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August 30, 2019

Mr. Steve Kahl  
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  
Case No. PU-19-**

Dear Mr. Kahl:

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 the North Dakota Public Service Commission at [ndpsc@nd.gov](mailto:ndpsc@nd.gov). If you have any questions regarding this filing, please contact me at 218-739-8577 or [lwolters@otpc.com](mailto:lwolters@otpc.com).

Sincerely,

/s/ LYNN A. WOLTERS  
Lynn A. Wolters  
Rates Analyst  
Regulatory Administration

kaw  
cc: Jerry Lein

Enclosures  
By electronic filing and U.S. mail

1 PU-19-311 Filed 08/30/2019 Pages: 67  
Transmission Facility Cost Recovery (2020)  
Otter Tail Power Company  
Lynn Wolters - Rates Analyst

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

Case No. PU-19-

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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

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**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 2020). 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 addition of seven new transmission projects not currently in base rates and not previously included in the Rider, (2) forecast updates to the BSAT-Ellendale MVP , Max-Ryder, Bagley and Lake Norden Area Transmission projects, (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 2020 upon which rates are developed is \$5,738,778. For a residential customer using 1,000 kWh per month, the bill impact of this update is an increase of \$0.73 per month. For a large general service customer with 425 kW of demand, the bill impact of this update is an increase of \$106.16 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**

Lynn A. Wolters, Rates Analyst, Regulatory Administration  
Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
(218) 739-8577

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

The date of this filing is August 30, 2019. The updated TCRR rate is calculated to take effect as of January 1, 2020.

**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 – 15 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 -8) and the new projects for which Otter Tail is requesting TCRR recovery (Attachments 9-15).

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 in the Settlement Agreement approved by the Commission<sup>1</sup> in Otter Tail's last general rate case.
- *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

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<sup>1</sup> Case No. PU-17-398, Order on Settlement, September 26, 2018.

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 prior to construction. 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 24 to this filing to show the ADIT proration calculation impact on the revenue requirement for the recovery period.

Based on research and analysis of United States Internal Revenue Service (IRS) rules related to proration, including the most recent issued IRS private letter rulings, Otter Tail provides Attachment 25 calculating 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.<sup>2</sup> Attachment 25 shows the preservation of the proration of ADIT resulting in a decrease of \$2,067 plus any applicable carrying charge to the revenue requirement. This item is included on Line No. 15 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 18 and 19 of the Tracker Account (Attachment 4) and are shown separately in Attachment 17. 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 (MISO Tariff).
- *Southwest Power Pool (SPP) Related Expenses (Attachment 18) and MISO Related Revenues (Attachment 19)*. 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 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. SPP Schedule 9 expenses appear on Line 20 and SPP Schedule 11 expenses on Line 21 of the Tracker Account (Attachment 4). Both are shown separately in Attachment 18.

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 is

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<sup>2</sup> See Treas. Reg. SS 1.167(l)-1(h)(6)(ii).

collecting in MISO for CPEC-owned transmission facilities that are eligible for inclusion in MISO. 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 25 of the Tracker Account (Attachment 4) and is shown in detail in Attachment 19.

- *MISO Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period appear on lines 26 and 29 of the Tracker Account Summary (Attachment 4) and are shown separately on Attachment 20 (Schedule 26) and Attachment 21 (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 22 and is reflected as a credit in the rider (Attachment 4, line 30).
- *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 20 and Attachment 21 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 23, 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 2019 is \$25,578 as can be seen in Attachment 4 on line 27. The Schedule 38 revenue credit reflected in this TCRR update for 2019 is \$30,224, as seen in Attachment 4 on line 28. These are actual amounts through July 2019 and are included as part of the 2019 true-up amount.

### **C. Projects previously approved for recovery in Otter Tail’s TCRR**

Four projects previously approved for inclusion in Otter Tail’s TCRR are included in this update. They were approved in Case Numbers PU-12-702, PU-16-624, PU-17-340 and PU-18-329.

The retail allocation of costs and revenues for these projects have been updated and carried out through 2019 and 2020 and are reflected in Attachments 5-8.

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|----|--------------------------------|--------------|
| 1. | BSAT – Ellendale MVP           | Attachment 5 |
| 2. | Max-Ryder 41.6 kV Line Upgrade | Attachment 6 |
| 3. | Bagley 115 kV Switch Station   | Attachment 7 |
| 4. | Lake Norden Area Transmission  | Attachment 8 |

BSAT-Ellendale MVP and Lake Norden Area Transmission Phase I went into service February 2019, Bagley Switch Station went into service December 2018 and all portions of Max-Ryder 41.6 kV line upgrade will be completed and in-service August 2019.

**D. 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 requests approval for inclusion of seven new projects 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 seven new projects were not included in Rate Case Docket No. PU-17-398 and that no portion of these seven projects is currently being recovered as a result of that proceeding.

Donaldson 115 kV Capacitor Bank – Attachment 9

Otter Tail and Minnkota Power Cooperative (MPC) have been closely monitoring the load growth in Northwest Minnesota in order to ensure that the system continues to reliably serve customers, especially during winter peak conditions when the transmission system in this area experiences its highest loads and lowest voltages. Through the course of coordinated transmission planning studies, Otter Tail and MPC reviewed past load patterns as a basis for forecasting future loads within this area and developed a regional transmission plan for the transmission system in northwest Minnesota that can be phased in as load continues to grow. The current studies have identified a regional transmission plan that includes the following projects (in sequence):

1. 115 kV Capacitor Banks at Donaldson (OTP) and Thief River Falls (MPC)
2. Under Voltage Load Shedding (UVLS) at Donaldson (OTP), Plummer (OTP), Crookston (OTP), and Thief River Falls (MPC)

3. Winger – Plummer 115 kV structure replacements (MPC) and substation improvements (OTP)
4. Winger 230/115 kV Transformer #2 (OTP)
5. Lake Ardoch 230/41.6 kV Substation (MPC)
6. Winger – Plummer 115 kV Line #2 (OTP/MPC)

Through the course of on-going transmission planning studies, Otter Tail and MPC concluded that the first three projects identified above are needed in the 2019-2020 timeframe. Otter Tail and MPC will continue to evaluate the needs on the transmission system and recommend future projects on this list as the load continues to grow in this area.

In order to address reliability concerns identified in planning studies for the 2019-2020 timeframe, and also through real-time operations, Otter Tail is proceeding with the addition of the Donaldson 115 kV capacitor bank during 2019 while MPC is installing the 115 kV capacitor bank and UVLS at Thief River Falls during 2019. The Donaldson 115 kV capacitor bank involves the addition of a new 115 kV circuit breaker, one 7.5 MVAR capacitor bank, protective relays and other associated equipment at the existing Donaldson 115/41.6 kV substation. The 115 kV capacitor bank at Donaldson will increase voltage profiles across the northern portion of the transmission system in northwest Minnesota, thereby increasing system capability and lessening the real-time operating concerns that are most challenging in the winter season.

Otter Tail and MPC have been working closely with MISO on the transmission planning studies related to northwest Minnesota. Through this coordination, Otter Tail included the Donaldson Capacitor Bank project in MISO's 2017 Transmission Expansion Plan (MTEP17), which was approved by MISO in December of 2017.<sup>3</sup>

The cost of the Donaldson Capacitor Bank project is estimated to be approximately \$0.53 million and is scheduled to be placed into service in November 2019. North Dakota's jurisdictional share of the total project cost based on the D2 allocation factor of 39.5989 percent is approximately \$0.21 million.

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<sup>3</sup> See Project Number 13043 in Appendix A of MISO's 2017 Transmission Expansion Plan, available at: <https://www.misoenergy.org/planning/planning/mtep-2017/#t=10&p=0&s=FileName&sd=desc>

## **Northwest MN UVLS (Crookston, Donaldson, Plummer) – Attachment 10**

As mentioned above, Otter Tail and Minnkota Power Cooperative (MPC) have been closely monitoring the load growth in northwest Minnesota and performing coordinated planning studies in order to ensure that the system can continue to reliably serve customers. In order to maintain acceptable voltages in preparation for the next contingency during prior outage conditions, Otter Tail and MPC identified four locations where Under Voltage Load Shedding is needed from a real-time operational perspective<sup>4</sup>. Through coordinated plans with MPC, Otter Tail is planning to install Under Voltage Load Shedding at its Crookston, Plummer, and Donaldson locations in Minnesota, while MPC is planning to install UVLS at Thief River Falls. The scope of work at each of the locations encompassed by the Otter Tail projects is described as follows:

- Crookston 115/41.6 kV Substation – Add under voltage load shedding relays on all the existing 41.6 kV circuit breakers
- Plummer 115/4.16 kV Substation – Establish a new substation near Plummer with a new 115 kV breaker and under voltage load shedding relays on the 115 kV line that serves the Enbridge Energy pumping station
- Donaldson 115/41.6 kV Substation – Add a new 115 kV breaker and under voltage load shedding relays on the 115 kV line that serves the Enbridge Energy pumping station

When the transmission system is in a prior outage condition, Power System Operators undergo an extensive sequence of switching events that prepare the system for reliably responding in case of the next contingency occurring. The UVLS Project will be designed to automatically shed load if there is another contingency during a prior outage condition without the Power System Operators preparing the system through extensive switching. This will result in more efficiency, less potential for errors, and a better utilization of the existing system during prior outage conditions, especially since the next contingency seldom occurs prior to the system being restored to its' system intact state.

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<sup>4</sup> NERC Standards that apply to the transmission planning horizon are not the same as the NERC Standards that apply in real-time operations. Power System Operators must operate the system in a manner that allows for the next contingency to occur without violating performance criteria. During real-time operations, a prior outage can occur due to planned maintenance or an unplanned failure during a storm. Regardless of the cause that leads to a prior outage, the system must be able to withstand the next contingency without jeopardizing the reliability of the larger, regional transmission system.

Otter Tail and MPC have been working closely with MISO on the transmission planning studies related to northwest Minnesota. Through this coordination, Otter Tail has included the UVLS project in MISO's current planning process (MTEP19) and is anticipated to be approved as part of MTEP19.<sup>5</sup>

The cost of the UVLS installations in northwest Minnesota is approximately \$1.2 million and the projects will be placed into service in November 2020. North Dakota's jurisdictional share of the total project cost based on the D2 allocation factor of 39.5989 percent is approximately \$0.47 million.

#### Blair 230 kV Substation – Attachment 11

The Blair 230 kV substation was constructed in the early 1970's, just prior to the Big Stone Plant coming on-line. The substation equipment is co-owned discretely between East River Electric Power Cooperative (East River) and Otter Tail. During 2017 and 2018, Otter Tail and East River began planning for a rebuild of the Blair 230 kV substation due to the condition of the equipment showing signs of aging and being at 'end of life'.<sup>6</sup> In coordination with East River, Otter Tail undertook a multi-year effort in 2018 and 2019 to replace its antiquated equipment at the Blair Substation with new modernized equipment that conforms with Otter Tail's latest design standards. The scope of work involved the replacement of two 230 kV breakers along with the necessary relaying equipment to reliably protect the transmission system. Otter Tail also installed a new control house for the Otter Tail relaying equipment to separate Otter Tail's equipment from East River's equipment in order to facilitate compliance with the critical infrastructure protection (CIP) requirements contained within North American Electric Reliability Corporation's (NERC's) reliability standards.

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<sup>5</sup> MTEP19 project number 4232. MISO's 2019 Transmission Expansion Plan (MTEP19) will not be finalized until December 2019.

<sup>6</sup> 'End of Life' refers to a condition in which the equipment has reached a point where if it failed, it would be more cost effective to replace the equipment entirely rather than trying to fix the equipment due to the unavailability of spare parts and the equipment no longer meeting current design standards.

Otter Tail receives facility credits from Southwest Power Pool (SPP) for its facilities within the Blair Substation.<sup>7</sup> Otter Tail will request recovery of the Blair Substation Rebuild through SPP facility credits during the 2020 calendar year. Any additional facility credits related to the new Blair Substation facilities received from SPP will reduce Otter Tail's Schedule 9 expenses in SPP and will be included in the TCRR tracker. Otter Tail's customers will receive the benefit of these higher facility credits and corresponding lower Schedule 9 expenses from SPP through this, and future annual TCRR filings.

The cost of the Blair Substation Rebuild was \$1.3 million and the facilities went into service in July 2019. North Dakota's jurisdictional share of the total project cost based on the D2 allocation factor of 39.5989 percent is approximately \$0.50 million.

#### Veblen 41.6 kV Capacitor Banks – Attachment 12

Otter Tail has experienced load growth along the 41.6 kV system between Browns Valley, Minnesota, and Summit, South Dakota. In addition to growing load in the lakes area near Waubay and Enemy Swim, Otter Tail has experienced load growth in the Summit area. As a result of this growing load, Otter Tail has experienced low voltage concerns during certain times of the year between Browns Valley and Summit that require looping the 41.6 kV system between the Browns Valley 230 kV substation and the Hankinson 230 kV substation. Looping the 41.6 kV system between these two high voltage sources improves voltage profiles along the existing 41.6 kV system but results in more interruptions to customers served along this system due to the extensive line exposure.

