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March 31, 2026

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

RE: In the Matter of Otter Tail Power Company's Application for Approval of Tariff Updates to Section 5.02 Special Facilities, Section 9.03 Farm Service, Section 13.01 Energy Adjustment Rider, and Section 14.02 Real-Time Pricing
Case No. PU-26-
Initial Filing

Dear Mr. Johnson:

Otter Tail Power Company (Otter Tail Power) hereby submits to the North Dakota Public Service Commission (Commission) its application requesting approval of updates to several sections of its North Dakota Electric Rate Schedule. The enclosed filing includes proposed revisions to:

- Section 5.02 – Special Facilities
- Section 9.03 – Farm Service
- Section 13.00 – Mandatory Riders – Applicability Matrix
- Section 13.01 – Energy Adjustment Rider
- Section 13.04 – Renewable Resource Cost Recovery Rider
- Section 13.05 – Transmission Cost Recovery Rider
- Section 14.00 – Voluntary Riders – Availability Matrix
- Section 14.02 – Real-Time Pricing
- Section 14.04 – Controlled Service – Interruptible Load
- Section 14.06 – Controlled Service – Deferred Load Rider
- Section 14.08 – Air Conditioning Control Rider

Copies have been sent to you via USPS along with a $10,000 check for the filing fee.

Please contact me at (218) 739-8728 or agrenier@otpco.com if you have any questions regarding this filing.

Sincerely,

/S/ AMBER GRENIER
Amber Grenier
Manager, Regulatory Economics
Regulatory Administration

vjm
Enclosures
By electronic filing and U.S. mail

Case No. PU-26-
Analyst Assigned: Amber Grenier

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Otter Tail Power Company's Application for Approval of Miscellaneous Tariff Updates	**Case No. PU-26-** **APPLICATION**

I. INTRODUCTION

Otter Tail Power Company (Otter Tail Power or the Company) respectfully submits this filing to the North Dakota Public Service Commission (Commission) requesting approval of revisions to several sections of its North Dakota Electric Rate Schedule. The proposed updates address necessary clarifications, administrative efficiencies, and tariff modifications related to Special Facilities (Section 5.02), Farm Service (Section 9.03), the Energy Adjustment Rider (Section 13.01), and the Real-Time Pricing tariff (Section 14.02). These changes are intended to ensure consistent application of tariff provisions, improve transparency, and align Otter Tail Power's rates and operational practices with current Midcontinent Independent System Operator (MISO) market requirements and jurisdictional cost-allocation principles.

This filing includes:

- Section 5.02 – Special Facilities: Clarifying definitions and cost responsibilities associated with Special Facilities and Extra Facilities to ensure consistent application of tariff provisions.
- Section 9.03 – Farm Service: Creating a separate rate code for three-phase customers to improve internal reporting and administrative accuracy without affecting existing rates or eligibility.
- Section 14.08 – Air Conditioning Control Credit: Expanding the available curtailment season, increasing customer compensation, and modernizing cycling requirements to leverage the Company's new Advanced Load Management System.
- Sections 14.04 and 14.06 – Conforming Load-Management Revisions: Updating the cycling provisions in Controlled Service – Interruptible (Section 14.04) and Deferred Load (Section 14.06) to ensure consistency

with the operational flexibility introduced in Section 14.08 and to support optimized system-wide demand-response capabilities.

- Section 13.01 – Energy Adjustment Rider: Transitioning from a system-wide to a jurisdiction-specific calculation for North Dakota to reflect recent operational changes—including Minnesota's Available Maximum Energy (AME) designation of Coyote Station—and to ensure proper cost allocation.
- Section 14.02 – Real-Time Pricing: Modernizing the tariff to incorporate MISO Day-Ahead and Real-Time pricing, integrate applicable market charges, enhance cost transparency, and provide customers with more accurate price signals.

The proposed changes modernize the Company's tariff language, enhance cost accuracy, and ensure alignment between customer billing and the market-based costs incurred to serve them. Except where otherwise described, these updates are administrative in nature and do not result in changes to existing customer rates, eligibility, or revenue requirements.

II. GENERAL FILING INFORMATION

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

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

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

B. Name, address, and telephone number of utility attorney

Lauren Donofrio
Senior Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone (218) 739-8956

C. Title of utility employee responsible for filing

Amber Grenier
Manager, Regulatory Economics
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8728

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

Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
regulatory_filing_coordinators@otpco.com

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

The date of this filing is March 31, 2026. Otter Tail Power proposes effective date of August 1, 2026, for the Energy Adjustment Rider, and June 1, 2026, for all other tariff updates.

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

Pursuant to N.D. Admin. Code § 69-02-02-04, a certified copy of Otter Tail Power's articles of incorporation and a current certificate of good standing is on file with the Commission in Case No. PU-09-677. The certificate and amendments are hereby incorporated by reference.

F. Customer Notification

Otter Tail Power will include a notice to North Dakota customers on April bills of the proposed changes to the RTP tariff and EAR tariff. Otter Tail Power will also include a bill insert implementation notice to North Dakota customers during the month rates and rate schedule changes are implemented following Commission approval. Attachment 1 is a sample of the bill message implementation notices.

III. SECTION 05.02, SPECIAL FACILITIES UPDATE

Section 5.02 of the Company's General Rules and Regulations addresses the charges applied when customers request line extensions or certain non-standard

equipment designs or installations. Under the existing tariff, customers who seek Special Facilities are required to execute an agreement or service form that outlines the applicable payments. After costs are calculated, customers pay a percentage of the equipment cost—similar to a rental arrangement—because the equipment remains Company-owned and maintained for as long as the customer requires it.

The Company proposes to revise the definitions in Section 5.02 to more clearly distinguish between "Special Facilities" and "Extra Facilities" Special Facilities refer to non-standard equipment or design necessary to provide service, while Extra Facilities refer to standard equipment provided in quantities that exceed those normally required for service. Correspondingly, the Company also proposes to clarify the distinction between "Excess Expenditures" (costs associated with Special Facilities) and Extra Facilities Expenditures (costs associated with Extra Facilities).

Under the proposed revisions, Extra Facilities Expenditures will be treated in the same manner as Excess Expenditures, unless the Company and the customer have expressly agreed to different terms in a Commission-approved Electric Service Agreement (ESA). These updates are intended to improve transparency, ensure consistent application of the tariff, and better align terminology with existing practices. The proposed changes are administrative in nature and do not alter existing rates, charges, or customer requirements. Attachment 2 contains the redline and clean version of the tariff.

IV. SECTION 09.03, FARM TARIFF UPDATE

The Farm Service Class currently includes a single rate identified as Farm Service (Section 9.03). Within this rate, customers may receive either single-phase or three-phase service, each of which already has a distinct facilities charge.

The Company proposes to add a separate rate code specifically for three-phase Farm Service customers. This change is purely administrative and does not modify the existing rates, facilities charges, or customer eligibility. The new rate code will allow for improved identification of single-phase and three-phase customers within the Company's customer information system, thereby enhancing internal reporting and analytics capabilities.

Because the underlying facilities charges for single-phase and three-phase services are already differentiated in the approved tariff, this update simply aligns internal coding with the existing tariff structure. No customer impacts, billing changes, or revenue effects are expected as a result of this proposal. Attachment 2 contains the redline and clean version of the tariff.

V. SECTION 14.08, AIR CONDITIONING CONTROL CREDIT

A. Background

The Air Conditioning Control (CoolSavings) credit is a voluntary demand-response option available to customers with central cooling equipment, including heat pumps. In exchange for a bill credit, participating customers authorize the Company to control service to their cooling equipment during periods of system need.

The Company seeks to eliminate the current seasonal limitation that restricts curtailment to May through October. Due to increasingly variable year-round load patterns, evolving regional market conditions, and the need for more flexible system operations, peak events requiring load management can occur outside the traditional summer season. Expanding the curtailment period to year-round, but only when cooling equipment is likely operating, will allow the Company to deploy CoolSavings load management whenever necessary to support system reliability, reduce capacity and energy costs, and mitigate upward pressure on customer rates.

To align customer compensation with the expanded availability period, the Company proposes increasing the bill credit months from five to six. Credits will be issued for the six months of May through October. Currently North Dakota customers receive the credit for five months of the year, in exchange for allowing up to six months of control. Residential customer compensation will increase from $41.25 ($8.25/month) for five months to $42.00 ($7.00/month) over six months. Commercial customer compensation will remain the same, currently at $30 ($6.00) per BTU/ton for five months and changing to $30 ($5.00) per BTU/ton for six months. This adjustment ensures participating customers receive appropriate and equitable compensation reflecting their allowance for curtailment. This proposal creates alignment with the Company and South Dakota Commission staff's agreement in the Company's existing South Dakota rate case. In addition, this proposal also creates alignment with Otter Tail Power's proposal in its pending Minnesota rate case.

