

215 South Cascade Street  
PO Box 496  
Fergus Falls, Minnesota 56538-0496  
218 739-8200  
[www.otpco.com](http://www.otpco.com) (web site)



March 31, 2015

Mr. Darrell Nitschke  
Director of Administration/Executive Secretary  
North Dakota Public Service Commission  
State Capitol  
600 East Boulevard, Dept. 408  
Bismarck, ND 58505-0408

**RE: In the Matter of Otter Tail Power Company's Application for Approval of the Annual Update to Environmental Cost Recovery Rider Charge, Rate Schedule 13.08 Case No. PU-15-\_\_\_\_\_**

Dear Mr. Nitschke:

Enclosed are an original and seven (7) copies of Otter Tail Power Company's ("Otter Tail's") Application for Approval of its Annual Update to the Environmental Upgrades Cost Recovery ("ECR") Charge along with a check in the sum of \$10,000. This application is an annual filing which simply updates the ECR Charge and should not require the amount of time and expense required for an initial application for a tariff filed under NDCC §49-05-04.2.2. Otter Tail requests the fee be reduced to \$10,000 and is therefore submitting a filing fee of \$10,000 with this application. Otter Tail will be responsible for amounts incurred in excess of the initial filing fee of \$10,000 up to \$100,000 unless the Commission approves the fee reduction request.

This filing is being sent to you electronically and by U.S. mail.

Should you have any questions, please feel free to contact me at 218-739-8607 or [pbeithon@otpco.com](mailto:pbeithon@otpco.com).

Very truly yours,

*/s/ PETE BEITHON*  
Pete Beithon  
Manager, Regulatory Recovery

jce  
Enclosures  
By electronic filing and US mail

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

Case No. PU-15-\_\_\_\_\_

---

In the Matter of Otter Tail Power  
Company's Application for Approval  
of the Annual Update to  
Environmental Cost Recovery Rider Charge,  
Rate Schedule 13.08

---

**APPLICATION**

**I. INTRODUCTION**

Otter Tail Power Company ("Otter Tail") submits this Application to the North Dakota Public Service Commission ("Commission") for approval of its annual update ("Update") to the Environmental Cost Recovery Charge under Otter Tail's Environmental Cost Recovery Rider ("ECR" or "Rider"), Rate Schedule 13.08.

On December 18, 2013, the Commission approved Otter Tail's ECR Rider Tariff and adjustment rate for the Big Stone generation plant's Air Quality Control System ("AQCS") in Case Nos. PU-13-79, and PU-13-84. On July 15, 2014, the Commission approved Otter Tail's first update to the ECR Rider in Case No. PU-14-142. Otter Tail is now filing its second update to the ECR Charge for actual and forecasted AQCS and Hoot Lake Plant Mercury and Air Toxics Standards ("MATS") project cost and revenue information through the recovery period of July 2015 through June 2016.<sup>1</sup>

The AQCS project is over 90 percent complete as of the date of this filing. The project budget is \$384 million. The initial budget for the AQCS project was \$489 million. The updated forecast cost and revenue information includes incremental operation and maintenance expenses

---

<sup>1</sup> On February 25, 2015, in case No PU-14-668, the Commission authorized recovery of reagent and allowance costs in the ECR Rider. Otter Tail had originally requested in that docket recovery of reagent and allowance costs through the Fuel Clause Adjustment, but the Commission authorized recovery of such costs through the ECR to better align recovery of these costs with the related capital costs being recovered through this ECR. This approach better communicates to customers that all such costs are being incurred to meet requirements of the U.S. Environmental Protection Agency.

which commence with the anticipated commissioning of the AQCS in October of 2015.

Since the last ECR update filing, a required environmental retrofit project has been completed at Otter Tail's Hoot Lake Plant, located near Fergus Falls, Minnesota. The Hoot Lake Plant environmental retrofit is necessary for compliance with the mercury and air toxics standards ("MATS") promulgated by United States Environmental Protection Agency ("EPA"). The initial budget for the MATS project was \$10 million. The final actual project costs are closer to \$7 million.

The Big Stone AQCS and Hoot Lake Plant MATS projects are necessary for continued operation of both facilities.

Otter Tail anticipates the rate impact of this request (for both projects) will increase the ECR Rider Factor from 7.531 percent of base rates to 9.193 percent of base rates. This component of the rate is calculated separately from the reagent and allowance cost recovery calculation that was approved in Case No. PU-14-668. Otter Tail estimates the total rate for the Big Stone AQCS alone, including the Reagents and Emissions Allowance Adjustment ("REAA") Rider Charge related to the Big Stone reagents will be approximately 9.5 percent. The total rate including the Big Stone AQCS, Hoot Lake MATS, reagents for Big Stone, Coyote, Hoot Lake and allowances for Hoot Lake will be approximately 10.5 percent once all costs are included on the customer's bill, which is substantially lower than the originally estimated 15 percent impact of just the Big Stone AQCS as described in Otter Tail's initial filings in Case Nos. PU-13-79 and PU-13-84. Otter Tail expects the ECR Rider Charge to decrease in next year's ECR update filing.

## **II. GENERAL FILING INFORMATION**

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

### **A. Name, address, and telephone number of the utility making the filing**

Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
Phone (218) 739-8200

**B. Name, address, and telephone number of the attorney for Otter Tail Power**

**Company**

Bruce Gerhardson  
Associate General Counsel  
Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
Phone (218) 739-8475

**C. Title of utility employee responsible for filing**

Peter J. Beithon  
Manager, Regulatory Recovery  
Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
(218) 739-8607

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

The date of this filing is March 31, 2015. Otter Tail proposes an effective date of July 1, 2015 for the updated rate.

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

A certified copy of Otter Tail's Articles of Incorporation is on file with the Commission, as is an original certificate of good standing.

**F. Customer Notification**

Otter Tail has begun serving notice of this filing on customers. Attachment 1 is a sample of the notice to customers that will be provided to customers on their April 2015 bills.

**III. BACKGROUND**

On December 18, 2013, the Commission approved Otter Tail's ECR tariff and rate in Case Nos. PU-13-79 and PU-13-84.<sup>2</sup> The December 18, 2013 Order, authorized implementation of in ECR rate of 4.319 percent (applied to base rates) effective with bills rendered on and after January 1, 2014 and which was calculated on a recovery period through March 2014. On July 10, 2014, in Case No. PU-14-142, the Commission approved the first update to Otter Tail's ECR

---

<sup>2</sup> PU-13-79 and PU-13-84, Findings of Fact, Conclusions of Law and Order.

rate, which adjusted the rate to 7.531 percent effective with bills rendered on and after August 1, 2014.

Otter Tail now requests to update its ECR Charge to reflect actual costs incurred through January 2015 and projected costs through June 2016 pursuant to its Electric Rate Schedule 13.08. As stated earlier, the updated forecast includes a total project budgeted amount of \$384 million (\$84 million Otter Tail North Dakota share) for the AQCS at Big Stone, and AQCS operation and maintenance (O&M) expenses of approximately \$330,000 (Otter Tail North Dakota share) for the recovery period (O&M starts in October 2015) plus actual capital costs of approximately \$7.0 million (\$2.8 million Otter Tail North Dakota share) for the Hoot Lake MATS project. As shown in Attachment 2, the projected revenue requirement for the AQCS and MATS projects, as allocated to North Dakota, is \$11,936,305 with a projected under recovery of the current period's costs of \$312,521 (including carrying cost credit) for a total cost of \$12,248,826 to be recovered through the ECR Charge over the period July 1, 2015 through June 30, 2016.

### **Statutory Requirements of the Rate Adjustment**

NDCC §49-05-04.2.2 provides as follows:

*2. Rate adjustments filed under the tariff must be accompanied by:*

- a. A description and quantification of the costs and expenses incurred by the public utility to meet federal environmental mandates which are subject to recovery;*
- b. A schedule for implementation of the applicable projects;*
- c. Calculations to establish that the rate adjustment is consistent with the terms of the tariff; and*
- d. An application fee in the amount of one hundred thousand dollars. Upon request of the commission and with the approval of the emergency commission, the applicant shall pay such additional fees as are reasonably necessary for completion of the application process by the commission. The commission may waive or reduce the fee.*

Sections B, C and D (and related attachments) below meet the requirements of the Statutory Requirements identified in 2.a, 2.b, and 2.c above.

As indicated in the cover letter for this Application, since this is an annual filing which simply updates the ECR Charge, Otter Tail requests the fee be reduced to \$10,000

and is therefore submitting a filing fee of \$10,000 with this application. Otter Tail will be responsible for amounts incurred in excess of the initial filing fee of \$10,000 up to \$100,000 unless the Commission approves the fee reduction request.

#### **IV. Project Description**

##### **A. Big Stone Plant Air Quality Control System**

Otter Tail operates the Big Stone Plant (“Big Stone”) near Big Stone City, South Dakota. The Big Stone Plant is co-owned by NorthWestern Corporation d/b/a NorthWestern Energy, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., and Otter Tail. The Big Stone Plant AQCS project is described in detail in Case Nos. PU-13-79, and PU-13-84, the cases in which the Commission approved the ECR for Otter Tail and Montana-Dakota. Otter Tail projects that the Big Stone AQCS will be in operation by October 2015.

Attachment 3 to this filing is the January 2015 quarterly project update filed in Case No. PU-11-165. The project remains on budget and on schedule. The total capital cost estimate for the AQCS project is \$384 million and the project is approximately 90 percent complete.

