

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpc.com (web site)



September 15, 2021

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 13.05,
Transmission Cost Recovery Rider
Case No. PU-21-376**

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. If you have any questions regarding this filing, please contact me at 218-739-8577 or lwalters@otpc.com.

Sincerely,

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

kaw
Enclosures
By electronic filing and U.S. mail

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

**In the Matter of Otter Tail Power
Company's Application for Approval
of the Annual Rate Update to Rate
Schedule, Section 13.05,
Transmission Cost Recovery Rider**

Case No. PU-21-376

**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 filing, Otter Tail's TCRR rates are updated to reflect the TCRR revenue requirements for the next recovery period (calendar year 2022). 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 three new transmission project/programs not currently in base rates and not previously included in the Rider, (2) forecast updates to previously approved 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 2022, upon which rates are developed, is \$6,079,317. For a residential customer using 1,000 kWh per month, the bill impact of this update is an increase of \$0.41 per month. For a large general service customer with 425 kW of demand, the bill impact of this update is an increase of \$118.22 per month.

II. GENERAL FILING INFORMATION

Pursuant to N.D.A.C. § 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 September 15, 2021. The updated TCRR rate is calculated to take effect as of January 1, 2022.

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.

III. TRANSMISSION COST RECOVERY

A. Background

In this Application, Otter Tail requests an annual update to its rate schedule, Section 13.05, 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 filed for a 15-day extension on August 27, 2021, to allow adequate time to incorporate and review updated MISO information filed with FERC on September 1 into the filing.

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 5-26 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 5-23) and the new projects for which Otter Tail is requesting TCRR recovery (Attachments 24-26).

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 Otter Tail facilities 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 Commission¹ in Otter Tail's last general rate case.
- *Depreciation expense.* Depreciation expense is calculated using the Company's current composite depreciation rates.

¹ Case No. PU-17-398, Order on Settlement, September 26, 2018.

- *Property taxes.* The property tax calculation is based on Otter Tail’s composite tax rate, for the jurisdiction in which the transmission facilities are located and is calculated in accordance with the procedures specified by that state.
- *Operation and maintenance (O&M) expense.* Annual O&M expense of transmission lines includes costs related to line patrol and inspections, vegetation management, small repair items, storm restoration, and supervision of this work. Scheduled transmission line patrols are typically done annually on high voltage transmission lines (115 kV and above). 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 within a specified easement area 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 35 to this filing to show the ADIT proration calculation impact on the revenue requirement for the recovery period.

Otter Tail provides Attachment 36 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.² Attachment 36 shows the preservation of the proration of ADIT resulted in an increase of \$747, plus any applicable carrying charge to the revenue requirement. This item is included on Line No. 26 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 29 and 30 of the Tracker Account Summary (Attachment 4) and are shown separately in Attachment 28. These represent Otter Tail’s retail share of the costs for projects that qualify for regional cost allocation under MISO’s Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff).
- *Southwest Power Pool (SPP) Related Expenses (Attachment 29) and MISO Related Revenues (Attachment 30).* 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

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

area. SPP Schedule 9 expenses appear on Line 31 and SPP Schedule 11 expenses on Line 32 of the Tracker Account Summary (Attachment 4). Both are shown separately in Attachment 29.

Otter Tail also receives MISO Schedule 9 revenues related to Central Power Electric Cooperative (CPEC) paying MISO charges for transmission service they receive through MISO. These revenues are offset by facility credits CPEC is collecting in MISO for CPEC-owned transmission facilities that are eligible for recovery under the MISO Tariff. The MISO Schedule 9 revenue from CPEC results in a reduction to Otter Tail's TCRR revenue requirement.

MISO Schedule 9 revenue from CPEC appears on Line 36 of the Tracker Account Summary (Attachment 4) and is shown in detail in Attachment 30.

- *MISO Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period appear on lines 37 and 40 of the Tracker Account Summary (Attachment 4) and are shown separately on Attachment 31 (Schedule 26) and Attachment 32 (Schedule 26A). These represent Otter Tail's retail share of the revenues derived from Otter Tail's investment in projects that qualify for regional cost allocation under 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 (TO), 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 TOs were granted a 50-basis point adder for participation in a Regional Transmission Organization (RTO) to be applied to the base ROE.

On November 21, 2019, FERC issued [Opinion No. 569^{\[1\]}](#), a ruling on the two MISO complaint cases. The opinion adopted in part and rejected in part a new approach for evaluating base ROEs, which FERC had proposed in response to the D.C. Circuit Court's action to vacate and remand FERC's standing ROE methodology that was used to set the MISO ROE at 10.32 percent in the first complaint. The November 21, 2019, Order granted rehearing on the first complaint and reaffirmed its prior finding that the existing 12.38 percent ROE is

^[1] 169 FERC ¶ 61,129 (2019).

unjust and unreasonable. FERC set the MISO base ROE at 9.88 percent plus any applicable adders effective September 28, 2016, and required refunds be made within 30 days of the Order for the period where the 10.32 percent base ROE was in effect (the fifteen-month refund period of November 12, 2013, to February 11, 2015, and the period from September 28, 2016, to December 31, 2019). As of January 1, 2020, MISO implemented the new base ROE of 9.88 percent in its rates and began processing refunds. On May 21, 2020, FERC issued Opinion 569-A, granting rehearing in part of Opinion 569. Opinion 569-A refines the methodology used for determining ROE. Under Opinion 569-A the base ROE was determined to increase from 9.88 percent to 10.02 percent. In addition to the increase in ROE, Opinion 569-A affirmed the dismissal of the second ROE complaint. On September 10, 2020, an extension of time to process the refunds was filed with the Commission by MISO. FERC granted an extension of time until September 23, 2021. On November 19, 2020, FERC issued Opinion 569-B which largely affirmed Opinion 569-A, including the base ROE of 10.02 percent.

MISO continues to work on the refunds, but it has become clear that given the complexity of the refunds related to Opinions 569, 569-A, and 569-B the September 2021 deadline was very difficult to achieve. The ROE percentage has changed several times throughout this process and has resulted in some partial refunds having taken place only to have the ROE changed again. Revised calculations for the latest Commission-approved ROE may result in either refunds or surcharges to customers. On June 30, 2021, MISO requested an additional extension of time to process the refunds and surcharges until June 30, 2022. In its June 2021 request for an additional extension of time, MISO explained the majority of refunds will still take place in 2021. FERC partially accepted the MISO request for extension of time on August 2, 2021. MISO did not receive the complete extension of time it requested but now has until February 28, 2022, to finalize processing refunds and surcharges. MISO and the MISO TOs remain committed to processing the refunds and surcharges efficiently and accurately.

Because Otter Tail uses a forward-looking rate formula in MISO, it makes an annual true-up filing with MISO. The true-up is generally calculated by determining the difference between the projected revenue requirement used in developing the rates for billing and the actual revenue requirements and billings based on actual operating results. MISO began processing the refund for the first complaint period of November 2013 to January 2015 in April 2020, with additional refunds coming through in the second half of 2020 and 2021. Otter Tail includes the impacts of the 2021 refund within this filing in Attachments 28, 30, 31, 32, and 34 collectively resulting in a \$825 increase to the ND share of the 2022 revenue requirement.

- *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 MISO Schedule 26A expenses are allocated to MISO market participants for all MVP projects. The revenue is identified in Attachment 33 and is reflected as a credit in the Tracker Account Summary (Attachment 4, line 41).

- *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 31 and Attachment 32 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 and 38 revenues represent Otter Tail’s share 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 34, there are no forecast amounts for Schedule 37 and 38 revenues for the 2022 recovery period. 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 2021 is \$21,770, as can be seen in Attachment 4 on line 38. The Schedule 38 revenue credit reflected in this TCRR update for 2021 is \$27,314, as seen in Attachment 4 on line 39. These are actual amounts through July 2021 and are included as part of the 2020 true-up amount.

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

Nineteen projects previously approved for inclusion in Otter Tail’s TCRR are included in this update. Table 1 reflects the prior approved projects and the case number in which they were approved for TCRR recovery.

The retail allocation of costs and revenues for these projects have been updated and

carried out through 2021 and 2022 and are reflected in Attachments 5-23.

Table 1

	Project	Case Number	Attachment
1	BSAT-Ellendale MVP	PU-12-702	5
2	Max-Ryder 41.6 kV Line Upgrade	PU-16-624	6
3	Bagley 115 kV Switch Station	PU-17-340	7
4	Lake Norden Area Transmission	PU-18-329	8
5	Donaldson 115 kV Cap Bank	PU-19-311	9
6	Northwest MN UVLS	PU-19-311	10
7	Blair 230 kV Substation	PU-19-311	11
8	Veblen 41.6 kV Cap Bank	PU-19-311	12
9	New Effington 230/41.6 kV Line	PU-19-311	13
10	Jamestown Substation	PU-19-311	14
11	CPEC Purchase	PU-19-311	15
12	Erie 230/115kV Substation	PU-20-383	16
13	Norcross 115kV Line-115/41.6kV Sub	PU-20-383	17
14	Winger 230/115kV Transformer	PU-20-383	18
15	Jamestown 41.6 kV Source	PU-20-383	19
16	Hoot Lake Capacitor	PU-20-383	20
17	Finley/McVile 41.6 kV Rebuild	PU-20-383	21
18	Turtle Lake/Mercer 41.6 kV Rebuild	PU-20-383	22
19	Doyon/Bartlett 41.6 kV Rebuild	PU-20-383	23

In Otter Tail’s 2020 annual update, Otter Tail forecasted the Norcross 115 kV Line and 115/41.6 kV Substation with an estimated \$6.7 million spend and an in-service date of May 2021. Otter Tail is currently forecasting a total project spend of \$4.4 million with an in-service date in the first quarter of 2022. Due to Otter Tail’s recent experience in past transmission projects located in Minnesota, a major assumption in the forecast for the Norcross project in the 2020 annual update was that route permitting would be completed under the Minnesota routing process before the Minnesota Public Utilities Commission. However, Otter Tail was able to qualify the project for review and approval by the local unit of government (Grant County), which resulted in a reduction in the project estimate. Additional reductions in the overall project cost were also obtained through lower than forecasted material and external labor costs. Despite the more expeditious permitting process, the project schedule has been delayed due to internal labor being redirected to higher priority projects.

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 three new projects/programs 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 these new projects were not included in its last general rate review, Case No. PU-17-398, and that no portion of these projects are currently being recovered as a result of that proceeding.

Hoot Lake 115/41.6/34.5 kV Transformer – Attachment 24

Otter Tail is planning to replace the existing Hoot Lake 115/41.6 kV Transformer in Fergus Falls, MN. A variety of factors is driving the replacement, including age and condition as well as system performance concerns. The new transformer will also support interconnection of Otter Tail’s future solar project.

The existing transformer is early 1960’s vintage and is showing signs that it is nearing end-of-life. The transformer has two of the secondary bushings showing signs of degradation that will lead to imminent failure. Repairing the existing transformer to address these issues is not economical for a transformer of this age.

Another driver for the transformer replacement is to enhance reliability of the existing transmission system. There are low voltage issues below Otter Tail’s low voltage criteria of 0.95 p.u. on the 41.6 kV transmission system around Hoot Lake for certain contingencies during the winter season. More specifically, low voltages can develop along the existing 41.6 kV system between Pelican Rapids and Silver Lake (i.e., Battle Lake) depending on the resulting system configuration following a contingency of either the Pelican Rapids 115 kV source, the Elbow Lake 115 kV source, or the Silver Lake 230 kV source. Additionally, the existing transformer is nearing its thermal capacity for certain contingencies as well. An outage of the adjacent sources mentioned above

requires serving additional load from the Hoot Lake 115/41.6 kV transformer. Study results have shown that outage of the Silver Lake 230 kV source will result in the existing Hoot Lake 115/41.6 kV transformer loading up to 97 percent of its 29.9 MVA rating.

To address these numerous concerns, Otter Tail has evaluated four alternatives from both a cost and performance perspective. The results of this evaluation are included in Table 2 below.

Table 2

Alternative	Description	Est. Cost (\$M)	Issues Mitigated		
			Age/Condition	Voltage	Loading
1	Replace existing transformer with larger transformer with an LTC	\$1.3	Yes	Yes	Yes
2	Add 2 nd Transformer with an LTC	\$2.5	No	Yes	Yes
3	Pelican Rapids 115 kV Load Conversion with 41.6 kV capacitor	\$2.6	No	Yes	Yes
4	Rothsay 115/41.6 kV Source with 41.6 kV capacitor	\$4.0	No	Yes	Yes

As shown in the table above, replacing the existing transformer with a larger transformer that has a load tap changer is the only alternative that addresses all of the various need drivers while having the least cost.

As Otter Tail evaluated the best alternative to address the various needs identified on the transmission system, Otter Tail also considered its resource planning needs. In accordance with Otter Tail’s latest integrated resource plan, the Company is planning to add 50 MW of solar at the Hoot Lake Substation³. The least cost alternative to accommodate a solar project in combination with addressing the transmission needs in the area is to add a 34.5 kV tertiary winding to the replacement transformer at Hoot Lake.

Therefore, Otter Tail is planning to replace the existing 115/41.6 kV transformer at Hoot Lake with a new 115/41.6/34.5 kV transformer. Otter Tail has coordinated this

³ See replacement interconnection request Project R1001 in MISO’s replacement interconnection queue.

transmission project with MISO through their 2020 planning cycle. MISO approved this project in Appendix A of MTEP20 as project number 19685.

Since a new 115/41.6/34.5 kV transformer at Hoot Lake will address both a transmission need and a generation need, the cost of the replacement transformer will be split accordingly. The base cost of the 115/41.6 kV transformer will be allocated to transmission while the incremental cost to add the 34.5 kV winding on the same transformer will be allocated to the generation project. The current estimate for the transmission portion of the project is \$1.3 million (OTP Total) / \$0.5 million (OTP ND) with a projected in-service date of December 2022. No costs associated with the 34.5 kV tertiary winding are included.

Transmission Line Rebuild Program and Extenda-Life Program

Otter Tail has approximately 5,800 miles of transmission lines across its service territory. Of those, approximately 3,800 miles are 41.6 kV transmission lines and are a core part of Otter Tail's delivery network to serve customers. Just over one-third of the Company's transmission poles are older than 55 years, which leaves a large portion of the poles either at or reaching the end of their useful life.

In light of this growing concern, Otter Tail has undertaken a multi-year effort called the System Infrastructure and Reliability Improvement (SIRI) Initiative. As part of this initiative, Otter Tail has put a focus on assessing overall transmission and distribution asset health conditions, which has led to the development of two new programs being put in place at Otter Tail called "Extenda-Life" and "Line Rebuild" programs.

Otter Tail's O&M and capital programs seek to extend the life of line sections to the greatest extent possible; however, once the overall condition and performance of a line reaches certain deterioration levels, it needs to be replaced. Prior to deeming a line in need of a total replacement, refurbishing the line is first considered. Refurbishing of line sections includes any combination of activities including, but not limited to, changing out rotten cross arms, replacing failed insulators, replacing poles that have failed strength tests, applying ground treatment for poles that pass strength tests, mitigating any vegetation issues, and reattaching guy wires. Otter Tail refers to these refurbishment projects internally as "Extenda-Life" projects. Factors that go into determining when a

replacement is needed include line framing style and pole height, reliability performance, hard to access areas (i.e., water), conductor condition, and overall line vintage.

Otter Tail has always had projects that involved refurbishment and replacement of existing lines,⁴ but it was not until 2019 when more targeted efforts were undertaken through the SIRI initiative. Since that time, Otter Tail has been closely monitoring the performance of both rebuild and Extenda-Life type projects and has observed a significant improvement in reliability as shown below.

Table 3
Line Breaker Operations both Pre and Post Investment

Project	2018	2019	2020	2021 ¹
Extenda-Life – Henning 625	8	5	3	0
Extenda-Life Elbow Lake 525	15	7	9	6
Rugby Extenda-Life & GFN 165	7	15	16	0
Turtle Lake Mercer Extenda-Life and Rebuild 655	17	24	11	3

- Black text represents breaker operations pre-investment
- Yellow text represents breaker operations with investments underway
- Green text represents breaker operations post investment
- ¹Through June 2021

Although the Extenda-Life and Rebuild programs are different, each improves the reliability of the Company’s transmission system. Any time that replacement of certain equipment along an existing line, or replacement of the entire line occurs, the line has inherently better performance not only because of new assets performing better but also because it allows Otter Tail to implement its updated construction and material standards that now include new framing styles. More specifically, the Company’s new standards include higher rated insulators

⁴ Examples of past rebuild and refurbishment projects in Otter Tail’s TCRR prior to the SIRI initiative have included Max – Ryder (2016), Finley – McVile (2020), Turtle Lake – Mercer (2020) and Bartlett – Doyon (2020).

