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October 1, 2015

**--Via Electronic Filing--**

Darrell Nitschke, Executive Secretary  
North Dakota Public Service Commission  
State Capitol Building, Dept. 408  
600 East Boulevard  
Bismarck, ND 58505-0480

RE: 2016 RENEWABLE ENERGY RIDER PROJECT ELIGIBILITY AND RATE  
ADJUSTMENT APPLICATION  
CASE NO. PU-15-\_\_\_\_\_

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed original and seven copies of the 2016 Renewable Energy Rider (RER) Application to the North Dakota Public Service Commission for approval of the RER rate factor.

Also enclosed is a check in the amount of \$10,000 for the filing fee.

An electronic copy of this filing is also being sent to you for your convenience.

Please contact me if you have any questions or comments.

Sincerely,

A handwritten signature in blue ink that reads 'David H. Sederquist'.

DAVID H. SEDERQUIST  
SR. CONSULTANT, REGULATION/FINANCE

c: Mike Diller

Enclosures

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

IN THE MATTER OF THE APPLICATION OF  
NORTHERN STATES POWER COMPANY  
FOR APPROVAL OF A 2016 RENEWABLE  
ENERGY RIDER RATE

CASE NO. PU-15-\_\_\_\_

**Application of Northern States Power Company**

**INTRODUCTION**

Northern States Power Company, doing business as Xcel Energy, submits to the North Dakota Public Service Commission this application for approval of a Renewable Energy Rider (RER) rate designed to recover the 2015 and 2016 revenue requirements associated with the Company's eligible renewable energy projects. We submit this application pursuant to N.D.C.C. § 49-02, 49-05, and 49-06, which authorizes the Commission to approve rate recovery of investments and expenses related to new or modified renewable energy facilities located in North Dakota.

Approval of the Company's use of an RER was established by the Commission's February 26, 2014 *Order Adopting Settlement* in Case No. PU-12-813. The Company filed a proposed RER tariff on June 6, 2014, and the final compliance tariff on August 8, 2014 (without an approved rate). In this filing we propose to update the RER tariff with a rate to recover the specific 2015 and 2016 costs related to two currently qualifying wind projects.

Specifically, this Petition seeks Commission approval of:

- the eligibility of two renewable energy facilities for RER recovery;
- the 2015-2016 RER revenue requirements for these projects;
- a rate to be implemented January 1, 2016; and
- a revised RER tariff sheet and customer bill message.

We request to begin recovery of the North Dakota jurisdictional portion of the revenue requirements related to two wind energy projects located in our North Dakota service territory. Our proposal is to recover \$428,252 in costs related to the 2015 calendar year (see Attachment 4) and an estimated \$1.914 million attributed to the 2016 calendar year (see Attachment 5), for a total of approximately \$2.342 million in revenue requirements.

The resulting rate we propose to implement on January 1, 2016 is \$0.001014 per kWh applied to all energy billed to each customer class based on the combined 2015 and 2016 revenue requirements for these projects. The rate has been calculated to be in place through the end of 2016 and takes into account the fact that there has been no RER rate in place to date. The average bill impact is \$0.76 per month for a typical residential electric customer using 750 kWh.

## **I. GENERAL 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**

Northern States Power Company  
2302 Great Northern Drive  
PO Box 2747  
Fargo, ND 58108-2747  
(701) 241-8632

### **B. Name, address, and telephone number of the attorney for Northern States Power Company**

Alison Archer  
Assistant General Counsel  
Xcel Energy Services Inc.  
414 Nicollet Mall – 5<sup>th</sup> Floor  
Minneapolis, MN 55401  
(612) 215-4662

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

David H. Sederquist  
Sr. Regulatory and Financial Consultant  
2302 Great Northern Drive  
PO Box 2747  
Fargo, ND 58108-2747

### **D. Date of filing and proposed effective date**

The date of this filing is October 1, 2015. The Company proposes the RER Rate be reflected in the Resource Adjustment included in the Company's retail electric billing

rates effective January 1, 2016, or in the first full month following Commission approval if Commission action occurs after December 2015<sup>1</sup>.

### **E. Articles of Incorporation**

Pursuant to North Dakota Rules Part 69-02-02-04, a certified copy of Xcel Energy's Articles of Incorporation is on file with the Commission, as is an original Certificate of Good Standing.

## **II. BACKGROUND AND PURPOSE OF FILING**

The Company has made and will make significant investments in two very low-cost wind energy facilities in North Dakota. These facilities will help keep customer energy bills low, further diversify our energy portfolio, and help to keep the state's air quality among the best in the nation. To recover the North Dakota jurisdictional portion of these investments in North Dakota, we propose an RER Rate in this application to be effective January 1, 2016 through December 31, 2016.

N.D.C.C. § 49-05-16 provides a rebuttable presumption that generation resources to be developed in North Dakota are prudent. Further, N.D.C.C. Chs. 49-02, 49-05 and 49-06 and Commission precedent in Case No. PU-06-466<sup>2</sup> allows for the recovery of costs of renewable resources developed in North Dakota. As approved in Case No. PU-12-813, the Company is permitted to recover costs including, but not limited to, depreciation expense, property taxes, and operation and maintenance expenses related to Company-owned renewable energy project costs and capacity-related renewable energy purchased power costs not currently being recovered in base rates or eligible for recovery through the Fuel Cost Rider (FCR). Eligible projects (or portions of these projects) must be located in the state of North Dakota and must have previously been granted an Advance Determination of Prudence (ADP) by the Commission.

This application seeks to implement an RER rate to recover the 2015 and 2016 revenue requirements of RER-eligible projects that are not currently included in base rates.

In support of our request, we include details of the following:

- The projected RER tracker account activity for 2015, included in Attachment 4;

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<sup>1</sup> Where implementation is to begin later than January 1, we request the monthly rate be adjusted to recover the approved level over the time remaining in 2016.

<sup>2</sup> Ottetail Power Company Renewable Generation Rider

- The projected RER tracker account activity for 2016, including both revenue requirements and projected revenues, included in Attachment 5;
- The projected 2015 and 2016 revenue requirements of \$428,252 and \$1.914 million, respectively, totaling approximately \$2.342 million, proposed to be recovered by the RER Rate from North Dakota electric customers; and
- The RER Rate of \$0.001014 per kWh for all customer classes, with supporting calculations shown in Attachment 7.

### **III. PROJECT ELIGIBILITY**

To be eligible for inclusion in the RER, a project must be a renewable energy resource, be located (all or in part) in the state of North Dakota and have been granted an ADP by the Commission. The Border Winds and Courtenay Wind projects are qualifying wind energy facilities located in the state of North Dakota that have each been granted an ADP by the Commission, but are not yet in service and thus not included in base rates. Both projects, therefore, meet the requirements established by the legislature and the Commission for inclusion in the RER. Each project is described more completely below. We propose to include the projected revenue requirements associated with these two wind projects in the RER rate effective January 1, 2016 based upon the projects' in-service dates in late 2015 and late 2016.

#### **A. Border Winds**

The Border Winds project is a 150 MW wind resource being developed by RES Americas in Rolette County, in northeastern North Dakota, which upon completion will be transferred to the Company to own and operate. The project will consist of 75 Vestas 2.0 MW wind turbine generators. Associated project infrastructure includes access roads, electrical collection system, meteorological monitoring stations, a project collector substation, a new interconnection substation and an operations and maintenance facility. The Company originally identified this project for acquisition through a competitive bidding process in which a Request for Proposals (RFP) for additional wind resources was issued in February 2013. On August 13, 2013, the Company filed an ADP Application seeking Commission approval to develop, own, and operate the Border Winds project. In Case No. PU-13-742, the Commission approved the ADP by Order dated February 26, 2014.

The Border Winds project is currently under construction; we expect it to be in-service in October 2015.

## **B. Courtenay Wind**

The Courtenay Wind project is a 200 MW wind resource in Stutsman County, North Dakota that will cover 24,900 acres of land and, consistent with the Certificate of Site Compatibility, will consist of 100 Vestas 2.0 MW wind turbine generators and associated infrastructure. This project is also the result of our February 2013 RFP for additional wind resources. NSP was originally granted an ADP for Courtenay Wind as a power purchase agreement in Case No. PU-13-706. However, due to changed circumstances, on April 30, 2015, the Company filed an ADP Application seeking Commission approval to develop, own, and operate the Courtenay Wind Farm. In Case No. PU-15-181, the Commission approved the ADP by Order dated August 26, 2015.