B. Proposed Revisions to Cycling Requirements

The Company further petitions the Commission to approve revisions to the cycling provisions contained in the Terms and Conditions under Section 14.08. The current tariff specifies a fixed cycling interval of 15 minutes off and 15 minutes on. As the Company transitions to its new Advanced Load Management System,

its operational tools will provide greater precision in the management of load-control resources. Maintaining rigid 15-minute cycling intervals will limit the Company's effectiveness in responding to real-time system conditions, such as MISO market pricing events and unplanned operational contingencies.

The Company proposes removing the prescribed 15-minute on/off schedule and replacing it with flexible cycling authority. Under the revised provisions, the Company may apply cycling durations appropriate to equipment type, weather conditions, system needs, and customer comfort considerations. Examples of potential cycling patterns include 30 minutes off and 30 minutes on, 15 minutes off and 30 minutes on, or other intervals supported by the Advanced Load Management System. The Company is committed to continuing reasonable cycling practices and minimizing impacts on customer comfort and will continue to maintain its limit on control hours to 300 hours annually, with the exception of system emergencies. Otter Tail Power's proposal to Section 14.08, adds flexibility to allow for more precise and advanced load control but maintains the total allowed annual hours.

C. Conforming Revisions to Other Cycling Program

To maintain consistency across its load-management offerings, the Company also petitions the Commission to approve corresponding revisions to the cycling provisions in Section 14.04 (Controlled Service – Interruptible) and Section 14.06 (Deferred Load). These sections currently specify the same 15-minute off/5-minute on cycling requirement. The Company proposes removing this fixed schedule to allow similar operational flexibility as proposed in Section 14.08.

While Otter Tail Power anticipates maintaining the existing 15-minute cycle pattern for the near future, it will require the flexibility to deviate from this pattern once the Advanced Load Management System is implemented. Consistent cycling flexibility across programs will allow the Company to optimize demand-response operations, enhance system reliability, and reduce costs for all customers. Again, through this proposal the Company does not plan to increase the number of annual control hours but instead add flexibility to allow for more precise and advanced load control in response to quickly changing energy market conditions.

VI. SECTION 13.01, ENERGY ADJUSTMENT RIDER TARIFF UPDATE

A. Background

The Energy Adjustment Rider (EAR) rate is calculated and implemented each month to reflect changes in fuel and purchase power costs, as outlined in Section 13.01 of Otter Tail Power's Electric Rate Schedule. Under this section, the EAR rate is determined on a system basis using a trailing four-month average of Commission-approved recoverable costs. Historically, Otter Tail Power has also operated its generation resource on a system-wide basis.

On May 30, 2024, the Minnesota Public Utilities Commission (MPUC) approved Otter Tail Power's Integrated Resource Plan, which adopted a new operational approach for the Company's Minnesota-jurisdictional share of the Coyote Station generating facility located in Beulah, North Dakota. Under the MPUC's decision, approximately 70 MW of Otter Tail Power's ownership share will transition to AME status beginning in June 2026. Under AME operations, this portion of the plant will not operate under normal economic dispatch and will run only when called upon during emergency events declared by the MISO. Minnesota customers will continue to be assigned the fixed costs associated with their share of Coyote Station and will bear the costs associated with energy produced during an AME event.

B. Need for Revisions

In recent years, Otter Tail Power's generation fleet has shifted from system-wide operation to jurisdiction-specific operation. This transition began with the Hoot Lake Solar facility and will continue with the Coyote AME designation, as well as the Minnesota and South Dakota jurisdictional investments in Abercrombie Solar and Solway Solar. This diversification of ownership and cost responsibility marks a departure from traditional system-basis operations and has implications for how EAR-eligible costs are calculated and allocated.

Because Minnesota's use of Coyote Station is now limited to emergency only operations and Minnesota customers are responsible solely for the Minnesota allocated portion of fixed and AME event costs, Otter Tail Power must modify the method it uses to calculate the North Dakota EAR. To ensure that costs and revenues are allocated appropriately and in accordance with jurisdictional cost causation principles, the Company proposes to shift from a system level EAR calculation to a jurisdiction specific EAR calculation for North Dakota. This modification is necessary to prevent the allocation of Minnesota specific Coyote

Station costs to North Dakota customers and to prevent the allocation of market revenues attributable to Coyote Station to Minnesota Customers. Otter Tail Power therefore requests Commission approval of the proposed revisions to its North Dakota EAR.

C. System-Wide Rate to Jurisdictional Rate

To support the transition from system-wide to jurisdiction-specific generation, Otter Tail Power has established separate MISO Asset Owners that correspond to each regulatory jurisdiction—or combination of jurisdictions—receiving cost responsibility. These Asset Owner IDs determine how MISO-related costs and revenues are allocated across states. For example, OTPM applies to Minnesota, OTPK represents a combined North Dakota–South Dakota allocation, OTPB represents a Minnesota–South Dakota allocation, and OTPW is used when costs and revenues are shared across all three jurisdictions.

Creating distinct Asset Owners enables each generation resource or allocation group to be uniquely identified in the MISO Market Portal and ensures that market-related transactions—including day-ahead and real-time energy revenues, ancillary service charges and credits, fuel costs, congestion charges, loss allocations, and other settlement components—are assigned to the appropriate jurisdiction. This structure allows Otter Tail Power to first segregate revenues and costs at the Asset Owner level and then allocate those amounts to individual jurisdictions within each Asset Owner based on jurisdictional energy sales. As a result, customers in each state bear only the costs—and receive only the benefits—associated with the generating resources assigned to them.

This approach represents a significant operational shift from historical system-basis operations and directly affects how EAR-eligible costs are calculated, allocated, and recovered.

D. Developing Multi-Jurisdictional MISO Asset Owner Structure

In developing this structure, the Company evaluated whether to create individual Asset Owners for each jurisdiction and an additional system-wide Asset Owner, or to use multi-jurisdictional Asset Owners. The Company ultimately determined that multi-jurisdictional Asset Owners were necessary for both operational and administrative reasons.

First, MISO does not provide a practical mechanism to split a single physical generating unit into multiple Asset Owners. If Otter Tail Power were to divide a unit—such as a future natural gas facility—into two separate Asset Owners, MISO

would treat those shares as distinct, independent units. This would allow MISO to commit one share and not the other, which is not feasible for a single physical generator. This challenge already affects jointly owned units, where different owners must offer their respective shares independently because they are separate companies. Creating this scenario within Otter Tail Power's own fleet would introduce unnecessary operational complexity.

Second, splitting all generation assets into separate Asset Owners would create substantial additional daily administrative work. Otter Tail Power staff would need to submit separate offers for each Asset Owner every day and would process additional settlement streams for each artificially created unit split.

Third, MISO commercial model updates would be required every time jurisdictional allocations change. Under a multi-jurisdictional structure, updates are far less frequent because each Asset Owner already represents the appropriate allocation group.

The Company will maintain single-jurisdiction Asset Owners for resources assigned exclusively to one state, and system-wide assets–such as Company load and any resource shared across all three jurisdictions–will continue to reside in the system-wide Asset Owner, OTPW.

E. Impact to Customer

The table below shows the projected changes to the EAR rates attributable to the implementation of the Company's multi-jurisdictional Asset Owner allocation mechanism from its start in August 2026 through December 2027.

Table 1

Effective Month	Projected EAR Rate Current Method	Projected EAR Rate Allocated Method
August 2026	$0.016370	$0.015790
September 2026	$0.019180	$0.013930
October 2026	$0.021420	$0.011970
November 2026	$0.021320	$0.008460
December 2026	$0.018870	$0.007110
January 2027	$0.018750	$0.010250
February 2027	$0.023440	$0.017860
March 2027	$0.026540	$0.021380
April 2027	$0.029550	$0.024740
May 2027	$0.028120	$0.023870
June 2027	$0.023470	$0.019980
July 2027	$0.019180	$0.016990
August 2027	$0.015520	$0.014150
September 2027	$0.014350	$0.012070
October 2027	$0.017160	$0.014230
November 2027	$0.018050	$0.014620
December 2027	$0.018750	$0.014740

F. EAR Tariff Language Revisions

Otter Tail Power submits proposed revisions to the EAR tariff language to provide clearer guidance regarding the treatment of energy-related costs and to better reflect jurisdiction-appropriate allocation methods in Attachment 2 along with a clean version of the tariff.

