STATE OF SOUTH DAKOTA
BEFORE THE
SOUTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. __________

In the Matter of Otter Tail Power Company's Petition for Approval of the Annual Rate Update to Rate Schedule, Section 13.05, Transmission Cost Recovery Rider

PETITION FOR ANNUAL UPDATE TO TRANSMISSION COST RECOVERY RIDER RATE

I. INTRODUCTION

In compliance with the South Dakota Public Service Commission's ("Commission's") November 30, 2011, ORDER GRANTING JOINT MOTION FOR APPROVAL OF STIPULATION in Docket No. El10-015 ("TCR Order"), Otter Tail Power Company ("OTP or Company") hereby Petitions for approval of its annual update to its Transmission Cost Recovery Rider ('TCR") rate. In this annual update filing, OTP's TCR rate has been adjusted to reflect the TCR revenue requirements for the next recovery period (calendar year 2013). The update includes the tracker balance estimated for the end of the current period so that no over- or under-recovery of TCR costs occurs and it includes the costs of new transmission projects that are not currently in base rates and have not previously been approved for inclusion in the Rider.

The proposed revenue to be collected is slightly less than for the current TCR, as shown in Attachment 24 ($594,953 compared to the current revenue requirement of $616,351, a decrease of $21,398). Because the last TCR rate proceeding took longer than expected, the current TCR rate is collecting 24 months of revenue requirements over a 13-month recovery period. This Petition updates the rate to collect 12 months of revenue requirements over a 12-month recovery period. The rates for this update are slightly higher even though the revenue requirement has declined due to a more-than-offsetting decrease in billing determinants.

The overall increase in rates is approximately 0.3% for both residential and large general service customers. The impact of the change in rates for a residential customer using 750 kWh per month is an increase of 20 cents per month. For a large general service customer using 486 kW and 222,350 kWh, the bill impact of this update is an increase of $36.62 per month.

II. GENERAL FILING INFORMATION

A. Name, address, and telephone number of the utility making the filing

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B. Name, address, and telephone number of the attorney for Otter Tail Power Company

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C. Title of utility employee responsible for filing

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D. The date of filing and the date changes will take effect

The date of this filing is September 1, 2012. OTP proposes the update to the rate to go into effect as of January 1, 2013.

E. Statute controlling schedule for processing the filing

ARSD Part 20:10:13:15 requires a 30-day notice to the Commission of a proposed change in a utility's tariff schedule, after which time the proposed changes take effect unless suspended. Because no determination of OTP's general revenue requirement is necessary, OTP requests an expedited and informal proceeding, including any variances that may be necessary.

Pursuant to ARSD 20:10:13:18, OTP will post a notice of proposed changes in each business office in OTP's affected electric service territory in South Dakota for at least 30 days before the change becomes effective. Pursuant to ARSD 20:10:13:19, OTP provides as Attachment 23 a proposed notice to be sent to customers with the first bill rendered when the rate is effective. OTP has also included Attachments 23 and 24 to comply with ARSD 20:10:13:26, which requires the Utility to report all rate schedule changes and customer impacts.

OTP is also providing notice to its customers pursuant to SDCL Chapter 49-34A-12. 3

III. TRANSMISSION COST RECOVERY

A. Background

In this Petition, OTP has provided an update of its tariff rate schedule, Section 13.05, in compliance with Paragraph 10 of the Settlement Stipulation approved by the Commission's TCR Order, referenced above, which requires the following:

> ***Annual Reporting:*** *The Parties agree OTP will submit an annual TCR filing on a going forward basis to be received by the PUC by September 1 of each year. Based on this annual report, OTP will adjust the TCR rate each year based on actual costs and collections.*

The Commission's TCR Order was made pursuant to SDCL §49-34A-25.1 and §49-34A-25.2. Annual updates to the approved tariff rate schedule are governed by SDCL §49-34A-25.3 and §49-34A-25.4, which read as follows:

