amount of plant that is allocated to each jurisdiction because the allocation factors that apply to each function are different. The following functional transfers were made: (i) increase Production Plant by $2,289,592; (ii) increase Distribution Plant by $3,595,708; and (iii) decrease Transmission Plant by ($5,885,300). The South Dakota share by function is: (i) increase to Production Plant of $227,895; (ii) increase to Distribution Plant of $376,397; and (iii) decrease to Transmission Plant of ($577,684).

Q. ARE THERE ANY OTHER ADJUSTMENTS RELATED TO THE RECLASSIFICATION OF PLANT?

A. Yes. In conjunction with the adjustment to reclassify plant balances, the Accumulated Depreciation associated with the particular assets also had to be transferred to the appropriate functions. Again, the adjustment had no overall impact on total system accumulated depreciation. The only impact is on the functional balances within the system, which ultimately impacts the jurisdictional amounts because of the differences in allocation factors referred to above. The adjustment to reclassify accumulated depreciation is as follows: (i) increase to Production Accumulated Depreciation of $309,382; (ii) increase to Distribution Accumulated Depreciation of $1,116,124; and (iii) decrease to Transmission Accumulated Depreciation of ($1,425,506). The South Dakota share by function is: (i) increase to Production Accumulated Depreciation of $30,794; (ii) increase to Distribution Accumulated Depreciation of $110,450; and (iii) decrease to Transmission Accumulated Depreciation of ($139,924).

Q. WERE THERE ANY ADJUSTMENTS TO DEPRECIATION EXPENSE?

A. Yes. As I mentioned earlier, the reclassifications took place during the 4^{th} Quarter of 2009 and the 1^{st} Quarter of 2010. For any reclassifications that took place during 2009, the associated depreciation expense was transferred to the correct functions as well so no adjustment was needed because the expense was correctly functionalized by the end of the year. However, an adjustment was needed for the depreciation expense related to the assets reclassified during 2010 because the expense was in the incorrect functions at the end of 2009. Again, the adjustment had no overall impact on the system total, only on the functional balances and jurisdictional amounts. The adjustment to move the expense to the correct function is as follows: (i) increase Production Depreciation by $870; (ii) increase Distribution Depreciation by $379,937; and (iii) decrease Transmission Depreciation by ($380,807). The South Dakota share by function is: (i) increase to Production Depreciation of $87; (ii) increase to Distribution Depreciation of $37,598; and (iii) decrease to Transmission Depreciation of ($37,379).

Q. PLEASE SUMMARIZE THE ADJUSTMENTS TO THE TEST YEAR FOR THE RECLASSIFICATION OF PLANT ASSETS.

A. The net impact of all adjustments on system-wide balances is zero. The net impact to South Dakota as a result of the functional reclassifications is an increase in allocated gross plant of $26,607 and an increase in allocated accumulated depreciation of $1,320 for a net plant increase of $25,287. The South Dakota share of the functional reclassifications to depreciation expense is an increase of $306. The net impact on South Dakota revenue requirements for the functional reclassification adjustments is an increase of $2,402. The rate base adjustments are provided on Exhibit__(KAS-1), Schedule 4, column D, and the operating income statement adjustments are provided on Exhibit__(PJB-1), Schedule 8, respectively. Test Year Adjustment Workpaper SD TY-03 located in Volume 4A, Tab – Test Year Workpapers, provides a schedule summarizing this adjustment as well. Please refer to the Boundary Guideline Study included in Volume 4B of the original filing for more discussion related to this adjustment.

4. Change in Depreciation Rates

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

A. Yes. In addition to the adjustments previously discussed, OTP is proposing an adjustment to both accumulated depreciation and depreciation expense related to changes in the annual depreciation rates that occurred after the end of the 2009 Actual Year.

Q. PLEASE DESCRIBE THE ADJUSTMENT RELATED TO THE ANNUAL CHANGE IN DEPRECIATION RATES?

A. I have adjusted the 2009 Test Year depreciation expense and accumulated depreciation to reflect the Minnesota Public Utilities Commission's approval of the depreciation parameters and rates for use in 2010 as Ordered in Docket No. E017/D-09-1019 dated January 11, 2010. Those parameters are then used to calculate depreciation rates for all three states.

Q. WHY IS IT APPROPRIATE TO USE THE SAME PARAMETERS FOR ALL THREE STATES TO CALCULATE DEPRECIATION RATES?

A. 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, required by Minnesota Rules,[2] 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

[2] Minnesota Statutes § 216B.11 and Minnesota Rules 7825.0600 through 7825.0900 give 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.

lower and the South Dakota Public Utilities Commission and its Staff may consider depreciation issues on an as needed basis.

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

A. The adjustment is an increase to depreciation expense and accumulated depreciation of $671,150. The South Dakota share is $66,786. This adjustment is provided on Exhibit__(KAS-1), Schedule 4, column E. Please refer to Workpaper series SD TY-04 in Volume 4A, Tab – 2009 Test Year Workpapers, for a summary of the calculation.

