

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-17-

Exhibit___

TRANSITION OF CAPITAL PROJECTS FROM RIDERS TO BASE RATES

Direct Testimony and Schedules of

BRYCE C. HAUGEN

November 2, 2017

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ATTACHED SCHEDULES

Schedule 1 – Haugen Resume

Schedule 2 – Rider Plant in Service

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Schedule 5 – TCRR 2018 Rider Tracker Schedule

1 **I. INTRODUCTION AND QUALIFICATIONS**

2 Q. PLEASE STATE YOUR NAME AND OCCUPATION.

3 A. My name is Bryce C. Haugen. I am employed by Otter Tail Power Company (OTP) as
4 Senior Rates Analyst, Regulatory Administration.

5
6 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

7 A. I graduated from Minnesota State Community and Technical College, Fergus Falls,
8 Minnesota in 2003 with an A.A. degree. I graduated from Moorhead State University, now
9 Minnesota State University, Moorhead, Minnesota, in 2005 with a B.S. degree in Finance.
10 I graduated from National University, La Jolla, California, in 2014 with a Master of Science
11 in Organizational Leadership. I started my career as the Operations Manager for the
12 Theodore Roosevelt Medora Foundation in 2005 in Medora, North Dakota. In 2009, I
13 joined Baker Boy Bake Shop in Dickinson, North Dakota as a cost accountant and became
14 a production supervisor in 2010. In 2012, I joined OTP as Business Coordinator in the
15 Project Management department. I subsequently worked as Credit Risk Analyst in the Risk
16 Management department and joined the Regulatory Administration department in 2013 as
17 Rates Analyst. I accepted my current position as Senior Rates Analyst in November 2015.
18 My primary responsibilities in this position are to lead the work team responsible for the
19 preparation and financial analysis used to determine revenue requirements associated with
20 various state and federal cost recovery mechanisms and to lead development of regulatory
21 filings associated with these cost recovery mechanisms. A copy of my resume is included
22 as Exhibit___(BCH-1), Schedule 1.

23 **II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY**

24 Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

25 A. My Direct Testimony describes: (1) Moving investments currently being recovered in the
26 Environmental Cost Recovery Rider, Renewable Resource Adjustment Rider,
27 Transmission Cost Recovery Rider into base rates, and the treatment of Renewable
28 Resource Adjustment Rider-related Production Tax Credits; and (2) Advertising expenses.

1 Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

2 A. I provide the background to OTP's three riders and explain OTP's proposed treatment of
3 the rider components, including production tax credits, for interim and final rates.
4

5 Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

6 A. In Section III, I discuss moving capital projects from riders into base rates. In Section IV
7 I discuss advertising expense.
8

9 Q. DID YOU USE ANY LABELING CONVENTIONS IN YOUR DIRECT TESTIMONY?

10 A. Yes. There are certain power plant and transmission projects where OTP is only a part
11 owner. In those circumstances, I included each of the following: the total project costs,
12 labeled as (Total Plant or Total Project), the OTP ownership allocation of the project
13 amounts, labeled as (OTP Total), and the North Dakota Jurisdictional share, labeled as
14 (OTP ND). There may also be instances with project-related amounts where an estimate
15 must be made of OTP's jurisdictional share of such costs, which are labeled as (OTP ND
16 EST).

17 **III. MOVING CAPITAL PROJECTS FROM RIDERS INTO RATE BASE**

18 Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR DIRECT
19 TESTIMONY.

20 A. As explained by OTP witness Mr. Stuart D. Tommerdahl, OTP proposes to transfer
21 recovery of certain costs presently recovered in the Environmental Cost Recovery Rider
22 (ECRR), Renewable Resource Adjustment Rider (RRAR) and Transmission Cost
23 Recovery Rider (TCRR) to base rates at the conclusion of this case. This section of my
24 Direct Testimony explains the mechanics of this proposal. OTP witness Mr. Tyler A.
25 Akerman quantifies the impact of this proposal on the 2018 Test Year revenue requirement.

26 Q. WILL OTP ADJUST THE 2018 TEST YEAR REVENUE REQUIREMENTS FOR THE
27 ECRR, RRAR AND TCRR?

28 A. Yes. As OTP neared completion of this filing, it discovered that the cost of debt used to
29 calculate the 2018 Test Year ECRR, RRAR and TCRR revenue requirements needs to be

1 adjusted by a small amount. The adjustment will not have a material impact on the revenue
2 requirement in this case.¹ OTP will update all schedules and estimates used in this filing
3 to the appropriate cost of debt at the earliest opportunity.

4 **A. ECRR**

5 Q. WHAT IS THE ECRR?

6 A. N.D.C.C. § 49-05-04.2 allows for adjustment of rates to recover jurisdictional capital costs
7 and associated operating expenses required to comply with federal environmental
8 mandates on existing electricity generating stations. OTP's ECRR was established in Case
9 Nos. PU-13-84 and PU-13-79, with initial rates going into effect January 1, 2014.

10
11 Q. WHAT IS OTP'S PROPOSAL WITH REGARD TO THE ECRR IN THIS CASE?

12 A. OTP requests the project investments included in the ECRR be rolled into base rates at the
13 time final rates go into effect.

14
15 Q. WHAT TYPES OF INVESTMENTS ARE CURRENTLY INCLUDED IN THE ECRR?

16 A. Two projects are recovered in the ECRR: The Big Stone Plant Air Quality Control System
17 (AQCS) project and the Hoot Lake Plant Mercury and Air Toxics Standards (HLP MATS)
18 project. OTP witnesses Mr. Kirk A. Phinney and Mr. Tommerdahl discuss these projects
19 in detail in Direct Testimony.

20
21 Q. WHEN WERE THE PROJECTS PLACED INTO SERVICE?

22 A. The HLP MATS project was placed in service in August 2014. The AQCS project was
23 placed in service in December 2015.

¹ The riders were calculated using a cost of debt of 5.32 percent and should be calculated using 5.39 percent, resulting in slightly lower revenue requirements being calculated in the riders. OTP estimates this impact to be less than 0.05 percent of the total revenue requirement requested in this case.

1 **1. Base Rates**

2 Q. HOW HAVE COSTS CURRENTLY BEING RECOVERED IN THE ECRR BEEN
3 HANDLED IN THE 2018 TEST YEAR FOR THIS RATE CASE?

4 A. The investments are part of the rate base used to determine the 2018 Test Year revenue
5 requirement. This includes all gross plant in service, forecasted accumulated depreciation,
6 and associated deferred income tax balances as of December 31, 2018.

7
8 Q. HAS OTP INCLUDED PROJECTED 2018 ECRR REVENUES IN THE 2018 TEST
9 YEAR CALCULATIONS?

10 A. Yes. The projected 2018 ECRR revenues are included in the calculation of present
11 revenues for the 2018 Test Year. The 2018 ECRR revenues included in the Test Year are
12 based on the projected calendar year 2018 ECRR revenue requirements. As discussed
13 below, an ECRR update is being filed within this case to synchronize the amounts included
14 in the 2018 Test Year with the ECRR in effect during interim rates. The update is proposed
15 to minimize the true-up impact when the ECRR investments are rolled into base rates at
16 the end of this case.

17
18 Q. WHY DID OTP INCLUDE PROJECTED ECRR REVENUE IN THE CALCULATION
19 OF 2018 TEST YEAR PRESENT REVENUES?

20 A. As explained by Mr. Tommerdahl, moving these projects from the ECRR into base rates
21 is merely a change to how the costs of the projects are recovered. Including the ECRR
22 revenue in the calculation of 2018 Test Year present revenues results in an accurate
23 measurement of the overall impact of the rate request on OTP customers.

24
25 Q. WHAT ARE THE PRIMARY TEST YEAR COST COMPONENTS THAT ARE
26 AFFECTED BY INCLUDING THESE PROJECTS IN BASE RATES AT THE
27 CONCLUSION OF THE CASE?

28 A. The primary rate base components are: (i) gross plant in service; (ii) accumulated
29 depreciation; and (iii) accumulated deferred income taxes. The primary operating expense
30 components that are impacted include: (i) depreciation and (ii) general tax expenses. The

1 impact on these items due to rolling these projects into base rates is quantified in Mr.
2 Tommerdahl's Direct Testimony.

3
4 Q. PLEASE IDENTIFY OTP'S PAST ECRR FILINGS.

