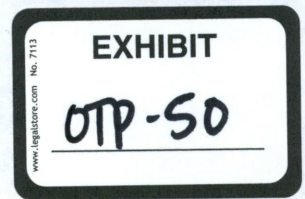


215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpc.com (web site)



February 15, 2017

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

**RE: Application for Authority to Increase Electric Rates in North Dakota
Case No. PU-17-398
Otter Tail Power Company Petition to Reduce Interim Rates to Conform
to the Tax Cut & Jobs Act**


Dear Mr. Nitschke:

Otter Tail Power Company (Otter Tail) respectfully submits the enclosed Petition to Reduce Interim Rates to Conform to the Tax Cut & Jobs Act. Through this filing Otter Tail seeks Commission approval to reduce interim rates in conformity with recent federal tax reforms. We have proposed that the revised, lower rates go into effect March 1, 2018. Although this filing is framed as a petition supplementing Otter Tail's previously filed Alternative Petition for Interim Rates, we have enclosed a fifty-dollar filing required by N.D.C.C. 49-05-05 should the Commission deem this filing as notice of changes in tariff rates under that statute.

In support of the present filing, Otter Tail provides the following *Revised* documents from its November 2, 2017 Initial Filing:

- Volume 1, Interim Supporting Schedules and Workpapers Part A through Part D
- Volume 1, Interim Tariff Sheets – Legislative
- Volume 1, Interim Tariff Sheets – Non-Legislative
- Volume 2a, Bryce C. Haugen Exhibit __ (BCH-1), Schedule 3, Page 1 and 2
- Volume 2a, Bryce C. Haugen Exhibit __ (BCH-1), Schedule 4, Page 1 and 2
- Volume 2a, Bryce C. Haugen Exhibit __ (BCH-1), Schedule 5, Page 1
- Volume 4a, Part C Interim Cost of Service Study.

An Equal Opportunity Employer

AN  OTTERTAIL COMPANY

Mr. Nitschke
February 15, 2018
Page 2

In addition, Otter Tail provides these additional documents:

- Volume 1, Interim Supporting Schedules and Workpapers, Part D.1, Page 1 of 1
 - This schedule compares the present interim rates that commenced January 1, 2018 and the proposed interim rates that OTP requests to implement March 1, 2018
- Bryce C. Haugen Exhibit __ (BCH-1), Schedule 6, Page 1 and 2
 - Originally established in Case No. PU-17-340, this schedule updates the Transmission Cost Recovery Rider rates that were implemented January 1, 2018 in that case with reduced rates Otter Tail requests to implement March 1, 2018.

An original and ten copies of this filing are being sent via mail. Please contact me at (218) 739-8956, or cstephenson@otpc.com should you have any questions with respect to this filing.

Very truly yours,

/S/ CARY STEPHENSON
Cary Stephenson
Associate General Counsel
Otter Tail Power Company

kaw
Enclosures
By electronic filing
c: Service List

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

In the Matter of the Application of
Otter Tail Power Company for
Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-17-398

**PETITION TO REDUCE INTERIM RATES
TO CONFORM TO THE TAX CUT & JOBS ACT**

A. Introduction

Otter Tail Power Company (Otter Tail or the Company) respectfully submits to the North Dakota Public Service Commission (Commission) this Petition to Reduce Interim Rates for its North Dakota retail electric customers. Otter Tail requests that the Commission approve the revised interim rate schedule, described herein, with an effective date of March 1, 2018.

This filing is made as a supplement to Otter Tail's Alternative Petition for Interim Rates in the above-entitled docket. To the extent that the Commission interprets Otter Tail's Petition to Reduce Interim Rates as notice of a change in tariff rates under N.D.C.C. § 49-05-05, Otter Tail respectfully requests that the Commission allow the requested changes to go into effect on less than thirty days' notice.

B. Background

On November 2, 2017 Otter Tail filed its Application for Authority to Increase Electric Rates (Case No. PU-17-398) seeking an annual increase of non-fuel base electric revenues of \$13,138,372 or 8.72 percent. Otter Tail included in its filing an Alternative Petition for Interim Rates, requesting that the Commission authorize, on an interim basis, rate relief of \$12,800,479 or 10.44 percent to be effective January 1, 2018.

On November 29, 2017, the Commission suspended the rates filed in Otter Tail Application. On December 20, 2017 the Commission issued an order approving the Company's

request for interim rates to increase annual revenue collection by \$12,800,479, effective for services rendered on after January 1, 2018.

On Dec. 22, 2017, President Trump signed the Tax Cut and Jobs Act (TCJA), which enacted significant changes to the Internal Revenue Code, including, among other things, a reduction in the maximum U.S. federal corporate income tax rate from 35 percent to 21 percent.¹

On January 10, 2018, the Commission ordered an investigation to determine the effect of the TCJA on investor-owned utilities serving customers in North Dakota². Among other things the Commission directed investor-owned utilities to file information regarding the impact of the TCJA with supporting calculations by February 15, 2018. Otter Tail has made a filing in Case No. PU-17-490 contemporaneously with this filing.

C. Description and Reasons for Reducing Interim Rates

The Company's evaluation of the impact of TCJA is on-going. There are numerous issues to assess. Although the Company's evaluation of the impacts of TCJA is not complete, there is sufficient information to support the reduction in interim rates requested in this filing. Federal corporate incomes taxes are a cost of service to our customers. The reduction of the federal corporate income tax rate from 35 percent to 21 percent reduces Otter Tail's cost of providing service. This results in a reduction in the gross-up factor Otter Tail uses to determine federal tax expense from 1.607756 to 1.322837.

Based on the foregoing, the Company seeks to reduce interim rates from 10.44% to 6.79%. If Otter Tail's request is approved, the revenue requirement for interim rates will be reduced from \$12.8 million to \$8.3 million, a total reduction in interim revenue of \$4.5 million. Otter Tail is also proposing to reduce rates in its Transmission, Renewable, and Environmental riders to further capture the impacts of the TCJA in those cost recovery mechanism. Adjusting those riders collectively reduces their revenue requirements by approximately \$1.7 million.

As noted in Otter Tail's comments in Case No. PU-17-490, Otter Tail believes its rate case, which uses a 2018 forecast test year, is the most efficient and accurate mechanism for identifying and passing on the beneficial impacts of the TCJA to our customers. Otter Tail

¹ In its final form, the TCJA recognizes the unique nature of public utilities and contains certain provisions specific to the industry, including the continuation of certain interest expense deductibility and relief from 100 percent expensing of capital investments.

² Public Service Commission Rate Impact & Accounting Treatment Investigation, Case No. PU 17-490.

anticipates filing supplemental direct testimony in this docket in March 2018, that will, among other things, address the impact of the TCJA on the Company's Application to increase electric rates in North Dakota.

D. Revised Interim Rate Schedules

The Company requests a reduction of interim rates from 10.44 percent to 6.79 percent. The following revised rate schedules are proposed to be revised on an interim basis on March 1, 2018:

| | | |
|---|--|-----------------------|
| <u>RESIDENTIAL AND WATER HEATING SERVICE</u> | | <u>Section</u> |
| Residential Service | | 9.01 |
| Residential Service (Controlled Demand) | | 9.02 |
| <u>FARM SERVICE</u> | | |
| Farm Service | | 9.03 |
| <u>GENERAL AND COMMERCIAL SERVICE</u> | | |
| Small General Service | | 10.01 |
| General Service (20 kW or Greater) | | 10.02 |
| Large General Service | | 10.03 |
| Commercial Service – Time of Use | | 10.04 |
| Large General Service- Time of Day- Experimental | | 10.05 |
| <u>INTERRUPTIBLE SERVICE</u> | | |
| Water Heating Control Rider | | 14.01 |
| Controlled Service - Interruptible Load CT Metering | | 14.04 |
| Controlled Service - Interruptible Load Self Contained Metering | | 14.05 |
| Controlled Service - Deferred Load | | 14.06 |
| Fixed Time of Delivery Service | | 14.07 |
| <u>PURCHASE POWER RATE SCHEDULES</u> | | |
| Small Power Producer Rider - Occasional Delivery | | 12.01 |
| Small Power Producer Rider - Time of Delivery | | 12.02 |
| Small Power Producer Rider - Dependable Service | | 12.03 |
| <u>OTHER ELECTRIC RATE SCHEDULES</u> | | |
| Standby Service | | 11.01 |
| Irrigation Service | | 11.02 |
| Outdoor Lighting – Energy Only | | 11.03 |
| Outdoor Lighting | | 11.04 |
| Municipal Pumping Service | | 11.05 |
| Fire Sirens | | 11.06 |

The following updated rate schedules are also proposed to be implemented on March 1, 2018, coinciding with interim rates, to reflect the impact of changes from the TCJA:

| <u>MANDATORY RIDERS</u> | <u>Section</u> |
|------------------------------------|-----------------------|
| Renewable Cost Recovery Rider | 13.04 |
| Transmission Cost Recovery Rider | 13.07 |
| Environmental Costs Recovery Rider | 13.08 |

The revised rate schedules containing lowered interim rates and lowered Mandatory Rider Rates are included along with this Petition (legislative and regular formats, respectively). No change has been made in the existing rate design. No change has been made to the base cost of energy set forth in the initial filing. The request decreases interim rates from \$12.8 million to \$8.3 million, on an annualized basis, in base rate revenue currently being recovered from each customer class; a reduction of \$4.5 million. The impact of the TCJA also reduces the Environmental, Renewable, and Transmission³ Cost Recovery Rider annualized revenue requirements from \$26.5 million to \$24.8 million; a reduction of approximately \$1.7 million to the revenue requirements used to establish current rates that were effective January 1, 2018. As a result, Otter Tail is requesting that the rates in these riders also be lowered to reduce collections in these riders associated with the TCJA. The updated lower rates are provided in the attached Mandatory Rider tariff sheets.

E. Supporting Schedules and Workpapers

Attached to this filing are Schedules and Workpapers offered in support of the Company's request to lower interim rates.

F. Interim Bills

The Company proposes to include an informational statement in customer bills beginning March 1, 2018 to communicate to customers that their bill reflects a reduction in Otter Tail's

³ Otter Tail expects further adjustments to the Transmission Rider for MISO and SPP related revenues and expense as impacts of the TCJA are incorporated into those Federal Energy Regulatory Commission (FERC) authorized rates. These adjustments will be incorporated into future Transmission Rider updates to true-up the impacts in the rider once approved by FERC and amounts become known.

interim rate request due to the Tax Cut and Jobs Act. The proposed informational statement provides the following:

We're passing savings from the reduced corporate tax rate to our North Dakota customers by lowering interim rates from 10.44% to 6.79% beginning March 1, 2018. The lower interim rates will remain in effect until the NDPSC determines our new final rates later this year.

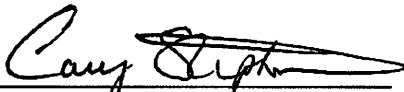
G. Conclusion

The Company respectfully requests that the Commission grant the Company permission to reduce interim rates as described herein.

Dated: February 15, 2018

Respectfully Submitted,

OTTER TAIL POWER COMPANY

By 

Cary Stephenson
Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, MN 56538
218-739-8956
cstephenson@otpc.com

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

Case No. PU-17-398

In the Matter of Otter Tail Power
Company's Application for Authority
To Increase Rates for Electric Service
In North Dakota

CERTIFICATE OF SERVICE

Kim A. Ward certifies that on the 15th day of February, 2018, she served a true and correct copy of the attached PETITION TO REDUCE INTERIM RATES TO CONFORM TO THE TAX CUT AND JOBS ACT by email addressed to the following individuals:

Cary Stephenson
Associate General Counsel
Otter Tail Power Company
P.O. Box 496
Fergus Falls, MN 56538-0496
cstephenson@otpc.com

Illona Jeffcoat-Sacco
General Counsel
ND Public Service Commission
600 East boulevard Avenue, Dept 408
Bismarck, ND 58505-0480
ilj@nd.gov

John Schuh
Special Assistant Attorney General
ND Public Service Commission
600 East boulevard Avenue, Dept 408
Bismarck, ND 58505-0480
jschuh@nd.gov

Darrell Nitschke
Executive Secretary
ND Public Service Commission
600 East boulevard Avenue, Dept 408
Bismarck, ND 58505-0480
dnitschk@nd.gov


Zachary Pelham
Advocacy Staff Counsel
Pearce-Durick PPLC
P.O. Box 400
Bismarck, ND 58502
zep@pearce-durick.com

Patrick Ward
Administrative Law Judge
Zuger Kirmis & Smit
P. O. Box 1695
Bismarck, ND 58501
pward@zkslaw.com

Rebecca L. Mann
Gunderson, Palmer, Nelson & Ashmore,
LLP
P.O. Box 8045
Rapid City, SD 57709-8045
rmann@gpna.com

Talbot J. Wiczorek
Gunderson, Palmer, Nelson & Ashmore,
LLP
P.O. Box 8045
Rapid City, SD 57709-8045
tjw@gpna.com

Stephen W. Chriss
Wal-Mart Legal Department
2001 SE 10th Street
Bentonville, AR 72715-5560
Stephen.chriss@wal-mart.com



Kim A. Ward

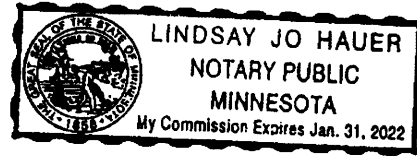
Richard Savelkoul
Martin & Squires, P.A.
332 Minnesota Street, Suite W2750
St. Paul, MN 55101
rsavelkoul@martinsquires.com

Kavita Maini
KM Energy Consulting, LLC
961 North Lost Woods Road
Oconomowoc, WI 53066
kmmaini@visi.com

Subscribed and sworn to before me this
15th day of February, 2018



Notary Public



**INTERIM RATE SCHEDULES
INDEX**

| PART A: Interim Rate Summary | | Schedule No. |
|--|--|---------------------|
| Revenues and Percent Increase | | 1 |
| North Dakota Policy Statements | | 2 |
| Definitions | | 3 |
| Summary of Revenue Requirements | | 4 |
| Statement of Operating Income | | 5 |
| Detailed Rate Base Components | | 6 |
| PART B: Comparison of Proposed Interim Test Year to 2018 Proposed Test Year | | Schedule No. |
| Detailed Rate Base Components | | 1 |
| Description of Adjustments to Rate Base | | 2 |
| Rate Base with Adjustments (Bridge Schedule) | | 3 |
| Statement of Operating Income | | 4 |
| Description of Adjustments to Operating Statement | | 5 |
| Statement of Operating Income with Adjustments (Bridge Schedule) | | 6 |
| Summary of Revenue Requirements | | 7 |
| PART C: Comparison of Proposed Interim Test Year to OTP's Most Recent General Rate Case | | Schedule No. |
| Detailed Rate Base Components | | 1 |
| Description of Changes to Rate Base | | 2 |
| Statement of Operating Income | | 3 |
| Description of Changes to Operating Statement | | 4 |
| Summary of Revenue Requirements | | 5 |
| Capital Structure and Rate of Return Calculations | | 6 |
| Description of Changes to Capital Structure and Rate of Return Calculations | | 7 |
| PART D: Summary | | Schedule No. |
| Summary of Revenue Requirements | | 1 |

**OTTER TAIL POWER COMPANY
INTERIM RATE INCREASE
REVENUES & PERCENT INCREASE**

**Case No. PU-17-398
PART A
Revised Schedule 1
Page 1 of 1**

Total Interim Retail Revenues

\$122,589,268

Interim Deficiency

\$8,319,184

Total Interim Revenue % Increase

6.79%

**OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE
Policy Statements**

**Case No. PU-17-398
PART A
Revised Schedule 2
Page 1 of 2**

**DESCRIPTION OF INTERIM RATE APPLICATION,
SUPPORTING SCHEDULES AND WORKPAPERS**

The supporting schedules include the following:

1) A schedule showing the interim rate of return calculation. These schedules show the capital structure and rate of return calculation approved by the Commission in the most recent general rate case; the capital structure and rate of return calculation proposed for interim rates; and a description and corresponding dollar amount of any changes between the two capital structures.

Note:

Part C, Schedule 7, contains this information.

2) A schedule showing the interim operating income statement. These schedules show the same operating income statement accounts as filed in the general rate case. Also, the schedules include the operating income statement approved by the Commission in the most recent general rate case, the operating income statement for the unadjusted projected fiscal year, and the operating income statement proposed for interim rates. A description of all changes and corresponding dollar amounts between each of the operating income statements should be provided. Workpapers should be provided which show how revenues, taxes, expenses, and other income statement components have been determined.

Notes:

Part C, Schedule 3, compares the operating income statement approved by the Commission in the most recent general rate case with the income statement for the proposed interim test year, including a description of all changes and corresponding dollar amounts.

OTP includes as Part B, Schedule 6, an operating statement bridge schedule for the proposed interim test year, as well as Part B, Schedule 4, a comparison of proposed interim rates to the statement of operating income for the proposed test year with the income statement for the proposed interim test year that includes a description of all known and measurable adjustments and corresponding dollar amounts.

Workpapers for the above Interim Rate Petition Schedules are located in Volume 4 of this filing.

**OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE
Policy Statements**

**Case No. PU-17-398
PART A
Revised Schedule 2
Page 2 of 2**

**DISCUSSION OF INTERIM RATE APPLICATION,
SUPPORTING SCHEDULES AND WORKPAPERS**

3) A schedule showing the interim proposed rate base. These schedules show the same rate base accounts as filed in the general rate case. These schedules include the average rate base approved by the Commission in the most recent general rate case; the average rate base with the unadjusted projected fiscal year, and the average rate base proposed for interim rates. A description of all changes and corresponding dollar amounts between each of the rate bases is provided. Workpapers are provided which show how the rate base components are determined.

Notes:

Part C, Schedule 1, compares the average rate base approved by the commission in the most recent general rate case with the average rate base proposed for interim rates, including a description of all changes and corresponding dollar amounts.

4) OTP includes as Part B, Schedule 1, comparison of the average rate base for the proposed test year with the average rate base for the proposed interim test year, as well as Part B, Schedule 3, a bridge schedule of the average rate base for the proposed test year with the average rate base for the proposed interim test year that includes a description of all known and measurable adjustments and corresponding dollar amounts.

Workpapers for the above Interim Rate Petition Schedules are located in Volume 1 of this filing. The Interim Jurisdictional Cost of Service Study is located in Volume 4A, Section C.

A schedule showing revenue deficiency calculations for each of the operating income statements and rate bases requested in (2) and (3) above. The revenue deficiency is calculated for the actual data and the interim data using the rate of return calculated in (1) above.

Notes:

Part C, Schedule 5, shows the revenue deficiency calculations for the most recent general rate case and for the proposed interim rates.

OTP includes as Part B, Schedule 7 of this volume, the revenue deficiency calculations for this general rate case filing and for the proposed interim rates.

**OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE**

**Case No. PU-17-398
PART A
Revised Schedule 3
Page 1 of 1**

DEFINITIONS

The following definitions are used in this filing:

Proposed Interim Test Year

The proposed interim test year information is for the calendar year ending December 31, 2018 and includes the effect of rate making adjustments due to H. R. 1, the Tax Cuts and Jobs Bill Act of 2017.

Present Interim Test Year

The present interim test year information is for the calendar year ending December 31, 2018 and includes the effect of rate making adjustments for interim rates included in Otter Tail Power's initial filing, November 2, 2017. The interim rates were approved on December 20, 2017 and went into effect January 1, 2018.

Proposed Test Year

The proposed test year information represents the test year financial information for the 2018 calendar year and includes the effects of rate making adjustments for final rates.

Most Recent General Rate Case

This information represents the financial data for the 12 months test year ending December 31, 2007, from Otter Tail Power Company's last North Dakota electric rate case (Case No. PU-08-862), as approved by the Commission.

Note on Rounding

The cost of service study on which these supporting schedules are based rounds numbers to the nearest whole dollar for display purposes. However, the subtotals and subsequent totals in the cost of service study may be based on actual values resulting in occasional differences in the totals displayed when compared to the sum of the line items. These supporting schedules were prepared using individual line items with subtotals and totals calculated on each schedule separately. This may result in occasional rounding differences of a few dollars when comparing between the subtotals and totals on the cost of service study to those on the supporting schedules.

**OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE
SUMMARY OF REVENUE REQUIREMENTS**

**Case No. PU-17-398
PART A
Revised Schedule 4
Page 1 of 1**

| <u>Line No.</u> | <u>Description</u> | <u>Proposed Interim Test Year</u> |
|---------------------|--|---------------------------------------|
| 1 | Average Rate Base | \$223,306,066 |
| 2 | Operating Income (Before AFUDC) | \$11,486,268 |
| 3 | Allowance for Funds Used During Construction (AFUDC) | \$0 |
| 4 | Total Available for Return (Line 2 + Line 3 + Rounding) | 11,486,268 |
| 5 | Overall Rate of Return (Line 4 / Line 1) | 5.14% |
| 6 | Required Rate of Return | 7.96% |
| 7 | Operating Income Requirement (Line 1 x Line 6) | \$17,775,163 |
| 8 | Income Deficiency (Line 7 - Line 4) | \$6,288,895 |
| 9 | Gross Revenue Conversion Factor | 1.32284 |
| 10 | Revenue Deficiency (Line 8 x Line 9) | \$8,319,184 |
| 11 | Retail Related Revenues Under Present Rates | \$122,589,268 |
| 12 | Percent Increase Needed in Overall Revenue (Line 10 / Line 11) | 6.79% |

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 INTERIM RATE SCHEDULE
 STATEMENT OF OPERATING INCOME

Case No. PU-17-398
 PART A
 Revised Schedule 5
 Page 1 of 1

| Line No. | Description | Proposed Interim Test Year |
|----------------------------------|---|-----------------------------------|
| <u>OPERATING REVENUES</u> | | |
| 1 | Retail | \$122,589,268 |
| 2 | Other Operating Revenue | <u>\$9,712,037</u> |
| 3 | TOTAL OPERATING REVENUE | \$132,301,305 |
| <u>OPERATING EXPENSES</u> | | |
| 5 | Production Expenses | \$58,417,943 |
| 6 | Transmission Expenses | 11,026,754 |
| 7 | Distribution Expenses | 7,680,921 |
| 8 | Customer Accounting Expenses | 6,091,579 |
| 9 | Customer Service & Information Expenses | 1,382,509 |
| 10 | Sales Expenses | 22,472 |
| 11 | Administration & General Expenses | 19,282,795 |
| 12 | Charitable Contributions | 0 |
| 13 | Depreciation Expense | 13,387,642 |
| 14 | General Taxes | <u>3,936,734</u> |
| 15 | TOTAL OPERATING EXPENSES | <u>\$121,229,349</u> |
| 16 | NET OPERATING INCOME BEFORE INCOME TAXES | \$11,071,955 |
| <u>INCOME TAX EXPENSE</u> | | |
| 18 | Investment Tax Credit | (\$1,183,682) |
| 19 | Deferred Income Taxes | (1,639,469) |
| 20 | Income Taxes | <u>2,408,839</u> |
| 21 | TOTAL INCOME TAX EXPENSE | <u>(\$414,312)</u> |
| 22 | NET OPERATING INCOME | \$11,486,268 |
| 23 | Allowance for Funds Used During Construction | <u>0</u> |
| 24 | TOTAL AVAILABLE FOR RETURN | <u><u>\$11,486,268</u></u> |

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 INTERIM RATE SCHEDULE
 DETAILED RATE BASE COMPONENTS

Case No. PU-17-398
 PART A
 Revised Schedule 6
 Page 1 of 1

| Line No. Description | Proposed Interim Test Year |
|--|-------------------------------|
| Utility Plant in Service: | |
| 1 Production | \$154,188,768 |
| 2 Transmission | 104,672,321 |
| 3 Distribution | 228,593,947 |
| 4 General | 36,081,097 |
| 5 Intangible | 5,727,482 |
| 6 TOTAL Utility Plant in Service | <u>\$529,263,615</u> |
| Accumulated Depreciation | |
| 8 Production | (\$98,334,309) |
| 9 Transmission | (45,254,234) |
| 10 Distribution | (98,387,399) |
| 11 General | (13,900,914) |
| 12 Intangible | (818,591) |
| 13 TOTAL Accumulated Depreciation | <u>(\$256,695,448)</u> |
| 14 NET Utility Plant in Service | |
| 15 Production | \$55,854,459 |
| 16 Transmission | 59,418,086 |
| 17 Distribution | 130,206,548 |
| 18 General | 22,180,183 |
| 19 Intangible | 4,908,890 |
| 20 NET Utility Plant in Service | <u>\$272,568,167</u> |
| 21 Utility Plant Held for Future Use | \$13,044 |
| 22 Construction Work in Progress | 271,747 |
| 23 Materials and Supplies | 7,946,645 |
| 24 Fuel Stocks | 4,430,805 |
| 25 Prepayments | (12,739,580) |
| 26 Customer Advances & Deposits | (353,143) |
| 27 Cash Working Capital | 3,548,095 |
| 28 Accumulated Deferred Income Taxes | (52,379,715) |
| 29 Total Average Rate Base | <u><u>\$223,306,066</u></u> |

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 COMPARISON OF PROPOSED INTERIM RATES TO
 PROPOSED TEST YEAR
 DETAILED RATE BASE COMPONENTS

Case No. PU-17-398
 PART B
 Revised Schedule 1
 Page 1 of 1

| Line No. | Description | (A) Proposed Test Year 2018 | (B) Proposed Interim Test Year | (C) Change (B) - (A) |
|----------------------------------|---------------------------------------|--------------------------------------|---|----------------------------|
| Utility Plant in Service: | | | | |
| 1 | Production | \$330,519,065 | \$154,188,768 | (\$176,330,297) |
| 2 | Transmission | 153,826,930 | 104,672,321 | (49,154,609) |
| 3 | Distribution | 228,593,947 | 228,593,947 | 0 |
| 4 | General | 36,403,979 | 36,081,097 | (322,882) |
| 5 | Intangible | 9,051,224 | 5,727,482 | (3,323,742) |
| 6 | TOTAL Utility Plant in Service | \$758,395,144 | \$529,263,615 | (\$229,131,529) |
| Accumulated Depreciation | | | | |
| 7 | Production | (\$142,605,272) | (\$98,334,309) | \$44,270,963 |
| 8 | Transmission | (48,351,302) | (45,254,234) | 3,097,068 |
| 9 | Distribution | (98,387,399) | (98,387,399) | 0 |
| 10 | General | (14,025,311) | (13,900,914) | 124,396 |
| 11 | Intangible | (1,383,019) | (818,591) | 564,428 |
| 12 | TOTAL Accumulated Depreciation | (\$304,752,302) | (\$256,695,448) | \$48,056,855 |
| 13 | NET Utility Plant in Service | | | |
| 14 | Production | \$187,913,793 | \$55,854,459 | (\$132,059,334) |
| 15 | Transmission | 105,475,628 | 59,418,086 | (46,057,541) |
| 16 | Distribution | 130,206,548 | 130,206,548 | 0 |
| 17 | General | 22,378,668 | 22,180,183 | (198,485) |
| 18 | Intangible | 7,668,205 | 4,908,890 | (2,759,314) |
| 19 | NET Utility Plant in Service | \$453,642,842 | \$272,568,167 | (\$181,074,675) |
| 20 | | | | |
| 21 | Utility Plant Held for Future Use | \$13,044 | \$13,044 | \$0 |
| 22 | Construction Work in Progress | 271,747 | 271,747 | 0 |
| 23 | Materials and Supplies | 8,275,549 | 7,946,645 | (328,904) |
| 24 | Fuel Stocks | 4,430,805 | 4,430,805 | 0 |
| 25 | Prepayments | (13,199,141) | (12,739,580) | 459,562 |
| 26 | Customer Advances & Deposits | (365,882) | (353,143) | 12,739 |
| 27 | Cash Working Capital | 3,602,273 | 3,548,095 | (54,178) |
| 28 | Accumulated Deferred Income Taxes | (102,479,471) | (52,379,715) | 50,099,756 |
| 29 | Total Average Rate Base | \$354,191,766 | \$223,306,066 | (\$130,885,700) |

**OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO
DETAILED RATE BASE COMPONENTS
DESCRIPTION OF ADJUSTMENTS**

**Case No. PU-17-398
PART B
Revised Schedule 2
Page 1 of 1**

There are a total of eight adjustments that convert the Rate Base of the Proposed Test Year to the Rate Base Proposed for Interim Rates. A bridge from the Proposed Test Year rate base to the Interim Rate Petition rate base is provided in Part B, Schedule 3.

Net Electric Plant in Service (4 related adjustments - Columns B, C, D, and E)

OTP's proposed 2018 Test year requests approval to include costs currently included in the Environmental Cost Recovery Rider (ECRR), Renewable Resource Adjustment Rider (RRAR), Transmission Cost Recovery Rider (TCRR) to be included in base rates at the conclusion of the general rate case. OTP also includes a plant normalization adjustment in its 2018 Test Year. An adjustment was made to the Interim Rate Application to remove the costs associated with these four items. The riders remain in effect during the interim period and the plant normalization is not considered like-kind.

Prorate ADIT (Column F)

To comply with IRS Regulation Section 1.167(l)-1(h)(6), a positive interim rate adjustment is made to include the difference between the required proration of Accumulated Deferred Income Taxes (ADIT) for the five future months (August to December) of the test year for purposes of computing final rates that are assumed to be effective August 1, 2018, and the proration of ADIT for the 12 future months (January to December) of the interim period for purposes of computing interim rates to be effective January 1, 2018.

Cash Working Capital (Column G)

A positive interim rate adjustment made to Materials and Supplies accounts for the removal of the RRAR, and their associated impacts on operation and maintenance expense, property tax expense, and income tax expense components of the Cash Working Capital calculation. The Cash Working Capital requirement is determined through the application of Lead-Lag study factors against applicable expense categories.

Changes in Allocations due to Interim Rate Adjustments (Column H)

OTP uses its jurisdictional cost of service study (JCOSS) model to calculate all operating statement and rate base schedules for both interim rates and the application for final rates. Certain allocation factors are developed within the JCOSS model. Any adjustment has the potential to change some of these allocation factors. This column shows the effect of the allocations on rate base components caused by adjustments.

Changes in Allocations due to Tax Cuts and Jobs Act (Column H.1)

Tax reform related adjustments due to H. R. 1, the Tax Cuts and Jobs Bill Act of 2017.

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 COMPARISON OF PROPOSED INTERIM RATES TO
 RATE BASE WITH ADJUSTMENTS (BRIDGE SCHEDULE)

Case No. PU-17-398
 PART B
 Revised Schedule 3
 Page 1 of 1

| Line No. | Description | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (H.1) | (I) |
|----------|-----------------------------------|-------------------------|-------------------------------------|---------------------------------|------------------------------------|--|-----------------------------|---|---|--------------------------------------|--------------------------------|
| | | Proposed Test Year 2018 | Environmental Rider Amounts Removec | Renewable Rider Amounts Removec | Transmission Rider Amounts Removec | Plant Normalization Intangible Plant Removec | Prorate ADIT Interim Adjust | Impact of Operating Statement Adjustments on Cash Working Capital | Changes in Allocations Due to Effect of Interim Adjustments | Changes Due to Tax Cuts and Jobs Act | Proposed Interim Test Year (1) |
| 1 | Electric Plant in Service * | \$758,395,144 | (\$73,882,796) | (\$102,447,501) | (\$49,154,609) | (\$3,243,463) | \$0 | \$0 | (\$403,161) | \$0 | \$529,263,614 |
| 2 | Less: Accumulated Depreciation* | (304,752,302) | 6,611,697 | 37,659,265 | 3,067,068 | 552,161 | 0 | 0 | \$136,663 | \$0 | (256,695,448) |
| 3 | Net Electric Plant in Service | \$453,642,842 | (\$67,271,099) | (\$64,788,235) | (\$46,057,541) | (\$2,691,302) | \$0 | \$0 | (\$266,498) | \$0 | \$272,568,167 |
| 4 | Other Rate Base Components: | | | | | | | | | | |
| 5 | Plant Held for Future Use | \$13,044 | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | \$13,044 |
| 6 | Construction Work in Progress | 271,747 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 271,747 |
| 7 | Materials and Supplies | 8,275,549 | 0 | (269,180) | 0 | 0 | 0 | 0 | (59,724) | 0 | 7,946,644 |
| 8 | Fuel Stocks | 4,430,805 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4,430,805 |
| 9 | Prepayments | (13,199,141) | 0 | 0 | 0 | 0 | 0 | 0 | 459,562 | 0 | (12,739,579) |
| 10 | Customer Advances | (365,882) | 0 | 0 | 0 | 0 | 0 | 0 | 12,739 | 0 | (353,143) |
| 11 | Cash Working Capital | 3,602,273 | 0 | 0 | 0 | 0 | 0 | (213,186) | 65,794 | 93,214 | 3,548,095 |
| 12 | Accumulated Deferred Income Taxes | (102,479,471) | 15,369,438 | 22,453,136 | 8,252,217 | 0 | 855,999 | 0 | 2,258,213 | 910,753 | (52,379,715) |
| 13 | | | | | | | | | | | |
| 14 | TOTAL | \$354,191,766 | (\$51,901,660) | (\$42,604,280) | (\$37,805,324) | (\$2,691,302) | \$855,999 | (\$213,186) | \$2,470,086 | \$1,003,967 | \$223,306,066 |

(1) Electric Utility - North Dakota Jurisdiction

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 COMPARISON OF PROPOSED INTERIM RATES TO
 STATEMENT OF OPERATING INCOME

Case No. PU-17-398
 PART B
 Revised Schedule 4
 Page 1 of 1

| Line No. | Description | (A) Proposed Test Year 2018 | (B) Proposed Interim Test Year | (C) Change (B) - (A) |
|----------------------------------|---|--------------------------------------|---|----------------------------|
| <u>OPERATING REVENUES</u> | | | | |
| 1 | Retail | \$148,071,948 | \$122,589,268 | (\$25,482,680) |
| 2 | Other Operating Revenue | 10,047,294 | 9,712,037 | (335,257) |
| 3 | TOTAL OPERATING REVENUE | \$158,119,242 | \$132,301,305 | (\$25,817,937) |
| <u>OPERATING EXPENSES</u> | | | | |
| 5 | Production Expenses | \$59,756,799 | \$58,417,943 | (\$1,338,856) |
| 6 | Transmission Expenses | 13,507,453 | 11,026,754 | (2,480,698) |
| 7 | Distribution Expenses | 7,680,921 | 7,680,921 | 0 |
| 8 | Customer Accounting Expenses | 6,091,579 | 6,091,579 | 0 |
| 9 | Customer Service & Information Expenses | 1,382,509 | 1,382,509 | 0 |
| 10 | Sales Expenses | 222,472 | 22,472 | (200,000) |
| 11 | Administration & General Expenses | 19,596,616 | 19,282,795 | (313,821) |
| 12 | Charitable Contributions | 0 | 0 | 0 |
| 13 | Depreciation Expense | 21,425,301 | 13,387,642 | (8,037,659) |
| 14 | General Taxes | 4,905,891 | 3,936,734 | (969,158) |
| 15 | TOTAL OPERATING EXPENSES | \$134,569,541 | \$121,229,349 | (\$13,340,192) |
| 16 | NET OPERATING INCOME BEFORE INCOME TAXES | \$23,549,700 | \$11,071,955 | (\$12,477,745) |
| <u>INCOME TAX EXPENSE</u> | | | | |
| 18 | Investment Tax Credit | (\$526,207) | (\$1,183,682) | (\$657,475) |
| 19 | Deferred Income Taxes | 1,317,384 | (1,639,469) | (2,956,853) |
| 20 | Income Taxes | 4,304,133 | 2,408,839 | (1,895,294) |
| 21 | TOTAL INCOME TAX EXPENSE | \$5,095,310 | (\$414,312) | (\$5,509,622) |
| 22 | NET OPERATING INCOME | \$18,454,391 | \$11,486,268 | (\$6,968,123) |
| 23 | Allowance for Funds Used During Construction | 0 | 0 | 0 |
| 24 | TOTAL AVAILABLE FOR RETURN | \$18,454,391 | \$11,486,268 | (\$6,968,123) |

Notes: Revenues reflect calendar month sales

**OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO
STATEMENT OF OPERATING INCOME
DESCRIPTION OF ADJUSTMENTS**

**Case No. PU-17-398
PART B
Revised Schedule 5
Page 1 of 1**

Part B, Schedule 6, contains a bridge schedule itemizing the changes from the Proposed Test Year operating income statement to the Interim Rate Petition operating income statement. Nine adjustments were made to bridge the Proposed Test Year operating income statement to the Proposed Interim operating income statement.

Adjustment to Remove Rider Costs (Columns B, C, D)

An adjustment was made to remove the costs currently tracked in the ECRR, RRA, and TCRR that OTP is proposing to move to base rates in the Proposed Test Year. Since the rider will remain in effect during the interim period, an adjustment is needed to remove the costs from interim rates to avoid double recovery.

Adjustment to remove Economic Development Costs (Column E)

An adjustment was made to remove the Economic Development costs included in the 2018 Test Year. These costs are not considered like-kind and not eligible for interim rate recovery.

Adjustment to remove Plant Normalization (Column F)

An adjustment was made to remove the expenses related to the Plant Normalization adjustment. These costs are not considered like-kind and not eligible for interim rate recovery.

Adjustment to remove PTC Normalization (Column G)

An adjustment was made to remove the PTC normalization. During the Interim Period, PTCs flow through the RRAR. This adjustment is needed to avoid double recovery.

Changes in Allocations due to Interim Rate Adjustments (Column H)

OTP uses its jurisdictional cost of service study (JCOSS) model to calculate all operating statement and rate base schedules for both interim rates and the application for final rates. Certain allocation factors are developed within the JCOSS model. Any adjustment has the potential to change some of these allocation factors. This column shows the effect of the allocations on the operating statement components caused by adjustments.

Changes in Allocations due to Tax Cuts and Jobs Act (Column H.1)

Tax reform related adjustments due to H. R. 1, the Tax Cuts and Jobs Bill Act of 2017.