Q. PLEASE SUMMARIZE THE SOUTH DAKOTA IMPACT OF THE PROPOSED ADJUSTMENTS DESCRIBED IN SECTIONS 1 THROUGH 4 ABOVE.

A. While there are some minor associated adjustments caused by how these adjustments affect allocations and cash working capital, Sections 1 through 4 are the drivers for all changes to the rate base. The South Dakota share of the proposed adjustments I have described is an increase to gross plant in service of $7,174,936 (See my Exhibit__(KAS-1), Schedule 4) and an increase in accumulated depreciation of $1,569,533 (See my Exhibit__(KAS-1), Schedule 4) for a net plant increase of $5,580,115. Also, the South Dakota share of depreciation expense related to the plant adjustments is an increase of $558,034. In addition to the net plant and depreciation expense adjustments described above, South Dakota's share of materials and supplies and ADIT liabilities (a reduction to rate base) was an increase of $16,827 and $1,755,523, respectively, resulting in an overall net increase to rate base on a South Dakota basis of $3,866,707. This increase in rate base does not include the impacts of changes in cash working capital and allocations which will be discussed later in my testimony. OTP witness Mr. Beithon will incorporate the results of all these adjustments plus the other O&M adjustments related to wind (see SD TY-18 and SD TY-19) into total Test Year revenue requirements in his testimony.

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 benefit existing customers. These are construction projects which cost less than $10,000 and require less than 30 days to complete. AFUDC is not added to the short-term CWIP. As mentioned earlier in my testimony, the Commission has ruled in our preceding cases that short-term and long-term CWIP should not be included in rate base as these are amounts that have yet to be placed in service and are not used and useful.

Q. HAVE YOU MADE A KNOWN AND MEASURABLE ADJUSTMENT TO CWIP FOR THE TEST YEAR?

A. Yes. I previously discussed Test Year adjustments related to plant additions that were in long-term CWIP at the end of 2008 that were capitalized during 2009 as well as plant additions that were in CWIP at the end of 2009 that are projected to be in service prior to the end of 2010. The adjustment is needed to remove the amounts from the 13-month long-term CWIP calculation for the 2009 Actual Year. In addition, I previously referenced adjustments to remove from long-term CWIP the costs related to Big Stone II and the Luverne wind project. There is no impact to South Dakota rate base or revenue requirements as a result of these adjustments since they have not been allowed in rate base to begin with. The adjustments were made to maintain accurate and consistent balances on a system-wide basis only.

C. CASH WORKING CAPITAL ITEMS

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

A. Yes. The study and procedures used to calculate the working capital requirement are consistent with the approach and methodology filed by the Company and approved by the Commission in Docket No. EL08-030. The Company reviewed the procedures used in the lead-lag study filed in that docket and concluded no significant changes in policies or procedures had occurred and conducted the current study using those same procedures updated with information from the 2008 calendar year.

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

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

Q. WHAT METHOD DOES OTP USE IN DEVELOPING THE AMOUNTS USED IN WORKING CAPITAL FOR THE 2009 TEST YEAR?

A. The dollar amount used to calculate revenue requirements for the working capital items listed above is based on a 13-month average, from December 2008 through December 2009, as recommended by Commission Staff and approved by the Commission in OTP’s most recent South Dakota rate case, Docket No. EL08-030.

Q. PLEASE DISCUSS WORKING CAPITAL BEGINNING WITH MATERIALS AND SUPPLIES ON LINE 15, PAGE 1 OF SCHEDULE F-1.

A. Required Schedule F-1 summarizes the materials and supplies inventory by month and shows the 13-month average calculation of the total utility amount used in rate base for the 2009 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.

Q. PLEASE EXPLAIN FUEL STOCKS, LINE 15, PAGE 1, OF SCHEDULE F-1?

A. Required Schedule F-1 presents a 13-month average of the 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 2009 Actual Year.

Q. WOULD YOU PLEASE DESCRIBE THE PREPAYMENTS SHOWN ON LINE 15, PAGE 2 OF SCHEDULE F-1?

A. Required Schedule F-1, page 2, line 15 presents a 13-month average of Prepayments that are included in rate base. Schedule F-1 shows the calculation of Prepayments for the total utility for both the 2009 Actual and 2009 Test Years. Because of some limitations in our JCOSS model, 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.

Q. PLEASE EXPLAIN THE 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. The Commission, in our last rate case, approved OTP's use of FAS No. 106 for ratemaking purposes. Since the amount collected in rates has been 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.

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 MATERIALS AND SUPPLIES IN THE TEST YEAR?

A. Yes. There is an adjustment to materials and supplies in the Test Year to reflect the change in balances for eliminating the 2009 Actual Year wind balances and to bring in the 2010 year-end wind balances as discussed earlier in my testimony (see SD TY-18 and SD TY-19). The South Dakota portion of this adjustment is an increase of $16,827.

Q. PLEASE CONTINUE YOUR DISCUSSION OF WORKING CAPITAL BY DISCUSSING CUSTOMER ADVANCES.

A. Customer advances and deposits represent two types of advances: funds received from customers as assurance of adequate revenues to justify the cost of extending facilities needed to support new electric service and customer deposits to assure payment. The payments for new electric service may be requested in situations where the utility's investment to extend service is not recovered by three years' of expected electric revenue. As provided in OTP's General Rules and Regulations for Electric Service, we may request a deposit from the customer as a three-year minimum revenue guarantee. If the customer satisfies the revenue requirement, the deposit is returned to the customer. Since these deposits are sources of cash, a reduction is made to rate base.

Q. PLEASE FINISH YOUR DISCUSSION OF THE WORKING CAPITAL PORTION OF RATE BASE BY DISCUSSING STATEMENT F, LINE 42, CASH WORKING CAPITAL.

A. This item represents a determination of cash working capital requirements for operation, maintenance, and other expenses and is supported by Exhibit__(KAS-1), Schedule 3.

