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August 31, 2018

Darrell Nitschke
Director of Administration/Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505-0480

**RE: In the Matter of Otter Tail Power Company's Application for
Approval of the Annual Rate Update to Rate Schedule, Section 13.07,
Transmission Cost Recovery Rider**

Dear Mr. Nitschke:

Enclosed please find an original and seven (7) copies of Otter Tail Power Company's (Otter Tail) Application to the North Dakota Public Service Commission for approval of the annual update to its Transmission Cost Recovery Rider rate as required by the Order in Case No. PU-11-153.

Also enclosed is Otter Tail's check in the amount of \$10,000 for the filing fee.

An electronic copy of this filing is also being sent to you at dnitschk@nd.gov and to the North Dakota Public Service Commission at ndpsc@nd.gov.

If you have any questions regarding this filing, please contact me at 218-739-8275 or gice@otpc.com.

Sincerely,

/s/ GINA S. ICE
Gina S. Ice
Rates Analyst
Regulatory Administration

jch
cc: Jerry Lein

Enclosures
By electronic filing and U.S. mail

**STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Case No. PU-18-

In the Matter of Otter Tail Power
Company's Application for Approval
of the Annual Rate Update to Rate
Schedule, Section 13.07,
Transmission Cost Recovery Rider

**APPLICATION FOR ANNUAL RATE UPDATE
FOR TRANSMISSION COST RECOVERY RIDER**

I. INTRODUCTION

Otter Tail Power Company (Otter Tail or Company) hereby applies to the North Dakota Public Service Commission (Commission) for approval of an annual rate update to its Transmission Cost Recovery Rider (TCRR) in compliance with N.D.C.C. § 49-05-04.3 and Ordering Paragraph 6 of the Commission's April 5, 2012 Order in Case Nos. PU-11-153 and PU-11-682 (the TCRR Order).

In this annual update, Otter Tail's TCRR rate is updated to reflect the TCRR revenue requirements for the next recovery period (calendar year 2019). The update includes the tracker balance estimated for the end of the current period to minimize over-or under-recovery of TCRR costs (in compliance with Ordering paragraph 6 of the TCRR Order). This update includes: (1) the impacts of Otter Tail's general rate case, Case No. PU-17-398, in which recovery for 16 transmission projects shifted from the TCRR to base rates, (2) the addition of three new transmission projects not currently in base rates and not previously included in the TCRR, (3) details of the pending Midcontinent Independent System Operator (MISO) Return on Equity complaint, and (4) details of Southwest Power Pool (SPP) related expenses.

The net revenue requirement for 2019 upon which rates are developed is \$5,039,477. For a residential customer using 1,000 kWh per month, the bill impact of this update is a decrease of

\$1.73 per month. For a large general service customer with 425 kW of demand, the bill impact of this update is a decrease of \$220.72 per month.

GENERAL FILING INFORMATION

Pursuant to § 69-02-02-04 of the Commission's Rules of Practice and Procedure, the following information is provided:

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 Power Company

Cary Stephenson
Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone (218) 739-8956

C. Title of utility employee responsible for filing

Gina S. Ice
Rates Analyst, Regulatory Administration
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8275

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

The date of this filing is August 31, 2018. The updated TCRR rate is calculated to take effect as of January 1, 2019.

E. Other requirements of North Dakota Rules Part 69-02-02-04

Articles of Incorporation. A certified copy of Otter Tail's Articles of Incorporation is on file with the Commission, as is an original Certificate of Good Standing.

II. TRANSMISSION COST RECOVERY

A. Background

In this Application, Otter Tail requests an annual update to its rate schedule, Section 13.07, in compliance with the TCRR Order referenced above. Paragraph 6 of that Order requires the following:

By September 1 of each year, OTP shall file with the Commission an annual TCR Rider rate on a going forward basis. In the annual filing, the tracker account will be updated so that any over- or under-recoveries at the end of the previous recovery period will be reflected in the TCR Rider adjustment for the upcoming recovery period.

Otter Tail's TCRR was approved by the Commission pursuant to N.D.C.C. § 49-05-04.3 which provides:

The commission may approve, reject, or modify a tariff filed under section 49-05-06 which provides for an adjustment of rates to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For purposes of this section, an electric transmission facility includes an electric transmission line as defined in chapter 49-21.1 and other transmission line equipment, including substations, transformers, and other equipment constructed to improve the power delivery capability or reliability of the electric transmission system; and operating costs include federally regulated costs charged to or incurred by the public utility to increase regional transmission capacity or reliability. The tariff must:

- a. Allow the public utility to recover on a timely basis its investment and associated costs for new or modified electric transmission facilities not reflected in the utility's general rate schedule;*
- b. Allow a return on the public utility's investment made for new or modified electric transmission facilities at the level approved in the utility's most recent general rate case;*

c. Provide a current return on construction work in progress for new or modified electric transmission facilities, provided the cost recovery from retail customers of the allowance for funds used during construction is not sought through any other means; and

d. Terminate cost recovery after the public utility's costs for new or modified electric transmission facilities have been recovered fully or have been reflected in the utility's general rate tariff.

B. TCRR rate update revenue requirement calculations

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

Attachments 5 – 10 provide the revenue requirement calculations for each of the transmission projects identified in this filing-both those previously approved in Otter Tail's prior TCRR (Attachments 5 -7) and the new projects for which Otter Tail is requesting TCRR recovery (Attachments 8-10).

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 including the effect of proration on Federal amounts, and a 13-month average rate base calculation.
- *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 and any credits to the revenue requirement for monies received for use of the lines by wholesale customers.
- *Return on investment (cost of capital).* Otter Tail uses the cost of capital agreed upon by the parties to the case in the Settlement Agreement¹ in its current general rate case (Case No. PU-17-398). Further discussion of the rate case's impact on the TCRR is included below.

¹ Case No. PU-17-398 Exhibit OTP-1 -Settlement Agreement.

- *Depreciation expense.* Depreciation expense is calculated using the Company's current composite depreciation rates.
- *Property taxes.* The property tax calculation is based on Otter Tail'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.
- *Operation and maintenance (O&M) expense.* Annual O&M expense of transmission lines 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 annually on single pole 115 kV lines. Unscheduled patrols are completed for line sections with unexplained interruptions. Vegetation management of new lines is typically limited during the first five years, since Otter Tail's construction standard is to remove as many trees as possible. After five years, vegetation management is completed based on information gathered during line patrols.
- *Proration of Accumulated Deferred Income Taxes (ADIT).* Otter Tail provides Attachment 19 to this filing to show the ADIT proration calculation impact on the revenue requirement for the recovery period.

Based on further research and analysis of United States Internal Revenue Service (IRS) rules related to proration, including recently issued IRS private letter rulings, Otter Tail identified revisions needed to its Accumulated Deferred Income Tax (ADIT) balances to preserve the effect of the application of the proration methodology for the true-up period. This calculation methodology is necessary in order to comply with Section 1.167(l)-1(h)(6)(ii) of the IRS regulations and to avoid a tax normalization violation.² Otter Tail includes Attachment 20 in this filing, which shows the preservation of the proration of ADIT results in an increase of \$11,536 plus any applicable carrying charge to the revenue requirement. This item is included on Line No. 25 of Attachment 4 to this filing.

- *Midcontinent Independent System Operator (MISO) Schedule 26 and 26A expenses.* Schedule 26 and Schedule 26A costs for the recovery period appear on Lines 28 and 29 of the Tracker Account (Attachment 4) and are shown separately in Attachment 12. These are Otter Tail's retail share of the costs for projects that qualify for regional cost allocation through MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff.
- *Southwest Power Pool (SPP) Related Expenses (Attachment 13) and MISO Related Revenues (Attachment 14).* SPP Schedules 7, 8, and 9 refer to different types of transmission service that Otter Tail may secure for serving Otter Tail load in SPP, which represent firm point-to-point, non-firm point-to-point, and

² See Treas. Reg. SS 1.167(l)-1(h)(6)(ii).

network integration transmission service, respectively.

SPP Schedule 11 expenses are for new projects approved through SPP's Integrated Transmission Planning process that have benefits beyond the local area. The expenses included in this TCRR update are Otter Tail's forecasted share of the costs for these new transmission projects approved by SPP, whose costs are shared on a regional and zonal basis. SPP Schedule 9 expenses appear on Line 30 and SPP Schedule 11 expense on Line 31 of the Tracker Account (Attachment 4). Both are shown separately in Attachment 13.

Otter Tail also receives MISO Schedule 9 revenues related to Central Power Electric Cooperative (CPEC) paying MISO charges for transmission service it secures through MISO. These revenues are offset by facility credits CPEC began collecting in MISO for CPEC-owned transmission facilities that were eligible for inclusion in MISO in May 2017. The revenues associated with MISO Schedule 9 results in a reduction to the TCRR revenue requirement.

MISO Schedule 9 revenue from CPEC appears on Line 35 of the Tracker Account (Attachment 4) and is shown in detail in Attachment 14.

- *MISO Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period appear on lines 36 and 39 of the Tracker Account Summary (Attachment 4) and are shown separately on Attachment 15 (Schedule 26) and Attachment 16 (Schedule 26A). These are Otter Tail's retail share of the revenues derived from Otter Tail's investment in projects that qualify for regional cost allocation through MISO's Tariff. These revenues are applicable to projects in the TCRR as well as projects that will be recovered in base rates.
- *MISO Return on Equity (ROE) Complaint.* On November 12, 2013 and February 12, 2015, two groups of industrial customers and other stakeholders filed complaints at FERC seeking to reduce the ROE component of the transmission rates that MISO Transmission Owners, including Otter Tail, may collect under the MISO Tariff. The two groups of complainants sought to reduce the, then current, ROE of 12.38 percent to 9.15 percent and 8.67 percent, respectively.

FERC issued its decision on the first complaint on September 28, 2016, granting approval of a 10.32 percent base ROE plus any applicable adder effective prospectively from that date. Otter Tail and other MISO Transmission Owners were granted a 50-basis point adder for participation in a Regional Transmission Organization (RTO) to be applied to the base ROE.

The second complaint for the time period of February 12, 2015 through May 11, 2016 is still pending before FERC. The Administrative Law Judge issued an Initial Decision on June 30, 2016 recommending a 9.7 percent base ROE plus any applicable adders. The timing of the FERC decision on the second complaint is unknown. Otter Tail does not include any adjustments in this filing related to the second complaint due to the uncertainty of timing and ultimate decision outcome.

- *MISO Multi-Value Project Auction Revenue Rights (MVP ARR)*. The MVP ARR revenues are derived from increased transmission capacity attributable to MVP projects placed in service within the MISO footprint. The value of these MVP ARRs is determined during MISO’s annual Financial Transmission Rights auction. The revenues are distributed to all MISO market participants in a manner similar to how Schedule 26A expenses are allocated to MISO market participants for all MVP projects. The revenue is identified in Attachment 18 and is reflected as a credit in the rider (Attachment 4, line 40).
- *Revenue credit for administrative and general expenses recovered through MISO Tariff for non-retail portion of projects qualifying for regional cost allocation*. These TCRR rate update calculations include a revenue credit (reduction to TCRR revenue requirements) to account for reimbursements through MISO’s Tariff for administrative and general operating and maintenance expenses. The revenue credit is for the entire amount of such revenues received through the MISO Tariff, whether related to the retail or non-retail 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 that may already be recovered through Otter Tail’s current retail rates. The revenue credit is reflected in Attachment 15 and Attachment 16 on the line titled “Overhead Credit for Non-Retail Share” for each project. For this period, the percentage is about one 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 adjustment for MISO Tariff Schedules 37 and 38*. The TCRR rate update calculation includes revenue credits to reflect revenues received from MISO pursuant to Schedules 37 and 38 of the MISO Tariff. The Schedule 37 revenues represent Otter Tail’s share from MISO of the Schedule 26 cost allocation assigned to former MISO transmission owners that withdrew from MISO. These owners have an ongoing obligation to pay for MISO Schedule 26 transmission projects due to their prior MISO membership.