OTTER TAIL POWER COMPANY
Electric Utility - Sale of Utility Dockets
COMPARISON OF PROPOSED INTERIM RATES TO
STATEMENT OF OPERATING INCOME WITH ADJUSTMENTS (BRIDGE SCHEDULE)

| Line No. | Description | (A) Proposed Test Year 2018 | (B) Environmental Rider Amounts Removed | (C) Renewable Rider Amounts Removed | (D) Transmission Rider Amounts Removed | (E) Economic Development Remove | (F) Plant Normalization Remove | (G) PTC Normalization Remove | (H) Changes In Allocations Due to Effect of Interim Adjustments | (H-1) Changes Due to Tax Cuts and Jobs Act | (I) Proposed Interim Test Year |
|----------|---|--------------------------------|--|--|---|------------------------------------|-----------------------------------|---------------------------------|--|---|-----------------------------------|
| 1 | Retail | \$148,071,948 | (\$7,581,594) | (\$8,871,617) | (\$7,391,542) | \$0 | \$0 | \$0 | \$0 | (\$1,637,927) | \$122,589,268 |
| 2 | Other Operating Revenue | 10,047,294 | 0 | 0 | 0 | 0 | 0 | 0 | (\$335,257) | 0 | 9,712,037 |
| 3 | TOTAL OPERATING REVENUE | \$158,119,242 | (\$7,581,594) | (\$8,871,617) | (\$7,391,542) | \$0 | \$0 | \$0 | (\$335,257) | (\$1,637,927) | \$132,301,305 |
| 4 | OPERATING EXPENSES | | | | | | | | | | |
| 5 | Production Expenses | \$59,756,799 | (\$230,588) | (1,106,288) | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | 58,417,943 |
| 6 | Transmission Expenses | 13,507,453 | 0 | 0 | (2,480,698) | 0 | 0 | 0 | 0 | 0 | 11,026,754 |
| 7 | Distribution Expenses | 7,660,921 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 7,660,921 |
| 8 | Customer Accounting Expenses | 6,091,579 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6,091,579 |
| 9 | Customer Service & Information Expenses | 1,382,509 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,382,509 |
| 10 | Sales Expenses | 222,472 | 0 | 0 | 0 | (\$200,000) | 0 | 0 | 0 | 0 | 22,472 |
| 11 | Administration & General Expenses | 19,596,616 | 0 | (210,167) | 0 | 0 | 0 | 0 | (103,654) | 0 | 19,282,795 |
| 12 | Charitable Contributions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Depreciation Expense | 21,425,301 | (\$2,377,681) | (\$4,240,716) | (693,135) | 0 | (\$702,750) | \$0 | (23,377) | 0 | 13,387,642 |
| 14 | General Taxes | 4,905,891 | 0 | (145,116) | (694,892) | 0 | 0 | 0 | (128,149) | 0 | 3,936,734 |
| 15 | TOTAL OPERATING EXPENSES | \$134,569,541 | (\$2,608,269) | (\$5,704,267) | (\$3,868,725) | (\$200,000) | (\$702,750) | \$0 | (\$256,180) | \$0 | \$121,229,349 |
| 16 | NET OPERATING INCOME BEFORE INCOME TAXES | \$23,549,700 | (\$4,973,325) | (\$3,167,349) | (\$3,522,817) | \$200,000 | \$702,750 | \$0 | (\$79,077) | (\$1,637,927) | \$11,071,956 |
| 17 | INCOME TAX EXPENSE | | | | | | | | | | |
| 18 | Investment/Production Tax Credit | (526,207) | \$0 | 486,358 | \$0 | \$0 | \$0 | (\$1,147,764) | \$3,931 | \$0 | (\$1,183,682) |
| 19 | Deferred Income Taxes | 1,317,384 | 0 | 0 | 0 | 0 | 0 | 0 | (352,223) | (2,604,630) | (1,639,469) |
| 20 | Income Taxes | 4,304,133 | (2,057,464) | (1,611,539) | (1,457,389) | \$2,740 | 290,728 | 474,830 | 2,090,485 | 192,316 | 2,408,839 |
| 21 | TOTAL INCOME TAX EXPENSE | \$5,095,310 | (\$2,057,464) | (\$1,025,181) | (\$1,457,389) | \$2,740 | \$290,728 | (\$672,934) | \$1,742,193 | (\$2,412,314) | (\$414,312) |
| 22 | NET OPERATING INCOME | \$18,454,391 | (\$2,915,860) | (\$2,142,169) | (\$2,065,428) | \$117,260 | \$412,022 | \$672,934 | (\$1,821,270) | \$774,387 | \$11,486,267 |
| 23 | Allowance for Funds Used During Construction | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | TOTAL AVAILABLE FOR RETURN | \$18,454,391 | (\$2,915,860) | (\$2,142,169) | (\$2,065,428) | \$117,260 | \$412,022 | \$672,934 | (\$1,821,270) | \$774,387 | \$11,486,267 |

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 COMPARISON OF PROPOSED INTERIM RATES TO
 SUMMARY OF REVENUE REQUIREMENTS

Case No. PU-17-398
 PART B
 Revised Schedule 7
 Page 1 of 1

| Line No. | Description | (A) Proposed Test Year 2018 | (B) Proposed Interim Test Year | Change (B) - (A) |
|----------|--|--------------------------------------|---|---------------------|
| 1 | Average Rate Base | \$354,191,766 | \$223,306,066 | (\$130,885,700) |
| 2 | Operating Income (Before AFUDC) | \$18,454,391 | \$11,486,268 | (\$6,968,123) |
| 3 | Allowance for Funds Used During Construction (AFUDC) | \$0 | \$0 | \$0 |
| 4 | Total Available for Return (Line 2 + Line 3 + Rounding) | \$18,454,391 | \$11,486,268 | (\$6,968,123) |
| 5 | Overall Rate of Return (Line 4 / Line 1) | 5.21% | 5.14% | -(0.07)% |
| 6 | Required Rate of Return | 7.97% | 7.96% | -0.01% |
| 7 | Operating Income Requirement (Line 1 x Line 6) | \$28,229,084 | \$17,775,163 | (\$10,453,921) |
| 8 | Income Deficiency (Line 7 - Line 4) | \$9,774,693 | \$6,288,895 | (\$3,485,798) |
| 9 | Gross Revenue Conversion Factor | 1.60776 | 1.32284 | 0 |
| 10 | Revenue Deficiency (Line 8 x Line 9) | \$15,715,320 | \$8,319,184 | (\$7,396,136) |
| 11 | Retail Related Revenues Under Present Rates | \$148,071,948 | \$122,589,268 | (\$25,482,680) |
| 12 | Percent Increase Needed in Overall Revenue (Line 10 / Line 11) | 10.61% | 6.79% | (3.83)% |

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 COMPARISON OF PROPOSED INTERIM RATES TO MOST RECENT GENERAL RATE CASE (2010)
 DETAILED RATE BASE COMPONENTS

Case No. PU-17-398
 PART C
 Revised Schedule 1
 Page 1 of 1

| Line No. | Description | (A) Results of Most Recent General Rate Case PU-08-862 | (B) Proposed Interim Test Year | (C) Change (B) - (A) |
|----------------------------------|---------------------------------------|--|---|----------------------------|
| Utility Plant in Service: | | | | |
| 1 | Production | \$154,602,785 | \$154,188,768 | (\$414,017) |
| 2 | Transmission | 83,873,091 | 104,672,321 | 20,799,230 |
| 3 | Distribution | 140,016,287 | 228,593,947 | 88,577,660 |
| 4 | General | 29,250,219 | 36,081,097 | 6,830,878 |
| 5 | Intangible | 1,677,249 | 5,727,482 | 4,050,233 |
| 6 | TOTAL Utility Plant in Service | \$409,419,630 | \$529,263,615 | \$119,843,984 |
| Accumulated Depreciation | | | | |
| 8 | Production | (\$86,542,454) | (\$98,334,309) | (\$11,791,855) |
| 9 | Transmission | (30,681,969) | (45,254,234) | (14,572,265) |
| 10 | Distribution | (59,273,728) | (98,387,399) | (39,113,671) |
| 11 | General | (11,712,740) | (13,900,914) | (2,188,174) |
| 12 | Intangible | (471,172) | (818,591) | (347,419) |
| 13 | TOTAL Accumulated Depreciation | (\$188,682,063) | (\$256,695,448) | (\$68,013,385) |
| 14 | NET Utility Plant in Service | | | |
| 15 | Production | \$68,060,331 | \$55,854,459 | (\$12,205,872) |
| 16 | Transmission | 53,191,122 | 59,418,086 | 6,226,964 |
| 17 | Distribution | 80,742,559 | 130,206,548 | 49,463,989 |
| 18 | General | 17,537,479 | 22,180,183 | 4,642,704 |
| 19 | Intangible | 1,206,077 | 4,908,890 | 3,702,813 |
| 20 | NET Utility Plant in Service | \$220,737,568 | \$272,568,167 | \$51,830,599 |
| 21 | | | | |
| 22 | Utility Plant Held for Future Use | 12,871 | 13,044 | 173 |
| 23 | Construction Work in Progress | 2,246,153 | 271,747 | (1,974,406) |
| 24 | Materials and Supplies | 5,722,628 | 7,946,645 | 2,224,017 |
| 25 | Fuel Stocks | 3,072,173 | 4,430,805 | 1,358,632 |
| 26 | Prepayments | (13,279,546) | (12,739,580) | 539,966 |
| 27 | Customer Advances & Deposits | (54,379) | (353,143) | (298,764) |
| 28 | Cash Working Capital | 1,485,939 | 3,548,095 | 2,062,156 |
| 29 | Unamortized Rate Case Expense | 0 | | |
| 30 | Accumulated Deferred Income Taxes | (32,611,608) | (52,379,715) | (19,768,107) |
| 31 | Total Average Rate Base | \$187,331,798 | \$223,306,066 | \$35,974,267 |

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO MOST RECENT GENERAL RATE CASE
DETAILED RATE BASE COMPONENTS
DESCRIPTION OF CHANGES

Case No. PU-17-398
PART C
Revised Schedule 2
Page 1 of 1

Total Average Rate Base proposed by OTP for interim rates increased by approximately \$36.0 million since the last approved electric rate case in Case No. PU-08-862. As noted earlier, interim rates exclude costs that are not of like-kind and rate base being recovered in OTP's riders during the interim period.

The increase in Average Rate Base is primarily related to the net effect of Utility Plant in Service and Accumulated Deferred Income Taxes. Gross Plant in Service increased by \$119.8 million and Reserve for Depreciation and Amortization increased by \$68.0 million. Total Net Plant in Service increased approximately \$51.8 million. In addition, Accumulated Deferred Income Taxes (ADIT) increased approximately \$19.8 million, which reduces rate base. These components account for approximately \$32.0 million of the \$36.0 million increase to rate base.

Distribution Plant now comprises 47.8 percent of Net Plant compared to 36.6 percent for OTP's Most Recent General Rate Case, increasing distribution plant by \$49.5 million, (capital additions of \$88.6 million offset by increases in depreciation reserves of \$39.1 million).

Transmission Plant increased by \$6.2 million (capital additions of \$20.8 million offset by increases in depreciation reserves of \$14.6 million). Transmission Plant comprises 21.8 percent of Net Plant as compared to 24.1 percent in OTP's Most Recent General Rate Case.

Net Production Plant in Service decreased \$12.2 million since OTP's Most Recent General Rate Case. Production Plant is now 20.5 percent of Plant in Service compared to 30.8 percent in that case.

As mentioned earlier, ADIT, a reduction to Average Rate Base, increased by \$19.8 million due to the impact of accelerated tax depreciation taken on OTP's capital expenditures. This increase is mainly caused by timing differences between book and tax depreciation on plant in service investment.

Cash Working Capital increased approximately \$2.0 million, Materials and Supplies comprised an increase of \$2.2 million, Fuel Inventory increased by \$1.4 million, and Customer Advances and Deposits increased by \$298,764 (reduction to rate base) since OTP's Most Recent General Rate Case.

The net effect of the \$51.8 million increase in Net Plant in Service, the \$19.8 million increase in Accumulated Deferred Income Taxes (a reduction to Average Rate Base), and other components shown in Part C, Schedule 1 account for the \$36.0 million increase in Total Average Rate Base for the interim rate period.

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 COMPARISON OF PROPOSED INTERIM RATES TO OTP'S MOST RECENT GENERAL RATE CASE
 STATEMENT OF OPERATING INCOME

Case No. PU-17-398
 PART C
 Revised Schedule 3
 Page 1 of 1

| Line No. | Description | (A) Results of Most Recent General Rate Case PU-08-862 | (B) Proposed Interim Test Year | (C) Change (B) - (A) |
|----------------------------------|---|--|--------------------------------------|----------------------------|
| <u>OPERATING REVENUES</u> | | | | |
| 1 | Retail | \$118,309,177 | \$122,589,268 | \$4,280,091 |
| 2 | Other Operating Revenue | 5,304,529 | 9,712,037 | 4,407,508 |
| 3 | TOTAL OPERATING REVENUE | \$123,613,706 | \$132,301,305 | \$8,687,599 |
| <u>OPERATING EXPENSES</u> | | | | |
| 5 | Production Expenses | \$62,213,340 | \$58,417,943 | (\$3,795,397) |
| 6 | Transmission Expenses | 4,467,061 | 11,026,754 | 6,559,693 |
| 7 | Distribution Expenses | 6,727,802 | 7,680,921 | 953,119 |
| 8 | Customer Accounting Expenses | 4,728,770 | 6,091,579 | 1,362,810 |
| 9 | Customer Service & Information Expenses | 1,027,290 | 1,382,509 | 355,220 |
| 10 | Sales Expenses | 251,476 | 22,472 | (229,005) |
| 11 | Administration & General Expenses | 13,526,788 | 19,282,795 | 5,756,007 |
| 12 | Charitable Contributions | 114,816 | 0 | (114,816) |
| 13 | Depreciation Expense | 10,442,094 | 13,387,642 | 2,945,548 |
| 14 | General Taxes | 3,964,363 | 3,936,734 | (27,629) |
| 15 | TOTAL OPERATING EXPENSES | \$107,463,801 | \$121,229,349 | \$13,765,550 |
| 16 | NET OPERATING INCOME BEFORE INCOME TAXES | \$16,149,905 | \$11,071,955 | (\$5,077,951) |
| <u>INCOME TAX EXPENSE</u> | | | | |
| 17 | Investment Tax Credit | (\$475,573) | (\$1,183,682) | (\$708,108) |
| 18 | Deferred Income Taxes | 216,508 | (1,639,469) | (1,855,978) |
| 19 | Income Taxes | 4,132,875 | 2,408,839 | (1,724,036) |
| 20 | TOTAL INCOME TAX EXPENSE | \$3,873,810 | (\$414,312) | (\$4,288,122) |
| 21 | NET OPERATING INCOME | \$12,276,096 | \$11,486,268 | (\$789,829) |
| 22 | Allowance for Funds Used During Construction | 0 | 0 | 0 |
| 23 | TOTAL AVAILABLE FOR RETURN | \$12,276,096 | \$11,486,268 | (\$789,829) |

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO MOST RECENT GENERAL RATE CASE
STATEMENT OF OPERATING INCOME
DESCRIPTION OF CHANGES

Case No. PU-17-398
PART C
Revised Schedule 4
Page 1 of 1

The Total Available for Return approved by the Commission in OTP's Most Recent General Rate Case compared to the Total Available for Return proposed in the Proposed Interim Test Year shows a decrease of \$0.8 million.

Major components of the change in utility available for return include the following:

Retail Electric Revenues increased by \$4.3 million or 3.6 percent.

Other Revenue increased by \$4.4 million from \$5.3 million in OTP's Most Recent General Rate Case to \$9.7 million in the Proposed Interim Test Year.

Fuel, Purchased Energy and Power Production costs decreased by approximately \$3.8 million compared to OTP's Most Recent General Rate Case.

Other Operating Expenses increased by approximately \$14.7 million. The changes that occurred in the various cost functions are: Transmission expense, an increase of \$6.6 million; Distribution expense, an increase of \$1.0 million; Customer Accounting, an increase of \$1.4 million; Customer Services combined with Information and Sales, an increase of \$0.1 million; and Administrative and General expense, an increase of \$5.8 million.

Depreciation expense increased by approximately \$2.9 million which represents a 28.2 percent increase over OTP's Most Recent General Rate Case.

Investment Tax Credits increased by \$0.7 million while Deferred Income Taxes decreased by \$1.8 million while Income Tax Expense decreased by \$1.7 million resulting in a decrease of approximately \$4.3 in Total Income Taxes since OTP's Most Recent General Rate Case.

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 COMPARISON OF PROPOSED INTERIM RATES TO MOST RECENT GENERAL RATE CASE
 SUMMARY OF REVENUE REQUIREMENTS

Case No. PU-17-398
 PART C
 Revised Schedule 5
 Page 1 of 1

| Line No. | Description | (A) Results of Most Recent General Rate Case PU-08-862 | (B) Proposed Interim Test Year | (C) Change (B) - (A) |
|----------|--|--|-----------------------------------|-------------------------|
| 1 | Average Rate Base | \$187,331,798 | \$223,306,066 | \$35,974,268 |
| 2 | Operating Income (Before AFUDC) | \$12,276,096 | \$11,486,268 | (\$789,828) |
| 3 | Allowance for Funds Used During Construction (AFUDC) | \$0 | \$0 | \$0 |
| 4 | Total Available for Return (Line 2 + Line 3 + Rounding) | \$12,276,096 | \$11,486,268 | (\$789,828) |
| 5 | Overall Rate of Return (Line 4 / Line 1) | 6.55% | 5.14% | (1.41)% |
| 6 | Required Rate of Return | 8.62% | 7.96% | (0.66)% |
| 7 | Operating Income Requirement (Line 1 x Line 6) | \$16,148,001 | \$17,775,163 | \$1,627,162 |
| 8 | Income Deficiency (Line 7 - Line 4) | \$3,871,905 | \$6,288,895 | \$2,416,990 |
| 9 | Gross Revenue Conversion Factor | 1.645413 | 1.322837 | 0 |
| 10 | Revenue Deficiency (Line 8 x Line 9) | \$6,370,885 | \$8,319,186 | \$1,948,300 |
| 11 | Retail Related Revenues Under Present Rates | \$118,309,177 | \$122,589,268 | \$4,280,091 |
| 12 | Percent Increase Needed in Overall Revenue (Line 10 / Line 11) | 5.38% | 6.79% | 1.40% |

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO OTP'S MOST RECENT GENERAL RATE CASE
CAPITAL STRUCTURE AND RATE OF RETURN CALCULATIONS

Case No. PU-17-398
PART C
Revised Schedule 6
Page 1 of 1

| Line No. | Capitalization: | (A) Amount | (B) % of Total Capitalization | (C) Cost of Capital | (D) Weighted Cost of Capital |
|---|-------------------------------|---------------|----------------------------------|------------------------|---------------------------------|
| I. Capital Structure and Rate of Return Calculation Approved by the Commission in the Most Recent General Rate Case (Case No. PU-08-862) | | | | | |
| 1 | Long-Term Debt | \$185,725,713 | 43.1% | 6.30% | 2.72% |
| 2 | Short-Term Debt | 0 | 0.0% | 0.00% | 0.00% |
| 3 | Long-Term and Short-Term Debt | \$185,725,713 | 43.1% | 6.30% | 2.72% |
| 4 | Preferred Stock | 15,500,000 | 3.597% | 4.75% | 0.17% |
| 5 | Net Common Equity | 229,633,133 | 53.3% | 10.75% | 5.73% |
| 6 | Total Equity | \$245,133,133 | 56.9% | | 5.90% |
| 7 | Total Capitalization | \$430,858,846 | 100.00% | | 8.62% |

| | | | | | |
|--|-------------------------------|-----------------|--------|--------|-------|
| II. Capital Structure and Rate of Return Calculation for Proposed Interim Rates | | | | | |
| 8 | Long-Term Debt | \$ 492,672,120 | 45.8% | 5.43% | 2.49% |
| 9 | Short-Term Debt | 18,025,434 | 1.7% | 3.83% | 0.06% |
| 10 | Long-Term and Short-Term Debt | \$510,697,554 | 47.5% | 5.37% | 2.55% |
| 11 | Preferred Stock | 0 | 0.0% | 0.00% | 0.00% |
| 12 | Net Common Equity | 564,383,902 | 52.5% | 10.30% | 5.41% |
| 13 | Total Equity | \$564,383,902 | 52.5% | | 5.41% |
| 14 | Total Capitalization | \$1,075,081,457 | 100.0% | | 7.96% |

III. Amount of Changes Between I and II

| Line No. | Capitalization: | Amount | | Change (C) = (B) - (A) |
|----------|-------------------------------|--------------------------------------|-----------------------|---------------------------|
| | | Most Recent General Rate Case Filing | Proposed Interim Rate | |
| | | (A) | (B) | |
| 15 | Long-Term Debt | \$185,725,713 | \$492,672,120 | \$306,946,407 |
| 16 | Short-Term Debt | 0 | 18,025,434 | 18,025,434 |
| 17 | Long-Term and Short-Term Debt | \$185,725,713 | \$510,697,554 | \$324,971,841 |
| 18 | Preferred Stock | 15,500,000 | 0 | (\$15,500,000) |
| 19 | Net Common Equity | 229,633,133 | 564,383,902 | 334,750,769 |
| 20 | Total Equity | \$245,133,133 | \$564,383,902 | \$319,250,769 |
| 21 | Total Capitalization | \$430,858,846 | \$1,075,081,457 | \$644,222,611 |

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
COMPARISON OF PROPOSED INTERIM RATES TO OTP'S MOST RECENT GENERAL RATE CASE
CAPITAL STRUCTURE AND RATE OF RETURN CALCULATIONS
DESCRIPTION OF CHANGES

Case No. PU-17-398
PART C
Revised Schedule 7
Page 1 of 1

Long-Term Debt in the Proposed Interim Test Year has increased by approximately \$306.9 million, compared to OTP's Most Recent General Rate Case. The increase in Long-Term Debt was necessary to support OTP's capital expenditure plan and maintain an appropriate balance of debt and equity and a balanced capital structure.

The capital structure for Interim Rates includes \$18.0 million of Short-Term Debt as compared to \$0.0 million in OTP's Most Recent General Rate Case.

Common Equity increased by approximately \$319.3 million primarily due to reinvestment of retained earnings and infusions of equity from Otter Tail Corporation to support OTP's capital expenditure plan and provide an appropriate balance of debt and equity and a balanced capital structure.

The overall cost of capital decreased from OTP's Most Recent General Rate Case. The decrease is equally driven by a decrease in the cost of debt and cost of equity. The 10.30 percent cost of common equity is lower than the 10.75 percent cost of common equity in OTP's Most Recent General Rate Case.

OTTER TAIL POWER COMPANY
 Electric Utility - State of North Dakota
 INTERIM RATE SCHEDULE
 SUMMARY COMPARISON OF OPERATING REVENUE
 UNDER PRESENT AND PROPOSED INTERIM RATES FOR THE TEST YEAR

Case No. PU-17-398
 PART D
 Page 1 of 1
 Revised Rate Schedule

| <u>Rate Schedule</u> | <u>Operating Revenue</u> | | | <u>Percent Change</u> |
|--|--------------------------|-------------------------|--------------------|-----------------------|
| | <u>Present Revenues</u> | <u>Proposed Interim</u> | <u>Increase</u> | |
| Residential Service | \$34,974,795 | \$37,348,263 | \$2,373,468 | 6.79% |
| Residential Demand Control | \$5,268,890 | \$5,626,448 | \$357,559 | 6.79% |
| Total Residential Class Revenue | \$40,243,684 | \$42,974,711 | \$2,731,027 | 6.79% |
| Farm Service | \$2,055,183 | \$2,194,653 | \$139,469 | 6.79% |
| General Service < 20 kW | \$7,963,977 | \$8,504,430 | \$540,453 | 6.79% |
| General Service >= 20 kW | \$24,590,129 | \$26,258,870 | \$1,668,741 | 6.79% |
| Commercial Time of Use | \$8,085 | \$8,633 | \$549 | |
| Total GS Class Revenue | \$32,562,190 | \$34,771,933 | \$2,209,743 | 6.79% |
| Large General Service | \$25,832,084 | \$27,585,107 | \$1,753,023 | 6.79% |
| Large General Service Time of Day | \$31,626 | \$33,772 | \$2,146 | 6.79% |
| Real Time Pricing | \$9,342,340 | \$9,976,332 | \$633,992 | 6.79% |
| Large General Service Rider | \$0 | \$0 | \$0 | 0.00% |
| Standby Service | \$12,048 | \$12,865 | \$818 | 6.79% |
| Total LGS Class Revenue | \$35,218,098 | \$37,608,078 | \$2,389,979 | 6.79% |
| Irrigation Services | \$51,061 | \$54,527 | \$3,465 | 6.79% |
| Outdoor Lighting - Energy Only | \$303,294 | \$323,876 | \$20,582 | 6.79% |
| Outdoor Lighting | \$2,209,569 | \$2,359,515 | \$149,946 | 6.79% |
| Total Lighting Class Revenue | \$2,512,863 | \$2,683,391 | \$170,529 | 6.79% |
| Municipal Pumping Service | \$979,983 | \$1,046,487 | \$66,504 | 6.79% |
| Civil Defense - Fire Sirens | \$3,241 | \$3,461 | \$220 | 6.79% |
| Total OPA Class Revenue | \$983,224 | \$1,049,948 | \$66,724 | 6.79% |
| Water Heating, Controlled | \$936,416 | \$999,963 | \$63,547 | 6.79% |
| Interruptible Load >= 80 kW | \$4,764,910 | \$5,088,267 | \$323,357 | 6.79% |
| Interruptible Load < 80 kW | \$1,998,017 | \$2,133,607 | \$135,590 | 6.79% |
| Total Interruptible Class Revenue | \$6,762,927 | \$7,221,874 | \$458,947 | 6.79% |
| Deferred Load Controlled Service | \$859,328 | \$917,644 | \$58,316 | 6.79% |
| Fix Time of Delivery Service | \$404,295 | \$431,731 | \$27,436 | 6.79% |
| Total Def. Ld. Class Revenue | \$1,263,623 | \$1,349,375 | \$85,752 | 6.79% |
| Total | \$122,589,268 | \$130,908,453 | \$8,319,184 | 6.79% |

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
INTERIM RATE SCHEDULE
SUMMARY COMPARISON OF OPERATING REVENUE
UNDER CURRENT INTERIM AND PROPOSED INTERIM RATES FOR THE TEST YEAR

Case No. PU-17-398
PART D.1
Page 1 of 1
Rate Schedule

| <u>Rate Schedule</u> | <u>Operating Revenue</u> | | | |
|--|--------------------------|-------------------------|---------------------|-----------------------|
| | <u>Present Interim</u> | <u>Proposed Interim</u> | <u>Increase</u> | <u>Percent Change</u> |
| Residential Service | \$38,626,780 | \$37,348,263 | -\$1,278,517 | -3.31% |
| Residential Demand Control | \$5,819,055 | \$5,626,448 | -\$192,607 | -3.31% |
| Total Residential Class Revenue | \$44,445,835 | \$42,974,711 | -\$1,471,124 | -3.31% |
| Farm Service | \$2,269,781 | \$2,194,653 | -\$75,128 | -3.31% |
| General Service < 20 kW | \$8,795,556 | \$8,504,430 | -\$291,126 | -3.31% |
| General Service >= 20 kW | \$27,157,772 | \$26,258,870 | -\$898,902 | -3.31% |
| Commercial Time of Use | \$8,929 | \$8,633 | -\$296 | |
| Total GS Class Revenue | \$35,962,257 | \$34,771,933 | -\$1,190,324 | -3.31% |
| Large General Service | \$28,529,409 | \$27,585,107 | -\$944,302 | -3.31% |
| Large General Service Time of Day | \$34,928 | \$33,772 | -\$1,156 | -3.31% |
| Real Time Pricing | \$10,317,845 | \$9,976,332 | -\$341,513 | -3.31% |
| Large General Service Rider | \$0 | \$0 | \$0 | 0.00% |
| Standby Service | \$13,306 | \$12,865 | -\$441 | -3.31% |
| Total LGS Class Revenue | \$38,895,488 | \$37,608,078 | -\$1,287,410 | -3.31% |
| Irrigation Services | \$56,393 | \$54,527 | -\$1,866 | -3.31% |
| Outdoor Lighting - Energy Only | \$334,963 | \$323,876 | -\$11,087 | -3.31% |
| Outdoor Lighting | \$2,440,287 | \$2,359,515 | -\$80,772 | -3.31% |
| Total Lighting Class Revenue | \$2,775,250 | \$2,683,391 | -\$91,859 | -3.31% |
| Municipal Pumping Service | \$1,082,311 | \$1,046,487 | -\$35,824 | -3.31% |
| Civil Defense - Fire Sirens | \$3,579 | \$3,461 | -\$118 | -3.30% |
| Total OPA Class Revenue | \$1,085,890 | \$1,049,948 | -\$35,942 | -3.31% |
| Water Heating, Controlled | \$1,034,194 | \$999,963 | -\$34,231 | -3.31% |
| Interruptible Load >= 80 kW | \$5,262,450 | \$5,088,267 | -\$174,183 | -3.31% |
| Interruptible Load < 80 kW | \$2,206,645 | \$2,133,607 | -\$73,038 | -3.31% |
| Total Interruptible Class Revenue | \$7,469,095 | \$7,221,874 | -\$247,221 | -3.31% |
| Deferred Load Controlled Service | \$949,057 | \$917,644 | -\$31,413 | -3.31% |
| Fix Time of Delivery Service | \$446,510 | \$431,731 | -\$14,779 | -3.31% |
| Total Def. Ld. Class Revenue | \$1,395,567 | \$1,349,375 | -\$46,192 | -3.31% |
| Total | \$135,389,749 | \$130,908,453 | -\$4,481,297 | -3.31% |



RESIDENTIAL SERVICE

| DESCRIPTION | RATE CODE |
|---------------------|--------------|
| Residential Service | 50-101 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to residential service as defined in the General Rules and Regulations.

RATE:

| RESIDENTIAL SERVICE | | | | |
|----------------------------|-----------------|-------|--------|-------|
| Customer Charge per Month: | \$8.00 | | | |
| Monthly Minimum Bill: | Customer Charge | | | |
| Energy Charge per kWh: | Summer | | Winter | |
| First 1,000: | 8.074 | ¢/kWh | 7.493 | ¢/kWh |
| Excess: | 8.074 | ¢/kWh | 6.803 | ¢/kWh |

R
R

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~
~~NR~~
~~N~~
~~N~~

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



RESIDENTIAL DEMAND CONTROL SERVICE
(Commonly identified as RDC)

| DESCRIPTION | RATE CODE |
|----------------------------|-----------|
| Residential Demand Control | 50-241 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to Residential Customers with approved demand control systems.

RATE:

| RESIDENTIAL DEMAND CONTROL SERVICE | | |
|------------------------------------|--------------------------|-------------|
| Customer Charge per Month: | \$18.38 | |
| Monthly Minimum Bill: | Customer + Demand Charge | |
| Energy Charge per kWh: | Summer | Winter |
| | 4.257 ¢/kWh | 4.301 ¢/kWh |
| Demand Charge per kW: | Summer | Winter |
| | \$6.52 /kW | \$2.63 /kW |

R

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

N
NR
N
N

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



Fergus Falls, Minnesota

FARM SERVICE

| DESCRIPTION | RATE CODE |
|--------------|-----------|
| Farm Service | 50-361 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to general Farm and home use. The Customer may elect to have the following service offerings in the farm home (for residential uses); Residential Service (Section 9.01) or Residential Demand Control Service Schedule (Section 9.02) if all the requirements specified for that schedule are satisfied.

RATE:

| FARM SERVICE | | | |
|----------------------------------|------------------------------|-------------|--|
| Customer Charge per Month: | \$12.00 | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | |
| Facilities Charge per Month: | | | |
| Single Phase | \$0.00 | | |
| Three Phase: Overhead <=25kVA | \$3.37 | | |
| Three Phase: Overhead > 25kVA | \$3.93 | | |
| Three Phase: Underground <=25kVA | \$9.39 | | |
| Three Phase: Underground > 25kVA | \$10.78 | | |
| Energy Charge per kWh: | Summer | Winter | |
| First 1600 | 7.272 ¢/kWh | 6.601 ¢/kWh | |
| Excess | 6.125 ¢/kWh | 5.555 ¢/kWh | |

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota.

Case No. PU-17-398

Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs

~~R~~
~~R~~

~~N~~
~~NR~~
~~N~~
~~N~~



SMALL GENERAL SERVICE
 Under 20 kW

| DESCRIPTION | RATE CODE |
|---|--------------|
| Metered Service under 20 kW – Secondary Service | 50-404 |
| Metered Service under 20 kW – Primary Service | 50-405 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to three-phase Residential Customers, and both single and three-phase nonresidential Customers. This schedule is not applicable for energy for resale, nor for municipal outdoor lighting. Emergency and supplementary/standby service will be supplied only as allowed by law.

RATE:

| SECONDARY SERVICE | | | PRIMARY SERVICE | |
|----------------------------|-----------------|-------------|-----------------|-------------|
| Customer Charge per Month: | \$13.00 | | \$13.00 | |
| Monthly Minimum Bill: | Customer Charge | | Customer Charge | |
| Energy Charge per kWh: | Summer | Winter | Summer | Winter |
| | 8.139 ¢/kWh | 7.392 ¢/kWh | 8.101 ¢/kWh | 7.355 ¢/kWh |

R

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

N
NR
N
N

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
 Winter: October 1 through May 31.

NORTH DAKOTA PUBLIC
 SERVICE COMMISSION
 Dakota.
 Case No. PU-17-398
 Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
 Vice President, Regulatory Affairs



GENERAL SERVICE
20 kW or Greater

| DESCRIPTION | RATE CODE |
|-------------------------------------|--------------|
| General Service – Secondary Service | 50-401 |
| General Service – Primary Service | 50-403 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to three-phase Residential Customers, and both single and three-phase nonresidential Customers, with a measured demand of at least 20 kW within the most recent 12 months. This schedule is not applicable for energy for resale, nor for municipal outdoor lighting. Emergency and supplementary/standby service will be supplied only as allowed by law.

RATE:

| | SECONDARY SERVICE | PRIMARY SERVICE | | | | | | | | |
|------------------------------|--|------------------------------|--------|-------------|-------------|--|--------|--------|-------------|-------------|
| Customer Charge per Month: | \$12.00 | \$12.00 | | | | | | | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | Customer + Facilities Charge | | | | | | | | |
| Facilities Charge per Month: | \$0.52/kW | \$0.38/kW | | | | | | | | |
| Energy Charge per kWh: | <table style="width: 100%; border-collapse: collapse;"> <tr> <td style="text-align: center; width: 50%;">Summer</td> <td style="text-align: center; width: 50%;">Winter</td> </tr> <tr> <td style="text-align: center;">7.843 ¢/kWh</td> <td style="text-align: center;">7.122 ¢/kWh</td> </tr> </table> | Summer | Winter | 7.843 ¢/kWh | 7.122 ¢/kWh | <table style="width: 100%; border-collapse: collapse;"> <tr> <td style="text-align: center; width: 50%;">Summer</td> <td style="text-align: center; width: 50%;">Winter</td> </tr> <tr> <td style="text-align: center;">7.806 ¢/kWh</td> <td style="text-align: center;">7.086 ¢/kWh</td> </tr> </table> | Summer | Winter | 7.806 ¢/kWh | 7.086 ¢/kWh |
| Summer | Winter | | | | | | | | | |
| 7.843 ¢/kWh | 7.122 ¢/kWh | | | | | | | | | |
| Summer | Winter | | | | | | | | | |
| 7.806 ¢/kWh | 7.086 ¢/kWh | | | | | | | | | |

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs

R
N
NR
N



INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~
~~NR~~
~~N~~
~~N~~

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the greater of 80 kW or the maximum 15 consecutive minute period measured by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be based on the largest of the most recent 12 monthly measured demands.

DETERMINATION OF BILLING DEMAND: The billing demand shall be the greater of 80 kW or the maximum kW as measured by a suitable demand meter for any period of 15 consecutive minutes during the month for which the bill is rendered adjusted for Excess Reactive Demand.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: The billing demand shall be increased by one kW for each whole 10 kvar of measured reactive demand in excess of 50% of the measured demand in kW.



Fergus Falls, Minnesota

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

N
NR
N
N

TERMS AND CONDITIONS: A Customer with a billing demand of less than 20 kW for 12 consecutive months will have the option to take service under the Small General Service schedule (Section 10.01).

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

DEFINITION OF DECLARED, INTERMEDIATE AND OFF-PEAK PERIODS BY SEASON:

WINTER SEASON - OCTOBER 1 THROUGH MAY 31 BILLINGS

Declared-Peak: Hours declared (see Declared Peak Notification)

Intermediate: All hours other than declared-peak and off-peak

Off-Peak: For all kW and kWh used Weekdays or Saturdays from 10:00 p.m. to 6:00 a.m., all day Sunday

SUMMER SEASON - JUNE 1 THROUGH SEPTEMBER 30 BILLINGS

Declared-Peak: Hours declared (see Declared-Peak Notification)

Intermediate: All hours other than declared-peak and off-peak

Off-Peak: For all kW and kWh used Weekdays or Saturdays from 10:00 p.m. to 6:00 a.m., all day Sunday

DECLARED-PEAK NOTIFICATION: The Company shall make available to Customers, no later than 4:00 p.m. (Central Time) of the preceding day, "declared-peak" designations for the next business day. Except for unusual periods, the Company will make "declared-peak" designations for Saturday through Monday available to Customers on the previous Friday. More than one-day-ahead "declared-peak" designations may also be used for the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



Fergus Falls, Minnesota

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~
~~NR~~
~~N~~
~~N~~

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the maximum demand in kW registered over any one-hour period by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be the greater of 80 kW or the largest of the most recent 12 monthly measured demands.

METERED AND ESTABLISHED DEMAND: The Metered Demand shall be the maximum kW registered over any period of one hour during the month for which the bill is rendered. The Established Demand shall be the Metered Demand adjusted for excess reactive demand.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: The Metered Demand shall be increased by one kW for each whole ten kVar of reactive demand in excess of 50% of the measured demand in kW.

DEFINITION OF ON-PEAK, SHOULDER AND OFF-PEAK PERIODS BY SEASON:

WINTER SEASON - OCTOBER 1 THROUGH MAY 31 BILLINGS

On-Peak: For all kW and kWh used Monday through Friday between 7:00 a.m. and 12:00 noon, and between 5:00 p.m. and 9:00 p.m.

Shoulder: For all kW and kWh used Monday through Friday hours 6:00 a.m. to 7:00 a.m., hours 12:00 noon to 5:00 p.m. and hours 9:00 p.m. to 10:00 p.m. and, Saturday through Sunday 6:00 p.m. to 10:00 p.m.

Off-Peak: For all other kW and kWh used Monday through Friday hours 10:00 p.m. to 9:00 a.m. and, Saturday and Sunday 10:00 p.m. through 9:00 a.m.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



Fergus Falls, Minnesota

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~
~~NR~~
~~N~~
~~N~~

MANDATORY AND VOLUNTARY RIDERS: The amount of bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DETERMINATION OF METERED DEMAND: Metered Demand shall be based on the maximum kW registered over any period of one hour during the month in which the bill is rendered.

CONTRACT PERIOD: Standby Service is applicable only by signed agreement, setting forth the location and conditions applicable to the electric service, such as the Contracted Backup Demand, type of standby service (Option A or B), excess facilities required for service and other applicable terms and conditions, and providing for an initial minimum contract period of one year, unless otherwise authorized by the Company.

TERMS AND CONDITIONS:

1. The Company's meter will measure power and energy from the Company to the Customer. Any flow of power and energy from the Customer to the Company will be separately metered under one of the Company's Purchase Power Rate Schedules, or by contract.
2. Option A - Firm Standby: Exclusive of any scheduled maintenance hours, if the number of hours on which Backup Service is supplied exceeds 120 On-Peak hours in the Summer season and 240 On-Peak hours in the Winter season, the Customer may be required to take service under a standard, non-standby, rate schedule.
3. Option B – Non-Firm Standby: Backup Service is not available during any On-peak season. This service is only available in the Summer Shoulder and Summer Off-Peak and Winter Shoulder and Winter Off-Peak hours on a non-firm basis. The Company makes no guarantee that this service will be available; however, the Company will make reasonable efforts to provide Backup Service under Option B whenever possible.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



| OPTION 2 | | | | |
|-------------------------------------|------------------------------|-------|--------|-------|
| Customer Charge per Month: | \$5.00 | | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | | |
| Facilities Charge per Month: | Customer-Specific see Tariff | | | |
| Energy Charge per kWh: | Summer | | Winter | |
| Declared-Peak | 14.080 | ¢/kWh | 8.390 | ¢/kWh |
| Intermediate | 5.071 | ¢/kWh | 4.741 | ¢/kWh |
| Off-Peak | 2.272 | ¢/kWh | 2.242 | ¢/kWh |

R
R
R

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

N
NR
N
N

FACILITIES CHARGE: Customers served under this rate shall pay an annual fixed charge equal to 18% of the investment of the Company in the extension of lines, including any rebuilding or cost of capacity increase in lines or apparatus necessary because of the irrigation pumping load.

Alternatively, Customers may prepay the installation and cost of the equipment and shall pay an annual fixed charge equal to 3.5% of the investment of the Company, in lieu of the 18% annual fixed charge.

In either option, equipment remains the property of the Company. This charge shall be reviewed if additional Customers are connected to the extension within five years. The annual fixed charge will be billed in seven equal monthly installments May through November of each year.

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



RATE – NON-METERED:

**SIGN LIGHTING/OUTDOOR LIGHTING
NON-METERED RATE**
Monthly charge = Connected kW x \$22.58, where Connected kW is the
rated power of the lighting fixture (including ballast).

R

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~

~~NR~~

~~N~~

~~N~~

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

SERVICE CONDITIONS: Company-owned lights shall not be attached to Customer-owned property.

The Company shall have the right to periodically review the Customer's lighting equipment to verify that the rated power (kW) of the non-metered fixtures is consistent with the Company's records.



| FLOODLIGHTING | | |
|---------------|------------------------|----------------|
| Fixture | Unit Type | Monthly Charge |
| 400 MV-Flood | Mercury Vapor | \$16.78 |
| 400 MA-Flood | Metal Additive Mercury | 17.91 |
| 400 HPS-Flood | High Pressure Sodium | 18.32 |
| 1000 MV-Flood | Mercury Vapor | 29.08 |
| 1000 MA-Flood | Metal Additive Mercury | 30.74 |

R
R
R
R
R

Due to the U.S. Government Energy Act of 2005, after July 1, 2008, the Company will no longer install Mercury Vapor fixtures for new installations.

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~
~~NR~~
~~N~~
~~N~~

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

SEASONAL CUSTOMERS: Seasonal Customers will be billed at the same rate as year-around Customers, except as follows:

A fixed charge of \$10.80 will be billed each seasonal Customer once per season per fixture in addition to the rate provided above. The fixed charge will be included in the first bill rendered for each season.

Each Customer will be billed for the number of months each season that the outdoor lighting fixture is in use, but not less than a minimum of four months, plus the seasonal fixed charge.

UNDERGROUND SERVICE: If a Customer requests underground service to any outdoor lighting unit or sign, the Company will supply a span of up to 200 feet of wire and add an additional \$1.96 to the monthly rate specified above. If overhead service is not available, there is no additional charge. **There is no additional charge for the MV-6PT, HPS-9PT, or the HPS-14PT fixtures.**

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



| PRIMARY SERVICE | | |
|------------------------------|------------------------------|-------------|
| Customer Charge per Month: | \$4.00 | |
| Monthly Minimum Bill: | Customer + Facilities Charge | |
| Facilities Charge per Month: | \$2.68 | |
| Energy Charge per kWh: | Summer | Winter |
| | 6.124 ¢/kWh | 5.552 ¢/kWh |

R

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

N
NR
N
N

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
 Winter: October 1 through May 31.



Fergus Falls, Minnesota

CIVIL DEFENSE - FIRE SIRENS

| DESCRIPTION | RATE CODE |
|-----------------------------|-----------|
| Civil Defense – Fire Sirens | 50-843 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to separately served civil defense and municipal fire sirens.

RATE:

| CIVIL DEFENSE - FIRE SIRENS | |
|------------------------------|-----------------|
| Customer Charge per Month: | \$1.00 |
| Monthly Minimum Bill: | Customer Charge |
| Facilities Charge per Month: | \$0.00 |
| Charge per HP: | 53.193¢/HP |

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~
~~NR~~
~~N~~
~~N~~

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

OTHER SIREN SERVICE: If the siren is served through a tariff applicable to the City Hall, fire hall or other tariffed service, no separate billing shall be made for the siren.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



**SMALL POWER PRODUCER RIDER
OCCASIONAL DELIVERY ENERGY SERVICE**
(Commonly identified as Net Energy Billing)

Base Avoided Costs Code 50-9020
Base Avoided Costs plus Renewable Energy Credit Code 50-9021

AVAILABILITY: Available to any qualifying facility not exceeding 100 kW of generating capacity.