Q. HOW WERE SUCH CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

A. The cash working capital requirement included in rate base is based on a lead-lag study prepared by OTP using calendar year 2008 financial data. The results of that study are summarized on Exhibit__(KAS-1), 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 Schedule 3, page 1 of 3, on average, OTP does not receive cash from its customers until 38.9 days after service has been rendered. The 38.9 days is comprised of a 15.2 day metering period lag, a 3.6 day bill processing lag, and a 20.1 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 THE OTHER COMPONENTS OF THE LEAD-LAG STUDY?

A. Page 1, Schedule 3 calculates the revenue lead days for total utility and South Dakota. Pages 2 and 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 2009 Actual Year, for OTP's South 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 Test Year.

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

A. Yes. Within the cash working capital calculation is a 13-month average balance for Special Deposits. This is an account that is set up with fiscal agents or others, which includes deposits for interest, dividends or for other special purposes. Such special deposits may include cash deposited as a guaranty for the fulfillment of obligations; cash deposited with trustees to be held until mortgaged property is sold, destroyed, or otherwise disposed of, is replaced; or cash realized from the sale of the accounting utility's securities and deposited with trustees to be held until invested in property of the utility. During the 2009 Actual Year large deposits were made for proceeds received from financing related to the Luverne wind investment. A Test Year adjustment is needed for two reasons: 1) to normalize the 13-month average balance and 2) to remove the impact related to the deposits as a known and measureable change since the deposit was eliminated during the test period. The amount of that adjustment is to reduce Special Deposits by ($21,456,213), which reduces the amount of South Dakota cash working capital included in rate base by ($2,104,951). Please refer to work paper SD TY-05 in Volume 4A, Tab – 2009 Test Year Workpapers, for a summary of the calculation.

Q. ARE THERE ANY ADDITIONAL ADJUSTMENTS TO CASH WORKING CAPITAL?

A. Yes. Cash working capital is embedded in the jurisdictional cost of service model. Any change to components of revenue requirements in the model changes the cash working capital amount. The adjustments for the 2009 Test Year increase the South Dakota share of cash working capital by $18,462 and represent the cumulative effect of all of the adjustments made to the 2009 Actual Year to arrive at the Test Year. See Exhibit (KAS-1), Schedule 1, line 10; and Exhibit __(KAS-1), Schedule 4, column M.

Q. DO YOU ANTICIPATE ANY CHANGES TO THE WORKING CAPITAL CALCULATION DURING THE COURSE OF THE RATE CASE PROCEEDING?

A. Yes. Cash working capital will need to be recalculated to reflect Commission approved financial adjustments that impact operating and maintenance expenses, rate base, and capital structure. OTP will incorporate the impacts of any adjustments to cash working capital in its compliance filing in this proceeding.

Q. PLEASE SUMMARIZE THE TEST YEAR ADJUSTMENTS MADE TO CASH WORKING CAPITAL.

A. The net impact on the South Dakota cash working capital included in rate base for the two Test Year adjustments discussed above is a reduction of ($2,086,489). Mr. Beithon will incorporate the results of these adjustments into total revenue requirements, as described in his testimony.

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. WERE THERE ANY TEST YEAR ADJUSTMENTS TO ACCUMULATED DEFERRED INCOME TAXES?

A. Yes, there were three adjustments to ADIT in the Test Year. The first two were discussed earlier in my testimony and relate to removing wind from the Actual Year and bringing in wind based on year-end 2010 amounts. These adjustments result in a system-wide increase in ADIT (a rate base reduction) of $25,786,432. The South Dakota share of this adjustment is an increase of $1,755,523 (see SD TY-18 and SD TY-19 for more detail). In addition to the adjustments for wind there also was an adjustment to ADIT related to the new legislation passed in March 2010 called the Patient Protection and Affordable Care Act (PPACA). The impacts of that legislation resulted in an immediate write-down of future deferred tax assets thus increasing the ADIT liability on a system-wide basis by $2,519,466. The South Dakota share of this adjustment is an increase in ADIT liability of $247,171. Please refer to Mr. Beithon's testimony for a more detailed discussion of the PPACA adjustment.

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

A. As shown on Exhibit (KAS-1) Schedule 1, line 11, $14,808,071 was deducted. This amount reflects a simple average of the beginning and ending test year ADIT balances. A simple average was used as the information for converting to a 13-month average was not available. ADIT is a detailed and time consuming calculation that is fully developed once a year during the closing of accounting books. Therefore, the

ADIT balance essentially does not change throughout the year and it is reasonable to use a simple average of beginning and end of year balances.

E. UNAMORTIZED RATE BASE ITEMS

Q. PLEASE EXPLAIN WHAT YOU HAVE INCLUDED IN RATE BASE RELATED TO UNAMORTIZED BALANCES.

A. There are two additional items of rate base to discuss related to unamortized balances for holding company formation costs and rate case expense as allowed in the settlement in the most recent South Dakota rate case Docket No. EL08-030.

Q. PLEASE BEGIN BY DISCUSSING THE UNAMORTIZED HOLDING COMPANY FORMATION COSTS.

A. The final settlement in Docket No. EL08-030 allowed for a five year amortization of actual holding company formation costs incurred with a return on rate base for the unamortized balance. The amount included in this filing, $221,082, represents the system-wide 13-month average balance of OTP's share of all unamortized costs associated with the formation of the Holding Company through December 31, 2010. The 13-month average was then compared to the average included in the 2009 Actual Year, $112,740 (also on a system-wide basis), to determine the Test Year adjustment needed to arrive at the correct Test Year balance for Unamortized Holding Company Formation costs. The adjustment needed was an increase on a system-wide basis of $108,342. The South Dakota jurisdictional share of this adjustment was an increase of $10,629 resulting in a South Dakota jurisdictional calculation of Unamortized Holding Company Formation costs included in the Test Year of $21,689 (see Exhibit__(KAS-1), Schedule 1, line 12). Please refer to Test Year adjustment work paper SD TY-10 for additional detail.