Otter Tail’s ownership share in the Big Stone Plant is 53.9 percent, and therefore Otter Tail is responsible for 53.9 percent of the costs, or \$207 million. Otter Tail’s North Dakota (“ND”) jurisdictional share of this cost responsibility is approximately 40 percent or \$84 million.

The December 18, 2013 Order in Case Nos. PU-13-79 and PU-13-84, paragraph 3 states “Otter Tail Power Company shall coordinate with Montana-Dakota Utilities Co. its Environmental Cost Recovery Rider updates so the same joint costs appear in each company's filing,” Attachment 4(a) is a schedule of the same joint project costs used by both Otter Tail and Montana-Dakota for purposes of this update. Montana-Dakota’s update is expected to be filed concurrently.

Shared project costs of \$276.9 million (\$59.7 million Otter Tail ND share) were incurred as of January 31, 2015. The projection for 2015 project expenditures is an additional \$105.7 million (\$22.8 million Otter Tail ND share) for a cumulative total of \$382.5 million (\$82.5 million Otter Tail ND share). The remaining \$1.7 million of the project will be spent in 2016 and 2017 for the total budgeted project costs of \$384.2 million. Otter Tail has also incurred costs on its own behalf which are not shared with the other owners. The Otter Tail-only costs included in the Rider tracker are \$1.1 million (Otter Tail’s North Dakota share). This request covers the

period of July 1, 2015 through June 30, 2016 for setting the updated ECR Charge.

After the commercial operation date (“COD”), the Plant will need to operate and maintain the equipment. The largest cost will be incurred to supply the equipment with the chemical reagents used to control emissions. The recovery of the reagents costs was approved in Case No. PU-14-668 therefore those costs will not be included in the ECR Charge calculation. The ECR Charge will be included on the same line of customers’ bills as the reagent recovery (REAA Charge). Operation and maintenance costs were included in the initial analysis of the AQCS alternatives submitted in the Advance Determination of Prudence in Case Nos. PU-11-163 and PU-11-165.

Because of the addition of the lime and powdered activated carbon and the capture of the SO<sub>2</sub> the volume of the ash collected will increase. Also, the ash produced is expected to be less dense than the previous ash. These two factors will increase the volume of ash that will need to be disposed of. Thus the labor to dispose the ash and maintenance of the ash unloading and hauling equipment will also increase.

With the increased amount of equipment there will be increased materials and consumables used to maintain the equipment. This will include things such as lubricating oil, filters, belts, replacement parts, etc.

Encompassing all of the above is the labor to receive the chemical reagents, prepare them for use, operate and maintain the equipment and haul the ash. All together we budgeted an increase in the Plant staff in 2015 by the equivalent of eight FTEs. The 2014 Big Stone Plant employee count was 72 employees. The budgeted amount for Otter Tail’s North Dakota share of the operation and maintenance expense for the period covered by this application is approximately \$330,000.

## **B. Hoot Lake Plant MATS Project**

Otter Tail Power has upgraded the existing Hoot Lake Units #2 and #3 electrostatic precipitators (“ESP”) to comply with the MATS. Compliance with MATS is required by April 16, 2015. Otter Tail reviewed various compliance options including retiring Hoot Lake in 2015 and replacing the generation (most likely with natural gas generation), refurbishing Hoot Lake to operate as a Coal Unit for long-term operation, or installing near-term required upgrades and planning for retirement in the 2020 timeframe. The Hoot Lake MATS Project original cost

estimates were approximately \$10,000,000, however at the time of completion the actual project cost was approximately \$7,000,000, including AFUDC (a 30 percent decrease from the estimate). The in-service date of the MATS equipment was October 2014. Further detail on the project is described below.

### 1. Background on MATS regulation

The 1990 Amendments to the Clean Air Act (“CAA”) required EPA to study the effects of emissions of listed hazardous air pollutants by electric steam generating plants. The EPA completed required studies and submitted reports to Congress, and determined that it would regulate mercury emissions from electric generating units under the hazardous air pollutant requirements of the CAA. EPA then published final rules that reversed this determination and set forth a cap and trade program for mercury emissions; however, EPA’s cap and trade mercury rule was reversed by the United States Court of Appeals for the D.C. Circuit in February 2008.

In response to the D.C. Circuit Court’s vacatur, on March 16, 2011, EPA proposed Section 112 air toxics standards for all coal- and oil-fired Electric Generating Units (“EGUs”) that reflect the application of the maximum achievable control technology (“MACT”) consistent with the requirements of the CAA. EPA signed a final rulemaking, termed the “mercury and air toxics standards” (MATS) rule, on December 16, 2011, which was subsequently published in the Federal Register on February 16, 2012.

Power plants were given three years and sixty days from the date of publication to comply with MATS (April 16, 2015), although EPA encouraged state permitting authorities to broadly grant a one-year compliance extension to plants that need additional time to install controls. Based on the final rule, Hoot Lake Plant will meet MATS by improving particulate control on Units #2 and #3 and including powdered activated carbon injection to control mercury emissions. Emissions monitoring equipment and/or stack testing was also needed to verify compliance with the standards.

### 2. Description of Project

Prior to the decision to upgrade the Hoot Lake units to meet the MATS rule and plan for a retirement in the 2020 timeframe, Otter Tail investigated various options around the Hoot Lake generation facility including engineering studies based for:

- A range of environmental controls necessary for a wide range of future regulatory restrictions
- Condition based assessments of Hoot Lake
- Generation Options for Hoot Lake replacement (including specific natural gas generation options)

Otter Tail went through a solution based competitive bid process to determine the preferred technology and vendor to complete the MATS upgrade project at Hoot Lake. Emissions guarantee requirements that would meet the MATS rule under current Hoot Lake operating conditions were issued to vendors for general solutions and firm project bids were compared against each other. After review, ESP upgrade projects compared favorably to baghouse retrofit projects primarily because of their ability to meet required MATS emissions requirements with maximum use of existing technology, lower costs for retrofit of both Units #2 and #3, and elimination of need to replace the existing large Induced Draft Fans.

## **V. Revenue Requirements Components and Tracker**

### **A. Components of the Revenue Requirement Calculation**

Attachments 2 and 4 show the revenue requirement calculation for the AQCS and MATS projects included in the Rider. The revenue requirement for the project included in the Rider includes several components as described below.

- *Rate base section.* This section provides details on the amount of Plant in service, accumulated depreciation (if applicable), construction work in progress (“CWIP”), accumulated deferred taxes, and a monthly rate base calculation per Staff request in Case No. PU-14-142.
- *CWIP.* NDCC §49-05-04.2 allows a current return on CWIP.
- *Expense section.* The expenses applicable to the project are listed here and include operating costs, property taxes, depreciation, and income taxes.
- *Revenue requirements section.* This section shows the components of the revenue requirements. Included are the items computed from the sections previously mentioned, including expenses and return on rate base.
- *Return on investment (cost of capital).* The return on investment utilizes the cost of

capital approved in Otter Tail's most recent general rate case.

- *Depreciation expense.* Depreciation expense is calculated using Otter Tail's latest composite depreciation rate.
- *Property taxes.* The property tax calculation is based on Otter Tail's composite tax rate for South Dakota, the jurisdiction where the AQCS is located, as well as Minnesota, the jurisdiction where the MATS is located. Each will be calculated in accordance with the procedures specified by that state.
- *O&M Expense.* Otter Tail will track O&M costs specifically related to the AQCS and MATS projects.

## **B. Tracker Balance**

Otter Tail maintains a tracker account worksheet (Attachment 4) and accounting system to track and account for retail revenue requirements until all costs have been fully recovered or reflected in base rates as part of a general rate case. The tracker account information compares Otter Tail's North Dakota jurisdictional costs and the amount recovered through North Dakota retail revenue. The tracker account balance (either positive or negative) will accrue monthly carrying charges at a rate of 1/12 of Otter Tail's cost of capital times the tracker balance. Carrying charges on a negative tracker balance will accrue to the benefit of retail customers and carrying charges on a positive tracker balance will accrue to Otter Tail.

Otter Tail has made a correction to the tracker (Attachment 4, page 5 of 12, line 4, 2013 Actual January) for an AFUDC calculation error. The correction reduced the AQCS project balance by approximately \$70,000 (approximately \$28,000 North Dakota share).

Attachment 4(b) reconciles the actual balance of the tracker as of the end of January 2015 as well as the end of June 2016 forecasted balance to Attachment 4(a), the Schedule of Joint Project Costs. The tracker reconciliation (Attachment 4 (b)) reflects \$190,033 more in line 4 than last year's Attachment 4(b). \$190,033 of AFUDC had been incorrectly included in line 5 last year (the OTP only costs). As a result line 5 is reduced by \$190,033. The net impact on the tracker balance is \$0.

Attachment 4(c) is a schedule of the anticipated incremental O&M costs for Big Stone Plant related to the new AQCS system. Reagent costs are not included in these incremental costs as they have been addressed in a separate case (No PU-14-668). Eight additional employees are being hired to cover the additional work required to operate and maintain the AQCS system. Prior to the AQCS system, Big Stone Plant had 72 employees. The North Dakota share of Otter Tail's share of the forecast incremental costs for labor and materials is \$105,311 for Oct.-Dec. 2015, \$433,880 for 2016 and \$446,869 for 2017.

When annual updates to the ECR Rider are filed, the tracker account is updated (trued-up) so that any over/under recovered amount at the end of the previous recovery period will be reflected in the Rider adjustment for the upcoming recovery period. This approach ensures that no under/over recovery occurs.

## **VI. RATE DESIGN**

Otter Tail proposes the continuation of the percent-of-bill method. The rate design is simply the calculated revenue requirement from July 2015 through June 2016 divided by the total base revenue from North Dakota electric retail customers from July 2015 through June 2016. The rate design calculation is shown on Attachment 5.