VII. SECTION 14.02, REAL-TIME PRICING TARIFF UPDATE

A. Background and Need for Revisions

The RTP Tariff was developed over 25 years ago, prior to the launch of the MISO Day 2 market in 2005. At its inception, the schedule was based on Otter Tail Power's internal projections of hourly system incremental costs, which include

marginal generation units or market purchases, voltage-level losses, and a profit margin. At the time, the schedule provided a reasonable approximation of incremental costs and supported customer participation based on then-prevailing operational and market conditions.

Since MISO market implementation and subsequent evolution, the Company's operational reliance on organized markets – and the complexity and volatility of associated pricing and settlement outcomes – have increased. As a result, the RTP Tariff's legacy approach has become increasingly misaligned with actual market-based costs incurred to serve participating load. Accordingly, the Company determined that the RTP Tariff should be evaluated and revised to better reflect market dynamics, improve cost transparency, and support rates that more accurately align with cost causation.

1. Existing Methodology and Its Limitations

Although referred to as "Real-Time Pricing," the current methodology relies on an internal resource-stack model to estimate the marginal resource serving load each hour rather than using MISO's Day-Ahead and Real-Time Locational Marginal Prices (LMPs). As a result, the existing approach does not reflect actual market conditions, including congestion, system constraints, or other factors embedded in MISO's LMP formation.

In addition, the current pricing method does not account for differences between customers Day-Ahead load forecasts and their actual Real-Time usages – difference that are central to MISO's settlement process and materially affects the costs incurred to serve participating load.

Otter Tail Power has determined that the current RTP methodology no longer aligns with the operational realities of the MISO market. Key limitations include:

- Static cost assumptions rather than market-based pricing: Prices are based on the Company's internal incremental-cost model rather than MISO's Day-Ahead and Real-Time LMPs.
- Exclusion of MISO market settlement components: The existing method does not incorporate several MISO market costs and credits that influence total service costs.
- Insufficient alignment with the real-time operational variability: The rate does not reflect financial impacts associated with deviations between Day-Ahead schedules and Real-Time load, which determine actual MISO settlement charges.

- Obsolescence amid increasing market complexity: Since Rate Schedule 14.02 was developed, MISO has implemented new pricing mechanisms, services, and operational structures, leaving the legacy RTP framework outdated and increasingly inconsistent with current market operations.

2. Customer Transparency and Economic Signaling

The existing model also fails to capture other costs incurred by the Company in serving these loads, including:

- Generation Capacity: Customers on this tariff are not required to curtail their load. As a result, OTP must account for their RTP load in capacity planning. However, the current tariff does not include any capacity-related costs in its rate structure.
- Transmission Service: Similar to generation capacity, OTP includes RTP customer load in transmission planning. Yet the current tariff excludes transmission-related costs from its pricing.
- MISO Schedules and Other Settlement Costs: OTP incurs the following costs on a $/MWh basis, which are not included in the current RTP tariff:
  - Schedule 1: Scheduling, System Control, and Dispatch Service
  - Schedule 10: ISO Cost Recovery Adder
  - Schedule 26A: Multi-Value Project (MVP) Usage Rate
  - Other MISO market settlement costs not reflected in Day-Ahead or Real-Time LMPs that flow through the EAR

It also lacks responsiveness to real-time market conditions and does not provide customers with the opportunity to make economically informed decisions based on actual market signals.

3. Prior Regulatory Action and Purpose of Closure to New Customers

To address the growing misalignment between the RTP Tariff and MISO market realties, Otter Tail Power requested the closure of the RTP tariff to new customers in Case No. PU-23-290. This closure served an important regulatory purpose: it prevented additional customers from enrolling under a pricing structure that no longer reflects market-based cost causation, while providing the Company time to evaluate and revise the tariff structure to better reflect market dynamics and improve cost transparency.

4. Prior Regulatory Action and Purpose of Closure to New Customers

While the MISO Day 2 market commenced operations in 2005, Otter Tail Power did not modify the RTP tariff because, during the initial years of MISO operations, the methodology provided a reasonable approximation of incremental costs for customers. Market-driven cost variability was comparatively limited in magnitude, and the Company's internal cost-based approach remained generally consistent with customer expectations and operational realities.

Over time, however, market and operational conditions have change materially, including:

- Greater reliance on MISO market transactions for both energy procurement and balancing services; and
- Increasing volatility in LMPs driven by congestion, renewable integration, fuel price variability, and other market conditions.

These developments have amplified the divergence between the RTP Tariff's internal, projected cost model and the Company's actual market-based costs under MISO settlements. As a result, continued reliance on a static, internally modeled pricing structure will further erode alignment with actual costs, underscoring the need for tariff revisions that more directly reflect market outcomes and improve cost transparency and rate integrity.

B. Eligibility, Operational Requirements, and Billing Components

1. Eligibility

The RTP tariff is a firm service tariff, meaning Otter Tail Power has planned and procured resources necessary to serve customers under this tariff. This approach is consistent with similar tariffs in Otter Tail Power's other jurisdictions. Otter Tail Power proposes to limit the RTP to the existing customer on the rate because if an existing customer elects to transfer a portion of its load from a firm service rate to the RTP rate, the customer's contribution toward the recovery of costs associated with existing resources will be reduced. This would mean higher rates for other customers.

Historically, Otter Tail Power customers have demonstrated minimal interest in participating in a RTP rate. This may be attributable to operational constraints that limit their ability to adjust load in response to market prices or to a preference for avoiding exposure to market volatility. The existing

customer currently served under the RTP rate has expressed interest in continuing service under this rate. Otter Tail Power intends to maintain this offering for the existing customer, including the proposed tariff updates filed in Case No. PU-25-203, which aligns the RTP rate with market-based pricing principles.

2. Operational Requirements

By 7 a.m. (Central Time) the preceding day, a customer taking service under the RTP rider will provide the Company its expected hourly load for the next business day.[1] The Company will submit that load to MISO and subsequently communicate back to the customer each day the hourly Day-Ahead price with applicable adders by 4 p.m. of the preceding day. The Company may deviate from this procedure in abnormal operating conditions and is not responsible for the Customer's failure to receive or obtain and act upon market energy prices. If the Customer does not receive or obtain the prices made available by the Company, it is the Customer's responsibility to notify the Company by 4:30 p.m. of the business day preceding the day the prices are to take effect. The Company reserves the right to revise its market energy prices at any time prior to the Customer's acceptance and will be responsible for notifying the Customer of such revised prices. If a customer does not provide its expected hourly load, Otter Tail Power will use a standard load profile provided by the customer as a substitute.

Any deviations in the hourly load between the Day-Ahead and Real-Time will be settled at the Real-Time prices with associated adders. The Company is not responsible for providing the hourly Real-Time prices with adders to the RTP customer. MISO publishes its Real-Time rates every hour on its public website.

The operational requirements were developed to ensure the Company has sufficient time to review and submit the Customer's Day-Ahead load bid to MISO for the following day. The MISO Day-Ahead Market closes at 9:30 a.m. daily, and Day-Ahead LMP results are posted by MISO at 12:30 p.m. After receiving these prices, OTP will process them through its manual billing system to apply hourly price adjustments or adders.

The proposed operational requirements are consistent with those in the original RTP, Section 14.02. That section required OTP to notify customers

[1] On Fridays the RTP customer will provide expected loads for Saturday through Monday to the Company. Similarly, the RTP customer will provide expected loads for holidays by 7 a.m. on last business day preceding a holiday.

of day-ahead prices by 4:00 p.m. and for customers who did not receive prices to notify the Company by 4:30 p.m. Similarly, OTP's Large General Service Rider (Section 14.03) and Thermal Market Energy Pricing Rider (Section 14.16) include the same provisions. The proposed requirements do not introduce substantial changes—they align with existing practices across OTP's riders.

3. Billing Components

A customer's monthly bill for energy will be calculated in two parts: (1) energy consumed up to and including the Baseline Demand, and (2) energy consumed above the Baseline Demand.

The Company will calculate the monthly bill for the firm energy the customer consumed, up to and including the Baseline Demand, by multiplying the customer's metered energy consumption by the energy rate provided in the rate schedule applicable to the customer. The customer will also be responsible for the non-energy portions of the Lare General Service (LGS) tariff including the customer charge, facilities charge, and demand charges. The customer will also pay applicable riders, including, but not limited to, Energy Adjustment Rider (EAR), Transmission Cost Recovery (TCR) Rider, and Renewable Resource Cost Recovery (RRCR) Rider on their firm load.

