STAFF MEMORANDUM

TO: COMMISSIONERS AND ADVISORS

FROM: BRITTANY MEHLHAFF AND KRISTEN EDWARDS

RE: EL12-054 - In the Matter of the Petition of Otter Tail Power Company for Approval of its 2013 Transmission Cost Recovery Eligibility and Rate Adjustment

DATE: April 17, 2013

Commission Staff (Staff) submits this Memorandum in support of the Settlement Stipulation of April 17, 2013, between Staff and Otter Tail Power Company (OTP or Company) in the above-captioned matter.

BACKGROUND

On September 4, 2012, the Commission received a petition from OTP requesting approval of its annual update to its Transmission Cost Recovery Rider (TCR) rate. The proposed revised TCR rate reflects the TCR revenue requirements for the year 2013, including the tracker balance estimated for the end of the current period and costs of new transmission projects that are not currently in base rates and have not previously been approved for inclusion in the TCR rider.

South Dakota Codified Laws Chapter 49-34A, Sections 25.1 through 25.4 authorize the Commission to approve a tariff mechanism for the automatic annual adjustment of charges for the jurisdictional costs of new or modified transmission facilities with a design capacity of thirty-four and one-half kilovolts or more and which are more than five miles in length.

In Docket EL10-015, the Commission approved the establishment of the TCR rider to recover the costs associated with three transmission projects, the CAPX2020 Fargo, CAPX2020 Bemidji, and Rugby Wind Farm Interconnection projects, and MISO Schedule 26 expenses. The Commission approved the Settlement Stipulation supporting the "hybrid" or "split method" approach for allocating MISO approved cost-shared projects with company investment.

The initial TCR rider implemented the following rates for each customer class effective December 1, 2011:

Class	¢/kWh	$/kW
Large General Service	0.083	0.072
Controlled Service	0.020	N/A
Lighting	0.108	N/A
All Other Service	0.180	N/A

In this filing, OTP requests to recover a projected 2013 revenue requirement of $594,953 associated with nine transmission projects and MISO Schedule 26[1] expenses. The request includes the Company's proposal to return to customers an estimated $19,997 in over-collection of the remaining balance in 2012. The Company proposed 2013 revenue requirement results in the following rates for the respective customer classes, calculated based on a January 1, 2013 effective date:

Class	¢/kWh	$/kW
Large General Service	0.075	0.184
Controlled Service	0.030	N/A
Lighting	0.117	N/A
All Other Service	0.207	N/A

STAFF'S ANALYSIS AND SETTLEMENT RESOLUTIONS

Staff's recommendation is based on analysis of OTP's filing, discovery information, relevant statutes, and previous Commission orders. Staff reviewed the tracker report and the forecasted 2013 revenue requirement associated with new transmission projects.

Staff and OTP (jointly the Parties) positions were discussed thoroughly at settlement conferences. As a result, some party positions were modified and others were accepted where consensus was found. Ultimately, the Parties agreed on a comprehensive resolution of all issues.

The Parties agree the over-collection of the remaining balance as of December 31, 2012 is $188,757. The 2013 TCR rate rider is based on estimated costs of eligible transmission projects subject to later "true-up" to actual costs and actual recoveries. Attachment 13 attached to the Settlement Stipulation is designed to implement the 2013 TCR rider on May 1, 2013.

TRACKER REPORT

Attachment 4 attached to the Settlement Stipulation summarizes the tracker activity by month. Individual project detail for the three initial projects approved for recovery in EL10-015, Fargo, Bemidji, and Rugby, is found on Attachments 5 through 8. Note the Bemidji project is separated into two parts: CAPX 2020 Bemidji and Cass Lake – Bemidji.

Staff reviewed the costs to determine if the costs were prudent and at the lowest reasonable cost to ratepayers. The changes discussed below are changes from the Company's originally filed position.