(72 kV rather than 45 kV), different conductors, more spacing between energized conductors, as well as a static wire above the energized conductors. This static wire provides for shielding protection against interruptions caused by weather events; specifically, lightning. Lastly, the current standard for Otter Tail’s 41.6 kV lines is T2 (twisted pair) conductor that improves the line’s performance during icing and frost conditions over the standard single conductor utilized in older lines. The ability to employ Otter Tail’s current construction and material standards to existing lines results in improved reliability of the lower voltage (41.6 kV) transmission system.

Transmission Line Rebuild Program – Attachment 25

As described above and listed in Table 4 below, Otter Tail has identified the following transmission projects as part of the Transmission Rebuild Program within the SIRI initiative for the 2022 calendar year with a total estimated cost of \$17.6 million (OTP Total) / \$7.0 million (OTP ND).

**Table 4
Transmission Line Rebuild Program**

Line Section	Voltage	State	Length (Miles)	Total Cost (\$MM)	ND Share (\$MM)	Projected In-Service Date
Wabek – Parshall	41.6 kV	ND	9	\$1.6	\$0.63	12/2023
Pickert – McVile	41.6 kV	ND	21	\$4.0	\$1.58	12/2025
Denhoff – McClusky	41.6 kV	ND	5	\$0.9	\$0.36	12/2022
Granville – Towner	41.6 kV	ND	8	\$1.4	\$0.55	12/2023
Granville – Granville Station	41.6 kV	ND	3	\$0.3	\$0.10	12/2022
Grenville – Veblen	41.6 kV	SD	30	\$6.3	\$2.49	11/2029
Michigan – Mapes	41.6 kV	ND	6	\$1.1	\$0.42	12/2023
Summit – WAPA Summit	41.6 kV	SD	2	\$0.8	\$0.30	11/2022
Alice – Enderlin	115 kV	ND	3	\$0.8	\$0.31	12/2022
Fertile – Twin Valley	41.6 kV	MN	19	\$0.6	\$0.24	12/2023
Totals =			106	\$17.6	\$6.98	

Wabek – Parshall Rebuild:

This line section serves customers in and around the North Dakota communities of Parshall, Wabek, Plaza, Makoti, Ryder, Douglas, and Max. This line section was constructed in 1960 and runs cross country along a trail with little to no access many times of the year. This area of the system has also been prone to lightning strikes and

weather events leading to further deterioration of the line condition. The amount of lightning and weather events that this line experiences makes it a top 20 “worst performer” across the Otter Tail system.

To address access concerns and improve performance, nine miles of this 41.6 kV line will be rerouted to more accessible areas near 37th St NW between Wabek and Parshall. As noted above, the Rebuild Program includes new vertical framing of the structures along this line, which provides lightning protection for the line to provide better reliability for customers. This project will also include a new automated switch installation at Wabek, which will improve restoration times following an outage.

Pickert-McVille Rebuild:

This line section serves customers in and around the North Dakota communities of Finley, Aneta, Kloten, McVille, Tolna, Pekin, Hamar, Warwick, and St. Michael. This area of the system was in the top five worst performing areas across Otter Tail’s service territory in 2020. This line is largely constructed of 1960s vintage poles; of which nearly 75 percent of them are 40-foot and 35-foot tall with class ratings of 4, 5, or 6. This height and class is considered light duty by today’s standards and is leading to failures and clearance concerns. This rebuild project will involve new construction with poles being at least 50-foot tall with a class rating of 2 or 3. Additionally, this line has nearly 30 poles in the water that need to be addressed to improve access to the line. Due to the performance, condition, and access challenges for the lines in this area, Otter Tail will remain focused on improvements in this area over the next few years.

Work to improve the reliability performance of this area started in 2020 with the addition of a sectionalizing breaker at McVille, which reduced exposure from 100 miles down to around 50 miles for over half of the customers in this area. In addition, automated switches to increase restoration time were also added in 2020 at McVille Junction due to the remote nature of the lines in this area. Otter Tail plans to continue performing reliability improvements in this area by rebuilding 21 miles of 41.6 kV line between 2022 and 2025. As part of OTP’s Rebuild Program, this line will be rebuilt with Otter Tail’s latest framing standards which will include a shield wire for lightning protection. In addition, parts of this line will be rerouted away from the water concerns

for easier access and longevity.

Denhoff – McClusky Rebuild:

This line section serves customers in and around the North Dakota communities of Turtle Lake, Mercer, McClusky, Denhoff, Goodrich, Hurdsfield, and Chaseley. The line was constructed in the 1950's with 30-foot and 40-foot tall poles. This line section ranks in the top five on Otter Tail's list of "worst performing" lines based on the total number of breaker operations. In addition, the line section runs along a minimum maintenance road, some of which is not maintained during the winter months, making access difficult in the event of an outage that requires repair to the line.

To improve performance of this line and address the access concerns during the winter months, this 5-mile line section will be rebuilt to new vertical framing with taller poles and be rerouted along Highway 200 between Denhoff and McClusky.

Granville Station - Towner Rebuild:

These line sections serve customers in and around the North Dakota communities of Rugby, Granville, Berwick, and Towner. This line was constructed in the 1960s and is in the top 20 "worst performing" line sections for Otter Tail. This line section currently includes nine poles that are in water and numerous other poles that have been damaged due to lightning. Likewise, portions of this line also have accessibility concerns due to the line traversing through wet lowlands off regularly maintained roads.

To mitigate these accessibility concerns and improve performance of this 41.6 kV line, eight miles will be rebuilt to new Otter Tail's new vertical framing standard and located in more accessible areas along Highway 2 around Granville.

Grenville - Veblen Rebuild:

This line section serves customers throughout South Dakota in and around the communities of Summit, Lake City, Eden, Grenville, Roslyn, Pickeral Lake, Enemy Swim Lake, Ortle, and Waubay. This line section is approximately 30 miles in length and was constructed in the 1950s and 1960s. The line is constructed of light duty 35- and 40-foot tall poles which are more prone to failure during weather events. This area of the system has seen over 11 icing events over the past 15 years resulting in increased stress

on the poles, conductor, and hardware along this line section. Due to these past weather events and overall age of the line, Otter Tail has now experienced the 1/0 conductor along this line section starting to fail in recent years. Furthermore, this line also traverses through a handful of swamp areas and ponds making access for repairs and maintenance difficult.

To mitigate the performance issues, the entire 30 miles of 41.6 kV line will be rebuilt to Otter Tail's new vertical framing standard over the course of the next 5 – 8 years. The new framing will improve performance of this line due to lightning-induced events during the summer months. Furthermore, the existing 1/0 conductor will be replaced with a new conductor using a "T2" or "Twisted Pair" design that will perform much better during icing events. Lastly, the existing line will be rerouted or "long-spanned" over wet areas to ensure future repairs and maintenance can be performed safely and efficiently.

Michigan – Mapes Rebuild:

This 6.2-mile line section provides service to customers in and around the communities of Mapes, Bartlett, Doyon, and Crary in North Dakota. This line was constructed in the 1950s and 1960s and runs through several wet areas with approximately nine poles located in the water and multiple others in wet locations. In addition, this line section has experienced enough faults and service interruptions over the past couple of years that has resulted in this line being in the top 20 "worst performing" line sections within Otter Tail's service territory. Based on information gathered from protection equipment, many of the interruptions occurring in this area appear to be happening along this line section between Michigan and Mapes or along the line section between Bartlett and Doyon, which was rebuilt in 2021.

To mitigate the performance and access challenges, this line will be rebuilt under Otter Tail's Rebuild Program to have new vertical framing. As part of this rebuild project, the line will also be rerouted around water and "long-spanned" over wet areas.

Summit – WAPA Summit Tie Rebuild:

The Summit to WAPA Summit Rebuild project includes the addition of a short 2-mile 41.6 kV line, as well as a rebuild of an existing 41.6 kV line. These lines serve customers in and around the communities of Summit, Ortley, Waubay, Enemy Swim Lake, Pickeral Lake, Roslyn, and Grenville in South Dakota. This line section is also located in an area that has been very prone to icing events over the past 15 years – some of which have resulted in this particular line section falling across Interstate 29 (I-29). During the past two years alone, data gathered from protection equipment suggests that there have been up to 11 faults along this relatively short line section.

To mitigate the failing assets due to the past weather events and improve the performance of this line section, it will be rebuilt over I-29 as a single circuit line rather than the current double circuit line. As part of this project, one circuit of the double circuit line will be rebuilt as a new line on new right-of-way from WAPA’s Summit substation to just west of the community of Summit. The remaining circuit on the existing double circuit line will be rebuilt along the same right-of-way as a single-circuit line. Lastly, new automated switches will also be installed as part of this project to improve restoration times to the area in the event of an interruption. This project reduces the likelihood of interruptions stemming from old, failing assets, as well as removes one circuit from crossing the interstate with the ability to add automation with new switches.

Alice – Enderlin Rebuild:

The Alice – Enderlin 115 kV line serves customers in and around the communities of Enderlin, Alice, Lisbon, and Gwinner in North Dakota. This line was originally constructed in the 1950s and 1960s as a 41.6 kV line and was converted to 115 kV operation in the 1980s. During that conversion from 41.6 kV to 115 kV, the insulators along the line were replaced but most of the poles along this 22-mile line section were not replaced due to their condition at the time of the conversion. This voltage conversion and the resulting 115 kV operation of this line served the area well for decades, but the line is now experiencing multiple failures annually. Poor historical performance makes this line section Otter Tail’s “worst performing” 115 kV line due to the multiple number of breaker operations. Research has shown that these failures have been the result of failing

insulators and poles. Over the past 5 years, Otter Tail has rebuilt approximately half of this line with Otter Tail's new 115 kV standards, but a few miles of the old 41.6 kV framing remain along this 115 kV line. From data gathered from protection equipment, nearly all of the interruptions are occurring along the section of line that has not yet been rebuilt to 115 kV standards and

Otter Tail plans to rebuild 2 – 3 miles of 115 kV line in 2022 that has been shown to be the area where most of the failures have been recently observed. This project is a continuation of the work that was completed along this same line section in 2021 under Otter Tail's Extenda-Life Program. This project will not only rebuild the existing 115 kV line with new vertical framing but also move the line closer to Highway 38 to improve access to it in the future for maintenance activities.

Fertile – Twin Valley Rebuild:

The Fertile – Twin Valley 41.6 kV line serves customers in and around the communities of Beltrami, Fertile, Twin Valley, and Gary in Minnesota. This line is comprised of a few 1950s poles but also some 1980s poles. This line section has had poor reliability performance in the recent past that has resulted in it appearing in the top ten of the “worst performing” lines across Otter Tail's service territory. Insulator failures have been the primary cause of interruptions along this line with a few cracked and splitting poles that have been found to have failed strength tests. Based on data gathered from protection equipment, it appears most of the interruptions are stemming from faults that are located between Gary and Twin Valley. To improve performance of this line, a few miles of insulator brackets out of the Fertile substation will be “un-bonded” (i.e. ungrounded) from the pole ground, which will improve insulation capabilities along the line and result in fewer interruptions. The line section between Gary and Twin Valley will be completely re-insulated with various poles being replaced as needed. Down guys will also be insulated where necessary in order to reduce the number of interruptions that this line has historically experienced.

Transmission Extenda-Life Program – Attachment 26

As described in further detail above, Otter Tail deploys various techniques to extend the life of existing transmission lines where possible before a complete rebuild is required. This effort has been developed into a program by Otter Tail and has been coined as the “Extenda-Life” Program by Otter Tail and is a valuable cost saving measure that can be used to replace select equipment along existing lines to maintain a high level of reliability for customers. The list of 2022 projects under Otter Tail’s Extenda-Life Program are shown in Table 5 with a total estimated cost of \$3.8 million (OTP Total) / \$1.5 million (OTP ND).

**Table 5
Transmission Extenda-Life Program**

Line Section	Voltage	State	Length (Miles)	Total Cost (\$MM)	ND Share (\$MM)	Projected In-Service Date
Oslo-Gilby	41.6 kV	ND	20	\$0.9	\$0.36	12/2022
Winger-Ogema	41.6 kV	MN	13	\$0.4	\$0.16	4/2022
Gackle Eldridge Area	41.6 kV	ND	40	\$0.3	\$0.13	4/2022
Verdi-Lake Benton	41.6 kV	MN	6	\$0.2	\$0.07	4/2022
Waubay-Enemy Swim Lake	41.6 kV	SD	8	\$0.5	\$0.20	11/2022
Bottineau-Dunseith	41.6 kV	ND	17	\$0.2	\$0.07	12/2022
Plummer-Gentilly	41.6 kV	MN	12	\$0.3	\$0.13	6/2022
Ulrich-Ogema	41.6 kV	MN	17	\$0.6	\$0.22	3/2022
Bemidji-Cass Lake	69 kV	MN	22	\$0.4	\$0.16	12/2023
Total =			155	\$3.8	\$1.50	

Oslo – Gilby Extenda-Life:

This line section serves customers in and around the communities of Ardoch, Fordville, Forest River, Gilby, Orr, Minto, and Inkster in North Dakota. This line was constructed in the 1960’s and 1970’s which makes its better suited for an Extenda-life project rather than a complete rebuild since most of the poles still have strength and integrity. The historical performance of this line has not been acceptable in the past resulting in it being included on the top ten “worst performing” line sections across Otter Tail’s service territory. Recent interruptions along this line appear to be stemming from insulators breaking, leading to energized conductors coming into contact with wooden poles and cross arms and in some cases causing the poles or cross arms to start on fire. In

fact, there were five poles along this line which started on fire on October 13, 2020, due to these failing insulators.

Due to the prominent insulator failures and growing insulator concerns along this line section, this Extenda-life project will replace all of the current porcelain insulators on the 20-mile line section with new polymer insulators in conformance with Otter Tail's new construction standard. This project will also replace any poles that fail strength tests. In addition, all down guys will have additional insulation added to them to reduce the number of interruptions being experienced along this line. Lastly, this project will include the installation of new switches at Gilby for improved restoration capability following an interruption.

Winger – Ogema Extenda-Life:

The Winger – Ogema 41.6 kV line serves customers in and around the communities of Winger, Waubon, and Bejou in Minnesota. This line was constructed in the 1960s with some equipment being replaced in the 1980s. Due to the recent performance of this line section, it appears as one of the top 15 “worst performing” lines across Otter Tail's service territory. Data from protection equipment and local inspections have shown that the majority of the interruptions are due to issues south of Mahnommen, which appear to be caused by failing insulators and poles that have been damaged by lightning. Given the mixed vintage of the poles and equipment along this line, an Extenda-Life project is preferred over a complete rebuild. To improve the performance of this line, this project will focus on re-insulating approximately 13 miles of line south of Mahnommen, along with any necessary pole replacements. In addition, down guys will be insulated to lower the number of interruptions occurring along this line.

Gackle – Eldridge Extenda-Life:

The Gackle – Eldridge 41.6 kV line section is approximately 40 miles long and serves customers in and around the communities of Gackle, Streeter, Medina, Cleveland, Windsor, and Eldridge in North Dakota. This line is around 40-50 years old with insulators that are largely porcelain and showing some signs of deterioration. This line section experienced 12 operations during 2020 and already in 2021, this line has had 35 operations. The number of interruptions that this line has experienced place it in the top

five “worst performing” lines across the Otter Tail service territory. In addition to the insulator concerns, this line section also has a large number of poles located in or around water, which are only accessible during limited times of the year.

Efforts are currently underway to relocate several poles located in water near Gackle and to replace several poles in water near Streeter. In addition to addressing the insulator and water challenges along this line, this project also plans to add insulation to down guys and replace poles if they fail strength tests.