The monthly bill for the non-firm energy consumed above the Baseline Demand under the RTP tariff will be calculated by multiplying the customer's expected hourly load by the Day-Ahead hourly prices plus the difference between the customer's expected hourly load and its realized hourly load (above Baseline Demand) multiplied by Real-Time hourly prices.

Day-Ahead hourly prices are calculated daily based on the Day-Ahead LMP at the OTP.OTP MISO pricing node. These prices include adjustments for voltage-level-specific losses, generation capacity costs, transmission charges, system contributions, and other MISO-related charges attributable to the Customer's load.

Real-Time hourly prices are calculated daily based on the Real-Time LMP at the OTP.OTP MISO pricing node. These prices incorporate the same adjustments as Day-Ahead pricing, including losses by voltage level, generation capacity costs, transmission charges, system contributions, and applicable MISO charges resulting from the Customer's load.

The revised methodology for calculating the Real-Time Pricing rate addresses the challenges associated with the original rate design. By settling differences between forecasted and actual usage at Real-Time energy prices – rather than Day-Ahead prices – the updated rate provides customers with the opportunity to make economically informed decisions based on real-time market signals.

Additionally, the revised approach more accurately reflects the Company's actual costs of serving these loads, as MISO settles deviations between Day-Ahead and Real-Time markets using Real-Time prices. Incorporating applicable MISO charges further ensures alignment between the costs incurred by the Company and those passed on to customers for their non-firm energy.

Finally, the inclusion of hourly pricing components ensures that customer bills more precisely capture the costs they impose on the system.

Table 1 below outlines the hourly price components and the frequency of price updates.

Table 2
Hourly Price Components

Item	Description	Frequency
Hourly Price	MISO DA/RT LMPs	Hourly
Capacity Adder	MISO Seasonal Capacity Auction Price	Seasonally
MISO Schedule 1	Scheduling, System Control & Dispatch	Annually
MISO Schedule 8	Point-to-point transmission service	Annually
MISO Schedule 10	ISO Cost Recovery Adder	Annually
MISO Schedule 26A	MVP Usage Rate	Annually
MISO Market Charges	MISO Energy Market Charges	Monthly
Line Loss Adder	Transmission, Primary, or Secondary service	Rate Case
System Contribution	Additional contribution	Rate Case

C. Applicability of Riders to RTP Tariff

The RTP tariff allows the Company to procure non-firm energy from the MISO market for the customer when usage exceeds the customer's Baseline Demand. Accordingly, sales under the RTP tariff are exempt from the Energy

Adjustment Rider, as outlined in the Mandatory Riders – Applicability Matrix (Section 13.00), included in Attachment 2 of this petition.

The RTP customer is assessed a transmission service adder and Network Integrated Transmission Service (NITS) charges for use of Otter Tail Power's transmission system above its baseline. As a result, the RTP tariff is not subject to the annual TCR Rider.

Additionally, because the Company must procure generation capacity for RTP customers—who are not curtailable—these customers will incur a generation capacity adder. As a result, the RTP tariff is exempt from the RRCR Rider.

D. Update to the EAR Tariff and TCR Tariff

Otter Tail Power proposes to exclude both the costs associated with Day-Ahead and Real-Time prices—collected from the RTP customer—and the corresponding kWh from the calculation of the Company's EAR rate. This adjustment ensures that the EAR rate more accurately reflects costs attributable to standard tariff customers, rather than those participating in the RTP tariff. By excluding Day-Ahead and Real-Time price-related costs and associated kWh from RTP customers, the calculation avoids distorting the EAR rate with market-driven variability that is not representative of the broader customer base.

In addition, Otter Tail Power addresses the recovery of NITS charges, specifically the Schedule 26A rate. Load-serving entities (LSEs), such as Otter Tail Power, pay their share of the MISO Schedule 26A expense based on their customers' relative energy usage compared to all MISO LSEs. This expense is currently recovered through the Company's TCR Rider. To prevent double recovery, Otter Tail Power proposes to credit the TCR Rider by the amount of Schedule 26A expense (NITS charges) recovered through the RTP tariff.

E. Credit Back to Customers

Otter Tail Power recognizes that the proposed revised rate design for the RTP tariff would have increased retail revenues in the Company's most recent rate case, which in turn would have lowered rates for other customers. To ensure customers receive the benefit of this outcome, Otter Tail Power proposes to credit the North Dakota jurisdiction $23,750 monthly ($285,000 annually) through the RRCR rider until interim rates take effect in its next rate case proceeding. This credit reflects the additional revenue that would have been realized in the Company's 2024 Test Year under the proposed revised RTP rate design, based on the

applicable billing determinants and adder amounts that would have been in place during that period.

F. Administrative Updates to Tariff Sections

Table 3 below summarizes administrative updates to a number of Tariff Sections that are included for purposes of incorporating the impacts of the RTP rate into Otter Tail Power's Tariff. Redline and clean versions of updated Tariff Sections listed below are included as Attachment 2 to this Petition.

Table 3

Tariff Section	Description	Changes
13.00	Mandatory Riders - Applicability Index	Updated Section 14.02 Real Time Pricing applicability references on page 2.
13.01	Energy Adjustment Rider	The list of how the cost of energy shall be determined in this Rider has been updated in paragraph 14 on page 3 to exclude any Real Time Pricing related costs under Section 14.02. Spelling of "ancillary" also corrected in paragraph 10 on page 3.
13.04	Renewable Cost Recovery Rider	This Rider (pages 1 and 2) has been updated to clearly identify that Section 14.02 is an exception.
13.05	Transmission Cost Recovery Rider	This Rider (pages 1) has been updated to clearly identify that Section 14.02 is an exception.
14.00	Voluntary Riders – Availability Matrix	Updated Section 14.02 Real Time Pricing availability references on page 1.

VIII. CONCLUSION

For the reasons detailed in this Application, Otter Tail Power Company respectfully requests that the North Dakota Public Service Commission approve the proposed revisions to Sections 5.02, 9.03, 14.08, 14.04, 14.06, 13.01, and 14.02 of its Electric Rate Schedule. These updates improve tariff clarity, enhance operational flexibility, and ensure alignment with current market practices and jurisdictional cost-causation principles.

The revisions to Section 14.08—and the conforming revisions to Sections 14.04 and 14.06—provide consistent and modernized cycling authority across all load-management programs, allowing the Company to utilize its Advanced Load Management System effectively while maintaining customer comfort and supporting system reliability. Updates to the Energy Adjustment Rider ensure North Dakota customers are allocated only the costs associated with their jurisdiction and receive the benefit of jurisdiction-specific revenues. The Real-Time Pricing revisions enhance transparency, and incorporate actual market-based pricing,

These modifications collectively strengthen the integrity of the Company's tariffs, promote fair and accurate cost recovery, and benefit customers through improved program design, accurate pricing signals, and the avoidance of double recovery. Otter Tail Power therefore respectfully requests Commission approval of all proposed tariff updates and administrative refinements included in this filing.

Date: March 31, 2026

Respectfully submitted:

OTTER TAIL POWER COMPANY

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Attachments

Attachment 1 Customer Notices

Attachment 2 Redline and Clean Version of Tariff Updates

Attachment 1
Customer Notices
Customer Bill Message

Customer notice

The North Dakota Public Service Commission approved an update to our Real Time Pricing tariff, including related indexes, matrices, and rider rate schedules, effective June 1, 2026.

Our Real Time Pricing tariff is designed for Large General Service customers with operational flexibility to adjust their energy use in response to changing market conditions. By shifting or reducing use during high-price periods, participating customers can better manage their energy costs and help support overall system efficiency. This tariff doesn't affect any other customer rates.

For more information, contact us at 800-257-4044 or visit otpco.com.

Customer notice

The North Dakota Public Service Commission approved an update to our Energy Adjustment Rider, effective August 1, 2026.

The Energy Adjustment Rider allows for recovery of the variable fuel and purchased power costs that aren't included in our standard electric rates. This rider doesn't affect any other customer rates.

For more information, contact us at 800-257-4044 or visit otpco.com.

Customer bill message

We filed a request with the North Dakota Public Service Commission to approve updates to our Real Time Pricing tariff (including related indexes, matrices, and rider rate schedules) and to our Energy Adjustment Rider.

For more information, contact us at 800-257-4044 or visit otpco.com.

