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December 21, 2010

Ms. Patricia Van Gerpen  
Executive Director  
South Dakota Public Utilities Commission  
Capitol Building, 1st floor  
500 East Capitol Avenue  
Pierre, SD 57501-5070

**Re: In the Matter of Otter Tail Power Company's Transmission Cost Recovery Rider Filing,  
Docket No. EL10-015.**

Dear Ms. Van Gerpen:

Enclosed please find the revised petition of Otter Tail Power Company, to the South Dakota Public Utilities Commission on implementation of a transmission cost recovery rider pursuant to Statutes §49-34A-25.1 through §49-34A-25.4. The initial petition was filed on November 5, 2010. Errors were discovered in the body of the original petition and Otter Tail is submitting this revised petition to correct the errors. The attachments included with the original petition are still valid, and have been included with the revised petition for convenience.

If you have any questions regarding this filing, please contact me at 218-739-8269 or [bmorlock@otpc.com](mailto:bmorlock@otpc.com).

Sincerely,

/s/ BRYAN D. MORLOCK  
Bryan D. Morlock, P.E.  
Consultant, Planning

wao  
Enclosures  
By electronic filing

**STATE OF SOUTH DAKOTA  
BEFORE THE  
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION**

Docket No. \_\_\_\_\_

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In the Matter of Otter Tail Power  
Company 's Petition to Establish a  
Transmission Cost Recovery Tariff

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**REVISED PETITION OF OTTER TAIL POWER COMPANY**

**I. INTRODUCTION.**

Otter Tail Power Company, ("Otter Tail or Company"), hereby petitions the South Dakota Public Utilities Commission ("Commission") for approval of a Transmission Cost Recovery Tariff, pursuant to SDCL Chapter 49-34A Sections 25.1 through 25.4.

**II. GENERAL FILING INFORMATION.**

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

Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
Phone (218) 739-8200

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

Bruce Gerhardson  
Associate General Counsel  
Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
Phone (218) 998-7108  
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**C. Title of utility employee responsible for filing.**

Bryan D. Morlock, P.E.  
Consultant, Planning  
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**D. The date of filing and the date changes will take effect.**

The date of the initial filing was November 5, 2010. The date of this revised filing is December 21, 2010. Otter Tail proposes that the tariff mechanism for the recovery of charges for jurisdictional costs of new or modified transmission facilities and federally regulated costs charged to Otter Tail to increase regional transmission capacity or reliability, contained herein, go into effect as of March 1, 2011.

**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 Otter Tail's general revenue requirement is necessary, the report called for under Part 20:10:13:26 and the general notice provisions applicable to changes in rates is not applicable in this filing. Otter Tail requests an expedited and informal proceeding, including any variances that may be necessary.

Pursuant to ARSD 20:10:13:18, Otter Tail will post a Notice of proposed changes contained in Attachment #10. This Notice will be placed in a conspicuous place in each business office in Otter Tail's affected electric service territory in South Dakota for at least 30 days before

the change becomes effective. Otter Tail has also included Attachment #7 to comply with ARSD 20:10:13:26, which requires the utility to report all rate schedule changes and customer impacts.

### **III. BACKGROUND OF ISSUE.**

The South Dakota Legislature in 2006 passed HB 1091 which authorizes the Commission to approve a tariff mechanism for the automatic annual adjustment of charges for a public utility to recover the South Dakota jurisdictional portion of eligible investments in and expenses related to new or modified transmission resources. Eligible projects are defined as new or modified transmission facilities more than 5 miles in length and rated at 34.5 kilovolts or more. Associated facilities such as transformers and substations are included.

HB 1091 is the Legislature's instrument to incentivize the investment in new transmission facilities to improve the capability and stability of the electric transmission system in South Dakota.

### **IV. PROPOSED CHANGES.**

During the 2006 South Dakota Legislative Session, SD Stat. §§49-34A-25.1 through 49-34A-25.4 were amended to read as follows:

*49-34A-25.1. Approval of tariff mechanisms for automatic annual adjustment of charges for jurisdictional costs of new or modified transmission facilities. Notwithstanding any other provision of this chapter, the commission may 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. For the purposes of §§49-34A-25.1 to 49-34A-25.4, inclusive,*

*electric transmission facilities and electric transmission lines covered by this section include associated facilities such as substations and transformers.*

*49-34A-25.2. Approval, rejection, or modification of certain tariffs—Notice and hearing.*

*Upon filing of an application consistent with rules promulgated by the commission by any public utility providing transmission service, the commission may approve, reject, or modify, after notice, hearing, and comment, a tariff that:*

- (1) Allows the public utility to recover on a timely basis the costs net of revenues of facilities described in §49-34A-25.1;*
- (2) Allows a return on investment at the level approved in the public utility's last general rate case, unless a different return is found to be consistent with the public interest;*
- (3) Provides a current return on construction work in progress, if the recovery from retail customers for the allowance for funds used during construction is not sought through any other mechanism;*
- (4) Allocates project costs appropriately between wholesale and retail customers; and*
- (5) Terminates recovery once costs have been fully recovered or have otherwise been reflected in the public utility's general rates.*

*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.*

In this petition, Otter Tail is proposing to implement a rate schedule (“Transmission Rider”) for the recovery of investments and expenses associated with new or modified transmission projects that are not included in base rates, and for the recovery of expenses or charges from the Midwest Independent Transmission System Operator (MISO) through Schedule 26 under the federally regulated MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

**a. Midwest ISO Regional Expansion Criteria and Benefits (“RECB”) charges (“MISO Schedule 26”)**

Otter Tail incurs charges from the Midwest ISO to pay for a portion of transmission investments of other electric utilities pursuant to Attachment FF of the Midwest ISO’s Open Access Transmission, Energy, and Operating Reserve Markets Tariff (“Tariff”). Attachment FF specifies the cost allocation procedures for new transmission projects within the Midwest ISO.