5 A. OTP's prior ECRR filings are shown in table 1 below:
6

7 **Table 1**
8 **ECRR – History**

ECRR History	Case Number	Commission Approved	Effective Date
Original ECRR Rate and Mechanism	PU-13-79 PU-13-84	December 18, 2013	January 1, 2014
First Update	PU-14-142	July 10, 2014	August 1, 2014
Second Update	PU-15-131	June 17, 2015	July 1, 2015
Third Update	PU-16-148	June 22, 2016	July 1, 2016
Fourth Update	PU-17-122	July 12, 2017	August 1, 2017

9
10 Q. WHAT LEVEL OF AQCS AND HLP MATS INVESTMENT IS REFLECTED IN THE
11 2018 TEST YEAR?

12 A. The 2018 Test Year reflects the 13-month average plant in service balance of
13 approximately \$365.5 million (Total Plant), \$193.0 million (OTP Total) and \$70.3 million
14 (OTP ND) of total AQCS investment and approximately \$6.5 million (Total Plant and OTP
15 Total) and \$2.4 million (OTP ND) of total HLP MATS investment. A summary of the 13-
16 month average plant in-service amounts rolling in to base rates is included as Exhibit __
17 (BCH-1), Schedule 2. The \$365.5 million (Total Plant) for the AQCS investment includes
18 removal costs, which are collected in depreciation rates.²
19

20 Q. ARE THESE THE FINAL COSTS OF THESE INVESTMENTS?

21 A. Yes. In his Direct Testimony, Mr. Phinney explains that these are the final costs of these
22 investments.

² During the course of the AQCS and HLP MATS projects, there were costs of removal for facilities removed from the plants due to the scope of the projects. The project investments reflected in the ECRR do not contain the costs of removal resulting in lower investment amounts reflected in the ECRR

1 Q. WHAT LEVEL OF INVESTMENT FOR THESE PROJECTS WILL BE REFLECTED
2 IN FINAL RATES?

3 A. OTP proposes the final rates reflect the net plant in-service balance of these projects as of
4 the implementation of final rates.

5
6 Q. WHEN WILL OTP TRANSFER THESE PROJECT COSTS OUT OF THE ECRR AND
7 INTO RATE BASE?

8 A. OTP proposes to transfer these project costs out of the ECRR and into rate base at the time
9 final rates go into effect at the end of the case. A corresponding adjustment to the ECRR
10 rates will also be made at the end of this case to reflect the transfer of the net plant in-
11 service value of these projects out of the ECRR. From that point forward, recovery of the
12 AQCS and HLP MATS projects will be in base rates.

13
14 Q. PLEASE DESCRIBE THE ADJUSTMENT TO ECRR RATES THAT WILL OCCUR AT
15 THE CONCLUSION OF THIS CASE.

16 A. At the conclusion of the case, OTP proposes that the ECRR rate be adjusted to remove the
17 net plant in-service balance of these projects as of the implementation of final rates. The
18 ECRR rate would then be set at a level to return to or recover from customers the ECRR
19 tracker account balance as of the implementation of final rates. OTP proposes the tracker
20 account balance be recovered from or returned to customers through the ECRR over the
21 subsequent 12 months following implementation of final rates. After that 12-month period,
22 the ECRR balance will be zero.

23
24 Q. WHY IS OTP PROPOSING TO RECOVER OR RETURN THE TRACKER BALANCE
25 TO CUSTOMERS THROUGH THE ECRR?

26 A. The ECRR tracker account balance will be the difference between forecasted ECRR costs
27 and revenues and actual ECRR costs and revenues over the recovery period prior to the
28 transfer to base rates. Recovering from or returning to customers the account balance,
29 positive or negative, allows for the tracker to be collected accurately and zeroed out with
30 no over- nor under-recovery of the tracker balance.

1 **2. Interim Rates**

2 Q. HOW DOES OTP PROPOSE TO HANDLE THE ECRR DURING THE INTERIM RATE
3 PERIOD?

4 A. OTP proposes that the AQCS and HLP MATS projects remain in the ECRR during the
5 interim rate period.

6
7 Q. DOES OTP ANTICIPATE FILING AN UPDATE TO THE ECRR RATE WITHIN THIS
8 CASE?

9 A. Yes. OTP’s current ECRR rate was approved in Case No. PU-17-122.³ The current ECRR
10 rate approved is based on the rate of return and North Dakota allocation factors approved
11 in OTP’s last general rate case⁴ and in the absence of an update, would remain in place
12 through June 2018. Exhibit __ (BCH-1), Schedule 3 provides the revised ECRR rate
13 calculation for the 2018 Test Year. The 2018 Test Year ECRR rate reflects the 2018 Test
14 Year rate of return, North Dakota allocation factors and projected sales and revenues.
15 These updates to the ECRR result in a reduction to the ECRR rate from 7.633 percent of
16 bill to 6.629 percent of bill.⁵

17
18 Q. WHAT REVENUE REQUIREMENT AND PROPOSED ECRR RATE DOES OTP
19 PROPOSE FOR IMPLEMENTATION ON JANUARY 1, 2018?

20 A. OTP proposes an ECRR rate of 6.629 percent of bill⁶ be implemented on January 1, 2018.
21 This rate is the result of the ECRR revenue requirement of \$8,353,891 for the 2018 Test
22 Year, plus the expected tracker balance of \$177,005 that is forecasted at the end of
23 December 2017, and a carrying charge of \$6,169. The ECRR rate for the 2018 Test Year
24 includes actual costs and revenues through July 2017.

25

³ Commission July 12, 2017 Order on Environmental Cost Recovery Rates for OTP’s 2017 ECRR Annual Update in Case No. PU-17-122 and an ECRR rate of 7.633 percent of bill.

⁴ Commission’s November 25, 2009 Order on Settlement in Case No. PU-08-862 for OTP’s Electric Rate Increase Application

⁵ Exhibit __ (BCH-1), Schedule 3, Page 2 provides the proposed rate of 6.629 percent of bill.

⁶ The rate is the result of the total ECRR 2018 Test Year revenue requirement, plus prior period true-up and carrying charge, of \$8,537,065 divided by projected 2018 Test Year base revenues of \$128,789,562.

1 Q. IF THE PROPOSED RATE REDUCTION IN THE ECRR WERE NOT IMPLEMENTED
2 JANUARY 1, 2018, WHAT WOULD THE RESULT BE?

3 A. The rate update is primarily the result of the reduced rate of return and lower North Dakota
4 allocation factors proposed in this case. If the updated rate is not implemented, OTP will
5 collect more revenues than required.
6

7 Q. HOW LONG WILL THE UPDATED RATE REMAIN IN EFFECT?

8 A. OTP proposes the updated ECRR rate remain in place until the implementation of final
9 rates in this case.
10

11 Q. PLEASE SUMMARIZE ECRR RECOVERY DURING THE 2018 TEST YEAR.

12 A. Table 2 below summarizes the costs and revenues included in the ECRR during the 2018
13 Test Year. The amount in Line No. 1 of Table 2 does not reflect any prior period true-up
14 amounts and any collections of revenue for the 2018 Test Year. Additional support for the
15 ECRR recovery during the 2018 Test Year is included as Exhibit___(BCH-1), Schedule 3,
16 Page 2.
17

18 **Table 2**
19 **ECRR During 2018 Test Year**
20 **(ND)**

Line No.	Description	2018 Test Year
1	Projects' ECRR Revenue Requirement	\$8,353,891
2	Projected ECRR Revenues (w/ December 2017 true-up and carrying charge)	\$8,537,160

21
22 Q. HOW WILL OTP ENSURE ECRR PROJECT COSTS ARE NOT DOUBLE
23 RECOVERED DURING THE INTERIM RATE PERIOD?

24 A. OTP made an interim rate adjustment (Interim Petition Part B, Schedules 3 and 6) to the
25 calculation of the interim rate revenue requirement that removes all costs and revenues
26 currently included in the ECRR from the 2018 Test Year for interim rate purposes. As a
27 result, the rate base used to compute interim rates does not include any project costs
28 currently being recovered in the ECRR. This adjustment is necessary to avoid any double

1 recovery of these costs during the interim rate period. The ECRR and its associated rates
2 will remain in effect during this case.

3
4 Q. PLEASE PROVIDE ADDITIONAL DETAIL RELATED TO THE INTERIM RATE
5 ADJUSTMENT FOR THE ECRR.