In order to address the low voltage concerns along the existing 41.6 kV system to avoid looping the 41.6 kV system between Browns Valley and Hankinson, Otter Tail identified the need for 41.6 kV capacitor banks located at the Veblen 41.6 kV Switching Station which is along the existing 41.6 kV system between Browns Valley and Summit, South Dakota. The Veblen 41.6 kV capacitor bank project included a rebuild of the existing Veblen 41.6 kV switching station in order to accommodate two new circuit

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<sup>7</sup> FERC approved SPP's request for Otter Tail facility credits on March 15, 2019, with an effective date of February 1, 2019 through FERC Docket Nos. ER19-450-001, ER19-457-000, and ER19-457-001, which was filed by SPP on November 30, 2018.

breakers, two 1.35 MVAR capacitor banks and a new control house for the protective relaying and associated equipment.

Based on transmission planning studies performed by Otter Tail, the Veblen 41.6 kV capacitor bank project will improve voltages to a level such that the 41.6 kV system will not have to be looped between Browns Valley and Hankinson as often. Avoiding a configuration that requires a 41.6 kV looped system to maintain acceptable voltages will keep the 41.6 kV line exposure to reasonable levels such that customer interruptions will be reduced. Furthermore, this project complements the New Effington 230/41.6 kV substation project (described in the next project summary) with the ability to extend system benefits along the 41.6 kV system down to Summit. MISO approved the Veblen 41.6 kV capacitor bank project as part of its 2018 Transmission Expansion Plan (MTEP18).<sup>8</sup>

The cost for the Veblen 41.6 kV capacitor bank project is estimated at \$1.3 million and is expected to be in service in third quarter 2019. North Dakota's jurisdictional share of the total project cost based on the D2 allocation factor of 39.5989 percent is approximately \$0.51 million.

#### New Effington 230/41.6 kV Substation – Attachment 13

Otter Tail's 41.6 kV transmission system between Hankinson, North Dakota, and Browns Valley, Minnesota needs infrastructure improvements in order to reliably serve increasing loads in the area. Specifically, continued load growth occurring in the Rosholt, South Dakota area, is causing the existing 41.6 kV transmission system to exceed its current load serving capability, especially during winter peak conditions.

Through Otter Tail's transmission planning studies of this area, Otter Tail identified the need for a new 230/41.6 kV substation near New Effington, South Dakota, in order to maintain reliability of the transmission system for the growing loads in this area. The New Effington 230/41.6 kV substation project involves tapping the existing 230 kV line from Hankinson, North Dakota to Big Stone, South Dakota and building a new 230/41.6 kV substation. This project location, near the middle of the 41.6 kV system between

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<sup>8</sup> See Project Number 14057 in Appendix A of MISO's 2018 Transmission Expansion Plan, available at: <https://www.misoenergy.org/planning/planning/mtep-2018/>

Hankinson and Browns Valley, will maximize the benefits of the new project which include: increasing the load serving capability of the system in order to serve the growing loads in the area; increasing voltages; off-loading the existing 41.6 kV system leaving more room for load growth; decreasing line exposure; and helping to mitigate interruptions to customers in this area.

The New Effington 230/41.6 kV Substation Project is currently being evaluated by MISO through its current planning process (MTEP19) and is anticipated to be approved as part of MTEP19.<sup>9</sup>

The current estimate for the New Effington 230/41.6 kV Substation Project is \$5.1 million with an in-service date of December 2020. North Dakota's jurisdictional share of the total project cost based on the D2 allocation factor of 39.5989 percent is approximately \$2.0 million.

#### Jamestown 345 kV Substation Reconfiguration – Attachment 14

The transmission planning standard<sup>10</sup> developed by the North American Electric Reliability Corporation (NERC) has undergone numerous changes over the past several years as the industry moves towards a more robust, reliable transmission system. As a result of these changes to the standard, Otter Tail needs to reconfigure the Jamestown 345 kV substation in order to stay in compliance with the transmission planning standard and avoid the possibility of load shedding during certain 345 kV contingencies.

The current 345 kV configuration has terminations in the order of line – line – transformer – transformer around the 345 kV ring bus (see illustration below).

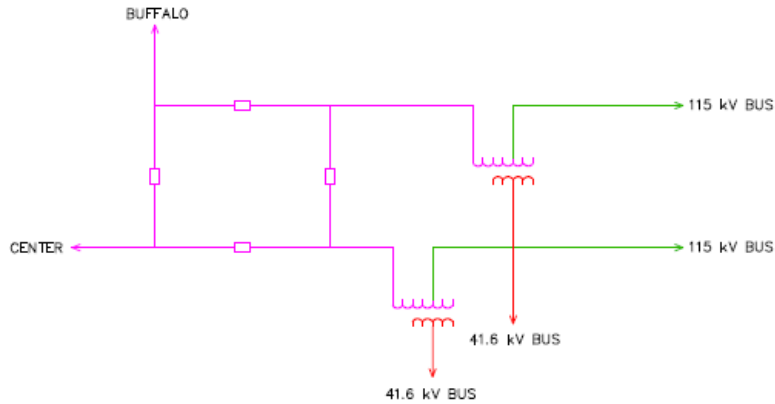
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<sup>9</sup> MTEP19 project number 15727. MISO's 2019 Transmission Expansion Plan (MTEP19) will not be finalized until December 2019.

<sup>10</sup> See NERC Standard TPL-001-4 available at:

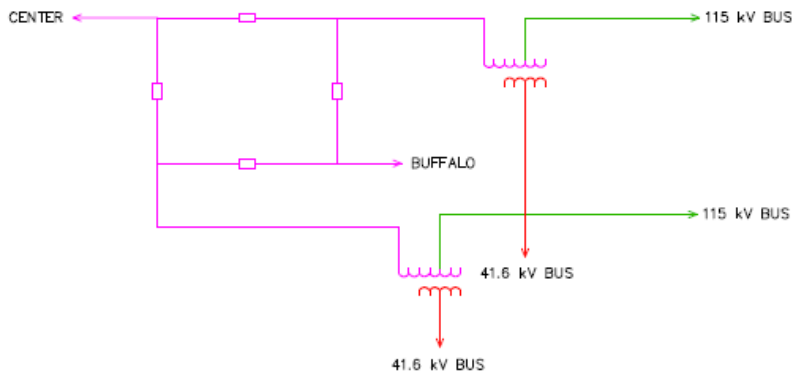
<https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCCompleteSet.pdf>

EXISTING CONFIGURATION



In the current configuration, a fault that involves a 345 kV stuck breaker could result in both transformers being tripped to clear the fault, which would cause load shedding in the Jamestown area. Load shedding as a result of a stuck breaker contingency on the 345 kV system is not allowed beyond January 1, 2021 under the currently effective transmission planning standard. Therefore, Otter Tail will undertake a project during 2020 to reconfigure the terminations in the order of line – transformer – line – transformer around the 345 kV ring bus (see illustration below).

NEW CONFIGURATION



This project must be undertaken during 2020 in order for Otter Tail to remain in compliance with the transmission planning standards. MISO approved the Jamestown 345 kV Substation project as part of its 2016 Transmission Expansion Plan (MTEP16).<sup>11</sup>

<sup>11</sup> See Project Number 10043 in Appendix A of MISO’s 2016 Transmission Expansion Plan, available at:

The current estimate for the Jamestown 345 kV Substation project is \$1.5 million with an in-service date of December 2020. North Dakota's jurisdictional share of the total project cost based on the D2 allocation factor of 39.5989 percent is approximately \$0.58 million.

#### Central Power Electric Cooperative (CPEC) Facility Purchase – Attachment 15

As part of on-going discussions between Central Power Electric Cooperative (CPEC) and Otter Tail surrounding the: (1) termination of the long-standing Integrated Transmission Agreement (ITA); (2) the Transmission Interconnection Agreement (TIA); and (3) the integration of CPEC into Southwest Power Pool (SPP), CPEC and Otter Tail recently executed a purchase agreement indicating Otter Tail's intent to purchase the following facilities (the Purchased Assets), subject to acquiring all regulatory approvals and Otter Tail's review of the equipment and sites:

- CPEC equipment within the Otter Tail Bottineau 115-43.8kV Substation;
- CPEC equipment within the Otter Tail Wahpeton 230x115-43.8kV Substation;
- CPEC equipment within the Otter Tail Rugby 230x115-43.8kV Substation; and
- CPEC's Rolette – Otter Tail Rolette four-mile long 69kV line.

Otter Tail reviewed the Purchased Assets through past test records and performed on-site inspections and concluded that the Purchased Assets are in good working order, conform with Otter Tail's standards and are expected to continue to provide reliable service.

Otter Tail has filed applications with the Commission<sup>12</sup> and the Minnesota Public Utilities Commission<sup>13</sup> seeking approval of the acquisition of the Purchased Assets. Assuming Otter Tail receives approvals from the state Commissions to proceed with the acquisition, Otter Tail expects to close on the purchase soon after. The purchase price for these facilities is the net book value of the Purchased Assets at the time of closing, which

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<https://www.misoenergy.org/planning/planning/mtep-2017/#t=10&p=0&s=FileName&sd=desc>

<sup>12</sup> See ND PSC Docket No. PU-19-298

<sup>13</sup> See MN PUC Docket No. E017-PA-19-533

is estimated to be approximately \$2.0 million on December 31, 2019.<sup>14</sup> Once the closing occurs, Otter Tail will notify the Federal Energy Regulatory Commission (FERC) of the transaction.

### **Benefits of Acquisition**

Otter Tail's purchase of the CPEC facilities offers several benefits centered around the efficiencies gained from more seamless ownership of facilities comprising the transmission system that supports the retail distribution of electric power to Otter Tail's North Dakota customers in the areas of Bottineau, Wahpeton, Rugby and Rolette (where the Purchased Assets are located). Otter Tail's purchase will result in Otter Tail's sole ownership of all the equipment located within each of these substations. Likewise, Otter Tail's purchase of CPEC's Rolette line segment will result in Otter Tail owning the entire 69 kV system between Rolette and Rolla (~34 miles). Continuous ownership of all the equipment within a substation or along an entire 69 kV system offers several efficiencies and benefits in the operation and maintenance of the system that promotes safe, reliable and cost-effective electric service to Otter Tail's retail customers. Thus, for a purchase price at a cost less than the cost of new equivalent facilities, the transaction increases Otter Tail's ability to efficiently manage the transmission system.

Otter Tail will also recognize financial benefits as a result of the purchase, which are expected to be in the form of higher MISO revenues from CPEC and lower SPP expenses. The financial benefits will be passed back to Otter Tail's customers through Otter Tail's annual TCRR filings.

Otter Tail's acquisition of the Purchased Assets will result in adding new assets to Otter Tail's transmission rate base. The current estimate for the acquisition of the Purchased Assets is \$2.0 million with North Dakota's jurisdictional share of the total cost based on the D2 allocation factor of 39.5989 percent is approximately \$0.8 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

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<sup>14</sup> A closing date before or after December 31, 2019 would change this value slightly due to the impacts of depreciation occurring on these facilities.

transmission demand allocation factor, D2, from Otter Tail’s most recent 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 (¢ / kWh) for all other customers. The rate design detail is included in Attachment 3.

#### **IV. RATE APPLICATION AND IMPACT**

The total 2020 revenue requirement is made up of three components: the estimated revenue requirement for calendar year 2020; the true-up associated with an updated projection of the 2019 revenue requirement; and the carrying charge attributable to any projected over or under-collection.

The revenue requirement attributable to calendar year 2020, as shown on line 33 of Attachment 4, page 2 of 2, is \$5,957,199. This amount is based on actual net revenues and expenses included in the TCRR tracker through July 2019, and projections for August through December of 2019 as well as 2020.

By design and structure of the TCRR, the related carrying credit of (\$22,797), as computed on Attachment 4, page 2 of 2, line 38, will be credited to customers as a reduction in the 2020 revenue requirements. The 2019 true-up portion of the revenue requirement calculation, as reflected on Attachment 2, line 24 and as computed in Attachment 4, page 1 of 2, line 39, reflects an estimated over-collection amount of (\$195,625) during the 2019 collection period. The net revenue requirement for 2020, upon which rates are developed, is \$5,738,778, as shown on line 35 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	\$1.310/kWh
Controlled Service	0.063¢
Lighting	0.242¢
All Other Service	0.425¢

The proposed rates are based on an effective date of January 1, 2020 through December 31, 2020. These rates represent an increase to the rates currently in effect. The estimated increase for a residential customer using 1,000 kWh is \$0.73 per month.

## **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 27 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 30, 2019, Otter Tail Power Company filed a request with the North Dakota Public Service Commission to increase 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, 2020. 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: \$106.16 (from \$1.060 to \$1.310 per kW)*
- *Controlled Service: \$0.12 (from 0.054 cents to 0.063 cents per kWh)*
- *Lighting: \$0.04 (from 0.201 cents to 0.242 cents per kWh)*
- *Residential and all other service: \$0.73/\$0.98 (from 0.352 cents to 0.425 cents per kWh)*

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

Attachment 27 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, 2020.