Construction on the Courtenay Wind project began recently with the project expected to be in-service in December 2016 in order to ensure eligibility for Production Tax Credits (PTCs) before the scheduled PTC expiration date.

## **IV. ALLOCATIONS, RATE DESIGN, AND ACCOUNTING**

### **A. 2015 and 2016 RER Revenue Requirements**

In this application we request recovery of both the 2015 and 2016 calendar year revenue requirements for the RER-eligible Border Winds and Courtenay projects. The Border Winds project is the first eligible project under this approved rider tariff to go into service, however, it will not go into service until near the end of calendar year 2015. Given the small revenue requirement in 2015, we believe that combining the 2015 and 2016 revenue requirements into one application to update the RER Rate is administratively efficient. Going forward, we would generally expect our proposed and approved RER rates for a given calendar year to reflect only the revenue requirements for that same year.

The detailed project costs and revenue requirements in support of the proposed RER Rate combining 2015 and 2016 revenue requirements are shown in the following attachments:

Attachment 1	RER Rate Calculation
Attachment 2	Capital Expenditure Forecast Through 2017
Attachment 3	Annual Tracker Summary
Attachment 4	2015 Tracker
Attachment 5	2016 Tracker
Attachment 6	2017 Tracker
Attachment 7	2016 Revenue Forecast
Attachment 8	Universal Inputs
Attachment 9	Border Winds Revenue Requirement by Month
Attachment 10	Courtenay Project Revenue Requirement by Month
Attachment 11	Production Tax Credit Allocation
Attachment 12	O&M Expense
Attachment 13	Revised Tariff Sheet No. 87

## **B. Jurisdictional, Energy and Demand Allocators**

The revenue requirements included in the RER tracker are only those related to North Dakota's share of the eligible energy facilities and associated costs. The Border Winds and Courtenay Wind projects will be owned by NSPM. NSPM and NSPW (together the NSP Companies) operate an integrated electric system (NSP System). The NSP Companies plan and operate the NSP System through the Federal Energy Regulatory Commission (FERC) approved Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin (Interchange Agreement) tariff. The Interchange Agreement is a formula rate which provides for charges between NSPM and NSPW for certain electric production and transmission costs related to the NSP Companies' integrated electric system.

The Interchange Agreement provides for a fully equalized sharing of NSP System production and transmission costs on a load ratio share basis in light of the integrated nature of the NSP System, and the charges between NSPM and NSPW are intended to accomplish such sharing. The Interchange Agreement fixed charges are shared based on 36 months of coincident peak demand data. Under the terms of the Interchange Agreement tariff, all fixed production and all transmission costs are shared between the NSP Companies based on the respective Company's load ratio share (using a 36 month coincident peak demand allocator). All variable production costs are shared between the NSP Companies based on energy. As a result, approximately 85 percent of all production and transmission costs incurred by both NSPM and NSPW support customers of NSPM while approximately 15 percent support NSPW customers.

NSPM provides service to customers in the North Dakota, South Dakota and Minnesota jurisdictions. In general, NSPM's fixed production and all transmission costs (again, approximately 85 percent of total NSP System costs) are allocated to these three state jurisdictions based on load ratio share (using the 12 month coincident peak jurisdictional demand allocator). All variable production costs are shared between the NSPM jurisdictions based on energy. Wind production investments (considered variable) are allocated to jurisdiction based on energy.

Based on the demand and energy allocators, approximately 7 percent of NSPM's production and transmission costs are allocated to the North Dakota jurisdiction. On an NSP System basis, approximately 6 percent (i.e., 85 percent multiplied by 7 percent) of total costs support the North Dakota jurisdiction.

In calculating the RER costs assigned to the North Dakota jurisdiction, the Company used the most current forecasts of demand and energy data available at the time of this filing and applied the composite demand and energy allocators for the applicable year<sup>3</sup>. The total project revenue requirements were allocated consistent with the process described above which serves to:

- Allocate a share of the total costs to NSPW; and
- Exclude the portion of NSPM costs not related to serving North Dakota retail customers. This step allocates a share of costs to the South Dakota and Minnesota retail jurisdictions, as well as the firm requirements wholesale sales jurisdiction.<sup>4</sup>

For purposes of allocating projected revenue requirements to the North Dakota jurisdiction, the Company proposes to use 2016 forecasted demand and energy. Any resulting over- or under- recovery from customers that occurs as a result of the use of forecast data will be trued-up to actual jurisdictional revenue requirements at the time the 2017 RER rate is determined.

Table 1 below shows the cost category, allocation method and allocator used to assign 2016 forecast costs to the North Dakota jurisdiction. The derivation of the individual allocators is shown in Attachment 8.

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<sup>3</sup> The 2015 and 2016 forecast revenue requirements are allocated to the North Dakota jurisdiction based on the 2015 and 2016 jurisdictional demand and energy allocators, respectively. The sales and demand data used to calculate the jurisdictional allocators is consistent with each period's sales, which is also used to estimate each period's customer collections.

<sup>4</sup> NSPM currently does not have any full requirements wholesale customers on the NSP system.

**Table 1: 2016 RER Allocators**

Cost Category	Allocation Method	2016 North Dakota Allocator
Wind Investment-related costs	Composite Energy & Demand	5.52%
Production O&M - Variable	Composite Energy	5.47%
Production O&M - Fixed	Composite Demand	5.22%
All Transmission costs	Composite Demand	5.22%
Wind Property Taxes & PTCs	Composite Energy	5.47%
Transmission Property Taxes	Composite Demand	5.22%

By performing this cost allocation process, we ensure that electric customers in other jurisdictions are allocated a share of the renewable energy facilities revenue requirements, consistent with the Company's allocation of similar costs in a general rate case.

### **C. Taxes**

The RER rate will include the following investment-related costs: property taxes, current and deferred taxes, book depreciation and operation and maintenance costs. In addition, the revenue requirements are off-set by PTCs and North Dakota Investment Tax Credits as further described below.

#### **1. Property Tax**

##### *a. Wind Facilities*

The tax in lieu of property taxes for the wind facilities is calculated based on a formula with two parts: one based on nameplate capacity and one based on energy production. We have applied the formula specific to the capacity and estimated wind generation for the Border Winds and Courtenay Wind projects and include the results in our revenue requirements calculations.

##### *b. Transmission Facilities*

The property tax associated with the transmission facilities is calculated using a method consistent with that used in our Transmission Cost Recovery (TCR) Rider. The North Dakota state composite property tax rate is applied to the gross transmission plant in service at the end of the prior year. The North Dakota composite rate is calculated by the Company's Tax Department and reflects the ratio of 2015 payable property taxes to North Dakota taxable investment as valued at the end of the prior year.

## 2. Revenue Requirements Offsets

### *a. PTC*

The Border Winds and Courtenay Wind projects are eligible for the federal PTC when each project goes in-service and is producing energy. We estimate PTC benefits based on expected energy production. We have calculated the expected PTC on a monthly basis and used the credit amount to offset the revenue requirement based on project in-service dates. The PTC was calculated by multiplying the expected kWh generated by the currently effective per kWh credit. The 2015 PTC credit is 2.3 cents per kWh. In this filing, we assumed the 2015 rate going forward; however, we would update the credit for future years if the Internal Revenue Service makes changes to the law that would redefine the credit. The actual PTC benefits will be trued up through the RER Tracker Account and updated in each annual filing.

Note that due to the variability of wind production, we propose to continue to true-up the PTC for the Border Winds and Courtenay Wind projects in future RER tracker updates, even after the project costs have been incorporated into base rates.

### *b. North Dakota Income Tax Credits (ND ITC)*

N.D.C.C. Section 57-38-01.8 provides for a tax credit against North Dakota income taxes for the installation of solar, biomass, geothermal, and wind projects that meet certain requirements. Because this tax credit is structured to provide a credit against North Dakota income taxes, an entity must have sufficient North Dakota income tax liability to realize the benefits.

