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Fargo, ND 5802

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September 29, 2026

—Via Electronic Mail and UPS—

Brian Johnson, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

RE: 2027 RENEWABLE ENERGY RIDER (RER) RATE ADJUSTMENT
CASE NO. PU-26-____

Dear Mr. Johnson:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed original and seven copies of the 2027 Renewable Energy Rider (RER) rate adjustment application to the North Dakota Public Service Commission for approval the 2027 revenue requirement. We do not propose to include any new projects in 2027.

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

Please contact me at alex.j.nisbet@xcelenergy.com or Megan Spear at megan.spear@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

ALEX NISBET
REGULATORY POLICY SPECIALIST

Enclosures
cc: Victor Schock

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STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF
NORTHERN STATES POWER COMPANY
FOR APPROVAL OF A 2027 RENEWABLE
ENERGY RIDER RATE

CASE NO. PU-26-____

APPLICATION

I. 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 2027 revenue requirements associated with the Company's eligible renewable energy projects. In this filing, we propose to continue recovering the costs of two previously approved projects.

The proposed 2027 RER rate is calculated to recover approximately \$0.5 million in 2027 revenue requirements. This is a decrease of approximately \$4.7 million compared to the 2026 revenue requirements approved in last year's RER proceeding.

The Company proposes a 2027 RER rate of \$0.000246 per kWh, to be effective on January 1, 2027. If approved, the rate will be applied to all energy billed to each customer class during calendar year 2027. For a typical residential non-heating electric customer using 750 kWh per month, the proposed rate would result in a monthly RER charge of approximately \$0.18, a decrease of about \$1.65 per month compared to the rate implemented on January 1, 2026.

In the Company's recently concluded electric rate case, Case No. PU-24-376, the Commission approved the continued recovery of the Pleasant Valley Repower and Border Winds Repower projects through the RER. The Commission also approved moving to base rates the projects that were placed in-service as of December 31, 2024, and were being recovered through the RER when the Company filed its rate case: Freeborn, Dakota Range, Nobles Repower, and Grand Meadow Repower.

In addition, the November 2025 Settlement Agreement, as approved by the Commission's February 5, 2026 Order in the rate case (2025 Settlement), authorizes the Company to recover the actual costs of Pleasant Valley and Border Winds projects through the RER, as discussed in more detail below. The Commission also approved

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an updated production tax credit (PTC) forecast level to be included in base rates, which affects the PTC true-up through the RER.

II. FILING INFORMATION

Pursuant to Section 69-02-02-04 of the North Dakota Administrative Code, the following information is provided:

A. Contact information for utility making the filing

Alex Nisbet
Regulatory Policy Specialist
Xcel Energy
2302 Great Northern Drive
PO Box 2747
Fargo, ND 58102-2747
(701) 241-8632
alex.j.nisbet@xcelenergy.com

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

Victor Barreiro
Regulatory Administrator
MN1180-07-MCA
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

B. Date of filing and proposed effective date

The date of this filing is September 29, 2026.

C. Statutory Authority

N.D.C.C. Sections 49-02, 49-05, and 49-06 authorize the Commission to approve rate recovery of the North Dakota jurisdictional portion of investments and expenses related to new or modified renewable energy facilities. N.D.C.C. Section 49-05-16 provides a rebuttable presumption that generation resources located in North Dakota are prudent.

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D. Articles of Incorporation

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

III. BACKGROUND

The RER tariff was approved by the Commission in its February 26, 2014 Order adopting the *Revised Second Amended Settlement Agreement* in Case No. PU-12-813. The Commission has approved the Company's subsequent RER rates as summarized in Table 1 below, which also shows the proposed 2027 RER rate for comparison.

Table 1
Historical and Proposed RER Rates

Test Year	Case No.	Revenue Requirement	MWh Sales	Rate ¹ (per kWh)	Avg. Res'l Mo. Charge
2016	PU-15-683	\$2,161,014	2,309,683	\$0.000936	\$0.70
2017	PU-16-687	\$2,026,203	2,255,537	\$0.000898	\$0.67
2018	PU-17-364	\$643,655	2,261,208	\$0.000285	\$0.21
2019	PU-18-368	\$2,104,840	2,233,684	\$0.001191	\$0.89
2020	PU-19-329	\$8,799,731	2,233,428	\$0.004566	\$3.42
Jan-Sept. 2021	PU-20-426	\$13,327,289	2,136,486	\$0.006238	\$4.68
Oct-Dec. 2021	PU-20-441	\$1,701,718	2,136,486	\$0.000797	\$0.60
2022	PU-21-389	\$3,971,059	2,139,862	\$0.001856	\$1.39
2023	PU-22-368	\$5,237,041	2,154,594	\$0.002557	\$1.92
2024	PU-23-312	\$4,506,236	2,185,499	\$0.002062	\$1.55
2025	PU-24-341	\$4,361,703	2,135,948	\$0.002042	\$1.53
Jan-June 2026	PU-25-248	\$5,210,625	2,137,960	\$0.002437	\$1.83
July-Dec 2026	PU-24-376	\$2,241,654	2,137,960	\$0.001049	\$0.79
Proposed					
2027	PU-26-____	\$523,218	2,128,617	\$0.000246	\$0.18

As approved in Case No. PU-12-813, the Company is permitted to recover costs associated with Company-owned renewable energy projects, including depreciation expense, property taxes, and operation and maintenance expenses as well as capacity-related renewable energy purchased power costs that are not recovered through base rates or eligible for recovery through the Fuel Cost Rider (FCR). The Commission's Order in that case limited recovery through the RER to renewable projects located in

¹ This table shows the annual revenue requirement and projected sales for each year, though we note that for some years we recalculated the rate to adjust for an implementation date later than January 1.

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North Dakota that have received an Advance Determination of Prudence (ADP). Eligible projects must also be in service when costs are recovered through the RER.

Subsequently, the Tax Cuts and Jobs Act (TCJA) Settlement² expanded eligibility under the RER to include certain wind facilities located outside North Dakota. As a result, the proposed 2027 RER rate includes costs associated with one project located outside North Dakota.

IV. PROPOSED COSTS TO BE RECOVERED IN 2027

For 2027, we propose to continue recovering the costs of two previously approved wind projects through the RER. Four projects that were previously recovered through the RER are now recovered through base rates, and the Company is not proposing recovery of any new projects through the rider.

Attachment 3 provides the forecasted capital expenditure for each project, and Attachment 10 provides the forecasted O&M expenses for each project.

A. Renewable Generation Projects Previously Approved for RER Recovery

The projects included in the 2027 revenue requirement calculation were approved for recovery through the RER in the following prior dockets:

- Pleasant Valley Repower and Border Winds Repower: Case No. PU-24-341.

A year-over-year comparison to the Company's prior RER filing shows an increased aggregate portfolio cost for the Pleasant Valley and Border Winds Repower projects of approximately \$10 million. This increase is primarily attributable to unforeseen schedule delays, vendor and supply chain delays, weather-related constraints, turbine-specific repair work, and federal tariff impacts.

The largest contributor to the cost increase was an extended project schedule resulting from manufacturing and delivery delays experienced by Vestas. Vestas encountered challenges producing and delivering specialized turbine components, including turbine blades that were not delivered until October 2025, near the end of the construction season. As winter conditions began limiting available construction windows, these delays affected project completion timelines. Because these specialized components were not readily available from alternative suppliers, the Company had limited ability to mitigate the resulting schedule impacts.

² *Northern States Power Company Tax Reform Effects – Electric Utility Rates*, ORDER ON SETTLEMENT, Case No. PU-18-155 (February 6, 2019).

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Although the projects were placed in service in December 2025, certain closeout and completion activities remain scheduled for 2026 because they could not reasonably be completed before year-end. For wind generation projects, trailing expenditures commonly occur after a project is placed in service, particularly when the in-service date falls later in the year and winter weather restricts remaining work. Final cost true-ups also commonly occur following a late-December in-service date.

Additional work remains necessary on two turbines at Border Winds. One turbine experienced a fire on July 4, 2025, requiring specialized repairs and the use of a crane that is not widely available. A second turbine required deconstruction following a separate incident. Following a series of delays, the primary crane components needed to complete these repairs began arriving on site in July 2026. The Company currently expects the remaining turbine-related work to be completed by late fall 2026.

The Company has also experienced vendor-related challenges with Vestas that have delayed project closeout activities beyond what it has experienced on prior wind projects. The Company continues to work with Vestas and our internal supply chain organization to support timely completion and closeout of both projects.

The Company has taken reasonable steps to mitigate cost impacts where possible, including sourcing available parts internally and negotiating change orders to reduce incremental costs. Vestas also provided certain concessions that offset a portion of the overall cost increase. Despite these mitigation efforts, the projects experienced increased material costs attributable to federal tariffs.

Accordingly, the cost increase of approximately \$10 million reflects the cumulative effect of these project-specific circumstances rather than any change in the scope or need for the repower projects. The Company continues to manage the remaining completion activities, pursue project closeout, and mitigate additional costs to the extent practicable.

Consistent with the 2025 Settlement, the Company proposes to continue recovering these costs through the RER. The resulting impacts on total portfolio costs are discussed below.

The following projects were previously approved for recovery through the RER but are now recovered through base rates. As discussed below, the Company provides final true-up amounts for these projects in this filing:

- Freeborn Wind: Case No. PU-19-329;
- Dakota Range: Case No. PU-20-426; and

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- Nobles Wind Repower and Grand Meadow Wind Repower: Case No. PU-22-368.

B. Self-Build Wind Project Portfolio

The *Second Settlement Agreement* resolving Case Nos. PU-17-120 and PU-17-372 specified an aggregate cost cap of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for the Company's five Self-Build wind projects.³ The cap was subsequently adjusted to reflect the impacts of the TCJA and is detailed in Table 1 of the *Joint Stipulation of Capital Expenditure Costs* attached to the *Second Settlement Agreement*, which the Commission approved.

As shown in Attachment 9, our capital forecast included in this filing shows the Self-Build projects were completed at a cost approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** over the cost cap. In the Company's 2026 RER filing, the above-cap amount was excluded from rider recovery pending a prudence determination and cost recovery request in the Company's general rate case.

In the Company's recently concluded rate case, Case No. PU-24-376, the Company requested recovery of the costs incurred above the Self-Build Portfolio cost cap, and the Commission approved that request. These projects' costs, including the amount above the cap, are recovered through base rates effective May 1, 2026, when final rates took effect.

C. Aggregate Cost Cap – Wind Repower Portfolio

The September 23, 2021 *Settlement Agreement* resolving Case Nos. PU-20-425 and PU-21-93 stipulated an aggregate capital expenditure cap for the Border Winds, Grand Meadow, Nobles, and Pleasant Valley Wind Repower projects. Under the Settlement, the projects were deemed prudent up to the budgeted capital expenditure amount identified in Table 1 of the *Joint Stipulation of Capital Expenditure Costs* attached to the Settlement. The aggregate amount identified in the Joint Stipulation⁴ is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

As shown in Attachment 9, our capital forecast included in the Company's last RER proceeding showed the Repower projects would be completed approximately

³ Foxtail, Blazing Star I, Blazing Star II, Freeborn, and Dakota Range.

⁴ Table 1 of the Joint Stipulation of Capital Expenditure Costs attached to the Settlement includes an aggregate amount that does not accurately reflect the true sum of each wind farm's individual cap. The total amount in the Joint Stipulation is approximately \$2 million lower than the true cap amount. We have therefore adjusted the total amount in this filing accordingly.

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over the cap. As explained above, the Pleasant Valley and Border Winds projects are forecasted to incur an additional \$10 million in 2026.

The 2025 Settlement permits the Company to recover the actual costs of the Border Winds and Pleasant Valley projects through the RER. The Settlement acknowledges that, while some repower projects were completed below budget and others exceeded budget, the portfolio as a whole exceeded the aggregate cap established in Docket No. PU-20-425.

The Parties further agreed that the Company sufficiently demonstrated that, notwithstanding any portfolio-basis cost overages, the repower projects will continue to provide substantial customer benefits consistent with the basis on which the Commission initially granted an Advanced Determination of Prudence. Accordingly, the Parties agreed that the Company may recover the actual costs of the Border Winds and Pleasant Valley projects through the RER.

The actual and forecasted project costs are reflected in Attachments 3 and 9.

D. RER and Rate Case Impacts and Considerations

The approval of the Company's 2025 Settlement necessitated an update to the RER rate since the recovery of several projects included in the RER moved from the rider to base rates. However, the corresponding tariff was inadvertently omitted from our Final Rates compliance filing, and the new rider rate was not implemented on May 1, 2026 with final rates. The Company filed a Supplement to update the tariff and the rider rate became effective July 1, 2026.⁵ The delay in updating the rider rate resulted in overcollections for the months of May and June which contribute to the 2026 credit balance of the RER tracker, as shown on Attachment 2. The overcollection reduces the rider rates for customers in 2027.

⁵ Supplemental Compliance Filing – Final Rates & Interim Refund Rider Tariffs, Case No. PU-24-376 (June 11, 2026).

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V. ALLOCATIONS AND ACCOUNTING

A. Jurisdictional Energy and Demand Allocators

The revenue requirements included in the RER tracker are only those related to North Dakota's share of the energy facilities and their associated costs. NSPM and Northern States Power Company-Wisconsin (NSPW), together referred to as the NSP Companies, operate as 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). The Interchange Agreement is a Commission-approved formula rate that provides for charges to flow 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 sharing of NSP System production and transmission costs on a load ratio share basis considering the integrated nature of the NSP System. The charges between the companies are intended to ensure that these costs are shared based on each company's proportionate use of the system. 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 (CP) demand allocator. All variable production costs are shared between the NSP Companies based on energy. As a result, approximately 84 percent of all production and transmission costs incurred by both NSPM and NSPW support customers of NSPM while approximately 16 percent support NSPW customers.

NSPM serves customers in North Dakota, South Dakota, and Minnesota. Under the jurisdictional allocation methodology approved by the three state commissions, NSPM's fixed production and all transmission costs (approximately 84 percent of total NSP System costs) are allocated among the three jurisdictions based on load ratio share using the 12-month CP jurisdictional demand allocator. Variable production costs, including wind production investments, are allocated based on energy.

Based on these demand and energy allocators, approximately 6.3 percent of NSPM's 2027 production and transmission costs are allocated to the North Dakota jurisdiction. On an NSP System basis, this represents approximately 5.3 percent (i.e., 84 percent multiplied by 6.3 percent) of total 2027 costs allocated to support North Dakota customers.

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The 2027 revenue requirements forecast is allocated to the North Dakota jurisdiction based on the 2027 jurisdictional demand and energy allocators, respectively. The sales and demand data used to calculate these allocators are based on the same forecast period used to estimate customer billings and rider collections.

Consistent with the cost-allocation methodology described above, total revenue requirements were allocated to:

- Allocate the appropriate share of the total NSP System 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 customer base.⁶

Any over- or under-recovery resulting from the use of forecast data in 2027 will be trued-up to actual jurisdictional revenue requirements through the calculation of the 2028 RER rate.

Table 2 below shows the cost category, allocation method, and allocator used to assign 2027 forecasted costs to the North Dakota jurisdiction. The derivation of the individual allocators is shown in Attachment 5.