METERING CHARGE: \$1.40 per month

PAYMENT SCHEDULES: Base Avoided Costs: 2.392¢ per kWh

R

Base Avoided Costs plus Renewable Energy Credit: 2.452¢ per kWh

R

SPECIAL CONDITIONS OF SERVICE: The Customer will be required to sign a contract, agreeing to terms and conditions specified for small power producers. The minimum term of the contract is 12 months.

RULES AND REGULATIONS: Terms and conditions of this rider and the General Rules and Regulations govern service of this schedule.

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the Metering Charge.

R

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

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-~~18-02217-398~~
Approved by order dated ~~January 31, 2018~~

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



**SMALL POWER PRODUCER RIDER
TIME OF DELIVERY ENERGY SERVICE**

| | |
|--|--------------|
| Base Avoided On-Peak Costs | Code 50-9030 |
| Base Avoided Off-Peak Costs | Code 50-9031 |
| Base Avoided On-Peak Costs Plus Renewable Energy Credit | Code 50-9032 |
| Base Avoided Off-Peak Costs Plus Renewable Energy Credit | Code 50-9033 |

AVAILABILITY: This rider is available to any Qualifying Facility not exceeding 100 kW of generating capacity. This rider is available to any Qualifying Facility exceeding 100 kW upon the approval of the Company. The Company reserves the right to require the Qualifying Facility to sign an Agreement.

METERING CHARGE: \$12.85 per month

PAYMENT SCHEDULE: ENERGY:

| | | | |
|--|------------------------|-------------------------|----------|
| Base Avoided Costs | <u>On-Peak 50-9030</u> | <u>Off-Peak 50-9031</u> | |
| Summer | 2.826¢ per kWh | 1.779¢ per kWh | R |
| Winter | 2.919¢ per kWh | 2.004¢ per kWh | R |
| | | | |
| Base Avoided Costs Plus Renewable Energy Credit | <u>On-Peak 50-9032</u> | <u>Off-Peak 50-9033</u> | |
| Summer | 2.886¢ per kWh | 1.839¢ per kWh | R |
| Winter | 2.979¢ per kWh | 2.064¢ per kWh | R |

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the Metering Charge. **R**

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



**SMALL POWER PRODUCER RIDER
DEPENDABLE SERVICE**

| | |
|--|--------------|
| Base Avoided On-Peak Costs | Code 50-9040 |
| Base Avoided Off-Peak Costs | Code 50-9041 |
| Base Avoided On-Peak Costs Plus Renewable Energy Credit | Code 50-9042 |
| Base Avoided Off-Peak Costs Plus Renewable Energy Credit | Code 50-9043 |

AVAILABILITY: Available to any qualifying facility which is capable of delivering power and energy to the Company on a dependable basis.

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the Metering Charge.

R

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

METERING CHARGE: \$12.85 per month

PAYMENT SCHEDULE:

ENERGY:

| | | | |
|--|------------------------|-------------------------|----------|
| Base Avoided Costs | <u>On-Peak 50-9040</u> | <u>Off-Peak 50-9041</u> | |
| Summer | 2.826¢ per kWh | 1.779¢ per kWh | R |
| Winter | 2.919¢ per kWh | 2.004¢ per kWh | R |
| | | | |
| Base Avoided Costs Plus Renewable Energy Credit | <u>On-Peak 50-9042</u> | <u>Off-Peak 50-9043</u> | |
| Summer | 2.886¢ per kWh | 1.839¢ per kWh | R |
| Winter | 2.979¢ per kWh | 2.064¢ per kWh | R |

CAPACITY:

| | | | |
|-------------|---------------|---------------|----------|
| Contract | Monthly \$/kW | Monthly \$/kW | |
| <u>Term</u> | Net Capacity | Levelized | |
| 60 mos. | <u>Rate</u> | <u>Rate</u> | R |
| | \$5.86 | \$2.34 | |

NORTH DAKOTA PUBLIC
 SERVICE COMMISSION
 Case No. PU-~~18-02217-398~~
 Approved by order dated ~~January 31, 2018~~

EFFECTIVE with bills rendered on
 and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
 Vice President, Regulatory Affairs



Fergus Falls, Minnesota

RENEWABLE RESOURCE COST RECOVERY RIDER

| DESCRIPTION | RATE CODE |
|--------------|-----------|
| All Services | 50-520 |

RULES AND REGULATIONS: Terms and conditions of this rider and the General Rules and Regulations govern use of this schedule.

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company’s Retail Rate Schedules in Section 9, 10, 11, 12, 13.05, and 14, except for Section 14.09 (*TailWinds*) and Section 14.11 (Released Energy Access Program Rider).

COST RECOVERY CHARGE: There shall be included on each North Dakota customer’s monthly bill a Renewable Resource Cost Recovery (“RRC”) charge based on the applicable cost recovery factor multiplied by the Customer’s monthly bill. The Customer’s monthly bill shall be based on all applicable charges and credits under the Company’s retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Section 14.09 (*TailWinds*) and Section 14.11 (Released Energy Access Program Rider). The RRC charge will not apply to any Mandatory Riders or sales tax and any local assessments as provided in the General Rules and Regulations for the Company’s electric service, except Section 13.05 (Economic Development Cost Removal Rider). The following charges are applicable in addition to all charges for service being taken under the Company’s standard rate schedules and will be included in the Energy and Renewable Adjustment line item on the customer’s bill.

Renewable Resource Cost Recovery Factor - ~~7.7567~~.493 percent

R

DETERMINATION OF RENEWABLE RESOURCE COST CHARGE: The RRC Factor shall be determined by dividing the forecasted *balance of the RRC Tracker account* by the *forecasted retail revenues subject to the RRC Factor*. The forecasted RRC Tracker balance and retail revenues shall be based on the forecast for the appropriate 12 month period (or such other period as may be approved by the Commission). The RRC Factor shall be rounded to the nearest 0.001 percent.



TRANSMISSION COST RECOVERY RIDER

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

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

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

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

RATE:

| TRANSMISSION COST RECOVERY | | | |
|----------------------------|-----|-------------------|----------------------|
| Energy Charge per kWh: | | kWh | kW |
| Large General Service | (a) | N/A | \$ <u>1.7391.632</u> |
| Controlled Service | (b) | <u>0.0910.085</u> | N/A |
| Lighting | (c) | <u>0.3320.312</u> | N/A |
| All Other Service | | <u>0.5780.543</u> | N/A |

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

**R
R
R
R**

NORTH DAKOTA PUBLIC
 SERVICE COMMISSION
 Dakota
 Case No. PU-17-340398
 Approved by order dated: November 29, 2017

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

APPROVED: Bruce G. Gerhardson
 Vice President, Regulatory Affairs



Fergus Falls, Minnesota

ENVIRONMENTAL COST RECOVERY RIDER

| DESCRIPTION | RATE CODE |
|---|-----------|
| All Service – Environmental Cost Recovery | 50-570 |
| All Service – Reagent and Allowance Cost Recovery | 50-572 |

RULES AND REGULATIONS: Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this rider.

APPLICATION OF RIDER: This rider consists of two separate charges; the Environmental Cost Recovery (“ECR”) Rider Charge and the Reagents and Emissions Allowance Adjustment (“REAA”) Rider Charge. This rider is applicable to electric service under all of the Company’s retail rate schedules in Sections 9, 10, 11, 12, 13.05, and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider).

ENVIRONMENTAL COST RECOVERY CHARGE: There shall be included on each North Dakota Customer’s monthly bill an Environmental Cost Recovery (“ECR”) Charge, based on the applicable ECR Factor multiplied by the Customer’s monthly bill. The Customer’s monthly bill shall be based on all applicable charges and credits under the Company’s retail rate schedules in Sections 9, 10, 11, 12 and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider). The ECR Factor will not apply to any Mandatory Riders, except Section 13.05 (Economic Development Cost Removal Rider). The ECR charge will be included as part of the charge reflected on the Customer’s bill on the line labeled “EPA Req Environmental Cst.”

| |
|---|
| Environmental Cost Recovery Factor - <u>6.6295.993</u> percent |
|---|

R

DETERMINATION OF ECR FACTOR: The ECR Factor shall be determined by dividing the forecasted *balance of the ECR Tracker account* by the *forecasted retail revenues subject to the ECR Factor*. The forecasted ECR Tracker balance and retail revenues shall be based on the forecast for the appropriate 12 month period (or such other period as may be approved by the Commission). The ECR Factor shall be rounded to the nearest 0.001 percent.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by Order dated ~~December 20, 2017~~
Bruce G. Gerhardson

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

APPROVED:

Vice President, Regulatory Affairs



Fergus Falls, Minnesota

WATER HEATING CONTROL RIDER

| DESCRIPTION | RATE CODE |
|--|-----------|
| Separately Metered Water Heating Control Service | 50-191 |
| Water Heating Credit Control Service | 50-192 |

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

AVAILABILITY: This rider is available for residential or nonresidential purposes.

RATE:

| WATER HEATING - CONTROLLED SERVICE 191 | | |
|--|------------------------------|-------------|
| Customer Charge per Month: | \$1.00 | |
| Monthly Minimum Bill: | Customer + Facilities Charge | |
| Facilities Charge per Month: | \$1.00 | |
| Energy Charge per kWh: | Summer | Winter |
| | 5.403 ¢/kWh | 5.268 ¢/kWh |

R

| WATER HEATING CREDIT 192 |
|--|
| A \$4.00 credit per month shall be applied to all bills having direct control water heating, except the credit shall not reduce the monthly billing to less than the Monthly Minimum Bill. |

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

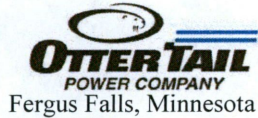
N
NR
N
N

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

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



REAL TIME PRICING RIDER

| DESCRIPTION | RATE CODE |
|----------------------|-----------|
| Transmission Service | 50-660 |
| Primary Service | 50-662 |
| Secondary Service | 50-664 |

RULES AND REGULATIONS: Terms and condition of this tariff and the General Rules and Regulations govern use of this schedule.

INTERIM RATE ADJUSTMENT: A ~~10.446.79~~ percent increase will be added to the Administrative Charge.

~~NR~~
~~N~~

AVAILABILITY: This rider is available on a voluntary basis to Customers who have maintained a measured demand of at least 200 kW during the historical period used for Customer Baseline Load (“CBL”) development. Priority will be established based on the date that an agreement is executed by both the Customer and the Company.

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

ADMINISTRATIVE CHARGE: An Administrative Charge in the amount of \$199.00 will be applied to each monthly bill to cover billing, administrative, metering, and communication costs associated with real-time pricing, plus any other applicable tariff charges.

TYPE OF SERVICE: Three-phase, 60 hertz at any available Standard Voltage.

TERM OF SERVICE: Service under this rider shall be for a period not less than one year. The Customer shall take service under this rider by either signing a new electric service agreement with the Company or by entering into amendments of existing electric service agreements. A Customer who voluntarily cancels service under this rider is not eligible to receive service again under this rider for a period of one year.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



LARGE GENERAL SERVICE RIDER

| DESCRIPTION | Option 1 | Option 2 |
|--|----------|----------|
| Fixed Rate Energy Pricing | 50-648 | 50-649 |
| System Marginal Energy Pricing | 50-642 | 50-645 |
| Short-term Marginal Capacity Purchases | 50-643 | 50-646 |
| Short-term Marginal Capacity Releases | 50-644 | 50-647 |

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

AVAILABILITY: This rider is available at the request of Customers who take service under the rate schedules listed in the Application Section of this tariff and have either (**Option 1**) a metered Demand of at least 1 MW, or (**Option 2**) a Total Coincident Demand of at least 10 MW for multiple, non-contiguous facilities that function in series.

INTERIM RATE ADJUSTMENT: A ~~10.446.79~~ percent increase will be added to the Administrative Charge.

NR
N

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

ELECTRIC SERVICE AGREEMENT: For service under this Rider, the Company may, at its discretion, require a written electric service agreement (ESA”) between the Company and the Customer that sets forth, among other things, the Customer’s Billing Demand, Firm Demand, On-Peak Baseline Demand and Off-Peak Baseline Demand.

FIXED RATE ENERGY PRICING:

Background: Certain Company industrial and commercial Customers have ESAs that designate, among other things, a Billing Demand, On-Peak and Off-Peak Baseline Demands and a Firm Demand. With On-Peak and Off-Peak Baseline Demands, the Company agrees to provide and the Customer agrees to purchase all of its Energy requirements at rates set forth in the Customer’s applicable rate schedule and/or a negotiated rate subject to Commission approval. Setting a Firm and Baseline Demands benefits both the Company and the Customer. With Firm Demands, the Company is able to curtail participating Customers’ load to predetermined levels which allows the Company to more accurately forecast its native load Capacity and Energy requirements.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

~~N~~
~~NR~~
~~N~~
~~N~~

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.

PENALTY PERIODS – OPTION 1 ONLY: Penalty periods are defined as periods when the Company signals to interrupt the Customer’s load and the Customer’s equipment does not shed the load. Installation of a dual register meter will be at the option of the Company. When a dual register meter is installed, penalty usage will be recorded on the peak register and the total register of the dual register meters.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

CONTROL CRITERIA: Service may be controlled up to a total of 24 hours during any 24-hour period, as measured from midnight to midnight. Short-duration cycling is approximately 15 minutes off / 15 minutes on of appropriate cooling equipment during the summer season (June 1-September 30). Domestic water heating may be controlled up to 14 hours in the 24-hour period.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the maximum 15 consecutive minute period measured by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand shall be based on the greatest of the current and preceding 11 monthly measured demands.

DETERMINATION OF CONTROL PERIOD DEMAND – OPTION 2 ONLY: The billing demand measured during the control period for which the bill is rendered shall be the maximum metered kW for any period of 15 consecutive minutes during the control period.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota

Case No. PU-17-398

Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



RATE:

| CONTROLLED SERVICE - INTERR LOAD – SELF-CONTAINED | | | |
|--|------------------------------|--|---------------|
| Customer Charge per Month: | \$2.00 | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | |
| Facilities Charge per Month: | \$5.00 | | |
| | Summer | | Winter |
| Energy Charge per kWh: | 3.289 ¢/kWh | | 3.081 ¢/kWh |
| Penalty | 38.606 ¢/kWh | | 12.924 ¢/kWh |

R

INTERIM RATE ADJUSTMENT:

A ~~4.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

N
NR
N
N

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

PENALTY PERIODS: Penalty periods are defined as periods when the Company signals to interrupt the Customer's load and the Customer's equipment does not shed the load. Penalty usage will be recorded on the peak register and the total register of the dual register meters. Installation of a dual register meter will be at the option of the Company.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

CONTROL CRITERIA: Service may be controlled up to a total of 24 hour during any 24-



RATE:

| CONTROLLED SERVICE - DEFERRED LOAD | | | |
|---|------------------------------|---------------|--|
| Customer Charge per Month: | \$3.00 | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | |
| Facilities Charge per Month: | \$4.00 | | |
| | <u>Summer</u> | <u>Winter</u> | |
| Energy Charge per kWh: | 4.784 ¢/kWh | 4.632 ¢/kWh | |
| Penalty | 33.802 ¢/kWh | 11.510 ¢/kWh | |

R

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

N
NR
N
N

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

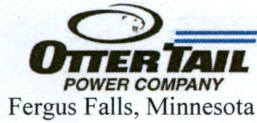
PENALTY PERIODS: Penalty periods are defined as periods when the Company signals to interrupt the Customer's load and the Customer's equipment does not shed the load. Penalty usage will be recorded on the peak register and the total register of the dual register meters. Installation of a dual register meter will be at the option of the Company.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



| FIXED TIME OF DELIVERY SERVICE - CT Metering | | | |
|---|------------------------------|--|-------------|
| Customer Charge per Month: | \$1.50 | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | |
| Facilities Charge per Month: | \$19.00 | | |
| | Summer | | Winter |
| Energy Charge per kWh: | 2.404 ¢/kWh | | 2.567 ¢/kWh |
| Penalty: | 9.400 ¢/kWh | | 7.385 ¢/kWh |

R

| FIXED TIME OF DELIVERY SERVICE – Primary CT Metering | | | |
|---|------------------------------|--|-------------|
| Customer Charge per Month: | \$3.00 | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | |
| Facilities Charge per Month: | \$9.00 | | |
| | Summer | | Winter |
| Energy Charge per kWh: | 2.393 ¢/kWh | | 2.556 ¢/kWh |
| Penalty: | 9.389 ¢/kWh | | 7.374 ¢/kWh |

R

INTERIM RATE ADJUSTMENT:

A ~~10.446.79~~ percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

N
NR
N
N

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-17-398
Approved by order dated ~~December 20, 2017~~

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

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



RESIDENTIAL SERVICE

| DESCRIPTION | RATE CODE |
|---------------------|--------------|
| Residential Service | 50-101 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to residential service as defined in the General Rules and Regulations.

RATE:

| RESIDENTIAL SERVICE | | | | |
|----------------------------|-----------------|-------|--------|-------|
| Customer Charge per Month: | \$8.00 | | | |
| Monthly Minimum Bill: | Customer Charge | | | |
| Energy Charge per kWh: | Summer | | Winter | |
| First 1,000: | 8.074 | ¢/kWh | 7.493 | ¢/kWh |
| Excess: | 8.074 | ¢/kWh | 6.803 | ¢/kWh |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



RESIDENTIAL DEMAND CONTROL SERVICE
(Commonly identified as RDC)

| DESCRIPTION | RATE CODE |
|----------------------------|-----------|
| Residential Demand Control | 50-241 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to Residential Customers with approved demand control systems.

RATE:

| RESIDENTIAL DEMAND CONTROL SERVICE | | |
|------------------------------------|--------------------------|-------------|
| Customer Charge per Month: | \$18.38 | |
| Monthly Minimum Bill: | Customer + Demand Charge | |
| Energy Charge per kWh: | Summer | Winter |
| | 4.257 ¢/kWh | 4.301 ¢/kWh |
| Demand Charge per kW: | Summer | Winter |
| | \$6.52 /kW | \$2.63 /kW |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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



Fergus Falls, Minnesota

FARM SERVICE

| DESCRIPTION | RATE CODE |
|--------------|-----------|
| Farm Service | 50-361 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to general Farm and home use. The Customer may elect to have the following service offerings in the farm home (for residential uses); Residential Service (Section 9.01) or Residential Demand Control Service Schedule (Section 9.02) if all the requirements specified for that schedule are satisfied.

RATE:

| FARM SERVICE | | | |
|-------------------------------------|------------------------------|-------------|--|
| Customer Charge per Month: | \$12.00 | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | |
| Facilities Charge per Month: | | | |
| Single Phase | \$0.00 | | |
| Three Phase: Overhead <=25kVA | \$3.37 | | |
| Three Phase: Overhead > 25kVA | \$3.93 | | |
| Three Phase: Underground <=25kVA | \$9.39 | | |
| Three Phase: Underground > 25kVA | \$10.78 | | |
| Energy Charge per kWh: | Summer | Winter | |
| First 1600 | 7.272 ¢/kWh | 6.601 ¢/kWh | |
| Excess | 6.125 ¢/kWh | 5.555 ¢/kWh | |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota.

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs

SMALL GENERAL SERVICE
Under 20 kW

| DESCRIPTION | RATE CODE |
|---|--------------|
| Metered Service under 20 kW – Secondary Service | 50-404 |
| Metered Service under 20 kW – Primary Service | 50-405 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to three-phase Residential Customers, and both single and three-phase nonresidential Customers. This schedule is not applicable for energy for resale, nor for municipal outdoor lighting. Emergency and supplementary/standby service will be supplied only as allowed by law.

RATE:

| | SECONDARY SERVICE | | PRIMARY SERVICE | |
|----------------------------|-------------------|-------------|-----------------|-------------|
| Customer Charge per Month: | \$13.00 | | \$13.00 | |
| Monthly Minimum Bill: | Customer Charge | | Customer Charge | |
| Energy Charge per kWh: | Summer | Winter | Summer | Winter |
| | 8.139 ¢/kWh | 7.392 ¢/kWh | 8.101 ¢/kWh | 7.355 ¢/kWh |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.



GENERAL SERVICE
 20 kW or Greater

| DESCRIPTION | RATE CODE |
|-------------------------------------|--------------|
| General Service – Secondary Service | 50-401 |
| General Service – Primary Service | 50-403 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to three-phase Residential Customers, and both single and three-phase nonresidential Customers, with a measured demand of at least 20 kW within the most recent 12 months. This schedule is not applicable for energy for resale, nor for municipal outdoor lighting. Emergency and supplementary/standby service will be supplied only as allowed by law.

RATE:

| | SECONDARY SERVICE | PRIMARY SERVICE | | | | | | | | |
|-------------------------------------|--|------------------------------|--------|-------------|-------------|--|--------|--------|-------------|-------------|
| Customer Charge per Month: | \$12.00 | \$12.00 | | | | | | | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | Customer + Facilities Charge | | | | | | | | |
| Facilities Charge per Month: | \$0.52/kW | \$0.38/kW | | | | | | | | |
| Energy Charge per kWh: | <table style="width: 100%; border-collapse: collapse;"> <tr> <td style="text-align: center; border-right: 1px solid black;">Summer</td> <td style="text-align: center;">Winter</td> </tr> <tr> <td style="text-align: center; border-right: 1px solid black;">7.843 ¢/kWh</td> <td style="text-align: center;">7.122 ¢/kWh</td> </tr> </table> | Summer | Winter | 7.843 ¢/kWh | 7.122 ¢/kWh | <table style="width: 100%; border-collapse: collapse;"> <tr> <td style="text-align: center; border-right: 1px solid black;">Summer</td> <td style="text-align: center;">Winter</td> </tr> <tr> <td style="text-align: center; border-right: 1px solid black;">7.806 ¢/kWh</td> <td style="text-align: center;">7.086 ¢/kWh</td> </tr> </table> | Summer | Winter | 7.806 ¢/kWh | 7.086 ¢/kWh |
| Summer | Winter | | | | | | | | | |
| 7.843 ¢/kWh | 7.122 ¢/kWh | | | | | | | | | |
| Summer | Winter | | | | | | | | | |
| 7.806 ¢/kWh | 7.086 ¢/kWh | | | | | | | | | |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge. **R**

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

NORTH DAKOTA PUBLIC
 SERVICE COMMISSION
 Case No. PU-17-398
 Approved by order dated

EFFECTIVE with bills rendered on
 and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
 Vice President, Regulatory Affairs



INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the greater of 80 kW or the maximum 15 consecutive minute period measured by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be based on the largest of the most recent 12 monthly measured demands.

DETERMINATION OF BILLING DEMAND: The billing demand shall be the greater of 80 kW or the maximum kW as measured by a suitable demand meter for any period of 15 consecutive minutes during the month for which the bill is rendered adjusted for Excess Reactive Demand.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: The billing demand shall be increased by one kW for each whole 10 kvar of measured reactive demand in excess of 50% of the measured demand in kW.



INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge. **R**

TERMS AND CONDITIONS: A Customer with a billing demand of less than 20 kW for 12 consecutive months will have the option to take service under the Small General Service schedule (Section 10.01).

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

DEFINITION OF DECLARED, INTERMEDIATE AND OFF-PEAK PERIODS BY SEASON:

WINTER SEASON - OCTOBER 1 THROUGH MAY 31 BILLINGS

Declared-Peak: Hours declared (see Declared Peak Notification)

Intermediate: All hours other than declared-peak and off-peak

Off-Peak: For all kW and kWh used Weekdays or Saturdays from 10:00 p.m. to 6:00 a.m., all day Sunday

SUMMER SEASON - JUNE 1 THROUGH SEPTEMBER 30 BILLINGS

Declared-Peak: Hours declared (see Declared-Peak Notification)

Intermediate: All hours other than declared-peak and off-peak

Off-Peak: For all kW and kWh used Weekdays or Saturdays from 10:00 p.m. to 6:00 a.m., all day Sunday

DECLARED-PEAK NOTIFICATION: The Company shall make available to Customers, no later than 4:00 p.m. (Central Time) of the preceding day, "declared-peak" designations for the next business day. Except for unusual periods, the Company will make "declared-peak" designations for Saturday through Monday available to Customers on the previous Friday. More than one-day-ahead "declared-peak" designations may also be used for the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.



Fergus Falls, Minnesota

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge. R

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
Winter: October 1 through May 31.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the maximum demand in kW registered over any one-hour period by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be the greater of 80 kW or the largest of the most recent 12 monthly measured demands.

METERED AND ESTABLISHED DEMAND: The Metered Demand shall be the maximum kW registered over any period of one hour during the month for which the bill is rendered. The Established Demand shall be the Metered Demand adjusted for excess reactive demand.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: The Metered Demand shall be increased by one kW for each whole ten kVar of reactive demand in excess of 50% of the measured demand in kW.

DEFINITION OF ON-PEAK, SHOULDER AND OFF-PEAK PERIODS BY SEASON:

WINTER SEASON - OCTOBER 1 THROUGH MAY 31 BILLINGS

On-Peak: For all kW and kWh used Monday through Friday between 7:00 a.m. and 12:00 noon, and between 5:00 p.m. and 9:00 p.m.

Shoulder: For all kW and kWh used Monday through Friday hours 6:00 a.m. to 7:00 a.m., hours 12:00 noon to 5:00 p.m. and hours 9:00 p.m. to 10:00 p.m. and, Saturday through Sunday 6:00 p.m. to 10:00 p.m.

Off-Peak: For all other kW and kWh used Monday through Friday hours 10:00 p.m. to 9:00 a.m. and, Saturday and Sunday 10:00 p.m. through 9:00 a.m.



Fergus Falls, Minnesota

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DETERMINATION OF METERED DEMAND: Metered Demand shall be based on the maximum kW registered over any period of one hour during the month in which the bill is rendered.

CONTRACT PERIOD: Standby Service is applicable only by signed agreement, setting forth the location and conditions applicable to the electric service, such as the Contracted Backup Demand, type of standby service (Option A or B), excess facilities required for service and other applicable terms and conditions, and providing for an initial minimum contract period of one year, unless otherwise authorized by the Company.

TERMS AND CONDITIONS:

1. The Company's meter will measure power and energy from the Company to the Customer. Any flow of power and energy from the Customer to the Company will be separately metered under one of the Company's Purchase Power Rate Schedules, or by contract.
2. Option A - Firm Standby: Exclusive of any scheduled maintenance hours, if the number of hours on which Backup Service is supplied exceeds 120 On-Peak hours in the Summer season and 240 On-Peak hours in the Winter season, the Customer may be required to take service under a standard, non-standby, rate schedule.
3. Option B – Non-Firm Standby: Backup Service is not available during any On-peak season. This service is only available in the Summer Shoulder and Summer Off-Peak and Winter Shoulder and Winter Off-Peak hours on a non-firm basis. The Company makes no guarantee that this service will be available; however, the Company will make reasonable efforts to provide Backup Service under Option B whenever possible.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



| OPTION 2 | | | | |
|-------------------------------------|------------------------------|-------|--------|-------|
| Customer Charge per Month: | \$5.00 | | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | | |
| Facilities Charge per Month: | Customer-Specific see Tariff | | | |
| Energy Charge per kWh: | Summer | | Winter | |
| Declared-Peak | 14.080 | ¢/kWh | 8.390 | ¢/kWh |
| Intermediate | 5.071 | ¢/kWh | 4.741 | ¢/kWh |
| Off-Peak | 2.272 | ¢/kWh | 2.242 | ¢/kWh |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

FACILITIES CHARGE: Customers served under this rate shall pay an annual fixed charge equal to 18% of the investment of the Company in the extension of lines, including any rebuilding or cost of capacity increase in lines or apparatus necessary because of the irrigation pumping load.

Alternatively, Customers may prepay the installation and cost of the equipment and shall pay an annual fixed charge equal to 3.5% of the investment of the Company, in lieu of the 18% annual fixed charge.

In either option, equipment remains the property of the Company. This charge shall be reviewed if additional Customers are connected to the extension within five years. The annual fixed charge will be billed in seven equal monthly installments May through November of each year.

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



RATE – NON-METERED:

| |
|--|
| <p>SIGN LIGHTING/OUTDOOR LIGHTING NON-METERED RATE</p> <p>Monthly charge = Connected kW x \$22.58, where Connected kW is the rated power of the lighting fixture (including ballast).</p> |
|--|

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

SERVICE CONDITIONS: Company-owned lights shall not be attached to Customer-owned property.

The Company shall have the right to periodically review the Customer's lighting equipment to verify that the rated power (kW) of the non-metered fixtures is consistent with the Company's records.



| FLOODLIGHTING | | |
|----------------------|------------------------|-----------------------|
| Fixture | Unit Type | Monthly Charge |
| 400 MV-Flood | Mercury Vapor | \$16.78 |
| 400 MA-Flood | Metal Additive Mercury | 17.91 |
| 400 HPS-Flood | High Pressure Sodium | 18.32 |
| 1000 MV-Flood | Mercury Vapor | 29.08 |
| 1000 MA-Flood | Metal Additive Mercury | 30.74 |

Due to the U.S. Government Energy Act of 2005, after July 1, 2008, the Company will no longer install Mercury Vapor fixtures for new installations.

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

SEASONAL CUSTOMERS: Seasonal Customers will be billed at the same rate as year-around Customers, except as follows:

A fixed charge of \$10.80 will be billed each seasonal Customer once per season per fixture in addition to the rate provided above. The fixed charge will be included in the first bill rendered for each season.

Each Customer will be billed for the number of months each season that the outdoor lighting fixture is in use, but not less than a minimum of four months, plus the seasonal fixed charge.

UNDERGROUND SERVICE: If a Customer requests underground service to any outdoor lighting unit or sign, the Company will supply a span of up to 200 feet of wire and add an additional \$1.96 to the monthly rate specified above. If overhead service is not available, there is no additional charge. **There is no additional charge for the MV-6PT, HPS-9PT, or the HPS-14PT fixtures.**

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



| PRIMARY SERVICE | | |
|-------------------------------------|------------------------------|-------------|
| Customer Charge per Month: | \$4.00 | |
| Monthly Minimum Bill: | Customer + Facilities Charge | |
| Facilities Charge per Month: | \$2.68 | |
| Energy Charge per kWh: | Summer | Winter |
| | 6.124 ¢/kWh | 5.552 ¢/kWh |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
 Winter: October 1 through May 31.



Fergus Falls, Minnesota

CIVIL DEFENSE - FIRE SIRENS

| DESCRIPTION | RATE CODE |
|-----------------------------|--------------|
| Civil Defense – Fire Sirens | 50-843 |

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

APPLICATION OF SCHEDULE: This schedule is applicable to separately served civil defense and municipal fire sirens.

RATE:

| CIVIL DEFENSE - FIRE SIRENS | |
|------------------------------|-----------------|
| Customer Charge per Month: | \$1.00 |
| Monthly Minimum Bill: | Customer Charge |
| Facilities Charge per Month: | \$0.00 |
| Charge per HP: | 53.193¢/HP |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

OTHER SIREN SERVICE: If the siren is served through a tariff applicable to the City Hall, fire hall or other tariffed service, no separate billing shall be made for the siren.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated

EFFECTIVE with bills rendered
on and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



**SMALL POWER PRODUCER RIDER
OCCASIONAL DELIVERY ENERGY SERVICE**
(Commonly identified as Net Energy Billing)

Base Avoided Costs Code 50-9020
Base Avoided Costs plus Renewable Energy Credit Code 50-9021

AVAILABILITY: Available to any qualifying facility not exceeding 100 kW of generating capacity.

METERING CHARGE: \$1.40 per month

PAYMENT SCHEDULES: Base Avoided Costs: 2.392¢ per kWh

Base Avoided Costs plus Renewable Energy Credit: 2.452¢ per kWh

SPECIAL CONDITIONS OF SERVICE: The Customer will be required to sign a contract, agreeing to terms and conditions specified for small power producers. The minimum term of the contract is 12 months.

RULES AND REGULATIONS: Terms and conditions of this rider and the General Rules and Regulations govern service of this schedule.

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the Metering Charge.

R

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



**SMALL POWER PRODUCER RIDER
 TIME OF DELIVERY ENERGY SERVICE**

| | |
|--|--------------|
| Base Avoided On-Peak Costs | Code 50-9030 |
| Base Avoided Off-Peak Costs | Code 50-9031 |
| Base Avoided On-Peak Costs Plus Renewable Energy Credit | Code 50-9032 |
| Base Avoided Off-Peak Costs Plus Renewable Energy Credit | Code 50-9033 |

AVAILABILITY: This rider is available to any Qualifying Facility not exceeding 100 kW of generating capacity. This rider is available to any Qualifying Facility exceeding 100 kW upon the approval of the Company. The Company reserves the right to require the Qualifying Facility to sign an Agreement.

METERING CHARGE: \$12.85 per month

PAYMENT SCHEDULE: ENERGY:

| | | |
|--------------------|------------------------|-------------------------|
| Base Avoided Costs | <u>On-Peak 50-9030</u> | <u>Off-Peak 50-9031</u> |
| Summer | 2.826¢ per kWh | 1.779¢ per kWh |
| Winter | 2.919¢ per kWh | 2.004¢ per kWh |

| | | |
|--|------------------------|-------------------------|
| Base Avoided Costs Plus Renewable Energy Credit | <u>On-Peak 50-9032</u> | <u>Off-Peak 50-9033</u> |
| Summer | 2.886¢ per kWh | 1.839¢ per kWh |
| Winter | 2.979¢ per kWh | 2.064¢ per kWh |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the Metering Charge.

R

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



**SMALL POWER PRODUCER RIDER
DEPENDABLE SERVICE**

| | |
|--|--------------|
| Base Avoided On-Peak Costs | Code 50-9040 |
| Base Avoided Off-Peak Costs | Code 50-9041 |
| Base Avoided On-Peak Costs Plus Renewable Energy Credit | Code 50-9042 |
| Base Avoided Off-Peak Costs Plus Renewable Energy Credit | Code 50-9043 |

AVAILABILITY: Available to any qualifying facility which is capable of delivering power and energy to the Company on a dependable basis.

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the Metering Charge.

R

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

METERING CHARGE: \$12.85 per month

PAYMENT SCHEDULE:

ENERGY:

| | | |
|--|------------------------|-------------------------|
| Base Avoided Costs | <u>On-Peak 50-9040</u> | <u>Off-Peak 50-9041</u> |
| Summer | 2.826¢ per kWh | 1.779¢ per kWh |
| Winter | 2.919¢ per kWh | 2.004¢ per kWh |
| | | |
| Base Avoided Costs Plus Renewable Energy Credit | <u>On-Peak 50-9042</u> | <u>Off-Peak 50-9043</u> |
| Summer | 2.886¢ per kWh | 1.839¢ per kWh |
| Winter | 2.979¢ per kWh | 2.064¢ per kWh |

CAPACITY:

| | | |
|-----------------|---------------|---------------|
| | Monthly \$/kW | Monthly \$/kW |
| <u>Contract</u> | Net Capacity | Levelized |
| <u>Term</u> | <u>Rate</u> | <u>Rate</u> |
| 60 mos. | \$5.86 | \$2.34 |

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



Fergus Falls, Minnesota

RENEWABLE RESOURCE COST RECOVERY RIDER

| DESCRIPTION | RATE CODE |
|--------------|--------------|
| All Services | 50-520 |

RULES AND REGULATIONS: Terms and conditions of this rider and the General Rules and Regulations govern use of this schedule.

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company’s Retail Rate Schedules in Section 9, 10, 11, 12, 13.05, and 14, except for Section 14.09 (*TailWinds*) and Section 14.11 (Released Energy Access Program Rider).

COST RECOVERY CHARGE: There shall be included on each North Dakota customer’s monthly bill a Renewable Resource Cost Recovery (“RRC”) charge based on the applicable cost recovery factor multiplied by the Customer’s monthly bill. The Customer’s monthly bill shall be based on all applicable charges and credits under the Company’s retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Section 14.09 (*TailWinds*) and Section 14.11 (Released Energy Access Program Rider). The RRC charge will not apply to any Mandatory Riders or sales tax and any local assessments as provided in the General Rules and Regulations for the Company’s electric service, except Section 13.05 (Economic Development Cost Removal Rider). The following charges are applicable in addition to all charges for service being taken under the Company’s standard rate schedules and will be included in the Energy and Renewable Adjustment line item on the customer’s bill.

| |
|--|
| Renewable Resource Cost Recovery Factor - 7.493 percent |
|--|

R

DETERMINATION OF RENEWABLE RESOURCE COST CHARGE: The RRC Factor shall be determined by dividing the forecasted *balance of the RRC Tracker account* by the *forecasted retail revenues subject to the RRC Factor*. The forecasted RRC Tracker balance and retail revenues shall be based on the forecast for the appropriate 12 month period (or such other period as may be approved by the Commission). The RRC Factor shall be rounded to the nearest 0.001 percent.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



TRANSMISSION COST RECOVERY RIDER

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

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

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

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

RATE:

| TRANSMISSION COST RECOVERY | | | |
|----------------------------------|-------|-------|---------|
| Energy Charge per kWh: | kWh | | kW |
| Large General Service (a) | N/A | ¢/kWh | \$1.632 |
| Controlled Service (b) | 0.085 | ¢/kWh | N/A |
| Lighting (c) | 0.312 | ¢/kWh | N/A |
| All Other Service | 0.543 | ¢/kWh | N/A |

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

R
R
R
R



Fergus Falls, Minnesota

ENVIRONMENTAL COST RECOVERY RIDER

| DESCRIPTION | RATE CODE |
|---|--------------|
| All Service – Environmental Cost Recovery | 50-570 |
| All Service – Reagent and Allowance Cost Recovery | 50-572 |

RULES AND REGULATIONS: Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this rider.

APPLICATION OF RIDER: This rider consists of two separate charges; the Environmental Cost Recovery (“ECR”) Rider Charge and the Reagents and Emissions Allowance Adjustment (“REAA”) Rider Charge. This rider is applicable to electric service under all of the Company’s retail rate schedules in Sections 9, 10, 11, 12, 13.05, and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider).

ENVIRONMENTAL COST RECOVERY CHARGE: There shall be included on each North Dakota Customer’s monthly bill an Environmental Cost Recovery (“ECR”) Charge, based on the applicable ECR Factor multiplied by the Customer’s monthly bill. The Customer’s monthly bill shall be based on all applicable charges and credits under the Company’s retail rate schedules in Sections 9, 10, 11, 12 and 14, except for Section 14.09 (**TailWinds**) and Section 14.11 (Released Energy Access Program Rider). The ECR Factor will not apply to any Mandatory Riders, except Section 13.05 (Economic Development Cost Removal Rider). The ECR charge will be included as part of the charge reflected on the Customer’s bill on the line labeled “EPA Req Environmental Cst.”

Environmental Cost Recovery Factor - 5.993 percent

R

DETERMINATION OF ECR FACTOR: The ECR Factor shall be determined by dividing the forecasted *balance of the ECR Tracker account* by the *forecasted retail revenues subject to the ECR Factor*. The forecasted ECR Tracker balance and retail revenues shall be based on the forecast for the appropriate 12 month period (or such other period as may be approved by the Commission). The ECR Factor shall be rounded to the nearest 0.001 percent.

The *balance of the ECR Tracker account* for determination of the ECR Factor shall include annual revenue requirements and any true-up balance described as follows:

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by Order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



Fergus Falls, Minnesota

WATER HEATING CONTROL RIDER

| DESCRIPTION | RATE CODE |
|--|-----------|
| Separately Metered Water Heating Control Service | 50-191 |
| Water Heating Credit Control Service | 50-192 |

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

AVAILABILITY: This rider is available for residential or nonresidential purposes.

RATE:

| WATER HEATING - CONTROLLED SERVICE 191 | | |
|--|------------------------------|-------------|
| Customer Charge per Month: | \$1.00 | |
| Monthly Minimum Bill: | Customer + Facilities Charge | |
| Facilities Charge per Month: | \$1.00 | |
| Energy Charge per kWh: | Summer | Winter |
| | 5.403 ¢/kWh | 5.268 ¢/kWh |

| WATER HEATING CREDIT 192 |
|--|
| A \$4.00 credit per month shall be applied to all bills having direct control water heating, except the credit shall not reduce the monthly billing to less than the Monthly Minimum Bill. |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



REAL TIME PRICING RIDER

| DESCRIPTION | RATE CODE |
|----------------------|--------------|
| Transmission Service | 50-660 |
| Primary Service | 50-662 |
| Secondary Service | 50-664 |

RULES AND REGULATIONS: Terms and condition of this tariff and the General Rules and Regulations govern use of this schedule.

INTERIM RATE ADJUSTMENT: A 6.79 percent increase will be added to the Administrative Charge.

R

AVAILABILITY: This rider is available on a voluntary basis to Customers who have maintained a measured demand of at least 200 kW during the historical period used for Customer Baseline Load (“CBL”) development. Priority will be established based on the date that an agreement is executed by both the Customer and the Company.

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

ADMINISTRATIVE CHARGE: An Administrative Charge in the amount of \$199.00 will be applied to each monthly bill to cover billing, administrative, metering, and communication costs associated with real-time pricing, plus any other applicable tariff charges.

TYPE OF SERVICE: Three-phase, 60 hertz at any available Standard Voltage.