Xcel Energy has North Dakota taxable income, and therefore a North Dakota tax liability. The Border Winds project will be in service sooner than Courtenay and is expected to generate sufficient ND ITC to offset the Company's anticipated tax liability for all but the last year that Courtenay qualifies for the ND ITC. As such, we have calculated the ND ITC specific to the Border Winds project and off-set the 2016 revenue requirements accordingly to the maximum extent possible based on estimated North Dakota taxable income.

### *c. Accumulated Deferred Income Taxes*

The Company is assessing its calculation of the plant related Accumulated Deferred Income Taxes offset to rate base to assure it is calculated in accordance with the proration formula in IRS regulation section 1.167(1)-1(h)(6). No estimates of the potential impact, if any, to the 2016 estimated annual revenue requirements are known at this time.

#### **D. CWIP and AFUDC**

The Company's RER revenue requirement model includes a current return on capital expenditures beginning with the cumulative Construction Work in Progress (CWIP) balance for each project at eligibility date, or the date construction expenditures begin, whichever is later. The beginning CWIP balance includes Allowance for Funds Used During Construction (AFUDC) incurred prior to the project eligibility date (pre-eligibility AFUDC). After that date, AFUDC is excluded from the CWIP balance. As a result, for each project, a current return is calculated on the North Dakota jurisdictional portion of the CWIP balance which includes only pre-eligibility AFUDC and accumulated capital expenditures.

#### **E. Capital Structure**

The Company has calculated the revenue requirements consistent with the approved *Revised Second Amended Settlement* in Case No. PU-12-813. The capital structure approved in that docket was included on Attachment D of the Settlement Agreement. (See Attachment 8.)

#### **F. Depreciation**

The remaining life assumptions used in this filing are consistent with the remaining lives approved in the last ND electric rate case. The Company is proposing a depreciable life assumption of 25 years for both of these wind projects as that is the standard depreciation the Company assigns to all wind assets. If any changes are made to the projects' remaining lives in future Commission Orders, those changes will be reflected in future filings.

#### **G. Operation and Maintenance Expense**

As allowed under the enabling statute, the proposed RER rate includes projected O&M expense for Company labor and related labor costs, consulting services and other outside contract vendor costs, routine janitorial, electric and gas service, sewer maintenance, snow removal, landowner payments, space costs and avian costs. (See Attachment 12.) We believe these expenses are reasonable and will be necessary to operate and maintain these two wind production facilities.

#### **H. Transmission Costs**

We include in the overall revenue requirement calculation the budgeted amount of payment to Otter Tail Power Company and Minnkota Power Cooperative which are

required to interconnect the Courtenay Wind project to the transmission system. (See Attachment 3.)

## **I. RER Tracker Account**

To ensure that customers are not under or overcharged, we will record the actual RER revenues and costs in a tracker account as the accounting mechanism for eligible RER facilities costs. Any differences based on the estimated end of year balance in the tracker account will be returned or collected as part of our next annual RER Rate application.

Each month as revenues are collected from retail customers, the Company will track the amount of recovery under the RER rate and will compare that amount with the actual monthly revenue requirements (costs). The difference will be recorded in the tracker account as the amount of over- or under-recovery. Any over- or under-recovery balance at the end of the year is used in the calculation of the rate factor for the next year's forecasted revenue requirement.

## **J. Accounting for the Tracker**

Xcel Energy calculates the monthly North Dakota jurisdictional revenue requirements (including appropriate overall return, income taxes, property taxes and depreciation), and compares them with monthly RER rate recoveries from customers. The under-recovered amounts are recorded in FERC Account 182.3, Other Regulatory Assets and the over-recovered amounts are recorded in FERC Account 254, Other Regulatory Liabilities (the Tracker Accounts).

## **V. RATE APPLICATION AND IMPACT**

### **A. Updated RER Rate**

The Company's RER rate design is the total annual calculated revenue requirements for both 2015 and 2016 divided by the forecasted energy sales to North Dakota electric retail customers during the 2016 calendar year. The rate is rounded to the nearest \$0.000001 per kWh. This calculation is shown on Attachment 7. Based on this rate design, we propose the following RER Rate:

**Table 2: 2016 RER Rate Calculation**

	Retail
ND Retail Revenue Requirements <i>2015 and 2016</i>	\$2,342,069
ND Retail Sales (kWh) <i>Jan.-Dec. 2016</i>	2,309,682,896
2016 RER Rate Cost Per kWh	\$0.001014

The average bill impact for a residential customer using 750 kWh per month would be \$0.76 per month.

For each 12-month period ending December 31, a true-up adjustment will be recorded to reset the Tracker Account. The true-up will reflect the difference between the RER revenues and the actual revenue requirements for the period.

**B. Tariff**

Xcel Energy proposes to update its Renewable Energy Rider tariff sheet number 87 in Section 5 of the North Dakota Electric Rate Book—NDPSC No. 2 with the proposed 2016 rate. Attachment 12 depicts the proposed tariff sheet.

The tariff states that the RER rate will be applied to customer bills subsequent to Commission approval. While we propose an effective date of January 1, 2016, the tariff sheet and revised RER rate will not be effective unless and until the Commission approves this application.

The RER tariff sheet will be updated to comply with the Commission’s final order in this proceeding. If the final RER rate goes into effect after January 1, 2016, or the Commission determines modifications need to be made to the level of revenues we have proposed for RER recovery, the Company will calculate the final RER rate based on the approved revenue requirement and forecasted sales over the remaining months of 2016. We will then file our 2017 RER rate application in late 2016.

**C. Notice to Customers**

The Company will provide notice to customers regarding the new RER rate reflected in their monthly electric bill. We propose the following language be included as a notice on customer bills during the month the RER rate is implemented:

*The Renewable Energy Rider (RER) line item on your bill funds investments in new and modified renewable energy facilities located in North Dakota. Beginning this month, the RER rate is \$0.001014 per kWh, in effect for all electric customers.*

We will work with Commission Staff if there are any suggestions to modify this proposed customer notice.

### **APPEARANCE OF COUNSEL**

The Company will be represented in this proceeding by the following counsel upon whom all pleadings, documents and other filings should be served:

Alison Archer  
Assistant General Counsel  
Xcel Energy  
414 Nicollet Mall, 5<sup>th</sup> Floor  
Minneapolis, MN 55401  
[Alison.C.Archer@xcelenergy.com](mailto:Alison.C.Archer@xcelenergy.com)

We request that all communications regarding this proceeding, including data requests, also be directed to:

SaGonna Thompson  
Regulatory Administrator  
Xcel Energy Services Inc.  
414 Nicollet Mall  
Minneapolis, MN 55401  
[Regulatory.Records@xcelenergy.com](mailto:Regulatory.Records@xcelenergy.com)

### **CONCLUSION**

Xcel Energy respectfully requests that the Commission approve the proposed renewable energy facilities as eligible for recovery through the existing Renewable Energy Rider, and approve the proposed RER rate factor for 2016 described in this filing. This factor is designed to recover the costs associated with significant investments in renewable energy facilities that are not presently reflected in our general rate schedules.