6 A. The interim rate adjustment removes the ECRR projects' present revenue and ECRR
7 projects' revenue requirements included in the 2018 Test Year from the interim cost of
8 service. OTP proposes to reset ECRR rates effective with interim rates so the amount
9 collected in the ECRR is equal to the present ECRR revenue in the case. Additional detail
10 on this adjustment can be found in Volume 1, Notice of Change in Rates and Interim Rate
11 Petition, Interim Rate Supporting Schedules and Workpapers.

12 **B. RRAR**

13 Q. WHAT IS THE RRAR?

14 A. The RRAR allows a public utility (in this case, OTP) to recover jurisdictional capital costs
15 and associated operating expenses of certain renewable resource additions outside of a rate
16 case. OTP's RRAR was established in Case No. PU-06-466.⁷

17
18 Q. WHAT IS OTP'S PROPOSAL REGARDING THE RRAR IN THIS CASE?

19 A. OTP requests that the project investments included in the RRAR be rolled into base rates
20 at the time final rates go into effect.

21
22 Q. WHAT PROJECTS ARE CURRENTLY INCLUDED IN OTP'S RRAR?

23 A. OTP's RRAR recovers costs associated with OTP's investments in the Langdon,
24 Ashtabula, and Luverne Wind Projects, all located in North Dakota. OTP received an
25 advanced determination of prudence for each of these projects.⁸

26

⁷ Commission's May 21, 2008 Order approving OTP's Renewable Resource Rider Application in Case No. PU-06-466.

⁸ Commission's May 21, 2008 Order in Case No. PU-06-466 (Langdon); Commission's November 25, 2009 Order in Case No. 08-742 (Ashtabula); Commission's August 4, 2010 Order in Case No. PU-10-018 (Luverne).

1 Q. PLEASE IDENTIFY OTP’S PAST RRAR FILINGS.
 2 A. OTP’s prior RRAR filings are shown in table 3 below:

3
 4 **Table 3**
 5 **RRAR – History**

RRAR History	Case Number	Commission Approved	Effective Date
RRAR Establish Application	PU-06-466	May 21, 2008	No rate established
Original RRA Rate and Mechanism	PU-08-742 PU-08-862	January 14, 2009	February 1, 2009
First Update	PU-10-18	August 4, 2010	September 1, 2010
Second Update*	PU-12-24	March 21, 2012	April 1, 2012
Third Update	PU-13-16	July 10, 2013	April 1, 2013
Fourth Update	PU-14-14	March 12, 2014	April 1, 2014
Fifth Update	PU-15-14	March 25, 2015	April 1, 2015
Sixth Update	PU-16-14	June 22, 2016	July 1, 2016
Seventh Update	PU-17-016	July 12, 2017	August 1, 2017

6 *Established the collection timeline of April through March of the following year.

7
 8 Q. WHEN WERE THE THREE PROJECTS INCLUDED IN THE RRAR PLACED INTO
 9 SERVICE?

10 A. The Langdon project was placed in service in December 2007. The Ashtabula project was
 11 placed in service in November 2008. The Luverne project was placed in service in
 12 September 2009.

13 **1. Base Rates**

14 Q. HOW HAVE COSTS CURRENTLY RECOVERED IN THE RRAR BEEN HANDLED
 15 IN THE 2018 TEST YEAR FOR THIS RATE CASE?

16 A. The investments are part of the rate base used to determine the 2018 Test Year revenue
 17 requirement. This includes all gross plant in service, forecasted accumulated depreciation,
 18 and associated deferred income tax balances as of December 31, 2018.

19

1 Q. HAS OTP INCLUDED PROJECTED 2018 RRAR REVENUES IN THE 2018 TEST
2 YEAR CALCULATIONS?

3 A. Yes. The projected 2018 RRAR revenues are included in the calculation of present
4 revenues for the 2018 Test Year. The 2018 Test Year RRAR revenues are based on the
5 projected calendar year 2018 RRAR revenue requirements.
6

7 Q. WHY DID OTP INCLUDE THE PROJECTED RRAR REVENUE IN THE
8 CALCULATION OF 2018 TEST YEAR PRESENT REVENUES?

9 A. As explained by Mr. Tommerdahl, moving these projects from the RRAR into base rates
10 is merely a change to how the costs of the project are recovered. Including the RRAR
11 revenue in the calculation of 2018 Test Year present revenues results in a more accurate
12 measurement of the overall impact of the rate request on OTP customers.
13

14 Q. WHAT ARE THE PRIMARY TEST YEAR COST COMPONENTS THAT ARE
15 AFFECTED BY INCLUDING THESE PROJECTS IN BASE RATES AT THE
16 CONCLUSION OF THE CASE?

17 A. The primary rate base components are: (i) gross plant in service; (ii) accumulated
18 depreciation; and (iii) accumulated deferred income taxes. The primary operating expense
19 components that are impacted include: (i) depreciation and (ii) general tax expenses. The
20 impact on these items due to rolling these projects into base rates is quantified in Mr.
21 Tommerdahl's Direct Testimony.
22

23 Q. WHAT LEVEL OF WIND PROJECT INVESTMENT IS REFLECTED IN THE 2018
24 TEST YEAR?

25 A. The 2018 Test Year reflects a 13-month average of approximately \$268.7 million (OTP
26 Total) and \$101.0 million (OTP ND) of total project investments for the Langdon,
27 Ashtabula, and Luverne wind projects. A detailed list of the plant in service amounts
28 moving from the RRAR to base rates is included as Exhibit __ (BCH-1), Schedule 2.
29

1 Q. HOW DID OTP DEVELOP THE 2018 TEST YEAR INVESTMENT LEVELS FOR
2 THESE PROJECTS?

3 A. The 2018 Test Year investment levels are based on actual in service amounts as of July
4 2017 and projected investment through December 31, 2018.

5
6 Q. WHAT LEVEL OF INVESTMENT FOR THESE PROJECTS WILL BE REFLECTED
7 IN FINAL RATES?

8 A. OTP proposes the final rates reflect the net plant in service balances of these projects as of
9 the implementation of final rates.

10
11 Q. WHEN WILL OTP TRANSFER THESE PROJECT COSTS OUT OF THE RRAR AND
12 INTO RATE BASE?

13 A. OTP proposes to transfer these project costs out of the RRAR and into rate base at the time
14 final rates go into effect. From that point forward, recovery of the Langdon, Ashtabula,
15 and Luverne wind projects will be in base rates. In addition, a corresponding adjustment
16 to the RRAR rates will also be made at the end of this case to reflect the transfer of the net
17 plant in service value of these projects out of the RRAR.

18
19 Q. PLEASE DESCRIBE THE ADJUSTMENT TO RRAR RATES THAT WILL OCCUR
20 AT THE CONCLUSION OF THIS CASE?

21 A. At the conclusion of the case, OTP proposes that the RRAR rate be adjusted to remove the
22 net plant in service balances of these three wind projects as of the implementation of final
23 rates. The RRAR rate would then be set at a level to return to or recover from customers
24 the remaining RRAR tracker account balance as of the implementation of final rates. OTP
25 proposes that the tracker account balance be recovered from or returned to customers
26 through the RRAR over the subsequent 12 months following implementation of final rates.

27

1 Q. WHY IS OTP PROPOSING TO RECOVER OR RETURN THE TRACKER BALANCE
2 TO CUSTOMERS THROUGH THE RRAR?

3 A. OTP proposes to keep the RRAR in effect going forward to include the impact of expiring
4 Production Tax Credits. The potential impacts are described in more detail in below.
5 Continuance of the RRAR provides for the appropriate mechanism to handle any true-up
6 balance at the time the projects roll-in to base rates.

7
8 Q. COULD THERE BE ADDITIONAL ADJUSTMENTS TO THE NET PLANT IN-
9 SERVICE BALANCE AFTER THE IMPLEMENTATION OF FINAL RATES?

10 A. No. There will not be additional adjustments to net plant in service for these three wind
11 projects after implementation of final rates

12 **2. Production Tax Credits**

13 Q. WHAT ARE PRODUCTION TAX CREDITS?

14 A. Production Tax Credits (PTCs) are tax credits authorized by the Internal Revenue Code 26
15 USC § 45. Owners of PTC-eligible wind turbines can claim a credit against taxable income
16 based on the amount of energy produced from those turbines. PTCs are available for ten
17 years after production commences.

18
19 Q. DOES OTP CURRENTLY RECEIVE PTCS EARNED FOR THE ENERGY
20 PRODUCTION FROM ITS WIND PROJECTS?