Date: August 30, 2019

Respectfully submitted:

OTTER TAIL POWER COMPANY

/s/ Lynn A. Wolters

Lynn A. Wolters

Rates Analyst

Regulatory Administration

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## Attachments

Attachment 1	Revenue
Attachment 2	Revenue Requirements Summary
Attachment 3	Rate Design
Attachment 4	Tracker Summary
Attachment 5	BSAT-Ellendale MVP Revenue Requirements
Attachment 6	Max to Ryder 41.6 kV Line Upgrade Revenue Requirements
Attachment 7	Bagley 115 kV Switch Station Revenue Requirements
Attachment 8	Lake Norden Area Transmission Improvements Revenue Requirements
Attachment 9	Donaldson 115 kV Cap Bank Revenue Requirements
Attachment 10	Northwest MN UVLS Revenue Requirements
Attachment 11	Blair 230 kV Substation Revenue Requirements
Attachment 12	Veblen 41.6 kV Cap Bank Revenue Requirements
Attachment 13	New Effington 230/41.6 kV Line Revenue Requirements
Attachment 14	Jamestown Substation (NERC) Revenue Requirements
Attachment 15	CPEC Purchase Revenue Requirements
Attachment 16	Attachment O Revenue Credit for Non-MISO Projects
Attachment 17	MISO Schedule 26 and 26A Expense
Attachment 18	SPP Expenses
Attachment 19	MISO Schedule 9 Revenue
Attachment 20	MISO Schedule 26 Revenue
Attachment 21	MISO Schedule 26A Revenue
Attachment 22	MISO Multi-Value Project Auction Revenue Rights Credit
Attachment 23	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 24	ADIT Pro-Rate Projection
Attachment 25	ADIT Pro-Rate Preservation
Attachment 26	Electric Rate Schedule Section 13.07 Redline and Clean
Attachment 27	Proposed Customer Notice

Projected Revenue for 2020

Line No.	Class		Units	Rate per Unit	Amount
1	Large General Service	(a)	1,216,211 kW	\$1.310	\$1,593,429
2					
3	Controlled Service	(b)	251,179,926 kWh	0.063¢	\$159,026
4					
5	Lighting	(c)	22,811,555 kWh	0.242¢	\$55,102
6					
7	All other service		925,599,002 kWh	0.425¢	\$3,931,221
8					
9	Total revenue				<u>\$5,738,778</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	2020
1	MVP - Ellendale to Big Stone South	\$102,286
2	Max - Ryder 41.6 kV Line Upgrades	\$96,330
3	Bagley 115kV Switch Station	\$111,740
4	Lake Norden Area Transmission	\$891,495
5	Donaldson 115 kV Cap Bank	\$23,445
6	Blair 230 kV Substation	\$51,313
7	Veblen 41.6 kV Cap Bank	\$52,726
8	Northwest MN UVLS	\$22,805
9	Jamestown Substation (NERC)	\$22,627
10	New Effington 230/41.6 kV Line	\$87,739
11	CPEC Purchase	\$71,658
12	<b>Total Revenue Requirement</b>	<b>\$1,534,163</b>
13	MISO Schedule 26 Expense	5,019,855
14	MISO Schedule 26A Expense	3,329,742
15	SPP Schedule 9 Expense	868,905
16	SPP Schedule 11 Expense	76,970
17	MISO Schedule 9 Revenue	(492,314)
18	MISO Schedule 26 Revenue	(3,833,872)
19	MISO Schedule 37 Revenue	(0)
20	MISO Schedule 38 Revenue	(0)
21	MISO Schedule 26A Revenue	(533,893)
22	MISO MVP ARR Revenue	(12,355)
23	Carrying Cost	(22,797)
24	True-Up	(195,625)
25	<b>Net Revenue Requirement</b>	<b>\$5,738,778</b>

**Class Allocation and Rate Design**

Line No.	2020		
1	North Dakota Revenue Requirements		\$5,738,778 *
2	Large General Service Class	27.77%	\$1,593,429
3	Controlled Service	2.77%	159,026
4	Lighting	0.96%	55,102
5	All Other Service	68.50%	3,931,221
6	Total		\$5,738,778
7	Large General Service Class	kW	1,216,211
8	Controlled Service	kWh	251,179,926
9	Lighting	kWh	22,811,555
10	All Other Service	kWh	925,599,002
11	Large General Service Class	\$ / kW	1.310
12	Controlled Service	cents / kWh	0.063
13	Lighting	cents / kWh	0.242
14	All Other Service	cents / kWh	0.425

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

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2019												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	MVP: Ellendale to Big Stone South	7,639	7,639	8,868	8,889	8,889	8,891	8,892	8,892	8,941	8,942	8,943	8,943	104,366
2	Max- Ryder 41.6 kV Line Upgrades	7,471	7,471	7,471	7,471	7,602	7,602	7,602	7,602	7,989	7,989	7,989	7,989	92,244
3	Badley 115kV Switch Station	9,518	9,518	9,518	9,518	9,518	9,518	9,518	9,518	9,518	9,518	9,518	9,518	114,221
4	Lake Norden Area Transmission Improvement	39,917	39,917	44,959	45,052	45,069	45,251	45,274	45,274	45,274	45,274	45,274	45,274	531,808
5	Donaldson 115 kV Cap Bank													
6	Blair 230 kV Substation													
7	Veblen 41.6 kV Cap Bank													
8	Northwest MN UVLS													
9	Jamestown Substation (NERC)													
10	New Effington 230/41.6 kV Line													
11	CPEC Purchase													
12														
13	<b>Total Revenue Requirements</b>	438,234	64,545	70,817	70,930	71,078	71,262	71,286	71,286	71,721	71,722	71,723	71,723	1,216,328
14														
15	<b>ADIT Preservation of Proration</b>	(189)	(189)	(189)	(189)	(189)	(189)	(189)	(189)	(189)	(189)	(189)	(189)	(2,266)
16														
17	<b>MISO &amp; SPP Expenses</b>													
18	MISO Schedule 26 Expense	479,670	399,119	409,548	323,643	294,625	324,905	385,023	418,437	360,902	407,976	418,437	523,047	4,745,333
19	MISO Schedule 26A Expense	328,636	289,909	260,833	225,062	219,178	227,865	214,838	250,403	240,090	253,220	291,842	333,981	3,135,858
20	SPP Schedule 9 Expense	68,289	72,047	72,163	71,844	71,559	71,542	73,873	69,438	69,438	69,438	69,438	69,438	848,506
21	SPP Schedule 11 Expense	7,489	7,288	7,163	7,123	9,522	7,163	7,126	6,171	6,171	6,171	6,171	6,171	83,728
22	<b>Total MISO &amp; SPP Expenses</b>	884,083	768,363	749,707	627,671	594,885	631,475	680,861	744,449	676,601	736,805	785,888	932,636	8,813,424
23														
24	<b>MISO Revenues</b>													
25	MISO Schedule 9 Revenue	(76,282)	(54,822)	(61,344)	(40,833)	(48,680)	(25,377)	(25,127)	(37,007)	(7,259)	(48,596)	(55,306)	(68,173)	(548,806)
26	MISO Schedule 26 Revenue	(330,158)	(285,761)	(314,623)	(267,033)	(293,014)	(343,597)	(405,422)	(369,011)	(385,765)	(293,619)	(281,054)	(331,315)	(3,900,373)
27	MISO Schedule 37 Revenue	(3,653)	(3,653)	(3,653)	(3,653)	(3,653)	(3,653)	(3,656)	(0)	(0)	(0)	(0)	(0)	(25,578)
28	MISO Schedule 38 Revenue	(4,327)	(4,327)	(4,327)	(4,327)	(4,327)	(4,295)	(4,295)	(0)	(0)	(0)	(0)	(0)	(30,224)
29	MISO Schedule 26A Revenue	(47,953)	(41,046)	(42,531)	(39,187)	(42,906)	(45,800)	(49,083)	(51,339)	(46,928)	(44,722)	(44,171)	(49,134)	(544,800)
30	MISO MVP ARR Revenue	(3,103)	(3,238)	(3,434)	(1,251)	(1,125)	(1,121)	(325)	(1,030)	(1,030)	(1,030)	(1,030)	(1,030)	(18,745)
31	<b>Total MISO Revenues</b>	(465,476)	(392,848)	(429,912)	(356,284)	(393,705)	(423,846)	(487,908)	(458,387)	(440,982)	(387,967)	(381,560)	(449,651)	(5,068,525)
32														
33	<b>Net Revenue Requirement</b>	856,652	439,871	390,423	342,128	272,069	278,702	264,050	357,160	307,151	420,371	475,863	554,519	4,958,961
34														
35	Billed (forecast kWh x adj factor)	812,675	746,812	439,730	364,161	320,243	314,565	330,601	338,769	345,629	339,690	359,741	426,477	5,139,093
36														
37	Difference	43,977	(306,941)	(49,307)	(22,032)	(48,174)	(35,863)	(66,551)	18,391	(38,478)	80,682	116,122	128,042	(180,133)
38	Carryina Charge	57	338	(1,615)	(1,939)	(2,092)	(2,412)	(2,656)	(3,096)	(2,999)	(3,263)	(2,770)	(2,048)	(24,495)
39	Cummulative Difference	53,037	(253,567)	(304,489)	(328,460)	(378,726)	(417,001)	(486,207)	(470,913)	(512,390)	(434,971)	(321,619)	(195,625)	(195,625)
40														
41	Carrying Charge Calculation	338	(1,615)	(1,939)	(2,092)	(2,412)	(2,656)	(3,096)	(2,999)	(3,263)	(2,770)	(2,048)	(1,246)	(1,246)
42	Cumulative Carrying Charge	(93,303)	(94,917)	(96,856)	(98,948)	(101,360)	(104,016)	(107,112)	(110,111)	(113,374)	(116,144)	(118,192)	(119,438)	(119,438)
43	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%
44														
45														
46	Forecasted Sales (MWh)							123,325	128,011	127,092	122,855	148,938	171,286	821,507
47														

Approved December 6, 2018 (PU-18-329);  
Rate Effective February 1, 2019

SUMMARY	Jan 2019 - Dec 2019
Revenue requirements	\$4,932,940
Carrying Charge	(7,431)
True-Up	(124,329)
Total requirements	\$4,801,181
Jan 2019-Dec 2019 projected sales in MWh	1,773,320
Average Rate	\$0.00271

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2020												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	
<b>Revenue Requirements</b>														
1	MVP: Ellendale to Big Stone South	8,537	8,537	8,521	8,521	8,521	8,521	8,521	8,521	8,521	8,521	8,521	8,521	102,286
2	Max- Ryder 41.6 kV Line Upgrades	8,027	8,027	8,027	8,027	8,027	8,027	8,027	8,027	8,027	8,027	8,027	8,027	96,330
3	Bailey 115kV Switch Station	9,312	9,312	9,312	9,312	9,312	9,312	9,312	9,312	9,312	9,312	9,312	9,312	111,740
4	Lake Norden Area Transmission Improvement	74,291	74,291	74,291	74,291	74,291	74,291	74,291	74,291	74,291	74,291	74,291	74,291	891,495
5	Donaldson 115 kV Cap Bank	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	23,445
6	Blair 230 kV Substation	4,276	4,276	4,276	4,276	4,276	4,276	4,276	4,276	4,276	4,276	4,276	4,276	51,313
7	Veblen 41.6 kV Cap Bank	4,394	4,394	4,394	4,394	4,394	4,394	4,394	4,394	4,394	4,394	4,394	4,394	52,726
8	Northwest MN UVLS	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	22,805
9	Jamestown Substation (NERC)	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829	22,627
10	New Effington 230/41.6 kV Line	7,109	7,109	7,109	7,109	7,109	7,109	7,109	7,109	7,109	7,109	7,109	7,109	87,739
11	CPEC Purchase	5,097	6,050	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	71,658
12														
13	<b>Total Revenue Requirements</b>	126,477	127,431	127,416	127,416	127,416	127,416	127,416	127,416	127,416	127,416	127,416	133,514	1,534,163
14														
15	<b>ADIT Preservation of Proration</b>													
16														
17	<b>MISO &amp; SPP Expenses</b>													
18	MISO Schedule 26 Expense	502,488	492,438	422,090	417,065	361,791	407,015	391,941	376,866	336,667	386,916	467,314	457,264	5,019,855
19	MISO Schedule 26A Expense	337,755	303,447	294,394	257,396	243,302	238,992	259,445	259,781	249,132	262,783	292,878	330,435	3,329,742
20	SPP Schedule 9 Expense	71,314	72,558	72,529	72,544	72,565	72,603	72,417	72,475	72,475	72,475	72,475	72,475	868,905
21	SPP Schedule 11 Expense	6,356	6,419	6,419	6,419	6,419	6,419	6,419	6,419	6,419	6,419	6,419	6,419	76,970
22	<b>Total MISO &amp; SPP Expenses</b>	917,914	874,862	795,433	753,425	684,078	725,030	730,222	715,542	664,693	728,593	839,086	866,593	9,295,471
23														
24	<b>MISO Revenues</b>													
25	MISO Schedule 9 Revenue	(74,917)	(60,307)	(49,070)	(40,130)	(21,395)	(23,463)	(13,006)	(36,034)	(6,200)	(46,778)	(54,237)	(66,775)	(492,314)
26	MISO Schedule 26 Revenue	(417,581)	(410,249)	(368,596)	(328,874)	(269,866)	(253,927)	(268,391)	(278,418)	(276,424)	(267,316)	(323,185)	(371,046)	(3,833,872)
27	MISO Schedule 37 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
28	MISO Schedule 38 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
29	MISO Schedule 26A Revenue	(58,151)	(57,130)	(51,329)	(45,798)	(37,581)	(35,361)	(37,375)	(38,772)	(38,494)	(37,226)	(45,006)	(51,671)	(533,893)
30	MISO MVP ARR Revenue	(1,030)	(1,030)	(1,030)	(1,030)	(1,030)	(1,030)	(1,030)	(1,030)	(1,030)	(1,030)	(1,030)	(1,030)	(12,355)
31	<b>Total MISO Revenues</b>	(551,679)	(528,716)	(470,025)	(415,832)	(329,872)	(313,780)	(319,802)	(354,254)	(322,148)	(352,350)	(423,457)	(490,521)	(4,872,434)
32														
33	<b>Net Revenue Requirement</b>	492,712	473,577	452,824	465,009	481,622	538,665	537,835	488,704	469,961	503,659	543,045	509,585	5,957,199
34														
35	Billed (forecast kWh x adj factor)	625,062	614,086	551,737	492,279	403,952	380,093	401,745	416,754	413,769	400,135	483,763	555,404	5,738,778
36														
37	Difference	(132,350)	(140,509)	(98,913)	(27,270)	77,670	158,572	136,090	71,950	56,193	103,524	59,283	(45,819)	218,422
38	Carryina Charge	(1,246)	(2,097)	(3,005)	(3,654)	(3,851)	(3,381)	(2,392)	(1,541)	(1,092)	(742)	(87)	290	(22,797)
39	Cummulative Difference	(329,221)	(471,826)	(573,744)	(604,668)	(530,848)	(375,656)	(241,958)	(171,549)	(116,449)	(13,667)	45,529	0	0
40														
41	Carrying Charge Calculation	(2,097)	(3,005)	(3,654)	(3,851)	(3,381)	(2,392)	(1,541)	(1,092)	(742)	(87)	290	0	
42	Cumulative Carrying Charge	(121,535)	(124,539)	(128,193)	(132,044)	(135,424)	(137,817)	(139,358)	(140,450)	(141,192)	(141,279)	(140,989)	(140,989)	
43	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%	
44														
45														
46	Forecasted Sales (MWh)	194,897	191,475	172,034	153,495	125,954	118,515	125,266	129,946	129,015	124,764	150,840	173,178	1,789,379
47														