Verdi-Lake Benton Extenda-Life:

The Verdi – Lake Benton 41.6 kV line is approximately six miles long and serves customers in and around the communities of Lake Benton, Verdi, Ivanhoe, Hendricks, Elkton, and Canby within both Minnesota and South Dakota. This line section is in an area that has experienced more lightning than most areas around the Otter Tail service territory. The older framing along this line section with no shield wire has caused several poles and equipment to be damaged by lightning that has resulted in several momentary interruptions. Due to the recent performance of this line, it is a top 20 “worst performer” across Otter Tail’s service territory.

This project will replace poles and install a shield wire to conform with Otter Tail’s current construction standard. These improvements are anticipated to help protect this line from future lightning-induced interruptions thereby improving the performance of this line.

Waubay – Enemy Swim Lake Extenda-Life:

The Waubay – Enemy Swim Lake 41.6 kV line serves customers in and around the communities of Summit, Ortley, Waubay, Enemy Swim Lake, Pickeral Lake, Roslyn, and Grenville in South Dakota. This line section was constructed in the 1950s using Otter Tail’s old construction standard (delta framing), but an ice storm that occurred in 2015 resulted in Otter Tail replacing several poles between Waubay and Enemy Swim Lake with vertical framing in accordance with Otter Tail’s new construction standard. Currently, about half of the existing line is vertically framed from the 2015 restoration efforts while the other half of the line still has the vintage 1950s poles with the old

framing. The newer vertical framed poles and the older vintage poles are scattered throughout the line, making it difficult to achieve the expected performance from Otter Tail's new construction standard.

This project will involve the replacement of the remaining delta framed poles with new vertical framed poles so that Otter Tail can add a shield wire along this entire line section for lightning protection during the summer season. In replacing the older poles along this line, this project is also expected to address future pole failures further improving the performance of this existing line during weather events. This project started in 2021 and is expecting to be completed in 2022.

Bottineau – Dunseith Extenda-Life:

The Bottineau – Dunseith 41.6 kV line section is approximately 17 miles long and comprises a portion of a 41.6 kV transmission line between Bottineau and Rolette. This line provides service to customers in and around the community of Dunseith in ND. This line section appears to have been constructed over several years between 1960 and 1980. Local field inspections have shown multiple hardware issues along this line leading to an unacceptable amount of interruptions occurring along this line. The biggest concern identified during the field inspection is the deteriorating condition of the crossarms and insulators. Given that the poles and conductors along this line are in fair condition, it is a prime candidate for a new project under Otter Tail's Extenda-Life program.

The project identified to improve performance along this line section involves re-insulating a significant portion of the line with an emphasis on corner structures, angle structures, flashed over insulators, and down guys. The project will also target the replacement of rotten crossarms where necessary. Otter Tail is also planning to utilize brackets on select pole tops to deter birds and other wildlife that may also be leading to performance challenges along this existing line.

Plummer – Gentilly Extenda – Life:

The Plummer – Gentilly 41.6 kV line serves customers in and around the communities of Plummer, Red Lake Falls, and Gentilly in Minnesota. This line was built when Otter Tail was still using its old construction standards with the structures having the delta framing without a shield wire for lightning protection. This line has experienced multiple interruptions during 2020 due to numerous insulator failures. Unfortunately, many of these interruptions were extended rather than momentary.

In 2021 and 2022, Otter Tail is proceeding with this project under the Extenda-Life program, which will involve the replacement of the existing insulators along a 12-mile stretch of line between Gentilly and Red Lake Falls along with adding insulated down guys. In addition, existing poles and cross arms will be replaced as necessary and lightning arrestors will be added. These upgrades are expected to improve the historical performance of this line in the future.

Ulrich – Ogema Extenda-Life:

This 41.6 kV line between Ulrich and Ogema serves customers in and around the communities of Callaway, Ogema, and White Earth in Minnesota. Approximately half of the poles between Ogema and Callaway have surpassed their expected service life leading to performance concerns in this area. A field inspection of this line has identified that this line has Otter Tail's old delta framing with most of the poles leaning or compromised damaged hardware on Otter Tail's old delta framing.

Otter Tail has identified a project for this line that will start in 2021 and finish in 2022 that includes replacing the existing poles with new poles that will have vertical framing in accordance with Otter Tail's new construction standard. Likewise, a new shield wire will be installed to mitigate lightning induced interruptions along this line. Furthermore, insulated down guys will be added where necessary. The structures that are accessible will be completed in 2021 while those structures that are in wet areas will be replaced in the first portion of 2022 when the ground is frozen.

Bemidji – Cass Lake Extenda-Life:

This 69kV loop between Bemidji and Cass Lake serves customers in and around the Minnesota communities of Cass Lake, Mission, Frohn, Long Lake, and Guthrie. This 69 kV loop provides a vital tie between the Bemidji-Nymore substation and the Cass Lake substation. The existing line has been struggling with performance issues due to failing porcelain insulators and structures that are inaccessible much of the year.

The Bemidji – Cass Lake 69 kV line will have upgrades completed through Otter Tail’s Extenda-Life program in both 2022 and 2023 to replace insulators and relocate structures that are located in difficult to reach areas during most times of the year.

IV. ALLOCATIONS AND RATE DESIGN

The allocations and rate design for this annual update are the same as approved by the Commission in the April 25, 2012, TCRR Order. Specifically, the class allocations use the transmission demand allocation factor, D2, from Otter Tail’s most recent North Dakota general rate review (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 (cents / kWh) for all other customers. The rate design detail is included in Attachment 3.

V. RATE APPLICATION AND IMPACT

The total 2022 revenue requirement is made up of three components: the estimated revenue requirement for calendar year 2022; the true-up associated with an updated projection of the 2021 revenue requirement; and the carrying charge attributable to any projected over or under-collection.

The revenue requirement attributable to calendar year 2022, as shown on line 44 of Attachment 4, page 2 is \$6,712,343. This amount is based on actual net revenues and expenses included in the TCRR tracker through July 2021 and projections for August 2021 through December 2022.

By design and structure of the TCRR, the related carrying credit of (\$28,724), as computed on Attachment 4, page 2, line 49, will be credited to customers as a reduction in the

2022 revenue requirements. The 2021 true-up portion of the revenue requirement calculation, as reflected on Attachment 2, line 35 and as computed in Attachment 4, page 1, line 50, reflects an estimated over-collection amount of (\$604,302) during the 2021 collection period. The over-collection is due to delayed in-service and reduced spend on projects of approximately \$175,000 as well as a reduction to the MISO Schedule 26 and 26A Expense and decrease to Schedule 26 and 9 Revenue in 2021, netting approximately a \$458,000 reduction to the Net Revenue Requirement for 2021. The net revenue requirement for 2022, upon which rates are developed, is \$6,079,317, as shown on line 36 of Attachment 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 Transmission Rider line on customers’ bills. The proposed rates, as calculated in Attachment 3 are provided in Table 6 with a comparison to previously approved rates:

Table 6

A		B	C
Line No.	Class	January 1, 2021- December 31, 2021 Approved Rates (PU-20-383) ¢ / kWh	January 1, 2022- December 31, 2022 Proposed Rates ¢ / kWh
1	Large General Service	\$1.290 /kW	\$1.568 /kW
2	Controlled Service	0.059¢	0.067¢
3	Lighting	0.330¢	0.303¢
4	All Other	0.421¢	0.462¢

The proposed rates are based on an effective date of January 1, 2022, through December 31, 2022. These rates represent a change to the rates currently in effect. The estimated increase for a residential customer using 1,000 kWh is \$0.41 per month.

VI. TRANSMISSION COST RECOVERY RIDER RATE SCHEDULE

Otter Tail's redline and clean update to the Transmission Cost Recovery Rider (Section 13.05) is Attachment 37 to this Application.

In addition to changes to the rates, Otter Tail has included, for administrative purposes, Rate Schedules 10.06 Super Large General Service and 14.13 Economic Development Rate Rider to the Large General Service category within the Transmission Cost Recovery rate box.

VII. 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.

VIII. 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 September 15, 2021, we filed a request with the North Dakota Public Service Commission to update our Transmission Cost Recovery Rider, which is part of the Transmission Rider line on your bill. The proposed change is for bill usage on and after January 1, 2022. 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: \$118.22 (from \$1.290 to \$1.568 per kW)*
- *Controlled Service: \$0.10 (from 0.059 cents to 0.067 cents per kWh)*
- *Lighting: (\$0.02) (from 0.330 cents to 0.303 cents per kWh)*
- *Residential and all other service: \$0.41/ \$0.55 (from 0.421 cents to 0.462 cents per kWh)*

For more information contact Customer Service at 800-257-4044 or visit otpc.com.

Attachment 38 is a draft of the proposed notice to customers upon implementation of the updated rates.

IX. REQUEST FOR CHANGE OF ANNUAL FILING DATE

Otter Tail respectfully requests a change to the filing date for the ND TCRR Annual update as per Ordering Paragraph 6 of the Commission's April 5, 2012, Order in Case Nos. PU-11-153 and PU-11-682 (the TCRR Order). Otter Tail requests a revised filing date of September 15 from September 1 for future filings in order to incorporate the most recent MISO Attachment O, GG, and MM information, which are filed with MISO by September 1 of each year. Adjusting the annual filing date to September 15 will allow Otter Tail time to incorporate the most up to date information in the annual update.

X. CONCLUSION

For all of the foregoing reasons, Otter Tail Power Company respectfully requests approval to implement this update to its Transmission Cost Recovery Rider, Section 13.05, effective as of January 1, 2022.

Date: September 15, 2021

Respectfully submitted:

OTTER TAIL POWER COMPANY

/s/ Lynn A. Wolters

Lynn A. Wolters

Rates Analyst

Regulatory Administration

215 South Cascade Street

P.O. Box 496

Fergus Falls, MN 56538-0496

Phone (218) 739-8577

Attachments

Attachment 1	Revenue
Attachment 2	Revenue Requirements Summary
Attachment 3	Rate Design
Attachment 4	Tracker Account 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 Facility Purchase Revenue Requirements
Attachment 16	Erie 230/115kV Substation Revenue Requirements
Attachment 17	Grant County-Norcross 115kV Line and Norcross 115/41.6kV substation Revenue Requirements
Attachment 18	Winger 230/115kV Transformer Revenue Requirements
Attachment 19	Jamestown 41.6 kV Source Revenue Requirements
Attachment 20	Hoot Lake Capacitor Revenue Requirements
Attachment 21	Finley/McVille 41.6 kV Rebuild Revenue Requirements
Attachment 22	Turtle Lake/Mercer 41.6 kV Rebuild Revenue Requirements
Attachment 23	Doyon/Bartlett 41.6 kV Rebuild Revenue Requirements
Attachment 24	Hoot Lake 115/43/13.8 kV Transformer Revenue Requirements
Attachment 25	Transmission Line Rebuild Program Revenue Requirements
Attachment 26	Transmission Extenda-Life Program Revenue Requirements
Attachment 27	Attachment O Revenue Credit for Non-MISO Projects

Attachment 28	MISO Schedule 26 and 26A Expense
Attachment 29	SPP Expenses
Attachment 30	MISO Schedule 9 Revenue
Attachment 31	MISO Schedule 26 Revenue
Attachment 32	MISO Schedule 26A Revenue
Attachment 33	MISO Multi-Value Project Auction Revenue Rights Credit
Attachment 34	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 35	ADIT Pro-Rate Projection
Attachment 36	ADIT Pro-Rate Preservation
Attachment 37	Electric Rate Schedule Section 13.05 Redline and Clean
Attachment 38	Proposed Customer Notice

Projected Revenue for 2022

Line No.	Class	Units	Rate per Unit	Amount
1	Large General Service	(a) 1,076,530 kW	\$1.568	\$1,687,983
2				
3	Controlled Service	(b) 251,236,334 kWh	0.067¢	\$168,463
4				
5	Lighting	(c) 19,267,421 kWh	0.303¢	\$58,372
6				
7	All other service	902,015,258 kWh	0.462¢	\$4,164,500
8				
9	Total revenue			<u>\$6,079,317</u>

- (a) Rate Schedules 10.04 Large General Service and 10.05 Large General Service - Time of Day, 10.06 Super Large General Service, 14.02 Real Time Pricing Rider, 14.03 Large General Service Rider, and 14.13 Economic Development 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), 11.04 Outdoor Lighting, and 11.07 LED Street and Area Lighting

Summary of Revenue Requirements

Line No.	Revenue Requirements	2022
1	MVP - Ellendale to Big Stone South	\$90,912
2	Max - Ryder 41.6 kV Line Upgrades	\$82,767
3	Bagley 115kV Switch Station	\$105,290
4	Lake Norden Area Transmission	\$1,099,309
5	Donaldson 115 kV Cap Bank	\$25,668
6	Blair 230 kV Substation	\$38,280
7	Veblen 41.6 kV Cap Bank	\$38,946
8	Northwest MN UVLS	\$28,734
9	Jamestown Substation (NERC)	\$44,452
10	New Effington 230/41.6 kV Line	\$189,151
11	CPEC Purchase	\$72,395
12	Erie 230/115kV Substation	\$15,327
13	Norcross 115kV Line-115/41.6kV substation	\$149,286
14	Winger 230/115kV Transformer	\$6,472
15	Jamestown 115 kV Source	\$66,514
16	Hoot Lake Capacitor	\$44,561
17	Finley/McVille 41.6 kV Rebuild	\$41,820
18	Turtle Lake/Mercer 41.6 kV Rebuild	\$46,581
19	Doyon/Barlett 41.6 kV Rebuild	\$37,833
20	Transmission Line Rebuild Program	\$37,690
21	Transmission Extenda-Life Program	\$82,179
22	Hoot Lake 115/43/13.8 kV Transformer	\$17,846
23	Total Revenue Requirement	\$2,362,012
24	MISO Schedule 26 Expense	4,805,955
25	MISO Schedule 26A Expense	3,227,418
26	SPP Schedule 9 Expense	915,722
27	SPP Schedule 11 Expense	125,146
28	MISO Schedule 9 Revenue	(354,722)
29	MISO Schedule 26 Revenue	(3,807,918)
30	MISO Schedule 37 Revenue	(0)
31	MISO Schedule 38 Revenue	(0)
32	MISO Schedule 26A Revenue	(548,914)
33	MISO MVP ARR Revenue	(12,355)
34	Carrying Cost	(28,724)
35	True-Up	(604,302)
36	Net Revenue Requirement	\$6,079,317

Class Allocation and Rate Design

Line No.	2022		
1	North Dakota Revenue Requirements		\$6,079,317 *
2	Large General Service Class	27.77%	\$1,687,983
3	Controlled Service	2.77%	168,463
4	Lighting	0.96%	58,372
5	All Other Service	68.50%	4,164,500
6	Total		\$6,079,317
7	Large General Service Class	kW	1,076,530
8	Controlled Service	kWh	251,236,334
9	Lighting	kWh	19,267,421
10	All Other Service	kWh	902,015,258
11	Large General Service Class	\$ / kW	1.568
12	Controlled Service	cents / kWh	0.067
13	Lighting	cents / kWh	0.303
14	All Other Service	cents / kWh	0.462