TERM OF SERVICE: Service under this rider shall be for a period not less than one year. The Customer shall take service under this rider by either signing a new electric service agreement with the Company or by entering into amendments of existing electric service agreements. A Customer who voluntarily cancels service under this rider is not eligible to receive service again under this rider for a period of one year.



LARGE GENERAL SERVICE RIDER

| DESCRIPTION | Option 1 | Option 2 |
|--|----------|----------|
| Fixed Rate Energy Pricing | 50-648 | 50-649 |
| System Marginal Energy Pricing | 50-642 | 50-645 |
| Short-term Marginal Capacity Purchases | 50-643 | 50-646 |
| Short-term Marginal Capacity Releases | 50-644 | 50-647 |

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

AVAILABILITY: This rider is available at the request of Customers who take service under the rate schedules listed in the Application Section of this tariff and have either (**Option 1**) a metered Demand of at least 1 MW, or (**Option 2**) a Total Coincident Demand of at least 10 MW for multiple, non-contiguous facilities that function in series.

INTERIM RATE ADJUSTMENT: A 6.79 percent increase will be added to the Administrative Charge. **R**

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

ELECTRIC SERVICE AGREEMENT: For service under this Rider, the Company may, at its discretion, require a written electric service agreement (ESA") between the Company and the Customer that sets forth, among other things, the Customer's Billing Demand, Firm Demand, On-Peak Baseline Demand and Off-Peak Baseline Demand.

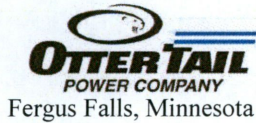
FIXED RATE ENERGY PRICING:

Background: Certain Company industrial and commercial Customers have ESAs that designate, among other things, a Billing Demand, On-Peak and Off-Peak Baseline Demands and a Firm Demand. With On-Peak and Off-Peak Baseline Demands, the Company agrees to provide and the Customer agrees to purchase all of its Energy requirements at rates set forth in the Customer's applicable rate schedule and/or a negotiated rate subject to Commission approval. Setting a Firm and Baseline Demands benefits both the Company and the Customer. With Firm Demands, the Company is able to curtail participating Customers' load to predetermined levels which allows the Company to more accurately forecast its native load Capacity and Energy requirements. Baseline Demands assure the Customer a fixed price for Energy up to the Baseline Demand and

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-17-398
Approved by order dated

EFFECTIVE with bills rendered on
and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
Vice President, Regulatory Affairs



INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.

PENALTY PERIODS – OPTION 1 ONLY: Penalty periods are defined as periods when the Company signals to interrupt the Customer's load and the Customer's equipment does not shed the load. Installation of a dual register meter will be at the option of the Company. When a dual register meter is installed, penalty usage will be recorded on the peak register and the total register of the dual register meters.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

CONTROL CRITERIA: Service may be controlled up to a total of 24 hours during any 24-hour period, as measured from midnight to midnight. Short-duration cycling is approximately 15 minutes off / 15 minutes on of appropriate cooling equipment during the summer season (June 1-September 30). Domestic water heating may be controlled up to 14 hours in the 24-hour period.

DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the maximum 15 consecutive minute period measured by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand shall be based on the greatest of the current and preceding 11 monthly measured demands.

DETERMINATION OF CONTROL PERIOD DEMAND – OPTION 2 ONLY: The billing demand measured during the control period for which the bill is rendered shall be the maximum metered kW for any period of 15 consecutive minutes during the control period.



RATE:

| CONTROLLED SERVICE - INTERR LOAD – SELF-CONTAINED | | | |
|--|------------------------------|--|---------------|
| Customer Charge per Month: | \$2.00 | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | |
| Facilities Charge per Month: | \$5.00 | | |
| | Summer | | Winter |
| Energy Charge per kWh: | 3.289 ¢/kWh | | 3.081 ¢/kWh |
| Penalty | 38.606 ¢/kWh | | 12.924 ¢/kWh |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
 Winter: October 1 through May 31.

PENALTY PERIODS: Penalty periods are defined as periods when the Company signals to interrupt the Customer's load and the Customer's equipment does not shed the load. Penalty usage will be recorded on the peak register and the total register of the dual register meters. Installation of a dual register meter will be at the option of the Company.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

CONTROL CRITERIA: Service may be controlled up to a total of 24 hour during any 24-

NORTH DAKOTA PUBLIC
 SERVICE COMMISSION
 Case No. PU-17-398
 Approved by order dated

EFFECTIVE with bills rendered on
 and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
 Vice President, Regulatory Affairs



RATE:

| CONTROLLED SERVICE - DEFERRED LOAD | | | |
|---|------------------------------|--------------|--|
| Customer Charge per Month: | \$3.00 | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | |
| Facilities Charge per Month: | \$4.00 | | |
| | Summer | Winter | |
| Energy Charge per kWh: | 4.784 ¢/kWh | 4.632 ¢/kWh | |
| Penalty | 33.802 ¢/kWh | 11.510 ¢/kWh | |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.
 Winter: October 1 through May 31.

PENALTY PERIODS: Penalty periods are defined as periods when the Company signals to interrupt the Customer's load and the Customer's equipment does not shed the load. Penalty usage will be recorded on the peak register and the total register of the dual register meters. Installation of a dual register meter will be at the option of the Company.

The penalty provision is not intended as a buy-through option. Under no circumstances should the penalty clause of this rider be interpreted as an approved buy-through option for service under this rider.

NORTH DAKOTA PUBLIC
 SERVICE COMMISSION
 Case No. PU-17-398
 Approved by order dated

EFFECTIVE with bills rendered on
 and after March 1, 2018, in North Dakota

APPROVED: Bruce G. Gerhardson
 Vice President, Regulatory Affairs



| FIXED TIME OF DELIVERY SERVICE - CT Metering | | | |
|---|------------------------------|--|-------------|
| Customer Charge per Month: | \$1.50 | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | |
| Facilities Charge per Month: | \$19.00 | | |
| | Summer | | Winter |
| Energy Charge per kWh: | 2.404 ¢/kWh | | 2.567 ¢/kWh |
| Penalty: | 9.400 ¢/kWh | | 7.385 ¢/kWh |

| FIXED TIME OF DELIVERY SERVICE – Primary CT Metering | | | |
|---|------------------------------|--|-------------|
| Customer Charge per Month: | \$3.00 | | |
| Monthly Minimum Bill: | Customer + Facilities Charge | | |
| Facilities Charge per Month: | \$9.00 | | |
| | Summer | | Winter |
| Energy Charge per kWh: | 2.393 ¢/kWh | | 2.556 ¢/kWh |
| Penalty: | 9.389 ¢/kWh | | 7.374 ¢/kWh |

INTERIM RATE ADJUSTMENT:

A 6.79 percent increase will be added to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge.

R

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

DEFINITIONS OF SEASONS:

- Summer: June 1 through September 30.
- Winter: October 1 through May 31.

Ofter Tail Power Company
 Environmental Cost Recovery Rider
 North Dakota

| Line No. | TRACKER SUMMARY Requirements Compared to Billed: | 2018 Test Year | | | | | | | | | | | | 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 | 590,913 | 590,913 | 590,913 | 590,913 | 590,913 | 590,913 | 590,913 | 590,913 | 590,913 | 590,913 | 590,913 | 590,913 | 590,913 | 7,090,956 |
| 2 | Air Quality Control System | 40,907 | 40,907 | 40,907 | 40,907 | 40,907 | 40,907 | 40,907 | 40,907 | 40,907 | 40,907 | 40,907 | 40,907 | 40,907 | 480,984 |
| 3 | Hoot Lake Plant MATS Project | 631,820 | 631,820 | 631,820 | 631,820 | 631,820 | 631,820 | 631,820 | 631,820 | 631,820 | 631,820 | 631,820 | 631,820 | 631,820 | 7,581,940 |
| 4 | Total Revenue Requirements | 972,678 | 945,688 | 850,671 | 777,977 | 631,446 | 596,907 | 501,226 | 518,470 | 516,777 | 500,783 | 584,556 | 669,877 | 6,077,056 | |
| 5 | Billed (forecast kWh x adj factor) | | | | | | | | | | | | | | |
| 6 | Difference ¹ | 370,941 | (313,868) | (218,851) | (146,157) | 374 | 34,913 | 130,584 | 113,350 | 115,043 | 131,037 | 37,264 | (38,057) | (1,667) | |
| 7 | Carrying Charge | 0 | 2,452 | 394 | (1,051) | (2,024) | (2,035) | (1,817) | (966) | (223) | 536 | 1,406 | 1,661 | 1,421 | |
| 8 | Cumulative Difference (True-Up) | 370,941 | 59,525 | (158,932) | (306,140) | (307,790) | (274,912) | (146,135) | (33,751) | 81,069 | 212,642 | 251,311 | 214,916 | 214,916 | |
| 9 | Carrying Charge Calculation | 2,452 | 394 | (1,051) | (2,024) | (2,035) | (1,817) | (966) | (223) | 536 | 1,406 | 1,661 | 1,421 | (246) | |
| 10 | Cumulative Carrying Charge | 2,452 | 2,846 | 1,795 | (229) | (2,264) | (4,081) | (5,047) | (5,270) | (4,511) | (3,105) | (1,444) | (23) | (23) | |
| 11 | Carrying cost | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | |

¹ January includes estimate of \$711,799 prior period true up.

| SUMMARY | | 2018 Test Year |
|----------------------|--|----------------|
| Revenue requirements | | \$7,581,940 |
| Carrying Charge | | (246) |
| Revenue requirements | | \$7,581,594 |

Otter Tail Power Company
 Environmental Cost Recovery Rider
 North Dakota

2018 Proposed ECRR Revenue Requirement and Rate

| Line No. | TRACKER SUMMARY Requirements Compared to Billed: | January | | February | | March | | April | | May | | June | | July | | August | | September | | October | | November | | December | | YE | | | |
|----------|---|------------|-------|------------|-------|------------|-------|------------|-------|------------|-------|------------|-------|------------|-------|------------|-------|------------|-------|------------|-------|------------|-------|------------|-------|------------|-------|------------|-------|
| | | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% | Projected | 7.93% |
| 1 | Revenue Requirements | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% | 590,913 | 7.93% |
| 2 | Air Quality Control System | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% | 40,907 | 7.93% |
| 3 | Hoot Lake Plant MATS Project | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% | 631,820 | 7.93% |
| 4 | Total Revenue Requirements | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% | 972,678 | 7.93% |
| 5 | Billed (forecast kWh x adj factor) | (340,658) | | (340,658) | | (340,658) | | (340,658) | | (340,658) | | (340,658) | | (340,658) | | (340,658) | | (340,658) | | (340,658) | | (340,658) | | (340,658) | | (340,658) | | (340,658) | |
| 6 | Difference | 1,271 | | 1,271 | | 1,271 | | 1,271 | | 1,271 | | 1,271 | | 1,271 | | 1,271 | | 1,271 | | 1,271 | | 1,271 | | 1,271 | | 1,271 | | 1,271 | |
| 7 | Carrying Charge | (162,982) | | (162,982) | | (162,982) | | (162,982) | | (162,982) | | (162,982) | | (162,982) | | (162,982) | | (162,982) | | (162,982) | | (162,982) | | (162,982) | | (162,982) | | (162,982) | |
| 8 | Cumulative Difference (True-Up) | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | |
| 9 | Carrying Charge Calculation | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | |
| 10 | Cumulative Carrying Charge | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | | (1,075) | |
| 11 | Carrying cost | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | | 196 | |
| 12 | Forecasted Revenue | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | | 13,068,373 | |

| SUMMARY | | Jan 2018 - | Dec 2018 |
|---------------------------------------|--|-------------|----------|
| Revenue requirements | | \$7,581,840 | (40,503) |
| Carrying Charge | | 177,005 | |
| December 2017 Estimated True Up | | \$7,718,343 | |
| Revenue requirements | | 128,789,562 | 5.993% |
| Jan 2018 - Dec 2018 projected revenue | | 128,789,562 | 5.993% |
| January 1, 2018 Rate | | | |

Otter Tail Power Company
Renewable Resource Adjustment Rider
North Dakota

| Line | 2018 Test Year | | | | | | | | | | | | 2018 YE Balance | |
|------|--|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|-------------|
| | Forecast Jan-18 | Forecast Feb-18 | Forecast Mar-18 | Forecast Apr-18 | Forecast May-18 | Forecast Jun-18 | Forecast Jul-18 | Forecast Aug-18 | Forecast Sep-18 | Forecast Oct-18 | Forecast Nov-18 | Forecast Dec-18 | | |
| 1 | TRACKER SUMMARY | | | | | | | | | | | | | |
| 2 | Requirements Compared to Billed: | | | | | | | | | | | | | |
| 3 | Revenue Requirements | | | | | | | | | | | | | |
| 4 | Langdon | 239,554 | 254,406 | 237,110 | 250,548 | 247,920 | 239,769 | 239,462 | 243,795 | 246,787 | 239,452 | 239,617 | 239,617 | 2,917,548 |
| 5 | Ashtabula | 215,833 | 264,388 | 240,594 | 244,636 | 216,486 | 303,576 | 314,627 | 268,497 | 232,706 | 417,719 | 407,366 | 407,366 | 3,403,758 |
| 6 | Luverne | 206,999 | 217,242 | 203,494 | 223,530 | 203,725 | 212,939 | 217,834 | 216,439 | 221,844 | 212,939 | 206,825 | 206,825 | 2,556,750 |
| 7 | Total | 662,386 | 736,036 | 681,198 | 718,714 | 668,131 | 756,284 | 771,923 | 728,730 | 701,338 | 870,111 | 853,807 | 853,807 | 8,878,055 |
| 8 | | Projected | Projected | Projected | Projected | Projected | Projected | Projected | Projected | Projected | Projected | Projected | Projected | |
| 9 | Billed (forecast kWh x adj factor) | 996,022 | 968,384 | 871,087 | 796,647 | 731,408 | 718,812 | 743,542 | 741,114 | 718,177 | 852,658 | 960,676 | 960,676 | 9,789,928 |
| 10 | | | | | | | | | | | | | | |
| 11 | Monthly Revenue Difference | (333,636) | (230,015) | (189,076) | (78,370) | (64,233) | 36,334 | 27,483 | (13,100) | (17,643) | 16,533 | (107,679) | (107,679) | |
| 12 | Cumulative Difference | 352,874 | 122,859 | (66,217) | (144,588) | (208,821) | (172,207) | (135,873) | (121,490) | (139,133) | (122,600) | (230,279) | (230,279) | |
| 13 | Adjusted Cumulative Difference | 425,039 | 195,024 | 5,948 | (72,423) | (136,656) | (63,708) | (36,225) | (49,325) | (66,968) | (50,435) | (158,114) | (158,114) | |
| 14 | | | | | | | | | | | | | | |
| 15 | | | | | | | | | | | | | | |
| 16 | | | | | | | | | | | | | | |
| 17 | Carrying Charge Calculation | 2,333 | 812 | (438) | (956) | (1,381) | (898) | (717) | (803) | (920) | (811) | (1,522) | (1,522) | (6,438.19) |
| 18 | Cumulative Carrying Charge | 788,680 | 789,492 | 789,054 | 788,098 | 786,718 | 784,681 | 783,965 | 783,161 | 782,242 | 781,431 | 779,909 | 779,909 | |
| 19 | Prime Rate | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | |
| 20 | Monthly Rate | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | |
| 21 | | | | | | | | | | | | | | |
| 22 | Life-to-Date Revenue Requirement | 355,207 | 123,671 | (66,655) | (145,544) | (210,201) | (136,772) | (109,107) | (122,294) | (140,053) | (123,410) | (231,801) | (231,801) | |
| 23 | Forecasted Revenue | 13,068,373 | 11,668,720 | 11,120,089 | 9,716,025 | 8,834,607 | 9,438,727 | 10,319,604 | 10,295,655 | 10,181,735 | 11,535,372 | 12,614,663 | 12,614,663 | 128,789,562 |
| 24 | January includes estimate of \$686,510 prior period true-up. | | | | | | | | | | | | | |

| 2018 Test Year | |
|----------------------|-----------|
| Revenue Requirements | 8,878,055 |
| Carrying Charge | (6,438) |
| Total Requirements | 8,871,617 |

Otter Tail Power Company
Renewable Resource Adjustment Rider
North Dakota

2018 Proposed RRAR Revenue Requirement and Rate

| Line | Forecast Jan-18 | Forecast Feb-18 | Forecast Mar-18 | Forecast Apr-18 | Forecast May-18 | Forecast Jun-18 | Forecast Jul-18 | Forecast Aug-18 | Forecast Sep-18 | Forecast Oct-18 | Forecast Nov-18 | Forecast Dec-18 | 2018 YE Balance |
|------|---|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|
| 1 | | | | | | | | | | | | | |
| 2 | TRACKER SUMMARY | | | | | | | | | | | | |
| 3 | Requirements Compared to Billed: | | | | | | | | | | | | |
| 4 | 239,554 | 254,406 | 237,110 | 250,548 | 247,920 | 239,126 | 239,769 | 239,462 | 243,795 | 246,787 | 239,452 | 239,617 | 2,917,548 |
| 5 | 215,833 | 264,388 | 240,594 | 244,636 | 216,486 | 277,330 | 303,576 | 314,627 | 268,497 | 232,706 | 417,719 | 407,366 | 3,403,758 |
| 6 | 206,999 | 217,242 | 203,494 | 223,530 | 203,725 | 212,939 | 212,939 | 217,834 | 216,439 | 221,844 | 212,939 | 206,825 | 2,556,750 |
| 7 | 662,386 | 736,036 | 681,198 | 718,714 | 668,131 | 729,395 | 756,284 | 771,923 | 728,730 | 701,338 | 870,111 | 853,807 | 8,878,055 |
| 8 | | | | | | | | | | | | | |
| 9 | Projected | Projected | Projected | Projected | Projected | Projected | Projected | Projected | Projected | Projected | Projected | Projected | 2018 YE |
| 10 | 979,159 | 874,288 | 833,182 | 727,981 | 661,940 | 707,204 | 773,205 | 771,410 | 748,958 | 762,875 | 864,297 | 945,164 | 9,649,664 |
| 11 | | | | | | | | | | | | | |
| 12 | (311,451) | (135,334) | (149,960) | (8,235) | 7,168 | 23,216 | (15,742) | 1,587 | (19,143) | (60,579) | 6,372 | (90,757) | (90,757) |
| 13 | 441,406 | 306,072 | 156,112 | 147,877 | 155,045 | 178,261 | 162,519 | 164,106 | 144,964 | 84,385 | 90,757 | (0.00) | (0.00) |
| 14 | 447,224 | 311,890 | 161,930 | 153,695 | 160,864 | 184,079 | 168,337 | 169,925 | 150,782 | 90,203 | 96,575 | 5,818.17 | |
| 15 | | | | | | | | | | | | | |
| 16 | | | | | | | | | | | | | |
| 17 | 2,918 | 2,023 | 1,032 | 978 | 1,025 | 1,178 | 1,074 | 1,085 | 958 | 558 | 600 | (0.00) | (0.00) |
| 18 | 789,265 | 791,288 | 792,320 | 793,298 | 794,323 | 795,502 | 796,576 | 797,661 | 798,619 | 799,177 | 799,777 | 799,777.09 | |
| 19 | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | 7.93% | |
| 20 | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | 0.66110% | |
| 21 | | | | | | | | | | | | | |
| 22 | 444,324 | 308,096 | 157,144 | 148,855 | 156,070 | 179,439 | 163,593 | 165,191 | 145,922 | 84,943 | 91,357 | (0) | (0.00) |
| 23 | | | | | | | | | | | | | |
| 24 | 13,068,373 | 11,668,720 | 11,120,089 | 9,716,025 | 8,834,607 | 9,438,727 | 10,319,604 | 10,295,655 | 9,995,992 | 10,181,735 | 11,535,372 | 12,614,663 | 128,789,562 |

| Rate Calculation - Calendar Year 2018 | |
|---|------------------|
| Revenue Requirements Jan 2018 thru Dec 2018 | 8,878,055 |
| Carrying Charge | 13,430 |
| Cumulative True-up | 758,179 |
| Total Requirements | 9,649,664 |
| Jan 2018 - Dec 2018 projected revenue | 128,789,562 |
| January 1, 2018 Rate | 7.493% |

Other Tail Power Company
Transmission Cost Recovery Rider
North Dakota

| Line No. | TRACKER SUMMARY Requirements Compared to Billed: | 2018 Test Year | | | | | | | | | | | | 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 | 205,171 | 205,171 | 207,001 | 205,171 | 205,171 | 207,001 | 205,171 | 207,001 | 205,171 | 205,171 | 207,001 | 205,171 | 207,001 | 2,489,369 |
| 2 | CAPX 2020: Fargo | 50,556 | 50,556 | 50,556 | 50,556 | 50,556 | 50,556 | 50,556 | 50,556 | 50,556 | 50,556 | 50,556 | 50,556 | 50,556 | 606,672 |
| 3 | Cass Lake-Navy-Helga-Bemidji | 8,200 | 8,200 | 8,200 | 8,200 | 8,200 | 8,200 | 8,200 | 8,200 | 8,200 | 8,200 | 8,200 | 8,200 | 8,200 | 98,404 |
| 4 | Rugby Wind Interconnection | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 1,041 | 12,486 |
| 5 | Cassellon - Buffalo 115 KV Project | 21,100 | 21,100 | 21,100 | 21,100 | 21,100 | 21,100 | 21,100 | 21,100 | 21,100 | 21,100 | 21,100 | 21,100 | 21,100 | 253,204 |
| 6 | CAPX 2020: Brookings - Hampton | 18,346 | 18,346 | 18,500 | 18,346 | 18,346 | 18,500 | 18,346 | 18,500 | 18,346 | 18,346 | 18,500 | 18,346 | 18,500 | 220,764 |
| 7 | MVP: Big Stone Area Transmission | 5,245 | 5,249 | 5,253 | 5,257 | 5,256 | 5,256 | 5,256 | 5,256 | 5,256 | 5,256 | 5,256 | 5,256 | 5,256 | 63,053 |
| 8 | MVP: Ellendale to Big Stone South | 6,202 | 6,202 | 6,202 | 6,202 | 6,202 | 6,202 | 6,202 | 6,202 | 6,202 | 6,202 | 6,202 | 6,202 | 6,202 | 74,418 |
| 9 | Ramsey 230/115 KV Transformer Upgrade | 1,174 | 1,174 | 1,174 | 1,174 | 1,174 | 1,174 | 1,174 | 1,174 | 1,174 | 1,174 | 1,174 | 1,174 | 1,174 | 14,090 |
| 10 | Karlsbad, MN Capacitor Bank Project | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | 3,038 | 36,455 |
| 11 | Oakes Area Transmission Improvements | 17,629 | 17,629 | 17,629 | 17,629 | 17,629 | 17,629 | 17,629 | 17,629 | 17,629 | 17,629 | 17,629 | 17,629 | 17,629 | 211,544 |
| 12 | Hankinson Transformer Addition | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 23,998 |
| 13 | NERC Compliance | 42,304 | 42,304 | 42,304 | 42,304 | 42,304 | 42,304 | 42,304 | 42,304 | 42,304 | 42,304 | 42,304 | 42,304 | 42,304 | 507,654 |
| 14 | Summit Transformer | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 25,652 |
| 15 | Spiritwood Station Interconnection | 2,014 | 2,014 | 2,014 | 2,014 | 2,014 | 2,014 | 2,014 | 2,014 | 2,014 | 2,014 | 2,014 | 2,014 | 2,014 | 24,169 |
| 16 | Max-Ryder 41.6 KV Line Upgrades | 2,097 | 2,097 | 2,097 | 2,097 | 2,097 | 2,097 | 2,097 | 2,097 | 2,097 | 2,097 | 2,097 | 2,097 | 2,097 | 25,889 |
| 17 | Rugby Breaker Station | 3,941 | 3,941 | 3,941 | 3,941 | 3,941 | 3,941 | 3,941 | 3,941 | 3,941 | 3,941 | 3,941 | 3,941 | 3,941 | 47,292 |
| 18 | Granville Jct Breaker Station | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 25,932 |
| 19 | Bagley 115KV Switch Station | 4,207 | 4,207 | 4,207 | 4,207 | 4,207 | 4,207 | 4,207 | 4,207 | 4,207 | 4,207 | 4,207 | 4,207 | 4,207 | 52,776 |
| 20 | Total Revenue Requirements | 398,564 | 398,567 | 400,555 | 398,575 | 398,575 | 400,559 | 398,575 | 400,559 | 398,575 | 398,575 | 402,427 | 398,575 | 402,427 | 4,793,824 |
| 21 | MISO & SPP Expenses | 485,727 | 445,667 | 425,637 | 365,547 | 315,472 | 345,517 | 400,600 | 345,517 | 400,600 | 345,517 | 400,600 | 345,517 | 400,600 | 4,822,217 |
| 22 | MISO Schedule 26 Expense | 289,914 | 261,250 | 252,884 | 221,319 | 205,456 | 202,418 | 220,116 | 220,116 | 210,355 | 221,643 | 227,620 | 221,643 | 227,620 | 2,829,362 |
| 23 | SPP Schedule 9 Expense | 4,654 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 852,795 |
| 24 | SPP Schedule 11 Expense | 3,292 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 74,798 |
| 25 | Total MISO & SPP Expenses | 783,587 | 790,521 | 782,125 | 670,470 | 604,532 | 631,539 | 704,320 | 631,539 | 704,320 | 631,539 | 704,320 | 631,539 | 704,320 | 8,579,172 |
| 26 | MISO Revenues | (30,910) | (30,910) | (30,910) | (30,910) | (30,910) | (30,910) | (30,910) | (30,910) | (30,910) | (30,910) | (30,910) | (30,910) | (30,910) | (370,917) |
| 27 | MISO Schedule 9 Revenue | (408,997) | (408,997) | (408,997) | (408,997) | (408,997) | (408,997) | (408,997) | (408,997) | (408,997) | (408,997) | (408,997) | (408,997) | (408,997) | (4,907,968) |
| 28 | MISO Schedule 26 Revenue | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 29 | MISO Schedule 37 Revenue | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 30 | MISO Schedule 38 Revenue | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 31 | MISO Schedule 26A Revenue | (54,130) | (54,130) | (54,130) | (54,130) | (54,130) | (54,130) | (54,130) | (54,130) | (54,130) | (54,130) | (54,130) | (54,130) | (54,130) | (649,555) |
| 32 | MISO MVP ARR Revenue | (2,178) | (2,178) | (2,178) | (2,178) | (2,178) | (2,178) | (2,178) | (2,178) | (2,178) | (2,178) | (2,178) | (2,178) | (2,178) | (26,135) |
| 33 | Total MISO Revenues | (496,215) | (496,215) | (496,215) | (496,215) | (496,215) | (496,215) | (496,215) | (496,215) | (496,215) | (496,215) | (496,215) | (496,215) | (496,215) | (5,984,575) |
| 34 | Net Revenue Requirement | 685,936 | 692,874 | 666,466 | 572,832 | 506,892 | 535,884 | 606,680 | 535,884 | 606,680 | 535,884 | 606,680 | 535,884 | 606,680 | 7,418,426 |
| 35 | Billed (forecast kWh x adj factor) | 777,027 | 755,466 | 679,582 | 621,489 | 504,433 | 476,841 | 495,746 | 512,802 | 511,127 | 495,308 | 588,056 | 495,308 | 588,056 | 7,080,410 |
| 36 | Difference | (91,091) | (62,592) | (13,096) | (48,657) | 2,459 | 59,043 | 110,934 | 83,954 | 32,694 | 102,884 | 46,850 | 102,884 | 46,850 | 338,016 |
| 37 | Carrying Charge | 0 | (2,659) | (3,090) | (3,197) | (3,540) | (3,547) | (3,161) | (2,468) | (1,663) | (990) | (687) | (1,663) | (990) | (26,884) |
| 38 | Cumulative Difference | (402,223) | (487,474) | (463,661) | (535,515) | (536,996) | (481,101) | (373,348) | (281,862) | (251,031) | (149,806) | (103,947) | (149,806) | (103,947) | 0 |
| 39 | Carrying Charge Calculation | (2,659) | (3,090) | (3,197) | (3,540) | (3,547) | (3,161) | (2,468) | (1,663) | (990) | (687) | (1,663) | (990) | (687) | 0 |
| 40 | Cumulative Carrying Charge | (2,659) | (5,750) | (8,947) | (12,487) | (16,035) | (19,215) | (21,688) | (23,547) | (25,205) | (26,197) | (26,884) | (26,884) | (26,884) | (26,884) |
| 41 | Carrying cost | 7,93% | 7,93% | 7,93% | 7,93% | 7,93% | 7,93% | 7,93% | 7,93% | 7,93% | 7,93% | 7,93% | 7,93% | 7,93% | 7,93% |

1 January includes estimate of \$311,132 prior period true-up.

| 2018 Test Year | |
|----------------------|-------------|
| Revenue requirements | \$7,418,426 |
| Carrying Charge | (26,884) |
| Total requirements | \$7,391,542 |

Class Allocation and Rate Design

| Line No. | | | 2018 |
|----------|-----------------------------------|-------------|---------------|
| 1 | North Dakota Revenue Requirements | | \$7,469,920 * |
| 2 | Large General Service Class | 27.77% | \$2,074,098 |
| 3 | Controlled Service | 2.77% | 206,997 |
| 4 | Lighting | 0.96% | 71,724 |
| 5 | All Other Service | 68.50% | 5,117,101 |
| 6 | Total | | \$7,469,920 |
| 7 | Large General Service Class | kW | 1,270,619 |
| 8 | Controlled Service | kWh | 243,255,777 |
| 9 | Lighting | kWh | 23,001,296 |
| 10 | All Other Service | kWh | 942,842,036 |
| 11 | Large General Service Class | \$ / kW | 1.632 |
| 12 | Controlled Service | cents / kWh | 0.085 |
| 13 | Lighting | cents / kWh | 0.312 |
| 14 | All Other Service | cents / kWh | 0.543 |

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

| Line No. | TRACKER SUMMARY Requirements Compared to Billed: | 2018 | | | | | | | | | | | | 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 | 203,090 | 203,090 | 204,920 | 203,090 | 203,090 | 204,920 | 203,090 | 203,090 | 203,090 | 203,090 | 203,090 | 203,090 | 204,920 | 2,444,397 |
| 2 | CAPX 2020: Fargo | 49,445 | 49,445 | 53,060 | 49,445 | 49,445 | 53,060 | 49,445 | 49,445 | 49,445 | 49,445 | 49,445 | 49,445 | 53,060 | 607,803 |
| 3 | Cass Lake-Nary-Helga-Bemidji | 8,149 | 8,149 | 8,149 | 8,077 | 8,077 | 8,077 | 8,077 | 8,077 | 8,077 | 8,077 | 8,077 | 8,077 | 8,077 | 97,140 |
| 4 | Rugby Wind Interconnection | 171 | 171 | 171 | 171 | 171 | 171 | 171 | 171 | 171 | 171 | 171 | 171 | 171 | 2,058 |
| 5 | Cassellon - Buffalo 115 kV Project | 23,117 | 23,117 | 23,117 | 23,117 | 23,117 | 23,117 | 23,117 | 23,117 | 23,117 | 23,117 | 23,117 | 23,117 | 23,117 | 277,399 |
| 6 | CAPX 2020: Brookings - Hampton | 18,365 | 18,365 | 18,519 | 18,365 | 18,365 | 18,519 | 18,365 | 18,365 | 18,365 | 18,365 | 18,365 | 18,365 | 18,519 | 220,994 |
| 7 | MVP: Big Stone Area Transmission | 5,195 | 5,198 | 5,202 | 5,207 | 5,207 | 5,207 | 5,207 | 5,207 | 5,207 | 5,207 | 5,207 | 5,207 | 5,207 | 62,455 |
| 8 | MVP: Ellendale to Big Stone South | 6,805 | 6,805 | 6,805 | 6,805 | 6,805 | 6,805 | 6,805 | 6,805 | 6,805 | 6,805 | 6,805 | 6,805 | 6,805 | 82,455 |
| 9 | Ramsey 230/115 kV Transformer Upgrade | 1,082 | 1,082 | 1,082 | 1,082 | 1,082 | 1,082 | 1,082 | 1,082 | 1,082 | 1,082 | 1,082 | 1,082 | 1,082 | 12,988 |
| 10 | Kanistad, MN Capacitor Bank Project | 3,234 | 3,234 | 3,234 | 3,234 | 3,234 | 3,234 | 3,234 | 3,234 | 3,234 | 3,234 | 3,234 | 3,234 | 3,234 | 38,803 |
| 11 | Oakes Area Transmission Improvements | 18,744 | 18,744 | 18,744 | 18,744 | 18,744 | 18,744 | 18,744 | 18,744 | 18,744 | 18,744 | 18,744 | 18,744 | 18,744 | 224,925 |
| 12 | Hankinson Transformer Addition | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 | 25,931 |
| 13 | NERC Compliance | 41,634 | 41,634 | 41,634 | 41,634 | 41,634 | 41,634 | 41,634 | 41,634 | 41,634 | 41,634 | 41,634 | 41,634 | 41,634 | 499,612 |
| 14 | Summit Transformer | 2,109 | 2,109 | 2,109 | 2,109 | 2,109 | 2,109 | 2,109 | 2,109 | 2,109 | 2,109 | 2,109 | 2,109 | 2,109 | 25,303 |
| 15 | Spiritwood Station Interconnection | 2,253 | 2,253 | 2,253 | 2,253 | 2,253 | 2,253 | 2,253 | 2,253 | 2,253 | 2,253 | 2,253 | 2,253 | 2,253 | 27,035 |
| 16 | Max-Ryder 41.6 kV Line Upgrades | 5,070 | 5,101 | 5,131 | 5,131 | 5,182 | 5,223 | 5,253 | 5,284 | 5,314 | 5,344 | 5,375 | 5,405 | 5,435 | 62,884 |
| 17 | Rugby Breaker Station | 4,833 | 4,833 | 4,833 | 4,833 | 4,833 | 4,833 | 4,833 | 4,833 | 4,833 | 4,833 | 4,833 | 4,833 | 4,833 | 58,002 |
| 18 | Granville Jct Breaker Station | 2,676 | 2,676 | 2,676 | 2,676 | 2,676 | 2,676 | 2,676 | 2,676 | 2,676 | 2,676 | 2,676 | 2,676 | 2,676 | 32,117 |
| 19 | Bagley 115kV Switch Station | 4,756 | 4,756 | 4,756 | 4,756 | 4,756 | 4,756 | 4,756 | 4,756 | 4,756 | 4,756 | 4,756 | 4,756 | 4,756 | 59,359 |
| 20 | Total Revenue Requirements | 402,869 | 402,923 | 408,557 | 402,920 | 402,950 | 408,560 | 403,011 | 403,042 | 403,103 | 403,164 | 403,225 | 403,286 | 409,908 | 4,860,834 |
| 21 | MISO & SPP Expenses | 485,728 | 445,668 | 425,638 | 365,548 | 315,473 | 345,518 | 400,600 | 400,600 | 390,585 | 390,585 | 400,600 | 400,600 | 500,750 | 4,822,225 |
| 22 | MISO Schedule 26 Expense | 289,914 | 261,250 | 252,884 | 221,319 | 205,456 | 202,418 | 220,418 | 220,418 | 210,355 | 210,355 | 221,644 | 247,196 | 276,621 | 2,829,366 |
| 23 | MISO Schedule 26A Expense | 4,654 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 77,104 | 852,786 |
| 24 | SPP Schedule 9 Expense | 3,292 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 6,501 | 74,789 |
| 25 | SPP Schedule 11 Expense | 783,588 | 790,522 | 762,126 | 670,471 | 604,533 | 631,540 | 704,321 | 704,396 | 695,833 | 695,833 | 731,401 | 860,975 | 860,975 | 8,579,185 |
| 26 | Total MISO & SPP Expenses | (37,079) | (17,751) | (24,562) | (37,019) | (4,647) | (21,663) | (27,764) | (31,121) | (23,499) | (39,206) | (44,465) | (44,465) | (66,520) | (375,335) |
| 27 | MISO Revenues | (413,643) | (413,643) | (413,643) | (413,643) | (413,643) | (413,643) | (413,643) | (413,643) | (413,643) | (413,643) | (413,643) | (413,643) | (413,643) | (4,963,718) |
| 28 | MISO Schedule 9 Revenue | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 29 | MISO Schedule 26 Revenue | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 30 | MISO Schedule 26A Revenue | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 31 | MISO Schedule 37 Revenue | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 32 | MISO Schedule 38 Revenue | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 33 | MISO Schedule 39 Revenue | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 34 | MISO Schedule 26A Revenue | (50,987) | (50,984) | (50,992) | (50,986) | (50,997) | (50,997) | (51,011) | (51,013) | (51,028) | (51,038) | (51,038) | (51,040) | (51,040) | (612,116) |
| 35 | MISO MVP ARR Revenue | (1,782) | (1,782) | (1,782) | (1,782) | (1,782) | (1,782) | (1,782) | (1,782) | (1,782) | (1,782) | (1,782) | (1,782) | (1,782) | (21,383) |
| 36 | Total MISO Revenues | (503,500) | (484,160) | (490,998) | (503,430) | (471,066) | (488,065) | (494,220) | (497,559) | (489,952) | (505,667) | (510,929) | (532,985) | (532,985) | (5,972,554) |
| 37 | Net Revenue Requirement | 682,977 | 709,285 | 679,684 | 569,962 | 536,415 | 552,036 | 613,113 | 609,879 | 593,269 | 593,269 | 624,750 | 737,889 | 737,889 | 7,467,464 |
| 38 | Billed (forecast kWh x adj factor) | 819,773 | 797,026 | 716,946 | 655,679 | 532,183 | 503,073 | 523,018 | 541,012 | 522,556 | 522,556 | 620,406 | 699,002 | 699,002 | 7,469,920 |
| 39 | Difference | (136,797) | (87,742) | (37,262) | (85,717) | 4,232 | 48,963 | 80,095 | 68,867 | 18,951 | 70,713 | 4,344 | 38,887 | 38,887 | (2,456) |
| 40 | Carrying Charge | 122 | (859) | (1,495) | (1,773) | (2,401) | (2,388) | (2,054) | (1,422) | (936) | (609) | (306) | (277) | (277) | (14,599) |
| 41 | Cumulative Difference | (119,619) | (208,219) | (246,976) | (334,467) | (332,636) | (286,062) | (199,021) | (130,576) | (112,562) | (42,657) | (38,619) | (0) | (0) | (0) |
| 42 | Carrying Charge Calculation | (859) | (1,495) | (1,773) | (2,401) | (2,388) | (2,054) | (1,422) | (938) | (306) | (277) | (277) | (277) | (277) | (0) |
| 43 | Cumulative Carrying Charge | (110,514) | (112,009) | (113,782) | (116,183) | (118,572) | (120,826) | (122,047) | (122,985) | (123,793) | (124,099) | (124,377) | (124,377) | (124,377) | (124,377) |
| 44 | Carrying cost | 8.62% | 8.62% | 8.62% | 8.62% | 8.62% | 8.62% | 8.62% | 8.62% | 8.62% | 8.62% | 8.62% | 8.62% | 8.62% | 8.62% |
| 45 | Forecasted Sales (MWh) | 198,821 | 193,304 | 173,882 | 159,023 | 129,071 | 122,011 | 126,848 | 131,213 | 126,736 | 126,736 | 150,468 | 169,530 | 169,530 | 1,811,684 |

| SUMMARY | | Jan 2018 - | Dec 2018 |
|----------------------|--|------------|-------------|
| Revenue requirements | | | \$7,467,464 |
| Carrying Charge | | | (14,599) |
| 2017 True-Up | | | 17,055 |
| Total requirements | | | \$7,469,920 |

| LINE NO | ITEM | ALLOC | REFERENCE | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|-----------------------------|---------|-------------------|---------------|--------------|-------------|---------|
| 1 | RATE BASE | | Page 2-1 Line 32 | 776,594,536 | 223,306,067 | 553,288,470 | 1 |
| 2 | TOTAL AVAILABLE FOR RETURN | | Page 7-1 Line 43 | 80,145,844 | 11,486,268 | 68,659,575 | 2 |
| 3 | RATE OF RETURN EARNED | | Page 17-1 Line 11 | 10.32% | 5.14% | 15.41% | 3 |
| 4 | RATE OF RETURN REQUESTED | | | | 7.86% | | 4 |
| 5 | OPERATING INCOME REQUIRED | | | | 17,775,163 | | 5 |
| 6 | TOTAL AVAILABLE FOR RETURN | | | | 11,486,268 | | 6 |
| 7 | OPERATING INCOME DEFICIENCY | | | | 6,288,895 | | 7 |
| 8 | INCREMENTAL TAXES | ORCFT = | 1,322,837 | | 2,030,268 | | 8 |
| 9 | REVENUE INCREASE REQUIRED | | | | 8,318,163 | | 9 |
| 10 | PERCENTAGE INCREASE | | | | 6.70% | | 10 |
| 11 | | | | | | | 11 |
| 12 | | | | | | | 12 |
| 13 | | | | | | | 13 |
| 14 | | | | | | | 14 |
| 15 | | | | | | | 15 |
| 16 | | | | | | | 16 |
| 17 | | | | | | | 17 |
| 18 | | | | | | | 18 |
| 19 | | | | | | | 19 |
| 20 | | | | | | | 20 |
| 21 | | | | | | | 21 |
| 22 | | | | | | | 22 |
| 23 | | | | | | | 23 |
| 24 | | | | | | | 24 |
| 25 | | | | | | | 25 |
| 26 | | | | | | | 26 |
| 27 | | | | | | | 27 |
| 28 | | | | | | | 28 |
| 29 | | | | | | | 29 |
| 30 | | | | | | | 30 |
| 31 | | | | | | | 31 |
| 32 | | | | | | | 32 |
| 33 | | | | | | | 33 |
| 34 | | | | | | | 34 |
| 35 | | | | | | | 35 |
| 36 | | | | | | | 36 |
| 37 | | | | | | | 37 |
| 38 | | | | | | | 38 |
| 39 | | | | | | | 39 |
| 40 | | | | | | | 40 |
| 41 | | | | | | | 41 |
| 42 | | | | | | | 42 |
| 43 | | | | | | | 43 |
| 44 | | | | | | | 44 |
| 45 | | | | | | | 45 |
| 46 | | | | | | | 46 |
| 47 | | | | | | | 47 |
| 48 | | | | | | | 48 |
| 49 | | | | | | | 49 |
| 50 | | | | | | | 50 |
| 51 | | | | | | | 51 |
| 52 | | | | | | | 52 |
| 53 | | | | | | | 53 |
| 54 | | | | | | | 54 |
| 55 | | | | | | | 55 |
| 56 | | | | | | | 56 |
| 57 | | | | | | | 57 |
| 58 | | | | | | | 58 |
| 59 | | | | | | | 59 |
| 60 | | | | | | | 60 |