## **VII. RATE IMPACT**

The proposed update to the ECR Charge moves the factor for all customers from 7.531 percent to 9.193 percent. The total July 2015 – June 2016 revenue requirements, as shown on line 4 in Attachment 2, are \$12,248,826. The proposed ECR Charge is then calculated in Attachment 5.

The increase from this update for a residential customer using 1,000 kWh would be approximately \$1.47 per month. The following table shows the estimated rate increase over the previous rate by a residential customer using 1,000 kWh and a Large General Service customer using 400,000 kWh and 1,000 kW:

	Average kWh's per month	Total Current Bill	Total Proposed Bill	Percent Increase
Residential	1,000	\$108.75	\$110.22	1.35%
Large General Service	400,000	\$33,258.51	\$33,701.17	1.33%

The above rate has been calculated based on an expected implementation date of July 1, 2015. Revenue Requirement calculations are based on July 2015 through June 2016 costs, assuming revenue collection occurs during the same period. The costs incurred up to January 2013 include AFUDC accrued through December 2012. If the effective date for the rate implementation is significantly later than July 1, 2015, Otter Tail requests the option to recalculate the Charge in order to recover all approved costs over the remainder of the proposed recovery period.

### **VIII. ENVIRONMENTAL COST RECOVERY RIDER RATE SCHEDULE**

Otter Tail's revised Rate Schedule 13.08 is provided in Attachment 6 to this application, in both redline and clean versions.

### **IX. CONCLUSION**

Otter Tail respectfully requests the Commission approve the updated Environmental Cost Recovery Charge effective July 1, 2015, based on the tracker activity and cost recovery for the Big Stone Plant AQCS project and the Hoot Lake MATS project.

Date: March 31, 2015

Respectfully submitted:

OTTER TAIL POWER COMPANY

/s/ PETE BEITHON

Pete Beithon  
Manager, Regulatory Recovery  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
Phone (218) 739-8607

## Attachments

Attachment 1	Customer Notice
Attachment 2	Summary of Revenue Requirements
Attachment 3	January 14, 2015 Quarterly Report in Case No. PU-11-165
Attachment 4	Project Tracker
Attachment 4(a)	Schedule of Joint Project Costs for Montana-Dakota and Otter Tail
Attachment 4(b)	Reconciliation of Otter Tail Tracker Balance to Schedule 4(a)
Attachment 4(c)	Incremental Operation and Maintenance costs for the AQCS
Attachment 5	Rate Design Calculation
Attachment 6	Environmental Cost Recovery Rider, Electric Rate Schedule 13.08

## **Notice to our North Dakota customers**

On March 31, 2015, we filed a request with the North Dakota Public Service Commission to change our Environmental Cost Recovery Rider rate for bills rendered on and after July 1, 2015. The proposed rate for all classes of service is 9.193 percent of base charges and credits. The current rate is 7.531 percent.

The Environmental Cost Recovery Rider recovers the cost of projects at electrical generation plants that are required by the Environmental Protection Agency (EPA). To meet EPA regulations, we are required to build environmental-control systems at our Big Stone and Hoot Lake Plants at a total Otter Tail cost in excess of \$200 million. Even with the additional cost, these units remain the least cost option for generating electricity. The proposed rate reflects our North Dakota customers' share of these project costs.

The change is proposed only, and the new rate will not be effective until the Commission takes action.

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

**Summary of Revenue Requirements**

Line No.	Revenue Requirements	2015 - 2016
1	AQCS	\$11,251,466
2	HLP MATS	684,839
3	Carrying Cost	(15,054)
4	True-Up	<u>327,575</u>
5	Total	<u><u>\$12,248,826</u></u>

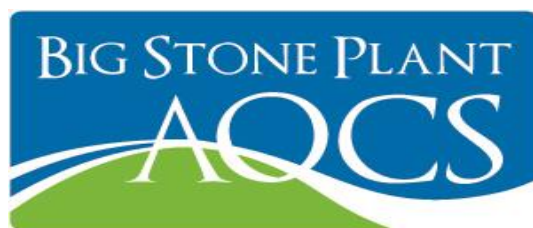
**BIG STONE PLANT  
AIR QUALITY CONTROL SYSTEM PROJECT  
QUARTERLY REPORT**

**TO THE**

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

**FOR THE**

**PERIOD OCTOBER 1 THROUGH DECEMBER 31, 2014**



**January 14, 2015**

Montana-Dakota Utilities Co. and Otter Tail Power Company submit this report on the Big Stone Plant Air Quality Control System (“AQCS”) Project in compliance with the North Dakota Public Service Commission May 9, 2012 Order in Cases No. PU-11-163 & PU-11-165, ordering paragraph 2.

This report describes progress made on the project during the quarter ending December 31, 2014. Specifically, in compliance with the above-referenced Order, this report includes information on the status of the United States Environmental Protection Agency (“EPA”) review of the South Dakota Regional Haze State Implementation Plan (“SIP”); it describes the types and amounts of costs incurred on the project to date; and it describes changed circumstances that are expected to affect the cost, schedule or installation of the AQCS Project.

## **Section I**

### **Status of the United States Environmental Protection Agency’s (“EPA”) review of the South Dakota Regional Haze State Implementation Plan (“SIP”)**

On March 29, 2012, the Administrator for EPA Region 8 signed as a final rule the approval of South Dakota’s Regional Haze SIP. The final rule was published in the *Federal Register* on April 26, 2012 and became effective on May 29, 2012.

## **Section II**

### **Types and amounts of Project cost actually incurred**

Actual construction on the project is now approximately 86 percent completed. Considerable progress was made this last quarter; however the early arrival of winter in early November has been challenging for the outside construction. Examples of accomplishments include:

- Structural steel to support the ductwork into the scrubber is now all in place. The ductwork is being fabricated and placed and should be completed in January.
- Inlet ductwork for the induced draft (“ID”) fans is all in place and outlet ductwork for B fan is complete until the tie-in outage work. Insulation on the ductwork and fans continues.
- Baghouse is complete structurally. Piping insulation, siding, electrical and instrumentation is all being worked on. Commissioning has started checking out systems in the lower baghouse area. A few systems, such as building heating, are being put into service.
- Selective Catalytic Reduction (“SCR”) is complete. Weld out is almost done. Siding, roofing, piping and electrical is all well underway structurally. The catalyst will begin arriving in early January for placement inside the reactor boxes.
- Ammonia system unloading facilities are substantially complete, piping to the control skids and then to the distribution grid are being worked on.
- Commissioning work is well underway.

- Preparation for the tie-in outage has begun. Numerous planning sessions have taken place and wiring and site preparation has begun for the boiler contractor that will mobilize to the site in January.
- The quarter began with approximately 425 construction workers onsite. In late November we passed the peak staffing and the number has declined to approximately 370 at the end of the period. The number will slowly drop for the next month and then start to pick up again as we approach the outage.

Costs incurred through December 31, 2014, can be broken down into the following general categories:

<b>Category</b>	<b>Costs Through December 31, 2014</b>
<b>Equipment/Material Procurement:</b>	\$94.2M
<b>Construction:</b>	\$138.5M
<b>Engineering/Field Engineering Support:</b>	\$21.7M
<b>Owners Cost:</b>	\$9.7M
<b>Total:</b>	<b>\$264.1M</b>

(Project costs identified do not include individual company costs.)

Equipment and Material Procurement: All owner-procured material for the project, such as the flue-gas desulfurization system equipment, selective catalytic reduction catalyst, induced draft fans and their motors, transformers, structural steel, ductwork, ammonia handling equipment and the Distributed Control System.