	Jan 2020 - Dec 2020
<b>SUMMARY</b>	
Revenue requirements	\$5,957,199
Carrying Charge	(22,797)
2019 True-Up	(195,625)
<b>Total requirements</b>	<b>\$5,738,778</b>
Jan 2020-Dec 2020 projected sales in MWh	1,789,379
Average Rate	\$0.00321

Line No.	Year>>	2019												2019 Projected Total
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	
<b>RATE BASE</b>														
1	Plant Balance	0	103,428,380	105,320,468	105,343,074	105,528,843	105,635,492	105,656,590	107,643,327	107,692,763	107,735,699	107,735,699	111,656,633	111,656,633
2	Accumulated Depreciation	0	0	(142,426)	(287,218)	(432,037)	(577,089)	(722,274)	(867,485)	(1,018,286)	(1,169,225)	(1,320,285)	(1,471,345)	(1,471,345)
3	Net Plant in Service	0	103,428,380	105,178,042	105,055,856	105,096,806	105,058,403	104,934,316	106,775,842	106,674,477	106,566,474	106,415,414	110,185,288	110,185,288
4	CWIP (Project #104593 & 105643)	103,197,968	0	0	0	0	0	0	0	0	0	0	0	
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	
6	Accumulated Deferred Income Taxes Federal & State	0	(123,862)	(212,965)	(301,492)	(390,011)	(478,473)	(566,903)	(655,327)	(742,386)	(829,412)	(916,408)	(1,003,404)	
7	Ending rate base	103,197,968	103,304,518	104,965,076	104,754,365	104,706,796	104,579,930	104,367,413	106,120,515	105,932,091	105,737,062	105,499,006	109,181,883	
8	OTP Load Percentage	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	
9	Remove Non-OTP Load Portion	(100,948,252)	(101,052,479)	(102,678,837)	(102,470,720)	(102,424,187)	(102,300,089)	(102,092,203)	(103,807,089)	(103,622,771)	(103,431,994)	(103,199,127)	(106,801,718)	
10	Retail Ending Rate Base	2,249,716	2,252,038	2,288,239	2,283,645	2,282,608	2,279,842	2,275,210	2,313,427	2,309,320	2,305,068	2,299,878	2,380,165	
11	Average rate base	190,720	190,720	190,720	190,720	190,720	190,720	190,720	190,720	190,720	190,720	190,720	2,288,639	
12	Return on Rate Base	14,575	14,575	14,575	14,575	14,575	14,575	14,575	14,575	14,575	14,575	14,575	174,898	
13	Available for return (equity portion of rate base)	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	117,390	
14	<b>EXPENSES</b>													
15	<b>O&amp;M and Depreciation</b>													
16	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	
17	Property Tax	71,435	71,435	71,435	71,435	71,435	71,435	71,435	71,435	71,435	71,435	71,435	857,218	
18	Book Depreciation	0	0	142,426	144,791	144,820	145,052	145,185	145,211	150,800	150,939	151,060	1,471,345	
19	Total O&M and Depreciation Expense	71,435	71,435	213,861	216,226	216,254	216,487	216,620	216,646	222,235	222,374	222,495	2,328,563	
20	OTP Load Percentage	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	
21	Remove Non-OTP Load Portion	(69,878)	(69,878)	(209,199)	(211,512)	(211,540)	(211,767)	(211,898)	(211,923)	(217,390)	(217,526)	(217,645)	(2,277,800)	
22	Retail O&M and Depreciation Expenses	1,557	1,557	4,662	4,714	4,714	4,719	4,722	4,723	4,845	4,848	4,850	50,763	
23	Income before Taxes	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	117,390	
24	Available for return (from above)	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	9,783	117,390	
25	Taxable Income (grossed up)	12,941	12,941	12,941	12,941	12,941	12,941	12,941	12,941	12,941	12,941	12,941	155,288	
26	Income Taxes	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	37,898	
27	Current and Def Income Taxes	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	37,898	
28	Total Income Tax Expense	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	37,898	
29	<b>REVENUE REQUIREMENTS</b>													
30	Expenses	4,715	4,715	7,820	7,872	7,872	7,878	7,880	7,881	8,003	8,006	8,009	8,009	
31	Return on rate base	14,575	14,575	14,575	14,575	14,575	14,575	14,575	14,575	14,575	14,575	14,575	174,898	
32	Subtotal revenue requirements	19,290	19,290	22,395	22,447	22,447	22,452	22,455	22,456	22,578	22,581	22,583	2,541,359	
33	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
34	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	
35	Total revenue requirements	19,290	19,290	22,395	22,447	22,447	22,452	22,455	22,456	22,578	22,581	22,583	2,541,359	
36	North Dakota share - D2 factor	41.26%	7,639	7,639	8,868	8,889	8,889	8,891	8,892	8,941	8,942	8,943	104,366	

Line No.	<b>SUPPORTING INFORMATION / DATA</b>													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	<b>Ratio</b>		<b>Cost</b>		<b>WA Cost</b>				<b>Property tax</b>				
3	Debt	47.50%		5.29%		2.51%				2019 composite rate		0.84%		
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	<b>Tax</b>													
8	Project life (years)	<b>Book</b>		<b>15-year MACRS</b>										
9														
10														
11														
12														
13	Effective Tax Rate	24.40%		20.09%		4.31%								
14	Tax conversion factor	1.32284												
15	Wholesale Revenue Credit	0.00%												
16	ND share - D2 factor	39.5989%												
17	<b>Deferred Tax</b>													
18	Book depreciation	0	0	142,426	144,791	144,820	145,052	145,185	145,211	150,800	150,939	151,060	1,471,345	
19	Tax depreciation-Federal	0	507,530	507,530	507,530	507,530	507,530	507,530	507,530	507,530	507,530	507,530	5,582,832	
20	Tax depreciation-ND	0	507,530	507,530	507,530	507,530	507,530	507,530	507,530	507,530	507,530	507,530	5,582,832	
21	Federal deferred income taxes	0	(101,988)	(73,367)	(72,892)	(72,886)	(72,840)	(72,813)	(72,808)	(71,685)	(71,657)	(71,632)	(826,199)	
22	State deferred income taxes	0	(21,875)	(15,736)	(15,634)	(15,633)	(15,623)	(15,617)	(15,616)	(15,375)	(15,369)	(15,364)	(177,205)	



Line No.	Year>>	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
		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
<b>RATE BASE</b>														
1	Plant Balance	1,633,047	1,633,047	1,633,047	1,880,089	1,880,089	1,880,089	1,880,089	2,609,437	2,609,437	2,609,437	2,609,437	2,609,437	2,609,437
2	Accumulated Depreciation	(51,296)	(53,587)	(55,879)	(58,171)	(60,809)	(63,448)	(66,086)	(68,724)	(72,386)	(76,048)	(79,710)	(83,372)	(83,372)
3	Net Plant in Service	1,581,752	1,579,460	1,577,168	1,821,919	1,819,280	1,816,642	1,814,003	2,540,712	2,537,050	2,533,388	2,529,726	2,526,064	2,526,064
4	CWIP (Project #127607 & #128423)	571,926	634,483	754,439	539,552	556,296	632,425	729,347	0	0	0	0	0	0
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	(284,559)	(286,670)	(288,781)	(290,892)	(292,919)	(294,945)	(296,972)	(298,998)	(300,775)	(302,552)	(304,328)	(306,105)	(306,105)
7	Ending rate base	1,869,118	1,927,273	2,042,826	2,070,578	2,082,657	2,154,122	2,246,379	2,241,714	2,236,275	2,230,837	2,225,398	2,219,960	2,219,960
8														
9	Average rate base	175,258	175,258	175,258	175,258	175,258	175,258	175,258	175,258	175,258	175,258	175,258	175,258	2,103,100
10														
11	Return on Rate Base	13,393	13,393	13,393	13,393	13,393	13,393	13,393	13,393	13,393	13,393	13,393	13,393	160,719
12														
13	Available for return (equity portion of rate base)	8,989	8,989	8,989	8,989	8,989	8,989	8,989	8,989	8,989	8,989	8,989	8,989	107,873
14														
<b>EXPENSES</b>														
<i>O&amp;M and Depreciation</i>														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	14,044
19	Book Depreciation	2,292	2,292	2,292	2,292	2,638	2,638	2,638	2,638	3,662	3,662	3,662	3,662	34,368
20	Total O&M and Depreciation Expense	3,462	3,462	3,462	3,462	3,809	3,809	3,809	3,809	4,832	4,832	4,832	4,832	48,412
21														
22	Income before Taxes													
23	Available for return (from above)	8,989	8,989	8,989	8,989	8,989	8,989	8,989	8,989	8,989	8,989	8,989	8,989	107,873
24	Taxable Income (grossed up)	11,892	11,892	11,892	11,892	11,892	11,892	11,892	11,892	11,892	11,892	11,892	11,892	142,699
25														
26	Income Taxes													
27	Current and Def Income Taxes	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	34,825
28	Total Income Tax Expense	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	34,825
29														
30														
<b>REVENUE REQUIREMENTS</b>														
32	Expenses	6,364	6,364	6,364	6,364	6,711	6,711	6,711	6,711	7,734	7,734	7,734	7,734	83,238
33	Return on rate base	13,393	13,393	13,393	13,393	13,393	13,393	13,393	13,393	13,393	13,393	13,393	13,393	160,719
34	Subtotal revenue requirements	19,757	19,757	19,757	19,757	20,104	20,104	20,104	20,104	21,128	21,128	21,128	21,128	243,957
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(892)	(892)	(892)	(892)	(907)	(907)	(907)	(907)	(954)	(954)	(954)	(954)	(11,012)
37	Total revenue requirements	18,866	18,866	18,866	18,866	19,197	19,197	19,197	19,197	20,174	20,174	20,174	20,174	232,945
38														
39	North Dakota share - D2 factor	7,471	7,471	7,471	7,471	7,602	7,602	7,602	7,602	7,989	7,989	7,989	7,989	92,244

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									
4	Preferred equity	0.00%	0.00%	0.00%	0.86%									
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	4.51%												
16	ND share - D2 factor	39.5989%												
17														
18	<b>Deferred Tax</b>													
19	Book depreciation	2,292	2,292	2,292	2,292	2,638	2,638	2,638	2,638	3,662	3,662	3,662	3,662	34,368
20	Tax depreciation-Federal	10,942	10,942	10,942	10,942	10,942	10,942	10,942	10,942	10,942	10,942	10,942	10,942	131,304
21	Tax depreciation-ND	10,942	10,942	10,942	10,942	10,942	10,942	10,942	10,942	10,942	10,942	10,942	10,942	131,304
22	Federal deferred income taxes	(1,738)	(1,738)	(1,738)	(1,738)	(1,669)	(1,669)	(1,669)	(1,669)	(1,463)	(1,463)	(1,463)	(1,463)	(19,479)
23	State deferred income taxes	(373)	(373)	(373)	(373)	(358)	(358)	(358)	(358)	(314)	(314)	(314)	(314)	(4,178)