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO | ITEM | ALLOC | REFERENCE | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|---|-------|-------------------|---------------|---------------|---------------|---------|
| 1 | ELECTRIC PLANT IN SERVICE | | Page 3-1 Line 52 | 1,422,111,785 | 529,263,615 | 892,848,150 | 1 |
| 2 | ACCUMULATED DEPRECIATION | | Page 4-12 Line 22 | (639,479,396) | (256,695,448) | (382,783,947) | 2 |
| 3 | NET PLANT EXCLUDING BIG STONE PLANT CAPITALIZED ITEMS | | | 782,632,370 | 272,568,167 | 510,064,303 | 3 |
| 4 | NET CAPITALIZED ITEMS - BIG STONE PLANT | | Page 4-1 Line 28 | 0 | 0 | 0 | 4 |
| 5 | NET ELECTRIC PLANT IN SERVICE | | | 782,632,370 | 272,568,167 | 510,064,303 | 5 |
| 6 | PLANT HELD FOR FUTURE USE | | Page 4-1 Line 47 | 29,857 | 13,044 | 16,813 | 6 |
| 7 | CONSTRUCTION WORK IN PROGRESS | | Page 5-1 Line 31 | 126,064,506 | 271,748 | 124,342,758 | 7 |
| 8 | MATERIALS AND SUPPLIES | | Page 5-1 Line 39 | 19,245,037 | 7,946,545 | 11,298,492 | 8 |
| 9 | FUEL STOCKS | | Page 5-1 Line 46 | 12,099,676 | 4,430,805 | 7,668,871 | 9 |
| 10 | PREPAYMENTS | | Page 5-1 Line 49 | (36,579,305) | (12,739,590) | (23,839,715) | 10 |
| 11 | CUSTOMER ADVANCES | | Page 5-1 Line 51 | (1,013,989) | (353,143) | (660,846) | 11 |
| 12 | CASH WORKING CAPITAL | | Page 5-1 Line 53 | 13,522,643 | 3,549,056 | 9,973,548 | 12 |
| 13 | ACCUMULATED DEFERRED INCOME TAXES | | Page 6-1 Line 16 | (138,415,660) | (62,379,715) | (76,035,945) | 13 |
| 14 | UNAMORTIZED BALANCE - SPPRITHOOD | | Page 6-1 Line 19 | 0 | 0 | 0 | 14 |
| 15 | UNAMORTIZED RATE CASE EXPENSE | | Page 6-1 Line 22 | 0 | 0 | 0 | 15 |
| 16 | TOTAL AVERAGE RATE BASE | | | 776,594,538 | 223,306,067 | 553,288,470 | 16 |
| 17 | | | | | | | 17 |
| 18 | | | | | | | 18 |
| 19 | | | | | | | 19 |
| 20 | | | | | | | 20 |
| 21 | | | | | | | 21 |
| 22 | | | | | | | 22 |
| 23 | | | | | | | 23 |
| 24 | | | | | | | 24 |
| 25 | | | | | | | 25 |
| 26 | | | | | | | 26 |
| 27 | | | | | | | 27 |
| 28 | | | | | | | 28 |
| 29 | | | | | | | 29 |
| 30 | | | | | | | 30 |
| 31 | | | | | | | 31 |
| 32 | | | | | | | 32 |
| 33 | | | | | | | 33 |
| 34 | | | | | | | 34 |
| 35 | | | | | | | 35 |
| 36 | | | | | | | 36 |
| 37 | | | | | | | 37 |
| 38 | | | | | | | 38 |
| 39 | | | | | | | 39 |
| 40 | | | | | | | 40 |
| 41 | | | | | | | 41 |
| 42 | | | | | | | 42 |
| 43 | | | | | | | 43 |
| 44 | | | | | | | 44 |
| 45 | | | | | | | 45 |
| 46 | | | | | | | 46 |
| 47 | | | | | | | 47 |
| 48 | | | | | | | 48 |
| 49 | | | | | | | 49 |
| 50 | | | | | | | 50 |
| 51 | | | | | | | 51 |
| 52 | | | | | | | 52 |
| 53 | | | | | | | 53 |
| 54 | | | | | | | 54 |
| 55 | | | | | | | 55 |
| 56 | | | | | | | 56 |
| 57 | | | | | | | 57 |
| 58 | | | | | | | 58 |
| 59 | | | | | | | 59 |
| 60 | | | | | | | 60 |

NORTH DAKOTA

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2016 Interim Test Year

| LINE NO | ITEM | ALLOE | FERC ACCOUNTS | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|---|-------------|---|---------------|--------------|-------------|---------|
| 1 | PLANT IN SERVICE | | | | | | 1 |
| 2 | AC 101 & 106 - Direct MN | Direct MN | | 3,520,019 | 0 | 3,520,019 | 2 |
| 3 | AC 101 & 106 - Direct ND | Direct ND | | 471,573 | 471,573 | 0 | 3 |
| 4 | AC 101 & 106 - Direct SD | Direct SD | | 1,146,073 | 0 | 1,146,073 | 4 |
| 5 | Subtotal AC 101 & 106 - Direct Assigned | | | 5,137,665 | 471,573 | 4,666,092 | 5 |
| 6 | PRODUCTION PLANT | | | | | | 6 |
| 7 | AC 101 & 106 - BASE DEMAND | E1 | | 376,022,810 | 134,083,371 | 241,939,440 | 7 |
| 8 | PEAK DEMAND | D1 | | 47,788,244 | 19,043,037 | 28,745,207 | 8 |
| 9 | BASE ENERGY | E2 | | 32,751 | 12,307 | 20,444 | 9 |
| 10 | SUBTOTAL AC 101 & 106 | | | 456,863,805 | 165,138,715 | 291,725,090 | 10 |
| 11 | AC 114 - BASE DEMAND | E1 | | 1,288,081 | 462,874 | 825,207 | 11 |
| 12 | PEAK DEMAND | D1 | | 280,174 | 115,607 | 164,567 | 12 |
| 13 | BASE ENERGY | E1 | | 0 | 0 | 0 | 13 |
| 14 | SUBTOTAL AC 114 | | | 1,568,255 | 578,481 | 989,774 | 14 |
| 15 | TOTAL PRODUCTION PLANT | P10 | 310-317, 330-335, 340-347 | 458,432,060 | 154,180,797 | 294,251,263 | 15 |
| 16 | TRANSMISSION PLANT | | | | | | 16 |
| 17 | AC 101 & 106 | D2 | | 264,273,051 | 104,649,241 | 159,623,810 | 17 |
| 18 | AC 101 & 106 (Over FERC) | Direct FERC | | 176,520,627 | 0 | 176,520,627 | 18 |
| 19 | AC 114 | D2 | | 59,287 | 23,081 | 36,206 | 19 |
| 20 | TOTAL TRANSMISSION PLANT | | 359-360, 1, 353-356, 368 | 399,852,965 | 104,672,322 | 295,180,643 | 20 |
| 21 | DISTRIBUTION PLANT | | | | | | 21 |
| 22 | PRIMARY DEMAND | D3 | 360, 362, 364-365, 367 | 186,296,281 | 85,455,191 | 100,841,091 | 22 |
| 23 | SECONDARY DEMAND | D4 | 365, 367-369, 1 | 102,024,443 | 46,993,034 | 55,031,409 | 23 |
| 24 | PRIMARY CUSTOMER | C2 | 364-365, 367 | 79,110,165 | 34,970,009 | 44,139,959 | 24 |
| 25 | SECONDARY CUSTOMER | C3 | 364-365, 367, 373 | 7,440,651 | 3,144,151 | 4,296,500 | 25 |
| 26 | STREET LIGHTING | C4 | 364-365, 367, 373 | 13,863,157 | 6,090,955 | 7,772,202 | 26 |
| 27 | AREA LIGHTING | C5 | 364-365, 367, 371, 2 | 8,020,685 | 4,151,729 | 3,868,956 | 27 |
| 28 | METERS | C6 | 370 | 26,594,887 | 11,882,166 | 14,712,721 | 28 |
| 29 | LOAD MANAGEMENT | C9 | 370, 1 | 8,713,737 | 3,794,879 | 4,918,858 | 29 |
| 30 | TOTAL DISTRIBUTION PLANT | P90 | | 407,992,871 | 228,953,947 | 179,038,924 | 30 |
| 31 | GENERAL PLANT | | | | | | 31 |
| 32 | PRODUCTION | P10 | | 33,863,235 | 12,061,856 | 21,801,470 | 32 |
| 33 | TRANSMISSION | D2 | | 13,030,468 | 5,159,935 | 7,870,533 | 33 |
| 34 | DISTRIBUTION | P90 | | 21,099,100 | 9,685,132 | 11,413,968 | 34 |
| 35 | CUSTOMER ACCOUNTS | CMC | | 16,779,659 | 7,390,245 | 9,389,414 | 35 |
| 36 | CUSTOMER SERVICE & INFO | CSI | | 3,705,137 | 1,658,501 | 2,046,636 | 36 |
| 37 | LOAD MANAGEMENT | C9 | 397, 3 | 317,659 | 136,429 | 181,230 | 37 |
| 38 | TOTAL GENERAL PLANT | P90 | 388-398, 390-396, 3, 391, 1-391, 5, 394, 2, 397, 1-397, 2 | 88,619,779 | 36,081,007 | 52,538,772 | 38 |
| 39 | INTANGIBLE PLANT | | | | | | 39 |
| 40 | | P90 | 302-303 | 14,067,426 | 5,727,462 | 8,339,964 | 40 |
| 41 | TOTAL PLANT IN SERVICE | EPS | | 1,422,111,785 | 528,263,615 | 893,848,170 | 41 |
| 42 | | | | | | | 42 |
| 43 | | | | | | | 43 |
| 44 | | | | | | | 44 |
| 45 | | | | | | | 45 |
| 46 | | | | | | | 46 |
| 47 | | | | | | | 47 |
| 48 | | | | | | | 48 |
| 49 | | | | | | | 49 |
| 50 | | | | | | | 50 |
| 51 | | | | | | | 51 |
| 52 | | | | | | | 52 |
| 53 | | | | | | | 53 |
| 54 | | | | | | | 54 |
| 55 | | | | | | | 55 |
| 56 | | | | | | | 56 |
| 57 | | | | | | | 57 |
| 58 | | | | | | | 58 |
| 59 | | | | | | | 59 |
| 60 | | | | | | | 60 |
| 61 | | | | | | | 61 |
| 62 | | | | | | | 62 |
| 63 | | | | | | | 63 |
| 64 | | | | | | | 64 |
| 65 | | | | | | | 65 |
| 66 | | | | | | | 66 |

| LINE NO | ITEM | ALLOC | FERC ACCOUNTS | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|---|-------------|---------------|---------------|---------------|---------------|---------|
| 1 | ACCUMULATED DEPRECIATION | | | | | | 1 |
| 2 | PRODUCTION PLANT | E1 | 108, 115 | (23,376,017) | (79,725,424) | (143,852,559) | 2 |
| 3 | BASE DEMAND | D1 | 108, 115 | (46,728,160) | (18,615,711) | (28,111,459) | 3 |
| 4 | PEAK DEMAND | E2 | 108 | 15,504 | 5,505 | 9,978 | 4 |
| 5 | BASE ENERGY | | | | | | 5 |
| 6 | TOTAL PRODUCTION PLANT | | | (27,238,673) | (93,334,308) | (171,354,365) | 6 |
| 7 | | | | | | | 7 |
| 8 | | | | | | | 8 |
| 9 | TRANSMISSION PLANT | D2 | 108, 115 | (114,261,523) | (45,254,235) | (69,027,289) | 9 |
| 10 | TRANSMISSION PLANT (Direct FERC) | Direct FERC | | (4,419,151) | 0 | (4,419,151) | 10 |
| 11 | TOTAL TRANSMISSION PLANT | | | (118,680,674) | (45,254,235) | (133,449,242) | 11 |
| 12 | | | | | | | 12 |
| 13 | | | | | | | 13 |
| 14 | DISTRIBUTION PLANT | P60 | 108, 115 | (214,337,362) | (98,367,400) | (115,846,962) | 14 |
| 15 | | | | | | | 15 |
| 16 | | | | | | | 16 |
| 17 | GENERAL PLANT | P90 | 108 | (34,142,419) | (13,900,914) | (20,241,505) | 17 |
| 18 | | | | | | | 18 |
| 19 | | | | | | | 19 |
| 20 | INTANGIBLE PLANT | P90 | 108 | (2,010,545) | (818,591) | (1,191,973) | 20 |
| 21 | | | | | | | 21 |
| 22 | TOTAL ACCUMULATED DEPRECIATION | | | (638,479,356) | (256,695,446) | (387,783,842) | 22 |
| 23 | | | | | | | 23 |
| 24 | NET PLANT EXCLUDING BSP CAPITALIZED ITEMS | | | 762,632,470 | 272,565,167 | 510,064,303 | 24 |
| 25 | | | | | | | 25 |
| 26 | BSP CAPITALIZED ITEMS | P10 | | 0 | 0 | 0 | 26 |
| 27 | TOTAL NET PLANT IN SERVICE | NETS | | 762,632,470 | 272,565,167 | 510,064,303 | 27 |
| 28 | | | | | | | 28 |
| 29 | | | | | | | 29 |
| 30 | | | | | | | 30 |
| 31 | | | | | | | 31 |
| 32 | | | | | | | 32 |
| 33 | | | | | | | 33 |
| 34 | | | | | | | 34 |
| 35 | | | | | | | 35 |
| 36 | | | | | | | 36 |
| 37 | | | | | | | 37 |
| 38 | | | | | | | 38 |
| 39 | | | | | | | 39 |
| 40 | | | | | | | 40 |
| 41 | PLANT HELD FOR FUTURE USE | | | | | | 41 |
| 42 | PRODUCTION PLANT | P10 | 105 | 0 | 0 | 0 | 42 |
| 43 | TRANSMISSION PLANT | D2 | 105 | 9,038 | 3,579 | 5,459 | 43 |
| 44 | DISTRIBUTION PLANT | P60 | 105 | 20,519 | 9,469 | 11,154 | 44 |
| 45 | GENERAL PLANT | P90 | 105 | 0 | 0 | 0 | 45 |
| 46 | INTANGIBLE PLANT | P90 | 105 | 0 | 0 | 0 | 46 |
| 47 | TOTAL PLANT HELD FOR FUTURE USE | | | 29,557 | 13,044 | 16,513 | 47 |
| 48 | | | | | | | 48 |
| 49 | | | | | | | 49 |
| 50 | | | | | | | 50 |
| 51 | | | | | | | 51 |
| 52 | | | | | | | 52 |
| 53 | | | | | | | 53 |
| 54 | | | | | | | 54 |
| 55 | | | | | | | 55 |
| 56 | | | | | | | 56 |
| 57 | | | | | | | 57 |
| 58 | | | | | | | 58 |
| 59 | | | | | | | 59 |
| 60 | | | | | | | 60 |
| 61 | | | | | | | 61 |
| 62 | | | | | | | 62 |

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO | ITEM | ALLOC | FERC ACCOUNTS | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|---|-------------|---------------|---------------|--------------|-------------|---------|
| 1 | CONSTR WORK-IN-PROGRESS - Direct Assigned | | | | | | 1 |
| 2 | PRODUCTION PLANT - Direct MN | P10 | | 0 | 0 | 0 | 2 |
| 3 | PRODUCTION PLANT - Direct ND | P10 | | 0 | 0 | 0 | 3 |
| 4 | PRODUCTION PLANT - Direct SD | P10 | | 0 | 0 | 0 | 4 |
| 5 | TRANSMISSION PLANT - Direct MN | D2 | | 0 | 0 | 0 | 5 |
| 6 | TRANSMISSION PLANT - Direct ND | D2 | | 0 | 0 | 0 | 6 |
| 7 | TRANSMISSION PLANT - Direct SD | D2 | | 0 | 0 | 0 | 7 |
| 8 | TRANSMISSION PLANT - Direct FERC | Direct FERC | | 95,778,331 | 0 | 95,778,331 | 8 |
| 9 | DISTRIBUTION PLANT - Direct MN | P60 | | 0 | 0 | 0 | 9 |
| 10 | DISTRIBUTION PLANT - Direct ND | P60 | | 0 | 0 | 0 | 10 |
| 11 | DISTRIBUTION PLANT - Direct SD | P60 | | 0 | 0 | 0 | 11 |
| 12 | DISTRIBUTION PLANT - Direct FERC | Direct FERC | | 0 | 0 | 0 | 12 |
| 13 | GENERAL PLANT - Direct MN | P90 | | 0 | 0 | 0 | 13 |
| 14 | GENERAL PLANT - Direct ND | P90 | | 0 | 0 | 0 | 14 |
| 15 | GENERAL PLANT - Direct SD | P90 | | 0 | 0 | 0 | 15 |
| 16 | GENERAL PLANT - Direct FERC | Direct FERC | | 0 | 0 | 0 | 16 |
| 17 | INTANGIBLE PLANT - Direct MN | P90 | | 0 | 0 | 0 | 17 |
| 18 | INTANGIBLE PLANT - Direct ND | P90 | | 0 | 0 | 0 | 18 |
| 19 | INTANGIBLE PLANT - Direct SD | P90 | | 0 | 0 | 0 | 19 |
| 20 | INTANGIBLE PLANT - Direct FERC | Direct FERC | | 0 | 0 | 0 | 20 |
| 21 | TOTAL CWP - Direct Assigned | | | 95,778,331 | 0 | 95,778,331 | 21 |
| 22 | | | | 0 | 0 | 0 | 22 |
| 23 | | | | 0 | 0 | 0 | 23 |
| 24 | | | | 0 | 0 | 0 | 24 |
| 25 | | | | 0 | 0 | 0 | 25 |
| 26 | CONSTR WORK-IN-PROGRESS - SHORT TERM | | | 0 | 0 | 0 | 26 |
| 27 | PRODUCTION PLANT | P10 | | 686,850 | 271,748 | 414,562 | 27 |
| 28 | DISTRIBUTION PLANT | D2 | | 0 | 0 | 0 | 28 |
| 29 | GENERAL PLANT | P90 | | 0 | 0 | 0 | 29 |
| 30 | INTANGIBLE PLANT | P90 | | 0 | 0 | 0 | 30 |
| 31 | TOTAL CWP - SHORT TERM | | | 686,850 | 271,748 | 414,562 | 31 |
| 32 | | | | 0 | 0 | 0 | 32 |
| 33 | | | | 0 | 0 | 0 | 33 |
| 34 | | | | 0 | 0 | 0 | 34 |
| 35 | | | | 0 | 0 | 0 | 35 |
| 36 | CONSTR WORK-IN-PROGRESS - LONG TERM | | | 0 | 0 | 0 | 36 |
| 37 | PRODUCTION PLANT (AFUDC Projects) | P10 | | 14,041,071 | 0 | 14,041,071 | 37 |
| 38 | TRANSMISSION PLANT (AFUDC Projects) | D2 | | 5,855,384 | 0 | 5,855,384 | 38 |
| 39 | DISTRIBUTION PLANT (AFUDC Projects) | P60 | | 1,149,148 | 0 | 1,149,148 | 39 |
| 40 | GENERAL PLANT (AFUDC Projects) | P90 | | 1,603,989 | 0 | 1,603,989 | 40 |
| 41 | INTANGIBLE PLANT (AFUDC Projects) | P90 | | 5,941,143 | 0 | 5,941,143 | 41 |
| 42 | TOTAL CWP - LONG TERM - AFUDC Projects | | | 28,591,635 | 0 | 28,591,635 | 42 |
| 43 | | | | 0 | 0 | 0 | 43 |
| 44 | TOTAL CWP - LONG TERM - Other Projects | | | 0 | 0 | 0 | 44 |
| 45 | TOTAL CWP - LONG TERM | | | 28,591,635 | 0 | 28,591,635 | 45 |
| 46 | | | | 0 | 0 | 0 | 46 |
| 47 | TOTAL CONSTRUCTION WORK-IN-PROGRESS | | 107 | 125,954,956 | 271,748 | 124,782,759 | 47 |
| 48 | | | | 0 | 0 | 0 | 48 |
| 49 | | | | 0 | 0 | 0 | 49 |
| 50 | | | | 0 | 0 | 0 | 50 |
| 51 | MATERIALS & SUPPLIES | | | 0 | 0 | 0 | 51 |
| 52 | PRODUCTION | P10 | | 5,478,732 | 1,961,911 | 3,516,822 | 52 |
| 53 | TRANSMISSION | D2 | | 5,450,400 | 2,158,259 | 3,292,101 | 53 |
| 54 | DISTRIBUTION | P60 | | 8,335,895 | 3,826,435 | 4,509,470 | 54 |
| 55 | TOTAL MATERIALS AND SUPPLIES | | 154, 158.1 | 19,265,027 | 7,946,605 | 11,318,422 | 55 |
| 56 | | | | 0 | 0 | 0 | 56 |
| 57 | FUEL STOCKS | | | 0 | 0 | 0 | 57 |
| 58 | COAL STOCKS | E1 | | 9,319,827 | 3,323,221 | 5,996,406 | 58 |
| 59 | FUEL OIL STOCKS | D1 | | 2,780,049 | 1,107,584 | 1,672,465 | 59 |
| 60 | TOTAL FUEL STOCKS | | 1510 | 12,099,876 | 4,430,805 | 7,669,071 | 60 |
| 61 | PREPAYMENTS | | | 0 | 0 | 0 | 61 |
| 62 | CUSTOMER ADVANCES | | 128, 228.3 | 0 | 0 | 0 | 62 |
| 63 | CASH WORKING CAPITAL | | 235, 253 | 0 | 0 | 0 | 63 |
| 64 | | | | 0 | 0 | 0 | 64 |
| 65 | | | | 0 | 0 | 0 | 65 |
| 66 | | | | 0 | 0 | 0 | 66 |
| 67 | TOTAL | | | 38,579,505 | (12,739,590) | 25,839,915 | 67 |
| 68 | | | | (1,913,888) | (553, 143) | (660,846) | 68 |
| 69 | | | | 13,522,643 | 3,548,065 | 9,974,548 | 69 |
| 70 | | | | 0 | 0 | 0 | 70 |
| 71 | | | | 0 | 0 | 0 | 71 |
| 72 | | | | 0 | 0 | 0 | 72 |
| 73 | | | | 0 | 0 | 0 | 73 |
| 74 | | | | 0 | 0 | 0 | 74 |
| 75 | | | | 0 | 0 | 0 | 75 |
| 76 | | | | 0 | 0 | 0 | 76 |
| 77 | | | | 0 | 0 | 0 | 77 |

SEPARATELY CALCULATED BY JURISDICTION

| LINE NO | ITEM | ALLOC | FERC ACCOUNTS | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE INS |
|---------|---|-------------|-----------------|---------------|--------------|--------------|----------|
| 1 | ACCUMULATED DEFERRED INCOME TAXES | | | | | | 1 |
| 2 | ITEMS BELOW THROUGH | | | | | | 2 |
| 3 | FEDERAL | NPWR | | 495,531 | 164,922 | 270,609 | 3 |
| 4 | MINNESOTA | NPWA | | 72,888 | 0 | 72,888 | 4 |
| 5 | NORTH DAKOTA | NPWA | | 35,772 | 35,772 | 0 | 5 |
| 6 | SUBTOTAL | | | 543,271 | 200,693 | 342,578 | 6 |
| 7 | ALL OTHER | | | | | | 7 |
| 8 | FEDERAL (incl FERC) | NEPR | | (45,449,439) | (15,828,777) | (29,620,713) | 8 |
| 9 | MINNESOTA | Direct FERC | | (23,579,516) | 0 | (23,579,516) | 9 |
| 10 | NORTH DAKOTA | NPWA | | (38,751,849) | (38,751,849) | 0 | 10 |
| 11 | SUBTOTAL | | | (138,569,337) | (52,560,426) | (86,378,923) | 11 |
| 12 | TOTAL ACCUMULATED DEFERRED INCOME TAXES | | 180,355,281-283 | (138,415,860) | (52,379,715) | (86,038,245) | 12 |
| 13 | UNAMORTIZED BALANCE - SPRITWOOD PLAN | P10 | | 0 | 0 | 0 | 13 |
| 14 | UNAMORTIZED RATE CASE EXPENSES | R10 | | 0 | 0 | 0 | 14 |
| 15 | TOTAL AVERAGE RATE BASE | | | 778,584,538 | 223,306,067 | 555,278,470 | 15 |
| 16 | | | | | | | 16 |
| 17 | | | | | | | 17 |
| 18 | | | | | | | 18 |
| 19 | | | | | | | 19 |
| 20 | | | | | | | 20 |
| 21 | | | | | | | 21 |
| 22 | | | | | | | 22 |
| 23 | | | | | | | 23 |
| 24 | | | | | | | 24 |
| 25 | | | | | | | 25 |
| 26 | | | | | | | 26 |
| 27 | | | | | | | 27 |
| 28 | | | | | | | 28 |
| 29 | | | | | | | 29 |
| 30 | | | | | | | 30 |
| 31 | | | | | | | 31 |
| 32 | | | | | | | 32 |
| 33 | | | | | | | 33 |
| 34 | | | | | | | 34 |
| 35 | | | | | | | 35 |
| 36 | | | | | | | 36 |
| 37 | | | | | | | 37 |
| 38 | | | | | | | 38 |
| 39 | | | | | | | 39 |
| 40 | | | | | | | 40 |
| 41 | | | | | | | 41 |
| 42 | | | | | | | 42 |
| 43 | | | | | | | 43 |
| 44 | | | | | | | 44 |
| 45 | | | | | | | 45 |
| 46 | | | | | | | 46 |
| 47 | | | | | | | 47 |
| 48 | | | | | | | 48 |
| 49 | | | | | | | 49 |
| 50 | | | | | | | 50 |
| 51 | | | | | | | 51 |
| 52 | | | | | | | 52 |
| 53 | | | | | | | 53 |
| 54 | | | | | | | 54 |
| 55 | | | | | | | 55 |
| 56 | | | | | | | 56 |
| 57 | | | | | | | 57 |
| 58 | | | | | | | 58 |
| 59 | | | | | | | 59 |
| 60 | | | | | | | 60 |
| 61 | | | | | | | 61 |

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO | ITEM | ALLOC | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|---|-------|---------------|--------------|-------------|---------|
| 1 | OPERATING REVENUES | | | | | 1 |
| 2 | SALES OF ELECTRICITY | | 369,865,140 | 122,966,268 | 237,275,872 | 2 |
| 3 | OTHER OPERATING REVENUE | | 58,232,545 | 9,712,037 | 48,520,508 | 3 |
| 4 | | | | | | 4 |
| 5 | TOTAL OPERATING REVENUE | | 418,097,684 | 132,301,305 | 285,796,379 | 5 |
| 6 | | | | | | 6 |
| 7 | OPERATING EXPENSES | | | | | 7 |
| 8 | PRODUCTION EXPENSES | | 157,419,623 | 58,417,943 | 99,001,580 | 8 |
| 9 | TRANSMISSION EXPENSES | | 29,047,390 | 11,026,754 | 18,020,636 | 9 |
| 10 | SALES AND DELIVERY EXPENSES | | 19,849,838 | 7,849,838 | 12,000,000 | 10 |
| 11 | DEPRECIATION EXPENSES | | 11,949,838 | 6,091,579 | 7,258,344 | 11 |
| 12 | CUSTOMER SERVICE AND INFORMATION EXPENSES | | 11,987,740 | 1,392,509 | 9,715,231 | 12 |
| 13 | SALES EXPENSES | | 273,627 | 22,472 | 251,155 | 13 |
| 14 | ADMINISTRATIVE AND GENERAL EXPENSES | | 49,279,686 | 19,262,795 | 29,996,891 | 14 |
| 15 | CHARITABLE CONTRIBUTIONS | | 0 | 0 | 0 | 15 |
| 16 | DEPRECIATION EXPENSE | | 35,016,724 | 13,387,642 | 21,629,082 | 16 |
| 17 | AMORTIZATION OF BIG STONE PLANT CAPITALIZED COSTS | | 0 | 0 | 0 | 17 |
| 18 | DEPRECIATION EXPENSE | | 0 | 0 | 0 | 18 |
| 19 | AMORTIZATION | | 13,082,883 | 0 | 13,082,883 | 19 |
| 20 | GENERAL TAXES | | 0 | 3,938,724 | 8,145,149 | 20 |
| 21 | | | | | | 21 |
| 22 | TOTAL OPERATING EXPENSES | | 325,884,772 | 121,229,349 | 204,755,423 | 22 |
| 23 | | | | | | 23 |
| 24 | NET OPERATING INCOME BEFORE INCOME TAXES | | 85,212,912 | 11,071,955 | 81,540,957 | 24 |
| 25 | | | | | | 25 |
| 26 | | | | | | 26 |
| 27 | | | | | | 27 |
| 28 | INCOME TAX EXPENSE | | | | | 28 |
| 29 | INVESTMENT TAX CREDIT | | (3,140,509) | (1,183,682) | (1,956,827) | 29 |
| 30 | DEFERRED INCOME TAXES | | (6,866,242) | (1,638,469) | (4,228,773) | 30 |
| 31 | INCOME TAXES | | 23,641,293 | 2,409,838 | 20,632,455 | 31 |
| 32 | | | | | | 32 |
| 33 | TOTAL INCOME TAX EXPENSE | | 13,942,544 | (414,313) | 14,456,857 | 33 |
| 34 | | | | | | 34 |
| 35 | | | | | | 35 |
| 36 | NET OPERATING INCOME | | 78,118,259 | 11,486,268 | 66,632,101 | 36 |
| 37 | | | | | | 37 |
| 38 | | | | | | 38 |
| 39 | Allowance for Funds Used During Construction - SAN Only | | 2,027,574 | 0 | 2,027,574 | 39 |
| 40 | Allowance for Funds Used During Construction - SD Only | | 0 | 0 | 0 | 40 |
| 41 | Allowance for Funds Used During Construction - SD Only | | 0 | 0 | 0 | 41 |
| 42 | TOTAL ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION | | 2,027,574 | 0 | 2,027,574 | 42 |
| 43 | | | | | | 43 |
| 44 | TOTAL AVAILABLE FOR RETURN | | 80,145,844 | 11,486,268 | 68,659,575 | 44 |
| 45 | | | | | | 45 |
| 46 | | | | | | 46 |
| 47 | | | | | | 47 |
| 48 | | | | | | 48 |
| 49 | | | | | | 49 |
| 50 | | | | | | 50 |
| 51 | AVERAGE CENTS PER KWH | | | | | 51 |
| 52 | | | | | | 52 |
| 53 | | | | | | 53 |
| 54 | | | | | | 54 |
| 55 | | | | | | 55 |
| 56 | | | | | | 56 |
| 57 | | | | | | 57 |
| 58 | | | | | | 58 |
| 59 | | | | | | 59 |
| 60 | | | | | | 60 |
| 61 | | | | | | 61 |
| 62 | | | | | | 62 |
| 63 | | | | | | 63 |

| LINE NO | ITEM | ALLOC | FERC ACCOUNTS | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NOS |
|---------|---------------------------------------|----------------|-----------------|---------------|--------------|-------------|----------|
| 1 | OPERATING REVENUES | | | | | | |
| 2 | SALES OF ELECTRICITY | R10 | 440,442,444.445 | 359,885,140 | 122,560,288 | 237,325,872 | 1 |
| 3 | OTHER OPERATING REVENUES | | | | | | 2 |
| 4 | SALES FOR RESALE | | | | | | 3 |
| 5 | MUNICIPALITIES & OFF SYSTEM SALES | | | | | | 4 |
| 6 | NON-ASSOCIATED UTILITIES, COOPS & OPA | | | | | | 5 |
| 7 | BUY SELL TRANSACTIONS | D2 | | 188,869 | | 188,869 | 6 |
| 8 | ADDITIONAL TRANSACTIONS | | | | | | 7 |
| 9 | BASE DEMAND | E1 | | | | | 8 |
| 10 | PEAK DEMAND | D1 | | | | | 9 |
| 11 | BASE ENERGY | E2 | | 15,026 | 5,646 | | 10 |
| 12 | PEAK ENERGY | D1 | | | | | 11 |
| 13 | TOTAL ALL OTHER TRANSACTIONS | | | 15,026 | 5,646 | | 12 |
| 14 | TOTAL SALES FOR RESALE | | | | | | 13 |
| 15 | OTHER ELECTRIC REVENUES | | | 214,025 | 5,646 | | 14 |
| 16 | LATE FEES | C1 | | | | | 15 |
| 17 | CONNECTION FEES | C1 | | | | | 16 |
| 18 | RENT FROM ELECTRIC PROPERTY - RPS | NEPS | | 705,671 | 277,659 | 428,022 | 17 |
| 19 | RENT FROM ELECTRIC PROPERTY - RSC | NEPS | | 353,894 | 135,015 | 218,879 | 18 |
| 20 | RENT FROM ELECTRIC PROPERTY - COV | NEPS | | 568,608 | 197,821 | 370,787 | 19 |
| 21 | OTHER MISC ELECTRIC REVENUE - MN | NEPS | | 1,113,600 | 4,413 | 1,109,187 | 20 |
| 22 | OTHER MISC ELECTRIC REVENUE - ND | NEPS | | 9,900 | 897,486 | 1,006,386 | 21 |
| 23 | OTHER MISC ELECTRIC REVENUE - SD | NEPS | | 2,576,576 | | 2,576,576 | 22 |
| 24 | IT/DEFICIENCY PAYMENTS | C1 | | | | | 23 |
| 25 | MISCELLANEOUS SERVICES | NEPS | | 1,773,638 | 617,707 | 1,155,932 | 24 |
| 26 | WHEELING | NEPS | | 38,101 | 9,797 | 28,304 | 25 |
| 27 | LOAD CONTROL AND DISPATCH | NEPS | | 439,772 | 439,772 | | 26 |
| 28 | RESIDENTIAL CONSERVATION SERVICES | Direct FERC C1 | | 21,716,525 | 7,553,374 | 14,163,150 | 27 |
| 29 | TOTAL OTHER ELECTRIC REVENUES | | | 29,831,233 | 29,831,233 | 29,831,233 | 28 |
| 30 | TOTAL OTHER OPERATING REVENUES | | | 2,676 | | 2,676 | 29 |
| 31 | TOTAL OTHER ELECTRIC REVENUES | | | 50,018,520 | 9,705,350 | 40,313,170 | 30 |
| 32 | TOTAL OTHER OPERATING REVENUES | | | 58,232,545 | 9,712,037 | 48,520,508 | 31 |
| 33 | TOTAL OPERATING REVENUES | | | 418,097,684 | 132,301,305 | 285,796,380 | 32 |
| 34 | | | | | | | 33 |
| 35 | | | | | | | 34 |
| 36 | | | | | | | 35 |
| 37 | | | | | | | 36 |
| 38 | | | | | | | 37 |
| 39 | | | | | | | 38 |
| 40 | | | | | | | 39 |
| 41 | | | | | | | 40 |
| 42 | | | | | | | 41 |
| 43 | | | | | | | 42 |
| 44 | | | | | | | 43 |
| 45 | | | | | | | 44 |
| 46 | | | | | | | 45 |
| 47 | | | | | | | 46 |
| 48 | | | | | | | 47 |
| 49 | | | | | | | 48 |
| 50 | | | | | | | 49 |
| 51 | | | | | | | 50 |
| 52 | | | | | | | 51 |
| 53 | | | | | | | 52 |
| 54 | | | | | | | 53 |
| 55 | | | | | | | 54 |
| 56 | | | | | | | 55 |
| 57 | | | | | | | 56 |
| 58 | | | | | | | 57 |
| 59 | | | | | | | 58 |
| 60 | | | | | | | 59 |
| 61 | | | | | | | 60 |
| 62 | | | | | | | 61 |
| 63 | | | | | | | 62 |
| 64 | | | | | | | 63 |