Dated: October 1, 2015

Northern States Power Company

<b>RER Rate - 2016</b>		
2016 Revenue Requirements	\$	2,342,069
Forecasted kWh Sales		2,309,682,896
RER Cost per kWh	\$	0.001014

<b>Capital Expenditures Excluding RWIP Forecast Through 2017</b>							
<b>Total: Wind Projects</b>		<b>253,490</b>	<b>-</b>	<b>-</b>	<b>9,338</b>	<b>15,833,276</b>	<b>16,096,104</b>
<b>Project Name</b>	<b>Sub Project</b>	<b>2013</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>Total</b>
Courtenay Wind	Production	42,370	-	-	-	-	89,594,655
Courtenay Wind	Transmission	42,370	-	-	-	-	217,297
Courtenay Wind	TSG	42,370	-	-	-	-	848,077
Courtenay Wind	Land Rights	42,370	-	-	-	-	269,922
Border Winds	Production	42,005	-	-	9,338	15,776,317	249,063,060
Border Winds	Transmission	42,005	-	-	-	56,959	56,942

<b>Annual Tracker Summary</b>			
	<b>2015</b>	<b>2016</b>	<b>2017</b>
	<b>Mixed</b>	<b>Forecast</b>	<b>Forecast</b>
Border Winds Capital	602,190	2,189,533	1,888,500
Property Taxes	-	33,062	33,062
ND ITC	-	(58,749)	(612,677)
Border PTCs	(236,965)	(990,611)	(1,052,206)
O&M	63,027	260,847	261,835
<b>Total Border Winds Costs</b>	<b>428,252</b>	<b>1,434,081</b>	<b>518,513</b>
Courtenay Wind Capital	-	405,745	2,576,084
Property Taxes	-	-	49,400
Courtenay PTCs	-	(3,075)	(1,276,091)
O&M	-	61,985	347,475
Transmission Costs (Interconnect)	-	15,082	120,653
<b>Total Courtenay Wind Costs</b>	<b>-</b>	<b>479,736</b>	<b>1,817,521</b>
Carryover Balance	-	428,252	50
<b>Revenue Requirement (RR)</b>	<b>428,252</b>	<b>2,342,069</b>	<b>2,336,085</b>
Revenue Collections (RC)	-	2,342,018	2,336,874
<b>Balance</b>	<b>428,252</b>	<b>50</b>	<b>(789)</b>

2015 Tracker													
Carryover	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual Total
	Actual	Actual	Actual	Actual	Actual	Actual	Mixed	Forecast	Forecast	Forecast	Forecast	Forecast	Mixed
Border Winds Capital	816	935	945	916	909	936	954	969	985	123,570	237,413	232,842	602,190
Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
ND ITC	-	-	-	-	-	-	-	-	-	-	-	-	-
Border PTCs	-	-	-	-	-	-	-	-	-	(78,988)	(78,988)	(78,988)	(236,965)
O&M	5,252	5,252	5,252	5,252	5,252	5,252	5,252	5,252	5,252	5,252	5,252	5,252	63,027
<b>Total Border Costs</b>	<b>6,068</b>	<b>6,187</b>	<b>6,197</b>	<b>6,168</b>	<b>6,161</b>	<b>6,189</b>	<b>6,207</b>	<b>6,222</b>	<b>6,237</b>	<b>49,834</b>	<b>163,677</b>	<b>159,106</b>	<b>428,252</b>
Courtenay Wind Capital	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
Courtenay PTCs	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Costs (Interconnect)	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total Courtenay Costs</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
<b>Revenue Requirement</b>	<b>6,068</b>	<b>6,187</b>	<b>6,197</b>	<b>6,168</b>	<b>6,161</b>	<b>6,189</b>	<b>6,207</b>	<b>6,222</b>	<b>6,237</b>	<b>49,834</b>	<b>163,677</b>	<b>159,106</b>	<b>428,252</b>
Revenue Collections	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Balance</b>	<b>6,068</b>	<b>12,255</b>	<b>18,452</b>	<b>24,620</b>	<b>30,781</b>	<b>36,969</b>	<b>43,176</b>	<b>49,397</b>	<b>55,635</b>	<b>105,469</b>	<b>269,146</b>	<b>428,252</b>	

2016 Tracker													
Carryover	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Annual Total
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Border Winds Capital	192,078	190,350	188,598	186,845	185,092	183,339	181,587	179,834	178,081	176,329	174,576	172,823	2,189,533
Property Taxes	2,755	2,755	2,755	2,755	2,755	2,755	2,755	2,755	2,755	2,755	2,755	2,755	33,062
ND ITC	(4,896)	(4,896)	(4,896)	(4,896)	(4,896)	(4,896)	(4,896)	(4,896)	(4,896)	(4,896)	(4,896)	(4,896)	(58,749)
Border PTCs	(82,551)	(82,551)	(82,551)	(82,551)	(82,551)	(82,551)	(82,551)	(82,551)	(82,551)	(82,551)	(82,551)	(82,551)	(990,611)
O&M	21,737	21,737	21,737	21,737	21,737	21,737	21,737	21,737	21,737	21,737	21,737	21,737	260,847
Total Border Costs	129,124	127,396	125,643	123,891	122,138	120,385	118,633	116,880	115,127	113,374	111,622	109,869	1,434,081
Courtenay Wind Capital	5,225	5,363	5,552	5,937	6,625	8,550	11,693	14,269	19,940	24,891	26,396	271,305	405,745
Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
Courtenay PTCs	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(256)	(3,075)
O&M	5,165	5,165	5,165	5,165	5,165	5,165	5,165	5,165	5,165	5,165	5,165	5,165	61,985
Transmission Costs (Interconnect)	-	-	-	-	-	-	-	-	-	-	-	-	15,082
Total Courtenay Costs	10,134	10,272	10,461	10,846	11,534	13,459	16,602	19,178	24,849	29,800	36,332	286,269	479,736
Carryover Balance	428,252	35,688	35,688	35,688	35,688	35,688	35,688	35,688	35,688	35,688	35,688	35,688	428,252
<b>Revenue Requirement</b>	<b>174,946</b>	<b>173,355</b>	<b>171,792</b>	<b>170,424</b>	<b>169,360</b>	<b>169,532</b>	<b>170,922</b>	<b>171,745</b>	<b>175,664</b>	<b>178,862</b>	<b>183,641</b>	<b>431,826</b>	<b>2,342,069</b>
Revenue Collections	233,421	206,861	205,812	174,267	174,018	176,855	198,163	195,963	175,283	179,112	196,291	225,972	2,342,018
<b>Balance</b>	<b>(58,476)</b>	<b>(91,982)</b>	<b>(126,002)</b>	<b>(129,845)</b>	<b>(134,503)</b>	<b>(141,826)</b>	<b>(169,067)</b>	<b>(193,285)</b>	<b>(192,904)</b>	<b>(193,154)</b>	<b>(205,804)</b>	<b>50</b>	

2017 Tracker													
Carryover	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Annual Total
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Border Winds Capital	163,797	162,629	161,462	160,294	159,126	157,959	156,791	155,624	154,456	153,288	152,121	150,953	1,888,500
Property Taxes	2,755	2,755	2,755	2,755	2,755	2,755	2,755	2,755	2,755	2,755	2,755	2,755	33,062
ND ITC	(51,056)	(51,056)	(51,056)	(51,056)	(51,056)	(51,056)	(51,056)	(51,056)	(51,056)	(51,056)	(51,056)	(51,056)	(612,677)
Border PTCs	(87,684)	(87,684)	(87,684)	(87,684)	(87,684)	(87,684)	(87,684)	(87,684)	(87,684)	(87,684)	(87,684)	(87,684)	(1,052,206)
O&M	21,820	21,820	21,820	21,820	21,820	21,820	21,820	21,820	21,820	21,820	21,820	21,820	261,835
Total Border Costs	49,631	48,464	47,296	46,129	44,961	43,793	42,626	41,458	40,290	39,123	37,955	36,787	518,513
Courtenay Wind Capital	225,423	223,468	221,514	219,560	217,605	215,651	213,697	211,742	209,788	207,833	205,879	203,925	2,576,084
Property Taxes	4,117	4,117	4,117	4,117	4,117	4,117	4,117	4,117	4,117	4,117	4,117	4,117	49,400
Courtenay PTCs	(106,341)	(106,341)	(106,341)	(106,341)	(106,341)	(106,341)	(106,341)	(106,341)	(106,341)	(106,341)	(106,341)	(106,341)	(1,276,091)
O&M	28,956	28,956	28,956	28,956	28,956	28,956	28,956	28,956	28,956	28,956	28,956	28,956	347,475
Transmission Costs (Interconnect)	10,054	10,054	10,054	10,054	10,054	10,054	10,054	10,054	10,054	10,054	10,054	10,054	120,653
Total Courtenay Costs	162,209	160,255	158,300	156,346	154,392	152,437	150,483	148,529	146,574	144,620	142,665	140,711	1,817,521
Carryover Balance	50	4	4	4	4	4	4	4	4	4	4	4	50
<b>Revenue Requirement</b>	<b>211,845</b>	<b>208,723</b>	<b>205,601</b>	<b>202,479</b>	<b>199,357</b>	<b>196,235</b>	<b>193,113</b>	<b>189,991</b>	<b>186,869</b>	<b>183,747</b>	<b>180,625</b>	<b>177,503</b>	<b>2,336,085</b>
Revenue Collections	233,400	202,496	204,233	174,849	175,082	176,597	197,919	195,741	175,084	179,033	196,199	226,242	2,336,874
<b>Balance</b>	<b>(21,555)</b>	<b>(15,329)</b>	<b>(13,961)</b>	<b>13,669</b>	<b>37,944</b>	<b>57,582</b>	<b>52,775</b>	<b>47,026</b>	<b>58,810</b>	<b>63,524</b>	<b>47,950</b>	<b>(789)</b>	