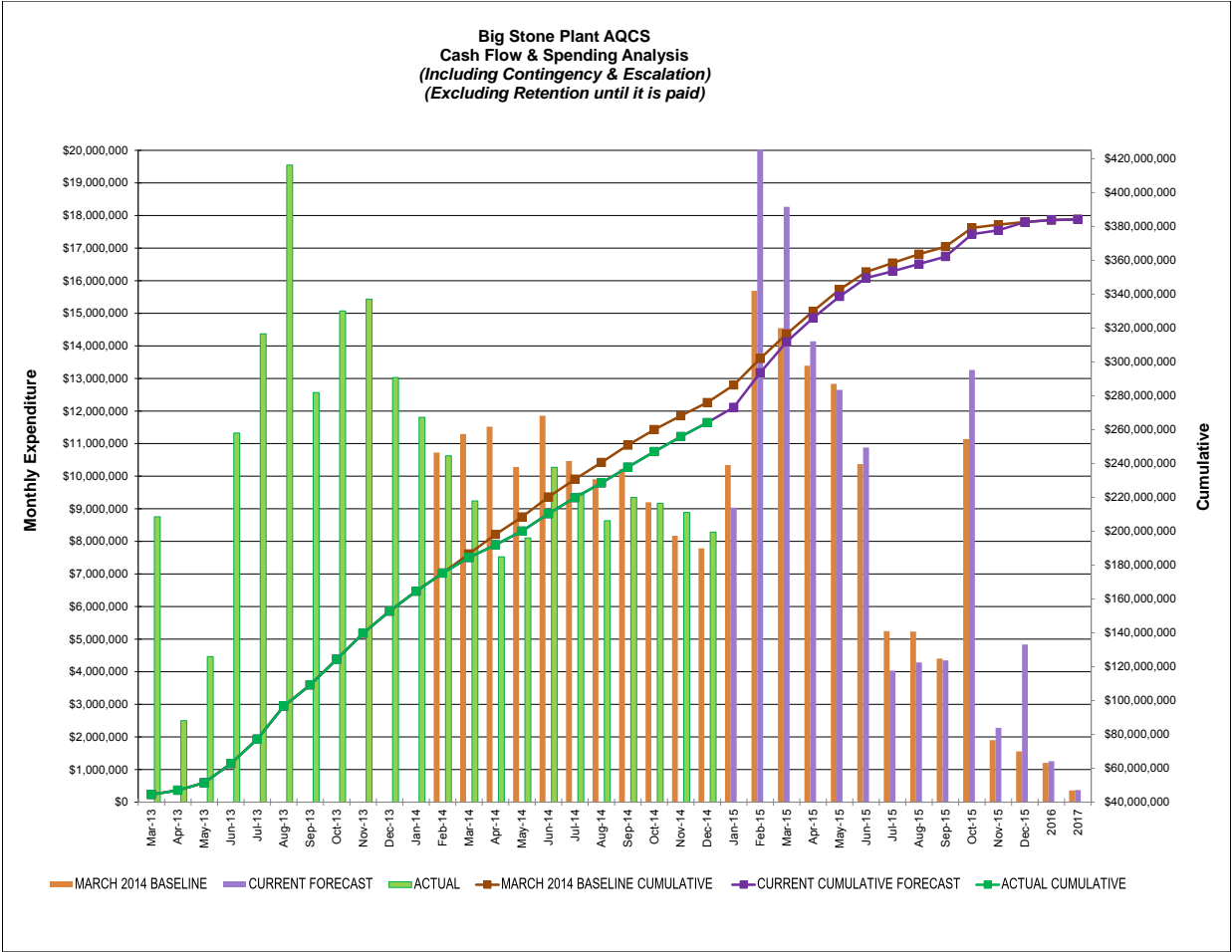
Construction: Payments made to Graycor (the General Work Contractor), site preparation work, testing work, surveying work and work to remove equipment that is no longer needed or which needs to be moved.

Engineering and Field Engineering Support: Engineering and procurement work done by Sargent & Lundy (Project engineer) and engineering field support for construction and commissioning.

Owners Cost: Items such as labor for project development and construction management, and such things as insurance, legal costs, permitting, office space and equipment; also spare parts and consumables used during testing and commissioning.

As described in previous quarterly reports, the project budget was reviewed in early 2013 and then again in early 2014. Following both reviews the projected project budget was reduced. The original project budget was \$491M; it was reduced in 2013 to \$405M and again reduced to \$384M in 2014.

Actual project cash flow and spending through December 2014, and forecast through project completion, is illustrated on the following graph:



The following photographs illustrate various construction activities on the project during the quarter.



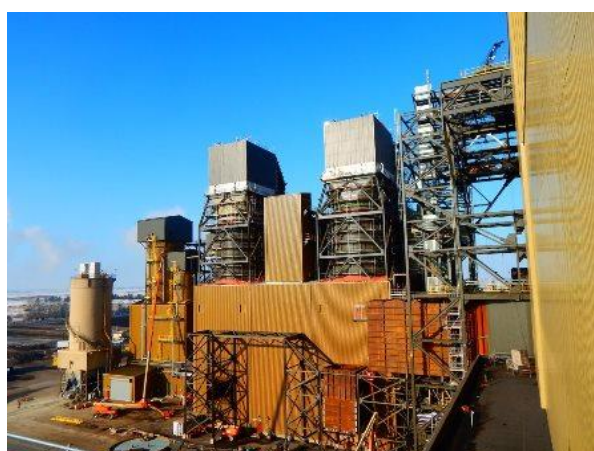
2014-10-07 Siding on SCR



2014-12-09 Siding work continues



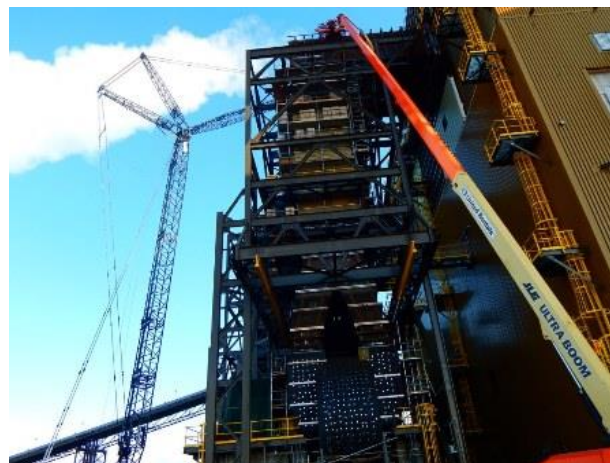
2014-10-21 SCR, CFB, WA



2014-12-09 SCR, CFB, WA/PL



2014-11-26 ID fans 1A & 1B



2014-12-09 ID fan 1B



2014-12-09 Siding waste ash silo



2014-11-14 Section 3 set, setting section 1



2014-10-14 G3A duct lift



2014-11-03 G28 duct lift



2014-10-07 G26 ID fan 1A  
discharge ductwork lift



2014-12-09 Insulating ductwork



2014-10-15 Aerial view of project

Safety is very important to us. We are taking extra steps to insure a safe work site. The table below is included to provide information on recordable and lost-time injuries and near miss incidents for the total labor hours worked on the project through December 31, 2014:

	<b>Hours</b>	<b>Recordable</b>	<b>Lost Time</b>	<b>Near Miss</b>	<b>First Aid</b>
Graycor	1,290,671	3	0	10	13
Project Team & Contractors	99,823	0	0	0	0
Engineering	165,921	0	0	0	0
<b>Totals</b>	<b>1,556,415</b>	<b>3</b>	<b>0</b>	<b>10</b>	<b>13</b>

OSHA rate for recordable incidents: 0.39

OSHA rate for lost time: 0.0 (There were no incidents during this last quarter.)

### **Section III**

#### **Any changed circumstances that will affect cost or project installation**

The EPA has issued the Mercury and Air Toxic Standards (“MATS”) rule, also known as the utility Maximum Achievable Control Technology (“MACT”) rules, which require control of hazardous air pollutants. While the final rule has been issued, several petitions for review have been filed in United States Court of Appeals for the D.C. Circuit which could ultimately delay its effective date. The rule as issued requires the Big Stone Plant to reduce mercury emissions, which can be controlled by adding Activated Carbon Injection (“ACI”) to the project. The estimated cost to add ACI as a standalone project is \$5M. Because of the synergies of installing the system at the same time as the AQCS, the owners have decided to include the ACI system as part of the scope of the AQCS Project; we have only increased the projected cost of the AQCS Project by \$2.1M to account for the ACI system. Although the standard MATS rule compliance date is April 16, 2015, on August 27, 2013 the South Dakota Department of Environment and Natural Resources granted a one year compliance extension for Big Stone Plant, such that the new compliance date is April 16, 2016.

Construction is now 86 percent complete. To date we have not seen anything to cause us to alter our schedule or increase our final project cost estimate.

#### **Summary**

The project continues to stay on schedule and on budget.



Otter Tail Power Company  
Environmental Cost Recovery Rider Tracker  
North Dakota

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2014						Collection Period
		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	
1	Revenue Requirements							
1	Air Quality Control System	476,171	476,171	476,171	476,171	476,171	476,171	4,987,606
2	Hoot Lake Plant MATS Project							
3	<b>Total Revenue Requirements</b>	476,171	476,171	476,171	476,171	476,171	476,171	4,987,606
4								
5	Billed (forecast kWh x adj factor)	638,868	599,883	542,833	499,604	424,392	425,397	3,130,976
6								
7	Difference	(162,697)	(123,712)	(66,662)	(23,433)	51,779	50,774	1,856,630
8	Carrying Charge	15,916	14,862	14,081	13,703	13,633	14,103	
9	Cumulative Difference (True-Up)	2,069,984	1,961,134	1,908,553	1,898,823	1,964,236	2,029,113	
10								
11	Carrying Charge Calculation	14,862	14,081	13,703	13,633	14,103	14,569	
12	Cumulative Carrying Charge	116,962	131,042	144,746	158,379	172,482	187,051	
13	Carrying cost	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	
14								
15								
16	Forecasted Revenue							

Approved in Case Numbers PU-13-79 & PU-13-84

<b>SUMMARY</b>		<b>Jan 2013 - March 2014</b>
Revenue requirements		\$4,247,862
Carrying Charge		60,611
Total Return on CWIP		\$4,308,473
July 2013 - Mar 2014 projected sales in mWh		1,394,198
Average Rate		\$0.00309

Otter Tail Power Company  
Environmental Cost Recovery Rider Tracker  
North Dakota