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO | ITEM | ALLOC | FERC ACCOUNTS | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|---|-------------|--|---------------|--------------|------------|---------|
| 1 | OPERATING EXPENSES | | | | | | 1 |
| 2 | PRODUCTION EXPENSES | | | | | | 2 |
| 3 | PROD EXPENSES EXCLUDING PURCHASED POWER | | | | | | 3 |
| 4 | BASE DEMAND | E1 | 505,579, 585,507, 595,511, 535, 537,543, 546, 548,554, 555,557 | 5,630,959 | 5,630,959 | 10,171,555 | 4 |
| 5 | BASE ENERGY | D1 | 500,300, 595,507, 599,511 | 1,395,510 | 1,395,510 | 2,045,916 | 5 |
| 6 | PEAK DEMAND | E2 | 501,512-514, 544-548, 548-554 | 68,148,362 | 24,855,736 | 41,291,595 | 6 |
| 7 | PEAK ENERGY | D1 | 547 | 509,800 | 202,629 | 305,971 | 7 |
| 8 | BASE DEMAND (Direct MN) | | | 1,032,569 | 0 | 1,032,569 | 8 |
| 9 | PEAK DEMAND (Direct MN) | | | 230,821 | 0 | 230,821 | 9 |
| 10 | TOTAL EXCLUDING PURCHASED POWER | | | 87,159,201 | 32,062,903 | 55,096,297 | 10 |
| 11 | | | | | | | 11 |
| 12 | | | | | | | 12 |
| 13 | | | | | | | 13 |
| 14 | PURCHASED POWER | | | | | | 14 |
| 15 | BUY/SELL TRANSACTIONS | D2 | | 0 | 0 | 0 | 15 |
| 16 | ALL OTHER TRANSACTIONS | | | | | | 16 |
| 17 | BASE DEMAND | E1 | 555 | 2,439,877 | 870,019 | 1,569,858 | 17 |
| 18 | BASE ENERGY | E2 | 555 | 67,820,445 | 25,485,120 | 42,335,325 | 18 |
| 19 | PEAK ENERGY | D1 | | 0 | 0 | 0 | 19 |
| 20 | TOTAL ALL OTHER TRANSACTIONS | | | 70,260,322 | 26,355,139 | 43,905,183 | 20 |
| 21 | TOTAL PURCHASED POWER | | | 70,260,322 | 26,355,139 | 43,905,183 | 21 |
| 22 | TOTAL PRODUCTION EXPENSES | | | 157,419,523 | 58,417,943 | 99,001,580 | 22 |
| 23 | | | | | | | 23 |
| 24 | | | | | | | 24 |
| 25 | | | | | | | 25 |
| 26 | | | | | | | 26 |
| 27 | | | | | | | 27 |
| 28 | TRANSMISSION EXPENSES | D2 | 560,1561.1-561.2, 561.4-561.6, 562-563, 565-566, 568, 1-569.2, 570-573 | 27,846,108 | 11,026,754 | 16,819,353 | 28 |
| 29 | TRANSMISSION EXPENSES (Direct MN) | | | 1,184,949 | 0 | 1,184,949 | 29 |
| 30 | TRANSMISSION EXPENSES (Direct FERC) | Direct FERC | | 16,223 | 0 | 16,223 | 30 |
| 31 | TOTAL TRANSMISSION EXPENSES | | | 29,047,280 | 11,026,754 | 18,020,576 | 31 |
| 32 | | | | | | | 32 |
| 33 | | | | | | | 33 |
| 34 | | | | | | | 34 |
| 35 | DISTRIBUTION EXPENSES | | | | | | 35 |
| 36 | PRIMARY DEMAND | D3 | 590-594, 598-599, 597-594, 598 | 5,246,830 | 2,406,783 | 2,840,136 | 36 |
| 37 | SECONDARY DEMAND | D4 | 590-591, 593-594, 598, 599, 593-595, 598 | 1,890,891 | 902,966 | 977,395 | 37 |
| 38 | PRIMARY CUSTOMER | C2 | 590-591, 593-594, 598-599, 593-594, 598 | 3,090,357 | 1,363,590 | 1,706,777 | 38 |
| 39 | SECONDARY CUSTOMER | C1 | 590-591, 593-594, 597-598, 590, 593-595, 598 | 2,200,175 | 724,521 | 1,214,684 | 39 |
| 40 | AREA LIGHTING | C5 | 590-591, 593-594, 598-599, 593-594, 598 | 143,949 | 74,046 | 69,903 | 40 |
| 41 | METERS | C6 | 590-591, 596, 598, 597-599 | 2,693,890 | 1,203,654 | 1,490,306 | 41 |
| 42 | LOAD MANAGEMENT | C9 | | 0 | 0 | 0 | 42 |
| 43 | TOTAL DISTRIBUTION | OXD | | 16,917,384 | 7,680,921 | 9,236,463 | 43 |
| 44 | | | | | | | 44 |
| 45 | | | | | | | 45 |
| 46 | | | | | | | 46 |
| 47 | CUSTOMER ACCOUNTING EXPENSES | C7 | 901-902 | 5,358,450 | 2,289,472 | 3,068,978 | 47 |
| 48 | METER READING | C8 | 901-903-905 | 8,493,476 | 3,802,108 | 4,691,368 | 48 |
| 49 | OTHER | OXC | | 13,849,826 | 6,091,579 | 7,758,246 | 49 |
| 50 | TOTAL CUSTOMER ACCOUNTS | | | | | | 50 |
| 51 | | | | | | | 51 |
| 52 | | | | | | | 52 |
| 53 | | | | | | | 53 |
| 54 | | | | | | | 54 |
| 55 | | | | | | | 55 |
| 56 | | | | | | | 56 |
| 57 | | | | | | | 57 |
| 58 | | | | | | | 58 |
| 59 | | | | | | | 59 |
| 60 | | | | | | | 60 |
| 61 | | | | | | | 61 |
| 62 | | | | | | | 62 |
| 63 | | | | | | | 63 |
| 64 | | | | | | | 64 |
| 65 | | | | | | | 65 |

| LINE NO | ITEM | ALLOC | PERC ACCOUNTS | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|----------------------------|-------------|---------------|---------------|--------------|------------|---------|
| 1 | DEPRECIATION EXPENSE | | | | | | 1 |
| 2 | PRODUCTION | | | | | | 2 |
| 3 | BASE DEMAND | E1 | | 10,181,475 | 3,630,542 | 6,550,933 | 3 |
| 4 | PEAK DEMAND | D1 | | 1,108,898 | 441,753 | 667,145 | 4 |
| 5 | BASE ENERGY | E2 | | 0 | 0 | 0 | 5 |
| 6 | TOTAL PRODUCTION | | | 11,290,373 | 4,072,295 | 7,218,128 | 6 |
| 7 | | | | | | | 7 |
| 8 | | | | | | | 8 |
| 9 | TRANSMISSION | D2 | | 5,192,072 | 2,020,365 | 3,171,707 | 9 |
| 10 | TRANSMISSION (Direct PERC) | Direct PERC | | 2,252,037 | 0 | 2,252,037 | 10 |
| 11 | TOTAL TRANSMISSION | | | 7,444,109 | 2,020,365 | 5,423,744 | 11 |
| 12 | | | | | | | 12 |
| 13 | | | | | | | 13 |
| 14 | DISTRIBUTION | P60 | | 11,725,197 | 5,385,437 | 6,339,760 | 14 |
| 15 | | | | | | | 15 |
| 16 | GENERAL | P90 | | 2,285,886 | 930,679 | 1,355,207 | 16 |
| 17 | | | | | | | 17 |
| 18 | INTANGIBLE | P90 | | 2,404,221 | 978,865 | 1,425,356 | 18 |
| 19 | | | | | | | 19 |
| 20 | | | | | | | 20 |
| 21 | TOTAL DEPRECIATION EXPENSE | | | 35,018,724 | 13,387,542 | 21,631,182 | 21 |
| 22 | | | | | | | 22 |
| 23 | | | 403 | | | | 23 |
| 24 | | | | | | | 24 |
| 25 | | | | | | | 25 |
| 26 | | | | | | | 26 |
| 27 | | | | | | | 27 |
| 28 | | | | | | | 28 |
| 29 | | | | | | | 29 |
| 30 | BIG STONE EXPENSE OFFSETS | P10 | | 0 | 0 | 0 | 30 |
| 31 | | | | | | | 31 |
| 32 | | | | | | | 32 |
| 33 | | | | | | | 33 |
| 34 | | | | | | | 34 |
| 35 | SPRITWOOD AMORTIZATION | P10 | 408 | 0 | 0 | 0 | 35 |
| 36 | | | | | | | 36 |
| 37 | | | | | | | 37 |
| 38 | | | | | | | 38 |
| 39 | | | | | | | 39 |
| 40 | | | | | | | 40 |
| 41 | | | | | | | 41 |
| 42 | | | | | | | 42 |
| 43 | | | | | | | 43 |
| 44 | | | | | | | 44 |
| 45 | | | | | | | 45 |
| 46 | | | | | | | 46 |
| 47 | | | | | | | 47 |
| 48 | | | | | | | 48 |
| 49 | | | | | | | 49 |
| 50 | | | | | | | 50 |
| 51 | | | | | | | 51 |
| 52 | | | | | | | 52 |
| 53 | | | | | | | 53 |
| 54 | | | | | | | 54 |
| 55 | | | | | | | 55 |
| 56 | | | | | | | 56 |
| 57 | | | | | | | 57 |
| 58 | | | | | | | 58 |
| 59 | | | | | | | 59 |
| 60 | | | | | | | 60 |
| 61 | | | | | | | 61 |
| 62 | | | | | | | 62 |

DIRECTLY ASSIGNED TO JURISDICTION

DIRECTLY ASSIGNED TO JURISDICTION

OTTED T&E POWERS COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO | ITEM | ALLOC | FERC ACCOUNTS | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|---|-------------|---------------|---------------|--------------|-------------|---------|
| 1 | GENERAL TAXES | NEPS | | 11,300,662 | 3,936,734 | 7,366,618 | 1 |
| 2 | GENERAL TAXES (Deduct FERC) | Deduct FERC | | 1,779,231 | 0 | 1,779,231 | 2 |
| 3 | TOTAL GENERAL TAXES | | 408.1 | 13,079,893 | 3,936,734 | 9,146,149 | 3 |
| 4 | NET OPERATING INCOME BEFORE TAX (NOBT) | | | 92,112,912 | 11,071,665 | 81,040,867 | 4 |
| 5 | INVESTMENT TAX CREDIT | | | (3,180,569) | (1,183,662) | (1,996,827) | 5 |
| 6 | AMORTIZE PRIOR YEARS CREDIT | | | 0 | 0 | 0 | 6 |
| 7 | DEBITS UTILIZED | | | 0 | 0 | 0 | 7 |
| 8 | TOTAL INVESTMENT TAX CREDIT | | 411.4 | (3,180,569) | (1,183,662) | (1,996,827) | 8 |
| 9 | DEFERRED INCOME TAXES | | | 0 | 0 | 0 | 9 |
| 10 | ITEMS SOUTH DAKOTA FLOWS THROUGH | | | 0 | 0 | 0 | 10 |
| 11 | FEDERAL | | | 0 | 0 | 0 | 11 |
| 12 | MINNESOTA | | | 0 | 0 | 0 | 12 |
| 13 | NORTH DAKOTA | | | 0 | 0 | 0 | 13 |
| 14 | SUBTOTAL | | | 0 | 0 | 0 | 14 |
| 15 | ALL OTHER | | | 0 | 0 | 0 | 15 |
| 16 | FEDERAL - Transfer from Current Income Taxes - NOL | | | (6,614,615) | (3,000,220) | (5,614,394) | 16 |
| 17 | FEDERAL (NEPS) | | | (6,614,615) | (3,000,220) | (5,614,394) | 17 |
| 18 | FEDERAL | | | 0 | 0 | 0 | 18 |
| 19 | MINNESOTA - Transfer from Current Income Taxes - NOL | | | 1,369,019 | 0 | 1,369,019 | 19 |
| 20 | MINNESOTA (NPSM) | | | 1,369,019 | 0 | 1,369,019 | 20 |
| 21 | MINNESOTA | | | 0 | 0 | 0 | 21 |
| 22 | NORTH DAKOTA - Transfer from Current Income Taxes - NOL | | | 515,450 | 515,545 | (95) | 22 |
| 23 | NORTH DAKOTA (NPSN) | | | 515,450 | 515,545 | (95) | 23 |
| 24 | NORTH DAKOTA | | | 845,206 | 0 | 845,206 | 24 |
| 25 | SUBTOTAL | | | 1,369,264 | 1,369,751 | (487) | 25 |
| 26 | TOTAL DEFERRED INCOME TAXES | | | (5,245,351) | (1,630,469) | (3,614,882) | 26 |
| 27 | CURRENT INCOME TAXES | | | (6,866,242) | (1,630,469) | (4,235,773) | 27 |
| 28 | FEDERAL - Transfer to Deferred Income Taxes - NOL | | | 0 | 0 | 0 | 28 |
| 29 | FEDERAL (NPSM) | | | 18,098,507 | 2,408,839 | 15,689,668 | 29 |
| 30 | FEDERAL INCOME TAXES | | | 18,098,507 | 2,408,839 | 15,689,668 | 30 |
| 31 | MINNESOTA - Transfer to Deferred Income Taxes - NOL | | | 4,944,670 | 0 | 4,944,670 | 31 |
| 32 | MINNESOTA CURRENT INCOME TAX | | | 4,944,670 | 0 | 4,944,670 | 32 |
| 33 | MINNESOTA INCOME TAXES | | | 0 | 0 | 0 | 33 |
| 34 | NORTH DAKOTA - Transfer to Deferred Income Taxes - NOL | | | (515,545) | (515,545) | 0 | 34 |
| 35 | NORTH DAKOTA CURRENT INCOME TAX | | | 515,545 | 515,545 | 0 | 35 |
| 36 | NORTH DAKOTA INCOME TAXES | | | 0 | 0 | 0 | 36 |
| 37 | TOTAL CURRENT INCOME TAXES | | | 23,041,293 | 2,408,838 | 20,632,455 | 37 |
| 38 | TOTAL INCOME TAXES | | 409.1 | 13,994,542 | (414,313) | 14,408,855 | 38 |
| 39 | NET OPERATING INCOME | | | 78,118,369 | 11,486,268 | 66,632,101 | 39 |
| 40 | AFDC | | | 2,027,574 | 0 | 2,027,574 | 40 |
| 41 | AFDC - MN Only | | | 0 | 0 | 0 | 41 |
| 42 | AFDC - SD Only | | | 0 | 0 | 0 | 42 |
| 43 | Total AFDC | | | 2,027,574 | 0 | 2,027,574 | 43 |
| 44 | TOTAL AVAILABLE FOR RETURN | | 419.1 | 80,145,943 | 11,486,268 | 68,659,675 | 44 |
| 45 | RATE OF RETURN ON RATE BASE | | | 10.32% | 5.14% | 12.41% | 45 |

OTTED T&E POWERS COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

LOTTERY POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO. | ITEM | ALLOC | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO. |
|----------|---|-------|---------------|--------------|--------------|----------|
| 1 | DEVELOPMENT OF FEDERAL INCOME TAX EXPENSE | | | | | 1 |
| 2 | NET OPERATING INCOME BEFORE TAX (NOBT) | | 92,112,812 | 11,071,955 | 81,040,857 | 2 |
| 3 | LESS: INTEREST COST | | 19,454,197 | 5,694,305 | 13,759,892 | 3 |
| 4 | NET INCOME BEFORE TAX | | 72,658,725 | 5,377,650 | 67,281,074 | 4 |
| 5 | FEDERAL SCHEDULE M ADJUSTMENTS: | | | | | 5 |
| 6 | ADDITIONAL TAX DEPRECIATION | | (9,985,336) | (3,477,603) | (6,507,734) | 6 |
| 7 | DIRECTLY ASSIGNED SCHEDULE M ITEMS | | 900,000 | 174,135 | 725,865 | 7 |
| 8 | CHANGES - OPERATING RESERVES | | 8,193,954 | 0 | 8,193,954 | 8 |
| 9 | PROVISIONS - OPERATING RESERVES | | (2,710,794) | 2,853,716 | (5,564,510) | 9 |
| 10 | UNBILLED REVENUES | | 0 | (944,091) | 944,091 | 10 |
| 11 | PREFERRED DIVIDENDS PAID CREDIT | | 0 | 0 | 0 | 11 |
| 12 | OTHER SCHEDULE M ITEMS | | (14,973,149) | (5,214,713) | (9,758,436) | 12 |
| 13 | SUBTOTAL FEDERAL SCHEDULE M ADJUSTMENTS | | (10,975,325) | (6,688,555) | (14,663,880) | 13 |
| 14 | FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES | | 81,683,400 | 11,596,205 | 70,087,195 | 14 |
| 15 | LESS: | | | | | 15 |
| 16 | MINNESOTA STATE INCOME TAXES | | 4,944,670 | 0 | 4,944,670 | 16 |
| 17 | NORTH DAKOTA STATE INCOME TAXES | | 515,567 | 515,545 | 22 | 17 |
| 18 | FEDERAL TAXABLE INCOME | | 86,173,843 | 11,070,660 | 75,103,183 | 18 |
| 19 | FEDERAL TAX RATE | | 21.00% | 21.00% | 21.00% | 19 |
| 20 | FEDERAL INCOME TAX BEFORE CREDITS | | 18,096,507 | 2,408,839 | 15,687,668 | 20 |
| 21 | INVESTMENT TAX CREDIT - DEBITS UTILIZED | | 0 | 0 | 0 | 21 |
| 22 | FEDERAL INCOME TAXES before transfer to Deferred due to NCL | | 18,096,507 | 2,408,839 | 15,687,668 | 22 |
| 23 | Less Current Federal Income Taxes Transferred to Deferred Income Taxes due to NCL | | 0 | 0 | 0 | 23 |
| 24 | FEDERAL INCOME TAXES | | 18,096,507 | 2,408,839 | 15,687,668 | 24 |
| 25 | | | | | | 25 |
| 26 | | | | | | 26 |
| 27 | | | | | | 27 |
| 28 | | | | | | 28 |
| 29 | | | | | | 29 |
| 30 | | | | | | 30 |
| 31 | | | | | | 31 |
| 32 | | | | | | 32 |
| 33 | | | | | | 33 |
| 34 | | | | | | 34 |
| 35 | | | | | | 35 |
| 36 | | | | | | 36 |
| 37 | | | | | | 37 |
| 38 | | | | | | 38 |
| 39 | | | | | | 39 |
| 40 | | | | | | 40 |
| 41 | | | | | | 41 |
| 42 | | | | | | 42 |
| 43 | | | | | | 43 |
| 44 | | | | | | 44 |
| 45 | | | | | | 45 |
| 46 | | | | | | 46 |
| 47 | | | | | | 47 |
| 48 | | | | | | 48 |
| 49 | | | | | | 49 |
| 50 | | | | | | 50 |
| 51 | | | | | | 51 |
| 52 | | | | | | 52 |
| 53 | | | | | | 53 |
| 54 | | | | | | 54 |
| 55 | | | | | | 55 |
| 56 | | | | | | 56 |
| 57 | | | | | | 57 |
| 58 | | | | | | 58 |
| 59 | | | | | | 59 |
| 60 | | | | | | 60 |
| 61 | | | | | | 61 |

| LINE NO | ITEM | ALLOC | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|--|-------|---------------|--------------|--------------|---------|
| 1 | DEVELOPMENT OF MINNESOTA STATE INCOME TAX EXPENSE | | | | | 1 |
| 2 | FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES | | 76,452,486 | 0 | 76,452,486 | 2 |
| 3 | MINNESOTA ADJUSTMENTS TO FEDERAL SCHEDULE M: | | | | | 3 |
| 4 | PAYCO ADJUSTMENT | | 0 | 0 | 0 | 4 |
| 5 | CHANGE IN EXCESS TAX DEPRECIATION - M | | (25,918,377) | 0 | (25,918,377) | 5 |
| 6 | NEPS | | 0 | 0 | 0 | 6 |
| 7 | CHANGE IN ACRS - ORDINARY LOSS | | 0 | 0 | 0 | 7 |
| 8 | PREFERRED DIVIDENDS PAID CREDIT | | 0 | 0 | 0 | 8 |
| 9 | NEPS | | 0 | 0 | 0 | 9 |
| 10 | MISCELLANEOUS ADJUSTMENTS TO FED SC | | (78,295) | 0 | (78,295) | 10 |
| 11 | NEPS | | 0 | 0 | 0 | 11 |
| 12 | TOTAL MINNESOTA ADJUSTMENTS TO FED SCHEDULE M | | (25,996,671) | 0 | (25,996,671) | 12 |
| 13 | MINNESOTA TAXABLE INCOME | | 50,455,814 | 0 | 50,455,814 | 13 |
| 14 | MINNESOTA TAX RATE | | 9.80% | 0.00% | 9.80% | 14 |
| 15 | MINNESOTA INCOME TAX | | 4,944,670 | 0 | 4,944,670 | 15 |
| 16 | Minnesota Current Income Tax transfer to Deferred Income Tax due to NOL | | 0 | 0 | 0 | 16 |
| 17 | Minnesota Current Income Tax transfer to Deferred Income Tax due to NOL | | 0 | 0 | 0 | 17 |
| 18 | MINNESOTA INCOME TAX | | 4,944,670 | 0 | 4,944,670 | 18 |
| 19 | | | | | | 19 |
| 20 | | | | | | 20 |
| 21 | | | | | | 21 |
| 22 | | | | | | 22 |
| 23 | | | | | | 23 |
| 24 | | | | | | 24 |
| 25 | | | | | | 25 |
| 26 | | | | | | 26 |
| 27 | | | | | | 27 |
| 28 | | | | | | 28 |
| 29 | DEVELOPMENT OF NORTH DAKOTA STATE INCOME TAX EXPENSE | | | | | 29 |
| 30 | FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES | | 11,986,205 | 11,986,205 | 0 | 30 |
| 31 | NORTH DAKOTA ADJUSTMENTS TO FEDERAL SCHEDULE M: | | | | | 31 |
| 32 | CHANGE IN EXCESS TAX DEPRECIATION - M | | (769) | (1,868) | (769) | 32 |
| 33 | NEPS | | 0 | 0 | 0 | 33 |
| 34 | CHANGE IN ACRS - ORDINARY LOSS | | 0 | 0 | 0 | 34 |
| 35 | MISCELLANEOUS ADJUSTMENTS TO FED SC | | (4,982) | (3,134) | (1,427) | 35 |
| 36 | NEPS | | 0 | 0 | 0 | 36 |
| 37 | TOTAL NORTH DAKOTA ADJUSTMENTS TO FED SCHEDULE M | | (7,019) | (4,823) | (2,196) | 37 |
| 38 | SUBTOTAL | | 11,979,186 | 11,981,383 | (2,196) | 38 |
| 39 | DEDUCTION OF FEDERAL INCOME TAXES | | 0 | 0 | 0 | 39 |
| 40 | NORTH DAKOTA TAXABLE INCOME | | 11,979,186 | 11,981,383 | (2,196) | 40 |
| 41 | NORTH DAKOTA TAX RATE | | 4.31% | 4.31% | 4.31% | 41 |
| 42 | NORTH DAKOTA INCOME TAX | | 515,545 | 515,545 | 22 | 42 |
| 43 | North Dakota Current Income Tax transfer to Deferred Income Tax due to NOL | | (515,545) | (515,545) | 95 | 43 |
| 44 | NORTH DAKOTA INCOME TAX | | 117 | 0 | 117 | 44 |
| 45 | | | | | | 45 |
| 46 | | | | | | 46 |
| 47 | | | | | | 47 |
| 48 | | | | | | 48 |
| 49 | | | | | | 49 |
| 50 | | | | | | 50 |
| 51 | | | | | | 51 |
| 52 | | | | | | 52 |
| 53 | | | | | | 53 |
| 54 | | | | | | 54 |
| 55 | | | | | | 55 |
| 56 | | | | | | 56 |
| 57 | | | | | | 57 |
| 58 | | | | | | 58 |
| 59 | | | | | | 59 |
| 60 | | | | | | 60 |
| 61 | | | | | | 61 |
| 62 | | | | | | 62 |
| 63 | | | | | | 63 |
| 64 | | | | | | 64 |

ALLOCATION FACTORS

| LINE NO | ITEM | FACTOR | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|---|--------|---------------------------|---------------------------|---------------------------|---------|
| 1 | MWH CONSUMPTION AT GENERATORS - PAR PERCENTAGE | E1 | 4,717,027 100.000000% | 1,692,012 35.659308% | 3,025,015 64.341692% | 1 |
| 2 | MWH CONSUMPTION AT GENERATORS - TOT PERCENTAGE | E2 | 5,271,408 100.000000% | 1,690,855 37.577942% | 3,580,553 62.422058% | 2 |
| 3 | GENERATION DEMAND FACTOR PERCENTAGE | D1 | 740,846 100.000000% | 295,156 39.840452% | 445,689 60.159548% | 3 |
| 4 | TRANSMISSION DEMAND FACTOR PERCENTAGE | D2 | 746,384 100.000000% | 295,156 39.556977% | 451,228 60.443023% | 4 |
| 5 | DISTRIBUTION - PRIMARY DEMAND FACTOR PERCENTAGE | D3 | 879,600 100.000000% | 403,477 45.870509% | 476,123 54.129491% | 5 |
| 6 | DISTRIBUTION - SECONDARY DEMAND FACTOR PERCENTAGE | D4 | 1,169,271 100.000000% | 551,014 48.026779% | 618,257 51.973221% | 6 |
| 7 | CUSTOMER OR METER FACTORS | | | | | 7 |
| 8 | TOTAL RETAIL CUSTOMERS PERCENTAGE | C1 | 133,037 100.000000% | 50,557 44.632048% | 82,480 55.367952% | 8 |
| 9 | RETAIL SERVICE LOCATIONS PERCENTAGE | C2 | 140,187 100.000000% | 62,754 44.770800% | 77,433 55.229200% | 9 |
| 10 | SECONDARY SERVICE LOCATIONS PERCENTAGE | C3 | 140,091 100.000000% | 62,738 44.787468% | 77,353 55.212532% | 10 |
| 11 | STREET LIGHTING FACTOR PERCENTAGE | C4 | 5,464,004 100.000000% | 2,381,279 43.581205% | 3,082,725 56.418795% | 11 |
| 12 | AREA LIGHTING FACTOR PERCENTAGE | C5 | 4,796,885 100.000000% | 2,477,050 51.762867% | 2,319,835 48.237133% | 12 |
| 13 | METER FACTOR PERCENTAGE | C6 | 52,803,325 100.000000% | 23,503,024 44.5119731% | 29,300,301 55.4880269% | 13 |
| 14 | METER READING FACTOR PERCENTAGE | C7 | 183,297 100.000000% | 77,918 42.742538% | 105,379 57.257462% | 14 |
| 15 | SYSTEM SERVICE LOCATIONS PERCENTAGE | C8 | 140,183 100.000000% | 62,757 44.755037% | 77,426 55.244963% | 15 |
| 16 | LOAD MANAGEMENT FACTOR PERCENTAGE | C9 | 42,771 100.000000% | 18,627 43.550537% | 24,144 56.449463% | 16 |
| 17 | | | | | | 17 |
| 18 | | | | | | 18 |
| 19 | | | | | | 19 |
| 20 | | | | | | 20 |
| 21 | | | | | | 21 |
| 22 | | | | | | 22 |
| 23 | | | | | | 23 |
| 24 | | | | | | 24 |
| 25 | | | | | | 25 |
| 26 | | | | | | 26 |
| 27 | | | | | | 27 |
| 28 | | | | | | 28 |
| 29 | | | | | | 29 |
| 30 | | | | | | 30 |
| 31 | | | | | | 31 |
| 32 | | | | | | 32 |
| 33 | | | | | | 33 |
| 34 | | | | | | 34 |
| 35 | | | | | | 35 |
| 36 | | | | | | 36 |
| 37 | | | | | | 37 |
| 38 | | | | | | 38 |
| 39 | | | | | | 39 |
| 40 | | | | | | 40 |
| 41 | | | | | | 41 |
| 42 | | | | | | 42 |
| 43 | | | | | | 43 |
| 44 | | | | | | 44 |
| 45 | | | | | | 45 |
| 46 | | | | | | 46 |
| 47 | | | | | | 47 |
| 48 | | | | | | 48 |
| 49 | | | | | | 49 |
| 50 | | | | | | 50 |
| 51 | | | | | | 51 |
| 52 | | | | | | 52 |
| 53 | | | | | | 53 |
| 54 | | | | | | 54 |
| 55 | | | | | | 55 |
| 56 | | | | | | 56 |
| 57 | | | | | | 57 |
| 58 | | | | | | 58 |
| 59 | | | | | | 59 |
| 60 | | | | | | 60 |

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO | ITEM | ALLOCATION FACTOR | TOTAL COMPANY | NORTH DAKOTA | OTHER | LINE NO |
|---------|-------------------------------------|-------------------|---------------|--------------|-------------|---------|
| 1 | GROSS PLANT IN SERVICE | | | | | 1 |
| 7 | PRODUCTION PLANT | P10 | 430,579,725 | 154,188,767 | 276,390,957 | 2 |
| 8 | PERCENTAGE | | 100.000000% | 35.06575% | 64.93425% | 3 |
| 9 | DISTRIBUTION PLANT | P00 | 497,592,871 | 228,593,947 | 269,000,924 | 4 |
| 10 | PERCENTAGE | | 100.000000% | 45.83065% | 54.16935% | 5 |
| 11 | GENERAL PLANT | P00 | 88,619,779 | 36,081,097 | 52,538,682 | 6 |
| 12 | PERCENTAGE | | 100.000000% | 40.714497% | 59.285503% | 7 |
| 13 | ELECTRIC PLANT IN SERVICE | EPS | 1,423,111,765 | 529,353,615 | 893,758,150 | 8 |
| 14 | PERCENTAGE | | 100.000000% | 37.216729% | 62.783271% | 9 |
| 15 | NET ELECTRIC PLANT IN SERVICE | NEPS | 782,632,470 | 272,558,167 | 510,074,303 | 10 |
| 16 | PERCENTAGE | | 100.000000% | 34.827097% | 65.172903% | 11 |
| 17 | OPERATION AND MAINTENANCE EXPENSE | OMPD | 21,878,778 | 7,573,298 | 13,305,480 | 12 |
| 18 | PERCENTAGE | | 100.000000% | 34.62844% | 65.371516% | 13 |
| 19 | DISTRIBUTION EXPENSE | OXD | 18,917,384 | 7,680,921 | 11,236,463 | 14 |
| 20 | PERCENTAGE | | 100.000000% | 40.602337% | 59.397663% | 15 |
| 21 | CUSTOMER ACCOUNTS EXPENSE | ONC | 13,849,828 | 6,091,579 | 7,758,249 | 16 |
| 22 | PERCENTAGE | | 100.000000% | 43.99725% | 56.00275% | 17 |
| 23 | CUSTOMER SERVICE & INFORMATION EXPE | OXI | 3,097,502 | 1,382,509 | 1,714,992 | 18 |
| 24 | PERCENTAGE | | 100.000000% | 44.633048% | 55.366952% | 19 |
| 25 | OTHER DEFERRED INCOME TAX FACTOR | NP5M | 447,239,409 | 0 | 447,239,409 | 20 |
| 26 | MINNESOTA | | 100.000000% | 0.000000% | 100.000000% | 21 |
| 27 | NORTH DAKOTA | NP5N | 272,558,167 | 272,558,167 | 0 | 22 |
| 28 | PERCENTAGE | | 100.000000% | 100.000000% | 0.000000% | 23 |
| 29 | EXCLUDING SOUTH DAKOTA | NP5NR | 719,907,576 | 272,558,167 | 447,349,409 | 24 |
| 30 | PERCENTAGE | | 100.000000% | 37.865810% | 62.134190% | 25 |
| 31 | LONG TERM CMP RATIO (NW/FCC) | CNRLT | 28,581,825 | 0 | 28,581,825 | 26 |
| 32 | PERCENTAGE | | 100.000000% | 0.000000% | 100.000000% | 27 |
| 33 | REVENUE | R10 | 359,865,140 | 122,589,288 | 237,275,852 | 28 |
| 34 | PERCENTAGE | | 100.000000% | 34.085336% | 65.914664% | 29 |
| 35 | LABOR AND RELATED EXPENSE | LRE | 140,669,570 | 53,337,857 | 87,331,713 | 30 |
| 36 | PERCENTAGE | | 100.000000% | 37.917186% | 62.082814% | 31 |
| 37 | TOTAL O & M EXPENSE | OX | | | | 32 |
| 38 | PERCENTAGE | | | | | 33 |
| 39 | | | | | | 34 |
| 40 | | | | | | 35 |
| 41 | | | | | | 36 |
| 42 | | | | | | 37 |
| 43 | | | | | | 38 |
| 44 | | | | | | 39 |
| 45 | | | | | | 40 |
| 46 | | | | | | 41 |
| 47 | | | | | | 42 |
| 48 | | | | | | 43 |
| 49 | | | | | | 44 |
| 50 | | | | | | 45 |
| 51 | | | | | | 46 |
| 52 | | | | | | 47 |
| 53 | | | | | | 48 |
| 54 | | | | | | 49 |
| 55 | | | | | | 50 |
| 56 | | | | | | 51 |
| 57 | | | | | | 52 |
| 58 | | | | | | 53 |
| 59 | | | | | | 54 |
| 60 | | | | | | 55 |
| 61 | | | | | | 56 |
| 62 | | | | | | 57 |
| 63 | | | | | | 58 |
| 64 | | | | | | 59 |
| 65 | | | | | | 60 |
| 66 | | | | | | 61 |

| LINE NO. | ITEM | AMOUNT | AMOUNT AS A PERCENT OF TOTAL | COST OF CAPITAL | RATE OF RETURN | LINE NO. |
|----------|------------------------------------|---------------|------------------------------|-----------------|----------------|----------|
| 1 | | | | | | 1 |
| 2 | | | | | | 2 |
| 3 | | | | | | 3 |
| 4 | CAPITAL STRUCTURE - RATE OF RETURN | | | | | 4 |
| 5 | LONG-TERM DEBT | 510,687,554 | 47.50% | 5.38% | 2.85% | 5 |
| 6 | PREFERRED STOCK | 0 | 0.00% | 0.00% | 0.00% | 6 |
| 7 | COMMON EQUITY | 564,363,902 | 52.50% | 10.50% | 5.41% | 7 |
| 8 | | | | | | 8 |
| 9 | | | | | | 9 |
| 10 | | | | | | 10 |
| 11 | TOTAL | 1,075,051,457 | 100.00% | | 7.86% | 11 |
| 12 | | | | | | 12 |
| 13 | | | | | | 13 |
| 14 | | | | | | 14 |
| 15 | | | | | | 15 |
| 16 | | | | | | 16 |
| 17 | | | | | | 17 |
| 18 | | | | | | 18 |
| 19 | | | | | | 19 |
| 20 | | | | | | 20 |
| 21 | | | | | | 21 |
| 22 | | | | | | 22 |
| 23 | | | | | | 23 |
| 24 | | | | | | 24 |
| 25 | | | | | | 25 |
| 26 | | | | | | 26 |
| 27 | | | | | | 27 |
| 28 | | | | | | 28 |
| 29 | | | | | | 29 |
| 30 | | | | | | 30 |
| 31 | | | | | | 31 |
| 32 | | | | | | 32 |
| 33 | | | | | | 33 |
| 34 | | | | | | 34 |
| 35 | | | | | | 35 |
| 36 | | | | | | 36 |
| 37 | | | | | | 37 |
| 38 | | | | | | 38 |
| 39 | | | | | | 39 |
| 40 | | | | | | 40 |
| 41 | | | | | | 41 |
| 42 | | | | | | 42 |
| 43 | | | | | | 43 |
| 44 | | | | | | 44 |
| 45 | | | | | | 45 |
| 46 | | | | | | 46 |
| 47 | | | | | | 47 |
| 48 | | | | | | 48 |
| 49 | | | | | | 49 |
| 50 | | | | | | 50 |
| 51 | | | | | | 51 |
| 52 | | | | | | 52 |
| 53 | | | | | | 53 |
| 54 | | | | | | 54 |
| 55 | | | | | | 55 |
| 56 | | | | | | 56 |
| 57 | | | | | | 57 |
| 58 | | | | | | 58 |
| 59 | | | | | | 59 |
| 60 | | | | | | 60 |

| LINE NO | ITEM | ALLOCATION | TOTAL COMPANY | NORTH DAKOTA | ALL OTHER | LINE NO |
|---------|---|------------|----------------|---------------|----------------|---------|
| 1 | CASH WORKING CAPITAL CALCULATION - REVENUE LEAD DAYS | | | | | 1 |
| 2 | REVENUES | | 329,488,936 | 119,394,113 | 208,014,812 | 2 |
| 3 | MANUALLY MAINTAINED BILLINGS | | 32,488,212 | 11,077,479 | 21,410,733 | 3 |
| 4 | COMPUTER MAINTAINED BILLINGS | | 2,817,578 | (4,463,840) | 7,281,418 | 4 |
| 5 | COST OF ENERGY REVENUES | R10 | 190,587 | 5,646 | 184,950 | 5 |
| 6 | SALES FOR RESALE | | 568,008 | 197,821 | 370,187 | 6 |
| 7 | RENT FROM ELECTRIC PROPERTY | | 2,576,976 | 897,486 | 1,679,490 | 7 |
| 8 | MISCELLANEOUS | | 1,779,638 | 617,707 | 1,161,931 | 8 |
| 9 | ITA DEFICIENCY PAYMENTS | | 4,297,722 | 0 | 4,297,722 | 9 |
| 10 | LOAD CONTROL AND DISPATCH | | 217,118,225 | 7,593,371 | 14,833,559 | 10 |
| 11 | RENT FROM ELECTRIC PROPERTY - BIG STONE | | 9,800 | 3,413 | 6,387 | 11 |
| 12 | RENT FROM ELECTRIC PROPERTY - COYOTE | | 28,101 | 8,787 | 19,314 | 12 |
| 13 | PROFIT ON MATERIALS AND SUPPLIES | | 2,676 | 0 | 2,676 | 13 |
| 14 | RUBBER GOODS TESTING | | 0 | 0 | 0 | 14 |
| 15 | RESIDENTIAL CONSERVATION SERVICES | | 0 | 0 | 0 | 15 |
| 16 | TOTAL REVENUES | | 388,286,651 | 132,301,365 | 255,985,142 | 16 |
| 17 | | | | | | 17 |
| 18 | | | | | | 18 |
| 19 | | | | | | 19 |
| 20 | | | | | | 20 |
| 21 | REVENUE LEAD DAYS FROM SERVICE TO COLLECTION | | | | | 21 |
| 22 | COMPUTER MAINTAINED BILLINGS | | N/A | 43.4 | N/A | 22 |
| 23 | MANUALLY MAINTAINED BILLINGS | | N/A | 41.3 | N/A | 23 |
| 24 | COST OF ENERGY REVENUES | | N/A | 127.7 | N/A | 24 |
| 25 | SALES FOR RESALE | | N/A | 23.1 | N/A | 25 |
| 26 | RENT FROM ELECTRIC PROPERTY | | N/A | 34.9 | N/A | 26 |
| 27 | MISCELLANEOUS | | N/A | 48.4 | N/A | 27 |
| 28 | ITA DEFICIENCY PAYMENTS | | N/A | 35.8 | N/A | 28 |
| 29 | WHEELING | | N/A | 27.9 | N/A | 29 |
| 30 | LOAD CONTROL AND DISPATCH | | N/A | 38.3 | N/A | 30 |
| 31 | RENT FROM ELECTRIC PROPERTY - BIG STONE | | N/A | 38.3 | N/A | 31 |
| 32 | RENT FROM ELECTRIC PROPERTY - COYOTE | | N/A | 38.3 | N/A | 32 |
| 33 | PROFIT ON MATERIALS AND SUPPLIES | | N/A | 38.3 | N/A | 33 |
| 34 | RUBBER GOODS TESTING | | N/A | 38.3 | N/A | 34 |
| 35 | RESIDENTIAL CONSERVATION SERVICES | | N/A | 38.3 | N/A | 35 |
| 36 | TOTAL DOLLAR DAYS | | | | | 36 |
| 37 | | | | | | 37 |
| 38 | | | | | | 38 |
| 39 | REVENUE DOLLAR DAYS REVENUES X REVENUE LEAD DAYS | | 13,962,521,342 | 5,051,504,523 | 8,941,016,819 | 39 |
| 40 | COMPUTER MAINTAINED BILLINGS | | 1,058,520,370 | 365,320,370 | 693,199,999 | 40 |
| 41 | MANUALLY MAINTAINED BILLINGS | | 68,590,370 | (570,109,920) | 1,379,609,290 | 41 |
| 42 | COST OF ENERGY REVENUES | | 4,395,811 | 130,200 | 4,264,655 | 42 |
| 43 | SALES FOR RESALE | | (52,469,606) | (18,280,609) | (34,209,000) | 43 |
| 44 | RENT FROM ELECTRIC PROPERTY | | 89,989,014 | 31,340,213 | 58,647,801 | 44 |
| 45 | MISCELLANEOUS | | 85,944,699 | 29,897,098 | 55,947,092 | 45 |
| 46 | ITA DEFICIENCY PAYMENTS | | 157,293,231 | 0 | 157,293,231 | 46 |
| 47 | WHEELING | | 605,802,201 | 211,016,146 | 394,786,055 | 47 |
| 48 | LOAD CONTROL AND DISPATCH | | 1,181,182,225 | 42,947,371 | 1,224,129,596 | 48 |
| 49 | RENT FROM ELECTRIC PROPERTY - BIG STONE | | 403,887 | 134,133 | 269,754 | 49 |
| 50 | RENT FROM ELECTRIC PROPERTY - COYOTE | | 0 | 0 | 0 | 50 |
| 51 | PROFIT ON MATERIALS AND SUPPLIES | | 1,156,622 | 384,615 | 772,007 | 51 |
| 52 | RUBBER GOODS TESTING | | 114,533 | 0 | 114,533 | 52 |
| 53 | RESIDENTIAL CONSERVATION SERVICES | | 0 | 0 | 0 | 53 |
| 54 | TOTAL DOLLAR DAYS | | 16,620,146,650 | 5,193,447,593 | 11,626,705,447 | 54 |
| 55 | | | | | | 55 |
| 56 | AVG REVENUE LEAD DAYS (TOTAL REV DOLLAR DAYS / TOTAL REV) | | 43.3 | 38.3 | 45.4 | 56 |
| 57 | | | | | | 57 |
| 58 | | | | | | 58 |
| 59 | | | | | | 59 |
| 60 | | | | | | 60 |