21 A. Yes. OTP currently receives PTCs for its Langdon and Ashtabula wind projects. OTP's
22 Luverne wind project does not receive PTCs, as OTP elected to take an up-front Investment
23 Tax Credit in lieu of PTCs.

24
25 Q. WILL OTP STOP RECEIVING PTCS FOR LANGDON AND ASHTABULA IN THE
26 NEAR FUTURE?

27 A. Yes. Due to the 10-year sunset on PTCs based on original in service dates, OTP will stop
28 receiving PTCs for Langdon in November 2017 and for Ashtabula in October 2018.

29

1 Q. HOW DID OTP TREAT PTCS IN ITS 2018 TEST YEAR?

2 A. The Langdon wind project PTCs expire prior to the 2018 Test Year and are not included
3 in the Test Year. OTP made an adjustment to remove the Ashtabula wind project PTCs
4 from the 2018 Test Year so that these PTCs are not included in the final rate determination.⁹
5

6 Q. WILL CUSTOMERS RECEIVE CREDIT FOR ALL PTCS RELATED TO THESE
7 WIND PROJECTS?

8 A. Yes. PTCs are currently credited to customers through the RRAR. This will continue
9 during interim rates. If final rates go into effect prior to the expiration of the Ashtabula
10 PTCs (in October 2018), OTP proposes those PTCs be credited to customers through the
11 RRAR, which, as discussed below, will remain in effect for the 12-month period following
12 the implementation of final rates in this case.

13 **3. Interim Rates**

14 Q. HOW DOES OTP PROPOSE TO HANDLE THE RRAR DURING THE INTERIM
15 RATE PERIOD?

16 A. OTP proposes that the Langdon, Ashtabula, and Luverne wind projects remain in the
17 RRAR during the interim rate period.
18

19 Q. DOES OTP ANTICIPATE FILING AN UPDATE TO THE RRAR RATE WITHIN THIS
20 CASE?

21 A. Yes. OTP's current RRAR rate was approved in Case No. PU-17-16.¹⁰ The current RRAR
22 rate approved is based on the rate of return and North Dakota allocation factors approved
23 in OTP's last general rate case¹¹ and in the absence of an update, would remain in place
24 through March 2018. Exhibit __ (BCH-1), Schedule 4 provides the revised RRAR rate
25 calculation for the 2018 Test Year. The 2018 Test Year RRAR rate reflects the 2018 Test

⁹ Exhibit __ (TAA-1), Schedule 9.

¹⁰ Commission March 15, 2017 Order approving OTP's 2017 Renewable Resource Cost Recovery Adjustment Factor in Case No. PU-17-16 and an RRAR rate of 7.005 percent of bill.

¹¹ Commission's November 25, 2009 Order on Settlement in Case No. PU-08-862 for OTP's Electric Rate Increase Application

1 Year rate of return, North Dakota allocation factors and projected sales and revenues.
2 These updates to the RRAR result in an increase to the RRAR Rate from 7.005 percent of
3 bill to 7.756 percent of bill.¹²
4

5 Q. WHAT ARE THE REVENUE REQUIREMENT AND PROPOSED RRAR RATE OTP
6 PROPOSES BE IMPLEMENTED JANUARY 1, 2018?

7 A. OTP proposes to implement a RRAR rate of 7.756 percent of bill on January 1, 2018. This
8 rate is the result of the RRAR project revenue requirement of \$9,220,833 for the 2018 Test
9 Year plus the expected tracker balance of \$757,824 that is forecasted at the end of
10 December 2017 and carrying charge of \$10,733. It includes actual costs and revenues
11 through July 2017.
12

13 Q. DOES THE PROPOSED RRAR REFLECT THE FULL EXPIRATION OF THE PTCs?

14 A. Yes. The proposed RRAR rate includes the full annual impact of the expiration of the
15 Langdon wind project PTCs as well as a portion of the annual impact of the Ashtabula
16 wind project PTC expiration which OTP stops earning in November 2018. This is a change
17 from the current rate approved to be in effect April 1, 2017 through March 31, 2018 in
18 Case No. PU-17-16, which only reflects a portion of the annual impact the expiration of
19 the Langdon wind project PTCs.
20

21 Q. WHY IS IT REASONABLE TO UPDATE THE RRAR EFFECTIVE
22 JANUARY 1, 2018?

23 A. The rate update is primarily the result of: (1) expiration of PTCs, (2) reduced rate of return,
24 and (3) lower allocation factors proposed in this case. The lower rate of return and lower
25 North Dakota allocation factors offset some of the increase resulting from the expiration
26 of PTCs. If the updated rate is not implemented, OTP will collect less revenues than
27 required, resulting in an under-collected tracker balance at the time these projects roll in to
28 base rates.

¹² Exhibit __ (BCH-1), Schedule 4, Page 2 provides the proposed rate of 7.756 percent of bill.

1 Q. PLEASE SUMMARIZE RRAR RECOVERY DURING THE 2018 TEST YEAR.
 2 A. Table 4 below summarizes the costs and revenues included in the RRAR during the 2018
 3 Test Year. Note that amounts in Lines 1-4 of Table 4 do not reflect any prior period true-
 4 up amount or any collections of revenue for the 2018 Test Year; Line No. 5 of Table 4
 5 reflects the prior period true-up amount and estimated collections of revenue for the 2018
 6 Test Year. Additional support for the RRAR recovery during the 2018 Test Year is
 7 included as Exhibit __ (BCH-1), Schedule 4.

8
 9 **Table 4**
 10 **RRAR During 2018 Test Year**

Line No.	Description	2018 Test Year (ND)
	Revenue Requirement	
1	Langdon	\$3,072,847
2	Ashtabula	\$3,440,839
3	Luverne	\$2,707,147
4	Total Revenue Requirement	\$9,220,833
5	Projected RRAR Revenue Collections	\$9,989,390

11
 12 Q. HOW WILL OTP ENSURE RRAR PROJECT COSTS ARE NOT DOUBLE
 13 RECOVERED DURING THE INTERIM RATE PERIOD?

14 A. OTP made an interim rate adjustment (Interim Petition Part B, Schedules 3 and 6) to the
 15 calculation of the interim rate revenue requirement that removes all costs and revenues
 16 currently included in the RRAR from the 2018 Test Year for interim rate purposes. As a
 17 result, the rate base used to compute interim rates does not include any project costs
 18 currently being recovered in the RRAR. This adjustment is necessary to avoid double
 19 recovery of these costs during the interim rate period. The RRAR and its associated rates
 20 will remain in effect while this general rate case.

21
 22 Q. PLEASE PROVIDE ADDITIONAL DETAIL RELATED TO THE INTERIM RATE
 23 ADJUSTMENT FOR THE RRAR.

24 A. The interim rate adjustment removes the RRAR projects' present revenue and RRAR
 25 project revenue requirements included in the 2018 Test Year from the interim cost of

1 service. OTP proposes to reset RRAR rates effective with interim rates so the amount
 2 collected in the RRAR is equal to the present RRAR revenue in the case. Additional detail
 3 on this adjustment can be found in Volume 1, Notice of Change in Rates and Interim Rate
 4 Petition, Interim Rate Supporting Schedules and Workpapers.

5 **C. TCRR**

6 Q. WHAT IS THE TCRR?

7 A. N.D.C.C. § 49-05-04.3 and N.D.C.C. § 49-5-06 authorize the Commission to approve a
 8 rider to recover capital costs related to transmission investments and for the recovery of
 9 costs assigned by regional transmission organizations (RTOs) for projects subject to cost
 10 sharing. OTP’s TCRR is such a rider.

11
 12 Q. PLEASE IDENTIFY OTP’S PAST TCRR FILINGS.

13 A. OTP’s prior TCRR filings are shown in table 5 below:

14
 15 **Table 5**
 16 **TCRR – History**

TCRR History	Case Number	Commission Approved	Effective Date
Initial TCRR Rate and Mechanism	PU-11-153 PU-11-682	April 25, 2012	May 1, 2012
First Update	PU-12-702	December 12, 2012	January 1, 2013
Second Update	PU-13-755	December 30, 2013	January 1, 2014
Third Update	PU-14-690	December 17, 2014	January 1, 2015
Fourth Update	PU-15-661	December 16, 2015	January 1, 2016
Fifth Update	PU-16-624	December 14, 2016	January 1, 2017
Sixth Update	PU-17-340	Open Proceeding	January 1, 2018*

17 *Proposed

18
 19 Q. WHAT PROJECTS ARE CURRENTLY BEING RECOVERED IN THE TCRR?