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2014						2015						Collection Period
		July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	January Actual	February Projected	March Projected	April Projected	May Projected	June Projected	
1	Revenue Requirements													
1	Air Quality Control System	476,171	476,171	476,171	476,171	476,171	476,171	740,882	740,882	740,882	740,882	740,882	740,882	
2	Hoot Lake Plant MATS Project			49,602	50,590	51,209	51,271	56,004	56,159	56,873	56,873	58,321	58,813	
3	<b>Total Revenue Requirements</b>	<b>476,171</b>	<b>476,171</b>	<b>525,773</b>	<b>526,761</b>	<b>527,380</b>	<b>527,442</b>	<b>796,886</b>	<b>797,041</b>	<b>797,755</b>	<b>797,755</b>	<b>799,203</b>	<b>799,695</b>	
4														
5	Billed (forecast kWh x adj factor)	428,204	745,723	765,290	708,801	792,935	925,255	1,014,866	1,068,692	946,296	857,661	711,006	673,660	
6														
7	Difference	47,967	(269,552)	(239,517)	(182,040)	(265,555)	(397,813)	(217,980)	(271,651)	(148,542)	(59,906)	88,197	126,034	
8	Carrying Charge	14,569	15,018	13,190	11,565	10,341	8,509	5,714	4,190	2,269	1,219	798	1,437	
9	Cumulative Difference (True-Up)	2,091,649	1,837,114	1,610,787	1,440,313	1,185,099	795,795	583,529	316,068	169,796	111,109	200,104	327,575	
10														
11	Carrying Charge Calculation	15,018	13,190	11,565	10,341	8,509	5,714	4,190	2,269	1,219	798	1,437	2,352	
12	Cumulative Carrying Charge	202,069	215,260	226,825	237,167	245,676	251,389	255,579	257,848	259,068	259,865	261,302	263,654	
13	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%	
14														
15														
16	Forecasted Revenue								199,880	176,988	160,410	132,981	125,996	
													796,255	

Approved in Case Number PU-14-142

<b>SUMMARY</b>		<b>July 2014 - June 2015</b>
Revenue requirements		\$7,507,342
Carrying Charge		85,081
2012-2013 True Up		<u>2,287,457</u>
Total Return on CWIP		\$9,879,880
Jul 2014 - Jun 2015 projected sales in mWh		1,847,855
Average Rate		\$0.00535

Otter Tail Power Company  
Environmental Cost Recovery Rider Tracker  
North Dakota

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2015						2016						Collection Period
		July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	
	Revenue Requirements													
1	Air Quality Control System	740,882	740,882	740,882	775,986	1,005,497	1,006,954	1,039,725	1,039,974	1,040,008	1,040,008	1,040,278	1,040,390	
2	Hoot Lake Plant MATS Project	58,636	58,351	58,019	57,687	57,355	57,024	57,024	56,712	56,399	56,399	55,773	55,460	
3	<b>Total Revenue Requirements</b>	<b>799,518</b>	<b>799,233</b>	<b>798,901</b>	<b>833,673</b>	<b>1,062,853</b>	<b>1,063,977</b>	<b>1,096,749</b>	<b>1,096,686</b>	<b>1,096,407</b>	<b>1,096,407</b>	<b>1,096,051</b>	<b>1,095,850</b>	
4														
5	Billed (forecast kWh x adj factor)	947,384	975,492	977,779	872,565	997,639	1,108,648	1,237,818	1,226,118	1,105,291	1,022,888	875,274	901,930	
6														
7	Difference	(147,866)	(176,258)	(178,878)	(38,892)	65,214	(44,670)	(141,069)	(129,432)	(8,884)	73,519	220,777	193,920	
8	Carrying Charge	2,352	1,307	51	(1,233)	(1,521)	(1,064)	(1,392)	(2,415)	(3,362)	(3,450)	(2,946)	(1,382)	
9	Cumulative Difference (True-Up)	182,061	7,109	(171,717)	(211,842)	(148,149)	(193,884)	(336,345)	(468,192)	(480,437)	(410,368)	(192,537)	0	
10														
11	Carrying Charge Calculation	1,307	51	(1,233)	(1,521)	(1,064)	(1,392)	(2,415)	(3,362)	(3,450)	(2,946)	(1,382)	0	
12	Cumulative Carrying Charge	264,961	265,012	263,779	262,258	261,195	259,803	257,388	254,026	250,577	247,630	246,248	246,248	
13	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%	
14														
15														
16	Forecasted Revenue	10,305,996	10,611,764	10,636,647	9,492,087	10,852,689	12,060,285	13,465,447	13,338,168	12,023,765	11,127,357	9,521,552	9,811,529	

<b>SUMMARY</b>		<b>Jul 2015 - Jun 2016</b>
Revenue requirements		\$11,936,305
Carrying Charge		(15,054)
2014 True Up		327,575
Total Return on CWIP		\$12,248,826
July 2015 - June 2016 projected revenue		133,247,286
Percent of Bill		9.193%





Otter Tail Power Company  
Environmental Cost Recovery Rider Tracker  
North Dakota

Line No.	Year>>	2015 Actual January	2015 Projected February	2015 Projected March	2015 Projected April	2015 Projected May	2015 Projected June	2015 Projected July	2015 Projected August	2015 Projected September	2015 Projected October	2015 Projected November	2015 Projected December	2015 Projected Total
<b>RATE BASE</b>														
1	Plant Balance	0	0	0	0	0	0	0	0	0	204,881,422	206,181,635	209,723,651	209,723,651
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	(568,546)	(1,140,700)	(1,140,700)
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	204,881,422	205,613,089	208,582,951	208,582,951
4	CWIP	152,772,992	158,368,726	168,734,631	176,743,337	183,676,626	190,201,688	193,039,067	195,451,287	197,858,877	(0)	(0)	(0)	(0)
5	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	(3,331,046)	(6,472,115)	(9,611,979)	(9,611,979)
6	Ending Rate Base	152,772,992	158,368,726	168,734,631	176,743,337	183,676,626	190,201,688	193,039,067	195,451,287	197,858,877	201,550,376	199,140,973	198,970,972	198,970,972
7														
8	Average Rate Base	15,143,728	15,143,728	15,143,728	15,143,728	15,143,728	15,143,728	15,143,728	15,143,728	15,143,728	15,143,728	15,143,728	15,143,728	181,724,738
9	Return on Rate Base	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	15,657,336
10														
11	Available for Return (equity portion of rate base)	867,649	867,649	867,649	867,649	867,649	867,649	867,649	867,649	867,649	867,649	867,649	867,649	10,411,787
12														
13														
<b>EXPENSES</b>														
14	O&M and Depreciation													
15	Operating Costs	0	0	0	0	0	0	0	0	0	86,958	86,958	86,958	260,875
16	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Book Depreciation	0	0	0	0	0	0	0	0	0	0	568,546	572,154	1,140,700
18														
19	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	86,958	655,504	659,112	1,401,575
20														
21	Income before Taxes													
22	Available for Return (from above)	867,649	867,649	867,649	867,649	867,649	867,649	867,649	867,649	867,649	867,649	867,649	867,649	10,411,787
23	Taxable Income (grossed up)	1,398,182	1,398,182	1,398,182	1,398,182	1,398,182	1,398,182	1,398,182	1,398,182	1,398,182	1,398,182	1,398,182	1,398,182	16,778,186
24														
25	Income Taxes													
26	Current and Def Income Taxes	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	6,366,399
27	Total Income Tax Expense	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	6,366,399
28														
29														
<b>REVENUE REQUIREMENTS</b>														
30	Expenses	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	530,533	617,492	1,186,038	1,189,646	7,767,974
31	Return on Rate Base	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	1,304,778	15,657,336
32	Subtotal Revenue Requirements	1,835,311	1,835,311	1,835,311	1,835,311	1,835,311	1,835,311	1,835,311	1,835,311	1,835,311	1,922,270	2,490,816	2,494,424	23,425,310
33	Adjustments													
34	Total Revenue Requirements	1,835,311	1,835,311	1,835,311	1,835,311	1,835,311	1,835,311	1,835,311	1,835,311	1,835,311	1,922,270	2,490,816	2,494,424	23,425,310
35														
36														
37	Base Demand Factor	66.87%	1,227,235	1,227,235	1,227,235	1,227,235	1,227,235	1,227,235	1,227,235	1,227,235	1,285,382	1,665,557	1,667,969	15,864,018
38	Peak Demand Factor	33.13%	608,077	608,077	608,077	608,077	608,077	608,077	608,077	608,077	636,888	825,259	826,454	7,761,291
39														
40	North Dakota share - E1 factor	39.7309%	487,591	487,591	487,591	487,591	487,591	487,591	487,591	487,591	510,694	661,741	662,699	6,223,455
41	North Dakota share - D1 factor	41.6544%	253,291	253,291	253,291	253,291	253,291	253,291	253,291	253,291	265,292	343,757	344,255	3,232,921
42	ND Revenue Requirements		740,882	740,882	740,882	740,882	740,882	740,882	740,882	740,882	775,986	1,005,497	1,006,954	9,456,376
43														
44														
45	Total North Dakota Share		740,882	740,882	740,882	740,882	740,882	740,882	740,882	740,882	775,986	1,005,497	1,006,954	9,456,376
<b>SUPPORTING INFORMATION / DATA</b>														
1														
2														
3	ND Cap Structure with allowed ROE per order.													
4	Capital Structure													
5	Debt													
6	Preferred equity													
7	Common equity													
8	Total													
9														
10	Project life (years)													
11														
12														
13														
14	Statutory Tax Rate													
15	Tax conversion factor													
16	Base Demand Factor													
17	Peak Demand Factor													
18	ND share - E1 factor													
19	ND share - D1 factor													
20														
21	Deferred Tax													
22	Book depreciation		0	0	0	0	0	0	0	0	0	568,546	572,154	1,140,700
23	Tax depreciation-Federal		0	0	0	0	0	0	0	0	9,968,864	9,968,864	9,968,864	29,906,593
24	Tax depreciation-State		0	0	0	0	0	0	0	0	9,968,864	9,968,864	9,968,864	29,906,593
25	Federal deferred income taxes	35.00%	0	0	0	0	0	0	0	0	(3,331,046)	(3,141,069)	(3,139,864)	(9,611,979)
26	State deferred income taxes		0	0	0	0	0	0	0	0	(451,590)	(425,834)	(425,671)	(1,303,095)

Otter Tail Power Company  
Environmental Cost Recovery Rider Tracker  
North Dakota