Attachment 2
Legislative and Non-Legislative Versions of

Section 5.02 – Special Facilities
Section 9.03 – Farm Services
Section 13.00 – Mandatory Riders – Applicability Matrix
Section 13.01 – Energy Adjustment Rider
Section 13.04 – Renewable Resource Cost Recovery Rider
Section 13.05 – Transmission Cost Recovery Rider
Section 14.00 – Voluntary Riders – Availability Matrix
Section 14.02 – Real Time Pricing Rider
Section 14.04 – Controlled Service – Interruptible Load
Section 14.06 – Controlled Service – Deferred Load Rider
Section 14.08 – Air Conditioning Control Rider

Section 5.02 SPECIAL FACILITIES

For the purposes of Section 5.02, the following definitions apply:

"Distribution Facilities" are defined as all primary and secondary voltage wires, poles, insulators, transformers, fixtures, cables, trenches, and other associated accessories and equipment, including substation equipment, rated below 41.6 kV, whose express function and purpose is for the Distribution of electrical power from the Company's Distribution substation directly to Customers. Distribution Facilities exclude all facilities used primarily for the purpose of transferring electricity from a Generator to a substation and/or from one substation to another substation. As such, Distribution Facilities serve only Customers on the primary and secondary rates of the Company.

"Transmission Facilities" are defined as all poles, towers, wires, insulators, transformers, fixtures, cables, and other associated structures, accessories and equipment, including substation equipment, rated equal to or greater than 41.6 kV, whose express function and purpose is the transmission of electricity from a Generator to a substation or substations, and from one substation to another.

"Standard Facilities" are those facilities whose design or location constitutes the reasonable and prudent, least-cost alternative that is consistent with the existing electric system configuration, will meet the needs of the Company's Customers, and will maintain system Reliability and performance under the circumstances. In determining the design or location of a "Standard Facility," the Company shall use good utility practices and evaluate all of the circumstances surrounding the proposal, including 1) public and employee safety in the installation, operation and maintenance of the facility; 2) compliance with applicable engineering standards, codes, electric utility norms and standards; 3) electric system Reliability requirements; 4) the presence, age, condition and configuration of existing facilities in the affected area; 5) the presence and size of existing right-of-way in the affected area; 6) existing topography, soil, spacing, and any environmental limitations in the specific area; 7) existing and reasonably projected development in the affected area; 8) installation, maintenance, useful life and replacement cost factors; and 9) other relevant factors under the particular circumstances.

"Special Facilities" are non-Standard Facilities or the non-standard design or location of facilities. Common examples of Special Facilities include duplicate service facilities, special switching equipment, special service voltage, Tthree-phase service where Ssingle-phase service is determined by the Company to be adequate, excess Capacity, Capacity for intermittent equipment, trailer park Distribution systems, underground installations, conversion from

overhead to underground service, specific area or other special undergrounding, and location and relocation or replacement of existing Company facilities.

"Extra Facilities" are facilities reasonably necessary to serve a Customer who, due to the unanticipated additional load to the system, will require a quantity of facilities, though Standard Facilities, that exceeds the cost of a typical customer service request in the same customer class and therefore should be recovered from the Customer requiring the additional facilities-.

The Company is not obligated to provide any Special Facilities or Extra Facilities and may refuse to do so at its sole discretion.

~~Payments required will be made on a nonrefundable basis and may be required in advance of construction unless other arrangements are agreed to in writing with the Company. The facilities installed by the Company are the property of the Company. Any payment by a requesting or ordering party will not change the Company's ownership interest or rights. Payment for Special Facilities may be required by either, or a combination, of the following methods as prescribed by the Company: a single charge for the costs incurred or to be incurred by the Company due to such a special installation, or a monthly charge being one twelfth of the Company's annual fixed costs necessary to provide such special installation. The charge for Special Facilities will be computed from a formula rate template using inputs from FERC Form 1 with the following expense components; operation and maintenance expense, general and common depreciation expense, taxes other than income tax, and distribution depreciation expense. The return component will contain income taxes and return on rate base. The monthly charge will be discontinued if the Special Facilities are removed (however the customer is responsible for any undepreciated installation charges upon departing or discontinuing service) or if the requester eventually qualifies for the originally requested Special Facilities as Standard Facilities. The charge for Special Facilities will be calculated annually and applied to any Electric Service Agreement (ESA) entered into while that rate is in effect and applicable for the life of the ESA. This section will apply for new connected loads of 200 kW or less unless the company and customer have expressly agreed to different charges in an ESA approved by the Commission. New loads above 200 kW will be addressed through authorized ESAs.~~

"Excess Expenditures" is defined as the total reasonable incremental cost above that of Standard Facilities, for construction and operation of Special Facilities, including: the value of the undepreciated life of existing facilities being removed and removal costs less salvage; the fully allocated incremental labor costs for design, surveying, engineering, construction, administration, operations, or any other activity associated with the project; the incremental easement or other land costs incurred by the Company; the incremental costs of immediately required changes to associated electric facilities, including backup facilities, to ensure Reliability, structural integrity and operational integrity of the electric system; the incremental taxes associated with requested or ordered Special Facilities; the incremental cost represented by accelerated replacement cost if the Special Facility has a materially shorter life expectancy than the standard installation; the incremental material cost for all items associated with the construction, less salvage value of removed facilities; and any other prudent costs incurred by the Company directly related to the applicable Special Facilities.

"Extra Facilities Expenditure" is defined as the total reasonable incremental cost, above that of a typical customer service request in the same customer class, for construction and operation of Extra Facilities, including: the value of the un-depreciated life of existing facilities being removed and removal costs less salvage; the fully allocated incremental labor costs for design, surveying, engineering, construction, administration, operations or any other activity associated with the project; the incremental easement or other land costs incurred by the Company; the incremental costs of immediately required changes to associated electric facilities, including backup facilities, to ensure Reliability, structural integrity and operational integrity of the electric system; the incremental taxes associated with requested or ordered Extra Facilities; the incremental material cost for all items associated with the construction, less salvage value of removed facilities, and any other prudent costs incurred by the Company directly related to the applicable Extra Facilities.

FACILITIES INSTALLATIONS: When the Company is requested by a Customer, group of Customers, developer, City, or Municipality to provide types of service that result in expenditures in excess of Company designated Standard Facility installation for a typical customer of the same rate class, the requesting Customer, group of Customers, developer, or Governmental UnitCity, or Municipality is responsible for the Excess Expenditure and any Extra Facilities Expenditures, unless otherwise required by applicable law, rule or regulation.

When requested, the Company will evaluate the circumstances and determine the Standard Facilities that would be appropriate to the particular situation and determine what, if any, Excess Expenditures and/or Extra Facilities Expenditures are associated with a Customer request or Customer requirement for Special Facilities.

The Company may require an advance payment prior to conducting an evaluation associated with facilities installations. The advance payment may be used by the Company to cover costs associated with evaluation of the circumstances and determination of the Standard Facilities that would be appropriate to the particular situation and determine what, if any, Extra Facilities Expenditures or Excess Expenditures are associated with a Customer request or Customer requirement for the service request. Company will provide Customer with an accounting of the amounts spent, upon request. The Company will return any unused portion of the advance payment upon completion of the evaluation. Any advance payment the Company spends under this Section will neither be refunded nor returned to the Customer if they do not execute an ESA with the Company.

Subject to the requirements of applicable laws, rules and regulations, and subject to the Company's previously scheduled or emergency work, the Company will initially install Special Facilities (including, but not limited to, lighting facilities other than those described in a rate ride) and/or Extra Facilities, or will replace, modify or relocate to a Company-approved location or route its existing Distribution Facilities or Transmission Facilities a1) upon the request of a Customer, a group of Customers, developer, or upon request or lawful order of a City or MunicipalityGovernmental Unit if the Company determines the requested or ordered Special Facilities and/or Extra Facilities will not adversely affect the Reliability, structural integrity, ability to efficiently expand Capacity or operational integrity of the Company''s Distribution Facilities or Transmission Facilities; and b2) the requesting or ordering Customer, group of Customers, developer, City, or Municipalityor Governmental Unit arranges for payment of the Excess Expenditures and/or Extra Facilities Expenditures, or a requesting or ordering City Governmental Unit elects that the Excess Expenditures and/or Extra Facilities Expenditures for undergrounding of Distribution Facilities be recovered by a surcharge.

Special Facilities and Extra Facilities in Public Right-Of-Way:

Whenever a Municipality as a governing body of public right-of-way Governmental Unit orders or requests the Company to replace, modify or relocate its existing Distribution Facilities or Transmission Facilities located by permit in the public right-of-way to the extent necessary to avoid interference with construction on the public right-of-way and not merely for the convenience of the local Governmental Unit, in connection with 1) a present or future local government use of the right-of-way for a public project; 2) the public health or safety; or 3) the safety and convenience of travel over the right-of-way, such facilities will be replaced, modified or relocated at the Company's expense, provided the construction is the Standard Facilities installation designated by the Company.