* 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:	2021												YE Projected			
		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Projected	September Projected	October Projected	November Projected	December Projected				
1	Revenue Requirements	7,635	7,635	7,635	7,635	7,635	7,635	7,635	7,635	7,635	7,635	7,635	7,635	7,635	7,635	8,268	92,249
2	MVP: Ellendale to Big Stone South	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	7,083	84,994
3	Max: Ryder 41.6 kV Line Upgrades	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	108,004
4	Bagley 115kV Switch Station	78,905	78,955	78,955	78,955	78,955	79,802	79,802	79,802	79,802	87,773	87,871	87,871	87,871	87,871	87,871	986,365
5	Lake Norden Area Transmission Improvement	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	26,359
6	Donaldson 115 kV Cap Bank	3,309	3,309	3,309	3,309	3,309	3,309	3,309	3,309	3,309	3,309	3,309	3,309	3,309	3,309	3,309	39,712
7	Blair 230 kV Substation	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	40,068
8	Veblen 41.6 kV Cap Bank	1,781	1,781	1,781	2,083	2,084	2,084	2,084	2,084	2,084	2,084	2,090	2,090	2,090	2,090	2,090	24,125
9	Northwest MN UVLS	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	45,776
10	Jamestown Substation	12,587	12,587	12,587	12,587	12,587	12,587	12,587	12,587	12,587	12,587	14,798	14,798	14,798	14,798	14,798	159,891
11	New Ellington 230/41.6 kV Line	6,211	6,211	6,211	6,211	6,211	6,211	6,211	6,211	6,211	6,211	6,211	6,211	6,211	6,211	6,211	74,531
12	CPEC Purchase	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	1,661
13	Erie 230/115kV Substation	9,880	9,880	9,880	9,880	9,880	9,880	9,880	9,880	9,880	9,880	9,880	9,880	9,880	9,880	9,880	118,566
14	Norcross 115kV Line-115/41.6kV substation	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	143
15	Winger 230/115kV Transformer	443	443	443	443	443	443	443	443	443	443	443	443	443	443	443	5,320
16	Jamestown 41.6 kV Source	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	22,456
17	Hoot Lake Capacitor	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	16,504
18	Finley/McVillie 41.6 kV Rebuild	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	38,748
19	Turtle Lake/Mercer 41.6 kV Rebuild	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	17,715
20	Dowon/Bartlett 41.6 kV Rebuild																
21	Hoot Lake 115/43/13.8 kV Transformer																
22	Transmission Line Rebuild Program																
23	Transmission Extenda-Life Program																
24	Total Revenue Requirements	154,025	154,075	154,075	154,377	155,225	155,225	155,225	155,225	155,225	165,413	165,511	166,845	167,965	167,965	167,965	1,903,187
25	ADIT Preservation of Proration	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	747
26	MISO & SPP Expenses																
27	MISO Schedule 26 Expense	379,156	371,060	367,106	298,076	214,321	309,345	327,755	406,556	350,655	356,797	366,961	448,803	419,592	448,803	4,196,592	
28	MISO Schedule 26A Expense	309,565	303,469	273,042	227,012	195,892	229,415	263,701	243,223	230,250	249,405	285,536	323,444	313,954	323,444	3,133,954	
29	SPP Schedule 9 Expense	72,016	73,248	71,640	73,958	73,789	74,077	74,083	73,788	73,788	73,788	73,788	73,788	73,788	73,788	73,788	881,753
30	SPP Schedule 11 Expense	8,145	9,758	9,728	9,793	9,806	9,810	9,822	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	117,307
31	Total MISO & SPP Expenses	768,882	757,534	721,517	608,840	493,808	622,647	675,361	733,657	664,782	690,079	736,374	856,124	832,906	856,124	8,329,606	
32	MISO Revenues																
33	MISO Schedule 9 Revenue	(62,181)	(60,180)	(52,790)	(32,129)	2,374	(15,082)	(21,329)	(9,183)	(8,211)	(32,102)	(36,666)	(43,286)	(370,764)	(43,286)	(370,764)	
34	MISO Schedule 26 Revenue	(263,083)	(261,885)	(252,555)	(245,248)	(222,784)	(343,784)	(362,715)	(329,233)	(321,745)	(265,580)	(254,347)	(258,091)	(3,381,050)	(258,091)	(3,381,050)	
35	MISO Schedule 37 Revenue	(3,091)	(3,136)	(3,136)	(3,031)	(3,103)	(3,136)	(3,136)	(3,136)	(0)	(0)	(0)	(0)	(21,710)	(0)	(21,710)	
36	MISO Schedule 38 Revenue	(3,865)	(3,936)	(3,936)	(3,815)	(3,886)	(3,938)	(3,938)	(3,938)	(0)	(0)	(0)	(0)	(27,314)	(0)	(27,314)	
37	MISO Schedule 26A Revenue	(41,510)	(40,260)	(38,794)	(33,346)	(30,475)	(42,571)	(49,576)	(49,486)	(43,453)	(40,437)	(40,940)	(42,951)	(493,798)	(40,940)	(493,798)	
38	MISO MVP ARR Revenue	(1,790)	(1,769)	(1,865)	(1,364)	(1,310)	(1,130)	(299)	(1,030)	(1,030)	(1,030)	(1,030)	(1,030)	(14,675)	(1,030)	(14,675)	
39	Total MISO Revenues	(375,520)	(371,166)	(353,076)	(318,932)	(259,183)	(409,641)	(440,993)	(388,931)	(374,438)	(339,149)	(332,982)	(345,358)	(4,309,370)	(345,358)	(4,309,370)	
40	Net Revenue Requirement	547,449	540,506	522,579	444,346	389,913	368,294	389,655	500,013	455,819	516,503	570,300	678,794	5,924,170	678,794	5,924,170	
41	Billed (forecast kWh x adj factor)	544,059	512,424	515,338	434,881	374,465	380,209	410,871	403,823	386,380	425,853	501,351	588,843	5,478,496	588,843	5,478,496	
42	Difference	3,390	28,081	7,241	9,466	15,448	(11,916)	(21,215)	96,189	69,439	90,650	68,949	89,951	445,674	68,949	445,674	
43	Carrying Charge	(6,243)	(6,261)	(6,122)	(6,115)	(6,094)	(6,034)	(6,149)	(6,323)	(5,751)	(5,345)	(4,802)	(4,393)	(69,633)	(4,802)	(69,633)	
44	Cumulative Difference	(983,197)	(961,377)	(960,258)	(956,908)	(947,554)	(965,504)	(992,868)	(903,001)	(839,313)	(754,007)	(689,860)	(604,302)	(604,302)	(689,860)	(604,302)	
45	Carrying Charge Calculation	(6,261)	(6,122)	(6,115)	(6,094)	(6,034)	(6,149)	(6,323)	(5,751)	(5,345)	(4,802)	(4,393)	(3,848)		(4,393)	(3,848)	
46	Cumulative Carrying Charge	(199,373)	(205,495)	(211,611)	(217,705)	(223,739)	(229,887)	(236,210)	(241,961)	(247,306)	(252,108)	(256,501)	(260,349)		(260,349)	(260,349)	
47	Carrying cost	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%		7.64%	7.64%	
48	Forecasted Sales (MWh)	192,043	173,325	163,234	136,718	120,705	113,928	125,292	126,092	120,645	132,971	156,544	183,863	1,745,361	183,863	1,745,361	

Approved November 18, 2020 (PU-20-383);
Rate Effective January 1, 2021

SUMMARY	Jan 2021 - Dec 2021
Revenue requirements	\$6,556,831
Carrying Charge	(51,277)
2020 True-Up	(935,424)
Total requirements	\$5,570,130
Jan 2021-Dec 2021 projected sales in MWh	1,739,247
Average Rate	\$0.00320

Line No.	TRACKER SUMMARY Requirements Computed to Billed:	2022												YE Projected	
		January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected		
1	Revenue Requirements														
1	MVP: Ellendale to Big Stone South	7,523	7,523	7,523	7,523	7,523	7,523	7,523	7,523	7,523	7,523	7,523	7,523	7,523	8,162
2	Max- Ryder 41.6 kV Line Upgrades	6,897	6,897	6,897	6,897	6,897	6,897	6,897	6,897	6,897	6,897	6,897	6,897	6,897	82,767
3	Bagley 115kV Switch Station	8,774	8,774	8,774	8,774	8,774	8,774	8,774	8,774	8,774	8,774	8,774	8,774	8,774	105,290
4	Lake Norden Area Transmission Improvement	91,609	91,609	91,609	91,609	91,609	91,609	91,609	91,609	91,609	91,609	91,609	91,609	91,609	1,099,309
5	Donaldson 115 kV Cap Bank	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	25,668
6	Blair 230 kV Substation	3,190	3,190	3,190	3,190	3,190	3,190	3,190	3,190	3,190	3,190	3,190	3,190	3,190	38,280
7	Veblen 41.6 kV Cap Bank	3,246	3,246	3,246	3,246	3,246	3,246	3,246	3,246	3,246	3,246	3,246	3,246	3,246	38,946
8	Northwest MN UVLS	2,394	2,394	2,394	2,394	2,394	2,394	2,394	2,394	2,394	2,394	2,394	2,394	2,394	28,734
9	Jamestown Substation	3,704	3,704	3,704	3,704	3,704	3,704	3,704	3,704	3,704	3,704	3,704	3,704	3,704	44,452
10	New Ellington 230/41.6 kV Line	15,763	15,763	15,763	15,763	15,763	15,763	15,763	15,763	15,763	15,763	15,763	15,763	15,763	189,151
11	CPEC Purchase	6,033	6,033	6,033	6,033	6,033	6,033	6,033	6,033	6,033	6,033	6,033	6,033	6,033	72,395
12	Erie 230/115kV Substation	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	15,327
13	Norcross 115kV Line-115/41.6kV substation	10,871	10,871	12,754	12,754	12,754	12,754	12,754	12,754	12,754	12,754	12,754	12,754	12,754	149,286
14	Winger 230/115kV Transformer	539	539	539	539	539	539	539	539	539	539	539	539	539	6,472
15	Jamestown 41.6 kV Source	4,927	4,927	4,927	4,927	4,927	4,927	5,571	5,889	6,164	6,375	6,460	6,492	6,514	66,514
16	Hoot Lake Capacitor	3,713	3,713	3,713	3,713	3,713	3,713	3,713	3,713	3,713	3,713	3,713	3,713	3,713	44,561
17	Finley/McVillie 41.6 kV Rebuild	3,485	3,485	3,485	3,485	3,485	3,485	3,485	3,485	3,485	3,485	3,485	3,485	3,485	41,820
18	Turtle Lake/Mercer 41.6 kV Rebuild	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882	3,882	46,581
19	Down/Bartlett 41.6 kV Rebuild	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	37,833
20	Hoot Lake 115/43/13.8 kV Transformer	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	17,846
21	Transmission Line Rebuild Program	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,112	37,690
22	Transmission Extenda-Life Program	6,346	6,346	6,346	6,610	6,934	6,934	7,076	7,076	7,076	7,076	7,076	7,076	7,283	82,179
23															
24	Total Revenue Requirements	194,065	194,065	195,948	196,213	196,537	196,537	197,322	197,640	197,915	198,127	198,211	199,432		2,362,012
25															
26	ADIT Preservation of Proration														
27															
28	MISO & SPP Expenses														
29	MISO Schedule 26 Expense	478,681	464,320	426,026	359,011	315,929	378,158	387,731	387,731	335,077	397,305	397,305	478,681		4,805,955
30	MISO Schedule 26A Expense	332,134	305,543	293,754	258,834	238,690	231,910	244,720	243,112	230,372	244,874	283,833	319,642		3,227,418
31	SPP Schedule 9 Expense	74,844	74,617	74,617	76,852	76,854	76,848	76,848	76,848	76,848	76,848	76,848	76,848		915,722
32	SPP Schedule 11 Expense	10,228	10,228	10,228	10,496	10,496	10,496	10,496	10,496	10,496	10,496	10,496	10,496		125,146
33	Total MISO & SPP Expenses	895,887	854,709	804,626	705,193	641,969	697,412	719,795	718,187	652,792	729,522	768,482	885,666		9,074,241
34															
35	MISO Revenues														
36	MISO Schedule 9 Revenue	(58,926)	(54,425)	(50,552)	(32,550)	(4,977)	(10,946)	(13,801)	(8,533)	(8,328)	(32,201)	(36,758)	(42,726)		(354,722)
37	MISO Schedule 26 Revenue	(317,326)	(317,326)	(317,326)	(317,326)	(317,326)	(317,326)	(317,326)	(317,326)	(317,326)	(317,326)	(317,326)	(317,326)		(3,807,918)
38	MISO Schedule 37 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)		(0)
39	MISO Schedule 38 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)		(0)
40	MISO Schedule 26A Revenue	(48,715)	(44,216)	(42,606)	(36,879)	(36,678)	(46,755)	(54,448)	(54,348)	(47,723)	(44,411)	(44,963)	(47,171)		(548,914)
41	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)
42	Total MISO Revenues	(425,997)	(416,997)	(411,514)	(387,785)	(360,011)	(376,057)	(386,605)	(381,237)	(374,408)	(394,968)	(400,077)	(408,253)		(4,723,909)
43															
44	Net Revenue Requirement	663,954	631,777	589,060	513,620	478,495	517,892	530,513	534,590	476,300	532,681	566,617	676,845		6,712,343
45															
46	Billed (forecast kWh x adj factor)	670,950	611,821	567,219	476,900	419,817	396,512	435,136	437,614	418,627	461,656	543,834	639,231		6,079,317
47															
48	Difference	(6,996)	19,956	21,842	36,719	58,678	121,380	95,377	96,976	57,673	71,025	22,783	37,614		633,026
49	Carrying Charge	(3,848)	(3,917)	(3,815)	(3,701)	(3,490)	(3,139)	(2,386)	(1,794)	(1,187)	(828)	(381)	(238)		(28,724)
50	Cumulative Difference	(615,147)	(599,109)	(581,082)	(548,064)	(492,875)	(374,634)	(281,643)	(186,461)	(129,975)	(59,778)	(37,376)	0		0
51															
52	Carrying Charge Calculation	(3,917)	(3,815)	(3,701)	(3,490)	(3,139)	(2,386)	(1,794)	(1,187)	(828)	(381)	(238)	0		
53	Cumulative Carrying Charge	(264,267)	(268,082)	(271,783)	(275,273)	(278,412)	(280,798)	(282,591)	(283,779)	(284,606)	(284,987)	(285,225)	(285,225)		
54	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%		
55															
56															
57	Forecasted Sales (MWh)	191,350	174,486	161,766	136,008	119,728	113,082	124,097	124,804	119,389	131,661	155,097	182,304		1,733,771
58															

SUMMARY		Jan 2022 - Dec 2022
Revenue requirements		\$6,712,343
Carrying Charge		(28,724)
2021 True-Up		(604,302)
Total requirements		\$6,079,317
Jan 2022-Dec 2022 projected sales in MW		1,733,771
Average Rate		\$0.00351

Line No.	Year>>	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021
		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 Total
RATE BASE														
1	Plant Balance	0	0	710,115	713,123	713,123	713,123	713,123	727,836	727,836	727,836	727,836	727,836	727,836
2	Accumulated Depreciation	(0)	(0)	(0)	(945)	(1,894)	(2,844)	(3,793)	(4,742)	(5,711)	(6,680)	(7,649)	(8,617)	(8,617)
3	Net Plant in Service	0	0	710,115	712,178	711,229	710,279	709,330	723,093	722,125	721,156	720,187	719,218	719,218
4	CWIP (Projects 106642 135672)	723,470	724,827	14,712	14,712	14,712	14,712	14,712	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	(0)	(0)	(888)	(1,546)	(2,202)	(2,859)	(3,515)	(4,172)	(4,823)	(5,475)	(6,127)	(6,778)	(6,778)
7	Ending rate base	723,470	724,827	723,939	725,345	723,739	722,133	720,528	718,922	717,301	715,681	714,060	712,440	712,440
9	Average rate base	60,032	60,032	60,032	60,032	60,032	60,032	60,032	60,032	60,032	60,032	60,032	60,032	720,386
11	Return on Rate Base	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	55,052
13	Available for return (equity portion of rate base)	3,079	3,079	3,079	3,079	3,079	3,079	3,079	3,079	3,079	3,079	3,079	3,079	36,950
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Book Depreciation	0	0	0	945	949	949	949	949	969	969	969	969	8,617
20	Total O&M and Depreciation Expense	0	0	0	945	949	949	949	949	969	969	969	969	8,617
22	Income before Taxes													
23	Available for return (from above)	3,079	3,079	3,079	3,079	3,079	3,079	3,079	3,079	3,079	3,079	3,079	3,079	36,950
24	Taxable Income (grossed up)	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	4,073	48,879
26	Income Taxes													
27	Current and Def Income Taxes	994	994	994	994	994	994	994	994	994	994	994	994	11,929
28	Total Income Tax Expense	994	994	994	994	994	994	994	994	994	994	994	994	11,929
REVENUE REQUIRMENTS														
32	Expenses	994	994	994	1,939	1,943	1,943	1,943	1,943	1,963	1,963	1,963	1,963	20,546
33	Return on rate base	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	55,052
34	Subtotal revenue requirements	5,582	5,582	5,582	6,527	6,531	6,531	6,531	6,531	6,551	6,551	6,551	6,551	75,598
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(1,083)	(1,083)	(1,083)	(1,267)	(1,268)	(1,268)	(1,268)	(1,268)	(1,272)	(1,272)	(1,272)	(1,272)	(14,674)
37	Total revenue requirements	4,498	4,498	4,498	5,260	5,263	5,263	5,263	5,263	5,279	5,279	5,279	5,279	60,924
39	North Dakota share - D2 factor	1,781	1,781	1,781	2,083	2,084	2,084	2,084	2,084	2,090	2,090	2,090	2,090	24,125