Line No.	Year>>	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
		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 Total
<b>RATE BASE</b>														
1	Plant Balance	209,946,269	209,976,943	209,966,770	210,217,549	210,317,408	210,326,715	210,336,022	210,345,329	210,354,636	210,396,055	210,411,399	210,420,706	210,420,706
2	Accumulated Depreciation	(1,722,683)	(2,305,284)	(2,887,970)	(3,470,628)	(4,053,982)	(4,637,612)	(5,221,269)	(5,804,951)	(6,388,660)	(6,972,394)	(7,556,243)	(8,140,135)	(8,140,135)
3	Net Plant in Service	208,223,586	207,671,659	207,078,800	206,746,921	206,263,427	205,689,103	205,114,753	204,540,377	203,965,976	203,423,661	202,855,156	202,280,571	202,280,571
4	CWIP	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
5	Accumulated Deferred Income Taxes Federal & State	(10,850,458)	(12,088,730)	(13,326,973)	(14,565,226)	(15,803,247)	(17,041,175)	(18,279,094)	(19,517,005)	(20,754,907)	(21,992,800)	(23,230,655)	(24,468,496)	(24,468,496)
6	Ending Rate Base	197,373,128	195,582,929	193,751,827	192,181,695	190,460,179	188,647,927	186,835,658	185,023,372	183,211,069	181,430,861	179,624,500	177,812,075	177,812,075
7														
8	Average Rate Base	15,710,937	15,710,937	15,710,937	15,710,937	15,710,937	15,710,937	15,710,937	15,710,937	15,710,937	15,710,937	15,710,937	15,710,937	188,531,245
9	Return on Rate Base	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	16,243,782
10														
11	Available for Return (equity portion of rate base)	900,147	900,147	900,147	900,147	900,147	900,147	900,147	900,147	900,147	900,147	900,147	900,147	10,801,761
12														
13														
<b>EXPENSES</b>														
<b>O&amp;M and Depreciation</b>														
15	Operating Costs	89,567	89,567	89,567	89,567	89,567	89,567	89,567	89,567	89,567	89,567	89,567	89,567	1,074,806
16	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Book Depreciation	581,983	582,601	582,686	582,658	583,354	583,631	583,657	583,682	583,708	583,734	583,849	583,892	6,999,435
18	Total O&M and Depreciation Expense	671,550	672,168	672,253	672,225	672,921	673,198	673,224	673,250	673,275	673,301	673,416	673,459	8,074,241
19														
20														
21	Income before Taxes													
22	Available for Return (from above)	900,147	900,147	900,147	900,147	900,147	900,147	900,147	900,147	900,147	900,147	900,147	900,147	10,801,761
23	Taxable Income (grossed up)	1,450,551	1,450,551	1,450,551	1,450,551	1,450,551	1,450,551	1,450,551	1,450,551	1,450,551	1,450,551	1,450,551	1,450,551	17,406,613
24														
25	Income Taxes													
26	Current and Def Income Taxes	550,404	550,404	550,404	550,404	550,404	550,404	550,404	550,404	550,404	550,404	550,404	550,404	6,604,852
27	Total Income Tax Expense	550,404	550,404	550,404	550,404	550,404	550,404	550,404	550,404	550,404	550,404	550,404	550,404	6,604,852
28														
29														
<b>REVENUE REQUIREMENTS</b>														
30	Expenses	1,221,955	1,222,572	1,222,658	1,222,629	1,223,325	1,223,602	1,223,628	1,223,654	1,223,680	1,223,706	1,223,821	1,223,863	14,679,093
31	Return on Rate Base	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	1,353,649	16,243,782
32	Subtotal Revenue Requirements	2,575,603	2,576,221	2,576,306	2,576,278	2,576,974	2,577,251	2,577,277	2,577,303	2,577,328	2,577,354	2,577,469	2,577,512	30,922,875
33	Adjustments													
34	Total Revenue Requirements	2,575,603	2,576,221	2,576,306	2,576,278	2,576,974	2,577,251	2,577,277	2,577,303	2,577,328	2,577,354	2,577,469	2,577,512	30,922,875
35														
36														
37	Base Demand Factor	66.87%	1,722,252	1,722,665	1,722,722	1,722,704	1,723,169	1,723,354	1,723,371	1,723,389	1,723,406	1,723,423	1,723,500	20,677,485
38	Peak Demand Factor	33.13%	853,351	853,555	853,584	853,574	853,805	853,897	853,905	853,914	853,922	853,931	853,969	10,245,391
39														
40	North Dakota share - E1 factor	39.7309%	684,266	684,430	684,453	684,453	684,630	684,704	684,711	684,718	684,725	684,732	684,762	8,215,358
41	North Dakota share - D1 factor	41.6544%	355,458	355,544	355,555	355,555	355,647	355,860	355,689	355,693	355,696	355,700	355,716	4,267,662
42	ND Revenue Requirements		1,039,725	1,039,974	1,040,008	1,040,008	1,040,278	1,040,390	1,040,411	1,040,421	1,040,431	1,040,478	1,040,495	12,483,020
43														
44														
45	Total North Dakota Share		1,039,725	1,039,974	1,040,008	1,040,008	1,040,278	1,040,390	1,040,400	1,040,411	1,040,421	1,040,431	1,040,478	12,483,020
<b>SUPPORTING INFORMATION / DATA</b>														
1														
2														
3	SD Cap Structure with allowed ROE per order.													
4	Capital Structure													
5	Debt													
6	Preferred equity													
7	Common equity													
8	Total													
9														
10														
11														
12														
13														
14														
15														
16														
17														
18														
19														
20														
21	Deferred Tax													
22	Book depreciation		581,983	582,601	582,686	582,658	583,354	583,631	583,657	583,682	583,708	583,734	583,849	6,999,435
23	Tax depreciation-Federal		4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	51,460,722
24	Tax depreciation-State		4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	4,288,394	51,460,722
25	Federal deferred income taxes	35.00%	(1,238,478)	(1,238,272)	(1,238,244)	(1,238,253)	(1,238,021)	(1,237,928)	(1,237,919)	(1,237,911)	(1,237,902)	(1,237,893)	(1,237,884)	(14,856,517)
25	State deferred income taxes		(167,900)	(167,872)	(167,869)	(167,870)	(167,838)	(167,826)	(167,825)	(167,823)	(167,822)	(167,821)	(167,816)	(2,014,096)



Otter Tail Power Company  
Environmental Cost Recovery Rider Tracker  
North Dakota

Line No.	Year>>	2014 Actual January	2014 Actual February	2014 Actual March	2014 Actual April	2014 Actual May	2014 Actual June	2014 Actual July	2014 Actual August	2014 Actual September	2014 Actual October	2014 Actual November	2014 Actual December	2014 Actual Total
<b>RATE BASE</b>														
1	Plant Balance	0	0	0	0	0	0	0	5,912,208	6,100,765	6,218,764	6,230,556	6,232,860	6,232,860
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	(76,782)	(156,012)	(236,776)	(317,692)	(317,692)
3	Net Plant in Service	0	0	0	0	0	0	0	5,912,208	6,023,983	6,062,752	5,993,780	5,915,168	5,915,168
4	CWIP	2,760,674	2,878,262	3,031,600	4,223,242	4,709,606	6,150,731	6,342,963	(0)	(0)	(0)	(0)	(0)	(0)
5	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	(237,967)	(450,278)	(661,770)	(872,750)	(1,083,679)	(1,083,679)
6	Ending Rate Base	2,760,674	2,878,262	3,031,600	4,223,242	4,709,606	6,150,731	6,342,963	5,674,241	5,573,705	5,400,981	5,121,030	4,831,488	4,831,488
7														
8	Average Rate Base	380,319	380,319	380,319	380,319	380,319	380,319	380,319	380,319	380,319	380,319	380,319	380,319	4,563,831
9	Return on Rate Base	32,768	32,768	32,768	32,768	32,768	32,768	32,768	32,768	32,768	32,768	32,768	32,768	393,218
10														
11	Available for Return (equity portion of rate base)	21,790	21,790	21,790	21,790	21,790	21,790	21,790	21,790	21,790	21,790	21,790	21,790	261,481
12														
13														
<b>EXPENSES</b>														
14														
15	O&M and Depreciation													
16	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Book Depreciation	0	0	0	0	0	0	0	0	76,782	79,231	80,763	80,916	317,692
19	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	76,782	79,231	80,763	80,916	317,692
20														
21	Income before Taxes													
22	Available for Return (from above)	21,790	21,790	21,790	21,790	21,790	21,790	21,790	21,790	21,790	21,790	21,790	21,790	261,481
23	Taxable Income (grossed up)	35,114	35,114	35,114	35,114	35,114	35,114	35,114	35,114	35,114	35,114	35,114	35,114	421,367
24														
25	Income Taxes													
26	Current and Def Income Taxes	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	159,886
27	Total Income Tax Expense	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	159,886
28														
29														
<b>REVENUE REQUIREMENTS</b>														
30														
31	Expenses	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	90,106	92,554	94,087	94,240	477,577
32	Return on Rate Base	32,768	32,768	32,768	32,768	32,768	32,768	32,768	32,768	32,768	32,768	32,768	32,768	393,218
33	Subtotal Revenue Requirements	46,092	46,092	46,092	46,092	46,092	46,092	46,092	46,092	122,874	125,323	126,855	127,008	870,795
34	Adjustments													
35	Total Revenue Requirements	46,092	46,092	46,092	46,092	46,092	46,092	46,092	46,092	122,874	125,323	126,855	127,008	870,795
36														
37	Base Demand Factor	66.87%	30,821	30,821	30,821	30,821	30,821	30,821	30,821	82,163	83,801	84,825	84,928	582,283
38	Peak Demand Factor	33.13%	15,271	15,271	15,271	15,271	15,271	15,271	15,271	40,711	41,522	42,030	42,080	288,513
39														
40	North Dakota share - E1 factor	39.7309%	12,245	12,245	12,245	12,245	12,245	12,245	12,245	32,644	33,295	33,702	33,743	231,346
41	North Dakota share - D1 factor	41.6544%	6,361	6,361	6,361	6,361	6,361	6,361	6,361	16,958	17,296	17,507	17,528	120,178
42	ND Revenue Requirements		18,606	18,606	18,606	18,606	18,606	18,606	18,606	49,602	50,590	51,209	51,271	351,524
43														
44														
45	Total North Dakota Share		18,606	18,606	18,606	18,606	18,606	18,606	18,606	49,602	50,590	51,209	51,271	351,524