Q. PLEASE CONTINUE BY DISCUSSING THE UNAMORTIZED RATE CASE EXPENSE INCLUDED IN THE TEST YEAR.

A. As with the Unamortized Holding Company Formation balance discussed above, the final settlement in Docket No. EL08-030 allowed for a five year amortization of rate case expenses incurred with a return on rate base of the unamortized balance. The amount included with this filing, $172,500 (see Exhibit (KAS-1), Schedule 1, Line 13), is the 13-month average (through December 31, 2010) of the unamortized balance of the rate case expenses incurred in Docket No. EL08-030. Please refer to Test Year adjustment work paper SD TY-11 for more detail related to the 13-month average calculation as well as the adjustment made to arrive at the $172,500 referenced above.

F. IMPACT OF ADJUSTMENTS ON ALLOCATIONS

Q. PLEASE EXPLAIN THE COLUMN IN EXHIBIT__(KAS-1), SCHEDULE 4, LABELED "CHANGES IN ALLOCATONS DUE TO EFFECTS OF TEST YEAR ADJUSTMENTS."

A. This column provides the rate base changes due to changes in the allocators that result from the other financial adjustments made to the Actual Year. These changes are calculated within the Cost of Service model itself. For example, any adjustment to Net Plant will have a direct impact on the Net Electric Plant in Service (NEPIS) allocation factor calculated as a percentage of total system Net Plant. The allocation percentage is simultaneously re-calculated each time an adjustment to Plant occurs thereby providing the most up-to-date factor possible. As a result, anything that is allocated on NEPIS is simultaneously re-calculated on a jurisdictional basis as well. See Exhibit__(PJB-1), Schedule 10, page 5, for a list of other factors that are calculated within the Cost of Service model itself.

III. CONCLUSION

Q. WHAT IS THE AVERAGE RATE BASE FOR THE SOUTH DAKOTA JURISDICTION AS DEVELOPED ON EXHIBIT__(KAS-1), SCHEDULE 1?

A. The average rate base for the South Dakota jurisdiction for the 2009 Actual Year and the Test Year is $62,922,312 and $64,406,556, respectively. Rate base in the Test Year is higher than the Actual Year due to the adjustments discussed previously in my testimony.

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

A. Exhibit__(KAS-1), Schedule 4, attached to my testimony, shows the 2009 Actual Year rate base, a summary of proposed adjustments, and the Test Year rate base of $64,406,556 referenced above.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
RATE BASE SUMMARY

Docket No. EL10-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 1

		South Dakota Jurisdiction		
		(A)	(B)	(C)
				(C) = (B) - (A)
Line No.	Description	2009 Actual Year	2009 Test Year	$ Change
1	Electric Plant in Service	$123,393,484	$130,567,028	$7,173,544
2	Less: Accumulated Depreciation	(49,764,183)	(51,343,632)	(1,579,449)
3	Net Electric Plant in Service	$73,629,301	$79,223,396	$5,594,095
	Other Rate Base Components:			
4	Plant Held for Future Use	$2,926	$2,928	$2
5	Construction Work in Progress	0	0	0
6	Materials and Supplies	1,604,175	1,621,042	16,867
7	Fuel Stocks	857,871	857,871	0
8	Prepayments	(3,433,622)	(3,434,900)	(1,278)
9	Customer Advances	(38,894)	(38,909)	(15)
10	Cash Working Capital	2,875,500	789,011	(2,086,489)
11	Accumulated Deferred Income Taxes	(12,800,615)	(14,808,071)	(2,007,456)
12	Unamortized Holding Company Formation Expense	11,056	21,689	10,633
13	Unamortized Rate Case Expense	214,615	172,500	(42,115)
14	TOTAL	$62,922,312	$64,406,556	$1,484,242

Note: The 2009 Actual Year is based on 2009 historic financial information. The 2009 Test Year is the 2009 Actual Year with known and measureable adjustments to arrive at the Test Year.