Table 2
2027 RER Allocators

Cost Category	Allocation Method	2027 ND Allocator
Wind Investment-related costs, Property Taxes	Composite Energy & Demand	5.3071%
Transmission-related costs, Fixed Production O&M	Composite Demand	4.9576%
PTCs, Variable Production O&M	Composite Energy	5.2276%

By performing this cost allocation process, we ensure that electric customers in each jurisdiction are allocated the appropriate share of each project's revenue requirements, consistent with the Company's allocation of similar costs in general rate cases.

⁶ NSPM currently does not have any full requirements wholesale customers on the NSP system.

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B. Taxes

The RER rate includes current and deferred taxes as well as property taxes on both wind and transmission facilities. In addition, the revenue requirements are offset by PTCs, North Dakota Investment Tax Credits (NDITCs), and Accumulated Deferred Income Taxes (ADIT) as further described below.

1. Property Taxes

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 the other based on energy production. We have applied the formula specific to the capacity and estimated wind generation for the projects included in the rider and include the resulting amounts in our revenue requirement 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 Rider (TCR). 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 payable property taxes to each state's taxable investment as valued at the end of the prior year.

2. Revenue Requirements Offsets

a. PTCs

PTC benefits are based on actual and expected energy production. We have calculated the PTCs using the levelized methodology approved by the Commission in a previous RER proceeding and in the Company's last electric rate case.⁷ The monthly levelized credit amount offsets the revenue requirement.

Under the levelized method, the Company forecasts the total PTCs that would be generated during a resource's first ten years of operation, allocates the appropriate amount to the ND jurisdiction, divides this amount by the resource's expected life, and assigns the quotient as a credit to each year of the resource's life. The 2025 actual PTCs are trued-up through the RER tracker based on the levelized forecast of PTCs

⁷ Case No. PU-24-376.

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included in the Company's 2025 electric rate case test year based on estimated generation for calendar year 2025. For wind projects included in base rates prior to the Company's 2025 electric rate case test year, forecasted levelized PTCs will be trued-up through the RER tracker based on the reestablished levelized forecast included in Case No. PU-24-376, beginning January 1, 2025. For the four wind projects that moved to base rates upon implementation of final rates,⁸ as well as the two wind projects remaining in the RER, the full levelized PTC for 2025 will be returned to customers through the RER. Beginning May 1, 2026, when the four wind projects moved to base rates, forecasted levelized PTCs are trued-up through the RER tracker based on the levelized forecast included in Case No. PU-24-376.

In this RER proceeding, the levelized forecasted PTC value included in base rates for each wind facility is trued up against actual production in 2025. The remaining years of levelized PTCs for each facility have been recalculated using 2025 actual production. This means the number of PTCs generated above the forecasted level, or conversely, the number of PTCs below the forecasted level, are being passed through to customers evenly over the remaining life of the project through the RER to maintain generational equity. This true-up occurs for all wind projects with production forecasted during 2026 whether the project is being recovered through base rates or through the RER. Attachment 8 shows the currently projected flow back of all the ND PTCs to customers over the life of each wind facility, showing both the amounts in base rates and the RER.

Due to the variability of wind production, we will continue to true-up the PTCs for these projects in future RER petitions, even after the project costs have been incorporated into base rates, as approved in the 2025 Settlement.

Annually, the Internal Revenue Service (IRS) releases inflation adjustment factors for PTC rates. The IRS issued guidance for a 2025 PTC rate of \$30 per MWh for wind farms placed in service prior to 2021 and a PTC rate of \$30 per MWh for wind farms placed in service after 2021. The IRS released 2026 rates which increased the PTC rate to \$31 per MWh for wind farms placed in service prior to 2021. The PTC rate for wind farms placed in service after 2021 remained at \$30 per MWh. As noted in the previous RER petition, the Pleasant Valley Repower and Border Winds Repower projects qualify for an additional 10 percent per MWh for meeting domestic content requirements by satisfying the safe harbor requirements outlined by the IRS. These rates are reflected in the RER tracker (and Attachment 8). The 2026 rate is used for 2026 and the remaining forecast periods. We will update the credit for future years if the IRS updates the value or changes are made to the law that redefine the credit. The actual PTC benefits will continue to be trued-up through the RER tracker and

⁸ Freeborn, Dakota Range, Nobles Repower, and Grand Meadow Repower

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updated in each annual filing. We discuss recent changes to federal law governing PTCs below.

b. Participation in the Tax Credit Market

The federal Inflation Reduction Act of 2022 (IRA) permits the Company to transfer or sell PTCs. Although these transactions result in upfront transaction costs, they also generate significant net customer benefits over time but result in an immediate cost in the form of transaction costs incurred by the Company. The Company expects the long-term benefits of transferring or selling PTCs to substantially outweigh the associated transaction costs over time.

We include a true-up of the value of the transferred credits to the actual sales amounts in the RER tracker in this Petition for 2025 and 2026 through June. For the second half of 2026 through 2027 we have included in the tracker a forecast of the value of likely sales or transfers based on our (and others') experience in the transfer market thus far. This forecast will be trued up in subsequent RER proceedings based on the results of actual transfers. This process encourages the Company to maximize the value of tax credits for customers, while allowing us to recover our actual costs for participating in the tax credit market.

The transfer or sale of PTCs also helps avoid the continued buildup of the deferred tax asset (DTA), which will result in lower future rates for customers. Because the DTA is part of rate base and adjusted in base rate case filings, reducing the DTA lowers the total revenue requirement ultimately recovered from customers through base rates. The Company expects the long-term customer savings associated with avoiding additional DTA buildup exceed the annual transaction costs associated with PTC sales and transfers. However, those savings may not exceed annual transaction costs in the initial years.

See Attachment 8 for the PTC tracker.

c. North Dakota Investment Tax Credits (NDITCs)

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. The tax credits we receive for the Border Winds project have more than offset our North Dakota income tax liability, leaving no additional North Dakota income tax liability against which to apply the tax credits to other eligible projects.

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In the Company's 2025 test year, the forecast NDITC was removed as part of the RER Rider Removal, with the intention that all benefits from the utilized NDITC would be returned to customers in the RER Rider going forward. We have included actual 2025 NDITCs and a forecast for 2026 and 2027. The Company will true-up the forecasted NDITCs in our future annual RER filings to ensure that customers receive the actual benefit. Attachment 2 provides the actual NDITC amounts received in 2025 and the forecasted amounts through 2027.

d. South Dakota Reinvestment Payment Program Grant

In 2017, the Company applied for a Reinvestment Payment Program grant from the State of South Dakota for the construction of the Dakota Range wind project. In 2018, the Company accepted the grant award offer. The grants are an economic development tool South Dakota offers to induce investment within the state. The grant is administered as a rebate of sales/use tax paid during construction. At the end of the project, the Company was able to aggregate all the sales/use tax that the Company and its contractors have paid on construction of the project and request the rebate from the State. The rebate is capped at the lesser of 65 percent of the sales/use tax paid or \$8,187,266. The Company received a rebate in 2022 of approximately \$6.6 million. This grant amount offsets the total capital expenditure for the project and has been reflected in the total capital expenditures shown in Attachment 3.

e. Accumulated Deferred Income Taxes (ADIT)

The Company continues to calculate the plant-related ADIT offset to rate base in accordance with the proration formula in IRS regulation section 1.167(1)-1(h)(6).

3. *Recent Federal Actions Updating Tax Treatment*

On July 4, 2025, the "One Big, Beautiful Bill" (OB BB) Act was signed into law. As relevant to the Company's current RER calculations, the legislation makes no retroactive changes to the tax credits available to renewable energy projects that began construction before September 1, 2025. Accordingly, all projects currently recovered through base rates and the RER remain eligible to earn PTCs as discussed above. In addition, the legislation preserves the transferability of energy tax credits.

On July 7, 2025, an Executive Order was directed the U.S. Department of the Treasury to provide further guidance for PTCs and ITCs for wind and solar projects. In response, the U.S. Treasury issued Notice 2025-42 on August 15, 2025. The Notice applies only to projects that began construction after September 1, 2025. The

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Company has not sought Commission approval of any wind or solar projects with construction starting after that date.

C. Capital Structure

The Company has calculated the 2027 revenue requirements consistent with the 2025 Settlement. The approved capital structure, included on page 3 of the Settlement Agreement, was used in the calculation. See Attachment 5 of this application for detailed inputs.

D. Depreciation

The Company is using a depreciable life assumption of 25 years for the wind projects recovered through this rider, consistent with their expected life based on manufacturing warranties, lease terms, or engineering estimates. If the Commission approves a different remaining life for any project in a future order, the Company will incorporate that change in future rider filings.

E. Operation and Maintenance Expense

As allowed under the enabling statute, the proposed RER rate includes projected O&M expenses for the wind projects, including Company labor and related labor costs, consulting services, contractor costs, maintenance services, landowner payments, space costs, and avian monitoring costs. We believe these expenses are reasonable and are necessary to operate and maintain these wind production facilities.

F. Transmission Costs

We include in the overall revenue requirement costs payable to transmission owners for the network upgrades and modifications necessary to interconnect the projects to the transmission system. These upgrades are required to enable the new generation resources to be injected into and delivered across the transmission grid. The associated costs are shown in Attachment 2.

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G. RER True-Up

To ensure that customers are not under- or over-charged, we record the net actual RER revenues and qualifying project revenue requirements and perform an annual true-up in the RER filing for eligible RER facilities costs. Any differences reflected in the estimated end-of-year true-up balance for the current year will be returned to or collected from customers in the subsequent RER rate. The annual true-up summary is provided as Attachment 2 to this filing.

Each month, as RER revenues are collected from retail customers, the Company compares that amount with the monthly actual qualifying renewable energy project revenue requirements (including appropriate overall return, income taxes, property taxes, and depreciation). The difference is reflected as the amount of over- or under-recovery. 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. Attachment 6 shows the detailed revenue requirements by project. Any over- or under-recovery balance at the end of the year is reflected in the calculation of the RER rate for the next year's forecasted revenue requirement.

VI. RER RATE COMPUTATION

A. Rate

The RER rate is calculated by dividing the annual projected revenue requirements by the forecasted energy sales to North Dakota electric retail customers from January through December 2027. The sales forecast is provided as Attachment 4. The rate is rounded to the nearest \$0.000001 per kWh. Based on this calculation, the 2027 RER rate is a decrease from the RER rate approved in our last RER proceeding:

Table 3
2027 RER Rate Calculation

	Retail
ND Retail Revenue Requirements <i>2027</i>	\$523,218
ND Retail Sales (kWh) <i>Jan.-Dec. 2027</i>	2,128,616,706
2027 RER Rate Cost per kWh	\$0.000246

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The proposed 2027 RER rate will result in a monthly charge of approximately \$0.18 for the typical non-heating residential customer using 750 kWh per month. This represents a decrease of approximately \$1.65 per month compared to the RER rate approved in our last RER proceeding and implemented on January 1, 2026. The detailed rate calculations are provided in Attachment 1.

B. Tariff Modifications

We have modified the tariff to show the proposed 2027 RER rate. See Attachment 11.

VII. CUSTOMER NOTICES

To ensure compliance with the customer information provisions of Section 69-09-02-02.1 of the North Dakota Administrative Code, the Company's North Dakota customers will see on their November bills the following notices of the proposed change in the RER rate, depending on customer class:

A. Residential⁹

The residential customer notice assumes an approximate usage of 750 kWh per month for non-space heating customers and 1,000 kWh per month for space heating customers.

Xcel Energy recently filed a request with the North Dakota Public Service Commission to decrease the Renewable Energy Rider rate from \$0.002437 to \$0.000246 per kWh. If approved by the Commission, you can expect an average monthly bill decrease of about \$1.65 (non-space heating) and about \$2.19 (space heating). The proposed rate change would be effective Jan. 1, 2027.

B. Small Commercial¹⁰

The small commercial customer notice assumes an approximate usage of 1,500 kWh per month.

Xcel Energy recently filed a request with the North Dakota Public Service Commission to decrease the Renewable Energy Rider rate from \$0.002437 to \$0.000246 per kWh. If approved by the Commission, you can expect an average monthly bill decrease of about \$3.29. The proposed rate change would be effective Jan. 1, 2027.

⁹ Rate Codes: D01, D02, D03, D04

¹⁰ Rate Codes: D12, D13, D14, D18, D19, D40

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

C. Large Commercial¹¹

The large commercial customer notice assumes an approximate usage of 40,000 kWh per month.

Xcel Energy recently filed a request with the North Dakota Public Service Commission to decrease the Renewable Energy Rider rate from \$0.002437 to \$0.000246 per kWh. If approved by the Commission, you can expect an average monthly bill decrease of about \$87.65. The proposed rate change would be effective Jan. 1, 2027.

Following approval of the RER rate by the Commission, the Company will provide customers notice of the rate change through a bill onsert comparing the impact of the prior RER rate to the impact of the newly approved RER rate. Attachment 12 shows our proposed customer notice, which will be distributed with customer bills the month the new RER rate factor is implemented, or as soon as practicable thereafter.

The Company commits to working collaboratively with Commission Staff if there are any suggested modifications to these customer notifications.

IX. CONCLUSION

The proposed 2027 RER rate is designed to recover the revenue requirements for qualifying investments in renewable energy facilities that are not presently reflected in our general rate schedules. Xcel Energy respectfully requests that the Commission approve the proposed RER revenue requirement for 2027.

Dated: September 29, 2026

Northern States Power Company

¹¹ Rate Codes: D16, D17, D20, D21, D22, D41

Renewable Energy Rider (RER) Application Attachments Table of Contents

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9. CWIP Cap
10. O&M Expenditure Forecast
11. Tariff
12. Customer Notice

Line No

2027 Rate Calculation**Northern States Power Company****North Dakota Renewable Energy Rider (RER)**

Projected 2027 effective January 1, 2027

DescriptionAll Classes

North Dakota Net Annual Cost ⁽¹⁾	\$ 523,218	From Line 51 of Attachment 2
Forecasted North Dakota kWh ⁽²⁾	2,128,616,706	From Line 25 of Attachment 4
Total Factor / kWh	\$ 0.000246	(Line 6 / Line 7)
Residential bill impact / Month ⁽³⁾	\$ 0.18	Line 8 * 750 kWh

Notes:

- (1) Annual cost includes true-up adjustment to Tracker Account for the previous year's over- or under-recovery. Please see line 4 of Attachment 2 for details.
- (2) Reflects calendar month sales. See Attachment 4 for detail.
- (3) Assumes 750 kWh per month.

Northern States Power Company**North Dakota Renewable Energy Rider (RER)**

2026 Approved Rate (effective July 1, 2026)

DescriptionAll Classes

North Dakota Net Annual Cost ⁽¹⁾	\$ 2,241,654
Forecasted North Dakota kWh ⁽²⁾	2,137,960,607
Total Factor / kWh	\$ 0.001049
Residential bill impact / Month ⁽³⁾	\$ 0.79

Notes:

- (1) Annual cost includes true-up adjustment to Tracker Account for the previous year's over- or under-recovery. Please see line 4 of Attachment 2 for details.
- (2) Reflects calendar month sales. See line 23 of Attachment 4 for detail.
- (3) Assumes 750 kWh per month.