Line No.	<b>SUPPORTING INFORMATION / DATA</b>													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	<b>Ratio</b>	<b>Cost</b>	<b>WA Cost</b>	<b>Property tax</b>									
3	Debt	43.11%	6.30%	2.72%	2014 composite rate	0.00%								
4	Preferred equity	3.60%	4.75%	0.17%										
5	Common equity	53.30%	10.75%	5.73%										
6	Total	100.00%		8.62%	Overall Return									
7														
8														
9														
10	Project life	<b>Book</b>	<b>Tax</b>											
11		6 yrs, 5 mths	7-year MACRS											
12				<b>Federal</b>	<b>State</b>									
13	Statutory Tax Rate	37.94%	33.41%	4.53%										
14	Tax conversion factor	1.61146												
15	Base Demand Factor	66.87%												
16	Peak Demand Factor	33.13%												
17	ND share - E1 factor	39.7309%												
18	ND share - D1 factor	41.6544%												
19														
20	<b>Deferred Tax</b>													
21	Book depreciation	0	0	0	0	0	0	0	76,782	79,231	80,763	80,916	317,692	
22	Tax depreciation-Federal	0	0	0	0	0	0	0	712,167	712,167	712,167	712,167	3,560,833	
23	Tax depreciation-State	0	0	0	0	0	0	0	712,167	712,167	712,167	712,167	3,560,833	
24	Federal deferred income taxes	35.00%	0	0	0	0	0	0	(237,967)	(212,311)	(211,482)	(210,980)	(1,083,679)	
25	State deferred income taxes		0	0	0	0	0	0	(32,261)	(28,783)	(28,672)	(28,603)	(146,914)	

Otter Tail Power Company  
Environmental Cost Recovery Rider Tracker  
North Dakota

Line No.	Year>>	2015 Actual January	2015 Projected February	2015 Projected March	2015 Projected April	2015 Projected May	2015 Projected June	2015 Projected July	2015 Projected August	2015 Projected September	2015 Projected October	2015 Projected November	2015 Projected December	2015 Projected Total
<b>RATE BASE</b>														
1	Plant Balance	6,233,908	6,347,689	6,454,584	6,558,334	6,697,849	6,720,304	6,729,352	6,729,352	6,729,352	6,729,352	6,729,352	6,729,352	6,729,352
2	Accumulated Depreciation	(398,638)	(479,598)	(562,035)	(645,861)	(731,034)	(818,019)	(905,295)	(992,690)	(1,080,084)	(1,167,478)	(1,254,872)	(1,342,266)	(1,342,266)
3	Net Plant in Service	5,835,270	5,868,091	5,892,549	5,912,473	5,966,815	5,902,285	5,824,056	5,736,662	5,649,268	5,561,874	5,474,480	5,387,086	5,387,086
4	CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Accumulated Deferred Income Taxes Federal & State	(1,079,855)	(1,076,026)	(1,071,704)	(1,066,917)	(1,061,680)	(1,055,838)	(1,049,899)	(1,043,920)	(1,037,941)	(1,031,962)	(1,025,983)	(1,020,004)	(1,020,004)
6	Ending Rate Base	4,755,415	4,792,065	4,820,846	4,845,556	4,905,135	4,846,447	4,774,158	4,692,742	4,611,327	4,529,912	4,448,497	4,367,082	4,367,082
7														
8	Average Rate Base	4,755,415	4,792,065	4,820,846	4,845,556	4,905,135	4,846,447	4,774,158	4,692,742	4,611,327	4,529,912	4,448,497	4,367,082	4,709,282
9	Return on Rate Base	34,144	34,407	34,614	34,791	35,219	34,797	34,278	33,694	33,109	32,525	31,940	31,356	405,750
10														
11	Available for Return (equity portion of rate base)	22,705	22,880	23,017	23,135	23,420	23,139	22,794	22,406	22,017	21,628	21,239	20,851	269,815
12														
13														
<b>EXPENSES</b>														
<b>O&amp;M and Depreciation</b>														
16	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Property Tax	9,760	9,760	9,760	9,760	9,760	9,760	9,760	9,760	9,760	9,760	9,760	9,760	117,115
18	Book Depreciation	80,946	80,960	82,437	83,826	85,173	86,985	87,277	87,394	87,394	87,394	87,394	87,394	1,024,574
19	Total O&M and Depreciation Expense	90,706	90,719	92,197	93,585	94,933	96,745	97,036	97,154	97,154	97,154	97,154	97,154	1,141,690
20														
21	Income before Taxes													
22	Available for Return (from above)	22,705	22,880	23,017	23,135	23,420	23,139	22,794	22,406	22,017	21,628	21,239	20,851	269,815
23	Taxable Income (grossed up)	36,588	36,870	37,091	37,281	37,740	37,288	36,732	36,106	35,479	34,853	34,227	33,600	434,796
24														
25	Income Taxes													
26	Current and Def Income Taxes	13,883	13,990	14,074	14,146	14,320	14,149	13,938	13,700	13,462	13,225	12,987	12,749	164,981
27	Total Income Tax Expense	13,883	13,990	14,074	14,146	14,320	14,149	13,938	13,700	13,462	13,225	12,987	12,749	164,981
28														
29														
<b>REVENUE REQUIREMENTS</b>														
30	Expenses	104,589	104,709	106,271	107,732	109,253	110,893	110,974	110,854	110,616	110,378	110,141	109,903	1,306,314
31	Return on Rate Base	34,144	34,407	34,614	34,791	35,219	34,797	34,278	33,694	33,109	32,525	31,940	31,356	404,873
32	Subtotal Revenue Requirements	138,733	139,116	140,885	142,523	144,472	145,691	145,252	144,548	143,725	142,903	142,081	141,259	1,711,187
33	Adjustments													
34	Total Revenue Requirements	138,733	139,116	140,885	142,523	144,472	145,691	145,252	144,548	143,725	142,903	142,081	141,259	1,711,187
35														
36														
37	Base Demand Factor	66.87%	92,768	93,024	94,207	95,302	96,605	97,420	97,127	96,656	96,106	95,556	95,007	1,144,235
38	Peak Demand Factor	33.13%	45,965	46,092	46,678	47,221	47,866	48,270	48,125	47,892	47,619	47,347	46,802	566,952
39														
40	North Dakota share - E1 factor	39.7309%	36,857	36,959	37,429	37,429	38,382	38,706	38,590	38,402	38,184	37,965	37,747	37,528
41	North Dakota share - D1 factor	41.6544%	19,146	19,199	19,443	19,443	19,938	20,107	20,046	19,949	19,835	19,722	19,609	235,934
42	ND Revenue Requirements		56,004	56,159	56,873	56,873	58,321	58,813	58,636	58,351	58,019	57,687	57,355	690,114
43														
44														
45	Total North Dakota Share		56,004	56,159	56,873	56,873	58,321	58,813	58,636	58,351	58,019	57,687	57,355	690,114

Line No.	SUPPORTING INFORMATION / DATA																
1	ND Cap Structure with allowed ROE per order.																
2	Capital Structure	Ratio		Cost		WA Cost		Property tax		2015 composite rate				0.00%			
3	Debt	43.11%		6.30%		2.72%											
4	Preferred equity	3.60%		4.75%		0.17%											
5	Common equity	53.30%		10.75%		5.73%											
6	Total	100.00%				8.62%		Overall Return									
7																	
8																	
9																	
10	Project life	Book 6 yrs, 5 mths		Tax 7-year MACRS													
11																	
12																	
13		Federal		State													
14	Statutory Tax Rate	37.94%		33.41%		4.53%											
15	Tax conversion factor	1.61146															
16	Base Demand Factor	66.87%															
17	Peak Demand Factor	33.13%															
18	ND share - E1 factor	39.7309%															
19	ND share - D1 factor	41.6544%															
20																	
<b>Deferred Tax</b>																	
21	Book depreciation	80,946	80,960	82,437	83,826	85,173	86,985	87,277	87,394	87,394	87,394	87,394	87,394	1,024,574			
22	Tax depreciation-Federal	69,501	69,501	69,501	69,501	69,501	69,501	69,501	69,501	69,501	69,501	69,501	69,501	834,013			
23	Tax depreciation-State	69,501	69,501	69,501	69,501	69,501	69,501	69,501	69,501	69,501	69,501	69,501	69,501	834,013			
24	Federal deferred income taxes	35.00%	3,824	3,829	4,323	4,786	5,237	5,842	5,940	5,979	5,979	5,979	5,979	63,675			
25	State deferred income taxes		518	519	586	649	710	792	805	811	811	811	811	8,632			