This cost allocation, oftentimes referred to as “RECB,” (after the Regional Expansion Criteria and Benefits Task Force (“RECB”) stakeholder committee) specifies the process in which the Midwest ISO identifies and evaluates new transmission expansion projects eligible for inclusion in the Midwest ISO Transmission Expansion Plan (“MTEP”). The MTEP issued by the Midwest ISO is a regional expansion plan with three primary objectives: 1) to perform a reliability assessment of the Midwest ISO integrated transmission system; 2) to review transmission owning members’ transmission plans and make sure that appropriate projects are reviewed and recommended to Midwest ISO Board of Directors for approval; and 3) to develop transmission upgrades to improve market performance.

Through its MTEP process, the Midwest ISO determines whether a proposed transmission project is eligible for cost-sharing pursuant to Attachment FF of the Midwest ISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”). There are a variety of project types under the Midwest ISO Tariff that are eligible for cost-sharing including the following: (1) Baseline Reliability Project (“BRP”) required to ensure Transmission System reliability consistent with North American Electric Reliability Corporation (“NERC”) standards, (2) Regionally Beneficial Project (“RBP”) that provides economic benefit to the Midwest ISO Transmission System, (3) Generator Interconnection Project (“GIP”) Network Upgrades required for the interconnection of generation to the Midwest ISO Transmission System, or (4) Multi Value Project (“MVP”) that address regional public policy, reliability, and economic value to the Midwest ISO footprint.

Baseline Reliability Projects that are 345 kV and greater and that have a project cost greater than \$5 million (or 5 percent or more of the Transmission Owner’s net transmission

plant) will be allocated 20 percent on a system-wide (postage stamp) rate to all Midwest ISO Transmission Customers, with the remaining 80 percent allocated on a sub-regional basis, which is based on a system power flow analysis referred to as Line Outage Distribution Factor (“LODF”).<sup>1</sup> Baseline Reliability Projects that are between 100 kV and 345 kV and have a project cost greater than \$5 million in project costs (or 5% or more of the Transmission Owner’s net transmission plant) will be allocated 100 percent on a sub-regional (“LODF”) basis to all Transmission Customers in designated pricing zones.

Regionally Beneficial Projects that have a project cost greater than \$5 million will be allocated 20 percent on a system-wide (postage stamp) rate to all Midwest ISO Transmission Customers and 80 percent will be allocated to each pricing zone within each of three Planning Sub Regions (West, Central, and East) based on the relative benefit determined for each Planning Sub Region that has a positive present value of annual benefits over the evaluation period using the methodology for project benefit determined pursuant to Section II.B.1 of Attachment FF to the Midwest ISO Tariff.

Generator Interconnection Project Network Upgrades (“GIP NUs”) are allocated pursuant to Attachment FF of the Midwest ISO Tariff, assigning up to 100 percent of the cost responsibility for Network Upgrades associated with GIPs to be allocated to the Interconnection Customer. For Network Upgrades to facilities in voltage classes at or above 345 kV, the

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1 LODF is an engineering calculation of the change of flows on the Transmission System created by the addition of a new transmission facility. MISO uses computer software to measure and model the LODF of all facilities within the MISO Transmission System for each new facility added to the system. MISO then models the LODF for each pricing zone for each new transmission facility. LODF is used because it is considered by MISO planners as a way to determine the added benefit of a new transmission facility to each of the pricing zones. Generally, pricing zones in close proximity to the proposed transmission facility have the greatest LODF cost allocation and those furthest away have little to no cost allocation from the LODF method, thus this benefit assignment is defined as Sub-Regional.



Interconnection Customer shall be repaid 10 percent of the costs of the Generation Interconnection Project funded by the interconnection Customer once Commercial Operation is achieved. The 10 percent reimbursement is recovered from all Transmission Customers in the Midwest ISO on a postage stamp basis. Network Upgrades to facilities in voltage classes below 345 kV are assigned 100% to the Interconnection Customer.

Multi Value Projects are a new project classification generally planned as regional transmission that provides multiple benefits. This project classification and its cost allocation are currently pending before FERC in Docket No. ER10-1791. As proposed, the Multi Value Project is a transmission expansion project that (1) enables the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement or (2) provides multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher, or (3) solves at least one projected violation of a NERC or Regional Entity standard and provides economic value across multiple pricing zones, which collectively generates total financially quantifiable benefits in excess of the total project costs. The costs of an approved MVP project shall be recovered from all load in, and exports from, the Midwest ISO footprint on a postage-stamp basis based on system usage (i.e. MWh).

If, through the MTEP eligibility screening process, a project does not meet the criteria for a BRP, RBP, GIP NU, or MVP but is determined to provide local benefits the assignment of costs for that facility is left to the local pricing zone of the transmission owner of the facility. For example, for a proposed transmission facility that primarily benefits a local load center, the Midwest ISO would not administer cost sharing provisions under Attachment FF and the local

transmission owner would be solely bear those costs and recover its revenue requirement under Attachment O to the Midwest ISO Tariff.

The BRP, RBP, GIP NU, and MVP cost allocation criteria and recovery mechanisms are specified in detail in Attachment FF,<sup>2</sup> Attachment GG,<sup>3</sup> and Schedule 26<sup>4</sup> of the Midwest ISO Tariff. The Midwest ISO's annual MTEP review process identifies those transmission projects that will be included in "Appendix A" to the MTEP and the respective cost-sharing is identified for each project as applicable.

The allocation of some project costs to MISO participants on a broader scale than just the utilities or companies that invest in the transmission project means that project investment on an individual company basis is unlikely to match the level of allocation on a load share ratio. In fact, each project which has a system-wide cost allocation would need to have every MISO entity with a cost allocation also be an investment participant in the project at the same level or the project would be underfunded and not be constructed. The alternative is that some project investors must invest in projects at a level that exceeds their cost allocation.

Otter Tail proposes to use the following methodology for cost recovery of transmission projects:

- For a project which does not meet the criteria for a BRP, RBP, GIP NU, or MVP designation but is determined to provide local benefits and thus the assignment of costs for that facility is left to the local pricing zone of the transmission owner of the facility, Otter Tail will use the Transmission Rider for cost recovery until the project is included in base rates or has been fully recovered. Revenue credits associated with wholesale use

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2 Attachment FF specifies the Transmission Expansion Planning Protocols.

3 Attachment GG specifies the calculation of the Network Upgrade Charge.

4 Schedule 26 specifies the Network Upgrade Charge from Transmission Expansion Plan.

of the project will be received for the project through the Attachment O process as discussed below.