Line No.	Year>>	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	
		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	
<b>RATE BASE</b>															
1	Plant Balance	0	0	0	0	0	0	0	0	0	523,630	523,630	523,630	523,630	
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	(694)	(694)		
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	523,630	522,937	522,937		
<b>CWIP Calculation:</b>															
	Beginning Balance	0	0	0	0	9,087	29,970	57,997	81,657	192,166	303,274	414,983	0	517,900	
	Additional CWIP				9,060	20,769	27,768	23,234	109,474	109,474	109,474	108,647	0		
	Closings from CWIP											(523,630)	0		
	AFDUC				27	114	259	426	1,035	1,634	2,236				
4	CWIP (Project #106643)	106353	0	0	9,087	29,970	57,997	81,657	192,166	303,274	414,983	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	0	(3,195)	(6,220)		
7	Accumulated Deferred Income Taxes Federal & State - No Pro	0	0	0	0	0	0	0	0	0	0	(3,195)	(6,220)		
8	Ending rate base	0	0	0	9,087	29,970	57,997	81,657	192,166	303,274	414,983	520,436	516,716		
9	Average rate base	13,630	13,630	13,630	13,630	13,630	13,630	13,630	13,630	13,630	13,630	13,630	13,630		
10	Return on Rate Base	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042		
11	Available for return (equity portion of rate base)	699	699	699	699	699	699	699	699	699	699	699	699		
12															
13															
14															
15	<b>EXPENSES</b>														
16	<b>O&amp;M and Depreciation</b>														
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	0	694	694		
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	694	694		
21															
22	Income before Taxes														
23	Available for return (from above)	699	699	699	699	699	699	699	699	699	699	699	699		
24	Taxable Income (grossed up)	925	925	925	925	925	925	925	925	925	925	925	925		
25															
26	Income Taxes														
27	Current and Def Income Taxes	226	226	226	226	226	226	226	226	226	226	226	226		
28	Total Income Tax Expense	226	226	226	226	226	226	226	226	226	226	226	226		
29															
30															
31	<b>REVENUE REQUIREMENTS</b>														
32	Expenses	226	226	226	226	226	226	226	226	226	226	226	920		
33	Return on rate base	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042		
34	Subtotal revenue requirements	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,961		
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0		
36	Wholesale Revenue Credit	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(89)	(718)		
37	Total revenue requirements	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,873		
38															
39	North Dakota share - D2 factor	479	479	479	479	479	479	479	479	479	479	479	742		
													6,013		

Line No.	<b>SUPPORTING INFORMATION / DATA</b>														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		<b>Ratio</b>	<b>Cost</b>	<b>WA Cost</b>										<b>Property tax</b>	
4	Debt	47.50%	5.29%	2.51%										2019 composite rate	
5	Preferred equity	0.00%	0.00%	0.00%										0.86%	
6	Common equity	52.50%	9.77%	5.13%											
7	Total	100.00%		7.64%	Overall Return										
8															
9															
10	Project life (years)		<b>Book</b>	<b>Tax</b>											
11			50	15-year MACRS											
12					<b>Fed Portion</b>	<b>State Portion</b>									
13	Effective Tax Rate		24.40%		20.09%	4.31%									
14	Tax conversion factor		1.32284												
15	Wholesale Revenue Credit		4.51%												
16	ND share - D2 factor		39.5989%												
17															
18	<b>Deferred Tax</b>														
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	694	694		
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	13,091	13,091		
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	13,091	13,091		
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	(2,631)	(2,491)		
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	(564)	(534)		





Line No.	Year>>	2020 Projected January	2020 Projected February	2020 Projected March	2020 Projected April	2020 Projected May	2020 Projected June	2020 Projected July	2020 Projected August	2020 Projected September	2020 Projected October	2020 Projected November	2020 Projected December	2020 Projected Total
<b>RATE BASE</b>														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	1,186,293	1,186,293	1,186,293
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(8,368)	(8,368)
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	1,186,293	1,177,925	1,177,925
4	CWIP (Projects 106170 106642 106641)	81,293	166,293	203,893	256,493	351,493	541,493	656,493	911,493	1,046,493	1,118,893	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	0	0	0	0	0	0	0	0	0	0	(1,801)	(2,730)	(2,730)
7	Ending rate base	81,293	166,293	203,893	256,493	351,493	541,493	656,493	911,493	1,046,493	1,118,893	1,184,492	1,175,195	1,175,195
8														
9	Average rate base	49,746	49,746	49,746	49,746	49,746	49,746	49,746	49,746	49,746	49,746	49,746	49,746	596,947
10														
11	Return on Rate Base	3,802	3,802	3,802	3,802	3,802	3,802	3,802	3,802	3,802	3,802	3,802	3,802	45,619
12														
13	Available for return (equity portion of rate base)	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552	30,619
14														
<b>EXPENSES</b>														
<i>O&amp;M and Depreciation</i>														
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	8,368	8,368
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	8,368	8,368
21														
22	Income before Taxes													
23	Available for return (from above)	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552	30,619
24	Taxable Income (grossed up)	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	3,375	40,504
25														
26	Income Taxes													
27	Current and Def Income Taxes	824	824	824	824	824	824	824	824	824	824	824	824	9,885
28	Total Income Tax Expense	824	824	824	824	824	824	824	824	824	824	824	824	9,885
29														
30														
<b>REVENUE REQUIREMENTS</b>														
32	Expenses	824	824	824	824	824	824	824	824	824	824	824	9,192	18,253
33	Return on rate base	3,802	3,802	3,802	3,802	3,802	3,802	3,802	3,802	3,802	3,802	3,802	3,802	45,619
34	Subtotal revenue requirements	4,625	4,625	4,625	4,625	4,625	4,625	4,625	4,625	4,625	4,625	4,625	12,993	63,872
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(455)	(455)	(455)	(455)	(455)	(455)	(455)	(455)	(455)	(455)	(455)	(1,278)	(6,281)
37	Total revenue requirements	4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,170	11,716	57,590
38														
39	North Dakota share - D2 factor	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	1,651	4,639	22,805

Line No.	<b>SUPPORTING INFORMATION / DATA</b>													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	<b>Ratio</b>	<b>Cost</b>	<b>WA Cost</b>										
4	Debt	47.50%	5.29%	2.51%	Property tax									
5	Preferred equity	0.00%	0.00%	0.00%	2020 composite rate									
6	Common equity	52.50%	9.77%	5.13%	0.86%									
7	Total	100.00%		7.64%	Overall Return									
8														
9														
10	Project life (years)	<b>Book</b>	<b>Tax</b>											
11		50	15-year MACRS											
12				<b>Fed Portion</b>	<b>State Portion</b>									
13	Effective Tax Rate	24.40%	20.09%	4.31%										
14	Tax conversion factor	1.32284												
15	Wholesale Revenue Credit	9.83%												
16	ND share - D2 factor	39.5989%												
17														
18	<b>Deferred Tax</b>													
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	8,368	8,368
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	29,657	29,657	59,315
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	29,657	29,657	59,315
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	(5,960)	(4,278)	(10,238)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	(1,278)	(918)	(2,196)

Line No.	Year>>	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019
		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
<b>RATE BASE</b>														
1	Plant Balance	102,683	102,683	102,683	102,683	102,683	102,683	976,990	1,048,336	1,119,681	1,191,027	1,262,372	1,262,372	1,262,372
2	Accumulated Depreciation	(133)	(266)	(400)	(533)	(666)	(799)	(932)	(2,200)	(3,560)	(5,012)	(6,557)	(8,195)	(8,195)
3	Net Plant in Service	102,550	102,417	102,283	102,150	102,017	101,884	976,058	1,046,136	1,116,122	1,186,015	1,255,815	1,254,177	1,254,177
<b>CWIP Calculation:</b>														
	Beginning Balance	115,929	159,643	258,955	385,558	546,830	682,325	849,098	0	0	0	0	0	0
	Additional CWIP	42,940	98,146	124,768	158,494	131,998	162,424	20,137	71,346	71,346	71,346	71,346	71,346	1,024,289
	Closings from CWIP							(874,307)	(71,346)	(71,346)	(71,346)	(71,346)	(71,346)	0
	AFDUC	775	1,166	1,835	2,777	3,497	4,349	5,073						
4	CWIP (Project #106337)	159,643	258,955	385,558	546,830	682,325	849,098	0	0	0	0	0	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	1.0000
6	Accumulated Deferred Income Taxes Federal & State	(2,598)	(3,943)	(5,288)	(6,634)	(7,979)	(9,324)	(10,669)	(11,737)	(12,783)	(13,806)	(14,807)	(15,785)	(15,785)
7	Ending rate base	259,595	357,429	482,553	642,346	776,363	941,658	965,389	1,034,399	1,103,339	1,172,208	1,241,008	1,238,393	1,238,393
8	Average rate base	66,872	66,872	66,872	66,872	66,872	66,872	66,872	66,872	66,872	66,872	66,872	66,872	802,464
9	Return on Rate Base	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110	61,324
10														
11	Available for return (equity portion of rate base)	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430	41,160
12														
13														
14														
<b>EXPENSES</b>														
<b>O&amp;M and Depreciation</b>														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	72	72	72	72	72	72	72	72	72	72	72	72	863
19	Book Depreciation	133	133	133	133	133	133	133	1,267	1,360	1,453	1,545	1,638	8,195
20	Total O&M and Depreciation Expense	205	205	205	205	205	205	205	1,339	1,432	1,524	1,617	1,709	9,058
21														
22	Income before Taxes													
23	Available for return (from above)	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430	41,160
24	Taxable Income (grossed up)	4,537	4,537	4,537	4,537	4,537	4,537	4,537	4,537	4,537	4,537	4,537	4,537	54,449
25														
26	Income Taxes													
27	Current and Def Income Taxes	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	13,288
28	Total Income Tax Expense	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	13,288
29														
30														
31														
<b>REVENUE REQUIRMENTS</b>														
32	Expenses	1,312	1,312	1,312	1,312	1,312	1,312	1,312	2,447	2,539	2,632	2,724	2,817	22,346
33	Return on rate base	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110	61,324
34	Subtotal revenue requirements	6,423	6,423	6,423	6,423	6,423	6,423	6,423	7,557	7,650	7,742	7,835	7,927	83,670
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(290)	(290)	(290)	(290)	(290)	(290)	(290)	(341)	(345)	(349)	(354)	(358)	(3,777)
37	Total revenue requirements	6,133	6,133	6,133	6,133	6,133	6,133	6,133	7,216	7,304	7,393	7,481	7,569	79,893
38														
39	North Dakota share - D2 factor	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,857	2,892	2,927	2,962	2,997	31,637

Line No.	<b>SUPPORTING INFORMATION / DATA</b>														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		<b>Ratio</b>	<b>Cost</b>	<b>WA Cost</b>											
4	Debt	47.50%	5.29%	2.51%											
5	Preferred equity	0.00%	0.00%	0.00%											
6	Common equity	52.50%	9.77%	5.13%											
7	Total	100.00%		7.64% Overall Return											
8															
9															
10	Project life (years)	50	15-year MACRS												
11															
12															
13		<b>Fed Portion</b>	<b>State Portion</b>												
14	Effective Tax Rate	24.40%	20.09%	4.31%											
15	Tax conversion factor	1.32284													
16	Wholesale Revenue Credit	4.51%													
17	ND share - D2 factor	39.5989%													
18	<b>Deferred Tax</b>														
19	Book depreciation	133	133	133	133	133	133	133	1,267	1,360	1,453	1,545	1,638	8,195	
20	Tax depreciation-Federal	5,645	5,645	5,645	5,645	5,645	5,645	5,645	5,645	5,645	5,645	5,645	5,645	67,739	
21	Tax depreciation-ND	5,645	5,645	5,645	5,645	5,645	5,645	5,645	5,645	5,645	5,645	5,645	5,645	67,739	
22	Federal deferred income taxes	(1,108)	(1,108)	(1,108)	(1,108)	(1,108)	(1,108)	(1,108)	(880)	(861)	(842)	(824)	(805)	(11,965)	
23	State deferred income taxes	(238)	(238)	(238)	(238)	(238)	(238)	(238)	(189)	(185)	(181)	(177)	(173)	(2,566)	



Line No.	Year>>	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	2019	
		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	
<b>RATE BASE</b>															
1	Plant Balance	0	0	0	0	0	0	0	1,289,586	1,289,586	1,289,586	1,289,586	1,289,586	1,289,586	
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	(1,709)	(3,417)	(5,126)	(5,126)	(5,126)	
3	Net Plant in Service	0	0	0	0	0	0	0	1,289,586	1,287,877	1,286,169	1,284,460	1,284,460	1,284,460	
<b>CWIP Calculation:</b>															
	Beginning Balance	286,460	314,080	330,388	410,968	514,342	860,190	980,454	1,093,843	1,194,934	0	0	0	972,851	
	Additional CWIP	25,931	14,513	78,475	100,627	341,963	114,898	107,139	94,653	94,653	0	0	0	0	
	Closings from CWIP														
	AFDUC	1,689	1,795	2,105	2,747	3,885	5,367	6,250	6,438	(1,289,586)	0	0	0	0	
4	CWIP (Project #106230)	314,080	330,388	410,968	514,342	860,190	980,454	1,093,843	1,194,934	0	0	0	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	1.0000	
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	(3,147)	(6,294)	(9,025)	(11,755)	(14,485)	(14,485)	
7	Ending rate base	314,080	330,388	410,968	514,342	860,190	980,454	1,093,843	1,191,786	1,283,292	1,278,853	1,274,414	1,269,975	1,269,975	
8	Average rate base	71,084	71,084	71,084	71,084	71,084	71,084	71,084	71,084	71,084	71,084	71,084	71,084	853,004	
9	Return on Rate Base	5.432	5.432	5.432	5.432	5.432	5.432	5.432	5.432	5.432	5.432	5.432	5.432	65,187	
10															
11	Available for return (equity portion of rate base)	3,646	3,646	3,646	3,646	3,646	3,646	3,646	3,646	3,646	3,646	3,646	3,646	43,753	
12															
13															
14															
<b>EXPENSES</b>															
<b>O&amp;M and Depreciation</b>															
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	1,709	1,709	1,709	1,709	5,126	
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	1,709	1,709	1,709	1,709	5,126	
21	Income before Taxes														
23	Available for return (from above)	3,646	3,646	3,646	3,646	3,646	3,646	3,646	3,646	3,646	3,646	3,646	3,646	43,753	
24	Taxable Income (grossed up)	4,823	4,823	4,823	4,823	4,823	4,823	4,823	4,823	4,823	4,823	4,823	4,823	57,878	
25															
26	Income Taxes														
27	Current and Def Income Taxes	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	14,125	
28	Total Income Tax Expense	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	14,125	
29															
30															
31	<b>REVENUE REQUIRMENTS</b>														
32	Expenses	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	2,886	2,886	2,886	19,251	
33	Return on rate base	5,432	5,432	5,432	5,432	5,432	5,432	5,432	5,432	5,432	5,432	5,432	5,432	65,187	
34	Subtotal revenue requirements	6,609	6,609	6,609	6,609	6,609	6,609	6,609	6,609	6,609	8,318	8,318	8,318	84,438	
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	
36	Wholesale Revenue Credit	(298)	(298)	(298)	(298)	(298)	(298)	(298)	(298)	(298)	(375)	(375)	(375)	(3,811)	
37	Total revenue requirements	6,311	6,311	6,311	6,311	6,311	6,311	6,311	6,311	6,311	7,943	7,943	7,943	80,626	
38															
39	North Dakota share - D2 factor	2,499	2,499	2,499	2,499	2,499	2,499	2,499	2,499	2,499	3,145	3,145	3,145	31,927	