If the Municipality Governmental Unit requests or orders a facility other than the Standard Facilities typical of a customer service request in the same customer class, the Company will provide the Municipality Governmental Unit notification of the Excess Expenditures to be incurred for Special Facilities, compared to Standard Facilities, and the Extra Facilities Expenditures to be incurred for Extra Facilities. If the Governmental UnitMunicipality requests or orders a type of construction with costs in excess of Company designated Standard Facilities construction, typical of a customer service request in the same customer class the Company shall be entitled to recovery of the Excess Expenditures and/or Extra Facilities Expenditures as provided in this section.

Except in emergencies, the Company has no obligation to commence initial construction of new Special Facilities or Extra Facilities, or to commence construction for replacement, modification, reconstruction or relocation of existing facilities, until the Company receives a permit or other written authorization from the Municipality Governmental Unit (or its designee) having jurisdiction over use of the applicable public right-of-way, authorizing the construction at a Company-approved reasonable location within the public right-of-way or at a location established by lawful order of the Governmental UnitMunicipality.

The Company reserves the right to require an order from a Governmental UnitCity or Municipality if the Company determines the requested Special Facilities or Extra Facilities constitute an improvement primarily for the benefit of a landowner or other group and only an incidental benefit to public use of the right-of-way. The Company also reserves the right to challenge the lawfulness of a Municipality's Governmental Unity's order.

Underground Facilities Requirements:

The following provisions apply when replacing overhead facilities with underground facilities at the request of a Customer or Governmental Unit:

When required, the Customer at Customer's expense must engage an electrician to adapt the Customer's electrical facilities to accept service from the Company underground facilities.

The Company will allow reasonable time for the Customer to make the necessary alterations to the facilities before removal of the existing overhead facilities. The Customer, group of Customers, developer or Governmental UnitMunicipality must provide the Company reasonable notice of the undergrounding request so Company may efficiently plan and install such facilities.

Perpetual easements will be granted to the Company at no cost to the Company whenever any portion of the underground Distribution system is located on private land. These easements also will grant the Company access for inspection, maintenance, and repair of Company facilities.

The Company must receive, by franchise or permit, full access to its facilities installed underground for the purpose of inspection, maintenance, and repair of such facilities, such right of access to include the right to open public ways.

Where a Governmental Unit is requesting undergrounding, the Governmental UnityA Municipality will give sufficient notice and will allow the Company sufficient time to place its facilities beneath public ways while the same are torn up for resurfacing. A Municipality Governmental Unit shall provide the Company with access to the torn up public ways during such period so that the Company will have unobstructed use of sufficiently large sections of the public ways to allow installation of the underground facilities in an economic manner.

The Customer shall install, own and maintain the necessary conduits and Secondary Service conductors to a point of common connection designated by the Company for secondary voltage service supplied from an underground Distribution lateral. A point of common connection can be the secondary compartment of the transformer, a current transformer cabinet, a self-contained Meter socket, or other type of Company-approved junction box. The Company will make final connection of the Customer's Secondary Service conductors to the Company's facilities.

Secondary voltage service supplied from underground S~~s~~econdary S~~s~~ervice conductors requires that the Customer install, own, or maintain necessary conduits on private property to a point designated by the Company. Secondary S~~s~~ervice conductors usually will be installed by the Customer in the Customer'~~'~~s conduit, however, in some installations it may be preferred to have the Company provide a continuous installation from Company facilities through the Customer conduit to the Customer'~~'~~s service equipment.

In these installations the Customer must pay the total installed cost of the Company'~~'~~s cable installed on private property. The Company will make the final connection of the Customer'~~'~~s S~~s~~econdary S~~s~~ervice conductors to the Company'~~'~~s facilities.

~~*Special Facilities Payments*~~

PAYMENTS FOR EXCESS EXPENDITURE AND EXTRA FACILITIES EXPENDITURE: Where the requesting or ordering Customer is required to prepay ~~or agrees to prepay~~ or arrange payment for Excess Expenditure or Extra Facilities Expenditure,~~Special Facilities~~, the requesting or ordering Customer shall execute an agreement or service form pertaining to the installation, operation and maintenance, and payment for the Special Facilities and/or Extra Facilities.

Payments required for Excess Expenditure or Extra Facilities will be made on a non-refundable basis and may be required in advance of construction unless other arrangements are agreed to in writing with the Company. The facilities installed by the Company are the property of the Company. Any payment by a requesting or ordering party shall~~will~~ not change the Company's ownership interest or rights.

~~Charges for Special Facilities shall be an annual fixed charge of the costs associated with the Excess Expenditures, billed in 12 equal monthly installments, unless another period is specified in the applicable rate schedule or Commission-approved ESA.~~

Alternatively, the Customer may prepay the Excess Expenditures amount and then, in lieu of the calculated charge for Special Facilities, pay an annual fixed charge for the recovery of operations and maintenance expenses related to the Excess Expenditures amount, billed in 12 equal monthly installments, as set out in Section 11.02. The operations and maintenance expense rate is a subcomponent of the Special Facilities charge described herein.

~~The monthly charge shall be discontinued if the Special Facilities are removed or if the Special Facilities eventually qualify as Standard Facilities.~~

The Company shall provide to the Customer an estimate with detail of the expenditures~~costs~~ prior to construction.

Payment for Excess Expenditure:

Payment for Excess Expenditure may be required by either, or a combination, of the following methods as prescribed by the Company: A monthly charge being one-twelfth of the Company's annual fixed costs necessary to provide such special installation and ongoing operations and maintenance.

Payments for Excess Expenditure ~~required will be made on a nonrefundable basis and may be required in advance of construction unless other arrangements are agreed to in writing with the Company. The facilities installed by the Company are the property of the Company. Any payment by a requesting or ordering party will not change the Company's ownership interest or rights. Payment for Special Facilities may be required by either, or a combination, of the following methods as prescribed by the Company: a single charge for the costs incurred or to be incurred by the Company due to such a special installation, or a monthly charge being one twelfth of the Company's annual fixed costs necessary to provide such special installation. The charge for Special Facilities~~ will be computed from a ~~formula~~ rate template using inputs from FERC Form 1 with the following expense components:~~;~~ operation and maintenance expense, general and common depreciation expense, taxes other than income tax, and distribution depreciation expense. The return component will contain income taxes and return on rate base. The monthly charge will be discontinued if the Special Facilities are removed (however the customer is responsible for any undepreciated installation charges upon departing or discontinuing service) or if the requester eventually qualifies for the originally requested Special Facilities as Standard Facilities. The charge for Excess Expenditure~~Special Facilities~~ will be calculated annually and applied to any Electric Service Agreement (ESA) entered into while that rate is in effect and applicable for the life of the ESA. This section will apply for new connected loads ~~of 200 kW or less~~ unless the C~~c~~ompany and C~~c~~ustomer have expressly agreed to different charges in an ESA approved by the Commission. ~~New loads above 200 kW will be addressed through authorized ESAs.~~

Payment for Extra Facilities Expenditure:

Payment for Extra Facilities Expenditure will be addressed in the same manner as Special Facilities, unless the Company and Customer have expressly agreed to different charges in an ESA approved by the Commission.

For loads with both Extra Facilities Expenditure and Excess Expenditure, the charges will be combined and be addressed in the Customer's ESA.

Section 5.02 SPECIAL FACILITIES

For the purposes of Section 5.02, the following definitions apply:

"Distribution Facilities" are defined as all primary and secondary voltage wires, poles, insulators, transformers, fixtures, cables, trenches, and other associated accessories and equipment, including substation equipment, rated below 41.6 kV, whose express function and purpose is for the Distribution of electrical power from the Company's Distribution substation directly to Customers. Distribution Facilities exclude all facilities used primarily for the purpose of transferring electricity from a Generator to a substation and/or from one substation to another substation. As such, Distribution Facilities serve only Customers on the primary and secondary rates of the Company.

"Transmission Facilities" are defined as all poles, towers, wires, insulators, transformers, fixtures, cables, and other associated structures, accessories and equipment, including substation equipment, rated equal to or greater than 41.6 kV, whose express function and purpose is the transmission of electricity from a Generator to a substation or substations, and from one substation to another.

"Standard Facilities" are those facilities whose design or location constitutes the reasonable and prudent, least-cost alternative that is consistent with the existing electric system configuration, will meet the needs of the Company's Customers, and will maintain system Reliability and performance under the circumstances. In determining the design or location of a "Standard Facility," the Company shall use good utility practices and evaluate all of the circumstances surrounding the proposal, including 1) public and employee safety in the installation, operation and maintenance of the facility; 2) compliance with applicable engineering standards, codes, electric utility norms and standards; 3) electric system Reliability requirements; 4) the presence, age, condition and configuration of existing facilities in the affected area; 5) the presence and size of existing right-of-way in the affected area; 6) existing topography, soil, spacing, and any environmental limitations in the specific area; 7) existing and reasonably projected development in the affected area; 8) installation, maintenance, useful life and replacement cost factors; and 9) other relevant factors under the particular circumstances.