<b>Universal Inputs</b>								Jan-15	Jan-16	Jan-17
<b>Dates</b>								Forecast	Forecast	Forecast
<b>Depreciation</b>										
Current			Production	Transmission	TSG	Land Rights				
	2015	Book Depreciation Life (yrs)	25.00	64.28	80.42	25.00				
	2015	Net Salvage %	-8.50%	-8.63%	-34.45%	0.00%				
Net Salvage %										
		Production					-8.50%	-8.50%	-8.50%	
		Transmission					-8.63%	-8.63%	-8.63%	
		TSG					-34.45%	-34.45%	-34.45%	
		Land Rights					0.00%	0.00%	0.00%	
Book Depreciation Lives										
		Production					25.00	25.00	25.00	
		Transmission					64.28	64.28	64.28	
		TSG					80.42	80.42	80.42	
		Land Rights					25.00	25.00	25.00	
Book Depreciation Rates (Composite)										
		Production					4.34%	4.34%	4.3400%	
		Transmission					1.69%	1.69%	1.6901%	
		TSG					1.67%	1.67%	1.6719%	
		Land Rights					4.00%	4.00%	4.0000%	
Book Depreciation Rate: Final Period										
		Production		100%						
		Transmission		100%						
		TSG		100%						
		Land Rights		100%						
<b>Tax Rates</b>										
<b>Income Tax Rates</b>										
		State Income Tax Rate					4.3100%	4.3100%	4.31%	
		Federal Income Tax Rate					35.0000%	35.0000%	35.0000%	
<b>Composite Income Tax Rate</b>										
		State Composite Income Tax Rate					37.8015%	37.8015%	37.8015%	
		Company Composite Income Tax Rate					40.8097%	40.8097%	40.8097%	
<b>Tax Depreciation Schedule: MACRS</b>										
Annual			5	15	SL_20					
	0		0.00%	0.00%	0.00%	0.00%				
	1		20.00%	5.00%	2.50%					
	2		32.00%	9.50%	5.00%					
	3		19.20%	8.55%	5.00%					
	4		11.52%	7.70%	5.00%					
	5		11.52%	6.93%	5.00%					
	6		5.76%	6.23%	5.00%					
	7		0.00%	5.90%	5.00%					
	8		0.00%	5.90%	5.00%					
	9		0.00%	5.91%	5.00%					
	10		0.00%	5.90%	5.00%					
	11		0.00%	5.91%	5.00%					
	12		0.00%	5.90%	5.00%					
	13		0.00%	5.91%	5.00%					
	14		0.00%	5.90%	5.00%					
	15		0.00%	5.91%	5.00%					
	16		0.00%	2.95%	5.00%					
	17				5.00%					
	18				5.00%					
	19				5.00%					
	20				5.00%					
	21				2.50%					
<b>Cap Structure (Last Authorized)</b>										
		Long Term Debt %					44.9600%	44.9600%	44.9600%	
		Long Term Debt Cost (\$s as a % of total)					5.1400%	5.1400%	5.1400%	
		Short Term Debt %					2.4800%	2.4800%	2.4800%	
		Short Term Debt Cost (\$s as a % of total)					0.7500%	0.7500%	0.7500%	
		Weighted Cost of Debt					2.33%	2.33%	2.33%	
		Common Stock %					52.5600%	52.5600%	52.5600%	
		Common Stock Cost (\$s as a % of total)					10.0000%	10.2500%	10.2500%	
		Preferred Stock %					0.0000%	0.0000%	0.0000%	
		Preferred Stock Cost (\$s as a % of total)					0.0000%	0.0000%	0.0000%	
		Weighted Cost of Equity					5.26%	5.39%	5.39%	
							7.59%	7.72%	7.72%	
<b>Property Tax Rates</b>										
		Percent Taxable					100.00%	100.00%	100.00%	
		Asset Rate					1.075%	1.075%	1.075%	
		Property Tax Rate					1.075%	1.075%	1.075%	
<b>OATT</b>										
		Total Cost of Capital					0.0000%	0.0000%	0.0000%	
		Equity Gross-Up Rate					0.0000%	0.0000%	0.0000%	
		Equity Gross-Up					0.0000%	0.0000%	0.0000%	
		Total Cost of Capital incl Gross-Up for Taxes - Annual Rate					0.0000%	0.0000%	0.0000%	
<b>Allocators</b>										
		MN 12-month energy (Electric Energy)					6.5856%	6.5597%	6.5597%	
		NSPM 36-month CP demand (Interchange Electric)					84.5789%	84.1349%	84.1349%	
		Wind Jurisdictional Allocator					5.5700%	5.5190%	5.5190%	
<b>Allocators</b>										
		MN 12-month CP demand (Electric Demand)					6.1657%	6.2102%	6.2102%	
		NSPM 36-month CP demand (Interchange Electric)					84.5789%	84.1349%	84.1349%	
		Trans Jurisdictional Allocator					5.2149%	5.2249%	5.2249%	
<b>Allocators</b>										
		MN 12-month energy (Electric Energy)					6.5856%	6.5597%	6.5597%	
		NSPM 3 Interchange Energy (Interchange Electric)					83.7278%	83.3146%	83.3146%	
		PTC Jurisdictional Allocator					5.5140%	5.4652%	5.4652%	

Border Winds Land, Line & Sub	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
<b>Rate Base</b>													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	-	-	-	-	-	-	-	-	-	266,501,983	266,574,437	266,638,755	266,638,755
Less Accumulated Book Depreciation Reserve	-	-	-	-	-	-	-	-	-	481,805	1,445,540	2,409,511	2,409,511
Less Accumulated Deferred Taxes	(68,663)	(71,997)	(77,493)	(85,715)	(96,817)	(105,809)	(115,100)	(124,456)	(133,879)	3,969,753	12,256,253	20,544,764	20,544,764
<b>End Of Month Rate Base</b>	<b>68,663</b>	<b>71,997</b>	<b>77,493</b>	<b>85,715</b>	<b>96,817</b>	<b>105,809</b>	<b>115,100</b>	<b>124,456</b>	<b>133,879</b>	<b>262,050,425</b>	<b>252,872,644</b>	<b>243,684,480</b>	<b>243,684,480</b>
<b>Return on Rate Base</b>													
Debt Return	124	137	145	158	177	197	214	233	251	254,537	499,904	482,074	1,238,152
Equity Return	279	308	328	358	400	444	484	525	566	574,621	1,128,540	1,088,288	2,795,140
<b>Total Return on Rate Base</b>	<b>403</b>	<b>445</b>	<b>473</b>	<b>516</b>	<b>577</b>	<b>641</b>	<b>699</b>	<b>758</b>	<b>817</b>	<b>829,158</b>	<b>1,628,444</b>	<b>1,570,362</b>	<b>4,033,292</b>
<b>Income Statement Items</b>													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
Book Depreciation	-	-	-	-	-	-	-	-	-	481,805	963,735	963,971	2,409,511
Deferred Taxes	(9,872)	(3,335)	(5,496)	(8,222)	(11,102)	(8,992)	(9,292)	(9,355)	(9,423)	4,103,632	8,286,500	8,288,511	20,603,554
Gross Up for Income Tax	24,119	19,680	21,988	24,147	26,843	25,166	25,731	26,007	26,295	(3,196,070)	(6,616,263)	(6,642,499)	(16,234,856)
<b>Total Income Statement Expense</b>	<b>14,247</b>	<b>16,345</b>	<b>16,492</b>	<b>15,925</b>	<b>15,741</b>	<b>16,174</b>	<b>16,439</b>	<b>16,652</b>	<b>16,872</b>	<b>1,389,367</b>	<b>2,633,971</b>	<b>2,609,983</b>	<b>6,778,209</b>
<b>Revenue Requirement</b>													
<b>Total</b>	<b>14,650</b>	<b>16,790</b>	<b>16,965</b>	<b>16,441</b>	<b>16,318</b>	<b>16,815</b>	<b>17,138</b>	<b>17,410</b>	<b>17,689</b>	<b>2,218,524</b>	<b>4,262,416</b>	<b>4,180,345</b>	<b>10,811,501</b>
Are costs eligible for recovery in the Rider?	1	1	1	1	1	1	1	1	1	1	1	1	1
<b>Rider Eligible Revenue Requirement</b>	<b>816</b>	<b>935</b>	<b>945</b>	<b>916</b>	<b>909</b>	<b>936</b>	<b>954</b>	<b>969</b>	<b>985</b>	<b>123,570</b>	<b>237,413</b>	<b>232,842</b>	<b>602,190</b>
Rider Eligible Revenue Requirement: Annual Totals	-	-	-	-	-	-	-	-	-	-	-	<b>602,190</b>	<b>602,190</b>