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%										2021 composite rate
4	Preferred equity	0.00%	0.00%	0.00%										1.85%
5	Common equity	52.50%	9.77%	5.13%										
6	Total	100.00%		7.64%	Overall Return									
7		Book	Tax											
8	Project life (years)	50	15-year MACRS											
9		Fed Portion	State Portion											
10	Effective Tax Rate	24.40%	20.09%	4.31%										
11	Tax conversion factor	1.32284												
12	Wholesale Revenue Credit	19.41%												
13	ND share - D2 factor	39.5989%												
18	Deferred Tax													
19	Book depreciation	0	0	945	949	949	949	949	969	969	969	969	969	8,617
20	Tax depreciation-Federal	0	0	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	36,392
21	Tax depreciation-ND	0	0	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	36,392
22	Federal deferred income taxes	(0)	(0)	(731)	(541)	(541)	(541)	(541)	(541)	(537)	(537)	(537)	(537)	(5,581)
23	State deferred income taxes	(0)	(0)	(157)	(116)	(116)	(116)	(116)	(116)	(115)	(115)	(115)	(115)	(1,197)

Line No.	Year>>	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	5,203,893	5,203,893	5,203,893	5,203,893	5,203,893	5,203,893	5,203,893
2	Accumulated Depreciation	0	0	0	0	0	0	0	(6,927)	(13,854)	(20,780)	(27,707)	(27,707)	(27,707)
3	Net Plant in Service	0	0	0	0	0	0	5,203,893	5,196,966	5,190,039	5,183,112	5,176,185	5,176,185	
CWIP Calculation:														
	Beginning Balance	3,813,422	4,008,096	4,134,871	4,361,498	4,778,657	4,820,110	5,015,464	5,097,403	0	0	0	0	0
	Additional CWIP	194,674	126,775	226,627	417,160	41,452	195,354	81,939	106,490	0	0	0	0	1,390,470
	Closings from CWIP													
	AFDUC								(5,203,893)	0	0	0	0	0
4	CWIP (Project #T02031.049)	4,008,096	4,134,871	4,361,498	4,778,657	4,820,110	5,015,464	5,097,403	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	0	0	0	0	0	0	0	(12,700)	(23,710)	(34,719)	(45,729)	(56,738)	(56,738)
7	Ending rate base	4,008,096	4,134,871	4,361,498	4,778,657	4,820,110	5,015,464	5,097,403	5,191,193	5,173,256	5,155,320	5,137,383	5,119,447	5,119,447
8														
9	Average rate base	396,193	396,193	396,193	396,193	396,193	396,193	396,193	396,193	396,193	396,193	396,193	396,193	4,754,317
10														
11	Return on Rate Base	30,277	30,277	30,277	30,277	30,277	30,277	30,277	30,277	30,277	30,277	30,277	30,277	363,325
12														
13	Available for return (equity portion of rate base)	20,322	20,322	20,322	20,322	20,322	20,322	20,322	20,322	20,322	20,322	20,322	20,322	243,861
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	2,606	2,606	2,606	2,606	2,606	2,606	2,606	2,606	2,606	2,606	2,606	2,606	31,270
19	Book Depreciation	0	0	0	0	0	0	0	0	6,927	6,927	6,927	6,927	27,707
20	Total O&M and Depreciation Expense	2,606	2,606	2,606	2,606	2,606	2,606	2,606	2,606	9,533	9,533	9,533	9,533	58,977
21														
22	Income before Taxes													
23	Available for return (from above)	20,322	20,322	20,322	20,322	20,322	20,322	20,322	20,322	20,322	20,322	20,322	20,322	243,861
24	Taxable Income (grossed up)	26,882	26,882	26,882	26,882	26,882	26,882	26,882	26,882	26,882	26,882	26,882	26,882	322,588
25														
26	Income Taxes													
27	Current and Def Income Taxes	6,561	6,561	6,561	6,561	6,561	6,561	6,561	6,561	6,561	6,561	6,561	6,561	78,727
28	Total Income Tax Expense	6,561	6,561	6,561	6,561	6,561	6,561	6,561	6,561	6,561	6,561	6,561	6,561	78,727
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	9,166	9,166	9,166	9,166	9,166	9,166	9,166	9,166	16,093	16,093	16,093	16,093	137,705
33	Return on rate base	30,277	30,277	30,277	30,277	30,277	30,277	30,277	30,277	30,277	30,277	30,277	30,277	363,325
34	Subtotal revenue requirements	39,444	39,444	39,444	39,444	39,444	39,444	39,444	39,444	46,370	46,370	46,370	46,370	501,030
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(7,656)	(7,656)	(7,656)	(7,656)	(7,656)	(7,656)	(7,656)	(7,656)	(9,001)	(9,001)	(9,001)	(9,001)	(97,254)
37	Total revenue requirements	31,787	31,787	31,787	31,787	31,787	31,787	31,787	31,787	37,369	37,369	37,369	37,369	403,775
38														
39	North Dakota share - D2 factor	12,587	12,587	12,587	12,587	12,587	12,587	12,587	12,587	14,798	14,798	14,798	14,798	159,891

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3		Ratio	Cost	WA Cost									Property tax	
4	Debt	47.50%	5.29%	2.51%									2021 composite rate	0.82%
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														
15														
16														
17														
18	Deferred Tax													
19	Book depreciation	0	0	0	0	0	0	0	0	6,927	6,927	6,927	6,927	27,707
20	Tax depreciation-Federal	0	0	0	0	0	0	0	52,039	52,039	52,039	52,039	52,039	260,195
21	Tax depreciation-ND	0	0	0	0	0	0	0	52,039	52,039	52,039	52,039	52,039	260,195
22	Federal deferred income taxes	0	0	0	0	0	0	0	(10,457)	(9,065)	(9,065)	(9,065)	(9,065)	(46,718)
23	State deferred income taxes	0	0	0	0	0	0	0	(2,243)	(1,944)	(1,944)	(1,944)	(1,944)	(10,020)

Line No.	Year>>	2022 Projected Jan	2022 Projected Feb	2022 Projected Mar	2022 Projected Apr	2022 Projected May	2022 Projected Jun	2022 Projected Jul	2022 Projected Aug	2022 Projected Sep	2022 Projected Oct	2022 Projected Nov	2022 Projected Dec	2022 Projected Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	0
CWIP Calculation:														
	Beginning Balance	25,000	25,000	25,000	25,000	25,000	25,000	25,000	125,000	225,000	325,000	465,000	665,000	840,000
	Additional CWIP	0	0	0	0	0	0	100,000	100,000	100,000	140,000	200,000	200,000	
	Closings from CWIP AFDUC													
4	CWIP (Project #6625) 6625	25,000	25,000	25,000	25,000	25,000	25,000	125,000	225,000	325,000	465,000	665,000	865,000	865,000
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	
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Ending rate base	25,000	25,000	25,000	25,000	25,000	25,000	125,000	225,000	325,000	465,000	665,000	865,000	865,000
8	Average rate base	18,237	18,237	18,237	18,237	18,237	18,237	18,237	18,237	18,237	18,237	18,237	18,237	218,846
11	Return on Rate Base	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	16,724
13	Available for return (equity portion of rate base)	935	935	935	935	935	935	935	935	935	935	935	935	11,225
EXPENSES														
<i>O&M and Depreciation</i>														
16	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Income before Taxes													
23	Available for return (from above)	935	935	935	935	935	935	935	935	935	935	935	935	11,225
24	Taxable Income (grossed up)	1,237	1,237	1,237	1,237	1,237	1,237	1,237	1,237	1,237	1,237	1,237	1,237	14,849
26	Income Taxes													
27	Current and Def Income Taxes	302	302	302	302	302	302	302	302	302	302	302	302	3,624
28	Total Income Tax Expense	302	302	302	302	302	302	302	302	302	302	302	302	3,624
REVENUE REQUIREMENTS														
32	Expenses	302	302	302	302	302	302	302	302	302	302	302	302	3,624
33	Return on rate base	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	16,724
34	Subtotal revenue requirements	1,696	1,696	1,696	1,696	1,696	1,696	1,696	1,696	1,696	1,696	1,696	1,696	20,348
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(4,005)
37	Total revenue requirements	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	16,343
38														
39	North Dakota share - D2 factor	539	539	539	539	539	539	539	539	539	539	539	539	6,472

Line No.	SUPPORTING INFORMATION / DATA
1	ND Cap Structure with allowed ROE per order.
2	Capital Structure
3	Ratio Cost WA Cost
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	Fed Portion State Portion
14	Effective Tax Rate 24.40% 20.09% 4.31%
15	Tax conversion factor 1.32284
16	Wholesale Revenue Credit 19.68%
17	ND share - D2 factor 39.5989%
18	Deferred Tax
19	Book depreciation 0 0 0 0 0 0 0 0 0 0 0 0 0 0
20	Tax depreciation-Federal 0 0 0 0 0 0 0 0 0 0 0 0 0 0
21	Tax depreciation-ND 0 0 0 0 0 0 0 0 0 0 0 0 0 0
22	Federal deferred income taxes 0 0 0 0 0 0 0 0 0 0 0 0 0 0
23	State deferred income taxes 0 0 0 0 0 0 0 0 0 0 0 0 0 0

Line No.	Year>>	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
		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 Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	1,520,973	2,270,973	2,920,973	3,420,973	3,620,973	3,695,973	3,725,973	3,725,973
2	Accumulated Depreciation	0	0	0	0	0	0	(2,025)	(5,047)	(8,935)	(13,489)	(18,309)	(23,229)	(23,229)
3	Net Plant in Service	0	0	0	0	0	1,520,973	2,268,948	2,915,926	3,412,037	3,607,484	3,677,664	3,702,744	3,702,744
CWIP Calculation:														
	Beginning Balance	575,973	585,973	595,973	670,973	820,973	1,020,973	0	0	0	0	0	0	0
	Additional CWIP	10,000	10,000	75,000	150,000	200,000	500,000	750,000	650,000	500,000	200,000	75,000	30,000	3,150,000
	Closings from CWIP						(1,520,973)	(750,000)	(650,000)	(500,000)	(200,000)	(75,000)	(30,000)	
	AFDUC													
4	CWIP (Project #T03032.038)	585,973	595,973	670,973	820,973	1,020,973	0	0	0	0	0	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	
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	(3,858)	(7,002)	(9,617)	(11,760)	(13,464)	(14,787)	(15,734)	(15,734)
7	Ending rate base	585,973	595,973	670,973	820,973	1,020,973	1,517,115	2,261,946	2,906,309	3,400,278	3,594,020	3,662,877	3,687,011	3,687,011
8														
9	Average rate base	162,182	162,182	162,182	162,182	162,182	162,182	162,182	162,182	162,182	162,182	162,182	162,182	1,946,184
10														
11	Return on Rate Base	12,394	12,394	12,394	12,394	12,394	12,394	12,394	12,394	12,394	12,394	12,394	12,394	148,727
12														
13	Available for return (equity portion of rate base)	8,319	8,319	8,319	8,319	8,319	8,319	8,319	8,319	8,319	8,319	8,319	8,319	99,825
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	413	413	413	413	413	413	413	413	413	413	413	413	4,953
19	Book Depreciation	0	0	0	0	0	0	2,025	3,023	3,888	4,554	4,820	4,920	23,229
20	Total O&M and Depreciation Expense	413	413	413	413	413	413	2,437	3,436	4,301	4,966	5,233	5,332	28,182
21														
22	Income before Taxes													
23	Available for return (from above)	8,319	8,319	8,319	8,319	8,319	8,319	8,319	8,319	8,319	8,319	8,319	8,319	99,825
24	Taxable Income (grossed up)	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004	132,052
25														
26	Income Taxes													
27	Current and Def Income Taxes	2,686	2,686	2,686	2,686	2,686	2,686	2,686	2,686	2,686	2,686	2,686	2,686	32,227
28	Total Income Tax Expense	2,686	2,686	2,686	2,686	2,686	2,686	2,686	2,686	2,686	2,686	2,686	2,686	32,227
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	3,098	3,098	3,098	3,098	3,098	3,098	5,123	6,121	6,986	7,652	7,918	8,018	60,409
33	Return on rate base	12,394	12,394	12,394	12,394	12,394	12,394	12,394	12,394	12,394	12,394	12,394	12,394	148,727
34	Subtotal revenue requirements	15,492	15,492	15,492	15,492	15,492	15,492	17,517	18,515	19,380	20,046	20,312	20,412	209,136
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(3,050)	(3,050)	(3,050)	(3,050)	(3,050)	(3,050)	(3,448)	(3,645)	(3,815)	(3,946)	(3,998)	(4,018)	(41,167)
37	Total revenue requirements	12,443	12,443	12,443	12,443	12,443	12,443	14,069	14,871	15,565	16,100	16,314	16,394	167,969
38														
39	North Dakota share - D2 factor	4,927	4,927	4,927	4,927	4,927	4,927	5,571	5,889	6,164	6,375	6,460	6,492	66,514

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3		Ratio	Cost	WA Cost									Property tax	
4	Debt	47.50%	5.29%	2.51%									2022 composite rate	0.86%
5	Preferred equity	0.00%	0.00%	0.00%										
6	Common equity	52.50%	9.77%	5.13%										
7	Total	100.00%												
8														
9														
10	Project life (years)	Book	Tax											
11		50	15-year MACRS											
12														
13			Fed Portion	State Portion										
14	Effective Tax Rate	24.40%	20.09%	4.31%										
15	Tax conversion factor	1.32284												
16	Wholesale Revenue Credit	19.68%												
17	ND share - D2 factor	39.5989%												
18	Deferred Tax													
19	Book depreciation	0	0	0	0	0	0	2,025	3,023	3,888	4,554	4,820	4,920	23,229
20	Tax depreciation-Federal	0	0	0	0	0	26,614	26,614	26,614	26,614	26,614	26,614	26,614	186,299
21	Tax depreciation-ND	0	0	0	0	0	26,614	26,614	26,614	26,614	26,614	26,614	26,614	186,299
22	Federal deferred income taxes	0	0	0	0	0	(5,348)	(4,941)	(4,741)	(4,567)	(4,433)	(4,380)	(4,359)	(32,769)
23	State deferred income taxes	0	0	0	0	0	(1,147)	(1,060)	(1,017)	(979)	(951)	(939)	(935)	(7,028)

Line No.	Year>>	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	1,122,914	1,122,914	1,122,914	1,122,914
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	(1,495)	(2,989)	(2,989)
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	1,122,914	1,121,420	1,119,925	1,119,925
CWIP Calculation:														
	Beginning Balance	386,027	394,737	404,248	407,962	425,371	433,112	450,626	473,219	707,650	1,017,455	0	0	0
	Additional CWIP	8,709	9,512	3,714	17,409	7,741	17,514	22,593	234,431	309,806	105,459	0	0	736,887
	Closings from CWIP	0	0	0	0	0	0	0	0	0	(1,122,914)	0	0	0
	AFDUC													
4	CWIP (Project #T06031.010)	394,737	404,248	407,962	425,371	433,112	450,626	473,219	707,650	1,017,455	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	0	0	(4,567)	(8,770)	(12,973)	(12,973)
7	Ending rate base	394,737	404,248	407,962	425,371	433,112	450,626	473,219	707,650	1,017,455	1,118,347	1,112,650	1,106,952	1,106,952
8														
9	Average rate base	54,092	54,092	54,092	54,092	54,092	54,092	54,092	54,092	54,092	54,092	54,092	54,092	649,104
10														
11	Return on Rate Base	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134	49,605
12														
13	Available for return (equity portion of rate base)	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	33,294
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	586	586	586	586	586	586	586	586	586	586	586	586	7,027
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	1,495	1,495	2,989
20	Total O&M and Depreciation Expense	586	586	586	586	586	586	586	586	586	586	2,080	2,080	10,016
21														
22	Income before Taxes													
23	Available for return (from above)	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	33,294
24	Taxable Income (grossed up)	3,670	3,670	3,670	3,670	3,670	3,670	3,670	3,670	3,670	3,670	3,670	3,670	44,043
25														
26	Income Taxes													
27	Current and Def Income Taxes	896	896	896	896	896	896	896	896	896	896	896	896	10,749
28	Total Income Tax Expense	896	896	896	896	896	896	896	896	896	896	896	896	10,749
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	1,481	1,481	1,481	1,481	1,481	1,481	1,481	1,481	1,481	1,481	2,976	2,976	20,765
33	Return on rate base	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134	49,605
34	Subtotal revenue requirements	5,615	5,615	5,615	5,615	5,615	5,615	5,615	5,615	5,615	5,615	7,110	7,110	70,369
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,380)	(1,380)	(13,659)
37	Total revenue requirements	4,525	4,525	4,525	4,525	4,525	4,525	4,525	4,525	4,525	4,525	5,730	5,730	56,710
38														
39	North Dakota share - D2 factor	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	2,269	2,269	22,456