Northern States Power Company**North Dakota Renewable Energy Rider (RER)**

2026 Approved Rate (effective January 1, 2026 - June 30, 2026)

DescriptionAll Classes

North Dakota Net Annual Cost (1)	\$ 5,210,625
Forecasted North Dakota kWh (2)	2,137,960,607
Total Factor / kWh	\$ 0.002437
Residential bill impact / Month ⁽³⁾	\$ 1.83

Notes:

- (1) Annual cost includes true-up adjustment to Tracker Account for the previous year's over- or under-recovery.
- (2) Reflects calendar month sales.
- (3) Assumes 750 kWh per month.

Line No:	Annual Tracker Summary			
	Amounts in dollars	2025	2026	2027
1				
2				
3	Carryover Balance	420,297	(426,141)	(872,660)
4				
5	Freeborn Capital	1,873,899	593,281	-
6	PTCs	(583,723)	(266,033)	(88,447)
7	O&M	314,878	95,988	-
8	Transmission (Interconnect) Costs	22,436	7,385	-
9	Property Taxes	50,736	17,362	-
10	Total Freeborn Costs	1,678,225	447,983	(88,447)
11				
12	Dakota Range Capital	1,992,193	647,442	-
13	PTCs	(807,157)	(282,693)	(34,427)
14	O&M	176,789	100,494	-
15	Transmission (Interconnect) Costs	53,622	17,706	-
16	Property Taxes	73,043	24,735	-
17	Total Dakota Range Costs	1,488,490	507,684	(34,427)
18				
19	Nobles Re-Power Capital	1,407,198	457,680	-
20	PTCs	(667,586)	(277,539)	(89,343)
21	Total Nobles Re-power Costs	739,612	180,141	(89,343)
22				
23	Grand Meadows Re-Power Capital	815,991	255,818	-
24	PTCs	(339,900)	(120,634)	(17,200)
25	Total Grand Meadows Re-power Costs	476,091	135,184	(17,200)
26				
27	Borders Re-power Capital	110,747	1,534,556	1,409,205
28	PTCs (net)	(43,977)	(555,042)	(555,042)
29	Total Borders Re-power Capital Costs	66,769	979,514	854,163
30				
31	Pleasant Valley Re-power Capital	139,868	1,965,380	1,736,148
32	PTCs (net)	(57,912)	(722,115)	(722,115)
33	Total Pleasant Valley Re-power Costs	81,956	1,243,265	1,014,033
34				
35	Borders ITC	(15,307)	-	(11,123)
36				
37	Borders PTC Levelization True-Up	11,625	11,321	11,321
38	Courtenay PTC Levelization True-Up	27,179	84,627	84,627
39	Blazing Star I PTC Levelization True-Up	(57,353)	(80,147)	(80,147)
40	Foxtail PTC Levelization True-Up	(36,495)	(47,674)	(47,674)
41	Crowned Ridge PTC Levelization True-Up	(43,061)	(35,793)	(35,793)
42	Lake Benton PTC Levelization True-Up	(23,850)	(42,528)	(42,528)
43	Blazing Star II PTC Levelization True-Up	(54,307)	(74,245)	(74,245)
44	Mower PTC Levelization True-Up	(21,232)	(47,339)	(47,339)
45	Total PTC Levelization True-Up Costs	(197,494)	(231,777)	(231,777)
46				
47	Pleasant Valley PTC True-Up	(878,447)	-	-
48				
49	Subtotal Calendar Year Rev. Req.	3,439,896	3,261,994	1,395,878
50				
51	Revenue Requirement (w/carryover)	3,860,194	2,835,853	523,218
52	Revenue Collections	4,286,335	3,708,513	523,640
53	Balance	(426,141)	(872,660)	(422)

North Dakota Calendar Month Electric Sales (MWh)
2027 Budget

Line No	North Dakota Calendar Month Electric Sales (MWh) 2027 Budget											Rate Revenues	
	Residential w/o Sp Heat	Residential w/ Sp Heat	Total Residential	Small C&I	Large C&I	Total C&I	Street Lighting	Public Authority	Interdept	Total Other	Total Retail	Rate	Revenues
Monthly													
1	2026-07	49,172	13,976	63,149	84,260	35,259	119,518	715	1,389	-	2,104	184,771	0.001049193,825
2	2026-08	48,137	13,083	61,220	81,319	31,851	113,170	764	1,432	-	2,196	176,586	0.001049185,239
3	2026-09	41,527	11,998	53,525	82,554	34,243	116,797	1,026	854	-	1,881	172,202	0.001049180,640
4	2026-10	36,805	12,927	49,732	78,913	31,299	110,212	1,140	950	-	2,090	162,034	0.001049169,974
5	2026-11	31,595	16,064	47,660	61,634	27,844	89,478	838	930	-	1,768	138,906	0.001049145,712
6	2026-12	49,974	32,971	82,945	97,160	34,674	131,834	1,970	975	-	2,946	217,725	0.001049228,393
7	2026 Total	257,210	101,019	358,230	485,840	195,170	681,010	6,455	6,530	-	12,984	1,052,224	0.0010491,103,783
8													
9													
10													
11													
12													
13	2027-01	47,956	34,825	82,781	80,269	25,963	106,232	1,121	1,226	-	2,347	191,360	0.00024647,075
14	2027-02	46,951	35,397	82,348	86,073	28,963	115,036	1,075	852	-	1,927	199,310	0.00024649,030
15	2027-03	50,546	34,392	84,938	93,842	33,060	126,903	941	953	-	1,894	213,735	0.00024652,579
16	2027-04	39,500	22,783	62,283	75,130	28,175	103,306	851	1,150	-	2,001	167,590	0.00024641,227
17	2027-05	31,407	14,097	45,504	65,735	28,939	94,674	778	1,164	-	1,942	142,120	0.00024634,962
18	2027-06	40,099	12,646	52,745	78,202	32,395	110,598	746	1,216	-	1,962	165,305	0.00024640,665
19	2027-07	46,289	13,276	59,565	80,127	34,278	114,405	715	1,389	-	2,104	176,074	0.00024643,314
20	2027-08	50,173	13,498	63,670	85,625	33,260	118,885	764	1,432	-	2,196	184,751	0.00024645,449
21	2027-09	40,986	11,794	52,780	80,141	34,467	114,608	1,026	854	-	1,881	169,269	0.00024641,640
22	2027-10	34,564	12,098	46,662	73,826	30,306	104,132	1,140	950	-	2,090	152,884	0.00024637,609
23	2027-11	33,359	17,947	51,305	70,254	29,297	99,551	838	930	-	1,768	152,624	0.00024637,546
24	2027-12	49,498	33,033	82,531	93,457	34,659	128,116	1,970	975	-	2,946	213,593	0.00024652,544
25	2027 Total	511,327	255,787	767,114	962,683	373,763	1,336,445	11,967	13,090	-	25,057	2,128,617	0.000246523,640

Key Inputs

Line No		2025			2026			2027		
		*ND PU-24-376 Approved Cap Structure			*ND PU-24-376 Approved Cap Structure			*ND PU-24-376 Approved Cap Structure		
	Capital Structure	Cost	Ratio	WACC	Cost	Ratio	WACC	Cost	Ratio	WACC
2	Long Term Debt	4.51%	46.71%	2.11%	4.51%	46.71%	2.11%	4.51%	46.71%	2.11%
3	Short Term Debt	5.31%	0.79%	0.04%	5.31%	0.79%	0.04%	5.31%	0.79%	0.04%
4	Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	Common Equity	9.80%	52.50%	5.15%	9.80%	52.50%	5.15%	9.80%	52.50%	5.15%
6	Required Rate of Return			7.30%			7.30%			7.30%
8	Income Tax Rates									
9	Federal Tax Rate			21.00%			21.00%			21.00%
10	State Tax Rate			4.31%			4.31%			4.31%
11	State Composite Income Tax Rate			24.40%			24.40%			24.40%
12	Company Composite Income Tax Rate			28.08%			28.08%			28.08%
14	Allocators									
15	ND 12-month CP Energy (Electric Energy)			6.3973%			6.4629%			6.3177%
16	NSPM 36-month CP Demand (Interchange Electric)			84.0693%			84.0636%			84.0043%
17	Wind Jurisdictional Allocator			5.3782%			5.4329%			5.3071%
19	ND 12-month CP Demand (Electric Demand)			6.0894%			6.0303%			5.9016%
20	NSPM 36-month CP Demand (Interchange Electric)			84.0693%			84.0636%			84.0043%
21	Transmission Jurisdictional Allocator			5.1193%			5.0693%			4.9576%
23	ND 12-month CP Energy (Electric Energy)			6.3973%			6.4629%			6.3177%
24	NSPM 36-month CP Energy (Interchange Electric)			82.9432%			82.5492%			82.7454%
25	PTC Jurisdictional Allocator			5.3061%			5.3351%			5.2276%

Details Data

Project	Rider Components	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	2025
Blazing Star I	Production Tax Credit	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(1,080,878)
Blazing Star I	Total Revenue Requirement	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(1,080,878)
Blazing Star I	Rider Revenue Requirement	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(57,353)
Blazing Star II	Production Tax Credit	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(1,023,484)
Blazing Star II	Total Revenue Requirement	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(1,023,484)
Blazing Star II	Rider Revenue Requirement	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(54,307)
Border Winds	Production Tax Credit	18,257	18,257	18,257	18,257	18,257	18,257	18,257	18,257	18,257	18,257	18,257	18,257	219,082
Border Winds	Income Tax Credit	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(284,611)
Border Winds	Total Revenue Requirement	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(65,529)
Border Winds	Rider Revenue Requirement	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(3,682)
Borders Wind Re-Power	Plant In-Service													189,937,331
Borders Wind Re-Power	Depreciation Reserve													360,045
Borders Wind Re-Power	Accumulated Deferred Taxes	830,777	1,039,225	1,247,673	1,456,121	1,664,568	1,873,016	2,081,464	2,289,912	2,498,360	2,706,808	2,915,256	3,123,703	3,123,703
Borders Wind Re-Power	Average Rate Base	(726,553)	(935,001)	(1,143,449)	(1,351,897)	(1,560,344)	(1,768,792)	(1,977,240)	(2,185,688)	(2,394,136)	(2,602,584)	(2,811,032)	91,769,164	91,769,164
Borders Wind Re-Power	Tax Depreciation Expense	1,077,560	785,398	776,087	826,355	1,930,315	4,225,837	1,204,988	2,394,386	(4,299,302)	1,055,283	859,585	465,160	11,301,650
Borders Wind Re-Power	CPI-TAX INTEREST	153,580	162,033	162,754	164,216	196,801	322,742	439,450	497,969	573,567	622,532	646,888	338,664	4,281,197
Borders Wind Re-Power	Debt Return	(1,302)	(1,675)	(2,049)	(2,422)	(2,796)	(3,169)	(3,543)	(3,916)	(4,289)	(4,663)	(5,036)	164,420	129,560
Borders Wind Re-Power	Equity Return	(3,118)	(4,013)	(4,907)	(5,802)	(6,696)	(7,591)	(8,486)	(9,380)	(10,275)	(11,169)	(12,064)	393,843	310,341
Borders Wind Re-Power	Current Income Tax Requirement	(232,007)	(135,246)	(132,296)	(148,341)	(494,510)	(1,195,220)	(182,589)	(547,967)	1,637,120	(76,019)	(5,266)	269,840	(1,242,501)
Borders Wind Re-Power	Book Depreciation													360,045
Borders Wind Re-Power	Deferred Taxes	208,448	208,448	208,448	208,448	208,448	208,448	208,448	208,448	208,448	208,448	208,448	208,448	2,501,374
Borders Wind Re-Power	Property Tax Expense													
Borders Wind Re-Power	Operating Expenses													
Borders Wind Re-Power	Production Tax Credit													
Borders Wind Re-Power	Interconnect Costs													(828,804)
Borders Wind Re-Power	Total Revenue Requirement	(27,979)	67,514	69,196	51,883	(295,554)	(997,532)	13,831	(352,816)	1,831,004	116,596	186,081	567,791	1,230,015
Borders Wind Re-Power	Rider Revenue Requirement	(1,505)	3,631	3,721	2,790	(15,895)	(53,649)	744	(18,975)	98,475	6,271	10,008	31,153	66,769
Courtenay Wind	Production Tax Credit	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	512,223
Courtenay Wind	Total Revenue Requirement	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	512,223
Courtenay Wind	Rider Revenue Requirement	2,265	2,265	2,265	2,265	2,265	2,265	2,265	2,265	2,265	2,265	2,265	2,265	27,179
Crowned Ridge	Production Tax Credit	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(811,531)
Crowned Ridge	Total Revenue Requirement	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(811,531)
Crowned Ridge	Rider Revenue Requirement	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(43,061)
Dakota Range	Plant In-Service	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939
Dakota Range	Depreciation Reserve	44,737,471	45,964,340	47,191,210	48,418,079	49,644,949	50,871,818	52,098,688	53,325,557	54,552,427	55,779,296	57,006,166	58,233,035	58,233,035
Dakota Range	Accumulated Deferred Taxes	50,712,036	51,259,474	51,806,913	52,354,352	52,901,790	53,449,229	53,996,668	54,544,106	55,091,545	55,638,983	56,186,422	56,733,861	56,733,861
Dakota Range	Average Rate Base	243,806,587	242,032,278	240,257,970	238,483,662	236,709,354	234,935,046	233,160,738	231,386,430	229,612,121	227,837,813	226,063,505	224,289,197	224,289,197
Dakota Range	Tax Depreciation Expense	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	37,338,002
Dakota Range	CPI-TAX INTEREST													
Dakota Range	Debt Return	436,820	433,641	430,462	427,283	424,104	420,925	417,746	414,567	411,388	408,209	405,030	401,851	5,032,390
Dakota Range	Equity Return	1,046,337	1,038,722	1,031,107	1,023,492	1,015,878	1,008,263	1,000,648	993,033	985,419	977,804	970,189	962,574	12,053,466
Dakota Range	Current Income Tax Requirement	(93,899)	(96,357)	(98,816)	(101,274)	(103,732)	(106,191)	(108,649)	(111,107)	(113,565)	(116,024)	(118,482)	(120,940)	(1,289,036)
Dakota Range	Book Depreciation	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	14,722,434
Dakota Range	Deferred Taxes	547,439	547,439	547,439	547,439	547,439	547,439	547,439	547,439	547,439	547,439	547,439	547,439	6,569,264
Dakota Range	Property Tax Expense	113,179	113,179	113,179	113,179	113,179	113,179	113,179	113,179	113,179	113,179	113,179	113,179	1,358,145
Dakota Range	Operating Expenses	398,355	395,582	458,607	428,209	422,289	535,601	422,589	427,425	430,624	627,589	(1,301,990)	208,500	3,453,380
Dakota Range	Production Tax Credit	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(15,211,802)
Dakota Range	Interconnect Costs	87,264	87,264	87,264	87,264	87,264	87,264	87,320	87,320	87,320	87,320	87,320	87,320	1,047,445
Dakota Range	Total Revenue Requirement	2,494,713	2,478,688	2,528,461	2,484,812	2,465,639	2,565,640	2,439,492	2,431,076	2,421,023	2,604,735	661,905	2,159,142	27,735,325
Dakota Range	Rider Revenue Requirement	133,617	132,763	135,277	133,009	131,994	137,079	130,588	130,123	129,575	138,946	39,452	116,067	1,488,490
Foxtail	Production Tax Credit	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(687,785)
Foxtail	Total Revenue Requirement	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(687,785)
Foxtail	Rider Revenue Requirement	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(36,495)
Freeborn	Plant In-Service	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299
Freeborn	Depreciation Reserve	53,209,849	54,416,187	55,622,525	56,828,863	58,035,201	59,241,539	60,447,877	61,654,216	62,860,554	64,066,892	65,273,230	66,479,568	66,479,568
Freeborn	Accumulated Deferred Taxes	59,062,779	59,603,349	60,143,919	60,684,489	61,225,059	61,765,629	62,306,198	62,846,768	63,387,338	63,927,908	64,468,478	65,009,047	65,009,047
Freeborn	Average Rate Base	223,223,125	221,476,217	219,729,309	217,982,401	216,235,493	214,488,585	212,741,677	210,994,770	209,247,862	207,500,954	205,754,046	204,007,138	204,007,138
Freeborn	Tax Depreciation Expense	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	37,081,538
Freeborn	CPI-TAX INTEREST													
Freeborn	Debt Return	399,941	396,812	393,682	390,552	387,422	384,292	381,162	378,032	374,902	371,773	368,643	365,513	4,592,725
Freeborn	Equity Return	957,999	950,502	943,005	935,508	928,011	920,514	913,016	905,519	898,022	890,525	883,028	875,531	11,001,179
Freeborn	Current Income Tax Requirement	(124,364)	(126,784)	(129,204)	(131,625)	(134,045)	(136,465)	(138,886)	(141,306)	(143,726)	(146,147)	(148,567)	(150,988)	(1,652,107)
Freeborn	Book Depreciation	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	14,476,057
Freeborn	Deferred Taxes	540,570	540,570	540,570	540,570	540,570	540,570	540,570	540,570	540,570	540,570	540,570	540,570	6,486,838
Freeborn	Property Tax Expense	78,614	78,614	78,614	78,614	78,614	78,614	78,614	78,614	78,614	78,614	78,614	78,614	943,370
Freeborn	Operating Expenses	519,190	449,414	485,717	444,014	478,440	589,772	526,819	516,821	620,750	507,962	530,495	481,382	6,150,774
Freeborn	Production Tax Credit	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(11,000,929)
Freeborn	Interconnect Costs	36,622	36,622	36,622	36,622	36,622	36,622	36,622	36,622	36,622	36,622	36,422	36,422	438,264
Freeborn	Total Revenue Requirement	2,698,167	2,615,344	2,638,599	2,583,849	2,605,227	2,703,512	2,627,512	2,604,466	2,695,348	2,568,712	2,578,798	2,516,638	31,436,171
Freeborn	Rider Revenue Requirement	144,052	139,779	140,936	138,100	139,162	144,160	140,236	139,024	143,643	137,127	137,610	134,395	1,678,225