> *§49-34A-25.3. Filing for annual rate adjustments—Contents. A public utility may file annual rate adjustments to be applied to customer bills paid under the tariff approved pursuant to §49-34A-25.2. In the utility's filing, the public utility shall provide:*
>
> *(1) A description of and context for the facilities included for recovery;*
>
> *(2) A schedule for implementation of applicable projects;*
>
> *(3) The public utility's costs for these projects;*
>
> *(4) A description of the public utility's efforts to ensure the lowest reasonable costs to ratepayers for the project; and*
>
> *(5) Calculations to establish that the rate adjustment is consistent with the terms of the tariff established in §49-34A-25.2.*
>
> *§49-34A-25.4. Standards for approval of annual rate adjustments. Upon receiving a filing under §49-34A-25.3 for a rate adjustment pursuant to the tariff established in §49-34A-25.2, the commission shall approve the annual rate adjustments if, after notice, hearing, and comment, the costs included for recovery through the tariff were or are expected to be prudently incurred and achieve transmission system improvements at the lowest reasonable cost to ratepayers.*

Consistent with these statutory requirements, the Commission Approved Settlement Stipulation requires as follows:

In the future, OTP's investment in new transmission projects will require Commission approval in a future TCR annual update filing through which Commission Staff shall be provided an opportunity to review such projects for statutory compliance. Such projects may be regional, like those described in this Settlement or they may be local (projects that do not qualify for regional cost allocation through MISO's FERC authorized rates). (Settlement Stipulation, page 4, paragraph 3).

In compliance with the above referenced statutes and the Approved Settlement Stipulation, this Petition provides information on OTP's calculations updating its TCR rate and each of the new projects so that Commission Staff may review the calculations and projects for statutory compliance.

B. TCR annual update revenue requirements calculations

Attachments 1 - 4 are, respectively, the Revenue, Revenue Requirements Summary, Rate Design, and Tracker Summary calculations used for OTP's proposed TCR rate update.

Attachments 5 – 16 provide the revenue requirement calculations for each of the transmission projects identified in this filing--both those previously included in OTP's TCR and the new projects for which OTP is requesting TCR recovery.

These calculations have been made in compliance with the Settlement Stipulation approved by the Commission's November 30, 2011 TCR Order and they are consistent with how OTP calculated its current TCR rate.

Specifically, the calculations include the following:

- *Rate base section.* This section provides details on the amount of plant in service, accumulated depreciation, construction work in progress (CWIP) (if applicable), accumulated deferred taxes, and includes a 13-month average rate base calculation.

- *CWIP.* SDCL §49-34A-25.2 allows a current return on CWIP.

- *Expense section.* The expenses applicable to a project are listed here and include operating costs, property taxes, depreciation, and, income taxes.

- *Revenue requirements section.* This section shows the components of the revenue requirements, including expenses and return on investment. A credit to the revenue requirement is included for monies received for use of the lines by wholesale customers. The calculation of the revenue credit adjustment is shown in the Attachments 19 and 20.

- *Return on investment (cost of capital).* Pursuant to paragraph 5 of the Approved Settlement Stipulation, OTP's revenue requirement for the retail load obligations of the transmission investment are to be based on the rate of return established in OTP's most recent general rate case (Commission Docket No. EL-10-011). The Approved Settlement Stipulation contemplates that this approved rate of return should be used until changes occur with respect to factors listed in that paragraph. Because no changes have occurred with respect to those factors, OTP's approved rate of return has been retained for this update.

- *Depreciation expense.* Depreciation expense has been calculated using the company's latest transmission composite depreciation rate.

- *Property taxes.* The property tax calculation is based on OTP's composite tax rate for the jurisdiction in which the transmission facilities are located, and is calculated in accordance with the procedures specified by that state.

- *O&M expense.* Annual operation and maintenance (O&M) expense of the transmission lines typically includes costs related to line patrol and inspections, vegetation management, small repair items, storm restoration, and supervision of this work. Scheduled transmission line patrols are typically done once every other year on single pole 115 kV lines. Unscheduled patrols are completed for line sections where an unexplained interruption has occurred. To reduce costs of patrol after an interruption, data from protective relays are used to limit the patrol area. Vegetation management of new lines is typically limited for the first five years since OTP's construction standard is to remove as many trees as possible and leave low growing brush. After five years, vegetation management is completed based on information gathered during line patrols. Other O&M costs are dependent on the severity of storms and resulting damage, tree growth, items found on line patrols, the cost of NERC reporting requirements, and supervision. OTP has set up transmission O&M accounting projects to track O&M costs specifically related to each line included in the Transmission Rider..