- For a project which does meet the criteria for a BRP, RBP, GIP NU, or MVP designation with MISO determined cost allocations on a regional or system-wide basis, Otter Tail will allow those projects to remain in Attachment GG and to collect the revenue requirements through the Attachment GG and Schedule 26 process. This will shield Otter Tail customers from revenue requirements of the project except for the revenue requirements specifically allocated to Otter Tail retail customers through the MISO process. Retail customers will already have received the benefit of the wholesale level usage of the project by other entities that received a cost allocation and the Schedule 26 revenue received by Otter Tail will provide the project revenue requirements to pay for project costs.

Otter Tail has included Schedule 26 costs for recovery in this filing. The costs appear on line 4 of the Tracker Account (Attachment 4) and are shown separately in Attachment #9.

**b. New or Modified Transmission Projects**

Otter Tail presently has a general rate case filed with the Commission in Docket No. EL10-011. All Otter Tail transmission projects for which the Company is seeking cost recovery are included in the rate case and are anticipated to be included in base rates. Otter Tail does not have any transmission projects in its current 5-year capital budget for which it plans to seek cost recovery through the Transmission Rider.

Attachments #5 and #6 are examples of revenue requirement calculations for transmission projects included in the Transmission Rider. The revenue requirement for a project included in the Transmission Rider will include several components as described below.

- *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 will be listed here and include operating costs, property taxes, depreciation, and, income taxes.
- *Revenue requirements section.* This section will show the components of the revenue requirements. Included are the items computed from the sections previously mentioned, including expenses and return on rate base. Adjustments (usually reductions) to the revenue requirement will be included for monies received or paid for non-retail use of the lines. This includes amounts of MISO revenues generated from the open access transmission tariff. It is a revenue credit that represents revenue that Otter Tail receives for the wholesale use of its transmission system from MISO and other non-MISO users. The revenue credit is a percentage of the revenue requirement based on the prior year's actual revenue credits divided by the most recent non-levelized revenue requirements from the MISO formula rate shown in MISO Attachment O. Using the information from Otter Tail's 2011 Attachment O, the revenue credit adjustment is 17.32 percent. This MISO revenue credit percentage is applied to in-service revenue requirements and updated each year thereafter. Therefore, the 17.32 percent is applied to the computed

revenue requirement for the project. The calculation of the revenue credit adjustment is shown in Attachment #8.

- *Return on investment (cost of capital).* The return on investment will utilize the cost of capital determined in the most recent approved general rate case.
- *Depreciation expense.* Depreciation expense will be calculated using the company's latest transmission composite depreciation rate.
- *Property taxes.* The property tax calculation will be based on Otter Tail's composite tax rate for the jurisdiction in which the transmission facilities are located, and will be 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 will include 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 our 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. Otter Tail will set up transmission O&M accounting projects to track O&M costs specifically related to each line included in the Rider.

**c. Tracker Balance**

Otter Tail maintains a tracker account worksheet and accounting system to track and account for retail revenue requirements until all costs have been fully recovered or reflected in base rates as the result of a general rate case. The tracker account information compares Otter Tail's costs and the amount recovered through South Dakota retail revenue. The tracker account balance (either positive or negative) will accrue monthly carrying charges at a rate of 1/12 of Otter Tail's cost of capital times the tracker balance. Carrying charges on a negative tracker balance will accrue to the benefit of retail customers and carrying charges on a positive tracker balance will accrue to Otter Tail.

Otter Tail anticipates continuing to make annual filings to revise the Transmission Cost Recovery Rates to reflect updated revenue requirements and additional new transmission projects. When submitting annual filings, the tracker account will be updated so that any over- or under-recovered amount at the end of the previous year will be reflected in the Transmission Rider adjustment for the upcoming year. Tracker Account detail is included in Attachment 4.

**V. RATE DESIGN.**

Otter Tail's proposed rate design uses the transmission demand allocation factor, D2, from Otter Tail's last South Dakota general rate case to allocate total revenue requirements to jurisdictions (South Dakota, 9.260463 percent) and rate classes. Otter Tail will update this allocator once Otter Tail's pending general rate case is completed and reflect any adjustment in the proposed tracker. The large general service (LGS) class's portion of retail revenue requirements based on D2 is 47.54 percent. The remaining portion (52.46 percent) of the retail

revenue requirements will be collected from the non-LGS rate classes. This allocation method appropriately reflects the demand-driven nature of transmission costs. Otter Tail's proposed LGS rate design for the Transmission Rider incorporates demand (\$/kW-month) and energy (¢/kWh) rates that recover the transmission project costs in a manner that follows existing LGS base rate design. Specifically, the LGS revenue requirements will be split between demand and energy based on the 2011 forecast base rate demand and energy revenue proportion of approximately 14 percent demand and 86 percent energy. As part of future filings, this split will be reviewed as necessary to reflect any material load changes. The LGS demand rate will be calculated as the LGS demand revenue requirements divided by the LGS class billing demand for the forecast year. The LGS energy rate will be calculated as the LGS energy revenue requirements divided by the LGS kilowatt-hour sales for the projected calendar year.

For the remaining retail rate classes (non-LGS) of controlled service, and lighting, and all other classes, Otter Tail proposes an energy rate only. A rate for each class is a separate energy-based (kWh) charge calculated as the revenue requirements divided by the kilowatt-hour sales for the projected period. This rate design for controlled service, lighting, and all other classes is appropriate because it reflects the primarily energy-based rates for these classes and reduces the complexity of administration.

## **VI. RATE APPLICATION AND IMPACT.**

Otter Tail proposes that the Transmission Rider should be applicable to electric service under all of Otter Tail's retail rate schedules. The charge will be included as part of the Fuel Adjustment line on customers' bills. The proposed rates are as follows:

<u>Class</u>	<u>¢ / kWh</u>	<u>\$ / kW</u>
Large General Service	0.045¢	\$0.039
Controlled Service	0.061¢	N/A
Lighting	0.067¢	N/A
All other service	0.043¢	N/A

The following table shows the estimated rate impact by retail customer class.