Details Data

Project	Rider Components	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	2025
Blazing Star I	Production Tax Credit	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(1,080,878)
Blazing Star I	Total Revenue Requirement	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(90,073)	(1,080,878)
Blazing Star I	Rider Revenue Requirement	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(4,779)	(57,353)
Blazing Star II	Production Tax Credit	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(1,023,484)
Blazing Star II	Total Revenue Requirement	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(85,290)	(1,023,484)
Blazing Star II	Rider Revenue Requirement	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(4,526)	(54,307)
Border Winds	Production Tax Credit	18,257	18,257	18,257	18,257	18,257	18,257	18,257	18,257	18,257	18,257	18,257	18,257	219,082
Border Winds	Income Tax Credit	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(23,718)	(284,611)
Border Winds	Total Revenue Requirement	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(65,529)
Border Winds	Rider Revenue Requirement	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(307)	(3,682)
Borders Wind Re-Power	Plant In-Service													189,937,331
Borders Wind Re-Power	Depreciation Reserve													360,045
Borders Wind Re-Power	Accumulated Deferred Taxes	830,777	1,039,225	1,247,673	1,456,121	1,664,568	1,873,016	2,081,464	2,289,912	2,498,360	2,706,808	2,915,256	3,123,703	3,123,703
Borders Wind Re-Power	Average Rate Base	(726,553)	(935,001)	(1,143,449)	(1,351,897)	(1,560,344)	(1,768,792)	(1,977,240)	(2,185,688)	(2,394,136)	(2,602,584)	(2,811,032)	91,769,164	91,769,164
Borders Wind Re-Power	Tax Depreciation Expense	1,077,560	785,398	776,087	826,355	1,930,315	4,225,837	1,204,988	2,394,386	(4,299,302)	1,055,283	859,585	465,160	11,301,650
Borders Wind Re-Power	CPI-TAX INTEREST	153,580	162,033	162,754	164,216	196,801	322,742	439,450	497,969	573,567	622,532	646,888	338,664	4,281,197
Borders Wind Re-Power	Debt Return	(1,302)	(1,675)	(2,049)	(2,422)	(2,796)	(3,169)	(3,543)	(3,916)	(4,289)	(4,663)	(5,036)	164,420	129,560
Borders Wind Re-Power	Equity Return	(3,118)	(4,013)	(4,907)	(5,802)	(6,696)	(7,591)	(8,486)	(9,380)	(10,275)	(11,169)	(12,064)	393,843	310,341
Borders Wind Re-Power	Current Income Tax Requirement	(232,007)	(135,246)	(132,296)	(148,341)	(494,510)	(1,195,220)	(182,589)	(547,967)	1,637,120	(76,019)	(5,266)	269,840	(1,242,501)
Borders Wind Re-Power	Book Depreciation													360,045
Borders Wind Re-Power	Deferred Taxes	208,448	208,448	208,448	208,448	208,448	208,448	208,448	208,448	208,448	208,448	208,448	208,448	2,501,374
Borders Wind Re-Power	Property Tax Expense													
Borders Wind Re-Power	Operating Expenses													
Borders Wind Re-Power	Production Tax Credit												(828,804)	(828,804)
Borders Wind Re-Power	Interconnect Costs													
Borders Wind Re-Power	Total Revenue Requirement	(27,979)	67,514	69,196	51,883	(295,554)	(997,532)	13,831	(352,816)	1,831,004	116,596	186,081	567,791	1,230,015
Borders Wind Re-Power	Rider Revenue Requirement	(1,505)	3,631	3,721	2,790	(15,895)	(53,649)	744	(18,975)	98,475	6,271	10,008	31,153	66,769
Courtenay Wind	Production Tax Credit	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	512,223
Courtenay Wind	Total Revenue Requirement	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	42,685	512,223
Courtenay Wind	Rider Revenue Requirement	2,265	2,265	2,265	2,265	2,265	2,265	2,265	2,265	2,265	2,265	2,265	2,265	27,179
Crowned Ridge	Production Tax Credit	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(811,531)
Crowned Ridge	Total Revenue Requirement	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(67,628)	(811,531)
Crowned Ridge	Rider Revenue Requirement	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(3,588)	(43,061)
Dakota Range	Plant In-Service	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939	338,368,939
Dakota Range	Depreciation Reserve	44,737,471	45,964,340	47,191,210	48,418,079	49,644,949	50,871,818	52,098,688	53,325,557	54,552,427	55,779,296	57,006,166	58,233,035	58,233,035
Dakota Range	Accumulated Deferred Taxes	50,712,036	51,259,474	51,806,913	52,354,352	52,901,790	53,449,229	53,996,668	54,544,106	55,091,545	55,638,983	56,186,422	56,733,861	56,733,861
Dakota Range	Average Rate Base	243,806,587	242,032,278	240,257,970	238,483,662	236,709,354	234,935,046	233,160,738	231,386,429	229,612,121	227,837,813	226,063,505	224,289,197	224,289,197
Dakota Range	Tax Depreciation Expense	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	3,111,500	37,338,002
Dakota Range	CPI-TAX INTEREST													
Dakota Range	Debt Return	436,820	433,641	430,462	427,283	424,104	420,925	417,746	414,567	411,388	408,209	405,030	401,851	5,032,030
Dakota Range	Equity Return	1,046,337	1,038,722	1,031,107	1,023,492	1,015,878	1,008,263	1,000,648	993,033	985,419	977,804	970,189	962,574	12,053,466
Dakota Range	Current Income Tax Requirement	(93,899)	(96,357)	(98,816)	(101,274)	(103,732)	(106,191)	(108,649)	(111,107)	(113,565)	(116,024)	(118,482)	(120,940)	(1,289,036)
Dakota Range	Book Depreciation	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	1,226,870	14,722,434
Dakota Range	Deferred Taxes	547,439	547,439	547,439	547,439	547,439	547,439	547,439	547,439	547,439	547,439	547,439	547,439	6,569,264
Dakota Range	Property Tax Expense	113,179	113,179	113,179	113,179	113,179	113,179	113,179	113,179	113,179	113,179	113,179	113,179	1,358,145
Dakota Range	Operating Expenses	398,355	395,582	458,607	428,209	422,289	535,601	422,589	427,425	430,624	627,589	(1,301,990)	208,500	3,453,380
Dakota Range	Production Tax Credit	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(1,267,650)	(15,211,802)
Dakota Range	Interconnect Costs	87,264	87,264	87,264	87,264	87,264	87,264	87,320	87,320	87,320	87,320	87,320	87,320	1,047,445
Dakota Range	Total Revenue Requirement	2,494,713	2,478,688	2,528,461	2,484,812	2,465,639	2,565,640	2,439,492	2,431,076	2,421,023	2,604,735	661,905	2,159,142	27,735,325
Dakota Range	Rider Revenue Requirement	133,617	132,763	135,277	133,009	131,994	137,079	130,588	130,123	129,575	138,946	39,452	116,067	1,488,490
Foxtail	Production Tax Credit	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(687,785)
Foxtail	Total Revenue Requirement	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(57,315)	(687,785)
Foxtail	Rider Revenue Requirement	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(3,041)	(36,495)
Freeborn	Plant In-Service	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299	334,622,299
Freeborn	Depreciation Reserve	53,209,849	54,416,187	55,622,525	56,828,863	58,035,201	59,241,539	60,447,877	61,654,216	62,860,554	64,066,892	65,273,230	66,479,568	66,479,568
Freeborn	Accumulated Deferred Taxes	59,062,779	59,603,349	60,143,919	60,684,489	61,225,059	61,765,629	62,306,198	62,846,768	63,387,338	63,927,908	64,468,478	65,009,047	65,009,047
Freeborn	Average Rate Base	223,223,125	221,476,217	219,729,309	217,982,401	216,235,493	214,488,585	212,741,677	210,994,770	209,247,862	207,500,954	205,754,046	204,007,138	204,007,138
Freeborn	Tax Depreciation Expense	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	3,090,128	37,081,538
Freeborn	CPI-TAX INTEREST													
Freeborn	Debt Return	399,941	396,812	393,682	390,552	387,422	384,292	381,162	378,032	374,902	371,773	368,643	365,513	4,592,725
Freeborn	Equity Return	957,999	950,502	943,005	935,508	928,011	920,514	913,017	905,519	898,022	890,525	883,028	875,531	11,001,179
Freeborn	Current Income Tax Requirement	(124,364)	(126,784)	(129,204)	(131,625)	(134,045)	(136,465)	(138,886)	(141,306)	(143,726)	(146,147)	(148,567)	(150,988)	(1,652,107)
Freeborn	Book Depreciation	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	1,206,338	14,476,057
Freeborn	Deferred Taxes	540,570	540,570	540,570	540,570	540,570	540,570	540,570	540,570	540,570	540,570	540,570	540,570	6,486,838
Freeborn	Property Tax Expense	78,614	78,614	78,614	78,614	78,614	78,614	78,614	78,614	78,614	78,614	78,614	78,614	943,370
Freeborn	Operating Expenses	519,190	449,414	485,717	444,014	478,440	589,772	526,819	516,821	620,750	507,962	530,495	481,382	6,150,774
Freeborn	Production Tax Credit	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(916,744)	(11,000,929)
Freeborn	Interconnect Costs	36,622	36,622	36,622	36,622	36,622	36,622	36,622	36,622	36,622	36,622	36,622	36,622	438,264
Freeborn	Total Revenue Requirement	2,698,167	2,615,344	2,638,599	2,583,849	2,605,227	2,703,512	2,627,512	2,604,466	2,695,348	2,568,712	2,578,798	2,516,638	31,436,171
Freeborn	Rider Revenue Requirement	144,052	139,779	140,936	138,100	139,162	144,160	140,236	139,024	143,643	137,127	137,610	134,395	1,678,225