In Attachment 18, there are no forecast amounts for Schedule 37 and 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 that MISO develops. MISO does delineate Schedule 37 and 38 revenues when reporting actuals. The Schedule 37 revenue credit reflected in this TCRR update for 2018 is \$26,568 as can be seen in Attachment 4, line number 37. The Schedule 38 revenue credit reflected in this TCRR update for 2018 is \$33,399, as seen in Attachment 4 on line 38. These are actual amounts through July 2018 and are included as part of the 2018 true-up amount.

C. General Rate Case No. PU-17-398

Otter Tail's current open rate case proceeding impacts this TCRR annual update. On July 6, 2018, the Parties³ to the proceeding filed a Settlement Agreement with the Commission. On July 11, 2018, the Commission held a hearing presided over by Administrative Law Judge Patrick Ward where the rate case and Settlement Agreement were discussed. On August 21, 2018, the Commission held a work session where the Commission considered the Settlement Agreement. While the Commission did not determine if the Settlement Agreement should be approved during this work session, the treatment of the TCRR within the rate case is uncontested; Otter Tail makes this annual TCRR update in expectation that treatment of the TCRR within the case is acceptable to the Commission. For the purposes of this update, Otter Tail provides details and revenue requirement data that includes the anticipated outcomes of the general rate case proceeding. Otter Tail's compliance filing will be made within 30 days of receipt of a final order and will include:

- Return on Equity of 9.77 percent effective January 2018
- D2 factor of 39.5989 percent effective January 2018
- 16 complete and in-service projects moving from the TCRR into base rates as of October 2018.
- Forecasted September 2018 tracker balance
- Expected October 2018 through December 2018 rates and resulting December 2018 tracker balance

In the event that the Commission's Order or timing of final rate implementation differs from the proposed Settlement Agreement in ways that impact Otter Tail's TCRR assumptions made in this update, Otter Tail will submit a Supplemental TCRR filing encompassing all items as Ordered by the Commission.

³ Otter Tail Power Company, North Dakota Public Service Commission Advocacy Staff, Midwest Large Energy Consumers and Wal-Mart Stores, Inc.

D. Change in SPP Related Expenses - Attachments 13 & 14

SPP related charges incurred by Otter Tail during 2018 are lower than originally forecasted in our 2017 Annual Update⁴. This is mainly driven by the timing of SPP invoice corrections caused by Otter Tail being over billed by SPP in early 2017. These 2017 invoice corrections came through SPP settlements in early 2018; thereby reducing the amount of SPP expenses incurred during 2018. In addition to these invoice corrections, the amount of Otter Tail load subject to the SPP tariff during 2018 decreased when compared to the load forecasted in last year's Annual Update.

As seen in Attachment 13 of this filing, SPP Schedule 7, 8 and 9 expenses are forecasted to be \$1.5 million (Total System) / \$0.59 million (ND), and Schedule 11 expenses are forecasted to be \$0.125 million (Total System) / \$0.050 million (ND) in 2018. Otter Tail does not anticipate as many invoice corrections in 2019 and forecasts 2019 using a higher amount of Otter Tail load taking SPP transmission service than what was used in 2018. Any difference between the forecasted charges and the actual charges incurred as a result of SPP Schedules 7, 8, 9 and 11 will be trued up in next year's filing.

MISO Schedule 9 revenues related to CPEC paying for transmission service in MISO are higher than originally forecasted. Due to the complex nature of unwinding the long-standing agreements that had been in place between Otter Tail and CPEC for nearly 60 years, CPEC's relatively recent move in joining the SPP, and Otter Tail's requirement to secure transmission service through SPP, the parties continue to work together to ensure that charges and revenues are accurately assigned to the appropriate party with any billing errors from prior periods being handled through settlements in later periods. As seen in Attachment 14 of this filing, MISO Schedule 9 revenues related to CPEC are forecasted to be \$0.362 million (Total System) / \$0.144 million (ND), in 2018.

⁴ Case No. PU-17-340.

E. Projects previously approved for recovery in Otter Tail’s TCRR

Three projects previously approved for inclusion in Otter Tail’s TCRR and still under construction, are included in this update. These were approved in Case Numbers PU-12-702, PU-16-624, and PU-17-340.

The retail allocation of costs and revenues for these projects have been updated and carried out through 2018 and 2019 and are reflected in Attachments 5-7.

- | | |
|---------------------------------------|--------------|
| 1. MVP - Big Stone South to Ellendale | Attachment 5 |
| 2. Max-Ryder 41.6 kV Line Upgrade | Attachment 6 |
| 3. Bagley 115 kV Switch Station | Attachment 7 |

These projects are still under construction. No portions of these three projects were included in rate base for the 2018 Test Year that will determine final base rates in Otter Tail’s current general rate case.

F. New transmission projects included in this TCRR rate update

N.D.C.C. § 49-05-04.3 authorizes an approved TCRR to provide “for an adjustment of rates to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities.” Each year, Otter Tail reviews the performance and reliability of its transmission system and identifies any existing facilities that need to be upgraded and any new facilities that are needed to ensure the continued reliable delivery of energy to its customers.

Otter Tail has three new projects that it is requesting approval for inclusion in this TCRR update, which are described in detail below. Otter Tail verified that the costs requested for recovery in the TCRR for each of the three new projects were not included in its current general rate case and that the three projects are not currently being recovered as a result of that proceeding.

Description of New Project – Lake Norden Area Transmission Improvements – Attachment 8

Otter Tail owns and operates a 41.6 kV transmission network in northeastern South Dakota. As a result of load growth occurring in the Lake Norden, South Dakota area and the lack of sufficient capability of the existing 41.6 kV transmission network, Otter Tail has identified the need for a new 115 kV transmission project to maintain reliability for the growing load in that area.

The Lake Norden Area Transmission Improvement Project includes construction of approximately 47 miles of 115 kV line, along with upgrades to the existing Hetland and Toronto 115 kV substations, to provide an additional 115 kV transmission path to the area in the event that the existing 115 kV transmission path is unavailable. This project will benefit the system by increasing reliability, decreasing line exposure, as well as adding operational flexibility to perform routine maintenance on facilities in the local area without putting as many customers at risk for a service interruption.

The current estimate for the Lake Norden Area Transmission Improvement project is approximately \$36 million (Total System) with an estimated in-service date of December 2020. Phase I is expected to be complete in June 2019 with an estimated cost of \$11 million. North Dakota's jurisdictional share of the total project cost based on the D2 allocation factor of 39.5989 percent is approximately \$14.3 million.

Description of New Project – Buffalo to Alice 115 kV Line Rebuild – Attachment 9

Otter Tail owns and operates a 115 kV line in North Dakota between Buffalo and Alice. As a result of the poor historical performance of this 115 kV line, approximately 7 miles of this existing 115 kV line needs to be upgraded in order to improve the reliability of the transmission system in the area. As a result, Otter Tail is rebuilding the existing 115 kV line with new vertical framing and static wire protection that will be more effective in reducing lightning-induced interruptions.

Approximately \$0.35 million (Total System) of capital cost for this project was included in the 2018 general rate case test year. Those project dollars are excluded from the project costs being requested for recovery in the TCRR to avoid double-recovery.

The current estimate for the Buffalo to Alice 115kV Line Rebuild that Otter Tail is seeking TCRR recovery is approximately \$1.6 million (Total System) with a total project estimated in-service date of December 2021. North Dakota's jurisdictional share of the total project based on the D2 allocation factor of 39.5989 percent is approximately \$0.64 million.

Description of New Project – Velva to Simcoe 41.6 kV Line Replacement – Attachment 10

Otter Tail owns and operates seven miles of 41.6kV transmission line in North Dakota between Velva and Simcoe. Due to the age and condition of this existing line resulting in poor reliability performance, Otter Tail will be replacing the structures and conductor along this line segment using its new 41.6 kV transmission line design to improve reliability in the area. The project consists of replacing structures, hardware, and conductor, along with installing a static wire for lightning protection.

The project is scheduled to happen in two phases: three miles will be replaced in 2018 and four miles will be replaced in 2019. The current estimate for replacing this transmission line is approximately \$0.97 million with an estimated in-service date of December 2019. North Dakota's jurisdictional share of this project based on the D2 allocation factor of 39.5989 percent is approximately \$0.39 million.

III. ALLOCATIONS AND RATE DESIGN

The allocations and rate design for this annual update are the same as approved by the Commission in the April 25, 2012, TCRR Order. Specifically, the class allocations use the transmission demand allocation factor, D2, from Otter Tail's current North Dakota general rate case (Case No. PU-17-398) to allocate total revenue requirements to jurisdictions (North Dakota, 39.5989 percent) and rate classes. The rate design uses a demand-only billing rate for the Large General Service Class (LGS) and an energy-only billing rate ($\text{\$/kWh}$) for all other customers. The rate design detail is included in Attachment 3.

IV. RATE APPLICATION AND IMPACT

The total 2019 revenue requirement is made up of three components: the estimated revenue requirement for calendar year 2019; the true-up associated with an updated projection of the 2018 revenue requirement; and the carrying charge attributable to any projected over or under-collection.

The revenue requirement attributable to calendar year 2019, as shown on line 43 of Attachment 4, page 2 of 2, is \$5,042,451. This amount is based on actual net revenues and expenses which have been included in the TCRR tracker through July 2018, and updated projections for August through December of 2018 as well as 2019.

Otter Tail anticipates making a rate case compliance filing 30 days after receiving the final order estimating an October 2018 through December 2018 rate that results in a tracker balance of zero at the end of December 2018. The 2018 true-up portion of the revenue requirement calculation, as reflected on Attachment 2, line 19 and as computed in Attachment 4, page 1 of 2, line 49, reflects no true-up balance.

By design and structure of the TCRR, the related carrying credit of \$2,832, as computed on Attachment 4, page 2 of 2, line 48, will be credited to customers as a reduction in the 2019 revenue requirements. The net revenue requirement for 2019 upon which rates are developed is \$5,039,477 as shown on line 45 of Attachment 4, page 2 of 2. The proposed rates for this net revenue requirement are calculated on lines 11-14 of Attachment 3.

The TCRR is applicable to electric service under all of Otter Tail's retail rate schedules. The charge is included as part of the Energy and Renewable Adjustment line on customers' bills. The proposed rates, as calculated in Attachment 3 are as follows:

<u>Class</u>	<u>¢ / kWh</u>
Large General Service	\$1.113/kW
Controlled Service	0.056¢
Lighting	0.211¢
All other service	0.370¢

These rates represent a decrease to the rates currently in effect. The estimated decrease for a residential customer using 1,000 kWh is \$1.73 per month.

The proposed rates are based on an effective date of January 1, 2019 through December 31, 2019. If the implementation date is significantly later than January 1, 2019, Otter Tail requests the option to recalculate the Transmission Cost Recovery Rates in order to recover all approved costs in the remainder of the recommended recovery time period.

V. TRANSMISSION COST RECOVERY RIDER RATE SCHEDULE

Otter Tail's redline and clean update to the Transmission Cost Recovery Rider (Section 13.07) is Attachment 21 to this Application.