2012 Transmission Projects

The Company included new projects in the 2012 revenue requirement calculation that were not approved for 2012 recovery in Docket EL10-015. Since these projects were not approved by the Commission for 2012 recovery, the Settlement removes the 2012 revenue requirements associated with projects not previously approved as a result of Docket EL10-015. Only the revenue requirements

[1] All references to Schedule 26 include both Schedule 26 and Schedule 26A. Schedule 26A relates specifically to MVP projects.

associated with the Fargo, Bemidji, and Rugby projects are included in the 2012 revenue requirement calculation.

Updated Tracker Activity

The filed 2012 TCR tracker report contained actual tracker activity from January 2011 through July 2012 and projected activity for August 2012 through December 2012. OTP provided Staff with an updated report of actual costs and revenues through December 2012. The Settlement reflects these updates.

After incorporating the above changes into the revenue requirement calculation, the over-collection of the remaining balance as of December 31, 2012 is $188,757.

2013 TCR RIDER PROJECTS AND METHODOLOGY

The Settlement 2013 TCR rates are based on the 2012 over-collection in the tracker account and the estimated 2013 revenue requirements associated with the following transmission projects: CAPX2020 Fargo Phase I, CAPX2020 Bemidji (including Cass Lake – Bemidji), and Casselton – Buffalo, and MISO Schedule 26 expenses. Descriptions of each project are found in OTP's filed petition. Changes from the Company's originally filed position are discussed below.

SDCL 49-34A Section 25.1 allows utilities to include costs associated with transmission facilities in the TCR rider with a design capacity 34.5 kV or more and which are more than five miles in length. Staff had concerns about the application of SDCL 49-34A Section 25.1 to stand-alone upgrades to associated facilities (such as substations and transformers) without an associated line upgrade or new line due to the "more than five miles in length" requirement. For settlement purposes the Company offered to withdraw the projects that may not qualify for inclusion due to the requirements set forth in SDCL 49-34A Section 25.1. Therefore, the Settlement reflects exclusion of the costs associated with the Ramsey Transformer Upgrade, Karlstad Capacitor Bank, and the Hankinson Transformer Addition.

During settlement negotiations, the Company offered to only collect 2013 revenue requirements associated with projects that have been completed and placed in-service during or prior to 2013. Therefore, the Settlement excludes the 2013 revenue requirements[2] associated with the Fargo Phase II, Fargo Phase III, Brookings-Hampton, Big Stone South-Brookings, Big Stone South-Ellendale, Sheyenne-Audubon, and Oakes Area Improvements projects as these projects are not expected to be placed in-service during 2013. The 2013 TCR rider is based on estimated costs of in-service projects, subject to later true-up to actual costs and in-service dates.

The TCR legislation requires consideration of whether the projects have and are expected to achieve transmission system improvements at the lowest reasonable cost to ratepayers. The Company evaluated several alternatives for the transmission project plans to ensure the options chosen were economical.

[2] All CWIP, Schedule 26 expenses, and Schedule 26 revenues related to OTP projects under construction are excluded.

The Commission approved the Settlement Stipulation entered into between OTP and Staff in Docket EL10-015. In processing EL10-015, Staff and the Company discussed three different types of transmission projects, each with separate treatments under the TCR rider. Specifically, the project types were:

(1) New or modified projects, ineligible for cost-sharing through the Midwest Independent Transmission System Operator (MISO) tariff;
(2) MISO Transmission Expansion Plan (MTEP)-approved cost-shared projects without company investment; and
(3) MTEP-approved cost-shared projects with company investment.

The projects included for 2013 recovery in OTP's current filing can also be allocated into these 3 project types, as detailed below.

Type (1) Projects

Projects in this category are ineligible for cost-sharing through MISO. The Settlement does not include any type (1) projects for 2013 recovery.

Type (2) Projects

Expenses incurred by a utility as a result of MISO's cost allocation methods are considered by Staff to be a cost of MISO membership. As was approved in Docket EL10-015, OTP's Schedule 26 expenses continue to be recovered through the TCR rider.