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3		Ratio	Cost	WA Cost									Property tax	
4	Debt	47.50%	5.29%	2.51%									2021 composite rate	1.85%
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)	Book	Tax											
11		50	15-year MACRS											
12														
13			Fed Portion	State Portion										
14	Effective Tax Rate	24.40%	20.09%	4.31%										
15	Tax conversion factor	1.32284												
16	Wholesale Revenue Credit	19.41%												
17	ND share - D2 factor	39.5989%												
18	Deferred Tax													
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	1,495	1,495	2,989
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	18,715	18,715	18,715	56,146
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	18,715	18,715	18,715	56,146
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	(3,761)	(3,460)	(3,460)	(10,682)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	(807)	(742)	(742)	(2,291)

Line No.	Year>>	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total	
RATE BASE															
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	1,143,746	1,143,746	1,143,746
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(1,522)	(1,522)
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	1,143,746	1,142,223	1,142,223
CWIP Calculation:															
	Beginning Balance	6,545	8,878	19,035	27,498	309,440	323,775	551,244	703,341	820,017	936,693	1,045,870	0	0	1,137,200
	Additional CWIP	2,333	10,158	8,462	281,943	14,334	227,469	152,098	116,676	116,676	109,176	97,876	0	0	0
	Closings from CWIP											(1,143,746)	0	0	0
	AFDUC														
4	CWIP (Project #T05002.020)	136358	8,878	19,035	27,498	309,440	323,775	551,244	703,341	820,017	936,693	1,045,870	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	1.0000
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	(6,978)	(13,585)	(13,585)
7	Ending rate base	8,878	19,035	27,498	309,440	323,775	551,244	703,341	820,017	936,693	1,045,870	1,136,767	1,128,638	1,128,638	
8															
9	Average rate base	44,986	44,986	44,986	44,986	44,986	44,986	44,986	44,986	44,986	44,986	44,986	44,986	44,986	539,826
10															
11	Return on Rate Base	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	41,254
12															
13	Available for return (equity portion of rate base)	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	27,689
14															
EXPENSES															
O&M and Depreciation															
17	Operating Costs	0	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	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	1,522	1,522
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	1,522	1,522
21															
22	Income before Taxes														
23	Available for return (from above)	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	27,689
24	Taxable Income (grossed up)	3,052	3,052	3,052	3,052	3,052	3,052	3,052	3,052	3,052	3,052	3,052	3,052	3,052	36,628
25															
26	Income Taxes														
27	Current and Def Income Taxes	745	745	745	745	745	745	745	745	745	745	745	745	745	8,939
28	Total Income Tax Expense	745	745	745	745	745	745	745	745	745	745	745	745	745	8,939
29															
30															
REVENUE REQUIREMENTS															
32	Expenses	745	745	745	745	745	745	745	745	745	745	745	745	2,267	10,461
33	Return on rate base	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	3,438	41,254
34	Subtotal revenue requirements	4,183	4,183	4,183	4,183	4,183	4,183	4,183	4,183	4,183	4,183	4,183	4,183	5,705	51,715
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(812)	(812)	(812)	(812)	(812)	(812)	(812)	(812)	(812)	(812)	(812)	(812)	(1,107)	(10,038)
37	Total revenue requirements	3,371	3,371	3,371	3,371	3,371	3,371	3,371	3,371	3,371	3,371	3,371	3,371	4,598	41,677
38															
39	North Dakota share - D2 factor	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,335	1,821	16,504

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3		<u>Ratio</u>	<u>Cost</u>	<u>WA Cost</u>						<u>Property tax</u>				
4	Debt	47.50%	5.29%	2.51%						2021 composite rate				0.86%
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)	<u>Book</u>	<u>Tax</u>											
11		50	15-year MACRS											
12														
13			<u>Fed Portion</u>	<u>State Portion</u>										
14	Effective Tax Rate	24.40%	20.09%	4.31%										
15	Tax conversion factor	1.32284												
16	Wholesale Revenue Credit	19.41%												
17	ND share - D2 factor	39.5989%												
18	Deferred Tax													
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	1,522	1,522
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	28,594	28,594	57,187
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	28,594	28,594	57,187
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	(5,746)	(5,440)	(11,186)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	(1,232)	(1,167)	(2,399)

Line No.	Year>>	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RATE BASE														
1	Plant Balance	307,399	307,399	307,399	307,399	307,399	307,399	307,399	307,399	307,399	1,294,127	1,294,127	1,294,127	1,294,127
2	Accumulated Depreciation	(10,300)	(10,709)	(11,119)	(11,528)	(11,937)	(12,346)	(12,755)	(13,164)	(13,574)	(13,983)	(15,705)	(17,428)	(17,428)
3	Net Plant in Service	297,098	296,689	296,280	295,871	295,462	295,052	294,643	294,234	293,825	1,280,145	1,278,422	1,276,699	1,276,699
CWIP Calculation:														
	Beginning Balance	595,434	616,181	690,280	792,422	883,637	945,849	982,350	985,565	986,729	986,729	0	0	0
	Additional CWIP	20,747	74,099	102,142	91,216	62,212	36,502	3,214	1,164	0	0	0	0	391,295
	Closings from CWIP										(986,729)	0	0	0
	AFDUC											0	0	0
4	CWIP (Project #T05008.027)	616,181	690,280	792,422	883,637	945,849	982,350	985,565	986,729	986,729	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	(8,899)	(9,333)	(9,768)	(10,203)	(10,637)	(11,072)	(11,507)	(11,941)	(12,376)	(16,824)	(20,952)	(25,079)	(25,079)
7	Ending rate base	904,381	977,635	1,078,934	1,169,305	1,230,673	1,266,331	1,268,701	1,269,022	1,268,178	1,263,320	1,257,470	1,251,620	1,251,620
8														
9	Average rate base	96,731	96,731	96,731	96,731	96,731	96,731	96,731	96,731	96,731	96,731	96,731	96,731	1,160,773
10														
11	Return on Rate Base	7.392	7.392	7.392	7.392	7.392	7.392	7.392	7.392	7.392	7.392	7.392	7.392	88,706
12														
13	Available for return (equity portion of rate base)	4,962	4,962	4,962	4,962	4,962	4,962	4,962	4,962	4,962	4,962	4,962	4,962	59,539
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	496	496	496	496	496	496	496	496	496	496	496	496	5,955
19	Book Depreciation	409	409	409	409	409	409	409	409	409	409	1,723	1,723	7,537
20	Total O&M and Depreciation Expense	905	905	905	905	905	905	905	905	905	905	2,219	2,219	13,492
21														
22	Income before Taxes													
23	Available for return (from above)	4,962	4,962	4,962	4,962	4,962	4,962	4,962	4,962	4,962	4,962	4,962	4,962	59,539
24	Taxable Income (grossed up)	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	78,760
25														
26	Income Taxes													
27	Current and Def Income Taxes	1,602	1,602	1,602	1,602	1,602	1,602	1,602	1,602	1,602	1,602	1,602	1,602	19,221
28	Total Income Tax Expense	1,602	1,602	1,602	1,602	1,602	1,602	1,602	1,602	1,602	1,602	1,602	1,602	19,221
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	2,507	2,507	2,507	2,507	2,507	2,507	2,507	2,507	2,507	2,507	3,821	3,821	32,713
33	Return on rate base	7,392	7,392	7,392	7,392	7,392	7,392	7,392	7,392	7,392	7,392	7,392	7,392	88,706
34	Subtotal revenue requirements	9,899	9,899	9,899	9,899	9,899	9,899	9,899	9,899	9,899	9,899	11,213	11,213	121,420
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(1,922)	(1,922)	(1,922)	(1,922)	(1,922)	(1,922)	(1,922)	(1,922)	(1,922)	(1,922)	(2,177)	(2,177)	(23,569)
37	Total revenue requirements	7,978	7,978	7,978	7,978	7,978	7,978	7,978	7,978	7,978	7,978	9,036	9,036	97,851
38														
39	North Dakota share - D2 factor	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,578	3,578	38,748

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3		Ratio	Cost	WA Cost									Property tax	
4	Debt	47.50%	5.29%	2.51%									2021 composite rate	0.86%
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)	Book	Tax											
11		50	15-year MACRS											
12														
13			Fed Portion	State Portion										
14	Effective Tax Rate	24.40%	20.09%	4.31%										
15	Tax conversion factor	1.32284												
16	Wholesale Revenue Credit	19.41%												
17	ND share - D2 factor	39.5989%												
18	Deferred Tax													
19	Book depreciation	409	409	409	409	409	409	409	409	409	409	1,723	1,723	7,537
20	Tax depreciation-Federal	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	18,636	18,636	18,636	75,619
21	Tax depreciation-ND	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	18,636	18,636	18,636	75,619
22	Federal deferred income taxes	(358)	(358)	(358)	(358)	(358)	(358)	(358)	(358)	(358)	(3,663)	(3,399)	(3,399)	(13,681)
23	State deferred income taxes	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(786)	(729)	(729)	(2,934)

Line No.	Year>>	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	1,032,184	1,033,210	1,035,535	1,035,535
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	(1,374)	(2,749)	(2,749)
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	1,032,184	1,031,836	1,032,786	1,032,786
CWIP Calculation:														
	Beginning Balance	49,631	50,474	58,317	77,084	313,437	392,932	616,671	800,741	915,300	1,029,859	0	0	985,904
	Additional CWIP	843	7,844	18,766	236,354	79,495	223,739	184,070	114,559	114,559	2,325	1,025	2,325	985,904
	Closings from CWIP										(1,032,184)	(1,025)	(2,325)	
	AFDUC													
4	CWIP (Project #T05002.037)	50,474	58,317	77,084	313,437	392,932	616,671	800,741	915,300	1,029,859	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	0	0	(4,212)	(8,089)	(11,965)	(11,965)
7	Ending rate base	50,474	58,317	77,084	313,437	392,932	616,671	800,741	915,300	1,029,859	1,027,972	1,023,747	1,020,820	1,020,820
8														
9	Average rate base	47,288	47,288	47,288	47,288	47,288	47,288	47,288	47,288	47,288	47,288	47,288	47,288	567,460
10														
11	Return on Rate Base	3,614	3,614	3,614	3,614	3,614	3,614	3,614	3,614	3,614	3,614	3,614	3,614	43,365
12														
13	Available for return (equity portion of rate base)	2,426	2,426	2,426	2,426	2,426	2,426	2,426	2,426	2,426	2,426	2,426	2,426	29,106
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	1,374	1,375	2,749
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	1,374	1,375	2,749
21														
22	Income before Taxes													
23	Available for return (from above)	2,426	2,426	2,426	2,426	2,426	2,426	2,426	2,426	2,426	2,426	2,426	2,426	29,106
24	Taxable Income (grossed up)	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	38,503
25														
26	Income Taxes													
27	Current and Def Income Taxes	783	783	783	783	783	783	783	783	783	783	783	783	9,397
28	Total Income Tax Expense	783	783	783	783	783	783	783	783	783	783	783	783	9,397
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	783	783	783	783	783	783	783	783	783	783	2,157	2,158	12,146
33	Return on rate base	3,614	3,614	3,614	3,614	3,614	3,614	3,614	3,614	3,614	3,614	3,614	3,614	43,365
34	Subtotal revenue requirements	4,397	4,397	4,397	4,397	4,397	4,397	4,397	4,397	4,397	4,397	5,771	5,772	55,511
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(853)	(853)	(853)	(853)	(853)	(853)	(853)	(853)	(853)	(853)	(1,120)	(1,120)	(10,775)
37	Total revenue requirements	3,543	3,543	3,543	3,543	3,543	3,543	3,543	3,543	3,543	3,543	4,651	4,652	44,736
38														
39	North Dakota share - D2 factor	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,403	1,842	1,842	17,715

Line No.	SUPPORTING INFORMATION / DATA													
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)		<u>Book</u>	<u>Tax</u>										
11			50	15-year MACRS										
12														
13														
14														
15														
16														
17														
18	Deferred Tax													
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	1,374	1,375	2,749
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	17,259	17,259	17,259	51,777
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	17,259	17,259	17,259	51,777
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	(3,468)	(3,192)	(3,192)	(9,852)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	(744)	(685)	(685)	(2,113)

Line No.	Year>>	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
		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 Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	1,252,060
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	1,252,060
CWIP Calculation:														
	Beginning Balance	94,210	188,560	188,560	188,560	188,560	188,560	506,610	610,960	988,360	1,053,360	1,147,710	1,252,060	
	Additional CWIP	94,350	0	0	0	0	318,050	104,350	377,400	65,000	94,350	104,350	0	1,157,850
	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	(1,252,060)	
	AFDUC													
4	CWIP (Project #T03032.031)	188,560	188,560	188,560	188,560	188,560	506,610	610,960	988,360	1,053,360	1,147,710	1,252,060	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	
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	(2,733)	(2,733)
7	Ending rate base	188,560	188,560	188,560	188,560	188,560	506,610	610,960	988,360	1,053,360	1,147,710	1,252,060	1,249,327	1,249,327
8														
9	Average rate base	50,291	50,291	50,291	50,291	50,291	50,291	50,291	50,291	50,291	50,291	50,291	50,291	603,492
10														
11	Return on Rate Base	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	46,119
12														
13	Available for return (equity portion of rate base)	2,580	2,580	2,580	2,580	2,580	2,580	2,580	2,580	2,580	2,580	2,580	2,580	30,955
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
21														
22	Income before Taxes													
23	Available for return (from above)	2,580	2,580	2,580	2,580	2,580	2,580	2,580	2,580	2,580	2,580	2,580	2,580	30,955
24	Taxable Income (grossed up)	3,412	3,412	3,412	3,412	3,412	3,412	3,412	3,412	3,412	3,412	3,412	3,412	40,948
25														
26	Income Taxes													
27	Current and Def Income Taxes	833	833	833	833	833	833	833	833	833	833	833	833	9,993
28	Total Income Tax Expense	833	833	833	833	833	833	833	833	833	833	833	833	9,993
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	833	833	833	833	833	833	833	833	833	833	833	833	9,993
33	Return on rate base	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	46,119
34	Subtotal revenue requirements	4,676	4,676	4,676	4,676	4,676	4,676	4,676	4,676	4,676	4,676	4,676	4,676	56,112
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(920)	(920)	(920)	(920)	(920)	(920)	(920)	(920)	(920)	(920)	(920)	(920)	(11,045)
37	Total revenue requirements	3,756	3,756	3,756	3,756	3,756	3,756	3,756	3,756	3,756	3,756	3,756	3,756	45,067
38														
39	North Dakota share - D2 factor	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	17,846

Line No.	SUPPORTING INFORMATION / DATA													
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%												
8														
9														
10	Project life (years)		<u>Book</u>	<u>Tax</u>										
11			50	15-year MACRS										
12														
13														
14														
15														
16														
17														
18	Deferred Tax													
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	0	62,603	62,603
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	62,603	62,603
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(12,580)	(12,580)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(2,698)	(2,698)