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
RATE BASE COMPONENTS

Docket No. EL10-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 2

		2009 Test Year					
		Total Utility			South Dakota Jurisdiction		
Line No.	Description	(A) 2009 Actual Year	(B) Adjustments	(C) 2009 Test Year	(D) 2009 Actual Year	(E) Adjustments	(F) = (D) + (E) 2009 Test Year
	Utility Plant in Service:						
1	Production	$603,927,547	$67,519,518	$671,447,065	$59,479,824	$6,583,254	$66,063,078
2	Transmission	215,989,544	1,670,238	217,659,782	21,200,923	163,945	21,364,868
3	Distribution	352,386,761	4,070,479	356,457,240	34,846,607	427,736	35,274,343
4	General	77,723,582	0	77,723,582	7,440,335	(1,318)	7,439,017
5	Intangible	4,412,810	0	4,412,810	422,430	(75)	422,355
6	**TOTAL Utility Plant in Service**	$1,254,440,244	$73,260,235	$1,327,700,479	$123,390,118	$7,173,542	$130,563,662
	Accumulated Depreciation						
7	Production	($235,205,522)	($16,659,867)	($251,865,389)	($23,389,938)	($1,582,593)	($24,972,531)
8	Transmission	(83,960,131)	1,232,300	(82,727,831)	(8,241,289)	120,959	(8,120,330)
9	Distribution	(148,619,722)	(1,101,444)	(149,721,166)	(14,696,617)	(119,510)	(14,816,127)
10	General	(32,896,050)	11,353	(32,884,697)	(3,149,078)	1,644	(3,147,434)
11	Intangible	(3,000,801)	0	(3,000,801)	(287,261)	51	(287,210)
12	**TOTAL Accumulated Depreciation**	($503,682,227)	($16,517,658)	($520,199,885)	($49,764,183)	($1,579,449)	($51,343,632)
13	**NET Utility Plant in Service**						
14	Production	$368,722,025	$50,859,651	$419,581,676	$36,089,886	$5,000,661	$41,090,547
15	Transmission	132,029,413	2,902,538	134,931,951	12,959,634	284,904	13,244,538
16	Distribution	203,767,039	2,969,035	206,736,074	20,149,990	308,226	20,458,216
17	General	44,827,532	11,353	44,838,885	4,291,257	326	4,291,583
18	Intangible	1,412,009	0	1,412,009	135,169	(24)	135,145
19	**NET Utility Plant in Service**	$750,758,017	$56,742,577	$807,500,594	$73,625,935	$5,594,093	$79,220,029
20	Big Stone Plant capitalized items	$40,651	$0	$40,651	$3,366	$0	$3,366
21	Utility Plant Held for Future Use	29,657	0	29,657	2,926	2	2,928
22	Construction Work in Progress	41,488,404	(27,475,003)	14,013,401	0	0	0
23	Materials and Supplies	16,272,126	171,022	16,443,148	1,604,175	16,867	1,621,042
24	Fuel Stocks	8,615,745	0	8,615,745	857,871	0	857,871
25	Prepayments	(35,012,678)	0	(35,012,678)	(3,433,622)	(1,278)	(3,434,900)
26	Customer Advances	(396,606)	0	(396,606)	(38,894)	(15)	(38,909)
27	Cash Working Capital*	26,087,939	(21,564,077)	4,523,862	2,875,500	(2,086,489)	789,011
28	Accumulated Deferred Income Taxes	(160,158,533)	(28,305,898)	(188,464,431)	(12,800,615)	(2,007,456)	(14,808,071)
29	Unamortized Holding Co. Formation Exp	112,740	108,342	221,082	11,056	10,633	21,689
30	Unamortized Rate Case Expense	214,615	(42,115)	172,500	214,615	(42,115)	172,500
31	**Total Average Rate Base**	$648,052,078	($20,365,151)	$627,686,927	$62,922,312	$1,484,242	$64,406,556

* Detailed on Schedule 3, pages 1-3

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
CASH WORKING CAPITAL

Docket No. EL10-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 3, page 1 of 3

LINE NO	ITEM	2009 ACTUAL YEAR TOTAL UTILITY	2009 ACTUAL YEAR SOUTH DAKOTA	2009 TEST YEAR TOTAL UTILITY	2009 TEST YEAR SOUTH DAKOTA
1	CASH WORKING CAPITAL CALCULATION - REVENUE LEAD DAYS				
2					
3	REVENUES				
4	COMPUTER MAINTAINED BILLINGS	$264,570,328	$23,146,519	$252,730,854	$23,180,105
5	MANUALLY MAINTAINED BILLINGS	31,382,878	2,745,600	29,978,500	2,749,584
6	COST OF ENERGY REVENUES	(6,669,437)	1,864,061	(6,669,437)	1,864,061
7	SALES FOR RESALE	10,567,840	1,000,424	10,567,840	1,000,424
8	RENT FROM ELECTRIC PROPERTY	638,477	62,614	638,477	62,637
9	OTHER MISC ELECTRIC REVENUE	15,017	1,473	15,017	1,473
10	ITA DEFICIENCY PAYMENTS	3,353,015	328,823	3,353,015	328,946
11	WHEELING	432,905	0	432,905	0
12	LOAD CONTROL AND DISPATCH	4,007,399	392,997	4,007,399	393,144
13	RENT FROM ELECTRIC PROPERTY - BIG STONE	1,550	152	1,550	152
14	RENT FROM ELECTRIC PROPERTY - COYOTE	6,583	646	6,583	646
15	PROFIT ON MATERIALS AND SUPPLIES	3,747,651	367,525	3,747,651	367,661
16	RUBBER GOODS TESTING/MISCELLANEOUS SERVICES	32,304	3,168	32,304	3,169
17	RESIDENTIAL CONSERVATION SERVICES/LOAN POOL INTEREST	24,609	768	24,609	768
18					
19	**TOTAL REVENUES**	$312,111,120	$29,914,769	$298,867,268	$29,952,770
20					
21	REVENUE LEAD DAYS FROM SERVICE TO COLLECTION				
22	COMPUTER MAINTAINED BILLINGS	N/A	38.9	N/A	38.9
23	MANUALLY MAINTAINED BILLINGS	N/A	41.3	N/A	41.3
24	COST OF ENERGY REVENUES	N/A	113.5	N/A	113.5
25	SALES FOR RESALE	N/A	28.4	N/A	28.4
26	RENT FROM ELECTRIC PROPERTY	N/A	(87.8)	N/A	(87.8)
27	OTHER MISC ELECTRIC REVENUE	N/A	42.6	N/A	42.6
28	ITA DEFICIENCY PAYMENTS	N/A	50.1	N/A	50.1
29	WHEELING	N/A	38.6	N/A	38.6
30	LOAD CONTROL AND DISPATCH	N/A	33.4	N/A	33.4
31	RENT FROM ELECTRIC PROPERTY - BIG STONE	N/A	43.3	N/A	43.3
32	RENT FROM ELECTRIC PROPERTY - COYOTE	N/A	43.3	N/A	43.3
33	PROFIT ON MATERIALS AND SUPPLIES	N/A	43.3	N/A	43.3
34	RUBBER GOODS TESTING/MISCELLANEOUS SERVICES	N/A	43.3	N/A	43.3
35	RESIDENTIAL CONSERVATION SERVICES/LOAN POOL INTEREST	N/A	43.3	N/A	43.3
36					
37	REVENUE DOLLAR DAYS (REVENUES X REVENUE LEAD DAYS)				
38	COMPUTER MAINTAINED BILLINGS	$10,291,785,755	$900,399,584	$9,831,230,232	$901,706,082
39	MANUALLY MAINTAINED BILLINGS	1,297,368,174	113,503,117	1,239,311,187	113,667,813
40	COST OF ENERGY REVENUES	(776,381,120)	211,570,924	(776,381,120)	211,570,924
41	SALES FOR RESALE	299,598,268	28,362,018	299,598,268	28,362,018
42	RENT FROM ELECTRIC PROPERTY	(56,032,750)	(5,495,018)	(56,032,750)	(5,497,063)
43	OTHER MISC ELECTRIC REVENUE	638,969	62,662	638,969	62,686
44	ITA DEFICIENCY PAYMENTS	167,952,508	16,470,761	167,952,508	16,476,890
45	WHEELING	16,705,821	0	16,705,821	0
46	LOAD CONTROL AND DISPATCH	133,847,127	13,126,116	133,847,127	13,131,000
47	RENT FROM ELECTRIC PROPERTY - BIG STONE	57,258	6,576	57,019	6,577
48	RENT FROM ELECTRIC PROPERTY - COYOTE	243,194	27,929	242,177	27,936
49	PROFIT ON MATERIALS AND SUPPLIES	138,441,034	15,899,000	137,862,032	15,902,955
50	RUBBER GOODS TESTING/MISCELLANEOUS SERVICES	1,193,334	137,046	1,188,343	137,080
51	RESIDENTIAL CONSERVATION SERVICES/LOAN POOL INTEREST	911,728	33,202	909,270	33,198
52					
53	**TOTAL DOLLAR DAYS**	$11,516,329,299	$1,294,103,917	$10,997,129,081	$1,295,588,095
54					
55	**AVG REVENUE LEAD DAYS (TOTAL REV DOLLAR DAYS / TOTAL REV)**	36.9	**43.3**	36.8	**43.3**
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		3.6		
60	Billing Date to Date collection is Received		20.1		
61	Total		38.9		