Border Winds Land, Line & Sub	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
<b>Rate Base</b>													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981
Less Accumulated Book Depreciation Reserve	3,373,703	4,338,006	5,302,309	6,266,611	7,230,914	8,195,217	9,159,519	10,123,822	11,088,125	12,052,427	13,016,730	13,981,033	13,981,033
Less Accumulated Deferred Taxes	23,045,952	25,547,421	28,048,890	30,550,359	33,051,828	35,553,297	38,054,766	40,556,235	43,057,704	45,559,172	48,060,641	50,562,110	50,562,110
<b>End Of Month Rate Base</b>	<b>240,286,325</b>	<b>236,820,553</b>	<b>233,354,782</b>	<b>229,889,010</b>	<b>226,423,239</b>	<b>222,957,467</b>	<b>219,491,695</b>	<b>216,025,924</b>	<b>212,560,152</b>	<b>209,094,381</b>	<b>205,628,609</b>	<b>202,162,838</b>	<b>202,162,838</b>
<b>Return on Rate Base</b>													
Debt Return	469,855	463,191	456,462	449,733	443,003	436,274	429,544	422,815	416,086	409,356	402,627	395,898	5,194,843
Equity Return	1,086,918	1,071,503	1,055,935	1,040,368	1,024,801	1,009,234	993,667	978,100	962,533	946,966	931,399	915,832	12,017,256
<b>Total Return on Rate Base</b>	<b>1,556,773</b>	<b>1,534,694</b>	<b>1,512,397</b>	<b>1,490,101</b>	<b>1,467,804</b>	<b>1,445,508</b>	<b>1,423,211</b>	<b>1,400,915</b>	<b>1,378,619</b>	<b>1,356,322</b>	<b>1,334,026</b>	<b>1,311,729</b>	<b>17,212,099</b>
<b>Income Statement Items</b>													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	106	106	106	106	106	106	106	106	106	106	106	106	1,273
Book Depreciation	964,192	964,303	964,303	964,303	964,303	964,303	964,303	964,303	964,303	964,303	964,303	964,303	11,571,522
Deferred Taxes	2,501,189	2,501,469	2,501,469	2,501,469	2,501,469	2,501,469	2,501,469	2,501,469	2,501,469	2,501,469	2,501,469	2,501,469	30,017,347
Gross Up for Income Tax	(1,541,877)	(1,551,493)	(1,560,954)	(1,570,415)	(1,579,876)	(1,589,337)	(1,598,798)	(1,608,259)	(1,617,720)	(1,627,181)	(1,636,642)	(1,646,103)	(19,128,652)
<b>Total Income Statement Expense</b>	<b>1,923,610</b>	<b>1,914,385</b>	<b>1,904,924</b>	<b>1,895,463</b>	<b>1,886,002</b>	<b>1,876,541</b>	<b>1,867,080</b>	<b>1,857,619</b>	<b>1,848,158</b>	<b>1,838,697</b>	<b>1,829,236</b>	<b>1,819,775</b>	<b>22,461,489</b>
<b>Revenue Requirement</b>													
<b>Total</b>	<b>3,480,382</b>	<b>3,449,079</b>	<b>3,417,321</b>	<b>3,385,564</b>	<b>3,353,806</b>	<b>3,322,049</b>	<b>3,290,291</b>	<b>3,258,534</b>	<b>3,226,776</b>	<b>3,195,019</b>	<b>3,163,262</b>	<b>3,131,504</b>	<b>39,673,588</b>
Are costs eligible for recovery in the Rider?	1	1	1	1	1	1	1	1	1	1	1	1	1
<b>Rider Eligible Revenue Requirement</b>	<b>192,078</b>	<b>190,350</b>	<b>188,598</b>	<b>186,845</b>	<b>185,092</b>	<b>183,339</b>	<b>181,587</b>	<b>179,834</b>	<b>178,081</b>	<b>176,329</b>	<b>174,576</b>	<b>172,823</b>	<b>2,189,533</b>
Rider Eligible Revenue Requirement: Annual Totals	-	-	-	-	-	-	-	-	-	-	-	-	<b>2,189,533</b>

Border Winds Land, Line & Sub	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
<b>Rate Base</b>													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981	266,705,981
Less Accumulated Book Depreciation Reserve	14,845,335	15,909,638	16,873,941	17,838,244	18,802,546	19,766,849	20,731,152	21,695,454	22,659,757	23,624,060	24,588,362	25,552,665	25,552,665
Less Accumulated Deferred Taxes	51,906,707	53,251,304	54,595,901	55,940,499	57,285,096	58,629,693	59,974,290	61,318,887	62,663,484	64,008,081	65,352,678	66,697,275	66,697,275
<b>End Of Month Rate Base</b>	<b>199,853,938</b>	<b>197,545,038</b>	<b>195,236,138</b>	<b>192,927,239</b>	<b>190,618,339</b>	<b>188,309,439</b>	<b>186,000,539</b>	<b>183,691,640</b>	<b>181,382,740</b>	<b>179,073,840</b>	<b>176,764,940</b>	<b>174,456,041</b>	<b>174,456,041</b>
<b>Return on Rate Base</b>													
Debt Return	390,291	385,808	381,325	376,842	372,359	367,876	363,393	358,909	354,426	349,943	345,460	340,977	4,387,610
Equity Return	902,863	892,492	882,121	871,750	861,379	851,009	840,638	830,267	819,896	809,525	799,155	788,784	10,149,879
<b>Total Return on Rate Base</b>	<b>1,293,154</b>	<b>1,278,300</b>	<b>1,263,446</b>	<b>1,248,592</b>	<b>1,233,738</b>	<b>1,218,884</b>	<b>1,204,030</b>	<b>1,189,177</b>	<b>1,174,323</b>	<b>1,159,469</b>	<b>1,144,615</b>	<b>1,129,761</b>	<b>14,537,489</b>
<b>Income Statement Items</b>													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	115	115	115	115	115	115	115	115	115	115	115	115	1,382
Book Depreciation	964,303	964,303	964,303	964,303	964,303	964,303	964,303	964,303	964,303	964,303	964,303	964,303	11,571,632
Deferred Taxes	1,344,597	1,344,597	1,344,597	1,344,597	1,344,597	1,344,597	1,344,597	1,344,597	1,344,597	1,344,597	1,344,597	1,344,597	16,135,165
Gross Up for Income Tax	(634,216)	(640,519)	(646,822)	(653,125)	(659,428)	(665,731)	(672,034)	(678,337)	(684,640)	(690,943)	(697,246)	(703,548)	(8,026,588)
<b>Total Income Statement Expense</b>	<b>1,674,799</b>	<b>1,668,496</b>	<b>1,662,193</b>	<b>1,655,890</b>	<b>1,649,587</b>	<b>1,643,284</b>	<b>1,636,981</b>	<b>1,630,678</b>	<b>1,624,375</b>	<b>1,618,072</b>	<b>1,611,769</b>	<b>1,605,467</b>	<b>19,681,591</b>
<b>Revenue Requirement</b>													
<b>Total</b>	<b>2,967,953</b>	<b>2,946,796</b>	<b>2,925,639</b>	<b>2,904,482</b>	<b>2,883,325</b>	<b>2,862,168</b>	<b>2,841,012</b>	<b>2,819,855</b>	<b>2,798,698</b>	<b>2,777,541</b>	<b>2,756,384</b>	<b>2,735,227</b>	<b>34,219,079</b>
Are costs eligible for recovery in the Rider?	1	1	1	1	1	1	1	1	1	1	1	1	1
<b>Rider Eligible Revenue Requirement</b>	<b>163,797</b>	<b>162,629</b>	<b>161,462</b>	<b>160,294</b>	<b>159,126</b>	<b>157,959</b>	<b>156,791</b>	<b>155,624</b>	<b>154,456</b>	<b>153,288</b>	<b>152,121</b>	<b>150,953</b>	<b>1,888,500</b>
Rider Eligible Revenue Requirement: Annual Totals	-	-	-	-	-	-	-	-	-	-	-	-	<b>1,888,500</b>