Line No.	<b>SUPPORTING INFORMATION / DATA</b>														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		<u>Ratio</u>	<u>Cost</u>	<u>WA Cost</u>											
4	Debt	47.50%	5.29%	2.51%											
5	Preferred equity	0.00%	0.00%	0.00%											
6	Common equity	52.50%	9.77%	5.13%											
7	Total	100.00%		7.64% Overall Return											
8															
9															
10	Project life (years)	50	15-year MACRS												
11															
12															
13															
14	Effective Tax Rate	24.40%	20.09%	4.31%											
15	Tax conversion factor	1.32284													
16	Wholesale Revenue Credit	4.51%													
17	ND share - D2 factor	39.5989%													
18	<b>Deferred Tax</b>														
19	Book depreciation	0	0	0	0	0	0	0	0	1,709	1,709	1,709	1,709	5,126	
20	Tax depreciation-Federal	0	0	0	0	0	0	12,896	12,896	12,896	12,896	12,896	12,896	64,479	
21	Tax depreciation-ND	0	0	0	0	0	0	12,896	12,896	12,896	12,896	12,896	12,896	64,479	
22	Federal deferred income taxes	0	0	0	0	0	0	(2,591)	(2,591)	(2,248)	(2,248)	(2,248)	(2,248)	(11,927)	
23	State deferred income taxes	0	0	0	0	0	0	(556)	(556)	(482)	(482)	(482)	(482)	(2,558)	





Line No.	Year>>	2020 Projected Jan	2020 Projected Feb	2020 Projected Mar	2020 Projected Apr	2020 Projected May	2020 Projected Jun	2020 Projected Jul	2020 Projected Aug	2020 Projected Sep	2020 Projected Oct	2020 Projected Nov	2020 Projected Dec	2020 Projected Total
<b>RATE BASE</b>														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	5,138,748	5,138,748	5,138,748
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(6,809)	(6,809)
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	5,138,748	5,131,939	5,131,939
<b>CWIP Calculation:</b>														
	Beginning Balance	468,748	493,748	738,748	953,748	1,078,748	1,273,748	2,418,748	2,638,748	3,838,748	4,463,748	4,788,748	0	0
	Additional CWIP	25,000	245,000	215,000	125,000	195,000	1,145,000	220,000	1,200,000	625,000	325,000	350,000	0	0
	Closings from CWIP											(5,138,748)	0	0
	AFDUC												0	0
4	CWIP (Project #106134)	493,748	738,748	953,748	1,078,748	1,273,748	2,418,748	2,638,748	3,838,748	4,463,748	4,788,748	0	0	0
5	ADIT 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	0	0	0	0	0	0	0	0	(7,800)	(13,111)	(13,111)
7	Ending rate base	493,748	738,748	953,748	1,078,748	1,273,748	2,418,748	2,638,748	3,838,748	4,463,748	4,788,748	5,130,948	5,118,829	5,118,829
8														
9	Average rate base	214,141	214,141	214,141	214,141	214,141	214,141	214,141	214,141	214,141	214,141	214,141	214,141	2,569,693
10														
11	Return on Rate Base	16,365	16,365	16,365	16,365	16,365	16,365	16,365	16,365	16,365	16,365	16,365	16,365	196,376
12														
13	Available for return (equity portion of rate base)	10,984	10,984	10,984	10,984	10,984	10,984	10,984	10,984	10,984	10,984	10,984	10,984	131,806
14														
<b>EXPENSES</b>														
<b>O&amp;M and Depreciation</b>														
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	6,809	6,809
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	6,809	6,809
21														
22	Income before Taxes													
23	Available for return (from above)	10,984	10,984	10,984	10,984	10,984	10,984	10,984	10,984	10,984	10,984	10,984	10,984	131,806
24	Taxable Income (grossed up)	14,530	14,530	14,530	14,530	14,530	14,530	14,530	14,530	14,530	14,530	14,530	14,530	174,358
25														
26	Income Taxes													
27	Current and Def Income Taxes	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	42,552
28	Total Income Tax Expense	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	42,552
29														
30														
<b>REVENUE REQUIREMENTS</b>														
32	Expenses	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	3,546	10,355	49,361
33	Return on rate base	16,365	16,365	16,365	16,365	16,365	16,365	16,365	16,365	16,365	16,365	16,365	16,365	196,376
34	Subtotal revenue requirements	19,911	19,911	19,911	19,911	19,911	19,911	19,911	19,911	19,911	19,911	19,911	26,719	245,737
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(1,958)	(1,958)	(1,958)	(1,958)	(1,958)	(1,958)	(1,958)	(1,958)	(1,958)	(1,958)	(1,958)	(2,628)	(24,166)
37	Total revenue requirements	17,953	17,953	17,953	17,953	17,953	17,953	17,953	17,953	17,953	17,953	17,953	24,092	221,570
38														
39	North Dakota share - D2 factor	7,109	7,109	7,109	7,109	7,109	7,109	7,109	7,109	7,109	7,109	7,109	9,540	87,739

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	<b>Deferred Tax</b>
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%	2020 composite rate
0.00%	0.00%	0.00%	0.86%
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%
9.83%	
39.5989%	

0	0	0	0	0	0	0	0	0	0	0	0	0	6,809	6,809
0	0	0	0	0	0	0	0	0	0	0	0	128,469	128,469	256,937
0	0	0	0	0	0	0	0	0	0	0	0	128,469	128,469	256,937
0	0	0	0	0	0	0	0	0	0	0	0	(25,816)	(24,447)	(50,263)
0	0	0	0	0	0	0	0	0	0	0	0	(5,537)	(5,244)	(10,781)



Line No.	Year>>	2020 Projected January	2020 Projected February	2020 Projected March	2020 Projected April	2020 Projected May	2020 Projected June	2020 Projected July	2020 Projected August	2020 Projected September	2020 Projected October	2020 Projected November	2020 Projected December	2020 Projected Total
<b>RATE BASE</b>														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	1,435,375	1,452,500	1,452,500
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(1,902)	(1,902)
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	1,435,375	1,450,598	1,450,598
4	CWIP (Project #T03032.028)	58,625	118,250	152,875	187,500	297,125	406,750	516,375	1,271,000	1,325,625	1,380,250	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	0	0	0	0	0	0	0	0	(2,205)	(3,707)	(3,707)
7	Ending rate base	58,625	118,250	152,875	187,500	297,125	406,750	516,375	1,271,000	1,325,625	1,380,250	1,433,170	1,446,891	1,446,891
8														
9	Average rate base	55,093	55,093	55,093	55,093	55,093	55,093	55,093	55,093	55,093	55,093	55,093	55,093	661,111
10														
11	Return on Rate Base	4,210	4,210	4,210	4,210	4,210	4,210	4,210	4,210	4,210	4,210	4,210	4,210	50,522
12														
13	Available for return (equity portion of rate base)	2,826	2,826	2,826	2,826	2,826	2,826	2,826	2,826	2,826	2,826	2,826	2,826	33,910
14														
<b>EXPENSES</b>														
<b>O&amp;M and Depreciation</b>														
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	1,902	1,902
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	1,902	1,902
21														
22	Income before Taxes													
23	Available for return (from above)	2,826	2,826	2,826	2,826	2,826	2,826	2,826	2,826	2,826	2,826	2,826	2,826	33,910
24	Taxable Income (grossed up)	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	44,857
25														
26	Income Taxes													
27	Current and Def Income Taxes	912	912	912	912	912	912	912	912	912	912	912	912	10,947
28	Total Income Tax Expense	912	912	912	912	912	912	912	912	912	912	912	912	10,947
29														
30														
<b>REVENUE REQUIREMENTS</b>														
32	Expenses	912	912	912	912	912	912	912	912	912	912	912	2,814	12,849
33	Return on rate base	4,210	4,210	4,210	4,210	4,210	4,210	4,210	4,210	4,210	4,210	4,210	4,210	50,522
34	Subtotal revenue requirements	5,122	5,122	5,122	5,122	5,122	5,122	5,122	5,122	5,122	5,122	5,122	7,024	63,371
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(691)	(6,232)
37	Total revenue requirements	4,619	4,619	4,619	4,619	4,619	4,619	4,619	4,619	4,619	4,619	4,619	6,334	57,139
38														
39	North Dakota share - D2 factor	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829	2,508	22,627

Line No.														
<b>SUPPORTING INFORMATION / DATA</b>														
1														
2														
3	ND Cap Structure with allowed ROE per order.													
4	Capital Structure		<b>Ratio</b>	<b>Cost</b>	<b>WA Cost</b>					<b>Property tax</b>				
5	Debt		47.50%	5.29%	2.51%					2020 composite rate			0.86%	
6	Preferred equity		0.00%	0.00%	0.00%									
7	Common equity		52.50%	9.77%	5.13%									
8	Total		100.00%		7.64%	Overall Return								
9														
10														
11	Project life (years)		<b>Book</b>	<b>Tax</b>										
12			50	15-year MACRS										
13														
14														
15														
16														
17														
18	<b>Deferred Tax</b>													
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	1,902	0
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	36,313	36,313	72,625
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	36,313	36,313	72,625
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	(7,297)	(6,915)	(14,212)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	(1,565)	(1,483)	(3,048)





2020 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$38,971,455
	REVENUE CREDITS	(Note T)	<u>Total</u>	<u>Allocator</u>	
2	Account No. 454	(page 4, line 34)	154,227	TP 1.00000	154,227
3	Account No. 456.1	(page 4, line 37)	4,921,549	TP 1.00000	4,921,549
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)				5,075,776
7	To back out Schedule 9 Revenues received				(1,243,252)
8	Total Revenue Subject to the Wholesale Revenue Credit				3,832,525
7				Wholesale Revenue Credit	9.83%

2019 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$34,935,763
	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				(1,385,911)
8	Total Revenue Subject to the Wholesale Revenue Credit				1,576,914
9				Wholesale Revenue Credit	4.51%

		2019													
Line No.		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	
	<b>SCHEDULE 26</b>														
1	MISO Schedule 26 Expense	1,211,320	1,007,904	1,034,241	817,302	744,024	820,489	972,308	1,056,689	911,394	1,030,272	1,056,689	1,320,862	11,983,495	
2	OTP owned portion of expenses not recoverable via rider	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	MISO Schedule 26 Expense Recoverable	1,211,320	1,007,904	1,034,241	817,302	744,024	820,489	972,308	1,056,689	911,394	1,030,272	1,056,689	1,320,862	11,983,495	
4															
5	<b>North Dakota share</b>	39.599%	479,670	399,119	409,548	323,643	294,625	324,905	385,023	418,437	360,902	407,976	418,437	523,047	4,745,333
6															
7	MISO Schedule 26A Expense	829,911	732,113	658,688	568,354	553,496	575,433	542,536	632,349	606,304	639,461	736,996	843,409	7,919,051	
8															
9	<b>North Dakota share</b>	39.599%	328,636	289,909	260,833	225,062	219,178	227,865	214,838	250,403	240,090	253,220	291,842	333,981	3,135,858

		2020												
Line No.		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
	<b>SCHEDULE 26</b>													
1	MISO Schedule 26 Expense	1,269,774	1,244,379	1,066,611	1,053,913	914,238	1,028,517	990,424	952,331	850,749	977,726	1,180,890	1,155,495	12,685,047
2	OTP owned portion of expenses not recoverable via rider	(830)	(814)	(698)	(689)	(598)	(673)	(648)	(623)	(556)	(639)	(772)	(756)	(8,296)
3	MISO Schedule 26 Expense Recoverable	1,268,944	1,243,565	1,065,913	1,053,224	913,640	1,027,845	989,776	951,708	850,193	977,087	1,180,118	1,154,739	12,676,751
4														
5	<b>North Dakota share</b>	39.599%	502,488	492,438	422,090	417,065	361,791	407,015	391,941	376,866	336,667	386,916	467,314	5,019,855
6														
7	MISO Schedule 26A Expense	852,941	766,302	743,441	650,008	614,417	603,532	655,183	656,032	629,138	663,612	739,612	834,454	8,408,671
8														
9	<b>North Dakota share</b>	39.599%	337,755	303,447	294,394	257,396	243,302	238,992	259,781	249,132	262,783	292,878	330,435	3,329,742