Details Data

Project	Rider Components	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	2025
Lake Benton	Production Tax Credit	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(449,480)
Lake Benton	Total Revenue Requirement	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(37,457)	(449,480)
Lake Benton	Rider Revenue Requirement	(1,987)	(1,987)	(1,987)	(1,987)	(1,987)	(1,987)	(1,987)	(1,987)	(1,987)	(1,987)	(1,987)	(1,987)	(23,850)
Nobles Re-Power	Plant In-Service	223,377,078	223,380,448	223,390,463	223,390,755	223,390,987	223,391,197	223,391,486	223,391,486	223,391,486	223,391,486	223,391,486	223,391,486	223,391,486
Nobles Re-Power	Depreciation Reserve	12,611,119	13,491,113	14,371,133	15,251,173	16,131,214	17,011,256	17,891,300	18,771,343	19,651,387	20,531,430	21,411,474	22,291,518	22,291,518
Nobles Re-Power	Accumulated Deferred Taxes	40,041,593	40,397,352	40,753,111	41,108,869	41,464,628	41,820,386	42,176,145	42,531,904	42,887,662	43,243,421	43,599,180	43,954,938	43,954,938
Nobles Re-Power	Average Rate Base	171,316,758	170,108,174	168,879,101	167,648,466	166,412,929	165,177,349	163,941,798	162,706,141	161,470,338	160,234,536	158,998,734	157,762,932	157,762,932
Nobles Re-Power	Tax Depreciation Expense	2,118,761	2,118,761	2,118,761	2,118,761	2,118,761	2,118,761	2,118,761	2,118,761	2,118,761	2,118,761	2,118,761	2,118,761	25,425,129
Nobles Re-Power	CPI-TAX INTEREST													
Nobles Re-Power	Debt Return	306,943	304,777	302,575	300,370	298,156	295,943	293,729	291,515	289,301	287,087	284,873	282,659	3,537,928
Nobles Re-Power	Equity Return	735,234	730,048	724,773	719,491	714,189	708,886	703,584	698,281	692,977	687,673	682,370	677,066	8,474,571
Nobles Re-Power	Current Income Tax Requirement	(47,741)	(49,381)	(51,076)	(52,774)	(54,486)	(56,198)	(57,909)	(59,621)	(61,333)	(63,045)	(64,758)	(66,470)	(684,792)
Nobles Re-Power	Book Depreciation	879,887	879,994	880,020	880,040	880,041	880,042	880,043	880,044	880,044	880,044	880,044	880,044	10,560,285
Nobles Re-Power	Deferred Taxes	355,759	355,759	355,759	355,759	355,759	355,759	355,759	355,759	355,759	355,759	355,759	355,759	4,269,103
Nobles Re-Power	Production Tax Credit	(1,048,451)	(1,048,451)	(1,048,451)	(1,048,451)	(1,048,451)	(1,048,451)	(1,048,451)	(1,048,451)	(1,048,451)	(1,048,451)	(1,048,451)	(1,048,451)	(12,581,413)
Nobles Re-Power	Total Revenue Requirement	1,181,630	1,172,744	1,163,599	1,154,435	1,145,208	1,135,981	1,126,754	1,117,526	1,108,296	1,099,066	1,089,836	1,080,606	13,575,681
Nobles Re-Power	Rider Revenue Requirement	64,342	63,864	63,372	62,879	62,382	61,886	61,389	60,893	60,396	59,900	59,403	58,907	739,612
Grand Meadow Re-Power	Plant In-Service	117,183,629	117,192,098	117,220,143	117,222,713	117,224,839	117,225,049	117,225,339	117,225,339	117,225,339	117,225,339	117,225,339	117,225,339	117,225,339
Grand Meadow Re-Power	Depreciation Reserve	9,800,409	10,333,112	10,865,899	11,398,755	11,931,622	12,464,494	12,997,368	13,530,242	14,063,115	14,595,989	15,128,863	15,661,737	15,661,737
Grand Meadow Re-Power	Accumulated Deferred Taxes	14,285,235	14,659,704	15,034,173	15,408,642	15,783,111	16,157,581	16,532,050	16,906,519	17,280,988	17,655,457	18,029,927	18,404,396	18,404,396
Grand Meadow Re-Power	Average Rate Base	93,540,618	92,648,634	91,759,676	90,867,693	89,962,710	89,056,540	88,149,448	87,242,250	86,334,907	85,427,564	84,520,220	83,612,877	83,612,877
Grand Meadow Re-Power	Tax Depreciation Expense	1,852,303	1,852,303	1,852,303	1,852,303	1,852,303	1,852,303	1,852,303	1,852,303	1,852,303	1,852,303	1,852,303	1,852,303	22,227,639
Grand Meadow Re-Power	CPI-TAX INTEREST													
Grand Meadow Re-Power	Debt Return	167,594	165,995	164,403	162,805	161,183	159,560	157,934	156,309	154,683	153,058	151,432	149,806	1,904,762
Grand Meadow Re-Power	Equity Return	401,445	397,617	393,802	389,974	386,090	382,201	378,308	374,415	370,521	366,627	362,733	358,839	4,562,570
Grand Meadow Re-Power	Current Income Tax Requirement	(175,544)	(176,757)	(177,962)	(179,176)	(180,426)	(181,680)	(182,936)	(184,193)	(185,450)	(186,707)	(187,965)	(189,222)	(2,188,020)
Grand Meadow Re-Power	Book Depreciation	532,635	532,704	532,787	532,856	532,867	532,872	532,873	532,874	532,874	532,874	532,874	532,874	6,393,964
Grand Meadow Re-Power	Deferred Taxes	374,469	374,469	374,469	374,469	374,469	374,469	374,469	374,469	374,469	374,469	374,469	374,469	4,933,630
Grand Meadow Re-Power	Production Tax Credit	(533,817)	(533,817)	(533,817)	(533,817)	(533,817)	(533,817)	(533,817)	(533,817)	(533,817)	(533,817)	(533,817)	(533,817)	(6,405,808)
Grand Meadow Re-Power	Total Revenue Requirement	766,782	760,211	753,681	747,111	740,366	733,605	726,831	720,056	713,279	706,503	699,726	692,949	8,761,099
Grand Meadow Re-Power	Rider Revenue Requirement	41,648	41,295	40,943	40,590	40,237	39,883	39,529	39,134	38,770	38,405	38,040	37,676	476,001
Mower	Production Tax Credit	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(400,146)
Mower	Total Revenue Requirement	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(33,346)	(400,146)
Mower	Rider Revenue Requirement	(1,769)	(1,769)	(1,769)	(1,769)	(1,769)	(1,769)	(1,769)	(1,769)	(1,769)	(1,769)	(1,769)	(1,769)	(21,232)
Pleasant Valley	Production Tax Credit	(3,128,382)	(2,666,727)	(3,150,943)	(2,660,749)	(1,888,609)	(1,292,278)	(846,787)	(633,634)	(287,227)				(16,555,337)
Pleasant Valley	Total Revenue Requirement	(3,128,382)	(2,666,727)	(3,150,943)	(2,660,749)	(1,888,609)	(1,292,278)	(846,787)	(633,634)	(287,227)				(16,555,337)
Pleasant Valley	Rider Revenue Requirement	(165,996)	(141,500)	(167,193)	(141,183)	(100,212)	(68,570)	(44,932)	(33,621)	(15,241)				(878,447)
Pleasant Valley Re-Power	Plant In-Service												243,751,388	243,751,388
Pleasant Valley Re-Power	Depreciation Reserve												471,056	471,056
Pleasant Valley Re-Power	Accumulated Deferred Taxes	1,057,401	1,317,529	1,577,657	1,837,786	2,097,914	2,358,042	2,618,170	2,878,298	3,138,426	3,398,554	3,658,682	3,918,810	3,918,810
Pleasant Valley Re-Power	Average Rate Base	(927,337)	(1,187,465)	(1,447,593)	(1,707,721)	(1,967,850)	(2,227,978)	(2,488,106)	(2,748,234)	(3,008,362)	(3,268,490)	(3,528,618)	117,851,420	117,851,420
Pleasant Valley Re-Power	Tax Depreciation Expense	1,386,349	1,006,298	997,534	1,093,071	2,734,611	2,489,956	3,529,198	3,090,379	(5,243,811)	1,338,934	1,222,653	483,909	14,129,082
Pleasant Valley Re-Power	CPI-TAX INTEREST	203,221	214,242	215,173	(1,765,407)	2,251,320	358,139	481,287	613,476	712,063	774,767	813,672	432,513	5,304,247
Pleasant Valley Re-Power	Debt Return	(1,661)	(2,128)	(2,594)	(3,060)	(3,526)	(3,992)	(4,458)	(4,924)	(5,390)	(5,856)	(6,322)	211,150	167,461
Pleasant Valley Re-Power	Equity Return	(3,980)	(5,096)	(6,213)	(7,329)	(8,445)	(9,562)	(10,678)	(11,795)	(12,911)	(14,027)	(15,144)	505,779	400,600
Pleasant Valley Re-Power	Current Income Tax Requirement	(299,263)	(173,371)	(170,602)	(841,210)	(74,772)	(607,337)	(903,447)	(719,465)	2,002,588	(102,684)	(52,944)	382,745	(1,559,762)
Pleasant Valley Re-Power	Book Depreciation												471,056	471,056
Pleasant Valley Re-Power	Deferred Taxes	260,128	260,128	260,128	260,128	260,128	260,128	260,128	260,128	260,128	260,128	260,128	260,128	3,121,537
Pleasant Valley Re-Power	Property Tax Expense													
Pleasant Valley Re-Power	Operating Expenses													
Pleasant Valley Re-Power	Production Tax Credit													
Pleasant Valley Re-Power	Interconnect Costs													
Pleasant Valley Re-Power	Total Revenue Requirement	(44,777)	79,533	80,720	(591,470)	173,385	(360,763)	(658,455)	(476,055)	2,244,415	137,561	185,718	739,441	1,509,253
Pleasant Valley Re-Power	Rider Revenue Requirement	(2,408)	4,277	4,341	(31,810)	9,325	(19,402)	(35,413)	(25,603)	120,708	7,398	9,988	40,555	81,956
Total	Plant In-Service	1,013,551,945	1,013,563,784	1,013,601,844	1,013,604,706	1,013,607,065	1,013,607,484	1,013,608,064	1,013,608,064	1,013,608,064	1,013,608,064	1,013,608,064	1,447,296,782	1,447,296,782
Total	Depreciation Reserve	120,358,848	124,204,753	128,050,767	131,896,871	135,742,987	139,589,109	143,435,233	147,281,358	151,127,483	154,973,608	158,819,733	163,496,959	163,496,959
Total	Accumulated Deferred Taxes	165,989,822	168,276,634	170,563,446	172,850,258	175,137,070	177,423,883	179,710,695	181,997,507	184,284,319	186,571,131	188,857,944	191,144,756	191,144,756
Total	Average Rate Base	730,233,197	724,142,837	718,035,014	711,922,604	705,792,292	699,660,750	693,528,315	687,395,668	681,262,730	675,129,793	668,996,856	679,292,727	879,292,727
Total	Tax Depreciation Expense	12,636,601	11,964,388	11,946,314	14,837,618	16,888,486	14,906,878	15,657,457	629,580	12,566,909	12,254,931	11,121,761	147,503,040	147,503,040
Total	CPI-TAX INTEREST	356,801	376,275	377,927	(1,601,191)	2,448,121	680,882	920,737	1,111,445	1,285,630	1,397,299	1,460,561	771,177	9,585,664
Total	Debt Return	1,308,334	1,297,423	1,286,479	1,275,528	1,264,545	1,253,559	1,242,572	1,231,584	1,220,596	1,209,608	1,198,619	1,175,399	15,364,245
Total	Equity Return	3,133,917	3,107,780	3,081,567	3,055,335	3,029,025	3,002,711	2,976,392	2,950,073	2,923,753	2,897,432	2,871,112	3,773,631	36,802,727
Total	Current Income Tax Requirement	(972,818)	(757,897)	(759,956)	(1,454,400)	(1,041,971)	(2,283,091)	(1,574,416)	(1,763,659)	3,135,633	(690,626)	(577,982)	124,966	(8,616,218)
Total	Book Depreciation	3,845,730	3,845,905	3,846,014	3,846,104	3,846,116	3,846,122	3,846,124	3,846,125	3,846,125	3,846,125	3,846,125	4,677,226	46,983,841
Total	Deferred Taxes	2,286,812	2,286,812	2,286,812	2,286,812	2,286,812	2,286,812	2,286,812	2,286,812	2,286,812	2,286,812	2,286,812	2,286,812	27,441,746
Total	Property Tax Expense	191,793	191,793	191,793	191,793	191,793	191,793	191,793	191,793	191,793	191,793	191,793	191,793	2,301,515
Total	Operating Expenses	917,545	844,995	944,323	872,223									

[illegible]