<b>Approved SD Rates Based on 2007 Test Year</b>			
<b>Rate Class Impacts <sup>(1)</sup></b>		<b>Rate Class Impacts <sup>(1)</sup></b>	
<b>Residential</b>		<b>Outdoor Lighting</b>	
Average Rate (¢/kWh)	8.416	Average Rate (¢/kWh)	13.137
Increase %	0.52%	Increase %	0.55%
Average Impact (\$/month)	\$0.35	Average Impact (\$/month)	\$0.05
<b>Farm</b>		<b>Municipal Pumping</b>	
Average Rate (¢/kWh)	7.797	Average Rate (¢/kWh)	5.892
Increase %	0.60%	Increase %	0.72%
Average Impact (\$/month)	\$0.81	Average Impact (\$/month)	\$1.49
<b>General Service</b>		<b>Water Heating, Controlled</b>	
Average Rate (¢/kWh)	7.857	Average Rate (¢/kWh)	6.465
Increase %	0.53%	Increase %	1.06%
Average Impact (\$/month)	\$1.13	Average Impact (\$/month)	\$0.13
<b>Large General Service</b>		<b>Interruptible Load</b>	
Average Rate (¢/kWh)	5.484	Average Rate (¢/kWh)	3.929
Average Rate (\$/kW)	\$4.30	Increase %	1.66%
Increase %	1.00%	Average Impact (\$/month)	\$1.10
Average Impact (\$/month)	\$117.96		
<b>Irrigation</b>		<b>Deferred Load</b>	
Average Rate (¢/kWh)	6.470	Average Rate (¢/kWh)	4.245
Increase %	0.67%	Increase %	1.37%
Average Impact (\$/month)	\$2.42	Average Impact (\$/month)	\$0.90

(1) Average rate calculation is from SD Docket No. EL08-030. Rate impacts are calculated from base rates.

The above rates are based on the assumption that they will be in effect beginning March 1, 2011. Revenue requirement calculations are based on the total 2011 costs, assuming revenue



collection over the entire year. With revenue collection only over the March 1 – December 31, 2011 time period, some 2011 revenue requirements will be carried over to 2012 through the tracker true-up process. It is estimated that approximately \$46,757 of revenue requirements plus \$3,538 of carrying cost will be carried into 2012. If the effective date is significantly later than March 1, 2011, Otter Tail requests the option to recalculate the Transmission Cost Recovery Rates in order to recover all approved costs in the remainder of 2011.

#### **VII. TRANSMISSION COST RECOVERY RIDER RATE SCHEDULE.**

Otter Tail's proposed Transmission Cost Recovery Rider is Attachment #7 to this Petition.

#### **VIII. REVISIONS TO OTHER RATE SCHEDULES.**

Attachment #7 to this Petition also includes redline and proposed final versions of Otter Tail's Rate Schedules Index and Rate Schedule 13.00, Mandatory Riders – Applicability Matrix, showing the addition of the Transmission Cost Recovery Rider.

#### **IX. FIVE-YEAR TRANSMISSION RIDER ESTIMATE.**

Otter Tail does not have any transmission projects in the five-year capital budget at this time that would be included in the Transmission Rider for ratebase recovery. It is possible that a project or projects could arise within the five-year period due to customer needs or unforeseen circumstances.

It is very difficult to forecast the Schedule 26 charges as MISO does not provide the information necessary to develop forward projections. Thus Otter Tail cannot forecast the Schedule 26 charges from RECB projects being constructed in other parts of MISO. Based on

the Company's expected investment levels in the Fargo to St. Cloud and Bemidji to Grand Rapids CAPX2020 projects, Otter Tail is forecasting the following *Company-wide* Schedule 26 charges:

2011	\$1,218,960
2012	\$4,840,000
2013	\$6,828,000
2014	\$8,223,000
2015	\$9,045,000

**X. CONCLUSION.**

For the foregoing reasons, Otter Tail respectfully requests approval to implement the rate schedule with Rate Designation 13.05 effective as of March 1, 2011.

Date: December 21, 2010

Respectfully submitted:

OTTER TAIL POWER COMPANY,

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(218) 998-7108

## **Attachments**

Attachment #1	Revenue
Attachment #2	Revenue Requirements Summary
Attachment #3	Rate Design
Attachment #4	Tracker Summary
Attachment #5	Transmission Project #1 Example Revenue Requirements Calculation
Attachment #6	Transmission Project #2 Example Revenue Requirements Calculation
Attachment #7	Redline and Clean Rate Schedules
Attachment #8	Wholesale Sales Revenue Credit Worksheet
Attachment #9	MISO Schedule 26 Expense Estimate
Attachment #10	Customer Notice

**Projected Revenue for 2011**

<b>Class</b>		<b>Units</b>	<b>Rate per Unit</b>	<b>Amount</b>
Large General Service	(a)	376,715 kW	\$0.039	\$14,791
		200,751,529 kWh	0.045 ¢	<u>90,858</u>
Total LGS				\$105,648
Controlled service	(b)	43,875,465 kWh	0.061 ¢	\$26,846
Lighting	(c)	4,509,929 kWh	0.067 ¢	3,034
All other service		201,185,118 kWh	0.043 ¢	<u>86,722</u>
Total revenue				<u><u>\$222,251</u></u>

(a) Rate Schedules 10.03 Large General Service and 10.05 Large General Service - Time of Day

(b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load (CT Metering), 14.05 Interruptible Load (Self-Contained Metering), 14.06 Deferred Load

(c) Rate Schedules 11.03 Outdoor Lighting (energy only), 11.04 Outdoor Lighting

Summary of Revenue Requirements

<b><u>Revenue Requirements</u></b>	<b><u>2011</u></b>
Project 1	\$ -
Project 2	-
Schedule 26	222,251
2010 Carrying cost	-
2010 True Up	-
Total	<u><u>\$ 222,251</u></u>

**Class Allocation and Rate Design**

		<u>2011</u>
Total South Dakota revenue requirements		\$222,251 *
Large General Service class	47.54%	\$105,648
Controlled service	12.08%	26,846
Lighting	1.37%	3,034
All other service	39.02%	<u>86,722</u>
Total		\$222,251
Large General Service class	kW	376,715
Large General Service class	kWh	200,751,529
Controlled service	kWh	43,875,465
Lighting	kWh	4,509,929
All other service	kWh	201,185,118
Large General Service class	\$ / kW month	0.039 **
Large General Service class	cents / kwh	0.045
Controlled service	cents / kwh	0.061
Lighting	cents / kwh	0.067
All other service	cents / kwh	0.043

\* Jurisdictional transmission allocation factor (D2 = 9.260463%) is from Otter Tail's last general rate case in South Dakota.