Line No.	Year>>	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021
		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 Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	387,641
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	387,641
4	CWIP (Project #T03032.028)	136,890	147,984	289,705	327,641	363,189	541,377	578,483	667,783	757,361	830,483	903,860	588,456	864,611
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	0	0	0	0	0	0	0	0	0	0	0	0	(4,730)
7	Ending rate base	136,890	147,984	289,705	327,641	363,189	541,377	578,483	667,783	757,361	830,483	903,860	971,366	1,247,522
9	Average rate base	41,770	41,770	41,770	41,770	41,770	41,770	41,770	41,770	41,770	41,770	41,770	41,770	501,240
11	Return on Rate Base	3,192	3,192	3,192	3,192	3,192	3,192	3,192	3,192	3,192	3,192	3,192	3,192	38,305
13	Available for return (equity portion of rate base)	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	25,710
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Income before Taxes													
23	Available for return (from above)	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	25,710
24	Taxable Income (grossed up)	2,834	2,834	2,834	2,834	2,834	2,834	2,834	2,834	2,834	2,834	2,834	2,834	34,010
26	Income Taxes													
27	Current and Def Income Taxes	692	692	692	692	692	692	692	692	692	692	692	692	8,300
28	Total Income Tax Expense	692	692	692	692	692	692	692	692	692	692	692	692	8,300
REVENUE REQUIRMENTS														
32	Expenses	692	692	692	692	692	692	692	692	692	692	692	692	8,300
33	Return on rate base	3,192	3,192	3,192	3,192	3,192	3,192	3,192	3,192	3,192	3,192	3,192	3,192	38,305
34	Subtotal revenue requirements	3,884	3,884	3,884	3,884	3,884	3,884	3,884	3,884	3,884	3,884	3,884	3,884	46,605
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(9,046)
37	Total revenue requirements	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	37,558
39	North Dakota share - D2 factor	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	14,873

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	Ratio	Cost	WA Cost										
4	Debt	47.50%	5.29%	2.51%	Property tax									
5	Preferred equity	0.00%	0.00%	0.00%	2021 composite rate									
6	Common equity	52.50%	9.77%	5.13%	0.82%									
7	Total	100.00%	7.64% Overall Return											
9	Project life (years)	Book	Tax											
10		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	19.41%												
16	ND share - D2 factor	39.5989%												
18	Deferred Tax													
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	0	19,382	19,382
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	19,382	19,382
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(3,895)	(3,895)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(835)	(835)

Line No.	Year>>	2022 Projected January	2022 Projected February	2022 Projected March	2022 Projected April	2022 Projected May	2022 Projected June	2022 Projected July	2022 Projected August	2022 Projected September	2022 Projected October	2022 Projected November	2022 Projected December	2022 Projected Total
RATE BASE														
1	Plant Balance	387,641	387,641	387,641	387,641	387,641	387,641	387,641	387,641	387,641	387,641	1,147,066	2,635,860	2,635,860
2	Accumulated Depreciation	(550)	(1,100)	(1,650)	(2,200)	(2,750)	(3,301)	(3,851)	(4,401)	(4,951)	(5,501)	(6,051)	(7,679)	(7,679)
3	Net Plant in Service	387,090	386,540	385,990	385,440	384,890	384,340	383,790	383,240	382,690	382,140	1,141,015	2,628,181	2,628,181
4	CWIP (Project #T03032.028)	365,833	365,833	350,833	910,833	350,833	350,833	368,333	358,333	678,333	380,833	609,833	599,333	5,690,000
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	(5,303)	(5,838)	(6,329)	(6,778)	(7,185)	(7,550)	(7,872)	(8,151)	(8,389)	(8,584)	(9,889)	(14,030)	(14,030)
7	Ending rate base	747,620	746,536	730,495	1,289,495	728,538	727,623	744,251	733,422	1,052,634	754,389	1,740,959	3,213,484	8,304,151
8														
9	Average rate base	92,673	92,673	92,673	92,673	92,673	92,673	92,673	92,673	92,673	92,673	92,673	92,673	1,112,074
10														
11	Return on Rate Base	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	84,985
12														
13	Available for return (equity portion of rate base)	4,753	4,753	4,753	4,753	4,753	4,753	4,753	4,753	4,753	4,753	4,753	4,753	57,041
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	619	619	619	619	619	619	619	619	619	619	619	619	7,429
19	Book Depreciation	550	550	550	550	550	550	550	550	550	550	550	1,628	7,679
20	Total O&M and Depreciation Expense	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169	2,247	15,108
21														
22	Income before Taxes													
23	Available for return (from above)	4,753	4,753	4,753	4,753	4,753	4,753	4,753	4,753	4,753	4,753	4,753	4,753	57,041
24	Taxable Income (grossed up)	6,288	6,288	6,288	6,288	6,288	6,288	6,288	6,288	6,288	6,288	6,288	6,288	75,456
25														
26	Income Taxes													
27	Current and Def Income Taxes	1,535	1,535	1,535	1,535	1,535	1,535	1,535	1,535	1,535	1,535	1,535	1,535	18,415
28	Total Income Tax Expense	1,535	1,535	1,535	1,535	1,535	1,535	1,535	1,535	1,535	1,535	1,535	1,535	18,415
29														
30														
REVENUE REQUIRMENTS														
32	Expenses	2,704	2,704	2,704	2,704	2,704	2,704	2,704	2,704	2,704	2,704	2,704	3,781	33,523
33	Return on rate base	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	84,985
34	Subtotal revenue requirements	9,786	9,786	9,786	9,786	9,786	9,786	9,786	9,786	9,786	9,786	9,786	10,864	118,508
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(1,926)	(1,926)	(1,926)	(1,926)	(1,926)	(1,926)	(1,926)	(1,926)	(1,926)	(1,926)	(1,926)	(2,138)	(23,328)
37	Total revenue requirements	7,860	7,860	7,860	7,860	7,860	7,860	7,860	7,860	7,860	7,860	7,860	8,725	95,180
38														
39	North Dakota share - D2 factor	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,112	3,455	37,690

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%											2022 composite rate
4	Preferred equity	0.00%	0.00%	0.00%											0.82%
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	19.68%													
16	ND share - D2 factor	39.5989%													
17															
18	Deferred Tax														
19	Book depreciation	550	550	550	550	550	550	550	550	550	550	550	1,628	7,679	
20	Tax depreciation-Federal	3,069	3,069	3,069	3,069	3,069	3,069	3,069	3,069	3,069	3,069	22,054	96,494	149,237	
21	Tax depreciation-ND	3,069	3,069	3,069	3,069	3,069	3,069	3,069	3,069	3,069	3,069	22,054	96,494	149,237	
22	Federal deferred income taxes	(506)	(506)	(506)	(506)	(506)	(506)	(506)	(506)	(506)	(506)	(4,321)	(19,063)	(28,446)	
23	State deferred income taxes	(109)	(109)	(109)	(109)	(109)	(109)	(109)	(109)	(109)	(109)	(927)	(4,089)	(6,101)	

Line No.	Year>>	2022 Projected January	2022 Projected February	2022 Projected March	2022 Projected April	2022 Projected May	2022 Projected June	2022 Projected July	2022 Projected August	2022 Projected September	2022 Projected October	2022 Projected November	2022 Projected December	2022 Projected Total
RATE BASE														
1	Plant Balance	0	0	585,535	1,303,951	1,303,951	1,618,200	1,618,200	1,618,200	1,618,200	1,618,200	2,076,090	3,375,339	3,375,339
2	Accumulated Depreciation	0	0	0	(831)	(2,681)	(4,532)	(6,828)	(9,124)	(11,421)	(13,717)	(16,014)	(18,960)	(18,960)
3	Net Plant in Service	0	0	585,535	1,303,120	1,301,269	1,613,668	1,611,371	1,609,075	1,606,779	1,604,482	2,060,076	3,356,379	3,356,379
4	CWIP (Project #)	1,189,922	1,549,506	1,323,554	964,722	1,146,805	1,014,640	1,171,723	1,328,806	1,485,890	1,642,973	1,342,166	200,000	200,000
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	(11,724)
6	Accumulated Deferred Income Taxes Federal & State	0	0	(571)	(1,846)	(2,956)	(4,044)	(5,057)	(5,935)	(6,682)	(7,294)	(8,525)	(11,724)	(11,724)
7	Ending rate base	1,189,922	1,549,506	1,908,518	2,265,995	2,445,119	2,624,263	2,778,037	2,931,946	3,085,986	3,240,161	3,393,717	3,544,656	3,544,656
8														
9	Average rate base	203,322	203,322	203,322	203,322	203,322	203,322	203,322	203,322	203,322	203,322	203,322	203,322	2,439,859
10														
11	Return on Rate Base	15,538	15,538	15,538	15,538	15,538	15,538	15,538	15,538	15,538	15,538	15,538	15,538	186,454
12														
13	Available for return (equity portion of rate base)	10,429	10,429	10,429	10,429	10,429	10,429	10,429	10,429	10,429	10,429	10,429	10,429	125,146
14														
EXPENSES														
<i>O&M and Depreciation</i>														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048	12,576
19	Book Depreciation	0	0	0	831	1,850	1,850	2,296	2,296	2,296	2,296	2,296	2,946	18,960
20	Total O&M and Depreciation Expense	1,048	1,048	1,048	1,879	2,898	2,898	3,344	3,344	3,344	3,344	3,344	3,994	31,536
21														
22	Income before Taxes													
23	Available for return (from above)	10,429	10,429	10,429	10,429	10,429	10,429	10,429	10,429	10,429	10,429	10,429	10,429	125,146
24	Taxable Income (grossed up)	13,796	13,796	13,796	13,796	13,796	13,796	13,796	13,796	13,796	13,796	13,796	13,796	165,548
25														
26	Income Taxes													
27	Current and Def Income Taxes	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	40,402
28	Total Income Tax Expense	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	3,367	40,402
29														
30														
REVENUE REQUIRMENTS														
32	Expenses	4,415	4,415	4,415	5,246	6,265	6,265	6,711	6,711	6,711	6,711	6,711	7,361	71,938
33	Return on rate base	15,538	15,538	15,538	15,538	15,538	15,538	15,538	15,538	15,538	15,538	15,538	15,538	186,454
34	Subtotal revenue requirements	19,953	19,953	19,953	20,784	21,803	21,803	22,249	22,249	22,249	22,249	22,249	22,899	258,392
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(3,928)	(3,928)	(3,928)	(4,091)	(4,292)	(4,292)	(4,380)	(4,380)	(4,380)	(4,380)	(4,380)	(4,508)	(50,863)
37	Total revenue requirements	16,025	16,025	16,025	16,692	17,511	17,511	17,869	17,869	17,869	17,869	17,869	18,391	207,529
38														
39	North Dakota share - D2 factor	6,346	6,346	6,346	6,610	6,934	6,934	7,076	7,076	7,076	7,076	7,076	7,283	82,179

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3	Debt	Ratio	Cost	WA Cost										Property tax
4		47.50%	5.29%	2.51%										2022 composite rate
5	Preferred equity	0.00%	0.00%	0.00%										0.82%
6	Common equity	52.50%	9.77%	5.13%										
7	Total	100.00%		7.64%	Overall Return									
8														
9	Project life (years)													
10		Book	Tax											
11		50	15-year MACRS											
12														
13		Effective Tax Rate	Fed Portion	State Portion										
14		24.40%	20.09%	4.31%										
15		Tax conversion factor												
16		1.32284												
17		Wholesale Revenue Credit												
18		19.68%												
19		ND share - D2 factor												
20		39.5989%												
Deferred Tax														
19	Book depreciation	0	0	0	831	1,850	1,850	2,296	2,296	2,296	2,296	2,296	2,946	18,960
20	Tax depreciation-Federal	0	0	2,928	7,974	7,974	10,219	10,219	10,219	10,219	10,219	22,562	76,233	168,767
21	Tax depreciation-ND	0	0	2,928	7,974	7,974	10,219	10,219	10,219	10,219	10,219	22,562	76,233	168,767
22	Federal deferred income taxes	0	0	(588)	(1,435)	(1,435)	(1,435)	(1,592)	(1,592)	(1,592)	(1,592)	(4,072)	(14,727)	(30,062)
23	State deferred income taxes	0	0	(126)	(308)	(264)	(361)	(341)	(341)	(341)	(341)	(873)	(3,159)	(6,457)

2022 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$40,512,693
	REVENUE CREDITS	(Note T)	Total	Allocator	
2	Account No. 454	(page 4, line 34)	196,605	TP 1.00000	196,605
3	Account No. 456.1	(page 4, line 37)	8,673,901	TP 1.00000	8,673,901
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)				8,870,506
7	To back out Schedule 9 Revenues received				(895,787)
8	Total Revenue Subject to the Wholesale Revenue Credit				7,974,719
7				Wholesale Revenue Credit	19.68%

2021 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$46,280,998
	REVENUE CREDITS	(Note T)	Total	Allocator	
2	Account No. 454	(page 4, line 34)	165,476	TP 1.00000	165,476
3	Account No. 456.1	(page 4, line 37)	9,776,508	TP 1.00000	9,776,508
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)				9,941,984
7	To back out Schedule 9 Revenues received				(958,438)
8	Total Revenue Subject to the Wholesale Revenue Credit				8,983,546
9				Wholesale Revenue Credit	19.411%

2021		2021												
Line No.	SCHEDULE 26	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected
1	MISO Schedule 26 Expense	1,050,637	937,140	927,155	785,937	600,308	781,273	827,770	1,026,788	885,605	901,118	926,788	1,133,485	10,784,004
2	OTP owned portion of expenses not recoverable via rider	0.010%	(105)	(94)	(93)	(79)	(60)	(78)	(83)	(103)	(89)	(93)	(113)	(1,078)
3	MISO Schedule 26 Expense Recoverable	1,050,532	937,046	927,062	785,858	600,248	781,195	827,687	1,026,686	885,516	901,028	926,696	1,133,372	10,782,926
4	MISO Settlements	(36,843)			(13,115)	(23,371)								
4	North Dakota share	39.599%	379,156	371,060	367,106	298,076	214,321	309,345	327,755	406,556	356,797	366,961	448,803	4,196,592
6	MISO Schedule 26A Expense	798,844	766,356	689,518	601,624	516,890	579,348	665,931	614,217	581,457	629,827	721,070	816,800	7,981,880
8	MISO Settlements	(6,768)			(11,224)	(8,791)								
8	North Dakota share	39.599%	309,565	303,469	273,042	227,012	195,892	229,415	243,223	230,250	249,405	285,536	323,444	3,133,954

2022		2022												
Line No.	SCHEDULE 26	Jan Projected	Feb Projected	Mar Projected	Apr Projected	May Projected	Jun Projected	Jul Projected	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected
1	MISO Schedule 26 Expense	1,208,944	1,172,676	1,075,960	906,708	797,903	955,066	979,245	979,245	846,261	1,003,424	1,003,424	1,208,944	12,137,798
2	OTP owned portion of expenses not recoverable via rider	0.010%	(121)	(117)	(108)	(91)	(80)	(96)	(98)	(98)	(85)	(100)	(100)	(1,214)
3	MISO Schedule 26 Expense Recoverable	1,208,823	1,172,558	1,075,853	906,617	797,823	954,970	979,147	979,147	846,176	1,003,323	1,003,323	1,208,823	12,136,584
4	MISO Settlements													
5	North Dakota share	39.599%	478,681	464,320	426,026	359,011	315,929	378,158	387,731	387,731	335,077	397,305	397,305	4,805,955
6	MISO Schedule 26A Expense	838,745	771,596	741,825	653,639	602,768	585,647	617,996	613,937	581,764	618,385	716,771	807,199	8,150,269
8	MISO Settlements													
8	North Dakota share	39.599%	332,134	305,543	293,754	258,834	238,690	231,910	244,720	243,112	230,372	244,874	283,833	3,227,418

		2021													
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)	(367,127)	(361,601)	(341,188)	(284,123)	(213,039)	(251,194)	(268,452)	(224,825)	(223,870)	(289,866)	(302,472)	(320,760)	(3,448,516)	
	CPEC Facility Credits in MISO	195,382	195,382	195,382	195,382	195,382	209,534	209,534	199,459	201,189	201,189	201,189	201,189	2,400,191	
2	Non-OTP Schedule 9 Revenues	14,719	14,245	12,496	7,605	1,513	3,574	5,055	2,176	1,946	7,608	8,690	10,259	89,887	
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(157,027)	(151,975)	(133,311)	(81,136)	(16,144)	(38,086)	(53,863)	(23,190)	(20,735)	(81,069)	(92,593)	(109,312)	(958,438)	
	MISO ROE					8,767									
5	North Dakota share	39.599%	(62,181)	(60,180)	(52,790)	(32,129)	2,374	(15,082)	(21,329)	(9,183)	(8,211)	(32,102)	(36,666)	(43,286)	(370,764)