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
CASH WORKING CAPITAL
Calculation applying lead-lag factors

Docket No. EL10-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 3, page 2 of 3

		2009 ACTUAL YEAR					
		SOUTH 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 43.3 Over Expense Lag Days	Net Revenue Lag Dollars	Net Revenue Lag Dollars
1	FUEL - COAL	5,463,645	$14,969	11.9	31.4	$470,019	3,891,583
2	FUEL - OIL	273,446	749	13.5	29.8	22,318	176,728
3	PURCHASED POWER	5,155,346	14,124	30.6	12.6	178,385	921,613
4	LABOR AND ASSOC PAYROLL EXPENSE	5,678,193	15,557	15.9	27.4	426,404	3,525,813
5	ALL OTHER O&M EXPENSE	3,663,015	10,036	14.5	28.8	288,724	2,445,233
6	PROPERTY TAX (EXCL COAL CONV TAX)	797,860	2,186	309.2	(265.9)	(581,254)	(6,068,224)
7	COAL CONVERSION TAXES	69,615	191	309.2	(265.9)	(50,716)	(529,464)
8	FEDERAL INCOME TAXES	(3,331,374)	(9,127)	0.0	43.3	0	0
9	STATE INCOME TAXES	0	0	0.0	43.3	0	0
10	INCREMENTAL FEDERAL INCOME TAXES	0	0	0.0	43.3	0	0
11	INCREMENTAL STATE INCOME TAXES	0	0	0.0	43.3	0	0
12	BANK BALANCES	0	0	0.0	0.0	779	7,946
13	SPECIAL DEPOSITS	0	0	0.0	0.0	2,166,686	22,093,721
14	WORKING FUNDS	0	0	0.0	0.0	2,064	21,047
15	TAX COLLECTIONS AVAILABLE					0	0
16	FICA WITHHOLDING	(395,696)	(1,084)	0.0	0.0	0	0
17	FEDERAL WITHHOLDING	(636,356)	(1,743)	0.0	0.0	0	0
18	STATE WITHHOLDING- MN	0	0	1.9	0.0	0	(9,108)
19	STATE WITHHOLDING- ND	0	0	62.0	0.0	0	(44,382)
20	STATE SALES TAX	(1,287,693)	(3,528)	13.6	0.0	(47,909)	(270,204)
21	FRANCHISE TAXES	0	0	0.0	0.0	0	(74,362)
22							
23	**TOTAL CASH WORKING CAPITAL REQUIREMENT**					**2,875,500**	26,087,939

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
CASH WORKING CAPITAL
Calculation applying lead-lag factors

Docket No. EL10-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 3, page 3 of 3