\*\* LGS revenue is 14% demand and 86% energy

**TRACKER SUMMARY**

Line	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	2011 July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	YE Projected ck
<b>Requirements Compared to Billed:</b>													
Revenue Requirements													
1	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0
4	20,385	20,659	22,164	19,617	19,250	14,994	17,380	18,022	18,986	18,925	15,380	16,490	222,251
5	20,385	20,659	22,164	19,617	19,250	14,994	17,380	18,022	18,986	18,925	15,380	16,490	222,251
6													
7	0	0	19,894	18,481	16,519	16,564	17,035	17,347	17,533	16,552	18,481	20,256	222,251
8													
9	20,385	20,659	2,411	1,423	3,036	(1,253)	685	1,008	1,795	2,723	(2,736)	(3,379)	(3,379)
10	-	142	286	305	317	340	334	341	350	365	387	370	
11	20,385	41,186	43,883	45,611	48,964	48,051	49,070	50,419	52,564	55,653	53,303	50,295	50,295
12													
13	0	142	286	305	317	340	334	341	350	365	387	370	
14	0	142	428	733	1,050	1,390	1,724	2,065	2,416	2,781	3,168	3,538	3,538
15	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
16	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%
17													
18													
19													
20													
21													
22	44,366	43,953	40,309	37,446	33,471	33,561	34,516	35,149	35,525	33,537	37,446	41,043	450,322
23												450,322	
24													
25													

<b>SUMMARY</b>	
Revenue requirements 2011	\$222,251
2010 Carrying Charge and True up	0
Total requirements	\$222,251
2011 projected sales in mWh	450,322
Average Rate	\$0.00049

**SUMMARY**

Year	2011
Revenue requirements	\$222,251
True up & Carrying Charge	0
Total requirements	\$222,251
2011 projected sales in mWh	450,322
Average Rate	\$0.00049













Fergus Falls, Minnesota

Original/First Revision

## Electric Service – South Dakota – Index

*Section Prior Sheet Item*

### **1.00 GENERAL SERVICE RULES**

- 1.01 99.9 Scope of General Rules and Regulations
- 1.02 99.9 Application for Service
- 1.03 98.3 Deposits, Guarantees and Credit Policy
- 1.04 98.1 Customer Connection Charge
- 1.05 N/A Contracts, Agreements and Sample Forms

### **2.00 RATE APPLICATION**

- 2.01 N/A Assisting Customers in Rate Selection
- 2.02 99.9 Service Classification

### **3.00 CURTAILMENT OR INTERRUPTION OF SERVICE**

- 3.01 N/A Disconnection of Service
- 3.02 N/A Curtailment or Interruption of Service
- 3.03 N/A N/A (section reserved for future use)
- 3.04 N/A N/A (section reserved for future use)
- 3.05 N/A Continuity of Service

SOUTH DAKOTA PUBLIC  
UTILITIES COMMISSION  
Filed on: November 5, 2010  
October 31, 2008  
Approved by order dated: DATE  
June 30, 2009  
Docket No. EL08-030

Thomas Brause  
Bernadeen Brutlag  
Manager, Regulatory  
Services Vice-President,  
Administration

EFFECTIVE with bills  
rendered on and after  
March 1, 2011  
July 1, 2009,  
in South Dakota



Fergus Falls, Minnesota  
(Continued)

*Original First Revision*

## Electric Service – South Dakota – Index

*Section    Prior Sheet    Item*

### **4.00            METERING & BILLING**

- 4.01    N/A    Meter and Service Installations
- 4.02    N/A    Meter Readings
- 4.03    99.9    Estimated Readings
- 4.04    98.4    Meter Testing
- 4.05    99.9    Access to Customer Premises
- 4.06    99.9    Establishing Demands
- 4.07    99.9    Monthly Billing Period and Prorated Bills
- 4.08    99.9    Electric Service Statement - Identification of Amounts and Meter Reading
- 4.09    N/A    Billing Adjustments
- 4.10    99.9    Payment Policy
- 4.11    N/A    Even Monthly Payment (EMP) Plan
- 4.12    N/A    Summary Billing Services
- 4.13    N/A    Account History Charge
- 4.14    N/A    Combined Metering

### **5.00            STANDARD INSTALLATION AND EXTENSION RULES**

- 5.01    99.9    Extension Rules and Minimum Revenue Guarantee
- 5.02    N/A    Special Facilities
- 5.03    N/A    Temporary Services
- 5.04    N/A    Standard Installation
- 5.05    N/A    Service Connection

### **6.00            USE OF SERVICE RULES**

- 6.01    N/A    Customer Equipment
- 6.02    99.9    Use of Service; Prohibition on Resale

SOUTH DAKOTA PUBLIC  
UTILITIES COMMISSION  
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Fergus Falls, Minnesota  
(Continued)

*Original/First Revision*

## Electric Service – South Dakota – Index

*Section    Prior Sheet    Item*

### **7.00            COMPANY’S RIGHTS**

- 7.01      99.9      Waiver of Rights or Default
- 7.02      N/A        Modification of Rates, Rules and Regulations

### **8.00            GLOSSARY AND SYMBOLS**

- 8.01      N/A        Glossary
- 8.02      N/A        Definition of Symbols

## **Rate Schedules & Riders**

### **9.00            RESIDENTIAL AND FARM SERVICES**

- 9.01      1            Residential Service
- 9.02      5            Residential Demand Control Service
- 9.03      16          Farm Service

### **10.00          GENERAL SERVICES**

- 10.01    N/A        Small General Service (Less than 20kW)
- 10.02    20         General Service (20kW or Greater)
- 10.03    30         Large General Service
- 10.04    N/A        Commercial Service – Time of Use
- 10.05    30.3      Large General Service – Time of Day

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Fergus Falls, Minnesota  
(Continued)