VI. FILING FEE

As allowed under N.D.C.C. § 49-05-04.3, Subd. 2.d, Otter Tail includes a filing fee of \$10,000 and will pay such additional fees as are reasonably necessary for completion of the application process as determined by the Commission.

VII. NOTICE TO CUSTOMERS

Otter Tail will include on September bills to its North Dakota customers, the following notice of the proposed change in rates for the transmission rider.

On August 31, 2018, Otter Tail Power Company filed a request with the North Dakota Public Service Commission to decrease our Transmission Cost Recovery Rider, which is part of the Energy and Renewable adj. line on your bill. The proposed change is for bills rendered on and after January 1, 2019. This change is proposed only and, if suspended by the Commission, the new rates will not be effective until the Commission takes action.

See panel below for more information.

If approved, customers can expect the following average monthly bill impacts: Large General Service: \$(220.72) (from \$1.632 per kW to \$1.113 per kW), Controlled Service: \$(0.37) (from 0.085 cents per kWh to 0.056 cents per kWh), Lighting: \$(0.09) (from 0.312 cents per kWh to 0.211 cents per kWh), all other service: (\$1.73/\$2.34) (from 0.543 cents per kWh to 0.370 cents per kWh).

For more information contact customer service at 800-257-4044 or place an inquiry from our web site at otpc.com.

Attachment 22 is a draft of the proposed notice to customers upon implementation of the updated rates.

VIII. CONCLUSION

For the foregoing reasons, Otter Tail Power Company respectfully requests approval to implement this update to its Transmission Cost Recovery Rider, Section 13.07, effective as of January 1, 2019.

Date: August 31, 2018

Respectfully submitted:

OTTER TAIL POWER COMPANY

/s/ Gina S. Ice

Gina S. Ice

Rates Analyst

Regulatory Administration

215 South Cascade Street

P.O. Box 496

Fergus Falls, MN 56538-0496

Phone (218) 739-8275

Attachments

Attachment 1	Revenue
Attachment 2	Revenue Requirements Summary
Attachment 3	Rate Design
Attachment 4	Tracker Summary
Attachment 5	MVP Big Stone South to Ellendale Revenue Requirements
Attachment 6	Max to Ryder 41.6 kV Line Upgrade
Attachment 7	Bagley 115 kV Switch Station
Attachment 8	Lake Norden Area Transmission Improvements
Attachment 9	Buffalo to Alice 115 kV Line Rebuild
Attachment 10	Velva-Simcoe 41.6 kV Line Replacement
Attachment 11	Attachment O Revenue Credit for Non-MISO Projects
Attachment 12	MISO Schedule 26 and 26A Expense
Attachment 13	SPP Expenses
Attachment 14	MISO Schedule 9 Revenue
Attachment 15	MISO Schedule 26 Revenue
Attachment 16	MISO Schedule 26A Revenue
Attachment 17	MISO Multi-Value Project Auction Revenue Rights Credit
Attachment 18	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 19	ADIT Pro-Rate Projection
Attachment 20	ADIT Pro-Rate Preservation
Attachment 21	Electric Rate Schedule Section 13.07 Redline and Clean
Attachment 22	Proposed Customer Notice

Projected Revenue for 2019

Line No.	Class		Units	Rate per Unit	Amount
1	Large General Service	(a)	1,257,189 kW	\$1.113	\$1,399,261
2					
3	Controlled Service	(b)	247,197,486 kWh	0.056¢	\$139,648
4					
5	Lighting	(c)	22,895,386 kWh	0.211¢	\$48,388
6					
7	All other service		934,077,741 kWh	0.370¢	\$3,452,181
8					
9	Total revenue				<u>\$5,039,477</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

Line No.	Revenue Requirements	2019
1	MVP - Ellendale to Big Stone South	\$109,985
2	Max - Ryder 41.6 kV Line Upgrades	\$87,298
3	Bagley 115kV Switch Station	\$138,069
4	Lake Norden Area Transmission	\$541,979
5	Buffalo - Enderlin	\$41,751
6	Velva - Simco	\$23,134
7	Total Revenue Requirement	\$942,216
8	MISO Schedule 26 Expense	5,036,850
9	MISO Schedule 26A Expense	3,337,978
10	SPP Schedule 9 Expense	934,262
11	SPP Schedule 11 Expense	73,139
12	MISO Schedule 9 Revenue	(957,152)
13	MISO Schedule 26 Revenue	(3,740,111)
14	MISO Schedule 37 Revenue	(0)
15	MISO Schedule 38 Revenue	(0)
16	MISO Schedule 26A Revenue	(568,099)
17	MISO MVP ARR Revenue	(16,632)
18	Carrying Cost	(2,832)
19	True-Up	0
20	Net Revenue Requirement	\$5,039,477

Class Allocation and Rate Design

Line No.			2019
1	North Dakota Revenue Requirements		\$5,039,477 *
2	Large General Service Class	27.77%	\$1,399,261
3	Controlled Service	2.77%	139,648
4	Lighting	0.96%	48,388
5	All Other Service	68.50%	3,452,181
6	Total		\$5,039,477
7	Large General Service Class	kW	1,257,189
8	Controlled Service	kWh	247,197,486
9	Lighting	kWh	22,895,386
10	All Other Service	kWh	934,077,741
11	Large General Service Class	\$ / kW	1.113
12	Controlled Service	cents / kWh	0.056
13	Lighting	cents / kWh	0.211
14	All Other Service	cents / kWh	0.370

* Jurisdictional transmission allocation factor (D2 = 39.598907%) is from Otter Tail's current general rate case in North Dakota Case No. PU-17-398.

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2018												YE Projected		
		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Projected	September Projected	October Projected	November Projected	December Projected			
1	Revenue Requirements															
2	CAPX 2020: Fargo	192,671	192,835	191,637	191,629	192,481	191,629	193,144	191,629	193,390						1,731,045
3	CAPX 2020: Bemidji	46,867	46,887	46,708	46,708	47,299	46,708	49,227	46,708	50,188						427,301
4	Cass Lake-Nary-Helga-Bemidji	7,735	7,735	7,735	7,738	7,738	7,738	7,738	7,738	7,738						69,632
5	Rugby Wind Interconnection	170	170	170	170	170	170	170	170	170						1,527
6	Casselton – Buffalo 115 kV Project	20,910	20,911	20,912	20,912	20,912	20,912	20,907	20,911	20,911						188,199
7	CAPX 2020: Brookings - Hampton	19,806	19,974	19,931	19,931	19,790	20,013	19,790	19,790	19,962						178,846
8	MVP: Big Stone Area Transmission	4,671	4,671	4,674	4,677	4,672	4,691	4,630	4,670	4,671						42,025
9	MVP: Big Stone South to Ellendale	6,869	6,869	6,869	6,869	6,869	6,869	6,869	6,869	6,869	6,869	6,869	6,869	6,869	6,869	82,431
10	Ramsey 230/115 kW Transformer Upgrade	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072						9,647
11	Karlstad, MN Capacitor Bank Project	3,208	3,208	3,208	3,208	3,208	3,208	3,208	3,208	3,208						28,869
12	Oakes Area Transmission Improvements	20,562	20,562	20,562	20,562	20,562	20,562	20,562	20,562	20,562						185,062
13	Hankinson Transformer Addition	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146						18,319
14	NERC Compliance	42,765	42,765	42,765	42,765	42,765	42,765	42,765	42,765	42,765						384,886
15	Summit Transformer	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260						20,341
16	Spiritwood Station Interconnection	2,213	2,213	2,213	2,213	2,213	2,213	2,213	2,213	2,213						19,913
17	Max- Ryder 41.6 kV Line Upgrades	5,407	5,407	5,407	5,407	5,407	5,407	5,589	5,589	5,634	5,634	5,634	5,634	5,634	5,634	66,154
18	Rugby Breaker Station	5,325	5,326	5,326	5,330	5,330	5,326	5,401	5,333	5,333						48,032
19	Granville Jct Breaker Station	2,943	2,943	2,943	2,943	2,943	2,943	2,943	2,943	2,943						26,486
20	Bagley 115kV Switch Station	5,424	5,424	5,424	5,424	5,424	5,424	5,424	5,424	5,424	5,424	5,424	5,424	5,424	5,424	68,013
21	Lake Norden Area Transmission Improvements															0
22	Buffalo to Alice 115 kV Line Rebuild															0
23	Velva to Simcoe 41.6 kV Line Replacement															0
24	Total Revenue Requirements	393,024	393,379	391,963	391,824	393,484	391,828	396,062	392,001	397,460	17,927	19,389	19,389	19,389	19,389	3,597,729
25	ADIT Preservation of Proration	961	961	961	961	961	961	961	961	961	961	961	961	961	961	11,536
26	MISO & SPP Expenses															
27	MISO Schedule 26 Expense	491,893	449,777	385,205	326,809	311,512	283,383	367,679	400,598	345,516	390,583	400,598	500,748	500,748	500,748	4,654,301
28	MISO Schedule 26A Expense	286,676	257,690	172,137	197,164	169,124	174,192	201,651	249,063	237,553	257,656	289,560	329,978	329,978	329,978	2,822,445
29	SPP Schedule 9 Expense	30,936	(38,136)	(19,846)	68,115	68,310	71,428	69,605	66,986	66,986	66,986	66,986	66,986	66,986	66,986	585,343
30	SPP Schedule 11 Expense	1,278	(189)	1,202	5,268	5,271	5,324	5,166	5,240	5,240	5,240	5,240	49,521	49,521	49,521	49,521
31	Total MISO & SPP Expenses	810,782	669,143	538,699	597,356	554,217	534,327	644,101	721,888	655,296	720,466	762,384	902,952	902,952	902,952	8,111,611
32	MISO Revenues															
33	MISO Schedule 9 Revenue	(88,947)	702,906	(56,500)	(47,749)	(29,853)	(25,360)	(15,240)	(91,439)	(78,213)	(97,253)	(151,666)	(164,200)	(164,200)	(164,200)	(143,514)
34	MISO Schedule 26 Revenue	(381,832)	(340,749)	(300,814)	(243,804)	(391,170)	(413,771)	(428,530)	(414,139)	(328,258)	(267,832)	(223,451)	(302,935)	(302,935)	(302,935)	(4,037,285)
35	MISO Schedule 37 Revenue	(4,177)	(4,177)	(3,790)	(3,016)	(3,790)	(3,810)	(3,810)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(26,568)
36	MISO Schedule 38 Revenue	(5,250)	(5,250)	(4,812)	(3,935)	(4,812)	(4,671)	(4,671)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(33,399)
37	MISO Schedule 26A Revenue	(57,574)	(48,511)	(36,891)	(42,374)	(45,312)	(50,390)	(55,752)	(59,460)	(52,125)	(47,610)	(45,353)	(44,789)	(44,789)	(44,789)	(586,140)
38	MISO MVP ARR Revenue	(2,190)	(2,074)	(2,199)	(984)	(913)	(745)	(394)	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(16,430)
39	Total MISO Revenues	(539,968)	302,144	(405,005)	(341,861)	(475,850)	(498,746)	(508,396)	(566,424)	(459,982)	(414,082)	(421,857)	(513,311)	(513,311)	(513,311)	(4,843,337)
40	Net Revenue Requirement	664,799	1,365,627	526,617	648,280	472,813	428,371	532,729	548,427	593,734	325,272	360,878	409,992	409,992	409,992	6,877,539
41	Billed (forecast kWh x adj factor)	865,720	806,154	693,188	618,577	546,741	519,730	542,541	585,971	582,688	241,321	296,749	344,247	344,247	344,247	6,643,628
42	Difference	(200,921)	559,473	(166,570)	29,703	(73,928)	(91,360)	(9,812)	(37,544)	11,047	83,951	64,129	65,745	65,745	65,745	233,911
43	Carrying Charge	(1,604)	(2,713)	833	(222)	(35)	(506)	(1,091)	(1,160)	(1,407)	(1,345)	(819)	(416)	(416)	(416)	(10,485)
44	Cumulative Difference	(425,951)	130,809	(34,928)	(5,448)	(79,411)	(171,276)	(182,179)	(220,883)	(211,244)	(128,638)	(65,329)	0	0	0	0
45	Carrying Charge Calculation	(2,713)	833	(222)	(35)	(506)	(1,091)	(1,160)	(1,407)	(1,345)	(819)	(416)	0	0	0	0
46	Cumulative Carrying Charge	(120,659)	(119,826)	(120,048)	(120,083)	(120,588)	(121,679)	(122,839)	(124,246)	(125,591)	(126,410)	(126,827)	(126,827)	(126,827)	(126,827)	(126,827)
47	Carrying cost	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%
48	Forecasted Sales (MWh)								124,286	123,589	120,291	147,921	171,597	171,597	171,597	687,684