		2009 TEST YEAR					
		SOUTH 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 43.3 Over Expense Lag Days	Net Revenue Lag Dollars	Net Revenue Lag Dollars
1	FUEL - COAL	$5,463,645	$14,969	11.9	31.4	$469,939	3,869,890
2	FUEL - OIL	273,446	749	13.5	29.8	22,314	175,702
3	PURCHASED POWER	5,093,202	13,954	30.6	12.6	176,160	890,608
4	LABOR AND ASSOC PAYROLL EXPENSE	5,735,412	15,713	15.9	27.4	430,617	3,503,204
5	ALL OTHER O&M EXPENSE	4,582,767	12,556	14.5	28.8	361,153	3,006,263
6	PROPERTY TAX (EXCL COAL CONV TAX)	869,186	2,381	309.2	(266.0)	(633,385)	(6,613,232)
7	COAL CONVERSION TAXES	75,838	208	309.2	(266.0)	(55,264)	(577,017)
8	FEDERAL INCOME TAXES	(2,126,193)	(5,825)	0.0	43.3	0	0
9	STATE INCOME TAXES	0	0	0.0	43.3	0	0
10	INCREMENTAL FEDERAL INCOME TAXES	0	0	0.0	43.3	0	0
11	INCREMENTAL STATE INCOME TAXES	0	0	0.0	43.3	0	0
12	BANK BALANCES	0	0	0.0	0.0	780	7,946
13	SPECIAL DEPOSITS	0	0	0.0	0.0	62,542	637,508
14	WORKING FUNDS	0	0	0.0	0.0	2,065	21,047
15	TAX COLLECTIONS AVAILABLE						
16	FICA WITHHOLDING	(399,684)	(1,095)	0.0	0.0	0	0
17	FEDERAL WITHHOLDING	(642,769)	(1,761)	0.0	0.0	0	0
18	STATE WITHHOLDING- MN	0	0	1.9	0.0	0	(9,108)
19	STATE WITHHOLDING- ND	0	0	62.0	0.0	0	(44,382)
20	STATE SALES TAX	(1,287,693)	(3,528)	13.6	0.0	(47,909)	(270,204)
21	FRANCHISE TAXES	0	0	0.0	0.0	0	(74,362)
22							
23	**TOTAL CASH WORKING CAPITAL REQUIREMENT**					**789,011**	$4,523,862

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENTS
2009 Actual Year versus 2009 Test Year

Docket No. EL10-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 4

Line No.	Description	(A) 2009 Actual Year	(B) Annualize Plant in Service	(C) BSP II Deferred Recovery	(D) Transmission Plant Transfer	(E) Depreciation to Reflect 2009 Rates	(F) Special Deposits	(G) Unamortized Hold Company Expense	(H) Unamortized Rate Case Expense	(I) Patient Protection and Affordable Care Act	(J) Wind Removal	(K) Wind Added	(L) Changes in Allocations due to Effect of Test Year Adjustments	(M) Income Statement Adjustments Affecting CWC	(N) 2009 Test Year
	Utility Plant in Service:														
1	Production	$59,479,824	$730,985	$1,010,651	$227,895						($21,245,007)	$25,858,731	$0		$66,063,078
2	Transmission	21,200,923	741,630		(577,684)								(1)		21,364,868
3	Distribution	34,846,607	51,339		376,397										35,274,343
4	General	7,440,335	0										(1,318)		7,439,017
5	Intangible	422,430	0										(75)		422,355
6	**TOTAL Utility Plant in Service**	$123,390,119	$1,523,954	$1,010,651	$26,607	$0	$0	$0	$0		($21,245,007)	$25,858,731	($1,394)	$0	$130,563,662
	Accumulated Depreciation														
7	Production	($23,389,938)	($29,853)		($30,794)	($63,473)					$715,083	($2,173,544)	($11)		($24,972,531)
8	Transmission	(8,241,289)	(14,768)		139,924	(4,196)									(8,120,330)
9	Distribution	(14,696,617)	1,656		(110,450)	(203)							(10,513)		(14,816,127)
10	General	(3,149,078)	0		0	1,087							557		(3,147,434)
11	Intangible	(287,261)	0										51		(287,210)
12	**TOTAL Accumulated Depreciation**	($49,764,182)	($42,965)	$0	($1,320)	($66,786)	$0	$0	$0	$0	$715,083	($2,173,544)	($9,916)	$0	($51,343,631)
13	**NET Utility Plant in Service**														
14	Production	$36,089,886	$701,132	$1,010,651	$197,101	($63,473)	$0	$0	$0	$0	($20,529,924)	$23,685,186	($11)	$0	$41,090,547
15	Transmission	12,959,634	726,862	0	(437,761)	(4,196)	0	0	0	0	0	0	(1)	0	13,244,538
16	Distribution	20,149,990	52,995	0	265,947	(203)	0	0	0	0	0	0	(10,513)	0	20,458,216
17	General	4,291,257	0	0	0	1,087	0	0	0	0	0	0	(761)	0	4,291,583
18	Intangible	135,169	0	0	0	0	0	0	0	0	0	0	(24)	0	135,145
19	**NET Utility Plant in Service**	$73,625,935	$1,480,989	$1,010,651	$25,287	($66,786)	$0	$0	$0	$0	($20,529,924)	$23,685,186	($11,310)	$0	$79,220,030
20	Big Stone Plant capitalized items	$3,366													3,366
21	Utility Plant Held for Future Use	2,926												$2	2,928
22	Construction Work in Progress	0													0
23	Materials and Supplies	1,604,175									(54,735)	71,562		$40	1,621,042
24	Fuel Stocks	857,871													857,871
25	Prepayments	(3,433,622)												(1,278)	(3,434,900)
26	Customer Advances	(38,894)												(15)	(38,909)
27	Cash Working Capital	2,875,500					(2,104,951)							18,462	789,011
28	Accumulated Deferred Income Taxes	(12,800,615)								(247,171)	5,437,370	(7,192,893)	(4,762)		(14,808,071)
29	Unamortized Holding Co. Formation Exp	11,056						10,629					4		21,689
30	Unamortized Rate Case Expense	214,615							(42,115)						172,500
31	**Total Average Rate Base**	$62,922,312	$1,480,989	$1,010,651	$25,287	($66,786)	($2,104,951)	$10,629	($42,115)	($247,171)	($15,147,290)	$16,563,855	($16,068)	$17,211	$64,406,557