- *Schedule 26 and 26A expenses.* Schedule 26 and Schedule 26A costs for the recovery period appear on lines 16 and 21 of the Tracker Account (Attachment 4) and are shown separately in Attachment 18. These reflect OTP's retail share of the costs for projects that qualify for regional cost allocation through MISO's Tariff.

- *Schedule 26 and 26A revenues*. Schedule 26 and 26A revenues for the recovery period appear on lines 17 and 22 of the Tracker Account Summary (Attachment 4) and are shown separately on Attachments 19 (Schedule 26) and Attachment 20 (Schedule 26A). These reflect OTP's retail share of OTP's investments in projects that qualify for regional cost allocation through MISO's tariff.

- *Revenue credit for administrative and general expenses recovered through MISO tariff for non-retail portion of projects qualifying for regional cost allocation.* OTP has included in these TCR rate update calculations an additional revenue credit (reduction to TCR revenue requirements) to account for reimbursements through MISO's tariff for administrative and general O & M expenses. The revenue credit is for the entire amount of such revenues received through the MISO tariff, whether related to the retail or nonretail portion of projects that qualify for regional cost allocations. This application of revenues to reduce the retail revenue requirement provides reimbursement to retail customers for any such costs as may already be recovered through OTP's current retail rates. The revenue credit is reflected in Attachment 20 and Attachment 21 on the line titled "Overhead Credit for Non-Retail Share" for each project. For this period the percentage is 2.02 percent of the total investment in the projects. This percentage was established for these costs as part of the FERC-approved MISO tariff.

- *Revenue Credit for MISO Tariff Schedules 37 and 38.* Included in this TCR rate update calculation are two revenue credits to reflect revenues received from MISO pursuant to Schedules 37 and 38 of the MISO tariff. The Schedule 37 revenues represent OTP's allocation from MISO of contributions it required from American Transmission Systems Inc. (ASTI) for transmission investments of MISO Transmission Owners. ASTI withdrew from MISO on June 1, 2011, to integrate with PJM. The Schedule 38 revenues represent OTP's allocation of payments from Duke-Ohio ("DEO") and Duke-Kentucky ("DEK") that departed MISO on December 31, 2011, yet have an ongoing obligation to pay for MISO projects due to their prior MISO membership. The Schedule 37 revenue credit is forecast at $7,630 for 2013. The Schedule 38 revenue credit is forecast at $10,962 for 2013. Detailed descriptions of MISO schedules can be found at:

  https://www.midwestiso.org/Library/Tariff/Pages/Tariff.aspx

C. Projects Previously Approved for Recovery in OTP's TCR

The Fargo – Monticello and Bemidji-Boswell CAPX 2020 and the Rugby Wind Farm Interconnection projects were previously approved for inclusion in OTP's TCR The costs for these projects have been updated and carried out through 2013 and are reflected in Attachments 5 through 7.

D. New transmission projects included in the TCR rate update.

The costs and revenue requirements for the new projects are included in Attachments 8 through 16. Detailed descriptions of each of these projects are provided below:

Description of Project 1– Casselton – Buffalo 115 kV Project – Attachment 8

The Casselton – Buffalo 115 kV project was approved as a Baseline Reliability Project ("BRP") within Appendix A of the 2011 MISO Transmission Expansion Plan ("MTEP11") by the MISO Board of Directors in December of 2011 under project 3481 (facility numbers 6432, 6433, and 6434). The project involves the construction of 16 miles of 115 kV line and substation modifications at Buffalo. Transmission planning studies performed by OTP have identified this project as the preferred plan for serving the increased load in eastern North Dakota. MISO confirmed the results of the OTP studies through the MTEP11 process and designated this project as a Baseline Reliability Project with regional cost sharing. Along with the Casselton – Buffalo 115 kV line, other underlying upgrades required on the transmission system include replacement of the Buffalo 345/115/41.6 kV transformer and reconductoring a portion of the Mapleton-Sheyenne 115 kV line. These underlying upgrades have been included in the MISO approval for this project.