Project	Rider Components	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	2026
Lake Benton	Production Tax Credit	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(797,138)
Lake Benton	Total Revenue Requirement	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(66,428)	(797,138)
Lake Benton	Rider Revenue Requirement	(3,544)	(3,544)	(3,544)	(3,544)	(3,544)	(3,544)	(3,544)	(3,544)	(3,544)	(3,544)	(3,544)	(3,544)	(42,528)
Nobles Re-Power	Plant In-Service	223,391,486	223,391,486	223,391,486	223,391,486									223,391,486
Nobles Re-Power	Depreciation Reserve	23,171,561	24,051,605	24,931,649	25,811,692									25,811,692
Nobles Re-Power	Accumulated Deferred Taxes	44,125,949	44,485,072	44,832,795	45,191,918									45,191,918
Nobles Re-Power	Average Rate Base	156,533,998	155,294,831	154,067,065	152,827,898									152,827,898
Nobles Re-Power	Tax Depreciation Expense	2,110,462	2,110,462	2,110,462	2,110,462									8,441,849
Nobles Re-Power	CPI-TAX INTEREST													
Nobles Re-Power	Debt Return	280,457	278,237	276,037	273,817									1,108,547
Nobles Re-Power	Equity Return	671,792	666,474	661,204	655,886									2,655,356
Nobles Re-Power	Current Income Tax Requirement	(66,248)	(67,964)	(69,665)	(71,382)									(275,260)
Nobles Re-Power	Book Depreciation	880,044	880,044	880,044	880,044									3,520,175
Nobles Re-Power	Deferred Taxes	353,423	353,423	353,423	353,423									1,413,691
Nobles Re-Power	Production Tax Credit	(1,021,435)	(1,021,435)	(1,021,435)	(1,021,435)	(139,552)	(139,552)	(139,552)	(139,552)	(139,552)	(139,552)	(139,552)	(139,552)	(5,202,160)
Nobles Re-Power	Total Revenue Requirement	1,098,032	1,088,777	1,079,607	1,070,352	(139,552)	(139,552)	(139,552)	(139,552)	(139,552)	(139,552)	(139,552)	(139,552)	3,320,349
Nobles Re-Power	Rider Revenue Requirement	60,678	60,175	59,676	59,174	(7,445)	(7,445)	(7,445)	(7,445)	(7,445)	(7,445)	(7,445)	(7,445)	180,141
Grand Meadow Re-Power	Plant In-Service	117,225,339	117,225,339	117,225,339	117,225,339									117,225,339
Grand Meadow Re-Power	Depreciation Reserve	16,194,611	16,727,485	17,260,359	17,793,233									17,793,233
Grand Meadow Re-Power	Accumulated Deferred Taxes	18,484,944	18,654,096	18,817,878	18,987,030									18,987,030
Grand Meadow Re-Power	Average Rate Base	82,812,220	82,110,195	81,413,539	80,711,513									80,711,513
Grand Meadow Re-Power	Tax Depreciation Expense	1,111,692	1,111,692	1,111,692	1,111,692									4,446,770
Grand Meadow Re-Power	CPI-TAX INTEREST													
Grand Meadow Re-Power	Debt Return	148,372	147,114	145,866	144,608									585,960
Grand Meadow Re-Power	Equity Return	355,402	352,390	349,400	346,387									1,403,579
Grand Meadow Re-Power	Current Income Tax Requirement	(18,385)	(19,358)	(20,323)	(21,296)									(79,362)
Grand Meadow Re-Power	Book Depreciation	532,874	532,874	532,874	532,874									2,131,496
Grand Meadow Re-Power	Deferred Taxes	166,467	166,467	166,467	166,467									665,868
Grand Meadow Re-Power	Production Tax Credit	(511,555)	(511,555)	(511,555)	(511,555)	(26,867)	(26,867)	(26,867)	(26,867)	(26,867)	(26,867)	(26,867)	(26,867)	(2,261,153)
Grand Meadow Re-Power	Total Revenue Requirement	673,175	667,932	662,728	657,485	(26,867)	(26,867)	(26,867)	(26,867)	(26,867)	(26,867)	(26,867)	(26,867)	2,446,387
Grand Meadow Re-Power	Rider Revenue Requirement	37,089	36,804	36,521	36,236	(1,433)	(1,433)	(1,433)	(1,433)	(1,433)	(1,433)	(1,433)	(1,433)	135,184
Mower	Production Tax Credit	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(887,324)
Mower	Total Revenue Requirement	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(73,944)	(887,324)
Mower	Rider Revenue Requirement	(3,945)	(3,945)	(3,945)	(3,945)	(3,945)	(3,945)	(3,945)	(3,945)	(3,945)	(3,945)	(3,945)	(3,945)	(47,339)
Pleasant Valley	Production Tax Credit													
Pleasant Valley	Total Revenue Requirement													
Pleasant Valley	Rider Revenue Requirement													
Pleasant Valley Re-Power	Plant In-Service	243,850,202	246,388,269	246,427,402	246,651,369	246,949,535	247,072,817	251,438,694	250,463,026	256,790,147	256,816,153	256,842,160	256,876,795	256,876,795
Pleasant Valley Re-Power	Depreciation Reserve	1,413,359	2,360,759	3,313,140	4,266,030	5,219,930	6,174,647	7,138,045	8,107,993	9,088,284	10,080,853	11,073,521	12,066,307	12,066,307
Pleasant Valley Re-Power	Accumulated Deferred Taxes	4,855,079	6,821,243	8,724,990	10,691,154	12,594,901	14,561,065	16,464,811	18,399,767	20,365,931	22,269,678	24,235,842	26,139,588	26,139,588
Pleasant Valley Re-Power	Average Rate Base	238,003,508	236,410,933	234,845,896	232,058,646	229,462,572	226,752,823	226,134,598	224,928,075	224,662,517	224,948,904	222,016,128	219,149,974	219,149,974
Pleasant Valley Re-Power	Tax Depreciation Expense	7,812,618	7,831,784	7,831,790	7,831,784	7,831,784	7,831,784	7,845,915	7,831,784	7,831,784	7,831,784	7,831,784	7,831,784	93,976,387
Pleasant Valley Re-Power	CPI-TAX INTEREST	7	16	34	90	97								245
Pleasant Valley Re-Power	Debt Return	426,423	423,570	420,766	415,772	411,120	406,265	405,158	402,996	402,520	403,033	397,779	392,644	4,908,046
Pleasant Valley Re-Power	Equity Return	1,021,432	1,014,597	1,007,880	995,918	984,777	973,148	970,494	965,316	964,177	965,406	952,819	940,519	11,756,483
Pleasant Valley Re-Power	Current Income Tax Requirement	(1,263,559)	(1,270,304)	(1,270,861)	(1,274,538)	(1,277,807)	(1,281,332)	(1,283,945)	(1,278,939)	(1,275,969)	(1,271,608)	(1,275,639)	(1,279,572)	(15,304,073)
Pleasant Valley Re-Power	Book Depreciation	942,303	947,400	952,382	952,890	953,899	954,718	963,397	969,949	980,291	992,568	992,669	992,786	11,595,252
Pleasant Valley Re-Power	Deferred Taxes	1,934,955	1,934,955	1,934,955	1,934,955	1,934,955	1,934,955	1,934,955	1,934,955	1,934,955	1,934,955	1,934,955	1,934,955	23,219,465
Pleasant Valley Re-Power	Property Tax Expense													
Pleasant Valley Re-Power	Operating Expenses													
Pleasant Valley Re-Power	Production Tax Credit	(1,127,937)	(1,127,937)	(1,127,937)	(1,127,937)	(1,127,937)	(1,127,937)	(1,127,937)	(1,127,937)	(1,127,937)	(1,127,937)	(1,127,937)	(1,127,937)	(13,535,243)
Pleasant Valley Re-Power	Interconnect Costs													
Pleasant Valley Re-Power	Total Revenue Requirement	1,933,617	1,922,281	1,917,185	1,897,060	1,879,008	1,859,817	1,862,123	1,866,340	1,878,038	1,896,418	1,874,646	1,853,395	22,639,929
Pleasant Valley Re-Power	Rider Revenue Requirement	106,156	105,540	105,264	104,170	103,190	102,147	102,272	102,501	103,137	104,136	102,953	101,798	1,243,265
Total	Plant In-Service	1,448,654,209	1,451,593,240	1,451,560,662	1,452,074,852	438,946,144	439,140,046	446,416,331	449,651,346	458,952,216	459,661,670	459,770,270	465,859,059	1,479,467,122
Total	Depreciation Reserve	169,007,660	174,526,600	180,051,354	185,577,038	9,208,139	10,890,895	12,587,979	14,305,106	16,046,186	17,806,473	19,568,313	21,341,896	199,392,255
Total	Accumulated Deferred Taxes	193,403,107	198,145,643	202,737,624	207,480,160	22,674,158	29,646,546	33,132,740	36,675,163	40,105,128	43,647,551	47,077,516		235,313,484
Total	Average Rate Base	1,088,320,080	1,080,210,951	1,071,550,350	1,061,523,401	407,664,900	402,776,998	401,392,206	401,454,557	402,450,972	402,275,485	397,381,026	395,282,044	1,044,526,843
Total	Tax Depreciation Expense	21,944,972	21,983,498	21,983,315	21,983,363	14,079,412	14,079,390	14,112,711	14,079,379	14,079,379	14,079,379	14,079,379		200,563,558
Total	CPI-TAX INTEREST	7	16	34	90	97								245
Total	Debt Return	1,949,907	1,935,378	1,919,861	1,901,896	730,400	721,642	719,161	719,273	721,058	720,744	711,974	708,214	13,459,507
Total	Equity Return	4,670,707	4,635,905	4,598,737	4,555,705	1,749,562	1,728,585	1,722,642	1,722,909	1,727,185	1,726,432	1,705,427	1,696,419	32,240,214
Total	Current Income Tax Requirement	(2,290,948)	(2,311,958)	(2,322,016)	(2,335,606)	(2,312,191)	(2,318,569)	(2,316,619)	(2,309,302)	(2,300,188)	(2,294,231)	(2,300,511)	(2,299,628)	(27,717,766)
Total	Book Depreciation	5,510,701	5,518,941	5,524,754	5,525,683	1,681,460	1,682,756	1,697,084	1,717,127	1,741,080	1,760,287	1,761,840	1,773,583	35,895,296
Total	Deferred Taxes	4,667,258	4,667,258	4,667,258	4,667,258	3,486,194	3,486,194	3,486,194	3,486,194	3,486,194	3,486,194	3,486,194	3,486,194	46,558,586
Total	Property Tax Expense	193,711	193,711	193,711	193,711									774,844
Total	Operating Expenses	1,177,013	871,556	798,427	1,028,942									3,875,938
Total	Production Tax Credit	(6,077,391)	(6,077,391)	(6,077,391)	(6,077,391)	(2,715,288)	(2,715,288)	(2,715,288)	(2,715,288)	(2,715,288)	(2,715,288)	(2,715,288)	(2,715,288)	(46,031,870)
Total	Income Tax Credit													
Total	Interconnect Costs	123,742	123,742	123,742	123,742									494,969
Total	Total Revenue Requirement	9,924,699	9,557,142	9,427,084	9,583,940	2,620,137	2,585,320	2,583,173	2,620,913	2,660,041	2,684,138	2,649,636	2,649,494	59,545,717
Total	Rider Revenue Requirement	539,805	520,948	514,161	521,846	145,031	143,140	143,023	145,073	147,199	148,508	146,634	146,626	3,261,994

[illegible]

Model Logic

Borders Wind Re-Power		Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	2027 Year End
A	Plant In-Service (Input)	\$ 208,982,264	\$ 209,000,664	\$ 209,019,064	\$ 209,037,464	\$ 209,055,864	\$ 209,074,264	\$ 209,092,664	\$ 209,111,064	\$ 209,129,464	\$ 209,147,864	\$ 209,166,264	\$ 209,184,664	\$ 209,203,064	\$ 209,203,064
B	Depreciation Reserve (Input)	9,275,588	10,067,889	10,860,260	11,652,701	12,445,211	13,237,791	14,030,441	14,823,160	15,615,949	16,408,808	17,201,737	17,994,735	18,787,803	18,787,803
C	Accumulated Deferred Taxes (Input)	20,937,928	22,186,543	23,127,293	24,038,177	24,978,927	25,889,812	26,830,561	27,741,446	28,667,263	29,608,013	30,518,897	31,459,647	32,370,531	32,370,531
D	Rate Base (A - B - C)	178,768,748	176,746,232	175,031,511	173,346,586	171,631,726	169,946,662	168,231,662	166,546,458	164,846,252	163,131,043	161,445,630	159,730,282	158,044,730	158,044,730
E	Average Rate Base (((Prior Month (A+B) + Cur Month(A+B))/2) - Cur Month C		177,133,182	175,418,497	173,733,606	172,018,781	170,333,752	168,618,787	166,933,618	165,233,446	163,518,273	161,832,894	160,117,581	158,432,064	158,432,064
F	Tax Depreciation Expense (Input)		4,070,349	4,070,349	4,070,349	4,070,349	4,070,349	4,070,349	4,070,349	4,070,349	4,070,349	4,070,349	4,070,349	4,070,349	48,844,193
G	Debt Return (E * Wtd Cost of Debt)		317,364	314,291	311,273	308,200	305,181	302,109	299,089	296,043	292,970	289,951	286,877	283,857	3,607,206
H	Equity Return (E * Wtd Cost of Equity)		760,197	752,838	745,607	738,247	731,016	723,656	716,423	709,127	701,766	694,533	687,171	679,938	8,640,518
I	Current Income Tax Req (See Calculation Below)		(513,968)	(516,321)	(518,633)	(520,986)	(523,298)	(525,652)	(527,964)	(530,297)	(532,651)	(534,964)	(537,318)	(539,631)	(6,321,684)
J	Book Depreciation (Input)		792,301	792,371	792,441	792,510	792,580	792,650	792,719	792,789	792,859	792,929	792,998	793,068	9,512,215
K	Deferred Taxes (Input)		925,817	925,817	925,817	925,817	925,817	925,817	925,817	925,817	925,817	925,817	925,817	925,817	11,109,805
L	Property Tax Expense (A * Monthly Property Tax Rate)		-	-	-	-	-	-	-	-	-	-	-	-	-
M	Operating Expenses (Input)		-	-	-	-	-	-	-	-	-	-	-	-	-
N	Interconnect Costs (Input)		-	-	-	-	-	-	-	-	-	-	-	-	-
O	Production Tax Credit (Input)		(884,793)	(884,793)	(884,793)	(884,793)	(884,793)	(884,793)	(884,793)	(884,793)	(884,793)	(884,793)	(884,793)	(884,793)	(10,617,516)
P	Total Rev Req (Sum of G thru O)		1,396,918	1,384,203	1,371,711	1,358,996	1,346,503	1,333,786	1,321,292	1,308,686	1,295,968	1,283,472	1,270,753	1,258,256	15,930,545
Q	Jurisdictional Factor (Varies by Input - refer to Att 5 Key Inputs)		5.36%	5.36%	5.36%	5.36%	5.36%	5.36%	5.36%	5.36%	5.36%	5.36%	5.36%	5.36%	5.36%
R	Jurisdiction/Rider Rev Req (P * Q)		\$ 74,863	\$ 74,188	\$ 73,525	\$ 72,850	\$ 72,187	\$ 71,512	\$ 70,848	\$ 70,179	\$ 69,504	\$ 68,841	\$ 68,166	\$ 67,502	\$ 854,163

Reconciliation to Att 2
Annual RR: Borders Wind Re-Power
Difference

854,163
-

Calculation: I - Current Income Tax Req

Equity Return (H)		760,197	752,838	745,607	738,247	731,016	723,656	716,423	709,127	701,766	694,533	687,171	679,938
Book Depreciation (I)		792,301	792,371	792,441	792,510	792,580	792,650	792,719	792,789	792,859	792,929	792,998	793,068
Deferred Taxes (K)		925,817	925,817	925,817	925,817	925,817	925,817	925,817	925,817	925,817	925,817	925,817	925,817
Less Tax Depreciation (F)		(4,070,349)	(4,070,349)	(4,070,349)	(4,070,349)	(4,070,349)	(4,070,349)	(4,070,349)	(4,070,349)	(4,070,349)	(4,070,349)	(4,070,349)	(4,070,349)
Plus CPI-Tax Interest (Input - If Applicable)		-	-	-	-	-	-	-	-	-	-	-	-
Sum		(1,592,035)	(1,599,324)	(1,606,485)	(1,613,775)	(1,620,937)	(1,628,227)	(1,635,389)	(1,642,616)	(1,649,908)	(1,657,071)	(1,664,363)	(1,671,527)
Tax Rate (Composite Tax/(1 - Composite Tax))		32.28%	32.28%	32.28%	32.28%	32.28%	32.28%	32.28%	32.28%	32.28%	32.28%	32.28%	32.28%
Current Income Tax Req (Sum * Tax Rate)		(513,968)	(516,321)	(518,633)	(520,986)	(523,298)	(525,652)	(527,964)	(530,297)	(532,651)	(534,964)	(537,318)	(539,631)

Att 5 - Keys Inputs

Capital Structure	2027 WACC	Production Allocation Factors	2027	Demand Allocation Factors	2027	PTC Allocation Factors	2027	Tax Rate	2027
Long Term Debt	2.11%	ND Jur Factor (Energy)	6.32%	ND Jur Factor (Demand)	5.90%	ND Jur Factor (Energy)	6.32%	Federal Tax Rate	21.00%
Short Term Debt	0.04%	IA Factor (Demand)	84.00%	IA Factor (Demand)	84.00%	IA Factor (Energy)	82.75%	ND State Tax Rate	4.31%
Common Equity	5.15%	ND Jurisdictional Factor	5.31%	ND Jurisdictional Factor	4.96%	ND Jurisdictional Factor	5.23%	ND Composite Income Tax Rate	24.40%
Required Rate of Return	7.30%								

Recalculation of PTC Allocation

Year	Border Winds (2015-2040)						Courtenay (2016-2041)					
	Remaining Months: 251			Levelized			Remaining Months: 262			Levelized		
	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER
2019												
2020	16,851,861	5.4515%	1.322837	1,215,267	-	(314,567)	17,588,806	5.4515%	1.322837	1,268,411	-	(415,655)
2021	15,859,567	5.4087%	1.322837	1,134,732	(83,640)	(250,920)	18,618,575	5.4087%	1.322837	1,332,135	(108,153)	(324,458)
2022	17,301,639	5.4908%	1.322837	1,256,686	(334,560)	38,364	21,215,655	5.4908%	1.322837	1,540,977	(432,610)	31,476
2023	15,517,095	5.3273%	1.322837	1,093,519	(334,560)	21,331	18,475,145	5.3273%	1.322837	1,301,979	(432,610)	20,277
2024	16,917,597	5.4139%	1.322837	1,211,579	(334,560)	8,586	20,315,909	5.4139%	1.322837	1,454,954	(432,610)	2,671
2025	9,838,835	5.3061%	1.322837	690,602	(324,956)	11,625	12,088,894	5.3061%	1.322837	848,536	(429,061)	27,179
2026					(324,956)	11,321	3,241,922	5.3351%	1.322837	228,796	(429,061)	84,627
2027					(324,956)	11,321					(429,061)	84,627
2028					(324,956)	11,321					(429,061)	84,627
2029					(324,956)	11,321					(429,061)	84,627
2030					(324,956)	11,321					(429,061)	84,627
2031					(324,956)	11,321					(429,061)	84,627
2032					(324,956)	11,321					(429,061)	84,627
2033					(324,956)	11,321					(429,061)	84,627
2034					(324,956)	11,321					(429,061)	84,627
2035					(324,956)	11,321					(429,061)	84,627
2036					(324,956)	11,321					(429,061)	84,627
2037					(324,956)	11,321					(429,061)	84,627
2038					(324,956)	11,321					(429,061)	84,627
2039					(324,956)	11,321					(429,061)	84,627
2040					(324,956)	11,321					(429,061)	84,627
2041											(393,306)	77,575
2042												
2043												
2044												
2045												
2046												
2047												
2048												
2049												
Total	92,286,595			6,602,384	(6,286,624)	(315,761)	111,544,907			7,975,789	(8,664,257)	688,469