"Special Facilities" are non-Standard Facilities or the non-standard design or location of facilities. Common examples of Special Facilities include duplicate service facilities, special switching equipment, special service voltage, Three-phase service where Single-phase service is determined by the Company to be adequate, excess Capacity, Capacity for intermittent equipment, trailer park Distribution systems, underground installations, conversion from C

overhead to underground service, specific area or other special undergrounding, and location and relocation or replacement of existing Company facilities.

"Extra Facilities" are facilities reasonably necessary to serve a Customer who, due to the unanticipated additional load to the system, will require a quantity of facilities, though Standard Facilities, that exceeds the cost of a typical customer service request in the same customer class and therefore should be recovered from the Customer requiring the additional facilities. **N N N N**

The Company is not obligated to provide any Special Facilities or Extra Facilities and may refuse to do so at its sole discretion. **N N**

"Excess Expenditure" is defined as the total reasonable incremental cost above that of Standard Facilities, for construction and operation of Special Facilities, including: the value of the undepreciated life of existing facilities being removed and removal costs less salvage; the fully allocated incremental labor costs for design, surveying, engineering, construction, administration, operations, or any other activity associated with the project; the incremental easement or other land costs incurred by the Company; the incremental costs of immediately required changes to associated electric facilities, including backup facilities, to ensure Reliability, structural integrity and operational integrity of the electric system; the incremental taxes associated with requested or ordered Special Facilities; the incremental cost represented by accelerated replacement cost if the Special Facility has a materially shorter life expectancy than the standard installation; the incremental material cost for all items associated with the construction, less salvage value of removed facilities; and any other prudent costs incurred by the Company directly related to the applicable Special Facilities. **C**

"Extra Facilities Expenditure" is defined as the total reasonable incremental cost, above that of a typical customer service request in the same customer class, for construction and operation of Extra Facilities, including: the value of the un-depreciated life of existing facilities being removed and removal costs less salvage; the fully allocated incremental labor costs for design, surveying, engineering, construction, administration, operations or any other activity associated with the project; the incremental easement or other land costs incurred by the Company; the incremental costs of immediately required changes to associated electric facilities, including backup facilities, to ensure Reliability, structural integrity and operational integrity of the electric system; the incremental taxes associated with requested or ordered Extra Facilities; the incremental material cost for all items associated with the construction, less salvage value of removed facilities, and any other prudent costs incurred by the Company directly related to the applicable Extra Facilities. **N N N N N N N N N N N N N N N**

FACILITIES INSTALLATIONS: When the Company is requested by a Customer, group of Customers, developer, City, or Municipality to provide types of service that result in expenditures in excess of Company designated Standard Facility installation for a typical customer of the same rate class, the requesting Customer, group of Customers, developer, or Governmental Unit is responsible for the Excess Expenditure and any Extra Facilities Expenditure, unless otherwise required by applicable law, rule or regulation. **C N N CN N**

When requested, the Company will evaluate the circumstances and determine the Standard Facilities that would be appropriate to the particular situation and determine what, if any, Excess Expenditures and/or Extra Facilities Expenditures are associated with a Customer request or Customer requirement for Special Facilities. **N**

The Company may require an advance payment prior to conducting an evaluation associated with facilities installations. The advance payment may be used by the Company to cover costs associated with evaluation of the circumstances and determination of the Standard Facilities that would be appropriate to the particular situation and determine what, if any, Extra Facilities Expenditures or Excess Expenditures are associated with a Customer request or Customer requirement for the service request. Company will provide Customer with an accounting of the amounts spent, upon request. The Company will return any unused portion of the advance payment upon completion of the evaluation. Any advance payment the Company spends under this Section will neither be refunded nor returned to the Customer if they do not execute an ESA with the Company. **N N N N N N N N N N N**

Subject to the requirements of applicable laws, rules and regulations, and subject to the Company's previously scheduled or emergency work, the Company will install Special Facilities and/or Extra Facilities, or replace, modify or relocate to a Company-approved location or route its existing Distribution Facilities or Transmission Facilities a) upon the request of a Customer, a group of Customers, developer, or upon request or lawful order of a Governmental Unit if the Company determines the requested or ordered Special Facilities and/or Extra Facilities will not adversely affect the Reliability, structural integrity, ability to efficiently expand Capacity or operational integrity of the Company's Distribution Facilities or Transmission Facilities; and b) the requesting or ordering Customer, group of Customers, developer, or Governmental Unit arranges for payment of the Excess Expenditures and/or Extra Facilities Expenditures, or a requesting or ordering Governmental Unit elects Excess Expenditures and/or Extra Facilities Expenditures be recovered by a surcharge. **C CN C C CN N T C CN CN N**

Special Facilities and Extra Facilities in Public Right-Of-Way: **LN**

Whenever a Governmental Unit orders or requests the Company to replace, modify or relocate its existing Distribution Facilities or Transmission Facilities located in the public right-of-way to the extent necessary to avoid interference with construction on the public right-of-way and not merely for the convenience of the local Governmental Unit, in connection with 1) a present or future local government use of the right-of-way for a public project; 2) the public health or safety; or 3) the safety and convenience of travel over the right-of-way, such facilities will be replaced, modified or relocated at the Company's expense, provided the construction is the Standard Facilities installation designated by the Company. **LC L LC LN LN LN L L**

If the Governmental Unit requests or orders a facility other than the Standard Facilities typical of a customer service request in the same customer class, the Company will provide the Governmental Unit notification of the Excess Expenditures to be incurred for Special Facilities, compared to Standard Facilities, and the Extra Facilities Expenditures to be incurred for Extra Facilities. If the Governmental Unit requests or orders a type of construction with costs in excess of Company designated Standard Facilities construction, typical of a customer service request in the same customer class the Company shall be entitled to recovery of the Excess Expenditures and/or Extra Facilities Expenditures as provided in this section. **C N C N NC N N N**

Except in emergencies, the Company has no obligation to commence initial construction of new Special Facilities or Extra Facilities, or to commence construction for replacement, modification, reconstruction or relocation of existing facilities, until the Company receives a permit or other written authorization from the Governmental Unit (or its designee) having jurisdiction over use of the applicable public right-of-way, authorizing the construction at a Company-approved reasonable location within the public right-of-way or at a location established by lawful order of the Governmental Unit. **N C C**

The Company reserves the right to require an order from a Governmental Unit if the Company determines the requested Special Facilities or Extra Facilities constitute an improvement primarily for the benefit of a landowner or other group and only an incidental benefit to public use of the right-of-way. The Company also reserves the right to challenge the lawfulness of a Governmental Unity's order. **C N C**

Underground Facilities Requirements: **CL**

The following provisions apply when replacing overhead facilities with underground facilities at the request of a Customer or Governmental Unit: **L NL**

When required, the Customer at Customer's expense must engage an electrician to adapt the Customer's electrical facilities to accept service from the Company underground facilities. **CL CL**

The Company will allow reasonable time for the Customer to make the necessary alterations to the facilities before removal of the existing overhead facilities. The Customer, group of Customers, developer or Governmental Unit must provide the Company reasonable notice of the undergrounding request so Company may efficiently plan and install such facilities. **L L CL L**

Perpetual easements will be granted to the Company at no cost to the Company whenever any portion of the underground Distribution system is located on private land. These easements also will grant the Company access for inspection, maintenance, and repair of Company facilities. **L L L L**

The Company must receive, by franchise or permit, full access to its facilities installed underground for the purpose of inspection, maintenance, and repair of such facilities, such right of access to include the right to open public ways.

Where a Governmental Unit is requesting undergrounding, the Governmental Unity will give sufficient notice and will allow the Company sufficient time to place its facilities beneath public ways while the same are torn up for resurfacing. A Governmental Unit shall provide the Company with access to the torn up public ways during such period so that the Company will have unobstructed use of sufficiently large sections of the public ways to allow installation of the underground facilities in an economic manner. **C C**

The Customer shall install, own and maintain the necessary conduits and Secondary Service conductors to a point of common connection designated by the Company for secondary voltage service supplied from an underground Distribution lateral. A point of common connection can be the secondary compartment of the transformer, a current transformer cabinet, a self-contained Meter socket, or other type of Company-approved junction box. The Company will make final connection of the Customer's Secondary Service conductors to the Company's facilities.