Cost recovery for this project will come from the MISO tariff for Baseline Reliability Projects. In conformance with the MISO tariff for regional cost allocation of projects under 345 kV, 100%

of this project was allocated based on the method of using Line Outage Distribution Factors ("LODF"). Through the MTEP11 process, the OTP pricing zone received 96.5% of the costs for this project. OTP load represents approximately 53% of the total load in the OTP pricing zone.

Total project capital costs are $12,754,169 with OTP ratepayers being allocated approximately 51% of the total costs.

South Dakota's jurisdictional share of OTP's total capital costs (by the end of construction in 2014) based on the D2 allocation factor of 9.815717% and a retail share of 51.02% is $638,726.

Description of Project 2 – Brookings, SD – Hampton, MN 345 kV Line – Attachment 9

As part of the 2011 MISO Transmission Expansion Plan ("MTEP11") approval, the MISO Board of Directors endorsed a portfolio of transmission projects across the MISO footprint called the Multi-Value Projects ("MVPs"). The MVPs have been identified and recommended to meet public policy requirements within the MISO states through 2026. The MVPs are "priority projects," which stem from the Regional Generator Outlet Study ("RGOS") in collaboration with the Upper Midwest Transmission Development Initiative ("UMTDI").

The MVP portfolio approved by the MISO Board of Directors includes 18 distinct transmission projects across MISO, with OTP being involved in three of these projects, namely: Brookings – Hampton 345 kV line, Big Stone – Ellendale 345 kV line, and Big Stone – Brookings 345 kV line.

OTP is planning to be a 4.1% owner of this project with an estimate total investment of $27,968,054 over the construction period, which runs through 2015.

South Dakota's jurisdictional share of OTP's total capital costs (by the end of construction in 2015) based on the D2 allocation factor of 9.81572% and a retail load share of 21.25% is $583,370.

Description of Project 3 – Big Stone South to Brookings – Attachment 10

Attachment 10 includes two projects. One project is the Big Stone South to Brookings and the other is the Big Stone South Substation which includes two 230 lines connecting Big Stone Plant to the new substation. Since the substation is closely related to the Big Stone South to Brookings project we included the costs in a single attachment.

The first project included in Attachment 10 is on where OTP is working closely with Xcel Energy ("XCEL") to develop the new 345 kV MVP transmission project that will be from Big Stone South to Brookings. This project is envisioned to be approximately 65 miles long and terminate at the existing Brookings County substation owned by Xcel Energy. OTP is planning to own 50% of the project. Major components of the project will involve the 345 kV line itself, as well as a new termination at the Big Stone South substation and the Brookings County substation. The schedule for this project is under development with the in-service date currently anticipated to be in 2017.

The Big Stone South – Brookings 345 kV project will help deliver low cost generation resources from western MISO to other parts of the MISO footprint. Therefore, this project is scheduled to be completed after the Brookings – Hampton 345 kV project. Forecasted costs for this project are as follows:

The second project included in Attachment 10 is as mentioned above, the new Big Stone 345 substation. Two 345 kV projects approved in the 2011 MISO Transmission Expansion Plan ("MTEP11") connect in the vicinity of Big Stone, South Dakota, namely Big Stone South – Ellendale 345 kV and Big Stone South – Brookings 345 kV. To facilitate the development of these two MVPs, it is necessary to develop a new 345 kV switchyard near Big Stone. After a review of the existing Big Stone 230/115 kV substation, it has become evident that physical limitations at the site will not allow for an adequate expansion for these future 345 kV terminations and transformers. Therefore, OTP is planning to build a new "Big Stone South" substation approximately 1.5 miles south of the existing Big Stone substation. The new Big Stone South substation and the existing Big Stone substation (i.e. "Big Stone Plant") are planning to be connected by two 230 kV lines to electrically connect the Big Stone Plant substation to the Big Stone South substation. The Big Stone South substation is planning to include two new 345/230 kV transformers and adequate space for the new 345 kV terminals into and out of the Big Stone area with room for future expansion. The existing Big Stone Plant substation will also require minor modifications to accommodate the additional 230 kV terminations for the new 230 kV lines down to the Big Stone South substation. The new 345 kV lines into and out of the Big Stone area (Ellendale and Brookings) will terminate at the new Big Stone South substation. This configuration was included within the models that were used by MISO in studying the MVPs during MTEP11.