Recalculation of PTC Allocation

Year	Foxtail (2019-2044)						Crowned Ridge (2020-2045)					
	Remaining Months: 296			Levelized			Remaining Months: 300			Levelized		
	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER
2019												
2020	15,388,359	5.4515%	1.322837	1,109,727	-	(421,126)	1,094,698	5.4515%	1.322837	78,944	-	(44,773)
2021	15,551,050	5.4087%	1.322837	1,112,658	(120,117)	(360,352)	20,566,510	5.4087%	1.322837	1,471,508	(155,676)	(467,027)
2022	14,475,228	5.4908%	1.322837	1,051,393	(480,470)	29,376	22,961,781	5.4908%	1.322837	1,667,805	(622,702)	3,996
2023	15,395,680	5.3273%	1.322837	1,084,963	(480,470)	29,255	20,653,032	5.3273%	1.322837	1,455,459	(622,702)	17,777
2024	16,168,601	5.4139%	1.322837	1,157,938	(480,470)	47,007	22,992,327	5.4139%	1.322837	1,646,629	(622,702)	13,928
2025	17,775,426	5.3061%	1.322837	1,247,682	(434,412)	(36,495)	24,806,821	5.3061%	1.322837	1,741,225	(612,151)	(43,061)
2026	18,547,476	5.3351%	1.322837	1,308,975	(434,412)	(47,674)	24,805,003	5.3351%	1.322837	1,750,596	(612,151)	(35,793)
2027	18,581,009	5.2276%	1.322837	1,284,927	(434,412)	(47,674)	23,724,412	5.2276%	1.322837	1,640,607	(612,151)	(35,793)
2028	18,631,344	5.1275%	1.322837	1,263,737	(434,412)	(47,674)	23,830,396	5.1275%	1.322837	1,616,381	(612,151)	(35,793)
2029	18,654,501	5.0489%	1.322837	1,245,907	(434,412)	(47,674)	23,928,210	5.0489%	1.322837	1,598,131	(612,151)	(35,793)
2030					(434,412)	(47,674)	23,064,388	4.7416%	1.322837	1,446,690	(612,151)	(35,793)
2031					(434,412)	(47,674)					(612,151)	(35,793)
2032					(434,412)	(47,674)					(612,151)	(35,793)
2033					(434,412)	(47,674)					(612,151)	(35,793)
2034					(434,412)	(47,674)					(612,151)	(35,793)
2035					(434,412)	(47,674)					(612,151)	(35,793)
2036					(434,412)	(47,674)					(612,151)	(35,793)
2037					(434,412)	(47,674)					(612,151)	(35,793)
2038					(434,412)	(47,674)					(612,151)	(35,793)
2039					(434,412)	(47,674)					(612,151)	(35,793)
2040					(434,412)	(47,674)					(612,151)	(35,793)
2041					(434,412)	(47,674)					(612,151)	(35,793)
2042					(434,412)	(47,674)					(612,151)	(35,793)
2043					(434,412)	(47,674)					(612,151)	(35,793)
2044					(434,412)	(47,674)					(612,151)	(35,793)
2045											(612,151)	(35,793)
2046												
2047												
2048												
2049												
Total	169,168,673			11,867,908	(10,249,771)	(1,618,136)	232,427,577			16,113,975	(14,878,953)	(1,235,022)

Recalculation of PTC Allocation

Blazing Star I (2020-2045)							Lake Benton (2019-2044)						
Year	Remaining Months: 300			Levelized			Year	Remaining Months: 300			Levelized		
	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER		Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER
2019							2019						
2020	14,201,105	5.4515%	1.322837	1,024,108	-	(362,973)	2020	11,384,935	5.4515%	1.322837	821,021	-	(292,471)
2021	20,149,863	5.4087%	1.322837	1,441,697	(159,984)	(479,953)	2021	11,029,975	5.4087%	1.322837	789,181	(80,673)	(242,019)
2022	23,756,742	5.4908%	1.322837	1,725,546	(639,938)	84,484	2022	11,832,545	5.4908%	1.322837	859,444	(322,692)	33,175
2023	21,461,355	5.3273%	1.322837	1,512,423	(639,938)	41,292	2023	11,474,531	5.3273%	1.322837	808,632	(322,692)	(13,599)
2024	22,511,301	5.4139%	1.322837	1,612,180	(639,938)	55,006	2024	12,063,339	5.4139%	1.322837	863,934	(322,692)	23,253
2025	24,904,827	5.3061%	1.322837	1,748,104	(586,654)	(57,353)	2025	12,547,980	5.3061%	1.322837	880,760	(298,159)	(23,850)
2026	24,875,436	5.3351%	1.322837	1,755,567	(586,654)	(80,147)	2026	12,609,865	5.3351%	1.322837	889,933	(298,159)	(42,528)
2027	24,639,312	5.2276%	1.322837	1,703,875	(586,654)	(80,147)	2027	12,208,789	5.2276%	1.322837	844,271	(298,159)	(42,528)
2028	24,800,154	5.1275%	1.322837	1,682,158	(586,654)	(80,147)	2028	12,253,284	5.1275%	1.322837	831,122	(298,159)	(42,528)
2029	24,814,405	5.0489%	1.322837	1,657,319	(586,654)	(80,147)	2029	10,762,081	5.0489%	1.322837	718,784	(298,159)	(42,528)
2030	6,607,564	4.7416%	1.322837	414,453	(586,654)	(80,147)	2030					(298,159)	(42,528)
2031					(586,654)	(80,147)	2031					(298,159)	(42,528)
2032					(586,654)	(80,147)	2032					(298,159)	(42,528)
2033					(586,654)	(80,147)	2033					(298,159)	(42,528)
2034					(586,654)	(80,147)	2034					(298,159)	(42,528)
2035					(586,654)	(80,147)	2035					(298,159)	(42,528)
2036					(586,654)	(80,147)	2036					(298,159)	(42,528)
2037					(586,654)	(80,147)	2037					(298,159)	(42,528)
2038					(586,654)	(80,147)	2038					(298,159)	(42,528)
2039					(586,654)	(80,147)	2039					(298,159)	(42,528)
2040					(586,654)	(80,147)	2040					(298,159)	(42,528)
2041					(586,654)	(80,147)	2041					(298,159)	(42,528)
2042					(586,654)	(80,147)	2042					(298,159)	(42,528)
2043					(586,654)	(80,147)	2043					(298,159)	(42,528)
2044					(586,654)	(80,147)	2044					(273,313)	(38,984)
2045					(195,551)	(26,716)	2045						
2046							2046						
2047							2047						
2048							2048						
2049							2049						
Total	232,722,064			16,277,430	(14,008,433)	(2,268,997)	Total	118,167,324			8,307,082	(6,987,088)	(1,319,995)

Recalculation of PTC Allocation

Year	Blazing Star II (2021-2046)						Freeborn (2021-2046)					
	Remaining Months: 300			Levelized			Remaining Months: 300			Levelized		
	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER
2019												
2020	-	5.4515%	1.322837	-	-	-	-	5.4515%	1.322837	-	-	-
2021	18,519,027	5.4087%	1.322837	1,325,013	(161,223)	(483,670)	9,744,981	5.4087%	1.322837	697,241	-	(390,835)
2022	23,259,181	5.4908%	1.322837	1,689,406	(644,894)	112,695	20,523,507	5.4908%	1.322837	1,490,703	-	(558,818)
2023	21,727,297	5.3273%	1.322837	1,531,164	(644,894)	49,189	20,103,188	5.3273%	1.322837	1,416,710	-	(548,654)
2024	22,776,989	5.4139%	1.322837	1,631,208	(644,894)	56,603	20,691,179	5.4139%	1.322837	1,481,829	-	(526,935)
2025	24,718,276	5.3061%	1.322837	1,735,010	(591,030)	(54,307)	22,405,031	5.3061%	1.322837	1,572,640	-	(583,723)
2026	24,665,668	5.3351%	1.322837	1,740,763	(591,030)	(74,245)	23,249,934	5.3351%	1.322837	1,640,848	(355,173)	(266,033)
2027	24,540,007	5.2276%	1.322837	1,697,008	(591,030)	(74,245)	23,821,522	5.2276%	1.322837	1,647,323	(532,759)	(88,447)
2028	24,810,922	5.1275%	1.322837	1,682,889	(591,030)	(74,245)	23,836,635	5.1275%	1.322837	1,616,804	(532,759)	(88,447)
2029	24,846,794	5.0489%	1.322837	1,659,482	(591,030)	(74,245)	24,016,473	5.0489%	1.322837	1,604,026	(532,759)	(88,447)
2030	24,905,186	4.7416%	1.322837	1,562,152	(591,030)	(74,245)	24,049,660	4.7416%	1.322837	1,508,490	(532,759)	(88,447)
2031	1,923,868	4.4501%	1.322837	113,254	(591,030)	(74,245)	10,452,352	4.4501%	1.322837	615,305	(532,759)	(88,447)
2032					(591,030)	(74,245)					(532,759)	(88,447)
2033					(591,030)	(74,245)					(532,759)	(88,447)
2034					(591,030)	(74,245)					(532,759)	(88,447)
2035					(591,030)	(74,245)					(532,759)	(88,447)
2036					(591,030)	(74,245)					(532,759)	(88,447)
2037					(591,030)	(74,245)					(532,759)	(88,447)
2038					(591,030)	(74,245)					(532,759)	(88,447)
2039					(591,030)	(74,245)					(532,759)	(88,447)
2040					(591,030)	(74,245)					(532,759)	(88,447)
2041					(591,030)	(74,245)					(532,759)	(88,447)
2042					(591,030)	(74,245)					(532,759)	(88,447)
2043					(591,030)	(74,245)					(532,759)	(88,447)
2044					(591,030)	(74,245)					(532,759)	(88,447)
2045					(591,030)	(74,245)					(532,759)	(88,447)
2046					(49,252)	(6,187)					(221,983)	(36,853)
2047												
2048												
2049												
Total	236,693,213			16,367,347	(14,556,779)	(1,810,568)	222,894,462			15,291,920	(10,699,580)	(4,592,340)

Recalculation of PTC Allocation

Year	Dakota Range (2022-2047)						Nobles Re-Power (2022-2045)					
	Remaining Months: 300			Levelized			Remaining Months: 300			Levelized		
	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER
2019												
2020	-	5.4515%	1.322837	-	-	-	-	5.4515%	1.322837	-	-	-
2021	-	5.4087%	1.322837	-	-	-	-	5.4087%	1.322837	-	-	-
2022	31,409,475	5.4908%	1.322837	2,281,394	-	(815,485)	2,133,624	5.4908%	1.322837	154,974	-	(51,873)
2023	24,725,133	5.3273%	1.322837	1,742,427	-	(776,545)	19,500,885	5.3273%	1.322837	1,374,265	-	(682,560)
2024	29,597,273	5.4139%	1.322837	2,119,652	-	(742,919)	21,475,406	5.4139%	1.322837	1,537,993	-	(566,304)
2025	29,015,850	5.3061%	1.322837	2,036,663	-	(807,157)	23,485,519	5.3061%	1.322837	1,648,481	-	(667,586)
2026	28,703,961	5.3351%	1.322837	2,025,762	(496,532)	(282,693)	22,545,110	5.3351%	1.322837	1,591,106	(376,393)	(277,539)
2027	28,650,674	5.2276%	1.322837	1,981,272	(744,798)	(34,427)	22,729,941	5.2276%	1.322837	1,571,837	(564,589)	(89,343)
2028	28,680,184	5.1275%	1.322837	1,945,335	(744,798)	(34,427)	22,855,384	5.1275%	1.322837	1,550,247	(564,589)	(89,343)
2029	28,766,453	5.0489%	1.322837	1,921,270	(744,798)	(34,427)	22,923,186	5.0489%	1.322837	1,531,007	(564,589)	(89,343)
2030	28,839,064	4.7416%	1.322837	1,808,900	(744,798)	(34,427)	22,985,304	4.7416%	1.322837	1,441,729	(564,589)	(89,343)
2031	28,845,151	4.4501%	1.322837	1,698,046	(744,798)	(34,427)	23,047,287	4.4501%	1.322837	1,356,739	(564,589)	(89,343)
2032	170,592	4.4501%	1.322837	10,042	(744,798)	(34,427)	20,963,734	4.4501%	1.322837	1,234,085	(564,589)	(89,343)
2033					(744,798)	(34,427)					(564,589)	(89,343)
2034					(744,798)	(34,427)					(564,589)	(89,343)
2035					(744,798)	(34,427)					(564,589)	(89,343)
2036					(744,798)	(34,427)					(564,589)	(89,343)
2037					(744,798)	(34,427)					(564,589)	(89,343)
2038					(744,798)	(34,427)					(564,589)	(89,343)
2039					(744,798)	(34,427)					(564,589)	(89,343)
2040					(744,798)	(34,427)					(564,589)	(89,343)
2041					(744,798)	(34,427)					(564,589)	(89,343)
2042					(744,798)	(34,427)					(564,589)	(89,343)
2043					(744,798)	(34,427)					(564,589)	(89,343)
2044					(744,798)	(34,427)					(564,589)	(89,343)
2045					(744,798)	(34,427)					(517,540)	(81,897)
2046					(744,798)	(34,427)						
2047					(62,066)	(2,869)						
2048												
2049												
Total	287,403,810			19,570,765	(15,454,549)	(4,116,215)	224,645,379			14,992,463	(11,056,537)	(3,935,926)