		2022													
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)	(361,443)	(349,009)	(338,310)	(288,583)	(212,416)	(233,181)	(241,660)	(227,109)	(228,189)	(294,134)	(306,721)	(323,206)	(3,403,961)	
	CPEC Facility Credits in MISO	198,669	198,669	198,669	198,669	198,669	202,945	203,538	203,538	205,184	205,184	205,184	205,184	2,424,102	
2	Non-OTP Schedule 9 Revenues	13,966	12,899	11,981	7,715	1,179	2,594	3,271	2,022	1,974	7,632	8,712	10,126	84,072	
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(148,808)	(137,441)	(127,660)	(82,199)	(12,568)	(27,642)	(34,851)	(21,549)	(21,031)	(81,318)	(92,825)	(107,896)	(895,787)	
5	North Dakota share	39.599%	(58,926)	(54,425)	(50,552)	(32,550)	(4,977)	(10,946)	(13,801)	(8,533)	(8,328)	(32,201)	(36,758)	(42,726)	(354,722)

Line No.	2021	2021												Total Projected	
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected		
1	Total Schedule 26A Revenue	(1,991,097)	(1,807,213)	(1,741,394)	(1,507,344)	(1,499,115)	(1,910,968)	(2,225,408)	(2,221,343)	(1,950,567)	(1,815,179)	(1,837,743)	(1,928,002)	(22,435,373)	
2	Overhead Credit for Non-Retail Share	0.993%	(19,771)	(17,945)	(17,292)	(14,968)	(14,886)	(18,976)	(22,058)	(19,369)	(18,024)	(18,248)	(19,145)	(222,779)	
4	CAPX 2020 - Brookings	12.799%	(254,846)	(231,311)	(222,886)	(192,929)	(191,876)	(244,590)	(284,837)	(284,316)	(249,659)	(232,330)	(235,218)	(246,771)	(2,871,571)
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		(58,100)	(52,734)	(50,814)	(43,984)	(43,744)	(55,762)	(64,937)	(64,818)	(56,917)	(52,967)	(53,625)	(56,259)	(654,661)
9	Overhead Credit for Non-Retail Share		(2,531)	(2,297)	(2,213)	(1,916)	(1,905)	(2,429)	(2,828)	(2,823)	(2,479)	(2,307)	(2,336)	(2,450)	(28,514)
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		(1,954)	(1,773)	(1,709)	(1,479)	(1,471)	(1,875)	(2,184)	(2,180)	(1,914)	(1,781)	(1,803)	(1,892)	(22,014)
13	Total Revenue Credit for CAPX Brookings		(60,054)	(54,507)	(52,522)	(45,463)	(45,215)	(57,637)	(66,998)	(58,831)	(54,748)	(55,428)	(58,151)	(676,674)	
15	MVP BS South - Brookings	35.965%	(716,092)	(649,959)	(626,287)	(542,112)	(539,152)	(687,274)	(800,361)	(798,899)	(701,516)	(652,824)	(660,939)	(693,400)	(8,068,815)
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		(14,665)	(13,310)	(12,826)	(11,102)	(11,041)	(14,075)	(16,390)	(16,361)	(14,366)	(13,369)	(13,535)	(14,200)	(165,240)
20	Overhead Credit for Non-Retail Share		(7,111)	(6,454)	(6,219)	(5,383)	(5,354)	(6,825)	(7,947)	(7,933)	(6,966)	(6,482)	(6,563)	(6,885)	(80,122)
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		(6,965)	(6,322)	(6,092)	(5,273)	(5,244)	(6,685)	(7,785)	(7,770)	(6,823)	(6,350)	(6,429)	(6,744)	(78,481)
23	Total Revenue Credit for MVP Brookings		(21,630)	(19,632)	(18,917)	(16,375)	(16,285)	(20,759)	(24,175)	(24,131)	(21,189)	(19,719)	(19,964)	(20,944)	(243,721)
24	MVP Ellendale - BS South	51.236%	(1,020,158)	(925,944)	(892,221)	(772,303)	(768,087)	(979,103)	(1,140,210)	(1,138,127)	(999,392)	(930,025)	(941,586)	(987,831)	(11,494,988)
26	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%	
27	Retail Revenue		(20,403)	(18,519)	(17,844)	(15,446)	(15,362)	(19,582)	(22,804)	(22,763)	(19,988)	(18,600)	(18,832)	(19,757)	(229,900)
29	Overhead Credit for Non-Retail Share		(10,130)	(9,194)	(8,860)	(7,669)	(7,627)	(9,722)	(11,322)	(11,301)	(9,924)	(9,235)	(9,350)	(9,809)	(114,143)
30	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%	
31	Non-Retail Overhead Credit		(9,927)	(9,011)	(8,682)	(7,515)	(7,474)	(9,528)	(11,096)	(11,075)	(9,725)	(9,050)	(9,163)	(9,613)	(111,860)
33	Total Revenue Credit for MVP Ellendale		(30,331)	(27,529)	(26,527)	(22,962)	(22,836)	(29,110)	(33,900)	(33,838)	(29,713)	(27,651)	(27,995)	(29,369)	(341,760)
36	Retail Share of Schedule 26A Revenue		(112,014)	(101,669)	(97,966)	(84,799)	(84,336)	(107,506)	(125,196)	(124,967)	(109,734)	(102,117)	(103,387)	(108,464)	(1,262,155)
37	MISO Settlements		2,846			234	2,922								6,002
38	North Dakota share	39.599%	(41,510)	(40,260)	(38,794)	(33,346)	(30,475)	(42,571)	(49,576)	(49,486)	(43,453)	(40,437)	(40,940)	(42,951)	(493,798)

Line No.	2022	2022												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 26A Revenue	(2,173,979)	(1,973,206)	(1,901,342)	(1,645,793)	(1,636,809)	(2,086,490)	(2,429,812)	(2,425,374)	(2,129,727)	(1,981,903)	(2,006,540)	(2,105,089)	(24,496,066)	
2	Overhead Credit for Non-Retail Share	1.040%	(22,609)	(20,521)	(19,774)	(17,116)	(17,023)	(21,699)	(25,270)	(25,224)	(22,149)	(20,612)	(20,868)	(21,893)	(254,759)
3															
4															
5	CAPX 2020 - Brookings	12.540%	(272,615)	(247,438)	(238,426)	(206,381)	(205,254)	(261,644)	(304,696)	(304,139)	(267,066)	(248,529)	(251,618)	(263,976)	(3,071,782)
6	Retail Load Share		23.007%	23.007%	23.007%	23.007%	23.007%	23.007%	23.007%	23.007%	23.007%	23.007%	23.007%	23.007%	
7	Retail Revenue		(62,720)	(56,928)	(54,855)	(47,482)	(47,223)	(60,196)	(70,101)	(69,973)	(61,444)	(57,179)	(57,890)	(60,733)	(706,725)
8															
9	Overhead Credit for Non-Retail Share		(2,835)	(2,573)	(2,480)	(2,146)	(2,135)	(2,721)	(3,169)	(3,163)	(2,777)	(2,585)	(2,617)	(2,745)	(31,947)
10	Non-Retail Load Share		76.993%	76.993%	76.993%	76.993%	76.993%	76.993%	76.993%	76.993%	76.993%	76.993%	76.993%	76.993%	
11	Non-Retail Overhead Credit		(2,183)	(1,981)	(1,909)	(1,653)	(1,644)	(2,095)	(2,440)	(2,435)	(2,138)	(1,990)	(2,015)	(2,114)	(24,597)
12															
13	Total Revenue Credit for CAPX Brookings		(64,903)	(58,909)	(56,764)	(49,135)	(48,866)	(62,291)	(72,541)	(72,409)	(63,582)	(59,169)	(59,905)	(62,847)	(731,322)
14															
15															
16	MVP BS South - Brookings	35.708%	(776,278)	(704,586)	(678,925)	(587,675)	(584,467)	(745,038)	(867,630)	(866,045)	(760,476)	(707,692)	(716,489)	(751,679)	(8,746,982)
17	Retail Load Share		2.067%	2.067%	2.067%	2.067%	2.067%	2.067%	2.067%	2.067%	2.067%	2.067%	2.067%	2.067%	
18	Retail Revenue		(16,042)	(14,561)	(14,031)	(12,145)	(12,079)	(15,397)	(17,930)	(17,898)	(15,716)	(14,625)	(14,807)	(15,534)	(180,764)
19															
20	Overhead Credit for Non-Retail Share		(8,073)	(7,328)	(7,061)	(6,112)	(6,078)	(7,748)	(9,023)	(9,007)	(7,909)	(7,360)	(7,451)	(7,817)	(90,969)
21	Non-Retail Load Share		97.933%	97.933%	97.933%	97.933%	97.933%	97.933%	97.933%	97.933%	97.933%	97.933%	97.933%	97.933%	
22	Non-Retail Overhead Credit		(7,906)	(7,176)	(6,915)	(5,986)	(5,953)	(7,588)	(8,837)	(8,821)	(7,746)	(7,208)	(7,297)	(7,656)	(89,089)
23	Total Revenue Credit for MVP Brookings		(23,949)	(21,737)	(20,945)	(18,130)	(18,031)	(22,985)	(26,767)	(26,718)	(23,461)	(21,833)	(22,104)	(23,190)	(269,853)
24															
25	MVP Ellendale - BS South	51.752%	(1,125,087)	(1,021,181)	(983,990)	(851,738)	(847,088)	(1,079,809)	(1,257,486)	(1,255,189)	(1,102,185)	(1,025,682)	(1,038,433)	(1,089,434)	(12,677,302)
26	Retail Load Share		2.018%	2.018%	2.018%	2.018%	2.018%	2.018%	2.018%	2.018%	2.018%	2.018%	2.018%	2.018%	
27	Retail Revenue		(22,704)	(20,607)	(19,857)	(17,188)	(17,094)	(21,791)	(25,376)	(25,330)	(22,242)	(20,698)	(20,956)	(21,985)	(255,828)
28															
29	Overhead Credit for Non-Retail Share		(11,701)	(10,620)	(10,233)	(8,858)	(8,810)	(11,230)	(13,078)	(13,054)	(11,463)	(10,667)	(10,800)	(11,330)	(131,844)
30	Non-Retail Load Share		97.982%	97.982%	97.982%	97.982%	97.982%	97.982%	97.982%	97.982%	97.982%	97.982%	97.982%	97.982%	
31	Non-Retail Overhead Credit		(11,465)	(10,406)	(10,027)	(8,679)	(8,632)	(11,003)	(12,814)	(12,791)	(11,231)	(10,452)	(10,582)	(11,101)	(129,183)
32															
33	Total Revenue Credit for MVP Ellendale		(34,169)	(31,013)	(29,884)	(25,867)	(25,726)	(32,794)	(38,190)	(38,120)	(33,473)	(31,150)	(31,537)	(33,086)	(385,011)
34															
35															
36	Retail Share of Schedule 26A Revenue		(123,021)	(111,660)	(107,593)	(93,132)	(92,624)	(118,070)	(137,498)	(137,247)	(120,517)	(112,152)	(113,546)	(119,123)	(1,386,185)
37															
38	North Dakota share	39.599%	(48,715)	(44,216)	(42,606)	(36,879)	(36,678)	(46,755)	(54,448)	(54,348)	(47,723)	(44,411)	(44,963)	(47,171)	(548,914)

Federal ADIT Proration

	A	B	C	D
1		January 2022 - December 2022 Recovery Period		
		All Projects' Revenue Requirements without ADIT Prorated	All Projects' Revenue Requirements with ADIT- Prorated	Difference due to Federal ADIT Proration (C-B)
2	Month			
3	Jan-22	\$193,644	\$194,065	\$421
4	Feb-22	\$193,644	\$194,065	\$421
5	Mar-22	\$195,528	\$195,948	\$421
6	Apr-22	\$195,792	\$196,213	\$421
7	May-22	\$196,116	\$196,537	\$421
8	Jun-22	\$196,116	\$196,537	\$421
9	Jul-22	\$196,902	\$197,322	\$421
10	Aug-22	\$197,219	\$197,640	\$421
11	Sep-22	\$197,494	\$197,915	\$421
12	Oct-22	\$197,706	\$198,127	\$421
13	Nov-22	\$197,791	\$198,211	\$421
14	Dec-22	\$199,011	\$199,432	\$421
15		\$2,356,964	\$2,362,012	\$5,048

16 **Revenue Requirement Adjustment Related to Federal ADIT Proration** **\$5,048**

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 2021 - December 2021				
	Month	Original ADIT Balance - All Projects with ADIT Pro-Rated	Updated ADIT Balance - All Projects without ADIT Pro-Rated	Difference due to Federal ADIT Proration (B - A)
13				
14	Dec-20	(\$3,993,424)	(\$3,941,512)	\$51,912
15	Jan-21	(\$4,135,265)	(\$4,080,675)	
16	Feb-21	(4,265,250)	(4,208,413)	
17	Mar-21	(4,382,110)	(4,324,269)	
18	Apr-21	(4,486,268)	(4,429,815)	
19	May-21	(4,582,251)	(4,522,214)	
20	Jun-21	(4,679,049)	(4,601,618)	
21	Jul-21	(4,757,101)	(4,668,273)	
22	Aug-21	(4,819,391)	(4,749,449)	
23	Sep-21	(4,866,466)	(4,809,584)	
24	Oct-21	(4,899,267)	(4,859,083)	
25	Nov-21	(4,916,382)	(4,898,738)	
26	Dec-21	(\$4,916,970)	(\$4,928,322)	-\$11,352
27	ADIT Simple Average	(\$4,455,197)	(\$4,434,917)	\$20,280

28	Rate Base Rev Req Gross Up Factor	9.30%
29	Total Company Revenue Requirement	\$1,885

30	ND Revenue Requirement Related to Federal ADIT Proration-Preservation	\$747
----	--	--------------

Attachment 37
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
Large General Service	(a)	N/A ¢/kWh	\$1,568 1,290
Controlled Service	(b)	0.067 59 ¢/kWh	N/A
Lighting	(c)	0.303 30 ¢/kWh	N/A
All Other Service		0.462 24 ¢/kWh	N/A
<p>(a) Rate schedules 10.04 Large General Service, 10.05 Large General Service – Time of Day, <u>10.06 Super Large General Service</u>, 14.02 Real Time Pricing Rider, and 14.03 Large General Service Rider, <u>and 14.13 Economic Development Rate Rider</u>.</p> <p>(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</p> <p>(c) Rate Schedules 11.03 Outdoor Lighting (Energy only) and 11.04 Outdoor Lighting, and 11.07 LED Street and Area Lighting</p>			

R
R
R
R

C
C
C

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
	Large General Service (a)	N/A	¢/kWh
Controlled Service (b)	0.067	¢/kWh	N/A
Lighting (c)	0.303	¢/kWh	N/A
All Other Service	0.462	¢/kWh	N/A

(a) Rate schedules 10.04 Large General Service, 10.05 Large General Service – Time of Day, 10.06 Super Large General Service, 14.02 Real Time Pricing Rider, 14.03 Large General Service Rider, and 14.13 Economic Development Rate 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

R
R
R
R

C
C
C

Changes to North Dakota’s Transmission Cost Recovery Rider

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

The changes below apply to bill usage on and after January 1, 2022 and are included in the Transmission Rider line item.

	Old rates		New rates		Impact of new rates ⁽¹⁾
Large General Service	\$1.290	per kW	\$1.568	per kW	\$118.22/month
Controlled Service	\$0.00059	per kWh	\$0.00067	per kWh	\$0.10/month
Lighting	\$0.00330	per kWh	\$0.00303	per kWh	(\$0.02)/month
Residential	\$0.00421	per kWh	\$0.00462	per kWh	\$0.41/month
All other service	\$0.00421	per kWh	\$0.00462	per kWh	\$0.55/month

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

For more information contact Customer Service at 800-257-4044 or visit otpc.com.