Approved November 29, 2017 (PU-17-340);
Rate Effective January 1, 2018

SUMMARY	Jan 2018 - Dec 2018
Revenue requirements	\$7,963,367
Carrying Charge	(16,014)
2017 True-Up	11,354
Total requirements	\$7,958,707
Jan 2018-Dec 2018 projected sales in MWh	1,584,387
Average Rate	\$0.00502

Approved February 27, 2018 (PU-17-398);
Rate Effective March 1, 2018

SUMMARY	Mar 2018 - Dec 2018
Revenue requirements	\$7,469,920
Carrying Charge	(16,014)
2017 True-Up	11,354
Total requirements	\$7,465,260
Jan 2018-Dec 2018 projected sales in MWh	1,584,387
Average Rate	\$0.00471

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2019												YE Projected
		January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	
1	Revenue Requirements													
2	CAPX 2020: Fargo													0
3	CAPX 2020: Bemidji													0
4	Cass Lake-Nary-Helga-Bemidji													0
5	Rugby Wind Interconnection													0
6	Casselton – Buffalo 115 kV Project													0
7	CAPX 2020: Brookings - Hampton													0
8	MVP: Big Stone Area Transmission													0
9	MVP: Big Stone South to Ellendale	8,095	8,095	8,095	9,509	9,512	9,514	9,517	9,517	9,533	9,533	9,533	9,533	109,985
10	Ramsey 230/115 kW Transformer Upgrade													0
11	Karlstad, MN Capacitor Bank Project													0
12	Oakes Area Transmission Improvements													0
13	Hankinson Transformer Addition													0
14	NERC Compliance													0
15	Summit Transformer													0
16	Spiritwood Station Interconnection													0
17	Max- Ryder 41.6 kV Line Upgrades	7,079	7,148	7,148	7,148	7,148	7,148	7,387	7,408	7,420	7,420	7,420	7,420	87,298
18	Rugby Breaker Station													0
19	Granville Jct Breaker Station													0
20	Bagley 115kV Switch Station	11,506	11,506	11,506	11,506	11,506	11,506	11,506	11,506	11,506	11,506	11,506	11,506	138,069
21	Lake Norden Area Transmission Improvements	41,786	41,786	41,786	41,786	41,786	41,786	48,544	48,544	48,544	48,544	48,544	48,544	541,979
22	Buffalo to Alice 115 kV Line Rebuild	3,479	3,479	3,479	3,479	3,479	3,479	3,479	3,479	3,479	3,479	3,479	3,479	41,751
23	Velva to Simcoe 41.6 kV Line Replacement	1,928	1,928	1,928	1,928	1,928	1,928	1,928	1,928	1,928	1,928	1,928	1,928	23,134
24	Total Revenue Requirements	73,873	73,942	73,942	75,356	75,359	75,361	82,361	82,362	82,410	82,410	82,410	82,410	942,216
25	ADIT Preservation of Proration													
26	MISO & SPP Expenses													
27	MISO Schedule 26 Expense	507,346	465,503	444,582	381,817	329,514	360,896	418,430	418,430	360,896	407,969	418,430	523,037	5,036,850
28	MISO Schedule 26A Expense	348,982	313,304	300,861	260,563	245,082	240,873	251,080	252,738	241,522	258,930	292,112	331,930	3,337,978
29	SPP Schedule 9 Expense	69,139	78,648	78,648	78,648	78,648	78,648	78,648	78,648	78,648	78,648	78,648	78,648	934,262
30	SPP Schedule 11 Expense	5,397	6,158	6,158	6,158	6,158	6,158	6,158	6,158	6,158	6,158	6,158	6,158	73,139
31	Total MISO & SPP Expenses	930,865	863,613	830,249	727,186	659,402	686,575	754,316	755,974	687,224	751,705	795,348	939,774	9,382,229
32	MISO Revenues													
33	MISO Schedule 9 Revenue	(93,216)	(69,512)	(58,593)	(66,164)	(31,306)	(28,020)	(18,557)	(92,489)	(78,865)	(98,477)	(154,522)	(167,432)	(957,152)
34	MISO Schedule 26 Revenue	(311,676)	(311,676)	(311,676)	(311,676)	(311,676)	(311,676)	(311,676)	(311,676)	(311,676)	(311,676)	(311,676)	(311,676)	(3,740,111)
35	MISO Schedule 37 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
36	MISO Schedule 38 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
37	MISO Schedule 26A Revenue	(47,342)	(47,342)	(47,342)	(47,342)	(47,342)	(47,342)	(47,342)	(47,342)	(47,342)	(47,342)	(47,342)	(47,342)	(568,099)
38	MISO MVP ARR Revenue	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(1,386)	(16,632)
39	Total MISO Revenues	(453,620)	(429,915)	(418,996)	(426,567)	(391,710)	(388,423)	(378,960)	(452,892)	(439,269)	(458,880)	(514,925)	(527,836)	(5,281,994)
40	Net Revenue Requirement	551,118	507,640	485,194	375,975	343,051	373,513	457,716	385,464	330,365	375,234	362,833	494,348	5,042,451
41	Billed (forecast kWh x adj factor)	563,184	555,393	497,164	444,229	354,354	330,808	340,446	352,520	351,110	341,736	420,600	487,933	5,039,477
42	Difference	(12,078)	(47,765)	(11,981)	(68,266)	(11,314)	42,693	117,258	32,933	(20,757)	33,486	(57,779)	6,403	2,832
43	Carrying Charge	0	(77)	(382)	(460)	(898)	(976)	(710)	32	242	111	325	(41)	(2,832)
44	Cumulative Difference	(12,078)	(59,921)	(72,283)	(141,010)	(153,222)	(111,505)	5,042	38,008	17,492	51,090	(6,363)	0	0
45	Carrying Charge Calculation	(77)	(382)	(460)	(898)	(976)	(710)	32	242	111	325	(41)	0	
46	Cumulative Carrying Charge	(126,903)	(127,285)	(127,745)	(128,643)	(129,619)	(130,329)	(130,297)	(130,055)	(129,944)	(129,618)	(129,659)	(129,659)	
47	Carrying cost	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	
48	Forecasted Sales (MWh)	198,177	195,435	174,945	156,318	124,692	116,407	119,798	124,047	123,551	120,252	148,003	171,697	1,773,320

Compliance Filing Estimate

SUMMARY	Oct 2018 - Dec 2018
Revenue requirements	\$1,096,142
Carrying Charge	(\$2,581)
2017 True-Up	(\$211,244)
Total requirements	\$882,318
Oct 2018-Dec 2018 projected sales in MWh	\$439,809
Average Rate	\$0.00201

SUMMARY	Jan 2019 - Dec 2019
Revenue requirements	\$5,042,451
Carrying Charge	(2,832)
True-Up	0
Total requirements	\$5,039,477
Jan 2019-Dec 2019 projected sales in MWh	1,773,320
Average Rate	\$0.00284

Line No.	Year>>	2019 Projected Jan	2019 Projected Feb	2019 Projected Mar	2019 Projected Apr	2019 Projected May	2019 Projected Jun	2019 Projected Jul	2019 Projected Aug	2019 Projected Sep	2019 Projected Oct	2019 Projected Nov	2019 Projected Dec	2019 Projected Total
RATE BASE														
1	Plant Balance	0	0	113,551,577	113,788,372	113,908,299	114,177,726	114,205,507	115,442,217	115,453,997	115,465,778	115,477,558	115,489,339	115,489,339
2	Accumulated Depreciation	0	0	0	(165,359)	(331,064)	(496,943)	(663,214)	(829,526)	(997,639)	(1,165,768)	(1,333,915)	(1,502,080)	(1,502,080)
3	Net Plant in Service	0	0	113,551,577	113,623,012	113,577,235	113,680,784	113,542,293	114,612,691	114,456,359	114,300,009	114,143,643	113,987,259	113,987,259
4	CWIP (Project #104593 & 105643)	109,080,982	109,211,458	0	0	0	0	0	0	0	0	0	0	0
5	ADIT Federal Proration Factors	0.9178	0.8411	0.7562	0.6740	0.5890	0.5068	0.4219	0.3370	0.2548	0.1699	0.0877	0.0027	0
6	Accumulated Deferred Income Taxes Federal & State	0	0	(112,631)	(186,203)	(252,727)	(312,444)	(365,027)	(410,588)	(449,188)	(480,801)	(505,653)	(523,518)	(523,518)
7	Ending rate base	109,080,982	109,211,458	113,438,946	113,436,809	113,324,509	113,368,339	113,177,266	114,202,103	114,007,170	113,819,208	113,637,990	113,463,741	113,463,741
8														
9	OTP Load Percentage	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%
10	Remove Non-OTP Load Portion	(106,724,832)	(106,852,491)	(110,988,685)	(110,986,574)	(110,876,699)	(110,919,593)	(110,732,637)	(111,735,339)	(111,544,616)	(111,360,719)	(111,183,409)	(111,012,924)	(111,012,924)
11	Retail Ending Rate Base	2,356,149	2,358,968	2,450,261	2,450,235	2,447,809	2,448,756	2,444,629	2,466,765	2,462,555	2,458,495	2,454,581	2,450,817	2,450,817
12														
13	Average rate base	202,397	202,397	202,397	202,397	202,397	202,397	202,397	202,397	202,397	202,397	202,397	202,397	2,428,763
14														
15	Return on Rate Base	15,467	15,467	15,467	15,467	15,467	15,467	15,467	15,467	15,467	15,467	15,467	15,467	185,606
16														
17	Available for return (equity portion of rate base)	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	124,577
18														
19	EXPENSES													
20	O&M and Depreciation													
21	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Property Tax	75,146	75,146	75,146	75,146	75,146	75,146	75,146	75,146	75,146	75,146	75,146	75,146	901,751
23	Book Depreciation	0	0	0	165,359	165,704	165,879	166,271	166,312	168,113	168,130	168,147	168,164	1,502,080
24	Total O&M and Depreciation Expense	75,146	75,146	75,146	240,505	240,850	241,025	241,417	241,458	243,259	243,276	243,293	243,310	2,403,831
25														
26	OTP Load Percentage	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%	2.16%
27	Remove Non-OTP Load Portion	(73,523)	(73,523)	(73,523)	(235,311)	(235,648)	(235,819)	(236,203)	(236,242)	(238,004)	(238,021)	(238,038)	(238,055)	(2,351,908)
28	Retail O&M and Depreciation Expenses	1,623	1,623	1,623	5,195	5,202	5,206	5,215	5,215	5,254	5,255	5,255	5,255	51,923
29														
30	Income before Taxes	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	124,577
31	Available for return (from above)	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	10,381	124,577
32	Taxable Income (grossed up)	13,733	13,733	13,733	13,733	13,733	13,733	13,733	13,733	13,733	13,733	13,733	13,733	164,795
33														
34	Income Taxes	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	40,218
35	Current and Def Income Taxes	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	40,218
36	Total Income Tax Expense	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	3,352	40,218
37														
38														
39	REVENUE REQUIREMENTS													
40	Expenses	4,975	4,975	4,975	8,546	8,554	8,558	8,566	8,567	8,606	8,606	8,607	8,607	2,444,049
41	Return on rate base	15,467	15,467	15,467	15,467	15,467	15,467	15,467	15,467	15,467	15,467	15,467	15,467	185,606
42	Subtotal revenue requirements	20,442	20,442	20,442	24,014	24,021	24,025	24,033	24,034	24,073	24,073	24,074	24,074	2,629,655
43	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
44	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
45	Total revenue requirements	20,442	20,442	20,442	24,014	24,021	24,025	24,033	24,034	24,073	24,073	24,074	24,074	2,629,655
46														
47	North Dakota share - D2 factor	8,095	8,095	8,095	9,509	9,512	9,514	9,517	9,517	9,533	9,533	9,533	9,533	109,985