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## Electric Service – South Dakota – Index

Section Prior Sheet Item

### 11.00 OTHER SERVICES

11.01	71.3	Standby Service
11.02	90	Irrigation Service
11.03	93	Outdoor Lighting – Energy Only
11.04	94	Outdoor Lighting
11.05	95	Municipal Pumping Service
11.06	96	Civil Defense – Fire Sirens

### 12.00 POWER PRODUCER RIDERS & APPLICABILITY MATRIX

12.01	70.8	Small Power Producer Rider – Occasional Delivery Energy Service
12.02	70.9	Small Power Producer Rider – Temperature-Time of Delivery Energy Service
12.03	71	Small Power Producer Rider – Dependable Service

### 13.00 MANDATORY RIDERS & APPLICABILITY MATRIX

13.01	98	Fuel Adjustment Clause Rider <ul style="list-style-type: none"> <li>• <i>Applicable to all services and riders unless otherwise stated in the mandatory riders matrix</i></li> </ul>	
13.02	N/A	N/A (reserved for future use)	
13.03	N/A	N/A (reserved for future use)	
13.04	98.3	Energy Efficiency Project (EEP) Rider	
13.05	N/A	Transmission Cost Recovery Rider	<b>N</b>

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION  
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EFFECTIVE with bills rendered on and after March 1, 2011/July 1, 2009, in South Dakota



Fergus Falls, Minnesota  
(Continued)

Original/First Revision

## Electric Service – South Dakota – Index

Section Prior Sheet Item

### 14.00 VOLUNTARY RIDERS & APPLICABILITY MATRIX

14.01	7	Water Heating – Controlled Service
14.02	N/A	Real Time Pricing Rider
14.03	30.9	Large General Service Rider
14.04	50	Controlled Service – Interruptible Load (CT Metering) Rider
14.05	50.1	Controlled Service – Interruptible Load (Self-Contained Metering) Rider
14.06	50.2	Controlled Service – Deferred Load Rider
14.07	50.3	Fixed Time of Delivery Rider
	50.4	
	50.5	
14.08	94.5	Voluntary Air Conditioning Control Rider ( <b>CoolSavings</b> )
14.09	91.5	Voluntary Renewable Energy Rider ( <b>TailWinds</b> )
14.10	N/A	N/A (section reserved for future use)
14.11	91	Released Energy Access Program (REAP) Rider
14.12	50.7	Bulk Interruptible Service Application and Pricing Guide

### 15.00 COMMUNITIES SERVED

15.00	N/A	South Dakota Communities Served
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### 16.00 SUMMARY OF CONTRACTS WITH DEVIATIONS

16.00	Section 4, Sheets 1-4	Summary of Contracts with Deviations
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SOUTH DAKOTA PUBLIC  
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Fergus Falls, Minnesota

First Revision

## Electric Service – South Dakota – Index

*Section Prior Sheet Item*

### **1.00 GENERAL SERVICE RULES**

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- 1.04 98.1 Customer Connection Charge
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- 3.02 N/A Curtailment or Interruption of Service
- 3.03 N/A N/A (section reserved for future use)
- 3.04 N/A N/A (section reserved for future use)
- 3.05 N/A Continuity of Service



Fergus Falls, Minnesota  
(Continued)

First Revision

## Electric Service – South Dakota – Index

Section    Prior Sheet    Item

### 4.00            METERING & BILLING

4.01	N/A	Meter and Service Installations
4.02	N/A	Meter Readings
4.03	99.9	Estimated Readings
4.04	98.4	Meter Testing
4.05	99.9	Access to Customer Premises
4.06	99.9	Establishing Demands
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4.09	N/A	Billing Adjustments
4.10	99.9	Payment Policy
4.11	N/A	Even Monthly Payment (EMP) Plan
4.12	N/A	Summary Billing Services
4.13	N/A	Account History Charge
4.14	N/A	Combined Metering

### 5.00            STANDARD INSTALLATION AND EXTENSION RULES

5.01	99.9	Extension Rules and Minimum Revenue Guarantee
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5.03	N/A	Temporary Services
5.04	N/A	Standard Installation
5.05	N/A	Service Connection

### 6.00            USE OF SERVICE RULES

6.01	N/A	Customer Equipment
6.02	99.9	Use of Service; Prohibition on Resale



Fergus Falls, Minnesota  
(Continued)

First Revision

## Electric Service – South Dakota – Index

*Section    Prior Sheet    Item*

### **7.00            COMPANY’S RIGHTS**

- 7.01      99.9      Waiver of Rights or Default
- 7.02      N/A        Modification of Rates, Rules and Regulations

### **8.00            GLOSSARY AND SYMBOLS**

- 8.01      N/A        Glossary
- 8.02      N/A        Definition of Symbols

## **Rate Schedules & Riders**

### **9.00            RESIDENTIAL AND FARM SERVICES**

- 9.01      1           Residential Service
- 9.02      5           Residential Demand Control Service
- 9.03      16          Farm Service

### **10.00          GENERAL SERVICES**

- 10.01    N/A        Small General Service (Less than 20kW)
- 10.02    20        General Service (20kW or Greater)
- 10.03    30        Large General Service
- 10.04    N/A        Commercial Service – Time of Use
- 10.05    30.3      Large General Service – Time of Day



Fergus Falls, Minnesota  
(Continued)

First Revision

## Electric Service – South Dakota – Index

Section    Prior Sheet    Item

### 11.00      OTHER SERVICES

11.01	71.3	Standby Service
11.02	90	Irrigation Service
11.03	93	Outdoor Lighting – Energy Only
11.04	94	Outdoor Lighting
11.05	95	Municipal Pumping Service
11.06	96	Civil Defense – Fire Sirens

### 12.00      POWER PRODUCER RIDERS & APPLICABILITY MATRIX

12.01	70.8	Small Power Producer Rider – Occasional Delivery Energy Service
12.02	70.9	Small Power Producer Rider – Temperature-Time of Delivery Energy Service
12.03	71	Small Power Producer Rider – Dependable Service