Courtenay Wind Land, Line & Sub	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
<b>Rate Base</b>													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	-	-	-	-	-	-	-	-	15,229,612	15,229,612	17,883,391	312,452,351	312,452,351
Less Accumulated Book Depreciation Reserve	-	-	-	-	-	-	-	-	10,664	31,993	57,744	620,598	620,598
Less Accumulated Deferred Taxes	(190,738)	(247,988)	(306,737)	(369,162)	(438,590)	(528,615)	(652,480)	(803,530)	(925,447)	(1,010,443)	(1,083,033)	(2,351,757)	(2,351,757)
<b>End Of Month Rate Base</b>	<b>190,738</b>	<b>247,988</b>	<b>306,737</b>	<b>369,162</b>	<b>438,590</b>	<b>528,615</b>	<b>652,480</b>	<b>803,530</b>	<b>16,144,395</b>	<b>16,208,063</b>	<b>18,918,680</b>	<b>289,479,996</b>	<b>289,479,996</b>
<b>Return on Rate Base</b>													
Debt Return	316	426	539	656	784	939	1,147	1,414	16,454	31,409	34,102	299,404	387,588
Equity Return	730	985	1,246	1,518	1,814	2,172	2,653	3,270	38,062	72,658	78,889	692,612	896,609
<b>Total Return on Rate Base</b>	<b>1,046</b>	<b>1,411</b>	<b>1,784</b>	<b>2,174</b>	<b>2,598</b>	<b>3,111</b>	<b>3,799</b>	<b>4,683</b>	<b>54,516</b>	<b>104,067</b>	<b>112,991</b>	<b>992,016</b>	<b>1,284,197</b>
<b>Income Statement Items</b>													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
Book Depreciation	-	-	-	-	-	-	-	-	10,664	21,328	25,751	562,853	620,598
Deferred Taxes	(56,320)	(57,249)	(58,749)	(62,425)	(69,428)	(90,025)	(123,865)	(151,051)	(121,917)	(84,996)	(82,590)	23,444,791	22,486,175
Gross Up for Income Tax	149,964	153,029	157,611	167,946	187,092	242,131	332,290	405,288	420,388	414,918	426,401	(20,079,552)	(17,022,493)
<b>Total Income Statement Expense</b>	<b>93,644</b>	<b>95,780</b>	<b>98,862</b>	<b>105,521</b>	<b>117,663</b>	<b>152,106</b>	<b>208,425</b>	<b>254,238</b>	<b>309,135</b>	<b>351,250</b>	<b>369,563</b>	<b>3,928,092</b>	<b>6,084,280</b>
<b>Revenue Requirement</b>													
<b>Total</b>	<b>94,690</b>	<b>97,191</b>	<b>100,647</b>	<b>107,696</b>	<b>120,262</b>	<b>155,218</b>	<b>212,225</b>	<b>258,921</b>	<b>363,651</b>	<b>455,317</b>	<b>482,554</b>	<b>4,920,107</b>	<b>7,368,478</b>
Are costs eligible for recovery in the Rider?	1	1	1	1	1	1	1	1	1	1	1	1	1
<b>Rider Eligible Revenue Requirement</b>	<b>5,225</b>	<b>5,363</b>	<b>5,552</b>	<b>5,937</b>	<b>6,625</b>	<b>8,550</b>	<b>11,693</b>	<b>14,269</b>	<b>19,940</b>	<b>24,891</b>	<b>26,396</b>	<b>271,305</b>	<b>405,745</b>
Rider Eligible Revenue Requirement: Annual Totals	-	-	-	-	-	-	-	-	-	-	-	<b>405,745</b>	<b>405,745</b>

Courtenay Wind Land, Line & Sub	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
<b>Rate Base</b>													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	312,452,351	312,452,351	312,452,351	312,452,351	312,452,351	312,452,351	312,452,351	312,452,351	312,452,351	312,452,351	312,452,351	312,452,351	312,452,351
Less Accumulated Book Depreciation Reserve	1,716,130	2,811,662	3,907,194	5,002,726	6,098,258	7,193,791	8,289,323	9,384,855	10,480,387	11,575,919	12,671,451	13,766,983	13,766,983
Less Accumulated Deferred Taxes	25,122,341	27,892,924	30,663,508	33,434,091	36,204,675	38,975,258	41,745,842	44,516,426	47,287,009	50,057,593	52,828,176	55,598,760	55,598,760
<b>End Of Month Rate Base</b>	<b>285,613,880</b>	<b>281,747,764</b>	<b>277,881,649</b>	<b>274,015,533</b>	<b>270,149,417</b>	<b>266,283,302</b>	<b>262,417,186</b>	<b>258,551,070</b>	<b>254,684,955</b>	<b>250,818,839</b>	<b>246,952,723</b>	<b>243,086,607</b>	<b>243,086,607</b>
<b>Return on Rate Base</b>													
Debt Return	558,320	550,814	543,307	535,800	528,293	520,787	513,280	505,773	498,267	490,760	483,253	475,747	6,204,401
Equity Return	1,291,565	1,274,200	1,256,834	1,239,469	1,222,104	1,204,738	1,187,373	1,170,008	1,152,643	1,135,277	1,117,912	1,100,547	14,352,670
<b>Total Return on Rate Base</b>	<b>1,849,885</b>	<b>1,825,013</b>	<b>1,800,141</b>	<b>1,775,269</b>	<b>1,750,397</b>	<b>1,725,525</b>	<b>1,700,653</b>	<b>1,675,781</b>	<b>1,650,909</b>	<b>1,626,037</b>	<b>1,601,165</b>	<b>1,576,293</b>	<b>20,557,071</b>
<b>Income Statement Items</b>													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	13,643	13,643	13,643	13,643	13,643	13,643	13,643	13,643	13,643	13,643	13,643	13,643	163,718
Book Depreciation	1,095,532	1,095,532	1,095,532	1,095,532	1,095,532	1,095,532	1,095,532	1,095,532	1,095,532	1,095,532	1,095,532	1,095,532	13,146,386
Deferred Taxes	2,770,584	2,770,584	2,770,584	2,770,584	2,770,584	2,770,584	2,770,584	2,770,584	2,770,584	2,770,584	2,770,584	2,770,584	33,247,002
Gross Up for Income Tax	(1,640,687)	(1,651,241)	(1,661,795)	(1,672,348)	(1,682,902)	(1,693,456)	(1,704,010)	(1,714,564)	(1,725,118)	(1,735,672)	(1,746,226)	(1,756,779)	(20,384,798)
<b>Total Income Statement Expense</b>	<b>2,239,072</b>	<b>2,228,518</b>	<b>2,217,964</b>	<b>2,207,410</b>	<b>2,196,857</b>	<b>2,186,303</b>	<b>2,175,749</b>	<b>2,165,195</b>	<b>2,154,641</b>	<b>2,144,087</b>	<b>2,133,533</b>	<b>2,122,979</b>	<b>26,172,309</b>
<b>Revenue Requirement</b>													
<b>Total</b>	<b>4,088,957</b>	<b>4,053,531</b>	<b>4,018,106</b>	<b>3,982,680</b>	<b>3,947,254</b>	<b>3,911,828</b>	<b>3,876,402</b>	<b>3,840,976</b>	<b>3,805,550</b>	<b>3,770,124</b>	<b>3,734,699</b>	<b>3,699,273</b>	<b>46,729,380</b>
Are costs eligible for recovery in the Rider?	1	1	1	1	1	1	1	1	1	1	1	1	1
<b>Rider Eligible Revenue Requirement</b>	<b>225,423</b>	<b>223,468</b>	<b>221,514</b>	<b>219,560</b>	<b>217,605</b>	<b>215,651</b>	<b>213,697</b>	<b>211,742</b>	<b>209,788</b>	<b>207,833</b>	<b>205,879</b>	<b>203,925</b>	<b>2,576,084</b>
Rider Eligible Revenue Requirement: Annual Totals	-	-	-	-	-	-	-	-	-	-	-	-	<b>2,576,084</b>