Recalculation of PTC Allocation

Recalculation of PTC Allocation													
Grand Meadow Re-Power (2023-2043)							Mower (2021-2046)						
Year	Remaining Months: 300			Levelized			Year	Remaining Months: 300			Levelized		
	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER		Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER
2019							2019						
2020	-	5.4515%	1.322837	-	-	-	2020	-	5.4515%	1.322837	-	-	-
2021	-	5.4087%	1.322837	-	-	-	2021	5,561,093	5.4087%	1.322837	397,889	(260,878)	-
2022	-	5.4908%	1.322837	-	-	-	2022	9,195,868	5.4908%	1.322837	667,932	(260,878)	42,960
2023	7,148,954	5.3273%	1.322837	503,800	-	(246,556)	2023	8,405,005	5.3273%	1.322837	592,317	(260,878)	43,619
2024	10,838,284	5.4139%	1.322837	776,200	-	(309,150)	2024	9,458,332	5.4139%	1.322837	677,372	(260,878)	52,573
2025	10,805,372	5.3061%	1.322837	758,444	-	(339,900)	2025	9,532,898	5.3061%	1.322837	669,127	(207,313)	(21,232)
2026	10,364,847	5.3351%	1.322837	731,492	(206,868)	(120,634)	2026	9,585,943	5.3351%	1.322837	676,521	(207,313)	(47,339)
2027	9,846,072	5.2276%	1.322837	680,883	(310,302)	(17,200)	2027	9,316,986	5.2276%	1.322837	644,295	(207,313)	(47,339)
2028	9,894,515	5.1275%	1.322837	671,131	(310,302)	(17,200)	2028	9,269,484	5.1275%	1.322837	628,736	(207,313)	(47,339)
2029	10,080,137	5.0489%	1.322837	673,238	(310,302)	(17,200)	2029	9,523,034	5.0489%	1.322837	636,030	(207,313)	(47,339)
2030	10,300,455	4.7416%	1.322837	646,085	(310,302)	(17,200)	2030	9,762,029	4.7416%	1.322837	612,313	(207,313)	(47,339)
2031	10,352,053	4.4501%	1.322837	609,401	(310,302)	(17,200)	2031	1,118,913	4.4501%	1.322837	65,868	(207,313)	(47,339)
2032	10,352,053	4.4501%	1.322837	609,401	(310,302)	(17,200)	2032					(207,313)	(47,339)
2033	1,754,376	4.4501%	1.322837	103,276	(310,302)	(17,200)	2033					(207,313)	(47,339)
2034					(310,302)	(17,200)	2034					(207,313)	(47,339)
2035					(310,302)	(17,200)	2035					(207,313)	(47,339)
2036					(310,302)	(17,200)	2036					(207,313)	(47,339)
2037					(310,302)	(17,200)	2037					(207,313)	(47,339)
2038					(310,302)	(17,200)	2038					(207,313)	(47,339)
2039					(310,302)	(17,200)	2039					(207,313)	(47,339)
2040					(310,302)	(17,200)	2040					(207,313)	(47,339)
2041					(310,302)	(17,200)	2041					(207,313)	(47,339)
2042					(310,302)	(17,200)	2042					(207,313)	(47,339)
2043					(284,443)	(15,767)	2043					(207,313)	(47,339)
2044							2044					(207,313)	(47,339)
2045							2045					(207,313)	(47,339)
2046							2046					(34,552)	(7,890)
2047							2047						
2048							2048						
2049							2049						
Total	101,737,119			6,763,350	(5,456,138)	(1,307,212)	Total	90,729,585			6,268,400	(5,431,643)	(836,757)

Recalculation of PTC Allocation

Year	Borders Re-power (2025-2049)						Pleasant Re-power (2025-2049)					
	Remaining Months: 289			Levelized			Remaining Months: 289			Levelized		
	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER	Orig PTC	ND Alloc	Tax Gross	Orig ND PTC	Base Rates	RER
2019												
2020	-	5.4515%	1.322837	-	-	-	-	5.4515%	1.322837	-	-	-
2021	-	5.4087%	1.322837	-	-	-	-	5.4087%	1.322837	-	-	-
2022	-	5.4908%	1.322837	-	-	-	-	5.4908%	1.322837	-	-	-
2023	-	5.3273%	1.322837	-	-	-	-	5.3273%	1.322837	-	-	-
2024	-	5.4139%	1.322837	-	-	-	-	5.4139%	1.322837	-	-	-
2025	-	5.3061%	1.322837	-	-	(43,977)	-	5.3061%	1.322837	-	-	(57,912)
2026	20,462,931	5.3351%	1.322837	1,444,157	-	(555,042)	25,267,130	5.3351%	1.322837	1,783,210	-	(722,115)
2027	20,627,057	5.2276%	1.322837	1,426,417	-	(555,042)	27,077,962	5.2276%	1.322837	1,872,515	-	(722,115)
2028	21,022,008	5.1275%	1.322837	1,425,892	-	(555,042)	27,701,527	5.1275%	1.322837	1,878,954	-	(722,115)
2029	21,292,349	5.0489%	1.322837	1,422,086	-	(555,042)	27,854,971	5.0489%	1.322837	1,860,394	-	(722,115)
2030	21,398,380	4.7416%	1.322837	1,342,191	-	(555,042)	27,923,766	4.7416%	1.322837	1,751,489	-	(722,115)
2031	21,444,075	4.4501%	1.322837	1,262,362	-	(555,042)	28,000,663	4.4501%	1.322837	1,648,333	-	(722,115)
2032	21,444,075	4.4501%	1.322837	1,262,362	-	(555,042)	28,000,663	4.4501%	1.322837	1,648,333	-	(722,115)
2033	21,444,075	4.4501%	1.322837	1,262,362	-	(555,042)	28,000,663	4.4501%	1.322837	1,648,333	-	(722,115)
2034	21,442,373	0	1	1,262,262	-	(555,042)	27,999,797	0	1	1,648,282	-	(722,115)
2035	21,317,195	0	1	1,254,893	-	(555,042)	28,009,114	0	1	1,648,830	-	(722,115)
2036					-	(555,042)					-	(722,115)
2037					-	(555,042)					-	(722,115)
2038					-	(555,042)					-	(722,115)
2039					-	(555,042)					-	(722,115)
2040					-	(555,042)					-	(722,115)
2041					-	(555,042)					-	(722,115)
2042					-	(555,042)					-	(722,115)
2043					-	(555,042)					-	(722,115)
2044					-	(555,042)					-	(722,115)
2045					-	(555,042)					-	(722,115)
2046					-	(555,042)					-	(722,115)
2047					-	(555,042)					-	(722,115)
2048					-	(555,042)					-	(722,115)
2049					-	(555,042)					-	(722,115)
Total	211,894,517			13,364,983	0	(13,364,983)	275,836,258			17,388,672	0	(17,388,672)

Recalculation of PTC Allocation

Pleasant Valley (2015-2040)							Current Projection of PTCs returned to Customers		
Year	Orig PTC	ND Alloc	Tax Gross	Non-Levelized			Orig ND PTC	Base Rates	RER
				Orig ND PTC	Base Rates	RER			
2019									
2020	-	5.4515%	1.322837	-	-	-	5,517,478	0.0000%	(1,851,564.854779)
2021	17,715,541	5.4087%	1.322837	1,267,524	(1,453,027)	185,503	10,969,577	-258337159.7973%	(2,813,731.668689)
2022	22,539,161	5.4908%	1.322837	1,637,108	(1,453,027)	(184,081)	16,023,369	-519177098.8354%	(1,233,728.756122)
2023	19,865,575	5.3273%	1.322837	1,399,965	(1,453,027)	53,062	15,817,624	-519177098.8354%	(1,992,111.096425)
2024	21,220,372	5.4139%	1.322837	1,519,728	(1,453,027)	(66,701)	17,691,195	-519177098.8354%	(1,952,380.784388)
2025	12,515,023	5.3061%	1.322837	878,447	-	(878,447)	16,455,723	-348373651.9505%	(3,576,196.371131)
2026							17,567,727	-491870156.1160%	(2,455,833.525669)
2027							16,995,229	-563618408.1987%	(1,738,351.004842)
2028							16,793,388	-563618408.1987%	(1,738,351.004842)
2029							16,527,673	-563618408.1987%	(1,738,351.004842)
2030							12,534,491	-563618408.1987%	(1,738,351.004842)
2031							7,369,307	-563618408.1987%	(1,738,351.004842)
2032							4,764,223	-563618408.1987%	(1,738,351.004842)
2033							3,013,971	-563618408.1987%	(1,738,351.004842)
2034							2,910,544	(5,636,184)	(1,738,351)
2035							2,903,723	(5,636,184)	(1,738,351)
2036							-	(5,636,184)	(1,738,351)
2037							-	(5,636,184)	(1,738,351)
2038							-	(5,636,184)	(1,738,351)
2039							-	(5,636,184)	(1,738,351)
2040							-	(5,636,184)	(1,738,351)
2041							-	(5,275,473)	(1,756,725)
2042							-	(4,882,167)	(1,834,299)
2043							-	(4,856,309)	(1,832,866)
2044							-	(4,547,019)	(1,813,555)
2045							-	(3,401,142)	(1,666,021)
2046							-	(1,050,585)	(1,362,514)
2047							-	(62,066)	(1,280,026)
2048							-	-	(1,277,157)
2049							-	-	(1,277,157)
Total	93,855,673			6,702,773	(5,812,108)	(890,665)	183,855,241	(129,542,460)	(54,312,780)

Summary of CWIP for Self Build Wind Farms Cap **Protected Data is Shaded.**

Build Type		Pre-2022	2022	2023	2024	2025	Total	CWIP CAP	Difference
Self-Build									
Blazing Star I	CWIP	315,595,293	1,204	-	-	-	315,596,497		
Blazing Star II	CWIP	342,502,116	331,870	1,856	-	-	342,835,842		
Foxtail	CWIP	230,240,048	45,690	-	-	-	230,285,739		
Freeborn	CWIP	317,922,660	210,034	3,611	-	-	318,136,304		
Dakota Range	CWIP	375,379,291	2,560,293	(162,888)	1,862	-	377,778,558	[PROTECTED DATA BEGINS	
Total Self-Build CWIP		1,581,639,409	3,149,091	(157,421)	1,862	-	1,584,632,940	PROTECTED DATA ENDS]	

(2) Re-Power Projects O&M is already being recovered in base rates.

Build Type		Pre-2022	2022	2023	2024	2025	2026	2027	2028	Total	CWIP CAP	Difference
Repowers												
Borders	CWIP	619,101	9,746	5,540,986	32,251,530	143,868,928	19,044,455	220,800	18,400	201,573,946		
Grand Meadows	CWIP	8,930,207	90,794,041	12,700,453	265,979	63,550	-	-	-	112,754,230		
Nobles	CWIP	99,761,185	112,345,774	736,928	302,461	65,268	-	-	-	213,211,615		
Pleasant Valley	CWIP	807,564	824,068	7,471,022	41,659,699	183,212,129	13,124,896	224,000	112,000	247,435,377	[PROTECTED DATA BEGINS	
Total Wind Repower Portfolio CV		110,118,058	203,745,102	26,257,623	38,042,578	385,076,072	12,719,853	444,800	130,400	774,975,169	*	
PROTECTED DATA ENDS]												

*Corrected Total of Table 1 Joint Stipulation of Capital Expenditure Costs from Case No. PU-20-425

Operations & Maintenance Expense^{1,2}				<u>Reference</u>
Amounts in dollars	2025	2026³	2027	
	<i>Actual</i>	<i>Mixed</i>	<i>Forecast</i>	
<u>Freeborn</u>				
Total O&M Costs	6,589,038	2,039,209	-	Att. 5
Allocator	5.1193%	5.0693%	4.9576%	Att. 2
O&M North Dakota Jurisdiction	337,314	103,373	-	
<u>Dakota Range</u>				
Total O&M Costs	4,500,825	2,331,698	-	Att. 5
Allocator	5.1193%	5.0693%	4.9576%	Att. 2
O&M North Dakota Jurisdiction	230,411	118,200	-	

Notes:

-
- (1) Total O&M Costs include: Labor/Consulting, Space/Lease Costs, Materials, and Other.
(2) Re-Power Projects O&M is already being recovered in base rates.
(3) Total O&M Costs through May 2026.

Legislative

RENEWABLE ENERGY RIDER

Section No. 5
~~16th~~17th 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 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 Fee 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 ~~\$0.0010490~~0.000246 per kWh

C

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 have previously been granted an Advance Determination of Prudence by the Commission.

TRUE-UP

For each 12-month period ending December 31, a true-up will be calculated reflecting the difference between actual RER revenue and the actual qualifying RER costs. The resulting true-up shall be netted with the forecasted RER cost for the current calendar year. The difference between forecasted RER revenue and forecasted qualifying RER costs for current calendar year is then included in the calculation of the RER rate proposed for the following calendar year.

For example, Year 1 actual RER revenue will be compared to actual Year 1 RER costs and the difference rolled into the forecasted Year 2 costs. Year 2 forecasted RER revenue is then compared to forecasted Year 2 RER costs and the difference included in the calculation of the proposed RER rate to be effective in Year 3.

Date Filed: ~~06-11-26~~09-29-26

By: Bria E. Shea

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President, Northern States Power Company, a Minnesota corporation

Case No. ~~PU-24-376~~PU-26-

Order Date: ~~02-05-26~~

Non-Legislative

RENEWABLE ENERGY RIDER

Section No. 5
17th 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 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 Fee 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

\$0.000246 per kWh

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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 have previously been granted an Advance Determination of Prudence by the Commission.

TRUE-UP

For each 12-month period ending December 31, a true-up will be calculated reflecting the difference between actual RER revenue and the actual qualifying RER costs. The resulting true-up shall be netted with the forecasted RER cost for the current calendar year. The difference between forecasted RER revenue and forecasted qualifying RER costs for current calendar year is then included in the calculation of the RER rate proposed for the following calendar year.

For example, Year 1 actual RER revenue will be compared to actual Year 1 RER costs and the difference rolled into the forecasted Year 2 costs. Year 2 forecasted RER revenue is then compared to forecasted Year 2 RER costs and the difference included in the calculation of the proposed RER rate to be effective in Year 3.

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Case No. PU-26-

Order Date:

Proposed Customer Bill Notice**Renewable Energy Rider Rate Decrease
Effective January 1, 2027**

The Renewable Energy Rider (RER) line item on your bill recovers investment costs associated with new and modified renewable energy generation facilities approved by the North Dakota Public Service Commission. These investments reduce fuel and purchased energy costs. Beginning January 1, 2027, the RER rate will decrease from the previously approved rate of \$0.002437 to \$0.000246 per kWh.

Residential Electric Service – Average Annual Bill

The chart below shows the change to typical customer bills from the RER rate decrease. The comparison does not reflect any other rate changes that may occur at the same time.

Usage (kWh)	Prior				New				Bill Change	Percent Change
	Other Charges	RER Rate	RER Charge	Bill	Other Charges	New RER Rate	New RER Charge	New Bill		
400	\$66.25	\$0.002437	\$0.97	\$67.22	\$66.25	\$0.000246	\$0.10	\$66.35	(\$0.87)	-1.29%
500	\$77.44	\$0.002437	\$1.22	\$78.66	\$77.44	\$0.000246	\$0.12	\$77.56	(\$1.10)	-1.40%
600	\$88.63	\$0.002437	\$1.46	\$90.09	\$88.63	\$0.000246	\$0.15	\$88.78	(\$1.31)	-1.45%
750	\$105.41	\$0.002437	\$1.83	\$107.24	\$105.41	\$0.000246	\$0.18	\$105.59	(\$1.65)	-1.54%
1000	\$133.38	\$0.002437	\$2.44	\$135.82	\$133.38	\$0.000246	\$0.25	\$133.63	(\$2.19)	-1.61%
1500	\$189.32	\$0.002437	\$3.66	\$192.98	\$189.32	\$0.000246	\$0.37	\$189.69	(\$3.29)	-1.70%
2000	\$245.26	\$0.002437	\$4.87	\$250.13	\$245.26	\$0.000246	\$0.49	\$245.75	(\$4.38)	-1.75%

For more information

You may examine the new rate riders by visiting our website at

https://www.xcelenergy.com/company/rates_and_regulations/rates

(Select “North Dakota” in the dropdown at top of page).