		2019													
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)	(398,405)	(338,263)	(356,539)	(299,059)	(321,050)	(264,313)	(263,611)	(298,621)	(215,254)	(331,100)	(349,904)	(385,964)	(3,822,083)	
	CPEC Facility Credits in MISO	184,624	184,624	184,624	184,624	184,624	193,194	193,194	194,911	194,911	194,911	194,911	194,911	2,284,061	
2	Non-OTP Schedule 9 Revenues	21,143	15,195	17,002	11,318	13,492	7,034	6,964	10,257	2,012	13,469	15,329	18,895	152,110	
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(192,638)	(138,444)	(154,913)	(103,117)	(122,933)	(64,085)	(63,453)	(93,454)	(18,332)	(122,721)	(139,665)	(172,158)	(1,385,911)	
5	North Dakota share	39.599%	(76,282)	(54,822)	(61,344)	(40,833)	(48,680)	(25,377)	(25,127)	(37,007)	(7,259)	(48,596)	(55,306)	(68,173)	(548,806)

		2020													
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)	(414,967)	(371,550)	(339,037)	(313,245)	(260,503)	(268,898)	(239,070)	(304,892)	(219,774)	(338,054)	(357,252)	(394,069)	(3,821,311)	
	CPEC Facility Credits in MISO	194,911	194,911	194,911	194,911	194,911	197,579	197,579	197,579	197,579	197,579	197,579	197,579	2,357,608	
2	Non-OTP Schedule 9 Revenues	30,866	24,344	20,209	16,993	11,563	12,066	8,647	16,315	6,538	22,344	22,708	27,860	220,452	
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(189,191)	(152,296)	(123,918)	(101,342)	(54,030)	(59,252)	(32,844)	(90,998)	(15,657)	(118,130)	(136,965)	(168,629)	(1,243,252)	
5	North Dakota share	39.599%	(74,917)	(60,307)	(49,070)	(40,130)	(21,395)	(23,463)	(13,006)	(36,034)	(6,200)	(46,778)	(54,237)	(66,775)	(492,314)



Line No.	2020	2020												Total Projected
		Jan Projected	Feb Projected	Mar Projected	Apr Projected	May Projected	Jun Projected	Jul Projected	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	
1	Total Schedule 26 Revenue	(1,556,587)	(1,529,255)	(1,373,986)	(1,225,919)	(1,005,959)	(946,543)	(1,000,463)	(1,037,839)	(1,030,405)	(996,455)	(1,204,711)	(1,383,119)	(14,291,240)
2	Overhead Credit for Non-Retail Share	1.020%	(15,877)	(15,598)	(14,015)	(12,504)	(10,261)	(9,655)	(10,205)	(10,586)	(10,510)	(12,288)	(14,108)	(145,771)
4														
5	Fargo	66.671%	(1,037,792)	(1,019,569)	(916,050)	(817,332)	(670,683)	(631,070)	(667,019)	(691,938)	(686,981)	(664,346)	(803,193)	(9,528,113)
6	Retail Load Share		71.34%	71.34%	71.34%	71.34%	71.34%	71.34%	71.34%	71.34%	71.34%	71.34%	71.34%	
7	Retail Revenue		(740,361)	(727,361)	(653,510)	(583,085)	(478,465)	(450,205)	(475,851)	(493,628)	(490,092)	(473,945)	(572,998)	(6,797,356)
8			(10,585)	(10,400)	(9,344)	(8,337)	(6,841)	(6,437)	(6,804)	(7,058)	(7,007)	(6,776)	(8,193)	(9,406)
9	Overhead Credit for Non-Retail Share		28.66%	28.66%	28.66%	28.66%	28.66%	28.66%	28.66%	28.66%	28.66%	28.66%	28.66%	
10	Non-Retail Load Share		(3,034)	(2,981)	(2,678)	(2,389)	(1,961)	(1,845)	(1,950)	(2,023)	(2,008)	(1,942)	(2,348)	(2,854)
11	Non-Retail Overhead Credit													
12														
13	Total Revenue Credit for Fargo		(743,395)	(730,341)	(656,188)	(585,474)	(480,426)	(452,050)	(477,801)	(495,651)	(492,101)	(475,887)	(575,346)	(6,825,209)
14														
15														
16	Bemidji	13.576%	(211,322)	(207,612)	(186,532)	(166,431)	(136,569)	(128,503)	(135,823)	(140,897)	(139,888)	(135,279)	(163,552)	(1,940,179)
17	Retail Load Share		87.75%	87.75%	87.75%	87.75%	87.75%	87.75%	87.75%	87.75%	87.75%	87.75%	87.75%	
18	Retail Revenue		(185,435)	(182,179)	(163,682)	(146,043)	(119,839)	(112,761)	(119,185)	(123,637)	(122,752)	(118,707)	(143,517)	(1,702,507)
19														
20	Overhead Credit for Non-Retail Share		(2,155)	(2,118)	(1,903)	(1,698)	(1,393)	(1,311)	(1,385)	(1,437)	(1,427)	(1,380)	(1,668)	(1,915)
21	Non-Retail Load Share		12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	
22	Non-Retail Overhead Credit		(264)	(259)	(233)	(208)	(171)	(161)	(170)	(176)	(175)	(169)	(204)	(242)
23														
24	Total Revenue Credit for Bemidji		(185,699)	(182,439)	(163,915)	(146,251)	(120,010)	(112,922)	(119,354)	(123,813)	(122,926)	(118,876)	(143,721)	(1,704,931)
25														
26														
27	Cass Lake - Nary - Helga - Bemidji	5.777%	(89,924)	(88,345)	(79,375)	(70,821)	(58,114)	(54,682)	(57,797)	(59,956)	(59,526)	(57,565)	(69,596)	(825,605)
28	Retail Load Share		33.75%	33.75%	33.75%	33.75%	33.75%	33.75%	33.75%	33.75%	33.75%	33.75%	33.75%	
29	Retail Revenue		(30,348)	(29,816)	(26,788)	(23,901)	(19,613)	(18,455)	(19,506)	(20,235)	(20,090)	(19,428)	(23,488)	(278,633)
30														
31	Overhead Credit for Non-Retail Share		(917)	(901)	(810)	(722)	(593)	(558)	(590)	(612)	(607)	(587)	(710)	(842)
32	Non-Retail Load Share		66.25%	66.25%	66.25%	66.25%	66.25%	66.25%	66.25%	66.25%	66.25%	66.25%	66.25%	
33	Non-Retail Overhead Credit		(608)	(597)	(536)	(479)	(393)	(370)	(391)	(405)	(402)	(389)	(470)	(579)
34														
35	Total Revenue Credit for Bemidji		(30,956)	(30,413)	(27,325)	(24,380)	(20,006)	(18,824)	(19,896)	(20,640)	(20,492)	(19,817)	(23,958)	(284,213)
36														
37														
27	Rugby	-0.400%	6,226	6,117	5,496	4,904	4,024	3,786	4,002	4,151	4,122	3,986	4,819	57,165
28	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%	
29	Retail Revenue		6,226	6,117	5,496	4,904	4,024	3,786	4,002	4,151	4,122	3,986	4,819	57,165
30														
31	Total Revenue Credit for Rugby		6,226	6,117	5,496	4,904	4,024	3,786	4,002	4,151	4,122	3,986	4,819	57,165
32														
33														
34	Casselton	12.299%	(191,445)	(188,083)	(168,987)	(150,776)	(123,723)	(116,415)	(123,047)	(127,644)	(126,730)	(122,554)	(148,167)	(1,757,680)
35	Retail Load Share		49.44%	49.44%	49.44%	49.44%	49.44%	49.44%	49.44%	49.44%	49.44%	49.44%	49.44%	
36	Retail Revenue		(94,654)	(92,992)	(83,550)	(74,547)	(61,171)	(57,558)	(60,837)	(63,110)	(62,658)	(60,593)	(73,257)	(869,032)
37														
38	Overhead Credit for Non-Retail Share		(1,953)	(1,918)	(1,724)	(1,538)	(1,262)	(1,187)	(1,255)	(1,302)	(1,293)	(1,250)	(1,511)	(1,735)
39	Non-Retail Load Share		50.56%	50.56%	50.56%	50.56%	50.56%	50.56%	50.56%	50.56%	50.56%	50.56%	50.56%	
40	Non-Retail Overhead Credit		(987)	(970)	(871)	(778)	(638)	(600)	(635)	(658)	(654)	(632)	(764)	(906)
41														
42	Total Revenue Credit for Casselton		(95,641)	(93,962)	(84,422)	(75,324)	(61,809)	(58,158)	(61,471)	(63,768)	(63,311)	(61,225)	(74,021)	(878,096)
43														
44														
45	Spiritwood	0.622%	(9,682)	(9,512)	(8,546)	(7,625)	(6,257)	(5,887)	(6,223)	(6,455)	(6,409)	(6,198)	(7,493)	(88,892)
46	Retail Load Share		51.26%	51.26%	51.26%	51.26%	51.26%	51.26%	51.26%	51.26%	51.26%	51.26%	51.26%	
47	Retail Revenue		(4,963)	(4,876)	(4,381)	(3,909)	(3,207)	(3,018)	(3,190)	(3,325)	(3,285)	(3,177)	(3,841)	(45,568)
48														
49	Overhead Credit for Non-Retail Share		(99)	(97)	(87)	(78)	(64)	(60)	(63)	(66)	(65)	(63)	(76)	(88)
50	Non-Retail Load Share		48.74%	48.74%	48.74%	48.74%	48.74%	48.74%	48.74%	48.74%	48.74%	48.74%	48.74%	
51	Non-Retail Overhead Credit		(48)	(47)	(42)	(38)	(31)	(29)	(31)	(32)	(32)	(31)	(37)	(44)
52														
53	Total Revenue Credit for Spiritwood		(5,011)	(4,923)	(4,423)	(3,947)	(3,239)	(3,047)	(3,221)	(3,341)	(3,317)	(3,208)	(3,878)	(46,009)
54														
55														
56	Courtenay Wind	0.176%	(2,740)	(2,691)	(2,418)	(2,158)	(1,770)	(1,666)	(1,761)	(1,827)	(1,814)	(1,754)	(2,120)	(25,153)
57	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%	
58	Retail Revenue		(23)	(23)	(21)	(18)	(15)	(14)	(15)	(16)	(16)	(15)	(21)	(215)
59														
60	Overhead Credit for Non-Retail Share		(28)	(27)	(25)	(22)	(18)	(17)	(18)	(19)	(18)	(18)	(22)	(257)
61	Non-Retail Load Share		99.14%	99.14%	99.14%	99.14%	99.14%	99.14%	99.14%	99.14%	99.14%	99.14%	99.14%	
62	Non-Retail Overhead Credit		(28)	(27)	(24)	(22)	(18)	(17)	(18)	(18)	(18)	(18)	(21)	(254)
63														
64	Total Revenue Credit for Courtenay Wind		(51)	(50)	(45)	(40)	(33)	(31)	(33)	(34)	(34)	(33)	(40)	(470)
65														
66														
67	Retail Share of Schedule 26 Revenue		(1,054,527)	(1,036,011)	(930,822)	(830,513)	(681,499)	(641,246)	(677,775)	(703,096)	(698,060)	(675,060)	(816,145)	(9,681,763)
68														
69	North Dakota Share	39.599%	(417,581)	(410,249)	(368,596)	(328,874)	(269,866)	(253,927)	(268,391)	(278,418)	(276,424)	(267,316)	(323,185)	(3,833,872)