The MVPs being developed in the Big Stone area include three distinct projects, which are Big Stone Plant – Big Stone South 230 kV; Big Stone South – Ellendale 345 kV; and Big Stone South – Brookings 345 kV. The Big Stone Plant – Big Stone South 230 kV portion of the project is viewed as the first critical development in the Big Stone area in order to develop the new 345 kV lines that emanate from Big Stone. OTP's total expected capital costs of the Big Stone Plant – Big Stone South 230 kV portion of the project are $49,138,876 by the end of construction in 2017. OTP's total expected capital costs of the Big Stone South to Brookings 345 kV portion of the project are $84,413,294 by the end of construction in 2017. OTP's total capital costs for the two related projects are $133,552,171 by the end of construction in 2017.

South Dakota's jurisdictional share of OTP's total capital costs (by the end of construction in 2017) based on the D2 allocation factor of 9.81572% and a retail load share of 1.70% is $222,855.

<u>Description of Project 4 – Big Stone South – Ellendale, ND 345 kV Line – Attachment 11</u>

OTP is working collaboratively with Montana-Dakota Utilities ("MDU") to develop one of the new 345 kV MVP transmission projects that will extend from Big Stone South to Ellendale. This project is in the early stages of development, but is envisioned to be approximately 150 miles long and terminate at an expanded Ellendale substation in south central North Dakota. OTP is planning to own 50% of the project. Major components of the project will involve a new substation expansion at Ellendale, performed and owned by MDU, the 345 kV line itself, as well as a new termination at the Big Stone South substation. The schedule for this project is under development with the in-service date currently anticipated to be in 2019. The Big Stone South – Ellendale 345 kV project is viewed as the westernmost segment of 345 kV lines being developed through the MVP portfolio. Therefore, this segment of line is scheduled to be completed after other major west-east transmission lines are completed to allow the efficient delivery of low cost generation resources from the western portion of the MISO footprint. OTP's total expected capital costs of the Big Stone South to Ellendale, ND 345 kV portion of the project are $150,486,418 by the end of construction in 2019.

South Dakota's jurisdictional share of OTP's total capital costs (by the end of construction in 2019) based on the D2 allocation factor of 9.81572% and a retail load share of 1.70% is $251,113.

The 2011 MISO Transmission Expansion Plan included details about this project by referencing the project under number 2220.

<u>Description of Project 5 – Ramsey 230/115 kV Transformer Upgrade - Attachment 12</u>

Interconnection studies performed by Minnkota Power Cooperative ("MPC") for the Langdon wind farm identified the need to upgrade the Ramsey 230/115 kV transformer near Devils Lake, North Dakota. The Ramsey 230/115 kV transformer is owned by Great River Energy ("GRE") and is currently rated at 84 MVA. To allow for an expedited interconnection of the Langdon Wind Farm in 2008, discussions between MPC, GRE, OTP, and the interconnection customers resulted in the installation of a Special Protection Scheme ("SPS") at the Ramsey substation to protect the Ramsey 230/115 kV transformer from overloading. This SPS consists of a relaying scheme that opens specific circuit breakers on the transmission system to eliminate excessive flows on the system, while still maintaining reliable service to customers.

GRE has informed OTP and the other the interconnection customers that GRE's guidelines for special protection schemes on its system allows for a five-year timeframe in which such a protection scheme may operate. Therefore, GRE is planning to retire the SPS that is currently in place to protect the Ramsey 230/115 kV transformer in 2013. As a result, OTP and the other interconnection customers will be required to upgrade the existing 230/115 kV transformer at Ramsey.

Detailed engineering studies are underway within GRE at this time to estimate the costs of replacing this existing 230/115 kV transformer with either a 140 MVA transformer or a 187 MVA transformer. OTP and the other Langdon Wind interconnection customers are obligated to pay for the transformer upgrade; however, if the final studies require a larger sized transformer (i.e. 187 MVA) there will be some additional load- serving benefits in the area. Therefore, a small increment of costs will be allocated to OTP and MPC, the utilities with load-serving obligations in the area, in proportion to their loads in the Devils Lake area. The transformer is expected to be ordered in 2012 and installed in 2013.

OTP's allocation of the expected capital costs for this upgrade based on the ownership percentage in the Langdon wind farm and the amount of OTP's load in the Devils Lake area is estimated to be $608,421 in total with a construction period running through 2013.

South Dakota's jurisdictional share of OTP's total capital costs (by the end of construction in 2013) based on the D2 allocation factor of 9.81572% is $59,721.

This project is currently within Appendix A of the 2012 MISO Transmission Expansion Plan ("MTEP") as project 2738, facility 4761. This project is expected to be approved by the MISO Board of Directors as an Appendix A project in December of 2012. This project is not eligible for MISO regional cost allocation since the upgrade is being triggered through MPC's Open Access Transmission Tariff ("OATT").

<u>Description of Project 6 – Sheyenne – Audubon 230 kV Line Upgrade – Attachment 13</u>

Interconnection studies performed by Minnkota Power Cooperative ("MPC") for the Luverne and Ashtabula wind farms have identified the need to upgrade the Sheyenne – Audubon 230 kV line. This transmission line is co-owned by Xcel Energy and OTP, with OTP owning approximately 96% of the line. Detailed engineering studies performed by OTP have identified that numerous structures along the existing

230 kV line will need to be modified in order to increase the line-to-ground clearance and thus, the capacity, of this line. In order to allow interconnection of the wind farms in an expedited manner, and to determine the status of other pending projects under development at the time of the interconnection studies, a temporary wind-adjusted rating methodology was implemented in mid-2009 to prevent this transmission line from overloading during real-time operating conditions. OTP's guidelines for wind-adjusted ratings allows for a five-year timeframe. The sunset date of the five-year timeframe for the wind-adjusted ratings of the Sheyenne – Audubon 230 kV line will expire in mid-2014. Due to the length of this line and the anticipated schedule to complete the necessary upgrades, investments for this 230 kV line upgrade are expected to begin in 2012 in order to meet a mid-2014 in-service date. This project is a result of the generation interconnection to the MPC transmission system and will be funded by OTP and the other interconnection customers.

OTP's allocation of the expected capital costs for this upgrade based on the ownership percentage in the wind farms interconnecting to the MPC system is estimated at $1,247,282 in total, with a construction period running through 2013.

South Dakota's jurisdictional share of OTP's total capital costs (by the end of construction in 2013) based on the D2 allocation factor of 9.81572% is $122,430.

This project currently resides within Appendix B of the MISO Transmission Expansion Plan ("MTEP") as project 3204, facility 5950. This project is expected to move into MTEP Appendix A during the 2013 MTEP planning cycle, which starts in September of 2012. This project is not eligible for MISO cost allocation since the upgrade is being triggered through the Open Access Transmission Tariff ("OATT") of MPC.

<u>Description of Project 7 – Karlstad, MN Capacitor Bank Project – Attachment 14</u>

Transmission planning studies performed by OTP and neighboring utilities have identified load serving concerns in the northern Red River Valley dating back to 2003, as illustrated by the 2003 Minnesota Biennial State Transmission Plan and later referenced with a tracking number of

2003-NW-N2. These load serving concerns were in part addressed by the CAPX Group 1 transmission projects currently under construction. However, information OTP has received about future load growth in northwest Minnesota has prompted additional studies. More recent transmission planning studies of this area reflecting possible load growth patterns have identified a long-term transmission plan for northwest Minnesota. The first phase of this transmission plan is to install two 10 MVAR capacitor banks on the 115 kV system at the Karlstad substation. This capacitor bank will help support voltages in northwest Minnesota for critical contingencies on the 115 kV system. This capacitor bank will need to be supplemented with a new Winger – Thief River Falls 230 kV line, which is envisioned to be the long-term transmission plan for this region. The capacitor banks project was originally targeted for installation in 2011, but was delayed after reviewing recent load patterns in northwest Minnesota. Recent operational studies have indicated the transmission system will need this voltage support prior to the winter of 2012/2013 based on historic loading patterns.

OTP's expected capital cost associated with this project is estimated to be $1,043,219, all of which will be incurred in 2012.

South Dakota's jurisdictional share of OTP's total capital costs based on the D2 allocation factor of 9.815717% is $102,400 (by the end of construction in 2012).

This project was approved by MISO as an Appendix A project during the 2010 MISO Transmission Expansion Plan ("MTEP10") as MTEP project 2826, facility 4956. This capacitor bank project was not regionally cost allocated through MISO's tariff due to it not meeting the $5 million cost threshold (a MISO tariff requirement for regional cost allocation). The investment will qualify towards investment credit in the MPC/OTP Integrated Transmission Agreement once it is in service.

<u>Description of Project 8 – Oakes Area Transmission Improvements – Attachment 15</u>

OTP has collaborated with Central Power Electric Cooperative ("CPEC") to develop the preferred transmission plan for serving the joint load in this area. The recommended plan involves the following key components:

- 230/41.6 kV Transformer
- 8 Miles of 41.6 kV Transmission Line
- 4 – 230 kV Circuit Breakers
- 4 – 41.6 kV Circuit Breakers
- 1 – 1800 KVAr Capacitor Bank

Load in this area has shown sustained growth over the past 10 years leading to the existing transmission system becoming insufficient during certain times of the year. In addition to improving the adequacy of the transmission system, this project will also add sectionalizing capability along the existing Ellendale – Hankinson 230 kV line and will help minimize momentary and sustained interruptions to the Oakes and Forman area customers. The Ellendale – Oakes – Forman – Hankinson 230 kV line is a portion of one of the few east-west 230 kV paths connecting low-cost generation resources from western North Dakota to Minnesota and

South Dakota. OTP's estimated capital costs for this project by the end of the construction period in 2013 are expected to be $5,998,219.

South Dakota's jurisdictional share of OTP's total capital costs (by the end of construction in 2013) based on the D2 allocation factor of 9.815717% is $588,770.

This project is expected to be approved as an Appendix A project by the MISO Board of Directors in December of 2012 through the MTEP12 efforts. The Oakes area transmission project is referenced in MTEP project 3658, facility numbers 6817, 6818, and 6819. This project is not eligible for regional cost-allocation through MISO's tariff due to the 230 kV portion of the project not meeting the $5 million threshold for regional allocation.

<u>Description of Project 9 – Hankinson Transformer Addition – Attachment 16</u>

OTP and Central Power Electric Cooperative ("CPEC") are working on a joint reliability project near Hankinson, North Dakota. This project involves the addition of a second 230/41.6 kV transformer, an expansion of the 230 kV and 41.6 kV buses at the Hankinson substation, and the replacement of a 230 kV circuit switcher with a 230 kV circuit breaker. This project is needed to enhance the reliability of the system by installing duplicate 230 kV deliveries to the 41.6 kV system and introducing new interrupting capabilities for 230 kV line faults. OTP's portion of this project involves the 230 kV ring bus, while CPEC is focused on the installation of the second 230/41.6 kV transformer and the 41.6 kV bus expansion. OTP's capital costs for the 230 kV portion of the substation are $877,358 with construction completed in 2012.

South Dakota's jurisdictional share of OTP's total capital costs (by the end of construction in 2012) based on the D2 allocation factor of 9.815717% is $86,120.

This project is expected to be approved as an Appendix A project by the MISO Board of Directors in December of 2012 through the MTEP12 efforts. The Hankinson transformer addition is referenced in MTEP project 3431, facility 6327. This project is not eligible for regional cost-allocation through MISO's tariff due to OTP's portion of the project not meeting the $5 million cost threshold, but this investment will qualify towards investment credit in the CPEC /OTP Integrated Transmission Agreement once it is in-service.