Type (3) Projects

The TCR rider recovery methodology for projects eligible for MISO cost-sharing was also discussed in Docket EL10-015. Staff and OTP explored three proposed recovery methods for these projects and the Commission approved the Settlement Stipulation supporting the "hybrid" or "split method" approach. In the approved approach, only the portion of the MISO cost-shared project investment that SD ratepayers are responsible for, as determined by MISO, was included in the TCR rider rate base. Ratepayers also received the benefit of Schedule 26 revenues associated with the retail load portion of the transmission investment. The Schedule 26 revenues offset the Schedule 26 expenses associated with the project, leaving ratepayers paying for the retail load responsibility of the project at the South Dakota rate of return. Please refer to the Staff Memorandum filed in Docket EL10-015 for a complete description of the methods considered.

In Docket EL12-035, the Commission approved the Settlement Stipulation between Staff and Northern States Power Company dba Xcel Energy incorporating a modification to the "split method", referred to as the "refined split method". Staff and OTP agree the "refined split method" is also appropriate for OTP's TCR rider. The Settlement incorporates the "refined split method" for all cost-shared projects beginning in 2013. The original "split method" approved by the Commission in Docket EL10-015 continues to be applied to the projects included in the 2011-2012 revenue requirement calculation. The "refined split method" is used for the following cost-shared projects in 2013: CAPX2020 Fargo Phase I, CAPX2020 Bemidji (including Cass Lake – Bemidji), Rugby Wind Interconnection, and Casselton – Buffalo.

The Fargo, Bemidji, and Casselton-Buffalo projects all qualify for regional cost allocation as Baseline Reliability Projects[3] (BRPs) and the Rugby Wind Interconnection project is a Generation Interconnection Project[4] (GIP).

The "split method," as originally contemplated in EL10-015, was designed to address a situation where the utility's investment in a project exceeds its retail load responsibility as determined by MISO. All of OTP's current MISO cost-shared projects fall under this scenario. "Retail load responsibility" is a determination made by MISO regarding the utility's use of the project to serve its own retail customer needs. When implemented, the "split method" included the Company's retail load responsibility for the project in the TCR rate base. The portion of the utility's investment above rate payer retail use responsibility was recovered through the excess Schedule 26 revenues not credited to ratepayers.

While OTP's investment currently exceeds its retail load responsibility for all of its projects, the case is not so for Xcel Energy, which created a new scenario not considered prior to Docket EL12-035. Specifically, Xcel's investment in Fargo and Bemidji is less than its MISO determined responsibility. This factual situation was not addressed in EL10-015 as the scenario did not exist for OTP. The new factual situation presented in EL12-035 caused Staff to reexamine the "split method".

For this new type of project in which a company's investment is less than its MISO responsibility, use of the "split method" could require the inclusion of the company's total project responsibility in rate base. That amount, in these circumstances, is more than the company invested. Staff does not believe the "split method" intended rate base to include more than the company's investment and thus examined how the "split method" applies to projects in which a company's investment is less than its responsibility.

A company's responsibility for project cost can be separated into (i) responsibility for its own investment in the project and (ii) responsibility for other MISO members' investment in the project. Under the original "split method" the company includes its responsibility for others' investment in the TCR rate base and thus earns the South Dakota return on this portion of the investment. However, the company is charged Schedule 26 expenses at the FERC return through MISO for this responsibility in others' investment. The original "split method" only allows the company to earn the South Dakota return, not the FERC return on these charges. It is important to remember, these Schedule 26 charges do not represent company investment. Rather, the charges allocated to the company due to its responsibility level in MISO are simply a cost of membership in MISO. These charges are no different than the Schedule 26 charges the company must pay for projects when the company has no investment level.

Staff argues the state rate making approach cannot decrease the return a company is allowed on charges from other MISO members. Staff argues, the Commission should not deny the utility its right to recover that federally allowed return. Therefore, the settlement in Docket EL12-035 introduced a more sophisticated version of the "split method" to be used for all cost-shared projects in which only the

[3] Projects qualifying as BRPs are required for regional reliability purposes.
[4] Projects qualifying as GIPs are identified through an interconnection study to be eligible for sharing.

company's responsibility for its own investment in the project is included in the TCR rate base. Staff has termed this method the "refined split method".