20 A. Costs associated with the projects listed in Table 6 below (collectively, the TCRR Projects)
 21 are currently being recovered in OTP’s TCRR:

1
2

**Table 6
TCRR Projects**

Project	Approved for Rider Recovery	In Service Date	Proposed Recovery
Fargo to Monticello CAPX 2020	PU-11-153 & PU-11-682	April 2015	Base Rates
Bemidji to Grand Rapids CAPX 2020	PU-11-153 & PU-11-682	August 2012	Base Rates
Bemidji to Cass Lake CAPX 2020	PU-11-153 & PU-11-682	August 2012	Base Rates
Rugby Wind Interconnection	PU-12-702	August 2011	Base Rates
Casselton – Buffalo 115 kV	PU-12-702	October 2017	Base Rates
Brookings to Hampton CAPX2020	PU-12-702	March 2015	Base Rates
MVP – Big Stone Area Transmission to Brookings	PU-12-702	September 2017	Base Rates
MVP – Ellendale to Big Stone South	PU-12-702	December 2019*	TCRR
Ramsey 230/115 Transformer Upgrade (Ramsey)	PU-12-702	December 2013	Base Rates
Karlstad, MN Capacity Bank Project	PU-12-702	December 2012	Base Rates
Oakes Area Transmission Improvements	PU-12-702	October 2015	Base Rates
Hankinson Transformer Addition	PU-12-702	December 2012	Base Rates
NERC Compliance	PU-13-755	September 2016	Base Rates
Summit Transformer	PU-14-690	May 2016	Base Rates
Spiritwood Station Interconnection	PU-14-690	August 2015	Base Rates
Max-Ryder 41.6 kV Line Upgrade	PU-16-624	December 2018*	TCRR
Rugby Interconnect 41.6 kV Breaker	PU-16-624	July 2017	Base Rates
Granville Junction Breaker Station	PU-16-624	July 2017	Base Rates
Bagley 115 kV Switch Station**	PU-17-340	October 2018*	TCRR
*Estimate			
**Proposed Project in ND Docket PU-17-340			

3
4
5
6

Q. WHAT IS OTP’S PROPOSAL REGARDING THE TCRR IN THIS CASE?

A. OTP proposes to move the 16 TCRR Projects that are expected to be in service at the time final rates go into effect out of the TCRR and into base rates concurrent with the

1 implementation of final rates in this case. OTP proposes to keep the three TCRR Projects
2 not in service at the time final rates go into effect in the TCRR.

3 **1. Base Rates**

4 Q. HOW HAVE THE TCRR PROJECTS BEEN HANDLED IN THE 2018 TEST YEAR
5 FOR THIS RATE CASE?

6 A. The TCRR Projects forecasted to be in service at the time final rates go into effect are part
7 of the rate base used to determine the 2018 Test Year revenue requirement. This includes
8 all gross plant in service, accumulated depreciation and accumulated deferred income tax
9 balances as of December 31, 2018.

10
11 Q. HAS OTP INCLUDED PROJECTED 2018 TCRR REVENUES FOR THE TCRR
12 PROJECTS IN THE TEST YEAR CALCULATIONS?

13 A. Yes. The projected 2018 TCRR revenues for the TCRR Projects are included in the
14 calculation of present revenues for the 2018 Test Year. The projected 2018 TCRR
15 revenues for the TCRR Projects are based on the calendar year 2018 revenue requirements
16 for the TCRR Projects, as computed in the TCRR.

17
18 Q. WHY DID OTP INCLUDE PROJECTED TCRR REVENUE FOR THE TCRR
19 PROJECTS IN THE CALCULATION OF PRESENT REVENUES?

20 A. As explained by Mr. Tommerdahl, moving the TCRR Projects from the TCRR into base
21 rates is merely a change to how the costs of the projects are recovered. Including the TCRR
22 revenue for the TCRR Projects in the calculation of 2018 Test Year present revenues results
23 in a more accurate measurement of the overall impact of the rate request on our customers.

24
25 Q. WHAT ARE THE PRIMARY TEST YEAR COST COMPONENTS THAT ARE
26 AFFECTED BY INCLUDING THE TCRR PROJECTS IN BASE RATES?

27 A. The primary rate base components are: (i) gross plant in service; (ii) accumulated
28 depreciation; and (iii) accumulated deferred income taxes. The primary operating expense
29 components that are impacted include: (i) depreciation and (ii) general tax expenses. The

1 impact on these items from rolling the TCRR Projects into base rates is quantified in Mr.
2 Akerman's Direct Testimony.

3
4 Q. WHAT IS THE TOTAL 2018 TEST YEAR INVESTMENT INCLUDED IN RATE
5 BASE FOR THE TCRR PROJECTS?

6 A. The total 2018 Test Year net electric plant in service for the TCRR Projects being moved
7 into rate base is \$246.5 million (OTP Total) and \$47.2 million (OTP ND). A detail of all
8 plant in service amounts moving into base rates is included as Exhibit __ (BCH-1),
9 Schedule 2.

10
11 Q. WHEN WILL OTP TRANSFER THE TCRR PROJECTS OUT OF THE TCRR AND
12 INTO RATE BASE?

13 A. OTP proposes to transfer the TCRR Projects that are in service at the time final rates are
14 implemented out of the TCRR and into rate base concurrently with the final rates. From
15 that point forward, the recovery of those TCRR Projects will be in base rates. At the time
16 final rates go into effect, a corresponding adjustment to the TCRR rates will also be made
17 to reflect the transfer of the net plant in service values of the TCRR Projects being moved
18 into base rates out of the TCRR.

19
20 Q. WHAT IS OTP'S PROPOSAL TO ADDRESS ANY TCRR TRACKER ACCOUNT
21 BALANCE ASSOCIATED WITH THE TCRR PROJECTS BEING MOVED INTO
22 BASE RATES AT THE END OF THE CASE?

23 A. OTP proposes that any TCRR tracker account balance associated with the TCRR Projects
24 moved into base rates at the conclusion of the case be recovered from or returned to
25 customers through the TCRR over the subsequent 12 months following the implementation
26 of final rates.

27
28 Q. WILL MISO AND SPP REVENUES AND EXPENSES REMAIN IN THE TCRR AT
29 THE END OF THE CASE?

30 A. Yes. OTP proposes these revenues and expenses stay in the TCRR.

1 Q. WHAT IS THE PRIMARY REASON FOR LEAVING THESE RTO REVENUES AND
2 EXPENSES IN THE TCRR?

3 A. OTP expects the amounts of RTO revenues and RTO expenses will continue to fluctuate
4 from year to year due in part to the continued growth and investment in regional cost shared
5 projects. RTO revenues and RTO expenses also continue to fluctuate as a result of
6 proceedings before the Federal Energy Regulatory Commission (FERC).¹³ OTP proposes
7 that any impacts of FERC's rulings on past and future RTO revenues and expenses would
8 best be trued-up within the TCRR.
9

10 Q. PLEASE PROVIDE A SUMMARY OF THE RECENT FERC PROCEEDINGS
11 REGARDING MISO REVENUES AND EXPENSES.

12 A. On November 12, 2013 and February 12, 2015 two groups of industrial customers and
13 other stakeholders filed complaints at FERC seeking to reduce the ROE component of the
14 transmission rates that MISO Transmission Owners, including OTP, may collect under the
15 MISO Tariff. FERC issued its Final Decision on the first complaint on September 28, 2016
16 reducing the base ROE applicable to investments under FERC's jurisdiction. The second
17 complaint is still pending before FERC.
18

19 Q. WHAT WAS THE RESULT OF THE FERC DECISION IN THE FIRST COMPLAINT?

20 A. The MISO Transmission Owners, including OTP, were required to refund to customers the
21 difference between revenues collected for the period November 12, 2013 to
22 February 12, 2016 and revenues over that same period assuming the ROE ordered in the
23 September 28, 2016 Final Decision. OTP uses a forward-looking rate formula in MISO
24 and makes an annual true-up filing with MISO. OTP's refund obligation was processed
25 by MISO in two parts: the refund obligation associated with the forecasted rate was
26 processed in February 2017 and the refund associated with the true-up was processed in
27 June 2017. OTP included the impacts of the refund within its 2017 Annual Update filing

¹³ FERC Docket No. EL 14-12-002. A final decision in this docket was issued on September 28, 2016. FERC Docket No. EL 14-12-002, 153 FERC ¶ 63,027, Final Decision (Sept. 28, 2016); FERC Docket No. EL 15-45-000. A preliminary decision in this docket was issued on June 30, 2016. FERC Docket No. EL 15-45-000, 155 FERC ¶ 63,030, Initial Decision (June 30, 2016).