Column references to adjustment workpapers:
(B) W/P 2009 SD TY-01
(C) W/P 2009 SD TY-02
(D) W/P 2009 SD TY-03
(E) W/P 2009 SD TY-04
(F) W/P 2009 SD TY-05

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
COMPARISON OF RATE BASE COMPONENTS
MOST RECENT RATE CASE WITH CURRENT PROPOSED TEST YEAR

Docket No. EL10-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 5

Line No.	Description	(A) Per Order in Docket No. EL08-030	(B) 2009 Test Year	(C) (C) = (B) - (A) $ Change
1	Electric Plant in Service	$113,253,148	$130,563,662	$17,310,514
2	Less: Accumulated Depreciation	(45,334,838)	(51,343,632)	(6,008,794)
3	Net Plant Excluding Big Stone Plant Capitalized Items	$67,918,310	$79,220,030	$11,301,720
4	Net Captialized Items - Big Stone Plant	$10,715	$3,366	(7,349)
5	Net Electric Plant in Service	$67,929,025	$79,223,396	$11,294,371
6	Other Rate Base Components:			
7	Plant Held for Future Use	$2,865	$2,928	$63
8	Construction Work in Progress	0	0	0
9	Materials and Supplies	1,441,036	1,621,042	180,006
10	Fuel Stocks	806,694	857,871	51,177
11	Prepayments	(2,870,841)	(3,434,900)	(564,059)
12	Customer Advances	(22,150)	(38,909)	(16,759)
13	Cash Working Capital	227,691	789,011	561,320
14	Accumulated Deferred Income Taxes	(7,011,433)	(14,808,071)	(7,796,638)
15	Unamortized Holding Company Formation Expense	7,508	21,689	14,181
16	Unamortized Rate Case Expense	112,500	172,500	60,000
17	Other Rate Base Components (1)	(154,678)	0	154,678
17	TOTAL	$60,468,218	$64,406,556	$3,783,662

OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
Plant-in-Service Project Additions Included as Test Year Adjustments
Total Company and South Dakota Jurisdiction

Docket No. EL10-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 6

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Total Company			South Dakota		
Line No.	Project Description	Gross Plant	Accumulated Depreciation	Net Plant	Gross Plant	Accumulated Depreciation	Net Plant
	Projects Placed-in-Service During 2009						
1	Coyote - Upgrade HP-IP Turbine Rotor	$3,760,121	($117,147)	$3,642,975	$374,264	($11,660)	$362,604
2	Coyote - Replacement of Reheat Outlet	1,984,385	(44,434)	1,939,951	197,516	(4,423)	193,093
3	HLP - Upgrade Honeywell Boiler Controls on Units #2 & #3	1,170,382	(64,221)	1,106,160	116,494	(6,392)	110,102
4	Cass Lake Reactive Support	771,032	(12,711)	758,320	75,682	(1,248)	74,435
5	Ladish Sub Work	768,912	(12,676)	756,236	75,474	(1,244)	74,230
6	Crookston 115kV Sub Rebuild	658,172	(10,851)	647,321	64,604	(1,065)	63,539
7	Ladish 115kV Substation Uprate	4,705,924	(79,038)	4,626,886	461,920	(7,758)	454,162
8	Dawson/Louisburg Jct 115kV Substation Uprate	542,842	(12,890)	529,952	53,284	(1,265)	52,019
9	Appleton/Candby-Uprate 17Mi of 41.6kV to 115kV	537,398	(11,109)	526,289	52,749	(1,090)	51,659
10	HLP - Replace Unit #3 Primary Superheater Tubes	1,904,514	(104,504)	1,800,010	189,566	(10,258)	179,308
11	Casselton Ethanol Plant Substation	638,279	(12,537)	625,742	62,652	(1,231)	61,421
12	**Total Adjustments for Projects Placed-in-Service During 2009**	$17,441,960	($482,119)	$16,959,841	$1,724,207	($47,635)	$1,676,572
	Projects Started in 2009 and Placed-in-Service During 2010						
13	New Substation in Fergus Falls	$550,000	($13,060)	$536,940	$59,474	($1,292)	$58,181
14	**Total Adjustments for Projects Started in 2009 and Placed-in-Service During 2010**	$550,000	($13,060)	$536,940	$59,474	($1,292)	$58,181
	Projects Started and Placed-in-Service During 2010						
15	Gwinner Capacitor Bank	$883,000	($14,557)	$868,443	$87,890	($1,449)	$86,441
16	APH Hot End Basket Replacement	431,200	(13,506)	417,694	42,920	(1,344)	41,575
17	**Total Adjustments for Projects Started and Placed-in-Service During 2010**	$1,314,200	($28,063)	$1,286,137	$130,809	($2,793)	$128,016
18	**Total Plant-in-Service Adjustments for 2009 Test Year**	$19,306,160	($523,243)	$18,782,917	$1,914,490	($51,720)	$1,862,769

Note: The Schedule above is a summary of the adjustments calculated within Work Paper TY-01 found in Volume 4A, Tab - 2009 Test Year Work Papers.