A major factor in Staff's previous recommendation of the "split method" centers on a legal jurisdictional issue. The distinction remains not only important, but is a focus for staff in its recommendation of the "refined split method." Staff believes it is responsible to not only advocate for the most reasonable and economic rates, but also to advocate for the most legally correct solution. The "refined split method" is legally correct as it respects the limits of state regulation recognizing the jurisdiction of the Federal Energy Regulatory Commission (FERC). FERC, an independent federal agency, regulates interstate transmission and wholesale sales of electricity. FERC action is reviewable by the Federal Courts. As a member of MISO, OTP is subject to the MISO tariff process. MISO tariffs are filed according to and in compliance with FERC Orders and Federal Code. It is improper for a state agency to disallow a rate approved by a federal agency through a federal tariff process. Schedule 26 charges and the federal return allowed OTP for participation in MISO are approved through the FERC tariff process.

Congress has the power to preempt or supersede state laws that interfere with, conflict with, or are contrary to federal law. *Hillsborough County v. Automated Medical Laboratories, Inc.,* 471 U.S. 707, 712 (1985). A "state law is pre-empted where it regulates conduct in a field that Congress intended the Federal Government to occupy exclusively." *English v. General Electric* Co., 496 U.S. 72, 79 (1990). A court may infer this intent "where the pervasiveness of the federal regulation precludes supplementation by the States, where the federal interest in the field is sufficiently dominant, or where the object sought to be obtained by the federal law and the character of the obligations imposed by it... reveal the same purpose." *Schneidewind V. ANR Pipeline* Co., 485 U.S. 293, 300 (1988) (quoting *Rice v. Santa Fe Elevator* Corp., 331 U.S. 218, 230 (1947)).

In this case we are not debating federal regulation versus state statute. However, federal regulations have the same "preemptive effect" as federal statutes if promulgated pursuant to the discretion and within the authority given by Congress. *Capital Cities Cable, Inc. v. Crisp,* 467 U.S. 691, 699 (1984). Federal regulations also are "indicative" of what powers Congress intended for an agency to exercise and of the parameters of the occupied regulatory field. *Schneidewind v. ANR Pipeline* Co., 485 U.S. at 309 n. 12. Congress intended to give FERC exclusive authority regarding interstate transmission and wholesale charges. Schedule 26 is a wholesale charge outside the jurisdiction or review of this Commission. As a result Staff's recommendation makes it possible for OTP to both comply with and enjoy the benefit of the federal tariff while remaining consistent with South Dakota rate making principles.

The "refined split method" allows all cost-shared projects to be treated equally and eliminates Staff's concerns about the application of the "split method" to projects in which a company's investment is less than its responsibility. Staff offers the following detailed explanation of the "refined split method" to clearly identify all aspects of this new level of sophistication.

As discussed above, to fully honor the federal/state jurisdictional divide, the "refined split method" only places into the TCR rate base the Company's MISO determined retail responsibility for its own investment. OTP is also responsible for a portion of the line invested in by others and is charged Schedule 26 expenses through the MISO tariff for this responsibility. These Schedule 26 charges flow through the TCR as an expense. Thus, rate payers are responsible for OTP's entire financial responsibility. The Company's financial responsibility is partially paid for through rate base at the South Dakota return and partially through expenses at the FERC return. Other members of MISO are financially responsible for the remaining portion of the line invested in by OTP. These MISO members are charged Schedule 26 expenses, through the MISO tariff, for this responsibility and OTP receives this amount as revenues from MISO. In sum, OTP is charged Schedule 26 expenses relating to its total financial responsibility, including OTP's responsibility for its own investment and OTP's responsibility for the portion of the line invested in by others. OTP receives revenues relating to its total investment in the projects, including OTP's responsibility for its own investment and others' responsibility for OTP's investment. In the "refined split method" the total Schedule 26 charges flow through to ratepayers as an expense and the total revenue is adjusted to remove the revenues the Company receives from others, leaving a revenue credit to ratepayers relating to OTP's responsibility for its own investment. Since rate base only includes the costs associated with the Company's responsibility for its own investment, ratepayers do not receive a credit for the revenues the Company receives from others. The Company uses this revenue to pay for the portion of its investment for which other members of MISO are responsible.