1 to its TCRR, in Case No. PU-17-340, resulting in an \$83,000 credit for North Dakota
2 customers.

3
4 Q. WILL OTP APPLY THE RESULTS OF THE SECOND COMPLAINT IN A SIMILAR
5 FASHION TO THE FIRST?

6 A. Yes. OTP expects MISO to process the second complaint related settlements in the same
7 fashion as the first complaint related settlements. OTP proposes to include any second
8 complaint related settlements in the TCRR as it did with the first complaint related
9 settlements. OTP will include any such settlements in the first Annual Update to its TCRR
10 following the FERC decision and MISO settlements.

11
12 Q. DO ANY OTHER UTILITIES INCLUDE RTO-RELATED REVENUES AND
13 EXPENSES IN THEIR TRANSMISSION RIDERS?

14 A. Yes. Montana-Dakota Utilities proposed to recover RTO-related revenues and expenses
15 in its transmission rider in its most recent general rate case.¹⁴

16
17 Q. WHAT HAPPENS WITH THE TCRR PROJECTS REMAINING IN THE TCRR?

18 A. OTP proposes to continue recovering the TCRR Projects not yet in service at the time final
19 rates go into effect through the TCRR. Annual updates will continue to be made in the
20 TCRR in compliance with N.D.C.C. § 49-05-04.3 and Ordering Paragraph 6 of the
21 Commission's April 5, 2012 Order in Case Nos. PU-11-153 and PU-11-682.

22 **2. Interim Rates**

23 Q. HOW DOES OTP PROPOSE TO HANDLE THE TCRR DURING THE INTERIM RATE
24 PERIOD?

25 A. OTP proposes that the TCRR Projects and all other costs and revenues currently included
26 in the TCRR remain in the TCRR during the interim rate period.

¹⁴ April 7, 2017 Settlement Agreement in the Matter of Application of Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Electric Service.

1 Q. DOES OTP ANTICIPATE FILING AN UPDATE TO THE TCRR RATE WHILE THIS
2 CASE IS PENDING?

3 A. Yes. OTP will submit a supplemental filing in its current open TCRR proceeding in Case
4 No. PU-17-340.¹⁵ The TCRR annual rate update in that case is proposed to take effect
5 January 1, 2018. OTP proposes to include updates to the rate of return and allocation
6 factors proposed in this case in the supplemental filing in its open TCRR proceeding. These
7 updates will result in a lower revenue requirement in the open TCRR proceeding.

8
9 Q. PLEASE SUMMARIZE TCRR RECOVERY DURING THE 2018 TEST YEAR.

10 A. Table 7 below summarizes the costs and revenues included in the TCRR during the 2018
11 Test Year. The amounts shown in Table 7 do not reflect any prior period true-up amounts
12 or any collections of revenue for the 2018 Test Year. Additional support for the TCRR
13 recovery during the 2018 Test Year is included as Exhibit___(BCH-1), Schedule 5.

¹⁵ OTP Initial Filing in PU-17-340 submitted August 31, 2017 with proposed rate update to be implemented January 1, 2018.

1
2

**Table 7
TCRR During 2018 Test Year**

Description	2018 Test Year (ND)
Revenue Requirements	
CAPX 2020: Fargo	\$ 2,725,914
CAPX 2020: Bemidji	667,538
Cass Lake-Nary-Helga-Bemidji	108,505
Rugby Wind Interconnection	13,868
Casselton – Buffalo 115 kV Project	286,565
CAPX 2020: Brookings - Hampton	243,905
MVP: Big Stone Area Transmission	70,714
MVP: Ellendale to Big Stone South	85,659
Ramsey 230/115 kW Transformer Upgrade	15,269
Karlstad, MN Capacitor Bank Project	40,097
Oakes Area Transmission Improvements	238,791
Hankinson Transformer Addition	26,662
NERC Compliance	575,316
Summit Transformer	29,231
Spiritwood Station Interconnection	27,088
Max- Ryder 41.6 kV Line Upgrades	24,961
Rugby Breaker Station	54,672
Granville Jct Breaker Station	29,983
Bagley 115kV Switch Station	51,947
Total Project Revenue Requirements	\$ 5,316,686
MISO & SPP Expenses	
MISO Schedule 26 Expense	\$ 4,822,217
MISO Schedule 26A Expense	2,829,362
SPP Schedule 9 Expense	852,795
SPP Schedule 11 Expense	74,798
Total MISO & SPP Expenses	\$ 8,579,172
MISO Revenues	
MISO Schedule 9 Revenue	\$ (370,917)
MISO Schedule 26 Revenue	(4,907,968)
MISO Schedule 37 Revenue	(0)
MISO Schedule 38 Revenue	(0)
MISO Schedule 26A Revenue	(649,555)
MISO MVP ARR Revenue	(26,135)
Total MISO Revenues	\$ (5,954,575)
Total Revenue Requirement	\$ 7,941,283

3
4

1 Q. HOW WILL OTP ENSURE TCRR PROJECT COSTS ARE NOT DOUBLE
2 RECOVERED DURING THE INTERIM RATE PERIOD?

3 A. OTP made an interim rate adjustment (Interim Petition Part B, Schedules 3 and 6) to the
4 calculation of the interim rate revenue requirement that removes all costs and revenues
5 currently included in the TCRR from the 2018 Test Year. As a result, the rate base used
6 to compute interim rates does not include any of the TCRR Project costs currently being
7 recovered in the TCRR, nor do the interim rates include any RTO revenues and expenses
8 currently being recovered through the TCRR. This adjustment is necessary to avoid any
9 double recovery of these costs during the interim rate period. The TCRR and its associated
10 rates will remain in effect during the course of this general rate case.

11
12 Q. PLEASE PROVIDE ADDITIONAL DETAIL RELATED TO THE INTERIM RATE
13 ADJUSTMENT FOR THE TCRR.

14 A. The interim rate adjustment removes the TCRR Project present revenues and TCRR Project
15 revenue requirements included in the 2018 Test Year from the interim cost of service.
16 Additional detail on this adjustment can be found in Volume 1, Notice of Change in Rates
17 and Interim Rate Petition, Interim Rate Supporting Schedules and Workpapers.

18 **IV. ADVERTISING EXPENSE**

19 Q. PLEASE DESCRIBE OTP'S TREATMENT OF ADVERTISING EXPENSE IN THE
20 2018 TEST YEAR.

21 A. According to Commission Rule 69-09-02-38, paragraph 2, any expenditure by a utility for
22 institutional, promotional, or political advertising shall be excluded from operating
23 expenses in the cost of service determination for ratemaking purposes. Paragraph 3 of this
24 same rule allows advertising expenditures which are reasonable in amount and which are
25 not excluded under paragraph 2 to be included as operating expenses in the cost of service
26 determination for ratemaking purposes.

27 OTP excluded \$506,032 (OTP ND) in advertising expenses allocated to North
28 Dakota from the 2018 Test Year to comply with paragraph 2 of Commission Rule 69-09-

1 02-38.¹⁶ The 2018 Test Year includes \$19,489 (OTP Total) / \$8,698 (OTP ND) of
2 allowable advertising expenses under Commission Rule 69-09-02-38, paragraph 3.

3 **V. CONCLUSION**

4 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

5 A. Yes, it does.

¹⁶ OTP Initial Filing, Volume 4a, Workpaper B-14, page 1 of 1

Mr. Bryce C. Haugen
Senior Rates Analyst, Regulatory Administration
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8385

CURRENT RESPONSIBILITIES: (November 2015 to Present)

Provide leadership for rates analysts for the preparation and financial analysis used to determine revenue requirements associated with various state and federal cost recovery mechanisms and to lead development of regulatory filings associated with these cost recovery mechanisms. Primary state responsibilities are related to the environmental, renewable, and transmission cost recovery riders.