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	Ratio		Cost		WA Cost				Property tax				
3	Debt	47.50%		5.29%		2.51%				2019 composite rate		0.85%		
4	Preferred equity	0.00%		0.00%		0.00%								
5	Common equity	52.50%		9.77%		5.13%								
6	Total	100.00%				7.64%		Overall Return						
7														
8														
9														
10	Project life (years)	Book		Tax		15-year MACRS								
11		50												
12														
13				Fed Portion		State Portion								
14	Effective Tax Rate	24.40%		20.09%		4.31%								
15	Tax conversion factor	1.32284												
16	Wholesale Revenue Credit	0.00%												
17	ND share - D2 factor	39.5989%												
18	Deferred Tax													
19	Book depreciation	0	0	0	165,359	165,704	165,879	166,271	166,312	168,113	168,130	168,147	168,164	1,502,080
20	Tax depreciation-Federal	0	0	577,447	577,447	577,447	577,447	577,447	577,447	577,447	577,447	577,447	577,447	5,774,467
21	Tax depreciation-ND	0	0	577,447	577,447	577,447	577,447	577,447	577,447	577,447	577,447	577,447	577,447	5,774,467
22	Federal deferred income taxes	0	0	(116,037)	(82,809)	(82,809)	(82,809)	(82,625)	(82,617)	(82,255)	(82,252)	(82,248)	(82,245)	(858,706)
23	State deferred income taxes	0	0	(24,888)	(17,761)	(17,746)	(17,746)	(17,722)	(17,720)	(17,642)	(17,642)	(17,641)	(17,640)	(184,147)

Line No.	Year>>	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018
		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected December
RATE BASE														
1	Plant Balance	1,309,000	1,309,000	1,309,000	1,309,000	1,309,000	1,632,910	1,632,910	1,712,021	1,712,021	1,712,021	1,712,021	1,712,021	1,712,021
2	Accumulated Depreciation	(23,271)	(25,332)	(27,393)	(29,454)	(31,515)	(33,576)	(36,147)	(38,719)	(41,414)	(44,110)	(46,806)	(49,501)	(49,501)
3	Net Plant in Service	1,285,729	1,283,668	1,281,607	1,279,546	1,277,485	1,599,334	1,596,763	1,673,302	1,670,606	1,667,911	1,665,215	1,662,519	1,662,519
4	CWIP (Project #127607 & #128423)	306,278	392,098	436,658	536,328	579,010	299,409	300,304	242,482	286,746	330,870	373,912	395,202	395,202
5	ADIT Federal Proration Factors	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000
6	Accumulated Deferred Income Taxes Federal & State	(272,336)	(273,411)	(274,486)	(275,561)	(276,635)	(277,710)	(278,660)	(279,611)	(280,530)	(281,450)	(282,370)	(283,290)	(283,290)
7	Ending rate base	1,319,671	1,402,356	1,443,779	1,540,314	1,579,860	1,621,033	1,618,406	1,636,173	1,676,822	1,717,330	1,756,756	1,774,432	1,774,432
8														
9	Average rate base	130,680	130,680	130,680	130,680	130,680	130,680	130,680	130,680	130,680	130,680	130,680	130,680	1,568,165
10														
11	Return on Rate Base	9,987	9,987	9,987	9,987	9,987	9,987	9,987	9,987	9,987	9,987	9,987	9,987	119,839
12														
13	Available for return (equity portion of rate base)	6,703	6,703	6,703	6,703	6,703	6,703	6,703	6,703	6,703	6,703	6,703	6,703	80,435
14														
EXPENSES														
O&M and Depreciation														
16	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Property Tax	927	927	927	927	927	927	927	927	927	927	927	927	11,127
18	Book Depreciation	2,061	2,061	2,061	2,061	2,061	2,061	2,571	2,571	2,696	2,696	2,696	2,696	28,292
19	Total O&M and Depreciation Expense	2,988	2,988	2,988	2,988	2,988	2,988	3,498	3,498	3,623	3,623	3,623	3,623	39,418
20														
21														
22	Income before Taxes													
23	Available for return (from above)	6,703	6,703	6,703	6,703	6,703	6,703	6,703	6,703	6,703	6,703	6,703	6,703	80,435
24	Taxable Income (grossed up)	8,867	8,867	8,867	8,867	8,867	8,867	8,867	8,867	8,867	8,867	8,867	8,867	106,403
25														
26	Income Taxes													
27	Current and Def Income Taxes	2,164	2,164	2,164	2,164	2,164	2,164	2,164	2,164	2,164	2,164	2,164	2,164	25,967
28	Total Income Tax Expense	2,164	2,164	2,164	2,164	2,164	2,164	2,164	2,164	2,164	2,164	2,164	2,164	25,967
29														
30														
REVENUE REQUIREMENTS														
31	Expenses	5,152	5,152	5,152	5,152	5,152	5,152	5,662	5,662	5,787	5,787	5,787	5,787	65,386
32	Return on rate base	9,987	9,987	9,987	9,987	9,987	9,987	9,987	9,987	9,987	9,987	9,987	9,987	119,839
33	Subtotal revenue requirements	15,139	15,139	15,139	15,139	15,139	15,139	15,649	15,649	15,773	15,773	15,773	15,773	185,225
34	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Wholesale Revenue Credit	(1,485)	(1,485)	(1,485)	(1,485)	(1,485)	(1,485)	(1,535)	(1,535)	(1,547)	(1,547)	(1,547)	(1,547)	(18,164)
36	Total revenue requirements	13,654	13,654	13,654	13,654	13,654	13,654	14,114	14,114	14,227	14,227	14,227	14,227	167,061
37														
38														
39	North Dakota share - D2 factor	5,407	5,407	5,407	5,407	5,407	5,407	5,589	5,589	5,634	5,634	5,634	5,634	66,154

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	Ratio	Cost	WA Cost	Property tax									
3	Debt	47.50%	5.29%	2.51%	2018 composite rate									
4	Preferred equity	0.00%	0.00%	0.00%	0.85%									
5	Common equity	52.50%	9.77%	5.13%										
6	Total	100.00%		7.64%	Overall Return									
7														
8														
9														
10	Project life (years)	Book	Tax											
11		50	15-year MACRS											
12				Fed Portion	State Portion									
13	Effective Tax Rate	24.40%	20.09%	4.31%										
14	Tax conversion factor	1.32284												
15	Wholesale Revenue Credit	9.81%												
16	ND share - D2 factor	39.5989%												
17														
18	Deferred Tax													
19	Book depreciation	2,061	2,061	2,061	2,061	2,061	2,061	2,571	2,571	2,696	2,696	2,696	2,696	28,292
20	Tax depreciation-Federal	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	77,579
21	Tax depreciation-ND	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	6,465	77,579
22	Federal deferred income taxes	(885)	(885)	(885)	(885)	(885)	(885)	(782)	(782)	(757)	(757)	(757)	(757)	(9,904)
23	State deferred income taxes	(190)	(190)	(190)	(190)	(190)	(190)	(168)	(168)	(162)	(162)	(162)	(162)	(2,124)

Line No.	Year>>	2019 Projected January	2019 Projected February	2019 Projected March	2019 Projected April	2019 Projected May	2019 Projected June	2019 Projected July	2019 Projected August	2019 Projected September	2019 Projected October	2019 Projected November	2019 Projected December	2019 Projected Total
RATE BASE														
1	Plant Balance	1,824,590	1,824,590	1,824,590	1,824,590	1,824,590	2,212,223	2,247,223	2,267,223	2,267,223	2,267,223	2,267,223	2,267,223	2,267,223
2	Accumulated Depreciation	(52,197)	(55,070)	(57,943)	(60,816)	(63,689)	(66,562)	(70,045)	(73,584)	(77,154)	(80,724)	(84,294)	(87,863)	(87,863)
3	Net Plant in Service	1,772,393	1,769,520	1,766,647	1,763,774	1,760,901	2,145,661	2,177,178	2,193,639	2,190,069	2,186,499	2,182,929	2,179,360	2,179,360
4	CWIP (Project #127607 & #128423)	282,633	282,633	282,633	317,633	352,633	0	0	0	0	0	0	0	0
5	ADIT Federal Proration Factors	0.9178	0.8411	0.7562	0.6740	0.5890	0.5068	0.4219	0.3370	0.2548	0.1699	0.0877	0.0027	
6	Accumulated Deferred Income Taxes Federal & State	(284,909)	(286,381)	(287,735)	(288,974)	(290,094)	(291,100)	(291,909)	(292,605)	(293,193)	(293,675)	(294,054)	(294,327)	(294,327)
7	Ending rate base	1,770,117	1,765,772	1,761,545	1,792,433	1,823,440	1,854,561	1,885,268	1,901,035	1,896,876	1,892,824	1,888,875	1,885,033	1,885,033
8														
9	Average rate base	153,155	153,155	153,155	153,155	153,155	153,155	153,155	153,155	153,155	153,155	153,155	153,155	1,837,862
10														
11	Return on Rate Base	11,704	11,704	11,704	11,704	11,704	11,704	11,704	11,704	11,704	11,704	11,704	11,704	140,449
12														
13	Available for return (equity portion of rate base)	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856	94,269
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	1,213	1,213	1,213	1,213	1,213	1,213	1,213	1,213	1,213	1,213	1,213	1,213	14,552
19	Book Depreciation	2,696	2,873	2,873	2,873	2,873	2,873	3,483	3,538	3,570	3,570	3,570	3,570	38,362
20	Total O&M and Depreciation Expense	3,908	4,086	4,086	4,086	4,086	4,086	4,696	4,751	4,783	4,783	4,783	4,783	52,914
21														
22	Income before Taxes													
23	Available for return (from above)	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856	94,269
24	Taxable Income (grossed up)	10,392	10,392	10,392	10,392	10,392	10,392	10,392	10,392	10,392	10,392	10,392	10,392	124,702
25														
26	Income Taxes													
27	Current and Def Income Taxes	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	30,433
28	Total Income Tax Expense	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	30,433
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	6,445	6,622	6,622	6,622	6,622	6,622	7,232	7,287	7,319	7,319	7,319	7,319	83,348
33	Return on rate base	11,704	11,704	11,704	11,704	11,704	11,704	11,704	11,704	11,704	11,704	11,704	11,704	140,449
34	Subtotal revenue requirements	18,149	18,326	18,326	18,326	18,326	18,326	18,936	18,991	19,023	19,023	19,023	19,023	223,797
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(271)	(274)	(274)	(274)	(274)	(274)	(283)	(284)	(284)	(284)	(284)	(284)	(3,342)
37	Total revenue requirements	17,878	18,052	18,052	18,052	18,052	18,052	18,653	18,708	18,739	18,739	18,739	18,739	220,455
38														
39	North Dakota share - D2 factor	7,079	7,148	7,148	7,148	7,148	7,148	7,387	7,408	7,420	7,420	7,420	7,420	87,298