MISO SCHEDULE 37 AND SCHEDULE 38 REVENUES

OTP included revenue credits to reflect revenues received from MISO pursuant to Schedules 37 and 38 of the MISO tariff. Companies subject to Schedule 37 and Schedule 38 who have departed MISO have an obligation to pay for MISO projects identified under these schedules for the life of the projects. OTP receives Schedule 37 and Schedule 38 revenues pursuant to the MISO tariff for its allocation from MISO of contributions required of the departing companies. MISO does not prepare a forecast for Schedule 37 and Schedule 38 revenues because they are embedded in the Schedule 26 forecast. Therefore, in the TCR rider, for months in which the MISO revenues are projected, no Schedule 37 and Schedule 38 revenues are shown as it is included under Schedule 26 revenues. Once the actual revenues are known, the revenue credits will be appropriately denoted under Schedule 26, Schedule 37, and Schedule 38 revenues.

OVERHEAD REVENUE CREDIT

The Company proposed to include an additional revenue credit to account for reimbursements through MISO's tariff for administrative and general O&M expenses. The revenue credit provides reimbursement to customers for any such costs that may already be recovered through OTP's retail rates. The Settlement reflects the revenue credits.

2013 RATE OF RETURN

For 2013, the Company proposed to continue to reflect the overall rate of return approved in OTP's last rate case, Docket EL10-011. The overall rate of return approved as a result of a settlement in that docket was 8.50%, incorporating a **Begin Confidential** [redacted] **End Confidential** ROE. Staff believed a current evaluation of OTP's capital structure, debt costs, and equity costs was necessary. The Settlement reflects the use of the actual capital structure and debt costs at the end of the preceding calendar year, December 31, 2012. **Begin Confidential** [redacted] **End Confidential**. This results in an overall rate of return of 7.58% for 2013.

FILING FEE

The Parties agree the filing fee is an eligible expense for inclusion in the TCR rider and the Settlement accepts this adjustment. The actual amount billed to the Company will be reflected in the next true-up filing.

CARRYING CHARGE

The Settlement continues to apply a carrying charge to the monthly over-or-under recoveries based on the overall rate of return implemented for each year.

RATE DESIGN

As proposed by OTP, the Settlement continues to incorporate the rate design approved in Docket EL10-015. The revenue requirement is allocated to customer classes based on the transmission demand allocation factor, D2, from OTP's most recent rate case, Docket EL10-011. The large general service class rate design incorporates both a demand charge and an energy charge while the remaining retail rate classes have an energy rate only.

EFFECTIVE DATE

The 2013 TCR rate is designed to be implemented effective May 1, 2013, based on forecasted sales from May through December 2013 and reflecting estimated revenues received through April of 2013 under the current TCR rates.

The net effect of the changes outlined in this memo is an estimated 2013 South Dakota revenue requirement of $433,418 associated with transmission investments, including the true-up of the 2012 over-collection of $188,757. The revised 2013 TCR rates for the respective customer classes to be effective May 1, 2013 are:

Class	¢/kWh	$/kW
Large General Service	0.082	0.202
Controlled Service	0.049	N/A
Lighting	0.134	N/A
All Other Service	0.250	N/A

OTHER ISSUES

<u>Reasonableness of Overall Earnings from Regulated Rates</u>

The Company agrees to file, by June 1 of each year, an annual report with the Commission detailing its South Dakota jurisdictional earnings for the preceding calendar year. Staff believes the report is necessary to monitor the Company's earnings and the potential effect of adding the TCR rider to its South Dakota tariff.

RECOMMENDATION

Staff recommends the Commission approve the Settlement Stipulation for the reasons stated above.