PREVIOUS POSITIONS:

Otter Tail Power Company

2015 - Present	Senior Rates Analyst, Regulatory Administration
2013 - 2015	Rates Analyst, Regulatory Administration
2012 - 2013	Credit Risk Analyst, Risk Management
2012 - 2012	Business Assistant, Project Management

Baker Boy Bake Shop Inc., Dickinson, ND

2010 - 2012	Supervisor, Production
2009 - 2010	Cost Accountant, Accounting

Theodore Roosevelt Medora Foundation, Medora, ND

2006 - 2009	Operations Manager
2005 - 2006	Assistant Operations Manager

EDUCATION / CERTIFICATIONS

Minnesota State Community & Technical College – Fergus Falls, MN – Associate of Arts
Minnesota State University Moorhead – Moorhead, MN - B.S. in Finance
National University – La Jolla, CA – Masters of Science in Organizational Leadership

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RIDER ROLL-IN SUMMARY SCHEDULE

Line No.		2018 Test Year	
		13MA OTP Total	13 MA OTP ND
1	ECRR Projects		
2	<i>Plant In Service:</i>		
3	Big Stone Plant AQCS	\$192,985,866	\$70,290,056
4	HLP MATS	6,460,514	\$2,353,073
5	Total Plant In Service	\$199,446,380	\$72,643,130
6			
7	RRAR Projects		
8	<i>Plant In Service:</i>		
9	Langdon Wind Project	\$79,417,900	\$29,843,126
10	Ashtabula Wind Project	\$116,261,976	\$43,688,146
11	Luverne Wind Project	72,996,881	27,430,279
12	Total Plant In Service	\$268,676,757	\$100,961,552
13			
14	TCRR Projects		
15	<i>Plant In Service:</i>		
16	CAPX 2020: Fargo	\$81,428,592	\$23,856,947
17	CAPX 2020: Bemidji	16,331,201	5,885,328
18	Cass Lake-Nary-Helga-Bemidji	7,039,948	975,736
19	Rugby Wind Interconnection	394,399	26,613
20	Casselton – Buffalo 115 kV Project	13,509,407	2,743,099
21	CAPX 2020: Brookings - Hampton	26,322,129	2,114,671
22	MVP: Big Stone Area Transmission	73,597,018	565,385
23	MVP: Ellendale to Big Stone South*	-	-
24	Ramsey 230/115 kW Transformer Upgrade	416,398	164,889
25	Karlstad, MN Capacitor Bank Project	1,103,974	437,161
26	Oakes Area Transmission Improvements	7,010,020	2,775,887
27	Hankinson Transformer Addition	828,844	328,213
28	NERC Compliance	14,078,440	5,574,900
29	Summit Transformer	853,991	338,171
30	Spiritwood Station Interconnection	720,137	285,166
31	Max- Ryder 41.6 kV Line Upgrades*	-	-
32	Rugby Breaker Station	1,824,862	722,624
33	Granville Jct Breaker Station	1,015,655	402,188
34	Bagley 115kV Switch Station*	-	-
35	Total Plant In Service	\$246,475,014	\$47,196,977
36	*Project will remain in Rider		

Otter 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													
1	Air Quality Control System	654,089	654,089	654,089	654,089	654,089	654,089	654,089	654,089	654,089	654,089	654,089	654,089	7,849,066
2	Hoot Lake Plant MATS Project	42,069	42,069	42,069	42,069	42,069	42,069	42,069	42,069	42,069	42,069	42,069	42,069	504,826
3	Total Revenue Requirements	696,158	696,158	696,158	696,158	696,158	696,158	696,158	696,158	696,158	696,158	696,158	696,158	8,353,891
4														
5	Billed (forecast kWh x adj factor)	1,007,729	979,767	881,326	806,012	654,201	618,417	556,734	575,889	574,008	556,242	660,401	744,063	8,614,789
6														
7	Difference ¹	273,041	(283,609)	(185,168)	(109,854)	41,957	77,741	139,424	120,269	122,150	139,916	35,757	(47,905)	
8	Carrying Charge	0	1,805	(58)	(1,282)	(2,017)	(1,753)	(1,251)	(337)	456	1,266	2,199	2,450	1,477
9	Cumulative Difference (True-Up)	273,041	(8,764)	(193,990)	(305,127)	(265,188)	(189,200)	(51,028)	68,904	191,509	332,690	370,646	325,191	325,191
10														
11	Carrying Charge Calculation	1,805	(58)	(1,282)	(2,017)	(1,753)	(1,251)	(337)	456	1,266	2,199	2,450	2,150	3,627
12	Cumulative Carrying Charge	1,805	1,747	465	(1,553)	(3,306)	(4,556)	(4,894)	(4,438)	(3,628)	(1,428)	1,022	3,172	
13	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%	

¹ January includes estimate of \$584,612 prior period true-up.

SUMMARY	2018 Test Year
Revenue requirements	\$8,353,891
Carrying Charge	3,627
Revenue requirements	<u>\$8,357,518</u>

Otter Tail Power Company
 Environmental Cost Recovery Rider
 North Dakota

		2018 Proposed ECRR Revenue Requirement and Rate												
Line No.	TRACKER SUMMARY	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	YE Projected
	Requirements Compared to Billed:													
	Revenue Requirements													
1	Air Quality Control System	654,089	654,089	654,089	654,089	654,089	654,089	654,089	654,089	654,089	654,089	654,089	654,089	7,849,066
2	Hoot Lake Plant MATS Project	42,069	42,069	42,069	42,069	42,069	42,069	42,069	42,069	42,069	42,069	42,069	42,069	504,826
3	Total Revenue Requirements	696,158	696,158	696,158	696,158	696,158	696,158	696,158	696,158	696,158	696,158	696,158	696,158	8,353,891
4														
5	Billed (forecast kWh x adj factor)	866,272	773,492	737,125	644,053	585,626	625,671	684,062	682,475	662,611	674,923	764,653	836,197	8,537,160
6														
7	Difference	(170,114)	(77,335)	(40,967)	52,105	110,532	70,486	12,095	13,683	33,547	21,234	(68,495)	(140,039)	
8	Carrying Charge	1,271	54	(457)	(731)	(391)	337	805	890	987	1,215	1,364	920	6,264
9	Cumulative Difference (True-Up)	8,162	(69,119)	(110,543)	(59,169)	50,972	121,795	134,696	149,269	183,802	206,251	139,119	0	0
10														
11	Carrying Charge Calculation	54	(457)	(731)	(391)	337	805	890	987	1,215	1,364	920	0	4,993
12	Cumulative Carrying Charge	1,325	868	137	(254)	83	888	1,779	2,765	2,994	4,357	5,277	5,277	25,495
13	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%	
14														
15														
16	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	9,995,992	10,181,735	11,535,372	12,614,663	128,789,562

SUMMARY	Jan 2018 - Dec 2018
Revenue requirements	\$8,353,891
Carrying Charge	6,264
December 2017 Estimated True Up	177,005
Revenue requirements	<u>\$8,537,160</u>
Jan 2018 - Dec 2018 projected revenue	128,789,562
January 1, 2018 Rate	6.629%

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	252,496	267,348	250,052	263,489	260,862	252,068	252,711	252,404	256,737	259,729	252,394	252,558	3,072,847	
5	205,840	262,103	236,254	237,984	205,979	279,927	311,826	324,162	266,983	223,484	448,325	437,972	3,440,839	
6	219,532	229,775	216,027	236,063	216,258	225,472	225,472	230,368	228,972	234,377	225,472	219,358	2,707,148	
7	677,868	759,226.46	702,333.01	737,536.33	683,098.29	757,467.40	790,009.81	806,933.61	752,691.35	717,590.04	926,191.67	909,887.87	9,220,833	
8														
9	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	2018 YE	
10	Billed (forecast kWh x adj factor)	1,002,578	974,758	876,821	801,891	777,328	734,809	763,941	790,224	787,643	763,266	906,191	1,020,991	10,200,441
11														
12	Monthly Revenue Difference	(324,710)	(213,298)	(173,664)	(64,679)	(94,982)	21,278	24,830	15,634	(35,923)	(46,885)	18,481	(112,500)	
13	Cumulative Difference ¹	337,885	124,587	(49,078)	(113,757)	(208,738)	(187,460)	(162,630)	(146,996)	(182,919)	(229,805)	(211,323)	(323,823.39)	
14	Adjusted Cumulative Difference	433,612	220,314	46,650	(18,029)	(113,011)	(91,733)	(66,903)	(51,269)	(87,192)	(134,077)	(115,596)	(228,095.99)	
15														
16														
17	Carrying Charge Calculation	2,234	824	(324)	(752)	(1,380)	(1,239)	(1,075)	(972)	(1,209)	(1,519)	(1,397)	(2,140.78)	
18	Cumulative Carrying Charge	788,565	789,388	789,064	788,312	786,932	785,693	784,617	783,646	782,436	780,917	779,520	777,379.29	
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	340,118	125,410	(49,402)	(114,509)	(210,118)	(188,699)	(163,706)	(147,968)	(184,129)	(231,324)	(212,720)	(325,964)	
23														
24	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	9,995,992	10,181,735	11,535,372	12,614,663	128,789,562

¹ January includes estimate of \$662,595 prior period true-up.