### 13.00      MANDATORY RIDERS & APPLICABILITY MATRIX

13.01	98	Fuel Adjustment Clause Rider <ul style="list-style-type: none"> <li>• <i>Applicable to all services and riders unless otherwise stated in the mandatory riders matrix</i></li> </ul>	
13.02	N/A	N/A (reserved for future use)	
13.03	N/A	N/A (reserved for future use)	
13.04	98.3	Energy Efficiency Project (EEP) Rider	
13.05	N/A	Transmission Cost Recovery Rider	<b>N</b>



Fergus Falls, Minnesota  
(Continued)

First Revision

## Electric Service – South Dakota – Index

Section Prior Sheet Item

### 14.00 VOLUNTARY RIDERS & APPLICABILITY MATRIX

14.01	7	Water Heating – Controlled Service
14.02	N/A	Real Time Pricing Rider
14.03	30.9	Large General Service Rider
14.04	50	Controlled Service – Interruptible Load (CT Metering) Rider
14.05	50.1	Controlled Service – Interruptible Load (Self-Contained Metering) Rider
14.06	50.2	Controlled Service – Deferred Load Rider
14.07	50.3	Fixed Time of Delivery Rider
	50.4	
	50.5	
14.08	94.5	Voluntary Air Conditioning Control Rider ( <b>CoolSavings</b> )
14.09	91.5	Voluntary Renewable Energy Rider ( <b>TailWinds</b> )
14.10	N/A	N/A (section reserved for future use)
14.11	91	Released Energy Access Program (REAP) Rider
14.12	50.7	Bulk Interruptible Service Application and Pricing Guide

### 15.00 COMMUNITIES SERVED

15.00	N/A	South Dakota Communities Served
-------	-----	---------------------------------

### 16.00 SUMMARY OF CONTRACTS WITH DEVIATIONS

16.00	Section 4, Sheets 1-4	Summary of Contracts with Deviations
-------	--------------------------	--------------------------------------



Fergus Falls, Minnesota

*First Revision*Original

## **MANDATORY RIDERS - APPLICABILITY MATRIX**

The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply, Voluntary Rate Riders selected by the Customer, and charges listed in the General Rules and Regulations.

SOUTH DAKOTA PUBLIC  
UTILITIES COMMISSION  
Filed on: November 5, 2010October 31,  
2008  
Approved by order dated: DATEJune  
30, 2009  
Docket No. EL10-\_\_08-030

Thomas BrauseBernadeen  
Brutlag  
Vice-President,  
Manager, Regulatory  
ServicesAdministration

EFFECTIVE with bills  
rendered on and after  
March 1, 2010July 1, 2009,  
in South Dakota



Fergus Falls, Minnesota

South Dakota P.U.C. Volume II  
 Section 13.00 – Sheet No. 2  
**ELECTRIC RATE SCHEDULE**  
**Mandatory Riders – Applicability Matrix**

*First Revision*Original



	<b>Mandatory Riders</b>	Fuel Adjustment Clause Rider	Energy Efficiency Partnership (EEP) Cost Recovery Rider	Transmission Cost Recovery Rider	N
<b>Base Tariffs</b>	Section Numbers	13.01	13.04	13.05	N
Residential Service	9.01				N
Residential Demand Control Service	9.02				N
Farm Service	9.03				N
Small General Service (Less than 20 kW)	10.01				N
General Service (20 kW or Greater)	10.02				N
Large General Service	10.03				N
Commercial Service - Time of Use	10.04				N
Large General Service - Time of Day	10.05				N
Standby Service	11.01				N
Irrigation Service	11.02				N
Outdoor Lighting - Energy Only	11.03				N
Outdoor Lighting	11.04				N
Municipal Pumping Service	11.05				N
Fire Sirens - Civil Defense	11.06			✓	N

✓ = May apply    ■ = Mandatory    □ = Not Applicable

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION  
 Filed on: November 5, 2010 October 31, 2008  
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Thomas BrauseBernadeen  
 Brutlag  
 Vice-President,  
 Manager, Regulatory  
 ServicesAdministration

EFFECTIVE with bills rendered on and after March 1, 2010 July 1, 2009, in South Dakota



Fergus Falls, Minnesota  
(Continued)

South Dakota P.U.C. Volume II  
Section 13.00 – Sheet No. 3  
**ELECTRIC RATE SCHEDULE**  
**Mandatory Riders – Applicability Matrix**

First Revision Original



	<b>Mandatory Riders</b>	Fuel Adjustment Clause Rider	Energy Efficiency Partnership (EEP) Cost Recovery Rider	Transmission Cost Recovery Rider	N
<b>Base Tariffs</b>	Section Numbers	13.01	13.04	13.05	N
Water Heating - Controlled Service	14.01				N
Real Time Pricing Rider	14.02				N
Large General Service Rider	14.03	✓			N
Controlled Service - Interruptible Load (CT Metering) Rider	14.04				N
Controlled Service - Interruptible Load (Self-Contained Metering) Rider	14.05				N
Controlled Service - Deferred Load Rider	14.06				N
Fixed Time of Delivery Rider	14.07				N
Air Conditioning Control Rider	14.08				N
Voluntary Renewable Energy Rider	14.09				N
Released Energy Rider	14.11				N
Bulk Interruptible Application and Pricing Guidelines Rider	14.12				N

✓ = May apply    ■ = Mandatory    □ = Not Applicable

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EFFECTIVE with bills rendered on and after March 1, 2010  
 July 1, 2009, in South Dakota





Fergus Falls, Minnesota

First Revision

**MANDATORY RIDERS - APPLICABILITY MATRIX**

The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply, Voluntary Rate Riders selected by the Customer, and charges listed in the General Rules and Regulations.