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2016 Inflation Test Year

| LINE NO | ITEM | OPERATING EXPENSE | EXPENSE PER DAY DAYS PER YEAR | EXPENSE LAG DAYS | EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS | NET REVENUE LAG DOLLARS | LINE NO |
|---------|--|-------------------|----------------------------------|---------------------|--|----------------------------|------------|
| 1 | CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF | | | | | | |
| 2 | LEAD-LAG FACTORS-MINNESOTA JURISDICTION E2 | | | | | | |
| 3 | FUEL - COAL | 26,396,748 | 77,799 | 15.5 | 27.3 | 2,123,149 | 1 |
| 4 | FUEL - OIL | 33,457 | 92 | 11.2 | 31.6 | 2,895 | 2 |
| 5 | PURCHASED POWER | 37,542,735 | 102,857 | 31.6 | 11.2 | 1,154,053 | 3 |
| 6 | LABOR AND ASSOCIATED PAYROLL EXPENSE | 3,101,105 | 8,496 | 15.1 | 27.7 | 235,259 | 4 |
| 7 | ALL OTHER O&M EXPENSE | 77,960,906 | 219,874 | 13.1 | 26.7 | 6,347,237 | 5 |
| 8 | PROPERTY TAXES (EXCL COAL CONVERSION TAXES) | 4,438,078 | 12,159 | 208.6 | -256.8 | (3,122,853) | 6 |
| 9 | COAL CONVERSION TAXES | 228,732 | 627 | 33.3 | 9.5 | 5,941 | 7 |
| 10 | FEDERAL INCOME TAXES | 10,116,054 | 27,715 | 0.0 | 42.8 | 1,186,211 | 8 |
| 11 | STATE INCOME TAXES | 3,183,159 | 8,748 | 0.0 | 42.8 | 374,431 | 9 |
| 12 | INCREMENTAL FEDERAL INCOME TAXES | 0 | 0 | 0.0 | 42.8 | 0 | 10 |
| 13 | INCREMENTAL STATE INCOME TAXES | 0 | 0 | 0.0 | 42.8 | 0 | 11 |
| 14 | BANK BALANCES | | | | | | 12 |
| 15 | SPECIAL DEPOSITS | | | | | | 13 |
| 16 | WORKING FUNDS | | | | | | 14 |
| 17 | TAX COLLECTIONS AVAIL - FICA WITHHOLDING | | | | | | 15 |
| 18 | TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING | | | | | | 16 |
| 19 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 17 |
| 20 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 18 |
| 21 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 19 |
| 22 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 20 |
| 23 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 21 |
| 24 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 22 |
| 25 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 23 |
| 26 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 24 |
| 27 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 25 |
| 28 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 26 |
| 29 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 27 |
| 30 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 28 |
| 31 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 29 |
| 32 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 30 |
| 33 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 31 |
| 34 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 32 |
| 35 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 33 |
| 36 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 34 |
| 37 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 35 |
| 38 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 36 |
| 39 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 37 |
| 40 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 38 |
| 41 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 39 |
| 42 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 40 |
| 43 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 41 |
| 44 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 42 |
| 45 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 43 |
| 46 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 44 |
| 47 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 45 |
| 48 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 46 |
| 49 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 47 |
| 50 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 48 |
| 51 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 49 |
| 52 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 50 |
| 53 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 51 |
| 54 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 52 |
| 55 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 53 |
| 56 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 54 |
| 57 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 55 |
| 58 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 56 |
| 59 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 57 |
| 60 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 58 |
| 61 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 59 |
| 62 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 60 |
| 63 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 61 |
| 64 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 62 |
| 65 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 63 |
| 66 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 64 |
| 67 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 65 |
| 68 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 66 |
| 69 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 67 |
| 70 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 68 |
| 71 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 69 |
| 72 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 70 |
| 73 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 71 |
| 74 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 72 |
| 75 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 73 |
| 76 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 74 |
| 77 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 75 |
| 78 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 76 |
| 79 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 77 |
| 80 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 78 |
| 81 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 79 |
| 82 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 80 |
| 83 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 81 |
| 84 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 82 |
| 85 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 83 |
| 86 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 84 |
| 87 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 85 |
| 88 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 86 |
| 89 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 87 |
| 90 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 88 |
| 91 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 89 |
| 92 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 90 |
| 93 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 91 |
| 94 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 92 |
| 95 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 93 |
| 96 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 94 |
| 97 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 95 |
| 98 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 96 |
| 99 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 97 |
| 100 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 98 |
| 101 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 99 |
| 102 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 100 |
| 103 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 101 |
| 104 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 102 |
| 105 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 103 |
| 106 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 104 |
| 107 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 105 |
| 108 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 106 |
| 109 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 107 |
| 110 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 108 |
| 111 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 109 |
| 112 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 110 |
| 113 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 111 |
| 114 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 112 |
| 115 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 113 |
| 116 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 114 |
| 117 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 115 |
| 118 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 116 |
| 119 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 117 |
| 120 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 118 |
| 121 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 119 |
| 122 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 120 |
| 123 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 121 |
| 124 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 122 |
| 125 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 123 |
| 126 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 124 |
| 127 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 125 |
| 128 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 126 |
| 129 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 127 |
| 130 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 128 |
| 131 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 129 |
| 132 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 130 |
| 133 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 131 |
| 134 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 132 |
| 135 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 133 |
| 136 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 134 |
| 137 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 135 |
| 138 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 136 |
| 139 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 137 |
| 140 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 138 |
| 141 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 139 |
| 142 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 140 |
| 143 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 141 |
| 144 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 142 |
| 145 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 143 |
| 146 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 144 |
| 147 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 145 |
| 148 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 146 |
| 149 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 147 |
| 150 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 148 |
| 151 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 149 |
| 152 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 150 |
| 153 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 151 |
| 154 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 152 |
| 155 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 153 |
| 156 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 154 |
| 157 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 155 |
| 158 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 156 |
| 159 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 157 |
| 160 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 158 |
| 161 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 159 |
| 162 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 160 |
| 163 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 161 |
| 164 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 162 |
| 165 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 163 |
| 166 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 164 |
| 167 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 165 |
| 168 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 166 |
| 169 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 167 |
| 170 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 168 |
| 171 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 169 |
| 172 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 170 |
| 173 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 171 |
| 174 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 172 |
| 175 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 173 |
| 176 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 174 |
| 177 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 175 |
| 178 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 176 |
| 179 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 177 |
| 180 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 178 |
| 181 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 179 |
| 182 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 180 |
| 183 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 181 |
| 184 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 182 |
| 185 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 183 |
| 186 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 184 |
| 187 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 185 |
| 188 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 186 |
| 189 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 187 |
| 190 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 188 |
| 191 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 189 |
| 192 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 190 |
| 193 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 191 |
| 194 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 192 |
| 195 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 193 |
| 196 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 194 |
| 197 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 195 |
| 198 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 196 |
| 199 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 197 |
| 200 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 198 |
| 201 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 199 |
| 202 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 200 |
| 203 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 201 |
| 204 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 202 |
| 205 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 203 |
| 206 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 204 |
| 207 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 205 |
| 208 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 206 |
| 209 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 207 |
| 210 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 208 |
| 211 | TAX COLLECTIONS AVAIL - STATE WITHHOLDING | | | | | | 2 |

| LINE NO. | ITEM | OPERATING EXPENSE | EXPENSE PER DAY DAYS PER YEAR | EXPENSE LAG DAYS | EXCESS REVENUE LEAD DAYS OF OTHER EXPENSE LAG DAYS | NET REVENUE LAG DOLLARS | LINE NO. |
|----------|---|-------------------|-------------------------------|------------------|--|-------------------------|----------|
| 1 | CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF LEAD-LAG FACTORS-NORTH DAKOTA JURISDICTION | | | | | | 1 |
| 2 | FUEL - COAL | 19,690,695 | 54,770 | 15.5 | 23.8 | 1,302,968 | 2 |
| 3 | FUEL - OIL | 21,698 | 59 | 11.2 | 28.1 | 1,669 | 3 |
| 4 | PURCHASED POWER | 26,355,139 | 72,206 | 31.6 | 7.7 | 557,429 | 4 |
| 5 | LABOR AND ASSOCIATED PAYROLL EX | 2,278,150 | 6,242 | 15.1 | 24.2 | 150,982 | 5 |
| 6 | ALL OTHER O&M EXPENSE | 55,259,091 | 191,385 | 13.1 | 26.2 | 3,967,406 | 6 |
| 7 | PROPERTY TAXES (EXCL COAL CONVERSION TAXES) | 3,743,783 | 10,257 | 299.6 | -260.3 | (2,670,241) | 7 |
| 8 | COAL CONVERSION TAXES | 192,951 | 529 | 33.3 | 6.0 | 3,161 | 8 |
| 9 | FEDERAL INCOME TAXES | 2,408,839 | 6,600 | 0.0 | 39.3 | 259,353 | 9 |
| 10 | STATE INCOME TAXES | 0 | 0 | 0.0 | 39.3 | 0 | 10 |
| 11 | INCREMENTAL FEDERAL INCOME TAXES | 0 | 0 | 0.0 | 39.3 | 0 | 11 |
| 12 | INCREMENTAL STATE INCOME TAXES | 0 | 0 | 0.0 | 39.3 | 0 | 12 |
| 13 | BANK BALANCES | | | | | | 13 |
| 14 | SPECIAL DEPOSITS | | | | | | 14 |
| 15 | WORKING FUNDS | | | | | | 15 |
| 16 | TAX COLLECTIONS AVAIL - FICA WITHH | (1,957,142) | (5,352) | 0.0 | 0 | 3,413 | 16 |
| 17 | TAX COLLECTIONS AVAIL - FEDERAL W | (3,186,397) | (8,727) | 0.0 | 0 | 2,612 | 17 |
| 18 | TAX COLLECTIONS AVAIL - STATE WITH | 0 | 0 | 1.9 | 0 | 4,340 | 18 |
| 19 | TAX COLLECTIONS AVAIL - STATE WITH | (185,000) | (507) | 69.1 | (9) | 0 | 19 |
| 20 | TAX COLLECTIONS AVAILABLE - STATE | (143) | (0) | 23.8 | (9) | 0 | 20 |
| 21 | TAX COLLECTIONS AVAILABLE - FRANC | 0 | 0 | 0.0 | 0 | 0 | 21 |
| 22 | CASH WORKING CAPITAL REQUIREMENT - NORTH DAKOTA | | | | | | 22 |
| 23 | | | | | | | 23 |
| 24 | | | | | | | 24 |
| 25 | | | | | | | 25 |
| 26 | | | | | | | 26 |
| 27 | | | | | | | 27 |
| 28 | | | | | | | 28 |
| 29 | | | | | | | 29 |
| 30 | | | | | | | 30 |
| 31 | | | | | | | 31 |
| 32 | | | | | | | 32 |
| 33 | | | | | | | 33 |
| 34 | | | | | | | 34 |
| 35 | | | | | | | 35 |
| 36 | | | | | | | 36 |
| 37 | | | | | | | 37 |
| 38 | | | | | | | 38 |
| 39 | | | | | | | 39 |
| 40 | | | | | | | 40 |
| 41 | | | | | | | 41 |
| 42 | | | | | | | 42 |
| 43 | | | | | | | 43 |
| 44 | | | | | | | 44 |
| 45 | | | | | | | 45 |
| 46 | | | | | | | 46 |
| 47 | | | | | | | 47 |
| 48 | | | | | | | 48 |
| 49 | | | | | | | 49 |
| 50 | | | | | | | 50 |
| 51 | | | | | | | 51 |
| 52 | | | | | | | 52 |
| 53 | | | | | | | 53 |
| 54 | | | | | | | 54 |
| 55 | | | | | | | 55 |
| 56 | | | | | | | 56 |
| 57 | | | | | | | 57 |
| 58 | | | | | | | 58 |
| 59 | | | | | | | 59 |
| 60 | | | | | | | 60 |

3,546,055

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2016 through Year 1 Year

NORTH DAKOTA

| LINE NO. | ITEM | OPERATING EXPENSE | EXPENSE PER DAY DAYS PER YEAR | EXPENSE LAG DAYS | EXCESS REVENUE LEAD DAYS OF LEAD DAYS OF OTHER EXPENSE LAG DAYS | NET REVENUE LAG DOLLARS | LINE NO. |
|----------|---|-------------------|-------------------------------|------------------|---|-------------------------|----------|
| 1 | CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF LEAD LAG FACTORS - SOUTH DAKOTA JURISDICTION | | | | | | |
| 2 | FUEL - COAL | 4,772,381 | 13,075 | 15.5 | 50.9 | 666,388 | 1 |
| 3 | FUEL - OIL | 5,643 | 15 | 11.2 | 55.2 | 653 | 2 |
| 4 | PURCHASED POWER | 4,310,384 | 17,288 | 31.6 | 34.8 | 601,984 | 3 |
| 5 | LABOR AND ASSOCIATED PAYROLL EXPENSE | 533,931 | 1,463 | 15.1 | 51.3 | 75,028 | 4 |
| 6 | ALL OTHER O&M EXPENSE | 12,952,082 | 35,465 | 13.1 | 53.3 | 1,891,558 | 5 |
| 7 | PROPERTY TAXES (EXCL. COAL CONVERSION TAXES) | 862,913 | 2,364 | 286.6 | -233.2 | (651,402) | 6 |
| 8 | COAL CONVERSION TAXES | 44,474 | 122 | 33.3 | 33.1 | 4,031 | 7 |
| 9 | FEDERAL INCOME TAXES | 671,032 | 1,638 | 0.0 | 66.4 | 122,073 | 8 |
| 10 | STATE INCOME TAXES | 0 | 0 | 0.0 | 66.4 | 0 | 9 |
| 11 | INCREMENTAL FEDERAL INCOME TAXES | 0 | 0 | 0.0 | 66.4 | 0 | 10 |
| 12 | INCREMENTAL STATE INCOME TAXES | 0 | 0 | 0.0 | 66.4 | 0 | 11 |
| 13 | BANK BALANCES | 0 | 0 | 0.0 | 66.4 | 0 | 12 |
| 14 | NEPS | | | | | | 13 |
| 15 | NEPS | | | | | | 14 |
| 16 | NEPS | | | | | | 15 |
| 17 | WORKING FUNDS | | | | | | 16 |
| 18 | TAX COLLECTIONS AVAIL. - FICA WITHHOLDING | (456,999) | (1,257) | 0.0 | 787 | 602 | 17 |
| 19 | TAX COLLECTIONS AVAIL. - FEDERAL WITHHOLDING | (746,551) | (2,045) | 0.0 | 1,000 | 1,000 | 18 |
| 20 | TAX COLLECTIONS AVAIL. - STATE WITHHOLDING | 0 | 0 | 0.0 | 0 | 0 | 19 |
| 21 | TAX COLLECTIONS AVAIL. - STATE WITHHOLDING | 0 | 0 | 1.9 | 0 | 0 | 20 |
| 22 | TAX COLLECTIONS AVAIL. - STATE WITHHOLDING | 0 | 0 | 66.1 | 0 | 0 | 21 |
| 23 | TAX COLLECTIONS AVAILABLE - STATE SALES TAX | (1,268,682) | (3,476) | 13.7 | (47,479) | (47,479) | 22 |
| 24 | TAX COLLECTIONS AVAILABLE - FRANCHISE TAX | 0 | 0 | 0.0 | 0 | 0 | 23 |
| 25 | CASH WORKING CAPITAL REQUIREMENT - SOUTH DAKOTA | | | | | | 24 |
| 26 | | | | | | | 25 |
| 27 | | | | | | | 26 |
| 28 | | | | | | | 27 |
| 29 | | | | | | | 28 |
| 30 | | | | | | | 29 |
| 31 | | | | | | | 30 |
| 32 | | | | | | | 31 |
| 33 | | | | | | | 32 |
| 34 | | | | | | | 33 |
| 35 | | | | | | | 34 |
| 36 | | | | | | | 35 |
| 37 | | | | | | | 36 |
| 38 | | | | | | | 37 |
| 39 | | | | | | | 38 |
| 40 | | | | | | | 39 |
| 41 | | | | | | | 40 |
| 42 | | | | | | | 41 |
| 43 | | | | | | | 42 |
| 44 | | | | | | | 43 |
| 45 | | | | | | | 44 |
| 46 | | | | | | | 45 |
| 47 | | | | | | | 46 |
| 48 | | | | | | | 47 |
| 49 | | | | | | | 48 |
| 50 | | | | | | | 49 |
| 51 | | | | | | | 50 |
| 52 | | | | | | | 51 |
| 53 | | | | | | | 52 |
| 54 | | | | | | | 53 |
| 55 | | | | | | | 54 |
| 56 | | | | | | | 55 |
| 57 | | | | | | | 56 |
| 58 | | | | | | | 57 |
| 59 | | | | | | | 58 |
| 60 | | | | | | | 59 |
| 61 | | | | | | | 60 |

OTTER TAIL POWER COMPANY
 CASH WORKING CAPITAL REQUIREMENT - PERCENT
 NORTH DAKOTA 2018 through 2019

| LINE NO | ITEM | OPERATING EXPENSE | EXPENSE PER DAY \$K | EXPENSE LAG DAYS | EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS | NET REVENUE LAG DOLLARS | LINE NO |
|---------|--|-------------------|---------------------|------------------|---|-------------------------|---------|
| 1 | CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF | | | | | | 1 |
| 2 | LEAD-LAG FACTOR - FERC JURISDICTION | | | | | | 2 |
| 3 | FUEL - COAL | 36,309 | 108 | 15.5 | 12.7 | 1,367 | 3 |
| 4 | FUEL - OIL | 51 | 0 | 11.2 | 17.0 | 2 | 4 |
| 5 | PURCHASED POWER | 52,163 | 143 | 31.6 | -3.4 | (483) | 5 |
| 6 | LABOR AND ASSOCIATED PAYROLL EXPENSE | 66,037 | 260 | 15.1 | 13.1 | 3,408 | 6 |
| 7 | ALL OTHER O&M EXPENSE | 2,154,378 | 5,802 | 13.1 | 15.1 | 89,160 | 7 |
| 8 | PROPERTY TAXES (EXCL COAL CONVERSION TAXES) | 1,704,902 | 4,671 | 289.6 | -271.4 | (1,287,883) | 8 |
| 9 | COAL CONVERSION TAXES | 87,889 | 241 | 33.3 | -6.1 | (1,233) | 9 |
| 10 | FEDERAL INCOME TAXES | 4,900,607 | 13,426 | 0.0 | 28.2 | 378,622 | 10 |
| 11 | STATE INCOME TAXES | 1,751,510 | 4,798 | 0.0 | 28.2 | 135,322 | 11 |
| 12 | INCREMENTAL FEDERAL INCOME TAXES | 0 | 0 | 0.0 | 28.2 | 0 | 12 |
| 13 | INCREMENTAL STATE INCOME TAXES | 0 | 0 | 0.0 | 28.2 | 0 | 13 |
| 14 | BANK BALANCES | | | | | | 14 |
| 15 | SPECIAL DEPOSITS | | | | | | 15 |
| 16 | WORKING FUNDS | | | | | | 16 |
| 17 | TAX COLLECTIONS AVAIL - FICA WITHHOLDING | (81,646) | (244) | 0.0 | | 0 | 17 |
| 18 | TAX COLLECTIONS AVAIL - FEDERAL WITHHOLD | (132,885) | (354) | 0.0 | | 0 | 18 |
| 19 | TAX COLLECTIONS AVAIL - STATE WITHHOLD | 0 | 0 | 1.9 | | 0 | 19 |
| 20 | TAX COLLECTIONS AVAIL - STATE WITHHOLD | 0 | 0 | 88.1 | | 0 | 20 |
| 21 | TAX COLLECTIONS AVAILABLE - STATE SALES | 0 | 0 | 0.0 | | 0 | 21 |
| 22 | TAX COLLECTIONS AVAILABLE - FRANCHISE | 0 | 0 | 0.0 | | 0 | 22 |
| 23 | TOTAL CASH WORKING CAPITAL REQUIREMENT - PERCENT | | | | | (656,977) | 23 |
| 24 | | | | | | | 24 |
| 25 | | | | | | | 25 |
| 26 | | | | | | | 26 |
| 27 | | | | | | | 27 |
| 28 | | | | | | | 28 |
| 29 | | | | | | | 29 |
| 30 | | | | | | | 30 |
| 31 | | | | | | | 31 |
| 32 | | | | | | | 32 |
| 33 | | | | | | | 33 |
| 34 | | | | | | | 34 |
| 35 | | | | | | | 35 |
| 36 | | | | | | | 36 |
| 37 | | | | | | | 37 |
| 38 | | | | | | | 38 |
| 39 | | | | | | | 39 |
| 40 | | | | | | | 40 |
| 41 | | | | | | | 41 |
| 42 | | | | | | | 42 |
| 43 | | | | | | | 43 |
| 44 | | | | | | | 44 |
| 45 | | | | | | | 45 |
| 46 | | | | | | | 46 |
| 47 | | | | | | | 47 |
| 48 | | | | | | | 48 |
| 49 | | | | | | | 49 |
| 50 | | | | | | | 50 |
| 51 | | | | | | | 51 |
| 52 | | | | | | | 52 |
| 53 | | | | | | | 53 |
| 54 | | | | | | | 54 |
| 55 | | | | | | | 55 |
| 56 | | | | | | | 56 |
| 57 | | | | | | | 57 |
| 58 | | | | | | | 58 |
| 59 | | | | | | | 59 |
| 60 | | | | | | | 60 |

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2016 through 2018 Year

| LINE NO | ITEM | OPERATING EXPENSE | EXPENSE PER DAY DAYS PER YEAR | EXPENSE LAG DAYS | EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS | NET REVENUE LAG DOLLARS | LINE NO |
|---------|---|-------------------|-------------------------------|------------------|---|-------------------------|---------|
| 1 | CASH WORKING CAPITAL CALCULATION BY THE APPLICATION | | | | | | 1 |
| 2 | LEAD LAG FACTORS - TOTAL CO | | | | | | 2 |
| 3 | FUEL - COAL | | | | | 4,092,896 | 3 |
| 4 | FUEL - OIL | | | | | 5,420 | 4 |
| 5 | PURCHASED POWER | | | | | 2,312,983 | 5 |
| 6 | LABOR AND ASSOCIATED PAYROLL EXPENSE | | | | | 464,678 | 6 |
| 7 | ALL OTHER O&M EXPENSE | | | | | 12,286,451 | 7 |
| 8 | PROPERTY TAXES (EXCL COAL CONVERSION TAXES) | | | | | (7,612,359) | 8 |
| 9 | COAL CONVERSION TAXES | | | | | 11,900 | 9 |
| 10 | FEDERAL INCOME TAXES | | | | | 1,846,269 | 10 |
| 11 | STATE INCOME TAXES | | | | | 509,753 | 11 |
| 12 | INCREMENTAL FEDERAL INCOME TAXES | | | | | 0 | 12 |
| 13 | INCREMENTAL STATE INCOME TAXES | | | | | 0 | 13 |
| 14 | BANK BALANCES | | | | | 0 | 14 |
| 15 | SPECIAL DEPOSITS | | | | | 0 | 15 |
| 16 | WORKING FUNDS | | | | | 9,800 | 16 |
| 17 | TAX COLLECTIONS AVAIL - FICA WITHHOLD | | | | | 7,500 | 17 |
| 18 | TAX COLLECTIONS AVAIL - FEDERAL WITHHOLD | | | | | 12,462 | 18 |
| 19 | TAX COLLECTIONS AVAIL - STATE WITHHOLD | | | | | 0 | 19 |
| 20 | TAX COLLECTIONS AVAIL - STATE SALES | | | | | 0 | 20 |
| 21 | TAX COLLECTIONS AVAIL - FRANCHISE | | | | | 0 | 21 |
| 22 | TAX COLLECTIONS AVAIL - TOTAL COMPANY | | | | | 0 | 22 |
| 23 | ASSIGN TO JURIS | | | | | (6,942) | 23 |
| 24 | ASSIGN TO JURIS | | | | | (34,989) | 24 |
| 25 | ASSIGN TO JURIS | | | | | (381,607) | 25 |
| 26 | ASSIGN TO JURIS | | | | | (107,532) | 26 |
| 27 | ASSIGN TO JURIS | | | | | 0 | 27 |
| 28 | ASSIGN TO JURIS | | | | | 0 | 28 |
| 29 | ASSIGN TO JURIS | | | | | 0 | 29 |
| 30 | ASSIGN TO JURIS | | | | | 0 | 30 |
| 31 | ASSIGN TO JURIS | | | | | 0 | 31 |
| 32 | ASSIGN TO JURIS | | | | | 0 | 32 |
| 33 | ASSIGN TO JURIS | | | | | 0 | 33 |
| 34 | ASSIGN TO JURIS | | | | | 0 | 34 |
| 35 | ASSIGN TO JURIS | | | | | 0 | 35 |
| 36 | ASSIGN TO JURIS | | | | | 0 | 36 |
| 37 | ASSIGN TO JURIS | | | | | 0 | 37 |
| 38 | ASSIGN TO JURIS | | | | | 0 | 38 |
| 39 | ASSIGN TO JURIS | | | | | 0 | 39 |
| 40 | ASSIGN TO JURIS | | | | | 0 | 40 |
| 41 | ASSIGN TO JURIS | | | | | 0 | 41 |
| 42 | ASSIGN TO JURIS | | | | | 0 | 42 |
| 43 | ASSIGN TO JURIS | | | | | 0 | 43 |
| 44 | ASSIGN TO JURIS | | | | | 0 | 44 |
| 45 | ASSIGN TO JURIS | | | | | 0 | 45 |
| 46 | ASSIGN TO JURIS | | | | | 0 | 46 |
| 47 | ASSIGN TO JURIS | | | | | 0 | 47 |
| 48 | ASSIGN TO JURIS | | | | | 0 | 48 |
| 49 | ASSIGN TO JURIS | | | | | 0 | 49 |
| 50 | ASSIGN TO JURIS | | | | | 0 | 50 |
| 51 | ASSIGN TO JURIS | | | | | 0 | 51 |
| 52 | ASSIGN TO JURIS | | | | | 0 | 52 |
| 53 | ASSIGN TO JURIS | | | | | 0 | 53 |
| 54 | ASSIGN TO JURIS | | | | | 0 | 54 |
| 55 | ASSIGN TO JURIS | | | | | 0 | 55 |
| 56 | ASSIGN TO JURIS | | | | | 0 | 56 |
| 57 | ASSIGN TO JURIS | | | | | 0 | 57 |
| 58 | ASSIGN TO JURIS | | | | | 0 | 58 |
| 59 | ASSIGN TO JURIS | | | | | 0 | 59 |
| 60 | ASSIGN TO JURIS | | | | | 0 | 60 |

| LINE NO | ITEM | ALLOC | MINNESOTA | NORTH DAKOTA | SOUTH DAKOTA | FERC | TOTAL COMPANY | LINE NO |
|---------|--|-------|---------------|---------------|--------------|--------------|---------------|---------|
| 1 | ELECTRIC PLANT IN SERVICE | | 640,243,183 | 529,263,615 | 122,404,512 | 130,200,455 | 1,422,111,765 | 1 |
| 2 | ACCUMULATED DEPRECIATION | | (317,130,899) | (256,695,448) | (59,579,619) | (8,074,130) | (639,479,296) | 2 |
| 3 | NET PLANT EXCLUDING BIG STONE PLANT CAPITALIZED IT | | 323,112,284 | 272,568,167 | 62,824,894 | 124,126,325 | 782,532,470 | 3 |
| 4 | NET CAPITALIZED ITEMS - BIG STONE PLANT | | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | NET ELECTRIC PLANT IN SERVICE | | 323,112,284 | 272,568,167 | 62,824,894 | 124,126,325 | 782,532,470 | 5 |
| 6 | PLANT HELD FOR FUTURE USE | | 13,983 | 13,044 | 2,816 | 114 | 29,657 | 6 |
| 7 | CONSTRUCTION WORK IN PROGRESS | | 15,242,434 | 271,748 | 0 | 96,653,803 | 175,354,566 | 7 |
| 8 | MATERIALS AND SUPPLIES | | 8,453,284 | 7,946,645 | 1,820,847 | 64,181 | 19,345,037 | 8 |
| 9 | FUEL STOCKS | | 6,534,970 | 4,430,805 | 1,122,620 | 11,281 | 12,099,676 | 9 |
| 10 | PREPAYMENTS | | (15,102,091) | (12,728,590) | (2,304,379) | (5,861,546) | (36,579,509) | 10 |
| 11 | CUSTOMER ADVANCES | | (418,639) | (353,143) | (81,397) | (109,820) | (1,071,968) | 11 |
| 12 | CASH WORKING CAPITAL | | 7,857,102 | 3,548,095 | 2,764,423 | (856,977) | 13,522,643 | 12 |
| 13 | ACCUMULATED DEFERRED INCOME TAXES | | (42,486,732) | (52,379,715) | (3,648,399) | (39,901,114) | (138,415,960) | 13 |
| 14 | UNAMORTIZED BALANCE - SPRINTWOOD | | 0 | 0 | 0 | 0 | 0 | 14 |
| 15 | UNAMORTIZED RATE CASE EXPENSE | | 0 | 0 | 0 | 0 | 0 | 15 |
| 16 | TOTAL AVERAGE RATE BASE | | 304,197,175 | 222,305,057 | 61,869,527 | 173,535,348 | 776,594,536 | 16 |
| 17 | | | | | | | | 17 |
| 18 | | | | | | | | 18 |
| 19 | | | | | | | | 19 |
| 20 | | | | | | | | 20 |
| 21 | | | | | | | | 21 |
| 22 | | | | | | | | 22 |
| 23 | | | | | | | | 23 |
| 24 | | | | | | | | 24 |
| 25 | | | | | | | | 25 |
| 26 | | | | | | | | 26 |
| 27 | | | | | | | | 27 |
| 28 | | | | | | | | 28 |
| 29 | | | | | | | | 29 |
| 30 | | | | | | | | 30 |
| 31 | | | | | | | | 31 |
| 32 | | | | | | | | 32 |
| 33 | | | | | | | | 33 |
| 34 | | | | | | | | 34 |
| 35 | | | | | | | | 35 |
| 36 | | | | | | | | 36 |
| 37 | | | | | | | | 37 |
| 38 | | | | | | | | 38 |
| 39 | | | | | | | | 39 |
| 40 | | | | | | | | 40 |
| 41 | | | | | | | | 41 |
| 42 | | | | | | | | 42 |
| 43 | | | | | | | | 43 |
| 44 | | | | | | | | 44 |
| 45 | | | | | | | | 45 |
| 46 | | | | | | | | 46 |
| 47 | | | | | | | | 47 |
| 48 | | | | | | | | 48 |
| 49 | | | | | | | | 49 |
| 50 | | | | | | | | 50 |
| 51 | | | | | | | | 51 |
| 52 | | | | | | | | 52 |
| 53 | | | | | | | | 53 |
| 54 | | | | | | | | 54 |
| 55 | | | | | | | | 55 |
| 56 | | | | | | | | 56 |
| 57 | | | | | | | | 57 |
| 58 | | | | | | | | 58 |
| 59 | | | | | | | | 59 |
| 60 | | | | | | | | 60 |

*** NOTE: TOTAL AVERAGE RATE BASE WILL NOT ADD ACROSS BECAUSE CMP IS NOT ALLOCATED TO ALL JURISDICTIONS.

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO | ITEM | ALLOC | MINNESOTA | NORTH DAKOTA | SOUTH DAKOTA | FERC | TOTAL COMPANY | LINE NO |
|---------|---|-------|------------|--------------|--------------|------------|---------------|---------|
| 1 | CONST. WORK-IN-PROGRESS - Direct Assigned | | 0 | 0 | 0 | 0 | 0 | 1 |
| 2 | PRODUCTION PLANT - Direct MN | P10 | 0 | 0 | 0 | 0 | 0 | 2 |
| 3 | PRODUCTION PLANT - Direct ND | P10 | 0 | 0 | 0 | 0 | 0 | 3 |
| 4 | PRODUCTION PLANT - Direct SD | P10 | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | PRODUCTION PLANT - Direct FERC | D2 | 0 | 0 | 0 | 0 | 0 | 5 |
| 6 | TRANSMISSION PLANT - Direct MN | D2 | 0 | 0 | 0 | 0 | 0 | 6 |
| 7 | TRANSMISSION PLANT - Direct ND | D2 | 0 | 0 | 0 | 0 | 0 | 7 |
| 8 | TRANSMISSION PLANT - Direct SD | D2 | 0 | 0 | 0 | 0 | 0 | 8 |
| 9 | TRANSMISSION PLANT - Direct FERC | D2 | 0 | 0 | 0 | 0 | 0 | 9 |
| 10 | DISTRIBUTION PLANT - Direct MN | P90 | 0 | 0 | 0 | 0 | 0 | 10 |
| 11 | DISTRIBUTION PLANT - Direct ND | P90 | 0 | 0 | 0 | 0 | 0 | 11 |
| 12 | DISTRIBUTION PLANT - Direct SD | P90 | 0 | 0 | 0 | 0 | 0 | 12 |
| 13 | DISTRIBUTION PLANT - Direct FERC | P90 | 0 | 0 | 0 | 0 | 0 | 13 |
| 14 | GENERAL PLANT - Direct MN | P90 | 0 | 0 | 0 | 0 | 0 | 14 |
| 15 | GENERAL PLANT - Direct ND | P90 | 0 | 0 | 0 | 0 | 0 | 15 |
| 16 | GENERAL PLANT - Direct SD | P90 | 0 | 0 | 0 | 0 | 0 | 16 |
| 17 | GENERAL PLANT - Direct FERC | P90 | 0 | 0 | 0 | 0 | 0 | 17 |
| 18 | INTANGIBLE PLANT - Direct MN | P90 | 0 | 0 | 0 | 0 | 0 | 18 |
| 19 | INTANGIBLE PLANT - Direct ND | P90 | 0 | 0 | 0 | 0 | 0 | 19 |
| 20 | INTANGIBLE PLANT - Direct SD | P90 | 0 | 0 | 0 | 0 | 0 | 20 |
| 21 | INTANGIBLE PLANT - Direct FERC | P90 | 0 | 0 | 0 | 0 | 0 | 21 |
| 22 | TOTAL CWP - Direct Assigned | | 0 | 0 | 0 | 0 | 0 | 22 |
| 23 | | | 0 | 0 | 0 | 0 | 0 | 23 |
| 24 | CONST. WORK-IN-PROGRESS - SHORT TERM | | 0 | 0 | 0 | 0 | 0 | 24 |
| 25 | PRODUCTION PLANT | P10 | 0 | 0 | 0 | 0 | 0 | 25 |
| 26 | TRANSMISSION PLANT | D2 | 0 | 0 | 0 | 0 | 0 | 26 |
| 27 | DISTRIBUTION PLANT | P90 | 346,123 | 271,748 | 0 | 5,006 | 686,250 | 27 |
| 28 | GENERAL PLANT | P90 | 0 | 0 | 0 | 0 | 0 | 28 |
| 29 | INTANGIBLE PLANT | P90 | 0 | 0 | 0 | 0 | 0 | 29 |
| 30 | | | 0 | 0 | 0 | 0 | 0 | 30 |
| 31 | TOTAL CWP - SHORT TERM | | 346,123 | 271,748 | 0 | 5,006 | 686,250 | 31 |
| 32 | | | 0 | 0 | 0 | 0 | 0 | 32 |
| 33 | | | 0 | 0 | 0 | 0 | 0 | 33 |
| 34 | | | 0 | 0 | 0 | 0 | 0 | 34 |
| 35 | CONST. WORK-IN-PROGRESS - LONG TERM | | 0 | 0 | 0 | 0 | 0 | 35 |
| 36 | PRODUCTION PLANT (AFUDC Projects) | P10 | 0 | 0 | 0 | 0 | 0 | 36 |
| 37 | TRANSMISSION PLANT (AFUDC Projects) | D2 | 0 | 0 | 0 | 0 | 0 | 37 |
| 38 | TRANSMISSION PLANT (Riser Projects) | D2 | 0 | 0 | 0 | 0 | 0 | 38 |
| 39 | TRANSMISSION PLANT (Riser Projects) | D2 | 0 | 0 | 0 | 0 | 0 | 39 |
| 40 | DISTRIBUTION PLANT | P90 | 588,542 | 0 | 0 | 2,706 | 1,149,148 | 40 |
| 41 | GENERAL PLANT | P90 | 2,987,775 | 0 | 0 | 3,158 | 1,603,969 | 41 |
| 42 | INTANGIBLE PLANT | P90 | 2,392,321 | 0 | 0 | 11,702 | 5,947,443 | 42 |
| 43 | | | 0 | 0 | 0 | 0 | 0 | 43 |
| 44 | TOTAL CWP - LONG TERM - AFUDC Projects | | 14,858,311 | 0 | 0 | 72,565 | 28,591,825 | 44 |
| 45 | TOTAL CWP - LONG TERM - Riser Projects | | 0 | 0 | 0 | 0 | 0 | 45 |
| 46 | | | 0 | 0 | 0 | 0 | 0 | 46 |
| 47 | TOTAL CONSTRUCTION WORK-IN-PROGRESS | | 15,242,424 | 271,748 | 0 | 95,833,903 | 125,954,506 | 47 |
| 48 | | | 0 | 0 | 0 | 0 | 0 | 48 |
| 49 | | | 0 | 0 | 0 | 0 | 0 | 49 |
| 50 | MATERIALS & SUPPLIES | | 0 | 0 | 0 | 0 | 0 | 50 |
| 51 | PRODUCTION | P10 | 0 | 0 | 0 | 0 | 0 | 51 |
| 52 | TRANSMISSION | D2 | 2,992,295 | 1,951,911 | 516,731 | 4,795 | 5,478,732 | 52 |
| 53 | DISTRIBUTION | P90 | 2,749,299 | 3,826,435 | 800,841 | 39,758 | 5,450,400 | 53 |
| 54 | | | 3,668,960 | 7,946,545 | 1,220,947 | 19,828 | 8,335,806 | 54 |
| 55 | TOTAL MATERIALS AND SUPPLIES | | 9,453,324 | 12,739,500 | 2,038,376 | 64,181 | 19,265,207 | 55 |
| 56 | | | 0 | 0 | 0 | 0 | 0 | 56 |
| 57 | FUEL STOCKS | | 0 | 0 | 0 | 0 | 0 | 57 |
| 58 | COAL STOCKS | E1 | 0 | 0 | 0 | 0 | 0 | 58 |
| 59 | FUEL OIL STOCKS | D1 | 6,124,248 | 3,323,221 | 864,322 | 7,836 | 9,319,627 | 59 |
| 60 | | | 1,410,722 | 1,107,584 | 258,298 | 3,445 | 2,780,049 | 60 |
| 61 | TOTAL FUEL STOCKS | | 5,524,970 | 4,430,805 | 1,122,620 | 11,281 | 12,099,676 | 61 |
| 62 | | | 0 | 0 | 0 | 0 | 0 | 62 |
| 63 | PREPAYMENTS | NEPS | 0 | 0 | 0 | 0 | 0 | 63 |
| 64 | CUSTOMER ADVANCES | NEPS | 0 | 0 | 0 | 0 | 0 | 64 |
| 65 | | | 0 | 0 | 0 | 0 | 0 | 65 |
| 66 | CASH WORKING CAPITAL | OX | 0 | 0 | 0 | 0 | 0 | 66 |
| 67 | | | 0 | 0 | 0 | 0 | 0 | 67 |
| 68 | | | 0 | 0 | 0 | 0 | 0 | 68 |
| 69 | | | 0 | 0 | 0 | 0 | 0 | 69 |
| 70 | | | 0 | 0 | 0 | 0 | 0 | 70 |
| 71 | | | 0 | 0 | 0 | 0 | 0 | 71 |
| 72 | | | 0 | 0 | 0 | 0 | 0 | 72 |
| 73 | | | 0 | 0 | 0 | 0 | 0 | 73 |
| 74 | | | 0 | 0 | 0 | 0 | 0 | 74 |
| 75 | | | 0 | 0 | 0 | 0 | 0 | 75 |
| 76 | | | 0 | 0 | 0 | 0 | 0 | 76 |
| 77 | | | 0 | 0 | 0 | 0 | 0 | 77 |

SEPARATELY CALCULATED BY JURISDICTION

NORTH DAKOTA

OTTERTAL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO. | ITEM | ALLOC | MINNESOTA | NORTH DAKOTA | SOUTH DAKOTA | FERC | TOTAL COMPANY | LINE NO. |
|----------|---|-----------------|--------------|--------------|--------------|--------------|---------------|----------|
| 1 | ACCUMULATED DEFERRED INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 1 |
| 2 | ITEMS SD JLGMS THROUGH | | 0 | 164,622 | 0 | 75,105 | 435,531 | 2 |
| 3 | FEDERAL | NPWR | 195,505 | 0 | 0 | 20,002 | 72,069 | 3 |
| 4 | MINNESOTA | NPSM | 52,067 | 0 | 0 | 0 | 35,172 | 4 |
| 5 | NORTH DAKOTA | NPSN | 0 | 35,172 | 0 | 0 | 0 | 5 |
| 6 | | | 0 | 0 | 0 | 0 | 0 | 6 |
| 7 | SUBTOTAL | | 247,571 | 200,653 | 0 | 95,108 | 543,371 | 7 |
| 8 | | | 0 | 0 | 0 | 0 | 0 | 8 |
| 9 | ALL OTHER | | 0 | 0 | 0 | 0 | 0 | 9 |
| 10 | FEDERAL (Net FERC) | NEPS | (16,793,987) | (15,826,717) | (3,648,399) | (7,208,227) | (45,448,430) | 10 |
| 11 | MINNESOTA | Direct FERC | 0 | 0 | 0 | (23,579,516) | (23,579,516) | 11 |
| 12 | NORTH DAKOTA | NPSM | (3,970,319) | (36,751,693) | 0 | (9,038,378) | (33,178,684) | 12 |
| 13 | | NPSN | 0 | 0 | 0 | 0 | (64,751,687) | 13 |
| 14 | | | 0 | 0 | 0 | 0 | 0 | 14 |
| 15 | SUBTOTAL | | (42,734,325) | (52,580,409) | (3,648,399) | (39,606,227) | (136,959,331) | 15 |
| 16 | TOTAL ACCUMULATED DEFERRED INCOME TAXES | 190,255,381-283 | 0 | (52,379,715) | (3,648,399) | (39,601,114) | (136,415,960) | 16 |
| 17 | | | 0 | 0 | 0 | 0 | 0 | 17 |
| 18 | | | 0 | 0 | 0 | 0 | 0 | 18 |
| 19 | UNAMORTIZED BALANCE - SPRINTWOOD PLAN | P10 | 0 | 0 | 0 | 0 | 0 | 19 |
| 20 | | | 0 | 0 | 0 | 0 | 0 | 20 |
| 21 | | | 0 | 0 | 0 | 0 | 0 | 21 |
| 22 | UNAMORTIZED RATE CASE EXPENSES | R10 | 0 | 0 | 0 | 0 | 0 | 22 |
| 23 | | | 0 | 0 | 0 | 0 | 0 | 23 |
| 24 | | | 0 | 0 | 0 | 0 | 0 | 24 |
| 25 | | | 0 | 0 | 0 | 0 | 0 | 25 |
| 26 | TOTAL AVERAGE RATE BASE | | 304,197,175 | 223,305,057 | 61,869,527 | 173,535,346 | 776,594,535 | 26 |
| 27 | | | 0 | 0 | 0 | 0 | 0 | 27 |
| 28 | | | 0 | 0 | 0 | 0 | 0 | 28 |
| 29 | | | 0 | 0 | 0 | 0 | 0 | 29 |
| 30 | | | 0 | 0 | 0 | 0 | 0 | 30 |
| 31 | | | 0 | 0 | 0 | 0 | 0 | 31 |
| 32 | | | 0 | 0 | 0 | 0 | 0 | 32 |
| 33 | | | 0 | 0 | 0 | 0 | 0 | 33 |
| 34 | | | 0 | 0 | 0 | 0 | 0 | 34 |
| 35 | | | 0 | 0 | 0 | 0 | 0 | 35 |
| 36 | | | 0 | 0 | 0 | 0 | 0 | 36 |
| 37 | | | 0 | 0 | 0 | 0 | 0 | 37 |
| 38 | | | 0 | 0 | 0 | 0 | 0 | 38 |
| 39 | | | 0 | 0 | 0 | 0 | 0 | 39 |
| 40 | | | 0 | 0 | 0 | 0 | 0 | 40 |
| 41 | | | 0 | 0 | 0 | 0 | 0 | 41 |
| 42 | | | 0 | 0 | 0 | 0 | 0 | 42 |
| 43 | | | 0 | 0 | 0 | 0 | 0 | 43 |
| 44 | | | 0 | 0 | 0 | 0 | 0 | 44 |
| 45 | | | 0 | 0 | 0 | 0 | 0 | 45 |
| 46 | | | 0 | 0 | 0 | 0 | 0 | 46 |
| 47 | | | 0 | 0 | 0 | 0 | 0 | 47 |
| 48 | | | 0 | 0 | 0 | 0 | 0 | 48 |
| 49 | | | 0 | 0 | 0 | 0 | 0 | 49 |
| 50 | | | 0 | 0 | 0 | 0 | 0 | 50 |
| 51 | | | 0 | 0 | 0 | 0 | 0 | 51 |
| 52 | | | 0 | 0 | 0 | 0 | 0 | 52 |
| 53 | | | 0 | 0 | 0 | 0 | 0 | 53 |
| 54 | | | 0 | 0 | 0 | 0 | 0 | 54 |
| 55 | | | 0 | 0 | 0 | 0 | 0 | 55 |
| 56 | | | 0 | 0 | 0 | 0 | 0 | 56 |
| 57 | | | 0 | 0 | 0 | 0 | 0 | 57 |
| 58 | | | 0 | 0 | 0 | 0 | 0 | 58 |
| 59 | | | 0 | 0 | 0 | 0 | 0 | 59 |
| 60 | | | 0 | 0 | 0 | 0 | 0 | 60 |
| 61 | | | 0 | 0 | 0 | 0 | 0 | 61 |