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	Ratio	Cost	WA Cost										
3	Debt	47.50%	5.29%	2.51%	Property tax									
4	Preferred equity	0.00%	0.00%	0.00%	2019 composite rate									
5	Common equity	52.50%	9.77%	5.13%	0.85%									
6	Total	100.00%		7.64%	Overall Return									
7														
8														
9														
10	Project life (years)	Book	Tax											
11		50	15-year MACRS											
12				Fed Portion	State Portion									
13	Effective Tax Rate	24.40%	20.09%	4.31%										
14	Tax conversion factor	1.32284												
15	Wholesale Revenue Credit	1.49%												
16	ND share - D2 factor	39.5989%												
17														
18	Deferred Tax													
19	Book depreciation	2,696	2,873	2,873	2,873	2,873	2,873	3,483	3,538	3,570	3,570	3,570	3,570	38,362
20	Tax depreciation-Federal	9,812	9,812	9,812	9,812	9,812	9,812	9,812	9,812	9,812	9,812	9,812	9,812	117,747
21	Tax depreciation-ND	9,812	9,812	9,812	9,812	9,812	9,812	9,812	9,812	9,812	9,812	9,812	9,812	117,747
22	Federal deferred income taxes	(1,430)	(1,394)	(1,394)	(1,394)	(1,394)	(1,394)	(1,272)	(1,261)	(1,254)	(1,254)	(1,254)	(1,254)	(15,952)
23	State deferred income taxes	(307)	(299)	(299)	(299)	(299)	(299)	(273)	(270)	(269)	(269)	(269)	(269)	(3,422)

Line No.	Year>>	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	3,000,654	3,000,654	3,073,639	3,073,639	
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	(4,094)	(8,188)	(8,188)	
3	Net Plant in Service	0	0	0	0	0	0	0	0	3,000,654	2,996,560	3,065,452	3,065,452	
CWIP Calculation:														
	Beginning Balance	769,578	820,865	950,415	1,184,487	1,527,058	1,819,205	2,046,570	2,133,153	2,370,388	2,867,962	0	0	
	Additional CWIP	51,287	129,550	234,072	342,570	292,148	227,365	86,583	237,235	497,574	132,693	0	72,985	
	Closings from CWIP										(3,000,654)	0	(72,985)	
	AFDUC													
													2,304,062	
4	CWIP (Project #106134)	106134	820,865	950,415	1,184,487	1,527,058	1,819,205	2,046,570	2,133,153	2,370,388	2,867,962	0	0	
5	ADIT Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	(12,502)	(24,005)	(35,508)	
7	Ending rate base	820,865	950,415	1,184,487	1,527,058	1,819,205	2,046,570	2,133,153	2,370,388	2,867,962	2,988,152	2,972,555	3,029,944	
8	Average rate base	163,335	163,335	163,335	163,335	163,335	163,335	163,335	163,335	163,335	163,335	163,335	163,335	
9	Return on Rate Base	12,482	12,482	12,482	12,482	12,482	12,482	12,482	12,482	12,482	12,482	12,482	12,482	
10													149,785	
11	Available for return (equity portion of rate base)	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	
12													100,535	
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	
18	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	
19	Book Depreciation	0	0	0	0	0	0	0	0	0	4,094	4,094	8,188	
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	4,094	4,094	8,188	
21	Income before Taxes	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	
22	Available for return (from above)	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	8,378	
23	Taxable Income (grossed up)	11,083	11,083	11,083	11,083	11,083	11,083	11,083	11,083	11,083	11,083	11,083	11,083	
24													132,991	
25	Income Taxes	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	
26	Current and Def Income Taxes	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	
27	Total Income Tax Expense	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	
28													32,456	
29													32,456	
30														
REVENUE REQUIREMENTS														
31	Expenses	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	6,799	6,799	
32	Return on rate base	12,482	12,482	12,482	12,482	12,482	12,482	12,482	12,482	12,482	12,482	12,482	12,482	
33	Subtotal revenue requirements	15,187	15,187	15,187	15,187	15,187	15,187	15,187	15,187	15,187	15,187	19,281	19,281	
34	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
35	Wholesale Revenue Credit	(1,489)	(1,489)	(1,489)	(1,489)	(1,489)	(1,489)	(1,489)	(1,489)	(1,489)	(1,489)	(1,891)	(1,891)	
36	Total revenue requirements	13,698	13,698	13,698	13,698	13,698	13,698	13,698	13,698	13,698	17,390	17,390	171,755	
37														
38	North Dakota share - D2 factor	5,424	5,424	5,424	5,424	5,424	5,424	5,424	5,424	5,424	5,424	6,886	6,886	
39													68,013	

Line No.	SUPPORTING INFORMATION / DATA
1	
2	ND Cap Structure with allowed ROE per order.
3	Capital Structure
4	Debt
5	Preferred equity
6	Common equity
7	Total
8	
9	
10	Project life (years)
11	
12	
13	Effective Tax Rate
14	Tax conversion factor
15	Wholesale Revenue Credit
16	ND share - D2 factor
17	
18	Deferred Tax
19	Book depreciation
20	Tax depreciation-Federal
21	Tax depreciation-ND
22	Federal deferred income taxes
23	State deferred income taxes

Ratio	Cost	WA Cost	Property tax
47.50%	5.29%	2.51%	2018 composite rate
0.00%	0.00%	0.00%	0.85%
52.50%	9.77%	5.13%	
100.00%		7.64% Overall Return	

Book	Tax
50	15-year MACRS

Fed Portion	State Portion
24.40%	20.09%
1.32284	4.31%
9.81%	
39.5989%	

0	0	0	0	0	0	0	0	0	0	0	4,094	4,094	8,188
0	0	0	0	0	0	0	0	0	0	51,227	51,227	51,227	153,682
0	0	0	0	0	0	0	0	0	0	51,227	51,227	51,227	153,682
0	0	0	0	0	0	0	0	0	0	(10,294)	(9,471)	(9,471)	(29,237)
0	0	0	0	0	0	0	0	0	0	(2,208)	(2,031)	(2,031)	(6,271)

Line No.	Year>>	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	0
CWIP Calculation:														
	Beginning Balance	0	0	1,717	6,739	102,895	150,012	157,886	161,971	211,943	263,777	315,879	368,247	
	Additional CWIP	0	1,711	4,996	95,873	46,461	7,060	3,249	48,987	50,577	50,577	50,577	2,832	362,902
	Closings from CWIP													
	AFDUC	0	5	26	283	656	814	835	985	1,257	1,524	1,792	1,933	10,111
4	CWIP (Project #2) T05008.038	0	1,717	6,739	102,895	150,012	157,886	161,971	211,943	263,777	315,879	368,247	373,012	373,012
5	ADIT Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Ending rate base	0	1,717	6,739	102,895	150,012	157,886	161,971	211,943	263,777	315,879	368,247	373,012	373,012
8														
9	Average rate base	13,552	13,552	13,552	13,552	13,552	13,552	13,552	13,552	13,552	13,552	13,552	13,552	162,621
10														
11	Return on Rate Base	1,036	1,036	1,036	1,036	1,036	1,036	1,036	1,036	1,036	1,036	1,036	1,036	12,428
12														
13	Available for return (equity portion of rate base)	695	695	695	695	695	695	695	695	695	695	695	695	8,341
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
21														
22	Income before Taxes													
23	Available for return (from above)	695	695	695	695	695	695	695	695	695	695	695	695	8,341
24	Taxable Income (grossed up)	920	920	920	920	920	920	920	920	920	920	920	920	11,034
25														
26	Income Taxes													
27	Current and Def Income Taxes	224	224	224	224	224	224	224	224	224	224	224	224	2,693
28	Total Income Tax Expense	224	224	224	224	224	224	224	224	224	224	224	224	2,693
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Return on rate base	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Subtotal revenue requirements	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Total revenue requirements	0	0	0	0	0	0	0	0	0	0	0	0	0
38														
39	North Dakota share - D2 factor	0	0	0	0	0	0	0	0	0	0	0	0	0

Line No.	SUPPORTING INFORMATION / DATA
1	
2	ND Cap Structure with allowed ROE per order.
3	Capital Structure
4	Debt
5	Preferred equity
6	Common equity
7	Total
8	
9	
10	Project life (years)
11	
12	
13	Effective Tax Rate
14	Tax conversion factor
15	Wholesale Revenue Credit
16	ND share - D2 factor
17	
18	Deferred Tax
19	Book depreciation
20	Tax depreciation-Federal
21	Tax depreciation-ND
22	Federal deferred income taxes
23	State deferred income taxes

Ratio	Cost	WA Cost	Property tax
47.50%	5.29%	2.51%	2018 composite rate
0.00%	0.00%	0.00%	0.85%
52.50%	9.77%	5.13%	
100.00%		7.64% Overall Return	

Book	Tax
50	15-year MACRS

Fed Portion	State Portion
24.40%	20.09%
1.32284	4.31%
9.81%	
39.5989%	

2019 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$36,547,470
	REVENUE CREDITS	(Note T)	<u>Total</u>	<u>Allocator</u>	
2	Account No. 454	(page 4, line 34)	117,879	TP 1.00000	117,879
3	Account No. 456.1	(page 4, line 37)	2,844,947	TP 1.00000	2,844,947
4	Revenues from Grandfathered Interzonal Transactions		0	TP 1.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP 1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)				2,962,826
7	To back out Schedule 9 Revenues received				(2,417,118)
8	Total Revenue Subject to the Wholesale Revenue Credit				545,708
9				Wholesale Revenue Credit	1.49%

2018 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$35,186,749
	REVENUE CREDITS	(Note T)	<u>Total</u>	<u>Allocator</u>	
2	Account No. 454	(page 4, line 34)	109,188	TP 1.00000	109,188
3	Account No. 456.1	(page 4, line 37)	3,703,797	TP 1.00000	3,703,797
4	Revenues from Grandfathered Interzonal Transactions		0	TP 1.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP 1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)				3,812,985
7	To back out Schedule 9 Revenues received				(362,420)
8	Total Revenue Subject to the Wholesale Revenue Credit				3,450,565
9				Wholesale Revenue Credit	9.81%

		2018												
Line No.	SCHEDULE 26	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected
1	MISO Schedule 26 Expense	1,242,210	1,135,853	972,785	825,313	786,683	715,646	928,524	1,011,658	872,555	986,366	1,011,658	1,264,572	11,753,822
2	OTP owned portion of expenses not recoverable via rider 0.002%	(22)	(20)	(18)	(15)	(14)	(13)	(17)	(18)	(16)	(18)	(18)	(23)	(212)
3	MISO Schedule 26 Expense Recoverable	1,242,187	1,135,832	972,768	825,298	786,669	715,633	928,508	1,011,639	872,539	986,348	1,011,639	1,264,549	11,753,611
4														
5	North Dakota share 39.5989%	491,893	449,777	385,205	326,809	311,512	283,383	367,679	400,598	345,516	390,583	400,598	500,748	4,654,301
6														
7	MISO Schedule 26A Expense	723,948	650,751	434,702	497,902	427,093	439,892	509,234	628,965	599,898	650,665	731,232	833,301	7,127,584
8														
9	North Dakota share 39.5989%	286,676	257,690	172,137	197,164	169,124	174,192	201,651	249,063	237,553	257,656	289,560	329,978	2,822,445