<b>Production Tax Credits</b>
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**Border Winds**

Year	Wind Production	PTC	ND JUR	Rev Req
2015	116,234	2,673,000	147,389	(236,965)
2016	490,167	11,274,000	616,145	(990,611)
2017	520,653	11,975,000	654,456	(1,052,206)

**Courtney Wind**

Year	Wind Production	PTC	ND JUR	Rev Req
2015	0	0	-	-
2016	1,503	35,000	1,913	(3,075)
2017	631,427	14,523,000	793,709	(1,276,091)

2015 Allocator	5.5140%
2016 Allocator	5.4652%
PTC Credit per MW hour \$	23.00
Gross Up Factor	1.607755814

5.21% 5.22% 5.22% 5.22% 5.22% 5.22%

Location	Description	Total Company						ND Jurisdiction					
		2015	2016	2017	2018	2019	2020	2015	2016	2017	2018	2019	2020
ES Borders Wind	Contract/Consulting	1,048,123	4,388,841	4,405,841	4,242,841	2,772,990	2,782,964	54,658	229,315	230,203	221,686	144,887	145,408
	Materials	-	-	-	315,238	909,248	918,347	-	-	-	16,471	47,508	47,983
	Other	18,759	36,647	38,545	39,087	41,005	42,305	978	1,915	2,014	2,042	2,142	2,210
	Space/Lease Costs	141,713	566,853	566,853	566,853	566,853	566,853	7,390	29,618	29,618	29,618	29,618	29,618
<b>ES Borders Wind Total</b>		<b>1,208,595</b>	<b>4,992,341</b>	<b>5,011,239</b>	<b>5,164,019</b>	<b>4,290,096</b>	<b>4,310,469</b>	<b>63,027</b>	<b>260,847</b>	<b>261,835</b>	<b>269,817</b>	<b>224,155</b>	<b>225,220</b>
ES Courtenay Wind	O&M Estimate	-	1,186,325	5,255,300	5,540,300	5,506,141	4,856,857	-	61,985	274,587	289,478	287,693	253,768
	Avian Costs for Geronimo	-	-	225,000	225,000	150,000	140,000	-	-	11,756	11,756	7,837	7,315
	Space/Lease Costs	-	-	1,170,000	1,192,400	1,215,248	1,238,553	-	-	61,132	62,302	63,496	64,714
<b>ES Courtenay Wind Total</b>		<b>-</b>	<b>1,186,325</b>	<b>6,650,300</b>	<b>6,957,700</b>	<b>6,871,389</b>	<b>6,235,410</b>	<b>-</b>	<b>61,985</b>	<b>347,475</b>	<b>363,536</b>	<b>359,026</b>	<b>325,797</b>

# Legislative

**NORTH DAKOTA ELECTRIC RATE BOOK - NDPSC NO. 2**

**RENEWABLE ENERGY RIDER**

Section No. 5  
2nd Revised Sheet No. 87

**APPLICATION**

Applicable to qualifying charges for electric service provided under all Company retail rate schedules.

**RENEWABLE ENERGY RIDER**

There will be included on each customer's monthly bill a Renewable Energy Rider ("RER") charge for purposes of recovering capital and operating costs of company-owned renewable energy generation located in the state of North Dakota and not presently reflected in base retail rates. The RER charge shall be determined by multiplying a customer's monthly billed kWh for electric service by the current RER Rate. The RER charge shall be calculated prior to the application of any city surcharges and/or sales tax.

**DETERMINATION OF RER RATE**

The RER Rate is determined by dividing the annual forecasted RER revenue requirement amount by the annual forecasted kWh sales. The annual forecasted RER revenue requirement is the sum of the RER costs for the forecast period and the carryover balance in the RER Tracker Account from the prior period. The RER Rate will be calculated annually, with the approval of the Commission. The present RER Rate is:

All Classes \$0.000000 \$0.001014 per kWh

All approved costs appropriately charged to the RER Tracker Account are eligible for recovery through this Rider, and all revenues recovered through the Rider are credited to the RER Tracker Account.

**QUALIFYING RENEWABLE ENERGY RIDER COSTS**

Qualifying RER costs include all annual revenue requirements eligible for recovery under N.D.C.C. § 49-02, 49-05 and 49-06. These costs include, but are not limited to, depreciation expense, property taxes, and operation and maintenance expenses related to Company-owned renewable energy project costs and capacity-related renewable energy purchased power costs not currently being recovered in base rates or eligible for recovery through the FCR. Eligible projects (or portions of these projects) must be located in the state of North Dakota and must have previously been granted an Advance Determination of Prudence by the Commission.

**TRUE-UP**

For each calendar year the RER is in place, a true-up adjustment to the Tracker Account will be calculated reflecting the difference between actual RER revenue and the actual RER costs (revenue requirements) for the recovery period. The true-up shall be recorded by May 1 of the following calendar year and will be included in the calculation of the RER rate effective for the next calendar year recovery period.

For example, Year 1 actual RER revenue will be compared to the actual RER revenue requirements for the same period and the difference recorded as an adjustment to the Tracker Account on or before May 1 of Year 2. This difference would then be included in the calculation of the new RER Rate to be filed with the Commission later in Year 2, and effective January 1 of Year 3.

Date Filed: 05-27-14 10-01-15 By: David M. Sparby Christopher B. Clark Effective Date: 07-06-14  
President, and CEO of Northern States Power Company, a Minnesota corporation  
Case No. PU-12-813 PU-15- Order Date: N/A

# **Non-Legislative**

**NORTH DAKOTA ELECTRIC RATE BOOK - NDPSC NO. 2**

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**RENEWABLE ENERGY RIDER**

Section No. 5  
2nd Revised Sheet No. 87

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**APPLICATION**

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**DETERMINATION OF RER RATE**

The RER Rate is determined by dividing the annual forecasted RER revenue requirement amount by the annual forecasted kWh sales. The annual forecasted RER revenue requirement is the sum of the RER costs for the forecast period and the carryover balance in the RER Tracker Account from the prior period. The RER Rate will be calculated annually, with the approval of the Commission. The present RER Rate is:

All Classes	\$0.001014 per kWh
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**TRUE-UP**

For each calendar year the RER is in place, a true-up adjustment to the Tracker Account will be calculated reflecting the difference between actual RER revenue and the actual RER costs (revenue requirements) for the recovery period. The true-up shall be recorded by May 1 of the following calendar year and will be included in the calculation of the RER rate effective for the next calendar year recovery period.

For example, Year 1 actual RER revenue will be compared to the actual RER revenue requirements for the same period and the difference recorded as an adjustment to the Tracker Account on or before May 1 of Year 2. This difference would then be included in the calculation of the new RER Rate to be filed with the Commission later in Year 2, and effective January 1 of Year 3.

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Date Filed: 10-01-15

By: Christopher B. Clark

Effective Date:

President, Northern States Power Company, a Minnesota corporation

Case No. PU-15-

Order Date: