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") 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 the annual update to OTP's Transmission Cost Recovery Rider ('TCR") rate. In this filing, OTP's TCR rate has been adjusted to reflect the TCR revenue requirements for the next recovery period (calendar year 2014). The update includes the tracker balance estimated for the end of the current recovery period so that no over- or under-recovery of TCR costs occurs. The update also includes the costs of one new transmission project that is not currently in base rates and has not previously been approved for inclusion in the Rider.

The calculation of the proposed revenue requirements within this Petition have been determined in accordance with the Settlement Stipulation approved by the Commission in the last Annual Update Docket No. EL12-054 ("12-054"). In the 12-054 Settlement Stipulation, projects that qualify for regional cost allocation through MISO's tariff are accounted for using what the Parties referred to as the "refined split" method. Projects included in this update are only projects which are currently in service or expect to be placed in service by the end of the proposed 2014 recovery period. The rate of return (ROR) included in this Update is based on the ROR approved by the Commission in Docket No. EL12-054.

The proposed revenue to be collected in 2014 is higher than for the current TCR, as shown in Attachment 17 ($902,536 for all of 2014 compared to the total revenue requirement of $433,418 for the May 1, 2013 to December 31, 2013 timeframe, an increase of $469,118).

Current rates that went into effect May 1, 2013, were designed to collect the <u>net remaining</u> revenue requirements for 2013, over an 8 month collection period (May 2013 to December 2013). The <u>total</u> 2013 revenue requirement was $828,235. This amount was reduced by a 2012 true-up amount ($188,757 over-collection), a carrying charge credit ($6,104) and collections received from January to April 2013 ($199,955) under the rates in place prior to May 1, 2013. After these adjustments, the net revenue requirement to be collected from May 1 to December 31, 2013 was $433,418. ($828,235 – $188,757 – $6,104 – $199,955 = $433,418).

This Petition updates the rates to collect 12 months of revenue requirements ($902,536) over a 12- month recovery period. The rates for this update are higher, driven in part by higher revenue requirements from increasing MISO Schedule 26 and 26A expenses as well as full year revenue requirements of one project scheduled to go in service in late 2013,

The overall increase in rates is approximately 0.8% 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 49 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 $91.04 per month.

II. GENERAL FILING INFORMATION

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

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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 August 30, 2013. OTP proposes the update to the rate to go into effect as of January 1, 2014.

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 16 and 17 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).* (TCR Order 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 – 10 provide the revenue requirement calculations for each of the transmission projects identified in this filing--both those previously included in OTP's TCR and any 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, as modified by the Settlement Stipulation approved by the Commission's Order in 12-054, 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. (No CWIP projects are currently included in the TCR).

- *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 transmission revenue credit adjustment % is shown in Attachment 11.

- *Return on investment (cost of capital).* Pursuant to Section III, 3. Rate of Return, found in the Approved 12-054 Settlement Stipulation, OTP's revenue requirement for the retail load obligations of the transmission investment are to be based on the rate of return stated in the 12-054 Settlement Stipulation.

- *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 12. As stated in the 12-054 Settlement Stipulation, Section III, 4.b., "*the TCR will flow through the jurisdictional share of Schedule 26 and Schedule 26A expenses incurred by OTP as an active member of MISO, adjusted for the amount of such expenses associated with OTP's investment in projects that are not included in the rider.*"

- *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 Attachment 13 (Schedule 26). As stated in the 12-054 Settlement

Stipulation, Section III,2.c, *"Retail customers will be credited a pro-rata share of FERC-authorized MISO Schedule 26 revenues associated with the Company's MISO-determined responsibility for OTP's investment in the regional transmission projects, offsetting corresponding Schedule 26 expenses. The Company will retain the portion of its Schedule 26 revenues associated with other MISO members' responsibility for OTP's investment in the projects in order to cover the remaining revenue requirements for such projects."*

No MISO Multi-Value Projects ("MVP Projects") have been completed or placed into service and therefore are not included in the TCR for this recovery period. Since Schedule 26A revenues are attributable to investment in MVP projects, 26A revenues are excluded from the TCR as well.

- *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 13 on the line titled "Overhead Credit for Non-Retail Share" for each project. For the 2014 recovery period, the percentage is 1.61 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 the schedule 26 cost allocation assigned to 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. Note that in Attachment 14, there are no forecast amounts for Schedule 37 or 38 revenues. MISO does not provide a separate forecast for those revenues, but includes any Schedule 37 and 38 revenues within the Schedule 26 revenue forecasts MISO develops. MISO does delineate Schedule 37 and 38 revenues when reporting actuals.

  The Schedule 37 revenue credit reflected in this TCR update is $7,630. The Schedule 38 revenue credit reflected in this TCR update is $10,962. These are actual amounts through July 2013 and included as part of the 2013 true-up amount. Detailed descriptions of MISO schedules can be found at:

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

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

The following projects were previously approved for inclusion in OTP's TCR in either Docket Nos. El10-015 or El12-054.

1. CapX2020 Fargo – Twin Cities Phase 1
2. CapX2020 Bemidji – Grand Rapids
3. Cass Lake - Bemidji (Part of CapX2020 Bemidji–Grand Rapids)
4. Rugby Wind Interconnection
5. Casselton – Buffalo 115 kV

The actual and forecast costs for these projects have been updated and carried out through 2014 and are reflected in Attachments 5 through 10. Part of the Casselton-Buffalo 115 kV project includes rebuilding an 8-mile portion of the Mapleton-Sheyenne 115 kV line, as discussed in the 12-054 update. That phase of the Casselton-Buffalo115 kV project will be completed and placed into service during the recovery period proposed within this update.

D. One new transmission project included in the TCR rate update.

Portions of one new project are included in this TCR update. The costs and revenue requirements for the new project are included in Attachment 10. A detailed description of this project is provided below:

<u>Description of Project 1 – Oakes Area Transmission Improvements – Attachment 10</u>

OTP has collaborated with Central Power Electric Cooperative ("CPEC") to develop the preferred transmission plan for serving the joint load in an area around Oakes, North Dakota. The recommended plan involves the following key components, which will be constructed in phases:

- 230/41.6 kV Transformer
- 9 Miles of 41.6 kV Transmission Line
- 4 – 230 kV Circuit Breakers
- 4 – 41.6 kV Circuit Breakers

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. Also, 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 project has been split into phases and will be completed and placed in service during different timeframes. During 2013, a second 230/41.6 kV transformer will be moved to the substation to be available as a spare in the event that the existing 230/41.6 kV transformer fails. A new 9-mile 41.6 kV transmission line will be built in 2014 from the expanded substation to add an alternative transmission path to reliably handle transmission outages of the existing transmission path. This portion of the project is scheduled to be placed in service December 2014. Finally, substation work will be completed during 2015 to add the new 230 kV and 41.6 kV breakers and energize the second 230/41.6 kV transformer permanently.

Phase	**Description**	**Completion Date**	**Cost**
2013/2014	Substation Site work and construction of 9-miles of 41.6 kV line	2014	$3,384,000
2015	Add 230 kV and 41.6 kV breakers and finish substation work	2015	$2,349,000
		TOTAL	**$5,933,000**

OTP’s estimated capital costs for this project by the end of the construction period in 2015 are expected to be approximately $5,933,000. 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 9.815717% is approximately $582,000.

This project was approved as an Appendix A project by the MISO Board of Directors in December of 2012 through the MTEP12 planning cycle. The Oakes area transmission project is referenced in MTEP project 3658, facility numbers 6817, 6818, and 6819. This project was 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.

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 2014 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 only rate, consistent with the current rate structure. A rate for each class is a separate energy based (kWh) charge calculated by dividing the total class revenue requirements by the corresponding 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 for 2014 is higher than the revenue being collected under the current TCR rate, as shown in Attachment 17 ($433,418 compared to the proposed revenue requirement of $902,654, an increase of $469,236). The magnitude of the increase is due in large part to the shortened collection period of the current 2013 net revenue requirement (May 1, 2013 to December 31, 2013), compared to the proposed 12 month collection period for the 2014 revenue requirement. The following table which compares the summaries from pages 1 and 2 of Attachment 4, help to illustrate the factors which contributed to the difference between the 2013 revenue requirement and the 2014 revenue requirement.

Attachment 4 Summaries

Line No.	Component:	Jan 2013 - Dec 2013 (1) (8 Month Collection Period) Page 1 of Attachment 4	Jan 2014- Dec 2014 (2) (12 Month Collection Period) Page 2 of Attachment 4
1	Revenue requirements	$828,235	$957,799
2	Carrying Charge	(6,104)	(3,753)
3	Prior Collection Period True-Up	(188,757)	(51,511)
4	Total requirements	$633,373	$902,536
5	Revenue Collected (Jan 2013-Apr 2013)	(199,955)	0
6	**Net Revenue Requirement**	**$433,418**	**$902,536**
7			
8	Sales in MWh (For corresponding collection period)	244,446	403,313
9	Average Rate	$0.00177	$0.00224

1) Settlement Agreement Approved April 23, 2013; Rates effective May 1, 2013 - December 31, 2013
2) Proposed for 2014

Line 1 in the table above reflects the corresponding 12 month revenue requirements for 2013 ($828,235) and 2014 ($957,799) as calculated for each year. Carrying charge credits and prior period true-up amounts are reflected on lines 2 and 3, yielding the total revenue requirement for the collection period after these adjustments. Because new rates did not go into effect until May 1, 2013, revenues collected from January to April 2013 were credited against the 2013 revenue requirement, as reflected in line 5 above. The net revenue requirement remaining for collection during the May to December 2013 is reflected on line 6 ($433,418). Current rates were designed and calculated to collect this revenue requirement from May to December 2013.

This Petition updates the rates to collect the 2014 revenue requirement of $902,536 (as shown on line 4 of the second column in the table above), over a 12 month recovery period (Jan 2014 to December 2014). Schedule 26 and 26A expenses are projected to increase in 2014 as investment in transmission projects continues to grow. In addition, the Casselton-Buffalo 115 kV project which was approved in the last TCR update, and scheduled to go in service in late 2013, will have a full year of revenue requirements factored into the 2014 recovery period.

The impact of the change in rates for a residential customer using 750 kWh per month is an increase of 49 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 $91.83 per month. The overall increase in rates is approximately a 0.8% increase for both residential and large general service customers.

The total 2014 revenue requirements, as shown on line 1 in Attachment 3, are $902,536. 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 beginning January 1, 2014 are as follows:

TCR Rate Class		Rate	
Large General Service	$	0.272	/kW
		0.108	¢/kWh
Controlled Service		0.045	¢/kWh
Lighting		0.178	¢/kWh
All Other Service		0.315	¢/kWh

The rate impact is contained in Attachment 16.

The proposed rates are based on the assumption that they will be in effect beginning January 1, 2014 through December 31, 2014. Revenue requirement calculations are based on January 2014 through December 2014 costs. If the effective date is significantly later than January 1, 2014, 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 TARIFF SHEET

OTP's redline and clean Transmission Cost Recovery Rider tariff sheet (Section 13.05) is Attachment 15 to this Application. The rates listed in the RATE section of the tariff sheet have been updated to reflect the changes described in this annual update. In addition during the process of assembling this filing, OTP discovered an administrative error in that the rate schedules listed in paragraph (a) in the RATE section of the tariff sheet did not reflect the correct rate schedules for the large general service class. This paragraph has been updated to reflect the correct large general service rates. Customer bills have not been affected by this administrative error.

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.

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VIII. CONCLUSION

For the foregoing reasons, OTP respectfully requests approval to implement the Transmission Cost Recovery Rider, Section 13.05, effective as of January 1, 2014.

Date: August 30, 2013

Respectfully submitted:

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