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO. | ITEM | ALLOC | MINNESOTA | NORTH DAKOTA | SOUTH DAKOTA | 0 PERC | TOTAL COMPANY | LINE NO. |
|----------|---|-------|-------------|--------------|--------------|-------------|---------------|----------|
| 1 | OPERATING REVENUES | | | | | | | 1 |
| 2 | SALES OF ELECTRICITY | | 207,311,002 | 122,580,268 | 39,544,870 | 0 | 369,436,140 | 2 |
| 3 | OTHER OPERATING REVENUE | | 11,550,253 | 9,712,037 | 2,887,828 | 34,702,337 | 59,232,545 | 3 |
| 4 | TOTAL OPERATING REVENUE | | 218,861,255 | 132,301,305 | 42,432,698 | | 418,095,258 | 4 |
| 5 | | | | | | | | 5 |
| 6 | OPERATING EXPENSES | | | | | | | 6 |
| 7 | PRODUCTION EXPENSES | | 84,805,995 | 56,417,543 | 14,076,276 | 118,209 | 157,419,523 | 7 |
| 8 | TRANSMISSION EXPENSES | | 15,228,844 | 11,026,754 | 2,571,537 | 219,345 | 29,047,280 | 8 |
| 9 | DISTRIBUTION EXPENSES | | 7,252,389 | 7,680,921 | 1,621,012 | 33,052 | 16,917,384 | 9 |
| 10 | SALES AND MARKETING EXPENSES | | 1,746,450 | 1,746,450 | 1,746,450 | 242 | 5,341,552 | 10 |
| 11 | CUSTOMER SERVICE AND INFORMATION EXPENSES | | 8,946,735 | 1,392,578 | 718,895 | 0 | 10,958,208 | 11 |
| 12 | SALES EXPENSES | | 242,641 | 22,472 | 8,104 | 0 | 1,733,827 | 12 |
| 13 | ADMINISTRATIVE AND GENERAL EXPENSES | | 23,653,383 | 19,282,795 | 4,384,417 | 1,969,092 | 49,279,686 | 13 |
| 14 | CHARITABLE CONTRIBUTIONS | | 0 | 0 | 0 | 0 | 0 | 14 |
| 15 | DEPRECIATION EXPENSE | | 16,261,713 | 13,367,642 | 3,881,270 | 2,286,099 | 35,016,724 | 15 |
| 16 | AMORTIZATION OF BIG STONE PLANT CAPITALIZED COST | | 0 | 0 | 0 | 0 | 0 | 16 |
| 17 | AMORTIZATION | | 4,656,760 | 3,636,734 | 897,287 | 3,571,002 | 13,061,863 | 17 |
| 18 | GENERAL TAXES | | 16,786,425 | 121,229,349 | 28,542,658 | 8,189,040 | 325,964,772 | 18 |
| 19 | TOTAL OPERATING EXPENSES | | 167,963,425 | 117,071,955 | 32,949,840 | 26,503,285 | 338,488,505 | 19 |
| 20 | | | | | | | | 20 |
| 21 | NET OPERATING INCOME BEFORE INCOME TAXES | | 51,287,830 | 11,071,955 | 3,482,858 | | 65,843,643 | 21 |
| 22 | | | | | | | | 22 |
| 23 | INCOME TAX EXPENSE | | (1,431,884) | (1,183,682) | (73,754) | (391,189) | (3,160,509) | 23 |
| 24 | INVESTMENT TAX CREDIT | | (2,553,067) | (1,639,469) | (691,528) | (862,875) | (5,646,949) | 24 |
| 25 | DEFERRED INCOME TAXES | | 13,309,213 | 2,408,838 | 671,032 | 6,652,118 | 23,041,293 | 25 |
| 26 | INCOME TAXES | | 9,326,262 | (414,313) | (294,250) | (5,380,654) | 13,964,542 | 26 |
| 27 | TOTAL INCOME TAX EXPENSE | | | | | | | 27 |
| 28 | | | | | | | | 28 |
| 29 | NET OPERATING INCOME | | 41,961,568 | 11,486,268 | 3,544,090 | 21,123,233 | 78,118,359 | 29 |
| 30 | | | | | | | | 30 |
| 31 | Allowance for Funds Used During Construction - All Only | | 1,056,360 | 0 | 0 | 5,146 | 2,071,574 | 31 |
| 32 | Allowance for Funds Used During Construction - SD Only | | 0 | 0 | 0 | 0 | 0 | 32 |
| 33 | Allowance for Funds Used During Construction - SD Only | | 1,056,360 | 0 | 0 | 5,146 | 2,071,574 | 33 |
| 34 | TOTAL ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION | | | | | | | 34 |
| 35 | | | | | | | | 35 |
| 36 | TOTAL AVAILABLE FOR RETURN | | 43,017,928 | 11,486,268 | 3,544,090 | 21,128,379 | 80,145,844 | 36 |
| 37 | | | | | | | | 37 |
| 38 | | | | | | | | 38 |
| 39 | | | | | | | | 39 |
| 40 | | | | | | | | 40 |
| 41 | | | | | | | | 41 |
| 42 | | | | | | | | 42 |
| 43 | | | | | | | | 43 |
| 44 | | | | | | | | 44 |
| 45 | | | | | | | | 45 |
| 46 | | | | | | | | 46 |
| 47 | | | | | | | | 47 |
| 48 | | | | | | | | 48 |
| 49 | | | | | | | | 49 |
| 50 | | | | | | | | 50 |
| 51 | | | | | | | | 51 |
| 52 | | | | | | | | 52 |
| 53 | | | | | | | | 53 |
| 54 | | | | | | | | 54 |
| 55 | | | | | | | | 55 |
| 56 | | | | | | | | 56 |
| 57 | | | | | | | | 57 |
| 58 | | | | | | | | 58 |
| 59 | | | | | | | | 59 |
| 60 | | | | | | | | 60 |
| 61 | | | | | | | | 61 |
| 62 | | | | | | | | 62 |
| 63 | | | | | | | | 63 |

*** NOTE: TOTAL AVAILABLE FOR RETURN WILL NOT ADD ACROSS BECAUSE AFUDC IS NOT ALLOCATED TO ALL JURISDICTIONS.

OTTERTAL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO. | ITEM | ALLOC | MINNESOTA | NORTH DAKOTA | SOUTH DAKOTA | FERC | TOTAL COMPANY | LINE NO. |
|----------|--|-------|-------------|--------------|--------------|-----------|---------------|----------|
| 1 | CUSTOMER SERVICE & INFORMATIONAL EXPENSE | | | | | | | 1 |
| 2 | CONSERVATION & PROMOTIONAL REBATE | C1 | 7,551,238 | 0 | 446,000 | 0 | 8,000,238 | 2 |
| 3 | OTHER | C1 | 1,445,487 | 1,382,539 | 269,505 | 0 | 3,097,531 | 3 |
| 4 | TOTAL | | 8,996,725 | 1,382,539 | 715,505 | 0 | 11,094,769 | 4 |
| 5 | TOTAL CUSTOMER SERV & INFORMATION | OCI | | | | | | 5 |
| 6 | SALES EXPENSES | | | | | | | 6 |
| 7 | OFF-PEAK DEVELOPMENT | C1 | 219,466 | 0 | 3,813 | 0 | 223,279 | 7 |
| 8 | OTHER | C1 | 23,495 | 22,472 | 4,381 | 0 | 50,347 | 8 |
| 9 | TOTAL | | 242,961 | 22,472 | 8,194 | 0 | 273,627 | 9 |
| 10 | TOTAL SALES EXPENSES | | | | | | | 10 |
| 11 | ADMINISTRATIVE & GENERAL EXPENSES | | | | | | | 11 |
| 12 | SALARIES, SUPPLIES, PENSIONS & BENEFITS | | | | | | | 12 |
| 13 | PRODUCTION | OCI | 7,875,200 | 5,285,949 | 1,346,087 | 13,103 | 14,499,338 | 13 |
| 14 | DISTRIBUTION | OCI | 2,820,959 | 4,121,185 | 517,981 | 40,915 | 7,506,138 | 14 |
| 15 | OC | OCI | 4,171,807 | 4,171,807 | 0 | 11,126 | 8,354,740 | 15 |
| 16 | OC | OCI | 3,412,710 | 3,178,803 | 633,265 | 11,126 | 7,233,905 | 16 |
| 17 | CUSTOMER ACCOUNTS | OCI | 745,090 | 712,628 | 138,919 | 0 | 1,596,637 | 17 |
| 18 | CUSTOMER SERVICE & INFO | C1 | | | | | | 18 |
| 19 | TOTAL | | 18,952,824 | 15,500,234 | 3,555,252 | 71,888 | 38,010,481 | 19 |
| 20 | TOTAL SALARIES, SUPPLIES, PENSIONS, AND BENEFITS | | | | | | | 20 |
| 21 | LOAD MANAGEMENT EXPENSES | C9 | 0 | 0 | 0 | 0 | 0 | 21 |
| 22 | OUTSIDE SERVICES | NEPS | 548,850 | 463,077 | 108,736 | 210,883 | 1,329,645 | 22 |
| 23 | PROPERTY INSURANCE | NEPS | 670,242 | 565,396 | 130,319 | 257,479 | 1,623,436 | 23 |
| 24 | INJURIES & DAMAGES | NEPS | 962,020 | 780,916 | 175,385 | 346,518 | 2,164,940 | 24 |
| 25 | REGULATORY COMMISSION EXPENSE | R10 | 718,778 | 444,626 | 89,452 | 1,074,876 | 2,327,732 | 25 |
| 26 | GENERAL ADVERTISING | C1 | 9,095 | 8,688 | 1,686 | 0 | 19,469 | 26 |
| 27 | MISCELLANEOUS, RENTS, MAINTENANCE | P90 | 1,883,464 | 1,539,848 | 351,304 | 7,447 | 3,782,064 | 27 |
| 28 | TOTAL ADMINISTRATIVE & GENERAL EXP | | 23,853,353 | 19,292,795 | 4,384,417 | 1,989,952 | 49,519,957 | 28 |
| 29 | CHARITABLE CONTRIBUTIONS | C1 | 0 | 0 | 0 | 0 | 0 | 29 |
| 30 | TOTAL O & M EXPENSES | | 147,064,952 | 103,904,973 | 24,574,301 | 2,340,839 | 277,885,165 | 30 |

OTTERTAL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO. | ITEM | ALLOC | MINNESOTA | NORTH DAKOTA | SOUTH DAKOTA | FERC | TOTAL COMPANY | LINE NO. |
|----------|---|-------------|------------|--------------|--------------|------------|---------------|----------|
| 1 | GENERAL TAXES | NEPS | 4,686,160 | 3,936,734 | 907,367 | 1,792,771 | 11,303,652 | 1 |
| 2 | GENERAL TAXES (Direct FERC) | Direct FERC | 0 | 0 | 0 | 1,779,231 | 1,779,231 | 2 |
| 3 | TOTAL GENERAL TAXES | | 4,686,160 | 3,936,734 | 907,367 | 3,572,002 | 13,082,883 | 3 |
| 4 | NET OPERATING INCOME BEFORE TAX (NOBT) | | 51,287,630 | 11,071,955 | 3,249,840 | 26,503,286 | 92,112,912 | 4 |
| 5 | INVESTMENT TAX CREDIT | | 0 | 0 | 0 | 0 | 0 | 5 |
| 6 | AMORTIZE PRIOR YEARS CREDIT | | 0 | 0 | 0 | 0 | 0 | 6 |
| 7 | DEBITS UTILIZED | | 0 | 0 | 0 | 0 | 0 | 7 |
| 8 | TOTAL INVESTMENT TAX CREDIT | | 0 | 0 | 0 | 0 | 0 | 8 |
| 9 | DEFERRED INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 9 |
| 10 | ITEMS SOUTH DAKOTA FLOWS THROUGH | | 0 | 0 | 0 | 0 | 0 | 10 |
| 11 | FEDERAL | | 0 | 0 | 0 | 0 | 0 | 11 |
| 12 | MINNESOTA | | 0 | 0 | 0 | 0 | 0 | 12 |
| 13 | NORTH DAKOTA | | 0 | 0 | 0 | 0 | 0 | 13 |
| 14 | SUBTOTAL | | 0 | 0 | 0 | 0 | 0 | 14 |
| 15 | ALL OTHER | | 0 | 0 | 0 | 0 | 0 | 15 |
| 16 | FEDERAL - transfer from Current Income Taxes - NOL | | 0 | 0 | 0 | 0 | 0 | 16 |
| 17 | FEDERAL (NEPS) | | 0 | 0 | 0 | 0 | 0 | 17 |
| 18 | FEDERAL | | 0 | 0 | 0 | 0 | 0 | 18 |
| 19 | MINNESOTA - transfer from Current Income Taxes - NOL | | 0 | 0 | 0 | 0 | 0 | 19 |
| 20 | MINNESOTA (NPSM) | | 0 | 0 | 0 | 0 | 0 | 20 |
| 21 | MINNESOTA | | 0 | 0 | 0 | 0 | 0 | 21 |
| 22 | NORTH DAKOTA - transfer from Current Income Taxes - NOL | | 0 | 0 | 0 | 0 | 0 | 22 |
| 23 | NORTH DAKOTA (NPSN) | | 0 | 0 | 0 | 0 | 0 | 23 |
| 24 | NORTH DAKOTA | | 0 | 0 | 0 | 0 | 0 | 24 |
| 25 | SUBTOTAL | | 0 | 0 | 0 | 0 | 0 | 25 |
| 26 | TOTAL DEFERRED INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 26 |
| 27 | CURRENT INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 27 |
| 28 | FEDERAL - transfer from Current Income Taxes - NOL | | 0 | 0 | 0 | 0 | 0 | 28 |
| 29 | FEDERAL (CURRENT INCOME TAX) | | 0 | 0 | 0 | 0 | 0 | 29 |
| 30 | FEDERAL INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 30 |
| 31 | MINNESOTA - transfer to Deferred Income Taxes - NOL | | 0 | 0 | 0 | 0 | 0 | 31 |
| 32 | MINNESOTA CURRENT INCOME TAX | | 0 | 0 | 0 | 0 | 0 | 32 |
| 33 | MINNESOTA INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 33 |
| 34 | NORTH DAKOTA - transfer to Deferred Income Taxes - NOL | | 0 | 0 | 0 | 0 | 0 | 34 |
| 35 | NORTH DAKOTA CURRENT INCOME TAX | | 0 | 0 | 0 | 0 | 0 | 35 |
| 36 | NORTH DAKOTA INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 36 |
| 37 | TOTAL CURRENT INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 37 |
| 38 | NET OPERATING INCOME | | 11,466,268 | 2,408,630 | 3,541,000 | 21,123,233 | 78,118,269 | 38 |
| 39 | AFDC | | 1,059,380 | 0 | 0 | 5,146 | 2,027,574 | 39 |
| 40 | AFDC - MN OH | | 0 | 0 | 0 | 0 | 0 | 40 |
| 41 | AFDC - SD OH | | 0 | 0 | 0 | 0 | 0 | 41 |
| 42 | TAM AFDC | | 1,059,380 | 0 | 0 | 5,146 | 2,027,574 | 42 |
| 43 | TOTAL AVAILABLE FOR RETURN | | 43,019,929 | 11,466,268 | 3,541,000 | 21,123,233 | 80,145,944 | 43 |
| 44 | RATE OF RETURN ON RATE BASE | | 14.14% | 5.14% | 5.73% | 12.18% | 10.32% | 44 |

ALLOWED ONLY IN MN & FERC

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2018 Interim Test Year

| LINE NO | ITEM | ALLOC | MINNESOTA | NORTH DAKOTA | SOUTH DAKOTA | FERC | TOTAL COMPANY | LINE NO |
|---------|--|-------|--------------|--------------|--------------|-------------|---------------|---------|
| 1 | DEVELOPMENT OF MINNESOTA STATE INCOME TAX EXPEN | | | | | | | 1 |
| 2 | FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES | | 51,354,644 | 0 | 0 | 25,087,641 | 76,452,486 | 2 |
| 3 | MINNESOTA ADJUSTMENTS TO FEDERAL SCHEDULE M: | | | | | | | 3 |
| 4 | PAYS/O ADJUSTMENT | | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | CHANGE IN EXCESS TAX DEPRECIATION - M | | (18,725,020) | 0 | 0 | (7,193,357) | (46,355,044) | 5 |
| 6 | NEPS | | 0 | 0 | 0 | 0 | 0 | 6 |
| 7 | CHANGE IN ACRS - ORDINARY LOSS | | 0 | 0 | 0 | 0 | 0 | 7 |
| 8 | PREFERRED DIVIDENDS PAID CREDIT | | 0 | 0 | 0 | 0 | 0 | 8 |
| 9 | MISCELLANEOUS ADJUSTMENTS TO FED SC | | (64,565) | 0 | 0 | (21,730) | (137,009) | 9 |
| 10 | NEPS | | 0 | 0 | 0 | 0 | 0 | 10 |
| 11 | TOTAL MINNESOTA ADJUSTMENTS TO FED SCHEDULE M | | (18,789,585) | 0 | 0 | (7,215,087) | (26,004,672) | 11 |
| 12 | MINNESOTA TAXABLE INCOME | | 32,565,260 | 0 | 0 | 17,872,554 | 50,455,814 | 12 |
| 13 | MINNESOTA TAX RATE | | 9.80% | 0.00% | 0.00% | 9.80% | 9.80% | 13 |
| 14 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 14 |
| 15 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 15 |
| 16 | DEVELOPMENT OF NORTH DAKOTA STATE INCOME TAX | | | | | | | 16 |
| 17 | FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES | | 0 | 11,966,205 | 0 | 0 | 11,966,205 | 17 |
| 18 | MINNESOTA ADJUSTMENTS TO FEDERAL SCHEDULE M: | | | | | | | 18 |
| 19 | PAYS/O ADJUSTMENT | | 0 | 0 | 0 | 0 | 0 | 19 |
| 20 | CHANGE IN EXCESS TAX DEPRECIATION - M | | 0 | (1,688) | 0 | (769) | (4,848) | 20 |
| 21 | NEPS | | 0 | 0 | 0 | 0 | 0 | 21 |
| 22 | CHANGE IN ACRS - ORDINARY LOSS | | 0 | 0 | 0 | 0 | 0 | 22 |
| 23 | PREFERRED DIVIDENDS PAID CREDIT | | 0 | 0 | 0 | 0 | 0 | 23 |
| 24 | MISCELLANEOUS ADJUSTMENTS TO FED SC | | 0 | (3,134) | 0 | (1,427) | (9,920) | 24 |
| 25 | NEPS | | 0 | 0 | 0 | 0 | 0 | 25 |
| 26 | TOTAL NORTH DAKOTA ADJUSTMENTS TO FED SCHEDULE M | | 0 | (4,822) | 0 | (2,195) | (13,848) | 26 |
| 27 | MINNESOTA TAXABLE INCOME | | 0 | 11,961,383 | 0 | 0 | 11,961,383 | 27 |
| 28 | MINNESOTA TAX RATE | | 0.00% | 4.31% | 0.00% | 4.31% | 4.31% | 28 |
| 29 | MINNESOTA INCOME TAX | | 0 | 515,545 | 0 | (95) | 515,450 | 29 |
| 30 | MINNESOTA INCOME TAX | | 0 | (515,545) | 0 | 95 | (515,450) | 30 |
| 31 | DEVELOPMENT OF FEDERAL INCOME TAXES | | | | | | | 31 |
| 32 | DEDUCTION OF FEDERAL INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 32 |
| 33 | NORTH DAKOTA TAXABLE INCOME | | 0 | 11,531,383 | 0 | 0 | 11,531,383 | 33 |
| 34 | NORTH DAKOTA TAX RATE | | 0.00% | 4.31% | 0.00% | 4.31% | 4.31% | 34 |
| 35 | NORTH DAKOTA INCOME TAX | | 0 | 515,545 | 0 | (95) | 515,450 | 35 |
| 36 | NORTH DAKOTA INCOME TAX | | 0 | (515,545) | 0 | 95 | (515,450) | 36 |
| 37 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 37 |
| 38 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 38 |
| 39 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 39 |
| 40 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 40 |
| 41 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 41 |
| 42 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 42 |
| 43 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 43 |
| 44 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 44 |
| 45 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 45 |
| 46 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 46 |
| 47 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 47 |
| 48 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 48 |
| 49 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 49 |
| 50 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 50 |
| 51 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 51 |
| 52 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 52 |
| 53 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 53 |
| 54 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 54 |
| 55 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 55 |
| 56 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 56 |
| 57 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 57 |
| 58 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 58 |
| 59 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 59 |
| 60 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 60 |
| 61 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 61 |
| 62 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 62 |
| 63 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 63 |
| 64 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 64 |
| 51 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 51 |
| 52 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 52 |
| 53 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 53 |
| 54 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 54 |
| 55 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 55 |
| 56 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 56 |
| 57 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 57 |
| 58 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 58 |
| 59 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 59 |
| 60 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 60 |
| 61 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 61 |
| 62 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 62 |
| 63 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 63 |
| 64 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 64 |
| 51 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 51 |
| 52 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 52 |
| 53 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 53 |
| 54 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 54 |
| 55 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 55 |
| 56 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 56 |
| 57 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 57 |
| 58 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 58 |
| 59 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 59 |
| 60 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 60 |
| 61 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 61 |
| 62 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 62 |
| 63 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 63 |
| 64 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 64 |
| 51 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 51 |
| 52 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 52 |
| 53 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 53 |
| 54 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 54 |
| 55 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 55 |
| 56 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 56 |
| 57 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 57 |
| 58 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 58 |
| 59 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 59 |
| 60 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 60 |
| 61 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 61 |
| 62 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 62 |
| 63 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 63 |
| 64 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 64 |
| 51 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 51 |
| 52 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 52 |
| 53 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 53 |
| 54 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 54 |
| 55 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 55 |
| 56 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 56 |
| 57 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 57 |
| 58 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 58 |
| 59 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 59 |
| 60 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 60 |
| 61 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 61 |
| 62 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 62 |
| 63 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 63 |
| 64 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 64 |
| 51 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 51 |
| 52 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 52 |
| 53 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 53 |
| 54 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 54 |
| 55 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 55 |
| 56 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 56 |
| 57 | MINNESOTA INCOME TAX | | 3,193,159 | 0 | 0 | 1,751,510 | 4,944,670 | 57 |

OTTER TAIL POWER COMPANY
 CLASS COST OF SERVICE STUDY
 North Dakota 2016 Incentive Trial Year

| LINE NO | ITEM | ALLOCATION FACTOR | MINNESOTA | NORTH DAKOTA | SOUTH DAKOTA | PERC | TOTAL COMPANY | LINE NO |
|---------|------------------------------------|-------------------|-------------|--------------|--------------|-------------|---------------|---------|
| 1 | NET ELECTRIC PLANT IN SERVICE | P10 | 235,402,591 | 154,186,767 | 40,610,509 | 376.857 | 430,579,725 | 1 |
| 7 | PERCENTAGE | | 54.671313% | 36.80657% | 9.43189% | 0.097633% | 100.000000% | 2 |
| 8 | DISTRIBUTION PLANT | P80 | 228,381,184 | 228,693,947 | 67,645,201 | 1,173,610 | 497,699,831 | 3 |
| 9 | PERCENTAGE | | 43.33897% | 45.90309% | 9.80761% | 0.235469% | 100.000000% | 4 |
| 11 | GENERAL PLANT | P90 | 44,132,567 | 36,081,057 | 8,231,609 | 174,506 | 88,619,779 | 5 |
| 12 | PERCENTAGE | | 48.799906% | 40.71452% | 9.28888% | 0.196919% | 100.000000% | 6 |
| 13 | ELECTRIC PLANT IN SERVICE | EPS | 648,245,183 | 529,263,616 | 122,854,613 | 138,290,455 | 1,422,111,765 | 7 |
| 14 | PERCENTAGE | | 49.02986% | 37.21674% | 9.80761% | 9.155941% | 100.000000% | 8 |
| 15 | NET ELECTRIC PLANT IN SERVICE | NEPS | 323,113,084 | 272,568,167 | 62,824,894 | 124,126,325 | 792,632,470 | 9 |
| 16 | PERCENTAGE | | 41.285418% | 34.82719% | 8.02738% | 15.860104% | 100.000000% | 10 |
| 17 | OPERATION AND MAINTENANCE EXPENSE | OMP | 11,774,659 | 7,073,399 | 2,811,110 | 15,590 | 21,670,726 | 11 |
| 18 | EXCL ENERGY | | 54,976,639 | 36,318,624 | 9,279,897 | 0.096307% | 100.000000% | 12 |
| 19 | DISTRIBUTION EXPENSE | OXD | 7,582,399 | 7,690,921 | 1,621,012 | 33,052 | 16,917,384 | 13 |
| 20 | PERCENTAGE | | 44,820184% | 45.40253% | 9.58183% | 0.195370% | 100.000000% | 14 |
| 21 | CUSTOMER ACCOUNTS EXPENSE | OCX | 6,543,844 | 6,091,579 | 1,214,260 | 242 | 13,849,928 | 15 |
| 22 | PERCENTAGE | | 47.246226% | 43.36276% | 8.76728% | 0.001750% | 100.000000% | 16 |
| 23 | CUSTOMER SERVICE & INFORMATION EXP | OXI | 1,445,487 | 1,382,509 | 269,505 | 0 | 3,097,502 | 17 |
| 24 | PERCENTAGE | | 46.666217% | 44.63305% | 8.70071% | 0.000000% | 100.000000% | 18 |
| 25 | OTHER DEFERRED INCOME TAX FACTOR | NRSM | 323,113,084 | 0 | 0 | 124,126,325 | 447,239,409 | 19 |
| 26 | MINNESOTA | | 72,246112% | 0.000000% | 0.000000% | 27,753888% | 100.000000% | 20 |
| 27 | PERCENTAGE | | 0.000000% | 0 | 0 | 0 | 100.000000% | 21 |
| 28 | NORTH DAKOTA | NRSD | 0 | 272,568,167 | 0 | 0 | 272,568,167 | 22 |
| 29 | PERCENTAGE | | 0.000000% | 100.000000% | 0.000000% | 0.000000% | 100.000000% | 23 |
| 30 | EXCLUDING SOUTH DAKOTA | NRNR | 323,113,084 | 272,568,167 | 0 | 124,126,325 | 718,607,576 | 24 |
| 31 | PERCENTAGE | | 44.888814% | 37.86891% | 0.000000% | 17.244375% | 100.000000% | 25 |
| 32 | LONG TERM SMP RATIO (WIPFC) | CMPLT | 14,889,311 | 0 | 0 | 7,586 | 24,591,925 | 26 |
| 33 | PERCENTAGE | | 52.99715% | 0.000000% | 0.000000% | 0.252799% | 100.000000% | 27 |
| 34 | REVENUE | R10 | 207,731,002 | 122,589,269 | 29,544,970 | 0 | 359,865,140 | 28 |
| 35 | PERCENTAGE | | 57.24680% | 34.06534% | 8.20988% | 0.000000% | 100.000000% | 29 |
| 36 | LABOR AND RELATED EXPENSE | LRE | 72,605,674 | 53,327,957 | 12,500,842 | 2,225,097 | 140,669,570 | 30 |
| 37 | PERCENTAGE | | 51.61543% | 37.91726% | 8.88667% | 1.581760% | 100.000000% | 31 |
| 38 | TOTAL O & M EXPENSE | OX | 51,615,430 | 37,917,226 | 8,886,667 | 1,581,760 | 100,000,000 | 32 |
| 39 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 33 |
| 40 | EXCLUDING SOUTH DAKOTA | | 0 | 272,568,167 | 0 | 0 | 272,568,167 | 34 |
| 41 | PERCENTAGE | | 0.000000% | 100.000000% | 0.000000% | 0.000000% | 100.000000% | 35 |
| 42 | LONG TERM SMP RATIO (WIPFC) | | 0 | 0 | 0 | 0 | 0 | 36 |
| 43 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 37 |
| 44 | REVENUE | | 207,731,002 | 122,589,269 | 29,544,970 | 0 | 359,865,140 | 38 |
| 45 | PERCENTAGE | | 57.24680% | 34.06534% | 8.20988% | 0.000000% | 100.000000% | 39 |
| 46 | LABOR AND RELATED EXPENSE | | 72,605,674 | 53,327,957 | 12,500,842 | 2,225,097 | 140,669,570 | 40 |
| 47 | PERCENTAGE | | 51.61543% | 37.91726% | 8.88667% | 1.581760% | 100.000000% | 41 |
| 48 | TOTAL O & M EXPENSE | | 51,615,430 | 37,917,226 | 8,886,667 | 1,581,760 | 100,000,000 | 42 |
| 49 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 43 |
| 50 | EXCLUDING SOUTH DAKOTA | | 0 | 272,568,167 | 0 | 0 | 272,568,167 | 44 |
| 51 | PERCENTAGE | | 0.000000% | 100.000000% | 0.000000% | 0.000000% | 100.000000% | 45 |
| 52 | LONG TERM SMP RATIO (WIPFC) | | 0 | 0 | 0 | 0 | 0 | 46 |
| 53 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 47 |
| 54 | REVENUE | | 207,731,002 | 122,589,269 | 29,544,970 | 0 | 359,865,140 | 48 |
| 55 | PERCENTAGE | | 57.24680% | 34.06534% | 8.20988% | 0.000000% | 100.000000% | 49 |
| 56 | LABOR AND RELATED EXPENSE | | 72,605,674 | 53,327,957 | 12,500,842 | 2,225,097 | 140,669,570 | 50 |
| 57 | PERCENTAGE | | 51.61543% | 37.91726% | 8.88667% | 1.581760% | 100.000000% | 51 |
| 58 | TOTAL O & M EXPENSE | | 51,615,430 | 37,917,226 | 8,886,667 | 1,581,760 | 100,000,000 | 52 |
| 59 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 53 |
| 60 | EXCLUDING SOUTH DAKOTA | | 0 | 272,568,167 | 0 | 0 | 272,568,167 | 54 |
| 61 | PERCENTAGE | | 0.000000% | 100.000000% | 0.000000% | 0.000000% | 100.000000% | 55 |
| 62 | LONG TERM SMP RATIO (WIPFC) | | 0 | 0 | 0 | 0 | 0 | 56 |
| 63 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 57 |
| 64 | REVENUE | | 207,731,002 | 122,589,269 | 29,544,970 | 0 | 359,865,140 | 58 |
| 65 | PERCENTAGE | | 57.24680% | 34.06534% | 8.20988% | 0.000000% | 100.000000% | 59 |
| 66 | LABOR AND RELATED EXPENSE | | 72,605,674 | 53,327,957 | 12,500,842 | 2,225,097 | 140,669,570 | 60 |
| 67 | PERCENTAGE | | 51.61543% | 37.91726% | 8.88667% | 1.581760% | 100.000000% | 61 |
| 68 | TOTAL O & M EXPENSE | | 51,615,430 | 37,917,226 | 8,886,667 | 1,581,760 | 100,000,000 | 62 |
| 69 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 63 |
| 70 | EXCLUDING SOUTH DAKOTA | | 0 | 272,568,167 | 0 | 0 | 272,568,167 | 64 |
| 71 | PERCENTAGE | | 0.000000% | 100.000000% | 0.000000% | 0.000000% | 100.000000% | 65 |
| 72 | LONG TERM SMP RATIO (WIPFC) | | 0 | 0 | 0 | 0 | 0 | 66 |
| 73 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 67 |
| 74 | REVENUE | | 207,731,002 | 122,589,269 | 29,544,970 | 0 | 359,865,140 | 68 |
| 75 | PERCENTAGE | | 57.24680% | 34.06534% | 8.20988% | 0.000000% | 100.000000% | 69 |
| 76 | LABOR AND RELATED EXPENSE | | 72,605,674 | 53,327,957 | 12,500,842 | 2,225,097 | 140,669,570 | 70 |
| 77 | PERCENTAGE | | 51.61543% | 37.91726% | 8.88667% | 1.581760% | 100.000000% | 71 |
| 78 | TOTAL O & M EXPENSE | | 51,615,430 | 37,917,226 | 8,886,667 | 1,581,760 | 100,000,000 | 72 |
| 79 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 73 |
| 80 | EXCLUDING SOUTH DAKOTA | | 0 | 272,568,167 | 0 | 0 | 272,568,167 | 74 |
| 81 | PERCENTAGE | | 0.000000% | 100.000000% | 0.000000% | 0.000000% | 100.000000% | 75 |
| 82 | LONG TERM SMP RATIO (WIPFC) | | 0 | 0 | 0 | 0 | 0 | 76 |
| 83 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 77 |
| 84 | REVENUE | | 207,731,002 | 122,589,269 | 29,544,970 | 0 | 359,865,140 | 78 |
| 85 | PERCENTAGE | | 57.24680% | 34.06534% | 8.20988% | 0.000000% | 100.000000% | 79 |
| 86 | LABOR AND RELATED EXPENSE | | 72,605,674 | 53,327,957 | 12,500,842 | 2,225,097 | 140,669,570 | 80 |
| 87 | PERCENTAGE | | 51.61543% | 37.91726% | 8.88667% | 1.581760% | 100.000000% | 81 |
| 88 | TOTAL O & M EXPENSE | | 51,615,430 | 37,917,226 | 8,886,667 | 1,581,760 | 100,000,000 | 82 |
| 89 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 83 |
| 90 | EXCLUDING SOUTH DAKOTA | | 0 | 272,568,167 | 0 | 0 | 272,568,167 | 84 |
| 91 | PERCENTAGE | | 0.000000% | 100.000000% | 0.000000% | 0.000000% | 100.000000% | 85 |
| 92 | LONG TERM SMP RATIO (WIPFC) | | 0 | 0 | 0 | 0 | 0 | 86 |
| 93 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 87 |
| 94 | REVENUE | | 207,731,002 | 122,589,269 | 29,544,970 | 0 | 359,865,140 | 88 |
| 95 | PERCENTAGE | | 57.24680% | 34.06534% | 8.20988% | 0.000000% | 100.000000% | 89 |
| 96 | LABOR AND RELATED EXPENSE | | 72,605,674 | 53,327,957 | 12,500,842 | 2,225,097 | 140,669,570 | 90 |
| 97 | PERCENTAGE | | 51.61543% | 37.91726% | 8.88667% | 1.581760% | 100.000000% | 91 |
| 98 | TOTAL O & M EXPENSE | | 51,615,430 | 37,917,226 | 8,886,667 | 1,581,760 | 100,000,000 | 92 |
| 99 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 93 |
| 100 | EXCLUDING SOUTH DAKOTA | | 0 | 272,568,167 | 0 | 0 | 272,568,167 | 94 |
| 101 | PERCENTAGE | | 0.000000% | 100.000000% | 0.000000% | 0.000000% | 100.000000% | 95 |
| 102 | LONG TERM SMP RATIO (WIPFC) | | 0 | 0 | 0 | 0 | 0 | 96 |
| 103 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 97 |
| 104 | REVENUE | | 207,731,002 | 122,589,269 | 29,544,970 | 0 | 359,865,140 | 98 |
| 105 | PERCENTAGE | | 57.24680% | 34.06534% | 8.20988% | 0.000000% | 100.000000% | 99 |
| 106 | LABOR AND RELATED EXPENSE | | 72,605,674 | 53,327,957 | 12,500,842 | 2,225,097 | 140,669,570 | 100 |
| 107 | PERCENTAGE | | 51.61543% | 37.91726% | 8.88667% | 1.581760% | 100.000000% | 101 |
| 108 | TOTAL O & M EXPENSE | | 51,615,430 | 37,917,226 | 8,886,667 | 1,581,760 | 100,000,000 | 102 |
| 109 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 103 |
| 110 | EXCLUDING SOUTH DAKOTA | | 0 | 272,568,167 | 0 | 0 | 272,568,167 | 104 |
| 111 | PERCENTAGE | | 0.000000% | 100.000000% | 0.000000% | 0.000000% | 100.000000% | 105 |
| 112 | LONG TERM SMP RATIO (WIPFC) | | 0 | 0 | 0 | 0 | 0 | 106 |
| 113 | PERCENTAGE | | 0.000000% | 0.000000% | 0.000000% | 0.000000% | 100.000000% | 107 |
| 114 | REVENUE | | 207,731,002 | 122,589,269 | 29,544,970 | 0 | 359,865,140 | 108 |
| 115 | PERCENTAGE | | 57.24680% | 34.06534% | 8.20988% | 0.000000% | 100.000000% | 109 |
| 116 | LABOR AND RELATED EXPENSE | | 72,605,674 | 53,327,957 | 12,500,842 | 2,225,097 | 140,669,570 | 110 |
| 117 | PERCENTAGE | | 51.61543% | 37.91726% | 8.88667% | 1.581760% | 100.000000% | 111 |
| 118 | TOTAL O & M EXPENSE | | 51,615,430 | 3 | | | | |

| LINE NO | ITEM | AMOUNT | A PERCENT OF TOTAL | COST OF CAPITAL | RATE OF RETURN | LINE NO |
|---------|------------------------------------|---------------|--------------------|-----------------|----------------|---------|
| 1 | CAPITAL STRUCTURE - RATE OF RETURN | | | | | 1 |
| 2 | LONG-TERM DEBT | 510,697,554 | 47.50% | 5.38% | 2.55% | 2 |
| 3 | PREFERRED STOCK | 0 | 0.00% | 0.00% | 0.00% | 3 |
| 4 | COMMON EQUITY | 564,383,902 | 52.50% | 22.07% | 11.55% | 4 |
| 5 | TOTAL | 1,075,081,457 | 100.00% | | 14.15% | 5 |
| 6 | | | | | | 6 |
| 7 | | | | | | 7 |
| 8 | | | | | | 8 |
| 9 | | | | | | 9 |
| 10 | | | | | | 10 |
| 11 | | | | | | 11 |
| 12 | | | | | | 12 |
| 13 | | | | | | 13 |
| 14 | | | | | | 14 |
| 15 | | | | | | 15 |
| 16 | | | | | | 16 |
| 17 | | | | | | 17 |
| 18 | | | | | | 18 |
| 19 | | | | | | 19 |
| 20 | | | | | | 20 |
| 21 | | | | | | 21 |
| 22 | | | | | | 22 |
| 23 | | | | | | 23 |
| 24 | | | | | | 24 |
| 25 | | | | | | 25 |
| 26 | | | | | | 26 |
| 27 | | | | | | 27 |
| 28 | | | | | | 28 |
| 29 | | | | | | 29 |
| 30 | | | | | | 30 |
| 31 | | | | | | 31 |
| 32 | | | | | | 32 |
| 33 | | | | | | 33 |
| 34 | | | | | | 34 |
| 35 | | | | | | 35 |
| 36 | | | | | | 36 |
| 37 | | | | | | 37 |
| 38 | | | | | | 38 |
| 39 | | | | | | 39 |
| 40 | | | | | | 40 |
| 41 | | | | | | 41 |
| 42 | | | | | | 42 |
| 43 | | | | | | 43 |
| 44 | | | | | | 44 |
| 45 | | | | | | 45 |
| 46 | | | | | | 46 |
| 47 | | | | | | 47 |
| 48 | | | | | | 48 |
| 49 | | | | | | 49 |
| 50 | | | | | | 50 |
| 51 | | | | | | 51 |
| 52 | | | | | | 52 |
| 53 | | | | | | 53 |
| 54 | | | | | | 54 |
| 55 | | | | | | 55 |
| 56 | | | | | | 56 |
| 57 | | | | | | 57 |
| 58 | | | | | | 58 |
| 59 | | | | | | 59 |
| 60 | | | | | | 60 |