2018 Test Year	
Revenue Requirements	9,220,833
Carrying Charge	(8,952)
Total Requirements	9,211,882

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	TRACKER SUMMARY													
2	Requirements Compared to Billed:													
3	Revenue Requirements													
4	Langdon	252,496	267,348	250,052	263,489	260,862	252,068	252,711	252,404	256,737	259,729	252,394	252,558	3,072,847
5	Ashtabula	205,840	262,103	236,254	237,984	205,979	279,927	311,826	324,162	266,983	223,484	448,325	437,972	3,440,839
6	Luverne	219,532	229,775	216,027	236,063	216,258	225,472	225,472	230,368	228,972	234,377	225,472	219,358	2,707,148
7	Total	677,867.60	759,226.46	702,333.01	737,536.33	683,098.29	757,467.40	790,009.81	806,933.61	752,691.35	717,590.04	926,191.67	909,887.87	9,220,833.45
8														
9														
10	Billed (forecast kWh x adj factor)	Projected 1,013,631	Projected 905,069	Projected 862,515	Projected 753,610	Projected 685,245	Projected 732,102	Projected 800,426	Projected 798,569	Projected 775,326	Projected 789,733	Projected 894,726	Projected 978,439	2018 YE 9,989,390
11														
12	Monthly Revenue Difference	(330,444)	(143,052)	(158,337)	(15,276)	(1,449)	26,052	(9,557)	9,161	(21,778)	(71,430)	31,707	(68,101)	
13	Cummulative Difference	422,061	279,009	120,672	105,395	103,946	129,998	120,441	129,602	107,825	36,395	68,101	(0.00)	
14	Adjusted Cumulative Difference	427,879	284,827	126,489	111,213	109,763	135,816	126,259	135,420	113,642	42,212	73,919	5,817.57	
15														
16														
17	Carrying Charge Calculation	2,790	1,845	798	697	687	859	796	857	713	241	450	(0.00)	
18	Cumulative Carrying Charge	789,121	790,966	791,763	792,460	793,147	794,007	794,803	795,660	796,373	796,613	797,063	797,063.45	
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	424,851	280,854	121,469	106,092	104,633	130,858	121,237	130,459	108,537	36,635	68,552	(0)	(0.00)
23														
24	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	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	9,220,833
Carrying Charge	10,733
Cumulative True-up	757,824
Total Requirements	9,989,390
Jan 2018 - Dec 2018 projected revenue	128,789,562
January 1, 2018 Rate	7.756%

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													
1	CAPX 2020: Fargo	226,549	226,549	228,380	226,549	226,549	228,380	226,549	226,549	228,380	226,549	226,549	228,380	2,725,914
2	CAPX 2020: Bemidji	55,628	55,628	55,628	55,628	55,628	55,628	55,628	55,628	55,628	55,628	55,628	55,628	667,538
3	Cass Lake-Nary-Helga-Bemidji	9,042	9,042	9,042	9,042	9,042	9,042	9,042	9,042	9,042	9,042	9,042	9,042	108,505
4	Rugby Wind Interconnection	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	13,868
5	Casselton – Buffalo 115 kV Project	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	286,565
6	CAPX 2020: Brookings - Hampton	20,274	20,274	20,428	20,274	20,274	20,428	20,274	20,274	20,428	20,274	20,274	20,428	243,905
7	MVP: Big Stone Area Transmission	5,884	5,887	5,891	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	70,714
8	MVP: Ellendale to Big Stone South	7,138	7,138	7,138	7,138	7,138	7,138	7,138	7,138	7,138	7,138	7,138	7,138	85,659
9	Ramsey 230/115 kW Transformer Upgrade	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	15,269
10	Karlstad, MN Capacitor Bank Project	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341	40,097
11	Oakes Area Transmission Improvements	19,899	19,899	19,899	19,899	19,899	19,899	19,899	19,899	19,899	19,899	19,899	19,899	238,791
12	Hankinson Transformer Addition	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	26,662
13	NERC Compliance	47,943	47,943	47,943	47,943	47,943	47,943	47,943	47,943	47,943	47,943	47,943	47,943	575,316
14	Summit Transformer	2,436	2,436	2,436	2,436	2,436	2,436	2,436	2,436	2,436	2,436	2,436	2,436	29,231
15	Spiritwood Station Interconnection	2,257	2,257	2,257	2,257	2,257	2,257	2,257	2,257	2,257	2,257	2,257	2,257	27,088
16	Max- Ryder 41.6 kV Line Upgrades	2,020	2,020	2,020	2,020	2,020	2,020	2,020	2,020	2,020	2,020	2,020	2,741	24,961
17	Rugby Breaker Station	4,556	4,556	4,556	4,556	4,556	4,556	4,556	4,556	4,556	4,556	4,556	4,556	54,672
18	Granville Jct Breaker Station	2,499	2,499	2,499	2,499	2,499	2,499	2,499	2,499	2,499	2,499	2,499	2,499	29,983
19	Bagley 115kV Switch Station	4,138	4,138	4,138	4,138	4,138	4,138	4,138	4,138	4,138	5,284	5,284	5,284	51,947
20	Total Revenue Requirements	442,135	442,139	444,127	442,147	442,146	444,131	442,146	442,146	444,131	442,146	443,293	445,998	5,316,686
21														
22	MISO & SPP Expenses													
23	MISO Schedule 26 Expense	485,727	445,667	425,637	365,547	315,472	345,517	400,600	400,600	345,517	390,585	400,600	500,749	4,822,217
24	MISO Schedule 26A Expense	289,914	261,250	252,884	221,319	205,456	202,418	220,116	220,191	210,355	221,643	247,196	276,620	2,829,362
25	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	852,795
26	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	74,798
27	Total MISO & SPP Expenses	783,587	790,521	762,125	670,470	604,532	631,539	704,320	704,395	639,476	695,832	731,399	860,974	8,579,172
28														
29	MISO Revenues													
30	MISO Schedule 9 Revenue	(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)
31	MISO Schedule 26 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)	(4,907,968)
32	MISO Schedule 37 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
33	MISO Schedule 38 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
34	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)	(649,555)
35	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)	(26,135)
36	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)	(5,954,575)
37														
38	Net Revenue Requirement	729,508	736,446	710,038	616,403	550,464	579,456	650,252	650,328	587,393	641,764	678,478	810,759	7,941,288
39														
40	Billed (forecast kWh x adj factor)	834,285	811,135	729,637	667,285	541,604	511,978	532,276	550,589	548,791	531,806	631,388	711,375	7,602,149
41														
42	Difference	(104,777)	(74,689)	(19,599)	(50,882)	8,860	67,478	117,976	99,739	38,602	109,958	47,090	99,384	339,139
43	Carrying Charge	0	(2,750)	(3,262)	(3,413)	(3,772)	(3,738)	(3,317)	(2,559)	(1,916)	(1,674)	(958)	(653)	(28,008)
44	Cumulative Difference ¹	(415,909)	(493,348)	(516,209)	(570,503)	(565,414)	(501,674)	(387,015)	(289,835)	(253,148)	(144,864)	(98,732)	0	0
45														
46	Carrying Charge Calculation	(2,750)	(3,262)	(3,413)	(3,772)	(3,738)	(3,317)	(2,559)	(1,916)	(1,674)	(958)	(653)	0	
47	Cumulative Carrying Charge	(2,750)	(6,011)	(9,424)	(13,195)	(16,933)	(20,250)	(22,808)	(24,724)	(26,398)	(27,356)	(28,008)	(28,008)	
48	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%	
49														
50														
51														
52														

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

SUMMARY	2018 Test Year
Revenue requirements	\$7,941,288
Carrying Charge	(28,008)
Total requirements	\$7,913,280