IV. RATE DESIGN

The TCR allocation factors and rate design follow the terms of the Approved Settlement Stipulation, paragraph 6. Specifically, the TCR uses a rate design based on the transmission demand allocation factor, D2 from OTP's most recent South Dakota general rate case (Docket No. El-10-011) to allocate total revenue requirements to jurisdictions (South Dakota, 9.815717%) and rate classes. The large general service (LGS) class's portion of retail revenue requirements based on this D2 is 33.96 percent. The remaining portion (66.04 percent) of the retail revenue requirements will be collected from the non-LGS rate classes.

OTP's current LGS rate design, as identified in the Approved Settlement Stipulation, incorporated the 2011 forecast demand ($/kW-month) and energy (¢/kWh) revenue components to recover the transmission project costs in a manner that follows existing LGS base rate design. For this update, OTP has similarly based the LGS rate design on the 2013 forecast demand and energy revenue components, specifically, 35 percent demand and 65 percent energy.

For the remaining retail rate classes (non-LGS), OTP proposes an energy rate only. A rate for each class is a separate energy based (kWh) change calculated as the revenue requirements divided by the kilowatt-hour sales for the projected period.

The rate design detail is included in Attachment 3.

V. RATE APPLICATION AND IMPACT

As earlier indicated, the proposed revenue to be collected is slightly less than for the current TCR rate, as shown in Attachment 24 ($594,953 compared to the current revenue requirement of $616,351, a decrease of $21,398). Because the last TCR rate proceeding took longer than expected, the current TCR rate is collecting 24 months of revenue requirements over a 13 month recovery period. This Petition updates the rate to collect 12 months of revenue requirements over a 12 month recovery period. The rates for this update are slightly higher even though the revenue requirement has declined due to a more-than-offsetting decrease in billing determinants. The sales forecast used for the rate currently in effect is approximately 10 percent higher than the actual sales over the period.

The impact of the change in rates for a residential customer using 750 kWh per month is an increase of 20 cents per month. For a large general service customer using 486 kW and 222,350 kWh, the bill impact of this update is an increase of $36.62 per month. The overall increase in rates is approximately a 0.3% increase for both residential and large general service customers.

The total 2013 revenue requirements, as shown on line 1 in Attachment 3, are $594,953. The proposed rates are then calculated on lines 2-16 of Attachment 3. The Transmission Rider is applicable to electric service under all of OTP's retail rate schedules. The charge is included, for administrative purposes, as part of the Energy and Renewable Adjustment line on customers' bills. The proposed rates are as follows:

TCR Rate Class	Rate
Large General Service	$0.184 kW
	0.075¢ kWh
Total LGS	
Controlled Service	0.030¢ kWh
Lighting	0.117¢ kWh
All other service	0.207¢ kWh

The rate impact is contained in Attachment 23.

The proposed rates are based on the assumption that they will be in effect beginning January 1, 2013 through December 31, 2013. Revenue requirement calculations are based on January 2013 through December 2013 costs. If the effective date is significantly later than January 1, 2013, OTP requests the option to recalculate the Transmission Cost Recovery Rates in order to recover all approved costs in the remainder of the suggested time period.

VI. TRANSMISSION COST RECOVERY RIDER RATE SCHEDULE

OTP's redline and clean Transmission Cost Recovery Rider (Rate Designation 13.05) is Attachment 22 to this Application.

VII. FILING FEE

Under SDCC § 49-1A-8, the commission may require a deposit of up to fifty thousand dollars for the filing of a tariff for approval under the provisions of §49-34A-4 and §49-34A-25.1 to §49-34A-25.4, inclusive, or makes a filing pursuant to §49-34A-97 to §49-34A-100. OTP will pay such deposit amount as the Commission determines appropriate upon the Commission's Order assessing such fee.

[Remainder of page intentionally left blank.]

VIII. CONCLUSION

For the foregoing reasons, OTP respectfully requests approval to implement the Transmission Cost Recovery Rider, Rate Designation 13.05, effective as of January 1, 2013.

Date: September 1, 2012

Respectfully submitted:

OTTER TAIL POWER COMPANY

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