		2019												
Line No.	SCHEDULE 26	Jan Projected	Feb Projected	Mar Projected	Apr Projected	May Projected	Jun Projected	Jul Projected	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected
1	MISO Schedule 26 Expense	1,281,236	1,175,567	1,122,732	964,229	832,143	911,394	1,056,689	1,056,689	911,394	1,030,272	1,056,689	1,320,862	12,719,897
2	OTP owned portion of expenses not recoverable via rider 0.002%	(23)	(21)	(20)	(17)	(15)	(16)	(19)	(19)	(16)	(19)	(19)	(24)	(229)
3	MISO Schedule 26 Expense Recoverable	1,281,213	1,175,546	1,122,712	964,212	832,128	911,378	1,056,670	1,056,670	911,378	1,030,253	1,056,670	1,320,838	12,719,668
4														
5	North Dakota share 39.5989%	507,346	465,503	444,582	381,817	329,514	360,896	418,430	418,430	360,896	407,969	418,430	523,037	5,036,850
6														
7	MISO Schedule 26A Expense	881,293	791,193	759,771	658,005	618,911	608,283	634,058	638,246	609,922	653,880	737,677	838,231	8,429,470
8														
9	North Dakota share 39.5989%	348,982	313,304	300,861	260,563	245,082	240,873	251,080	252,738	241,522	258,930	292,112	331,930	3,337,978

		2018												
Line No.	MISO Revenues	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected
1	MISO Schedule 9 Revenues (CPEC Portion)	(413,323)	(353,309)	(322,392)	(297,866)	(247,714)	(255,696)	(227,333)	(440,882)	(403,816)	(457,176)	(609,666)	(644,794)	(4,673,967)
2	CPEC Facility Credits in MISO	164,052	2,109,654	164,052	164,052	164,052	184,624	184,624	184,624	184,624	184,624	184,624	184,624	4,058,231
3	Non-OTP Schedule 9 Revenues	24,653	18,717	15,660	13,234	8,274	7,029	4,224	25,344	21,678	26,955	42,037	45,511	253,316
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(224,619)	1,775,063	(142,680)	(120,580)	(75,388)	(64,043)	(38,485)	(230,914)	(197,513)	(245,596)	(383,006)	(414,659)	(362,420)
5	North Dakota share 39.5989%	(88,947)	702,906	(56,500)	(47,749)	(29,853)	(25,360)	(15,240)	(91,439)	(78,213)	(97,253)	(151,666)	(164,200)	(143,514)

		2019												
Line No.	MISO Revenues	Jan Projected	Feb Projected	Mar Projected	Apr Projected	May Projected	Jun Projected	Jul Projected	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected
1	MISO Schedule 9 Revenues (CPEC Portion)	(445,862)	(379,429)	(348,829)	(370,048)	(272,359)	(273,435)	(246,916)	(454,109)	(415,930)	(470,891)	(627,956)	(664,138)	(4,969,902)
2	CPEC Facility Credits in MISO	184,624	184,624	184,624	184,624	184,624	194,911	194,911	194,911	194,911	194,911	194,911	194,911	2,287,494
3	Non-OTP Schedule 9 Revenues	25,836	19,266	16,240	18,338	8,677	7,766	5,143	25,635	21,859	27,294	42,828	46,407	265,290
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(235,401)	(175,539)	(147,965)	(167,085)	(79,058)	(70,758)	(46,862)	(233,563)	(199,161)	(248,686)	(390,218)	(422,821)	(2,417,118)
5	North Dakota share 39.5989%	(93,216)	(69,512)	(58,593)	(66,164)	(31,306)	(28,020)	(18,557)	(92,489)	(78,865)	(98,477)	(154,522)	(167,432)	(957,152)

Line No.	2018	2018												Total Projected	
		Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected		
1	Total Schedule 26 Revenue														
2	Overhead Credit for Non-Retail Share	1.184%	(1,397,033)	(1,246,721)	(1,100,607)	(892,020)	(1,431,199)	(1,513,890)	(1,567,891)	(1,515,236)	(1,201,019)	(979,936)	(817,556)	(1,108,369)	(14,771,477)
3			(16,543)	(14,763)	(13,033)	(10,563)	(16,948)	(17,927)	(18,566)	(17,943)	(14,222)	(11,604)	(9,681)	(13,125)	(174,917)
4															
5	Fargo	66.643%	(931,024)	(830,852)	(733,478)	(594,469)	(953,794)	(1,008,901)	(1,044,889)	(1,009,799)	(800,395)	(653,058)	(544,844)	(738,650)	(9,844,155)
6	Retail Load Share		71.22%	71.22%	71.22%	71.22%	71.22%	71.22%	71.22%	71.22%	71.22%	71.22%	71.22%	71.22%	
7	Retail Revenue		(663,066)	(591,725)	(522,375)	(423,375)	(679,283)	(718,530)	(744,160)	(719,169)	(570,034)	(465,102)	(388,032)	(526,059)	(7,010,909)
8															
9	Overhead Credit for Non-Retail Share		(11,025)	(9,839)	(8,685)	(7,039)	(11,294)	(11,947)	(12,373)	(11,958)	(9,478)	(7,733)	(6,452)	(8,747)	(116,570)
10	Non-Retail Load Share		28.78%	28.78%	28.78%	28.78%	28.78%	28.78%	28.78%	28.78%	28.78%	28.78%	28.78%	28.78%	
11	Non-Retail Overhead Credit		(3,173)	(2,832)	(2,500)	(2,026)	(3,251)	(3,438)	(3,561)	(3,442)	(2,728)	(2,226)	(1,857)	(2,517)	(33,550)
12															
13	Total Revenue Credit for Fargo		(666,239)	(594,556)	(524,875)	(425,401)	(682,533)	(721,968)	(747,721)	(722,610)	(572,761)	(467,327)	(389,889)	(528,577)	(7,044,459)
14															
15															
16	Bemidji	14.093%	(196,884)	(175,700)	(155,109)	(125,712)	(201,699)	(213,352)	(220,963)	(213,542)	(169,260)	(138,102)	(115,218)	(156,202)	(2,081,744)
17	Retail Load Share		87.60%	87.60%	87.60%	87.60%	87.60%	87.60%	87.60%	87.60%	87.60%	87.60%	87.60%	87.60%	
18	Retail Revenue		(172,474)	(153,917)	(135,878)	(110,127)	(176,692)	(186,901)	(193,568)	(187,067)	(148,275)	(120,980)	(100,933)	(136,836)	(1,823,650)
19															
20	Overhead Credit for Non-Retail Share		(2,331)	(2,081)	(1,837)	(1,489)	(2,388)	(2,526)	(2,617)	(2,529)	(2,004)	(1,635)	(1,364)	(1,850)	(24,651)
21	Non-Retail Load Share		12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	
22	Non-Retail Overhead Credit		(289)	(258)	(228)	(185)	(296)	(313)	(324)	(314)	(248)	(203)	(169)	(229)	(3,056)
23															
24	Total Revenue Credit for Bemidji		(172,763)	(154,175)	(136,106)	(110,311)	(176,988)	(187,214)	(193,892)	(187,381)	(148,523)	(121,183)	(101,103)	(137,066)	(1,826,706)
25															
26															
27	Cass Lake - Nary - Helga - Bemidji	5.994%	(83,738)	(74,728)	(65,970)	(53,468)	(85,786)	(90,743)	(93,979)	(90,823)	(71,989)	(58,737)	(49,004)	(66,436)	(885,402)
28	Retail Load Share		33.69%	33.69%	33.69%	33.69%	33.69%	33.69%	33.69%	33.69%	33.69%	33.69%	33.69%	33.69%	
29	Retail Revenue		(28,213)	(25,178)	(22,227)	(18,014)	(28,903)	(30,573)	(31,664)	(30,600)	(24,255)	(19,790)	(16,511)	(22,383)	(298,310)
30															
31	Overhead Credit for Non-Retail Share		(992)	(885)	(781)	(633)	(1,016)	(1,075)	(1,113)	(1,075)	(852)	(696)	(580)	(787)	(10,485)
32	Non-Retail Load Share		66.31%	66.31%	66.31%	66.31%	66.31%	66.31%	66.31%	66.31%	66.31%	66.31%	66.31%	66.31%	
33	Non-Retail Overhead Credit		(658)	(587)	(518)	(420)	(674)	(712)	(738)	(713)	(565)	(461)	(385)	(522)	(6,952)
34															
35	Total Revenue Credit for Bemidji		(28,871)	(25,764)	(22,745)	(18,434)	(29,577)	(31,285)	(32,401)	(31,313)	(24,820)	(20,251)	(16,895)	(22,905)	(305,262)
36															
37															
38															
39															
40															
41															
42															
43															
44															
45	Spiritwood	0.495%	(6,915)	(6,171)	(5,448)	(4,415)	(7,084)	(7,494)	(7,761)	(7,500)	(5,945)	(4,851)	(4,047)	(5,486)	(73,119)
46	Retail Load Share		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
47	Retail Revenue		(6,915)	(6,171)	(5,448)	(4,415)	(7,084)	(7,494)	(7,761)	(7,500)	(5,945)	(4,851)	(4,047)	(5,486)	(73,119)
48															
49	Total Revenue Credit for Spiritwood		(6,915)	(6,171)	(5,448)	(4,415)	(7,084)	(7,494)	(7,761)	(7,500)	(5,945)	(4,851)	(4,047)	(5,486)	(73,119)
50															
51															
52	Courtney Wind	0.305%	(4,261)	(3,802)	(3,357)	(2,721)	(4,365)	(4,617)	(4,782)	(4,621)	(3,663)	(2,989)	(2,494)	(3,381)	(45,053)
53	Retail Load Share		0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	
54	Retail Revenue		(36)	(33)	(29)	(23)	(37)	(39)	(41)	(40)	(31)	(26)	(21)	(29)	(385)
55															
56	Overhead Credit for Non-Retail Share		(50)	(45)	(40)	(32)	(52)	(55)	(57)	(55)	(43)	(35)	(30)	(40)	(533)
57	Non-Retail Load Share		99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	
58	Non-Retail Overhead Credit		(50)	(45)	(39)	(32)	(51)	(54)	(56)	(54)	(43)	(35)	(29)	(40)	(529)
59															
60	Total Revenue Credit for Courtney Wind		(86)	(77)	(68)	(55)	(89)	(94)	(97)	(94)	(74)	(61)	(51)	(69)	(914)
61															
62															
63															
64															
65															
66	Retail Share of Schedule 26 Revenue		(964,248)	(860,501)	(759,652)	(615,683)	(987,830)	(1,044,904)	(1,082,176)	(1,045,834)	(828,958)	(676,363)	(564,287)	(765,009)	(10,195,445)
67															
68	North Dakota Share	39.5989%	(381,832)	(340,749)	(300,814)	(243,804)	(391,170)	(413,771)	(428,530)	(414,139)	(328,258)	(267,832)	(223,451)	(302,935)	(4,037,285)