Schedule of Joint Project Costs for Montana-Dakota and Otter Tail

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Yearly Totals
<b>2010</b>													
Monthly Actuals	\$ -	\$ -	\$ -	\$ 63,141	\$ 28,086	\$ 561,588	\$ 67,317	\$ 137,901	\$ 161,259	\$ 284,023	\$ 59,035	\$ 69,335	\$ 1,431,685
Cumulative Actual	\$ -	\$ -	\$ -	\$ 63,141	\$ 91,227	\$ 652,815	\$ 720,132	\$ 858,033	\$ 1,019,292	\$ 1,303,315	\$ 1,362,350	\$ 1,431,685	
<b>2011</b>													
Monthly Actuals	\$ 7,731	\$ 36,511	\$ 37,512	\$ 126,056	\$ 241,078	\$ 318,353	\$ 315,201	\$ 245,209	\$ 333,662	\$ 343,605	\$ 379,290	\$ 453,285	\$ 2,837,493
Cumulative Actual	\$ 1,439,415	\$ 1,475,926	\$ 1,513,438	\$ 1,639,494	\$ 1,880,572	\$ 2,198,925	\$ 2,514,126	\$ 2,759,335	\$ 3,092,997	\$ 3,436,603	\$ 3,815,893	\$ 4,269,178	
<b>2012</b>													
Monthly Actuals	\$ 294,915	\$ 495,887	\$ 1,406,276	\$ 1,660,907	\$ 3,998,095	\$ 3,941,458	\$ 2,758,119	\$ 1,092,418	\$ 1,340,939	\$ 6,081,686	\$ 1,651,054	\$ 3,632,098	\$ 28,353,850
Cumulative Actual	\$ 4,564,093	\$ 5,059,980	\$ 6,466,256	\$ 8,127,162	\$ 12,125,257	\$ 16,066,715	\$ 18,824,833	\$ 19,917,251	\$ 21,258,190	\$ 27,339,876	\$ 28,990,930	\$ 32,623,028	
<b>2013</b>													
Monthly Actuals	\$ 619,545	\$ 2,452,373	\$ 8,755,767	\$ 2,497,186	\$ 4,465,330.38	\$ 11,326,502	\$ 14,370,444	\$ 19,549,151	\$ 12,566,513	\$ 15,073,982	\$ 15,435,691	\$ 13,027,140	\$ 120,139,625
Cumulative Actual	\$ 33,242,573	\$ 35,694,946	\$ 44,450,713	\$ 46,947,899	\$ 51,413,230	\$ 62,739,732	\$ 77,110,176	\$ 96,659,327	\$ 109,225,839	\$ 124,299,822	\$ 139,735,513	\$ 152,762,653	
<b>2014</b>													
Monthly Actuals/Forecasts	\$ 11,807,832	\$ 10,627,404	\$ 9,243,044	\$ 7,527,757	\$ 8,103,836	\$ 10,273,771	\$ 9,481,209	\$ 8,635,508	\$ 9,348,827	\$ 9,167,689	\$ 8,888,173	\$ 8,283,603	\$ 111,388,652
Cumulative Actuals/Forecasts	\$ 164,570,485	\$ 175,197,889	\$ 184,440,933	\$ 191,968,690	\$ 200,072,526	\$ 210,346,297	\$ 219,827,506	\$ 228,463,014	\$ 237,811,840	\$ 246,979,529	\$ 255,867,702	\$ 264,151,305	
<b>2015</b>													
Monthly Budget	\$ 10,341,465	\$ 15,689,071	\$ 14,546,765	\$ 13,390,994	\$ 12,833,582	\$ 10,371,436	\$ 5,246,822	\$ 5,233,197	\$ 4,403,818	\$ 11,138,868	\$ 1,897,441	\$ 1,555,862	\$ 106,649,319
Monthly Forecasts	\$ 12,742,158	\$ 10,380,953	\$ 19,230,992	\$ 14,857,711	\$ 12,862,411	\$ 12,105,124	\$ 5,263,411	\$ 4,474,528	\$ 4,466,029	\$ 13,028,841	\$ 2,412,269	\$ 6,571,459	\$ 118,395,886
Cumulative Forecasts	\$ 276,893,463	\$ 287,274,416	\$ 306,505,408	\$ 321,363,120	\$ 334,225,531	\$ 346,330,654	\$ 351,594,065	\$ 356,068,593	\$ 360,534,622	\$ 373,563,463	\$ 375,975,732	\$ 382,547,190	
<b>2016</b>													
Monthly Budget	\$ 391,722	\$ 70,054	\$ (6,008)	\$ 454,757	\$ 174,757	\$ 6,757	\$ 6,757	\$ 6,757	\$ 6,757	\$ 65,863	\$ 17,957	\$ 6,757	\$ 1,202,885
Monthly Forecasts	\$ 413,021	\$ 56,909	\$ (18,873)	\$ 465,267	\$ 185,267	\$ 17,267	\$ 17,267	\$ 17,267	\$ 17,267	\$ 76,845	\$ 28,467	\$ 17,267	\$ 1,293,237
Cumulative Forecasts	\$ 382,960,211	\$ 383,017,119	\$ 382,998,246	\$ 383,463,513	\$ 383,648,780	\$ 383,666,047	\$ 383,683,314	\$ 383,700,581	\$ 383,717,848	\$ 383,794,693	\$ 383,823,160	\$ 383,840,427	
<b>2017</b>													
Monthly Budget	\$ 6,757	\$ 80,586								\$ 269,149			\$ 356,492
Monthly Forecasts	\$ 22,880	\$ 73,829								\$ 262,864			\$ 359,573
Cumulative Forecasts	\$ 383,863,307	\$ 383,937,136	\$ 383,937,136	\$ 383,937,136	\$ 383,937,136	\$ 383,937,136	\$ 383,937,136	\$ 383,937,136	\$ 383,937,136	\$ 384,200,000	\$ 384,200,000	\$ 384,200,000	\$ 384,200,000
												<b>Budget Total</b>	\$ 384,200,000
												<b>Forecast Total</b>	\$ 384,200,000

Total AQCS Project

: Denotes actual expenditures

**Reconciliation of Otter Tail Tracker Balance to Schedule 4(a)**

	<b><u>Page 7 of 12</u></b>	<b><u>Page 8 of 12</u></b>
	January 2015	June 2016
1 Project amounts per Attachment 4(a)	\$276,893,463	\$383,666,049
2 OTP %	<u>53.9%</u>	<u>53.9%</u>
3 OTP share (1 x 2)	\$149,245,577	\$206,796,000
4 OTP AFUDC through 12-2012	\$1,111,536	\$1,111,536
5 OTP only costs	<u>\$2,415,879</u>	<u>\$2,419,179</u>
Tracker Balance (3 + 4 + 5)	\$152,772,992	\$210,326,715

**Incremental Operation and Maintenance costs for the AQCS**

<b>Description</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>
FGD By-Product Disposal Cost	\$ -	\$ 108,451	\$ 446,818	\$ 460,223
Ash Hauling	N/A	\$ 16,750	\$ 69,010	\$ 71,080
<b>Variable Costs (Dry FGD and ACI)</b>	<b>\$ -</b>	<b>\$ 125,201</b>	<b>\$ 515,828</b>	<b>\$ 531,303</b>
Operating Labor	\$ -	\$ 90,461	\$ 372,699	\$ 383,880
Maintenance Material	\$ -	\$ 99,605	\$ 410,371	\$ 422,682
Maintenance Labor	\$ -	\$ 90,461	\$ 372,699	\$ 383,880
<b>Fixed Costs (Dry FGD and ACI)</b>	<b>\$ -</b>	<b>\$ 280,527</b>	<b>\$ 1,155,769</b>	<b>\$ 1,190,442</b>
Operating Labor	\$ -	\$ 22,615	\$ 93,174	\$ 95,969
Maintenance Material	\$ -	\$ 33,041	\$ 136,129	\$ 140,213
Maintenance Labor	\$ -	\$ 22,615	\$ 93,174	\$ 95,969
<b>Fixed Costs (SCR)</b>	<b>\$ -</b>	<b>\$ 78,271</b>	<b>\$ 322,477</b>	<b>\$ 332,151</b>

<b>Annual Total</b>		<b>\$ 483,999</b>	<b>\$ 1,994,074</b>	<b>\$ 2,053,896</b>
---------------------	--	-------------------	---------------------	---------------------

<b>OTP Share (53.9%)</b>	<b>\$ 260,875</b>	<b>\$ 1,074,806</b>	<b>\$ 1,107,050</b>
<b>ND Share (40.3682%)</b>	<b>\$ 105,311</b>	<b>\$ 433,880</b>	<b>\$ 446,896</b>

**Rate Design Calculation**

North Dakota Revenue Requirements \$12,248,826

Forecasted Retail Revenue, all classes (July 2015 - June 2016) \$133,247,286

Revenue Requirement \$12,248,826

Percentage of Revenue Rate 9.193%

**ATTACHMENT 6**  
**ENVIRONMENTAL COST RECOVERY RIDER**  
**(Section 13.08)**

**ENVIRONMENTAL COST RECOVERY RIDER**

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

€  
N

**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.”

€  
  
€  
€

<b>Environmental Cost Recovery Factor - <u>9.193 7.531</u> percent</b>
--

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:

**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.”

<b>Environmental Cost Recovery Factor - 9.193 percent</b>
---

**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-15-\_\_\_\_\_  
Approved by Order dated: \_\_

EFFECTIVE with bills rendered on  
and after July 1, 2015, in North Dakota

APPROVED: Thomas R. Brause  
Vice President, Administration