	<b>Mandatory Riders</b>	Fuel Adjustment Clause Rider	Energy Efficiency Partnership (EEP) Cost Recovery Rider	Transmission Cost Recovery Rider	
<b>Base Tariffs</b>	Section Numbers	13.01	13.04	13.05	N
Residential Service	9.01				N
Residential Demand Control Service	9.02				N
Farm Service	9.03				N
Small General Service (Less than 20 kW)	10.01				N
General Service (20 kW or Greater)	10.02				N
Large General Service	10.03				N
Commercial Service - Time of Use	10.04				N
Large General Service - Time of Day	10.05				N
Standby Service	11.01				N
Irrigation Service	11.02				N
Outdoor Lighting - Energy Only	11.03				N
Outdoor Lighting	11.04				N
Municipal Pumping Service	11.05				N
Fire Sirens - Civil Defense	11.06			✓	N

✓ = May apply    ■ = Mandatory    □ = Not Applicable

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION  
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Thomas Brause  
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 Administration

EFFECTIVE with bills rendered on and after March 1, 2010, in South Dakota



Fergus Falls, Minnesota  
(Continued)

South Dakota P.U.C. Volume II  
Section 13.00 – Sheet No. 2  
**ELECTRIC RATE SCHEDULE**  
**Mandatory Riders – Applicability Matrix**

First Revision



	<b>Mandatory Riders</b>	Fuel Adjustment Clause Rider	Energy Efficiency Partnership (EEP) Cost Recovery Rider	Transmission Cost Recovery Rider	N
<b>Base Tariffs</b>	Section Numbers	13.01	13.04	13.05	N
Water Heating - Controlled Service	14.01				N
Real Time Pricing Rider	14.02				N
Large General Service Rider	14.03	✓			N
Controlled Service - Interruptible Load (CT Metering) Rider	14.04				N
Controlled Service - Interruptible Load (Self-Contained Metering) Rider	14.05				N
Controlled Service - Deferred Load Rider	14.06				N
Fixed Time of Delivery Rider	14.07				N
Air Conditioning Control Rider	14.08				N
Voluntary Renewable Energy Rider	14.09				N
Released Energy Rider	14.11				N
Bulk Interruptible Application and Pricing Guidelines Rider	14.12				N

✓ = May apply      ■ = Mandatory      □ = Not Applicable

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION  
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Administration

EFFECTIVE with bills rendered on and after March 1, 2010, in South Dakota



Fergus Falls, Minnesota

**TRANSMISSION COST RECOVERY RIDER** N

DESCRIPTION	RATE CODE	
Large General Service	30-510	N
Controlled Service	30-511	N
Lighting	30-512	N
All Other Service	30-513	N

**REGULATIONS:** Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule. N  
N

**APPLICATION OF SCHEDULE:** This rate schedule is applicable to any electric service under all of the Company's retail rate schedules. N  
N

**COST RECOVERY FACTOR:** There shall be included on each South Dakota Customer's monthly bill a Transmission Cost Recovery charge, which shall be calculated before any applicable municipal payment adjustments and sales taxes as provided in the General Rules and Regulations for the Company's electric service. The following charges are applicable in addition to all charges for service being taken under the Company's standard rate schedules. N  
N  
N  
N  
N

**RATE:** N

**TRANSMISSION COST RECOVERY** N

Energy Charge per kWh:		kWh		kW	
<b>Large General Service</b> (a)	0.045	¢/kWh		\$0.039	N
<b>Controlled Service</b> (b)	0.061	¢/kWh		N/A	N
<b>Lighting</b> (c)	0.067	¢/kWh		N/A	N
<b>All Other Service</b>	0.043	¢/kWh		N/A	N

- (a) Rate schedules 10.03 Large General Service, 10.05 Large General Service – Time of Day, 14.02 Real Time Pricing Rider and 14.03 Large General Service Rider. N  
N
- (b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load (CT Metering), 14.05 Interruptible Load (Self-Contained Metering), 14.06 Deferred Load, and 14.07 Fixed Time of Delivery N  
N
- (c) Rate Schedules 11.03 Outdoor Lighting (energy only) and 11.04 Outdoor Lighting N

SOUTH DAKOTA PUBLIC  
 UTILITIES COMMISSION  
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 in South Dakota



Fergus Falls, Minnesota

**DETERMINATION OF DEMAND CHARGE (LARGE GENERAL SERVICE CLASS ONLY):** The demand charge shall be billed according to the demand charge as defined in the applicable rate schedule the Customer is taking service. N  
N  
N

**MANDATORY AND VOLUNTARY RIDERS:** The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See sections 12.00, 13.00 and 14.00 of the Minnesota electric rates for the matrices of riders. N  
N  
N  
N

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UTILITIES COMMISSION  
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March 1, 2011,  
in South Dakota

**Attachment O**

<u>Line No.</u>					<u>Allocated Amount</u>
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$ 34,298,860
	REVENUE CREDITS	(Note T)	<u>Total</u>	<u>Allocator</u>	
2	Account No. 454	(page 4, line 34)	115,163	TP 1.00000	115,163
3	Account No. 456.1	(page 4, line 37)	5,805,049	TP 1.00000	5,805,049
4	Revenues from Grandfathered Interzonal Transactions		20,400	TP 1.00000	20,400
5	Revenues from service provided by the ISO at a discount		0	TP 1.00000	<u>0</u>
6	TOTAL REVENUE CREDITS (sum lines 2-5)				5,940,612
				Wholesale Revenue Credit	17.32%

18 *SCHEDULE 26*

	2011												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YE
	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
21 MISO Schedule 26 Expense	220,126	223,089	239,336	211,840	207,876	161,911	187,674	194,608	205,027	204,358	166,080	178,072	2,400,000
22 MISO Schedule 26 Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
23 Net Schedule 26	220,126	223,089	239,336	211,840	207,876	161,911	187,674	194,608	205,027	204,358	166,080	178,072	2,400,000
24 South Dakota Share	9.26% 20,385	20,659	22,164	19,617	19,250	14,994	17,380	18,022	18,986	18,925	15,380	16,490	222,251

## Notice to Otter Tail Power Company Customers

Otter Tail Power Company has upgraded transmission facilities to help ensure continued reliable service and to bring renewable energy to our South Dakota customers. The South Dakota Public Utilities Commission has approved an adjustment to the Transmission charge that is part of the Resource Adjustment on your monthly electric bill beginning March 1, 2011 to recover the cost of these transmission upgrades and expansions.

The current Transmission charge is:

Class	¢ / kWh	\$ / kW
Large General Service	0.045¢	\$0.039
Controlled Service	0.061¢	N/A
Lighting	0.067¢	N/A
All other service	0.043¢	N/A

For more information contact Customer Service at 800-257-4044 or place an inquiry from our web site at [www.otpc.com](http://www.otpc.com).