Line No.	2018	2018												Total Projected
		Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	
1	Schedule 26A Revenue	(2,371,505)	(1,998,146)	(1,519,591)	(1,745,447)	(1,866,440)	(2,075,598)	(2,296,462)	(2,449,260)	(2,147,092)	(1,961,143)	(1,868,168)	(1,844,924)	(24,143,777)
2	Overhead Credit for Non-Retail Share	1.184%	(28,082)	(23,661)	(17,994)	(20,669)	(22,101)	(24,578)	(29,003)	(25,425)	(23,223)	(22,122)	(21,847)	(285,899)
3														
4														
5	CAPX 2020 - Brookings	14.290%	(338,876)	(285,525)	(217,142)	(249,416)	(266,705)	(296,593)	(349,987)	(306,809)	(280,238)	(266,952)	(263,630)	(3,450,025)
6	Retail Load Share		22.589%	22.589%	22.589%	22.589%	22.589%	22.589%	22.589%	22.589%	22.589%	22.589%	22.589%	
7	Retail Revenue		(76,549)	(64,497)	(49,050)	(56,341)	(60,246)	(66,997)	(74,126)	(79,059)	(69,305)	(60,302)	(59,551)	(779,326)
8														
9	Overhead Credit for Non-Retail Share		(4,013)	(3,381)	(2,571)	(2,953)	(3,158)	(3,512)	(4,144)	(3,633)	(3,318)	(3,161)	(3,122)	(40,854)
10	Non-Retail Load Share		77.411%	77.411%	77.411%	77.411%	77.411%	77.411%	77.411%	77.411%	77.411%	77.411%	77.411%	
11	Non-Retail Overhead Credit		(3,106)	(2,617)	(1,990)	(2,286)	(2,445)	(2,719)	(3,208)	(2,812)	(2,569)	(2,447)	(2,417)	(31,625)
12														
13	Total Revenue Credit for CAPX Brookings		(79,655)	(67,115)	(51,041)	(58,627)	(62,691)	(69,716)	(82,267)	(72,117)	(65,872)	(62,749)	(61,968)	(810,951)
14														
15														
16	MVP BS South - Brookings	41.274%	(978,805)	(824,707)	(627,190)	(720,409)	(770,347)	(856,674)	(947,832)	(1,010,898)	(886,182)	(809,434)	(771,060)	(9,965,006)
17	Retail Load Share		1.982%	1.983%	1.982%	1.982%	1.982%	1.982%	1.982%	1.982%	1.982%	1.982%	1.982%	
18	Retail Revenue		(19,404)	(16,354)	(12,433)	(14,280)	(15,272)	(16,983)	(18,790)	(20,036)	(17,566)	(16,045)	(15,094)	(197,539)
19														
20	Overhead Credit for Non-Retail Share		(11,591)	(9,766)	(7,427)	(8,531)	(9,122)	(10,144)	(11,224)	(11,971)	(10,494)	(9,585)	(9,131)	(118,001)
21	Non-Retail Load Share		98.018%	98.017%	98.018%	98.018%	98.018%	98.018%	98.018%	98.018%	98.018%	98.018%	98.018%	
22	Non-Retail Overhead Credit		(11,361)	(9,572)	(7,280)	(8,362)	(8,941)	(9,943)	(11,001)	(11,733)	(10,286)	(9,395)	(8,950)	(115,662)
23														
24	Total Revenue Credit for MVP Brookings		(30,765)	(25,926)	(19,712)	(22,642)	(24,213)	(26,926)	(29,791)	(31,770)	(27,852)	(25,440)	(24,234)	(313,201)
25														
26														
27	MVP Ellendale - BS South	44.437%	(1,053,823)	(887,914)	(675,259)	(775,623)	(829,388)	(922,331)	(1,020,476)	(1,088,375)	(954,101)	(871,471)	(830,156)	(10,728,746)
28	Retail Load Share		2.160%	2.160%	2.160%	2.160%	2.160%	2.160%	2.160%	2.160%	2.160%	2.160%	2.160%	
29	Retail Revenue		(22,763)	(19,179)	(14,586)	(16,753)	(17,915)	(19,922)	(22,042)	(23,509)	(20,609)	(18,824)	(17,931)	(231,741)
30														
31	Overhead Credit for Non-Retail Share		(12,479)	(10,514)	(7,996)	(9,185)	(9,821)	(10,922)	(12,084)	(12,888)	(11,298)	(10,320)	(9,830)	(127,045)
32	Non-Retail Load Share		97.840%	97.840%	97.840%	97.840%	97.840%	97.840%	97.840%	97.840%	97.840%	97.840%	97.840%	
33	Non-Retail Overhead Credit		(12,209)	(10,287)	(7,823)	(8,986)	(9,609)	(10,686)	(11,823)	(12,610)	(11,054)	(10,097)	(9,618)	(124,300)
34														
35	Total Revenue Credit for MVP Ellendale		(34,972)	(29,466)	(22,409)	(25,740)	(27,524)	(30,608)	(33,865)	(36,119)	(31,663)	(28,920)	(27,549)	(356,041)
36														
37														
38	Retail Share of Schedule 26A Revenue		(145,392)	(122,506)	(93,162)	(107,008)	(114,428)	(127,250)	(140,791)	(150,155)	(131,632)	(120,232)	(114,532)	(1,480,193)
39														
40	North Dakota share	39.5989%	(57,574)	(48,511)	(36,891)	(42,374)	(45,312)	(50,390)	(55,752)	(59,460)	(52,125)	(47,610)	(45,353)	(586,140)

Federal ADIT Proration

	A	B	C	D
1		January 2019 - December 2019 Recovery Period		
		All Projects' Revenue Requirements	All Projects' Revenue Requirements with ADIT-Prorate	Difference due to Federal ADIT Proration (B - A)
2	Month			
3	Jan-19	\$73,776	\$73,873	\$97
4	Feb-19	\$73,845	\$73,942	\$97
5	Mar-19	\$73,845	\$73,942	\$97
6	Apr-19	\$75,259	\$75,356	\$97
7	May-19	\$75,262	\$75,359	\$97
8	Jun-19	\$75,263	\$75,361	\$97
9	Jul-19	\$82,263	\$82,361	\$97
10	Aug-19	\$82,285	\$82,382	\$97
11	Sep-19	\$82,313	\$82,410	\$97
12	Oct-19	\$82,313	\$82,410	\$97
13	Nov-19	\$82,313	\$82,410	\$97
14	Dec-19	\$82,313	\$82,410	\$97
15		\$941,050	\$942,216	\$1,166

16	Revenue Requirement Adjustment Related to Federal ADIT Proration	\$1,166
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Federal ADIT Proration

	A	B	C	D	E
1			Tax Conversion Factor	1.3228	(1/(1-24.4%))
2			Gross Up of Equity %	6.78%	(F9 * F17)
3			Equity Return %	5.13%	(F17)
4			Gross Up Factor	1.66%	(F10-F11)

		Annual	Monthly
5			
6	Debt Return %	2.51%	0.21%
7	Preferred Equity %	0.00%	0.00%
8	Equity Return %	5.13%	0.43%
9	Rate of Return	7.64%	0.64%
10	Tax RR on Equity Return	1.66%	0.14%
11	Rate Base Rev Req Gross Up Factor	9.30%	0.77%

		January 2018 - December 2018		
Month	Original ADIT Balance - All Projects	Federal ADIT Prorate Balance - All Projects	Difference due to Federal ADIT Proration (B - A)	
13				
14	Dec-17	(\$54,077,480)	(\$53,773,289)	\$304,191
15	Jan-18	(\$54,162,889)	(\$53,854,954)	
16	Feb-18	(54,241,066)	(53,929,884)	
17	Mar-18	(54,311,254)	(53,997,166)	
18	Apr-18	(54,373,728)	(54,057,164)	
19	May-18	(54,428,329)	(54,109,600)	
20	Jun-18	(54,475,312)	(54,154,719)	
21	Jul-18	(54,514,397)	(54,192,199)	
22	Aug-18	(54,545,608)	(54,222,145)	
23	Sep-18	(54,569,202)	(54,244,774)	
24	Oct-18	(54,586,496)	(54,262,480)	
25	Nov-18	(54,595,357)	(54,271,963)	
26	Dec-18	(\$54,595,634)	(\$54,273,182)	\$322,452
27	ADIT Simple Average	(\$54,336,557)	(\$54,023,235)	\$313,322

28	Rate Base Rev Req Gross Up Factor	9.30%
29	Total Company Revenue Requirement	\$29,131

30	ND Revenue Requirement Related to Federal ADIT Proration-Preservation	\$11,536
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Attachment 21

Redline and Clean

Rate Schedule

Section 13.07

TRANSMISSION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Large General Service	50-510
Controlled Service	50-511
Lighting	50-512
All Other Service	50-513

REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this rider.

APPLICATION OF RIDER: This rider is applicable to any electric service under all of the Company's retail rate schedules.

COST RECOVERY FACTOR: There shall be included on each North 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.

RATE:

TRANSMISSION COST RECOVERY			
Energy Charge per kWh:		kWh	kW
Large General Service	(a)	N/A ¢/kWh	\$1.113 4.632
Controlled Service	(b)	0.0560.085 ¢/kWh	N/A
Lighting	(c)	0.2110.312 ¢/kWh	N/A
All Other Service		0.3700.543 ¢/kWh	N/A

(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.

(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

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

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
North Dakota
Case No. PU-~~17-39818-~~
Approved by order dated: ~~February 27, 2018~~

EFFECTIVE with bills rendered on
and after ~~March-January 1, 2018, 2019~~ in

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs

TRANSMISSION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Large General Service	50-510
Controlled Service	50-511
Lighting	50-512
All Other Service	50-513

REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this rider.

APPLICATION OF RIDER: This rider is applicable to any electric service under all of the Company's retail rate schedules.

COST RECOVERY FACTOR: There shall be included on each North 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.

RATE:

TRANSMISSION COST RECOVERY			
Energy Charge per kWh:		kWh	kW
Large General Service	(a)	N/A ¢/kWh	\$1.113
Controlled Service	(b)	0.056 ¢/kWh	N/A
Lighting	(c)	0.211 ¢/kWh	N/A
All Other Service		0.370 ¢/kWh	N/A

(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.
 (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
 (c) Rate Schedules 11.03 Outdoor Lighting (energy only) and 11.04 Outdoor Lighting

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Changes to North Dakota's Transmission Cost Recovery Rider

The North Dakota Public Service Commission approved our request to update our Transmission Cost Recovery Rider. This rider recovers costs incurred for regional transmission projects that are necessary to provide our North Dakota customers with reliable and economical service.

The changes below apply to bills rendered on and after January 1, 2019, and are included in the Energy and Renewable Adjustment line item.

	Old rates		New rates		Impact of new rates ⁽¹⁾
Large General Service	\$1.632	per kW	\$1.113	per kW	(\$220.72)/month
Controlled Service	\$0.00085	per kWh	\$0.00056	per kWh	(\$0.37)/month
Lighting	\$0.00312	per kWh	\$0.00211	per kWh	(\$0.09)/month
Residential	\$0.00543	per kWh	\$0.00370	per kWh	(\$1.73)/month
All other service	\$0.00543	per kWh	\$0.00370	per kWh	(\$2.34)/month

(1) Assumes Large General Service uses 425 kW of demand, Controlled Services uses 1,300 kWh, Lighting uses 90 kWh per fixture, Residential uses 1,000 kWh, All other service uses 1,350 kWh.

For more information contact Customer Service at 800-257-4044 or place an inquiry from our web site at otpc.com.