Line No.	2019	2019												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	(2,095,445)	(1,793,639)	(1,858,551)	(1,712,383)	(1,874,918)	(2,001,401)	(2,144,859)	(2,243,436)	(2,050,664)	(1,954,277)	(1,930,181)	(2,147,050)	(23,806,803)	
2	Overhead Credit for Non-Retail Share	0.977%	(20,468)	(17,520)	(18,154)	(16,727)	(18,314)	(19,550)	(20,951)	(21,914)	(20,031)	(19,090)	(18,854)	(20,973)	(232,547)
5	<b>CAPX 2020 - Brookings</b>	13.173%	(276,041)	(236,283)	(244,834)	(225,579)	(246,990)	(263,652)	(282,551)	(295,537)	(270,142)	(257,445)	(254,270)	(282,839)	(3,136,165)
6	Retail Load Share		22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	
7	Retail Revenue		(62,932)	(53,868)	(55,817)	(51,428)	(56,309)	(60,107)	(64,416)	(67,376)	(61,587)	(58,692)	(57,969)	(64,482)	(714,983)
9	Overhead Credit for Non-Retail Share		(2,696)	(2,308)	(2,392)	(2,203)	(2,413)	(2,575)	(2,760)	(2,887)	(2,639)	(2,515)	(2,484)	(2,763)	(30,634)
10	Non-Retail Load Share		77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	
11	Non-Retail Overhead Credit		(2,082)	(1,782)	(1,846)	(1,701)	(1,863)	(1,988)	(2,131)	(2,229)	(2,037)	(1,941)	(1,917)	(2,133)	(23,650)
12	<b>Total Revenue Credit for CAPX Brookings</b>		(65,014)	(55,650)	(57,664)	(53,129)	(58,171)	(62,096)	(66,547)	(69,605)	(63,624)	(60,634)	(59,886)	(66,615)	(738,633)
16	<b>MVP BS South - Brookings</b>	35.243%	(738,489)	(632,125)	(655,002)	(603,488)	(660,770)	(705,346)	(755,904)	(790,645)	(722,707)	(688,738)	(680,246)	(756,676)	(8,390,136)
17	Retail Load Share		2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	
18	Retail Revenue		(15,124)	(12,946)	(13,414)	(12,359)	(13,532)	(14,445)	(15,481)	(16,192)	(14,801)	(14,105)	(13,931)	(15,497)	(171,828)
20	Overhead Credit for Non-Retail Share		(7,214)	(6,175)	(6,398)	(5,895)	(6,454)	(6,890)	(7,384)	(7,723)	(7,059)	(6,728)	(6,645)	(7,391)	(81,956)
21	Non-Retail Load Share		97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	
22	Non-Retail Overhead Credit		(7,066)	(6,048)	(6,267)	(5,774)	(6,322)	(6,749)	(7,233)	(7,565)	(6,915)	(6,590)	(6,509)	(7,240)	(80,277)
23	<b>Total Revenue Credit for MVP Brookings</b>		(22,190)	(18,994)	(19,681)	(18,133)	(19,855)	(21,194)	(22,713)	(23,757)	(21,716)	(20,695)	(20,440)	(22,736)	(252,105)
27	<b>MVP Ellendale - BS South</b>	51.584%	(1,080,912)	(925,229)	(958,713)	(883,314)	(967,156)	(1,032,400)	(1,106,402)	(1,157,252)	(1,057,812)	(1,008,092)	(995,663)	(1,107,532)	(12,280,477)
28	Retail Load Share		2.180%	2.180%	2.180%	2.180%	2.180%	2.180%	2.180%	2.180%	2.180%	2.180%	2.180%	2.180%	
29	Retail Revenue		(23,564)	(20,170)	(20,900)	(19,256)	(21,084)	(22,506)	(24,120)	(25,228)	(23,060)	(21,976)	(21,705)	(24,144)	(267,714)
31	Overhead Credit for Non-Retail Share		(10,558)	(9,038)	(9,365)	(8,628)	(9,447)	(10,085)	(10,807)	(11,304)	(10,333)	(9,847)	(9,726)	(10,818)	(119,957)
32	Non-Retail Load Share		97.820%	97.820%	97.820%	97.820%	97.820%	97.820%	97.820%	97.820%	97.820%	97.820%	97.820%	97.820%	
33	Non-Retail Overhead Credit		(10,328)	(8,841)	(9,161)	(8,440)	(9,241)	(9,865)	(10,572)	(11,058)	(10,108)	(9,632)	(9,514)	(10,583)	(117,342)
34	<b>Total Revenue Credit for MVP Ellendale</b>		(33,892)	(29,011)	(30,061)	(27,696)	(30,325)	(32,371)	(34,691)	(36,286)	(33,168)	(31,609)	(31,219)	(34,727)	(385,056)
38	Retail Share of Schedule 26A Revenue		(121,096)	(103,654)	(107,406)	(98,959)	(108,351)	(115,661)	(123,951)	(129,648)	(118,508)	(112,938)	(111,545)	(124,078)	(1,375,794)
40	<b>North Dakota share</b>	39.599%	(47,953)	(41,046)	(42,531)	(39,187)	(42,906)	(45,800)	(49,083)	(51,339)	(46,928)	(44,722)	(44,171)	(49,134)	(544,800)

Line No.	2020	2020												Total Projected	
		Jan Projected	Feb Projected	Mar Projected	Apr Projected	May Projected	Jun Projected	Jul Projected	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected		
1	Total Schedule 26 Revenue	(2,575,457)	(2,530,234)	(2,273,334)	(2,028,348)	(1,664,414)	(1,566,107)	(1,655,320)	(1,717,160)	(1,704,861)	(1,648,688)	(1,993,259)	(2,288,444)	(23,645,625)	
2	Overhead Credit for Non-Retail Share	1.020%	(26,270)	(25,808)	(23,188)	(20,689)	(16,977)	(15,974)	(16,884)	(17,515)	(17,390)	(16,817)	(20,331)	(23,342)	(241,185)
3															
4															
5	<b>CAPX 2020 - Brookings</b>	13.047%	(336,022)	(330,122)	(296,604)	(264,641)	(217,158)	(204,332)	(215,971)	(224,040)	(222,435)	(215,106)	(260,063)	(298,576)	(3,085,068)
6	Retail Load Share		22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	
7	Retail Revenue		(76,606)	(75,261)	(67,620)	(60,333)	(49,508)	(46,583)	(49,237)	(51,077)	(50,711)	(49,040)	(59,289)	(68,069)	(703,334)
8															
9	Overhead Credit for Non-Retail Share		(3,427)	(3,367)	(3,025)	(2,699)	(2,215)	(2,084)	(2,203)	(2,285)	(2,269)	(2,194)	(2,653)	(3,045)	(31,468)
10	Non-Retail Load Share		77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	
11	Non-Retail Overhead Credit		(2,646)	(2,600)	(2,336)	(2,084)	(1,710)	(1,609)	(1,701)	(1,764)	(1,752)	(1,694)	(2,048)	(2,351)	(24,294)
12															
13	<b>Total Revenue Credit for CAPX Brookings</b>		(79,252)	(77,861)	(69,955)	(62,417)	(51,218)	(48,193)	(50,938)	(52,841)	(52,462)	(50,734)	(61,337)	(70,420)	(727,628)
14															
15															
16	<b>MVP BS South - Brookings</b>	34.678%	(893,112)	(877,430)	(788,342)	(703,387)	(577,182)	(543,091)	(574,028)	(595,473)	(591,208)	(571,729)	(691,218)	(793,582)	(8,199,783)
17	Retail Load Share		2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	
18	Retail Revenue		(18,290)	(17,969)	(16,145)	(14,405)	(11,820)	(11,122)	(11,756)	(12,195)	(12,108)	(11,709)	(14,156)	(16,252)	(167,926)
19															
20	Overhead Credit for Non-Retail Share		(9,110)	(8,950)	(8,041)	(7,175)	(5,887)	(5,540)	(5,855)	(6,074)	(6,030)	(5,832)	(7,050)	(8,095)	(83,638)
21	Non-Retail Load Share		97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	
22	Non-Retail Overhead Credit		(8,923)	(8,766)	(7,876)	(7,028)	(5,767)	(5,426)	(5,735)	(5,949)	(5,907)	(5,712)	(6,906)	(7,929)	(81,925)
23															
24	<b>Total Revenue Credit for MVP Brookings</b>		(27,213)	(26,736)	(24,021)	(21,432)	(17,587)	(16,548)	(17,491)	(18,144)	(18,014)	(17,421)	(21,062)	(24,181)	(249,851)
25															
26															
27	<b>MVP Ellendale - BS South</b>	52.275%	(1,346,323)	(1,322,682)	(1,188,388)	(1,060,321)	(870,074)	(818,684)	(865,320)	(897,647)	(891,218)	(861,853)	(1,041,978)	(1,196,287)	(12,360,774)
28	Retail Load Share		2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	
29	Retail Revenue		(26,926)	(26,454)	(23,768)	(21,206)	(17,401)	(16,374)	(17,306)	(17,953)	(17,824)	(17,237)	(20,840)	(23,926)	(247,215)
30															
31	Overhead Credit for Non-Retail Share		(13,732)	(13,491)	(12,122)	(10,815)	(8,875)	(8,351)	(8,826)	(9,156)	(9,090)	(8,791)	(10,628)	(12,202)	(126,080)
32	Non-Retail Load Share		98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	
33	Non-Retail Overhead Credit		(13,458)	(13,222)	(11,879)	(10,599)	(8,697)	(8,184)	(8,650)	(8,973)	(8,909)	(8,615)	(10,416)	(11,958)	(123,558)
34															
35	<b>Total Revenue Credit for MVP Ellendale</b>		(40,384)	(39,675)	(35,647)	(31,805)	(26,099)	(24,557)	(25,956)	(26,926)	(26,733)	(25,852)	(31,255)	(35,884)	(370,774)
36															
37															
38	Retail Share of Schedule 26A Revenue		(146,850)	(144,272)	(129,623)	(115,655)	(94,903)	(89,298)	(94,385)	(97,911)	(97,210)	(94,007)	(113,654)	(130,485)	(1,348,252)
39															
40	<b>North Dakota share</b>	39.599%	(58,151)	(57,130)	(51,329)	(45,798)	(37,581)	(35,361)	(37,375)	(38,772)	(38,494)	(37,226)	(45,006)	(51,671)	(533,893)





**Federal ADIT Proration**

	A	B	C	D
1		January 2020 - December 2020 Recovery Period		
		<b>All Projects' Revenue Requirements</b>	<b>All Projects' Revenue Requirements with ADIT- Prorate</b>	<b>Difference due to Federal ADIT Proration (B - A)</b>
2	Month			
3	Jan-19	\$126,241	\$126,477	\$236
4	Feb-19	\$127,194	\$127,431	\$236
5	Mar-19	\$127,179	\$127,416	\$236
6	Apr-19	\$127,179	\$127,416	\$236
7	May-19	\$127,179	\$127,416	\$236
8	Jun-19	\$127,179	\$127,416	\$236
9	Jul-19	\$127,179	\$127,416	\$236
10	Aug-19	\$127,179	\$127,416	\$236
11	Sep-19	\$127,179	\$127,416	\$236
12	Oct-19	\$127,179	\$127,416	\$236
13	Nov-19	\$127,179	\$127,416	\$236
14	Dec-19	\$133,277	\$133,514	\$236
15		\$1,531,327	\$1,534,163	\$2,836

16	<b>Revenue Requirement Adjustment Related to Federal ADIT Proration</b>	<b>\$2,836</b>
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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%	(D1 * D8)
3			Equity Return %	5.13%	(D8)
4			Gross Up Factor	1.66%	(D2-D3)

		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 2019 - December 2019		
Month	Original ADIT Balance - All Projects	Federal ADIT Prorate Balance - All Projects	Difference due to Federal ADIT Proration (B - A)	
13				
14	Dec-18	(\$316,292)	(\$314,558)	\$1,734
15	Jan-19	(\$321,097)	(\$319,527)	
16	Feb-19	(325,470)	(435,683)	
17	Mar-19	(417,446)	(502,226)	
18	Apr-19	(476,951)	(561,959)	
19	May-19	(528,957)	(614,996)	
20	Jun-19	(573,707)	(661,512)	
21	Jul-19	(615,575)	(697,585)	
22	Aug-19	(649,008)	(726,496)	
23	Sep-19	(619,909)	(747,986)	
24	Oct-19	(636,698)	(762,400)	
25	Nov-19	(645,364)	(769,973)	
26	Dec-19	(\$645,634)	(\$770,480)	-\$124,846
27	ADIT Simple Average	(\$480,963)	(\$542,519)	-\$61,556

28	Rate Base Rev Req Gross Up Factor	9.30%
29	Total Company Revenue Requirement	-\$5,723

30	<b>ND Revenue Requirement Related to Federal ADIT Proration-Preservation</b>	<b>-\$2,266</b>
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Attachment 26  
Redline and Clean Versions of  
Tariff Sheet ND 13.05 – Transmission Cost Recovery Rider

**TRANSMISSION COST RECOVERY RIDER**

DESCRIPTION	RATE CODE
Large General Service – Demand Charge	NTCRD
Large General Service – Energy Charge	NTCRE
Controlled Service	NTCRC
Lighting	NTCRL
All Other Service	NTCRO

**RULES AND 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 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
	<b>Large General Service (a)</b>	N/A	¢/kWh
<b>Controlled Service (b)</b>	<del>0.054</del> <u>0.063</u>	¢/kWh	N/A
<b>Lighting (c)</b>	<del>0.201</del> <u>0.242</u>	¢/kWh	N/A
<b>All Other Service</b>	<del>0.352</del> <u>0.425</u>	¢/kWh	N/A

(a) Rate schedules 10.04 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, and 11.07 LED Street and Area Lighting

NORTH DAKOTA PUBLIC  
SERVICE COMMISSION

EFFECTIVE with bills rendered on  
and after ~~February 1, 2019~~ January 1, 2020, in  
North Dakota

Case No. ~~PU 17-398, PU 18-106 and PU 18-329~~ PU-19-  
Approved by order dated ~~September 26, 2018 (PU 17-398)~~  
~~December 6, 2018 (PU 18-329)~~

APPROVED: Bruce G. Gerhardson  
Vice President, Regulatory Affairs

**TRANSMISSION COST RECOVERY RIDER**

<b>DESCRIPTION</b>	<b>RATE CODE</b>
Large General Service – Demand Charge	NTCRD
Large General Service – Energy Charge	NTCRE
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All Other Service	NTCRO

**RULES AND 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 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:**

<b>TRANSMISSION COST RECOVERY</b>			
<b>Energy Charge per kWh:</b>	<b>kWh</b>		<b>kW</b>
<b>Large General Service (a)</b>	N/A	¢/kWh	\$1.310
<b>Controlled Service (b)</b>	0.063	¢/kWh	N/A
<b>Lighting (c)</b>	0.242	¢/kWh	N/A
<b>All Other Service</b>	0.425	¢/kWh	N/A

(a) Rate schedules 10.04 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, and 11.07 LED Street and Area Lighting

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Attachment 27  
Proposed Customer Notice

**On August 30, 2019, Otter Tail Power Company filed a request with the North Dakota Public Service Commission to increase 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, 2020. 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: \$106.16 (from \$1.060 to \$1.310 per kW)**
- **Controlled Service: \$0.12 (from .054 cents to .063 cents per kWh)**
- **Lighting: \$0.04 (from 0.201 cents to 0.242 cents per kWh)**
- **Residential and all other service: \$0.73/\$0.98 (from 0.352 cents to 0.425 cents per kWh)**

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