Secondary voltage service supplied from underground Secondary Service conductors requires that the Customer install, own, or maintain necessary conduits on private property to a point designated by the Company. Secondary Service conductors usually will be installed by the Customer in the Customer's conduit, however, in some installations it may be preferred to have the Company provide a continuous installation from Company facilities through the Customer conduit to the Customer's service equipment. CL L CL CL L L

In these installations the Customer must pay the total installed cost of the Company's cable installed on private property. The Company will make the final connection of the Customer's Secondary Service conductors to the Company's facilities. CL L CL

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PAYMENTS FOR EXCESS EXPENDITURE AND EXTRA FACILITIES EXPENDITURE: Where the requesting or ordering Customer is required to prepay or arrange payment for Excess Expenditure or Extra Facilities Expenditure,, the requesting or ordering Customer shall execute an agreement or service form pertaining to the installation, operation and maintenance, and payment for the Special Facilities and/or Extra Facilities. N NC C C

Payments required for Excess Expenditure or Extra Facilities will be made on a non-refundable basis and may be required in advance of construction unless other arrangements are agreed to in writing with the Company. The facilities installed by the Company are the property of the Company. Any payment by a requesting or ordering party shall not change the Company's ownership interest or rights. C C

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Alternatively, the Customer may prepay the Excess Expenditures amount and then, in lieu of the calculated charge for Special Facilities, pay an annual fixed charge for the recovery of operations and maintenance expenses related to the Excess Expenditures amount, billed in 12 equal monthly installments, as set out in Section 11.02. The operations and maintenance expense rate is a subcomponent of the Special Facilities charge described herein. C

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The Company shall provide to the Customer an estimate with detail of the expenditures prior to construction. C

Payment for Excess Expenditure: N

Payment for Excess Expenditure may be required by either, or a combination, of the following methods as prescribed by the Company: A monthly charge being one-twelfth of the Company's annual fixed costs necessary to provide such special installation and ongoing operations and maintenance. N N N N

Payments for Excess Expenditure will be computed from a rate template using inputs from FERC Form 1 with the following expense components: operation and maintenance expense, general and common depreciation expense, taxes other than income tax, and distribution depreciation expense. The return component will contain income taxes and return on rate base. The monthly charge will be discontinued if the Special Facilities are removed (however the customer is responsible for any undepreciated installation charges upon departing or discontinuing service) or if the requester eventually qualifies for the originally requested Special Facilities as Standard Facilities. The charge for Excess Expenditure will be calculated annually and applied to any Electric Service Agreement (ESA) entered into while that rate is in effect and applicable for the life of the ESA. This section will apply for new connected loads unless the Company and Customer have expressly agreed to different charges in an ESA approved by the Commission. **LC LC L L L L LC L LC LC**

Payment for Extra Facilities Expenditure: **N**

Payment for Extra Facilities Expenditure will be addressed in the same manner as Special Facilities, unless the Company and Customer have expressly agreed to different charges in an ESA approved by the Commission. **N N N**

For loads with both Extra Facilities Expenditure and Excess Expenditure, the charges will be combined and be addressed in the Customer's ESA. **N N**

FARM SERVICE

DESCRIPTION	RATE CODE
Farm Service – Single-phase	N361
Farm Service – Three-phase	N363

DESCRIPTION: The Farm Service Rate Schedule is designed to provide electric service for general farm and associated home use. This Rate Schedule applies to customers whose energy needs include typical agricultural operations as well as household consumption.

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

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

RATE:

	~~FARM SERVICE~~SINGLE-PHASE		THREE-PHASE	
Customer Charge per Month:	$22.00		$22.00	
Monthly Minimum Bill	Customer Charge + Facilities Charge		Customer Charge + Facilities Charge	
Facilities Charge per Month:	$20.00		$40.00	
~~Single Phase~~	~~$20.00~~			
~~Three Phase~~	~~$40.00~~			
Energy Charge per kWh:	Summer	Winter	Summer	Winter
	5.875 ¢/kWh	6.668 ¢/kWh	5.875 ¢/kWh	6.668 ¢/kWh

MANDATORY ~~AND VOLUNTARY~~ RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply~~ or Voluntary Rate Riders selected by the~~

~~Customer~~, unless otherwise noted in this rate schedule. See Section~~s~~ ~~12.00,~~ 13.00 ~~and 14.00~~ of the North Dakota electric rates for the ~~m~~Matri~~ces~~x of Mandatory Rate ~~r~~Riders.

DEFINITIONS OF SEASONS:

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

DETERMINATION OF FACILITIES CHARGE: An amount to be paid by the Customer in a fixed monthly amount for distribution facilities sized on the basis of the Customer's design demand (rather than metered) demand.

FARM SERVICE

DESCRIPTION	RATE CODE	
Farm Service – Single-phase	N361	C
Farm Service – Three-phase	N363	N

DESCRIPTION: The Farm Service Rate Schedule is designed to provide electric service for general farm and associated home use. This Rate Schedule applies to customers whose energy needs include typical agricultural operations as well as household consumption. N N N

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

APPLICATION OF SCHEDULE: This schedule applies to general Farm operations and associated residential use with the farm home. Customers may elect the farm home (for residential uses) to take service under Residential Service (Section 9.01) or Residential Demand Control (Section 9.02) provided all requirements specified for the selected schedule are satisfied. C C C C

RATE:

	SINGLE-PHASE		THREE-PHASE		CN
Customer Charge per Month:	$22.00		$22.00		N
Monthly Minimum Bill	Customer Charge + Facilities Charge		Customer Charge + Facilities Charge		CN
Facilities Charge per Month:	$20.00		$40.00		N
					DD
Energy Charge per kWh:	Summer	Winter	Summer	Winter	N
	5.875 ¢/kWh	6.668 ¢/kWh	5.875 ¢/kWh	6.668 ¢/kWh	N

MANDATORY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply, unless otherwise noted in this rate schedule. See Section 13.00 of the North Dakota electric rates for the Matrix of Mandatory Rate Riders. C C C

DEFINITIONS OF SEASONS: **L**

Summer: June 1 through September 30. **L**

Winter: October 1 through May 31. **L**

DETERMINATION OF FACILITIES CHARGE: An amount to be paid by the Customer in a fixed monthly amount for distribution facilities sized on the basis of the Customer's design demand rather than metered demand. **C**

MANDATORY RIDERS - APPLICABILITY MATRIX (*Continued*)

~~Applicability Matrix~~	~~Mandatory Riders~~	Energy Adjustment Rider	Reserved for Future Use	Reserved for Future Use	Renewable Resource Cost Recovery Rider	Transmission Cost Recovery Rider	Generation Cost Recovery Rider	Reserved for Future Use	Environmental Cost Recovery Rider	Reserved for Future Use	Reserved for Future Use	Metering & Distribution Technology Cost Recovery Rider	Interim Rate Rider
Base Tariffs	Section Numbers	13.01	13.02	13.03	13.04	13.05	13.06	13.07	13.08	13.09	13.10	13.11	13.12
MANDATORY RIDERS													
Energy Adjustment Rider	13.01												
Reserved for Future Use	13.02												
Reserved for Future Use	13.03												
Renewable Resource Cost Recovery Rider	13.04												
Transmission Cost Recovery Rider	13.05												
Generation Cost Recovery Rider	13.06												
Reserved for Future Use	13.07												
Environmental Cost Recovery Rider	13.08												
Reserved for Future Use	13.09												
Reserved for Future Use	13.10												
Metering & Distribution Technology Cost Recovery Rider	13.11												
Interim Rate Rider	13.12												
Key:	a = May apply	a = Mandatory	o = Not Applicable										

MANDATORY RIDERS - APPLICABILITY MATRIX (*Continued*)

Applicability Matrix	Mandatory Riders	Energy Adjustment Rider	Reserved for Future Use	Reserved for Future Use	Renewable Resource Cost Recovery Rider	Transmission Cost Recovery Rider	Generation Cost Recovery Rider	Reserved for Future Use	Environmental Cost Recovery Rider	Reserved for Future Use	Reserved for Future Use	Metering & Distribution Technology Cost Recovery Rider	Interim Rate Rider
Base Tariffs	Section Numbers	13.01	13.02	13.03	13.04	13.05	13.06	13.07	13.08	13.09	13.10	13.11	13.12
VOLUNTARY RIDERS													
Water Heating Control Rider	14.01				✓	✓	✓		✓			✓	✓
Real Time Pricing ~~Rider~~	14.02				N/A	N/A	N/A		✓				
Large General Service Rider	14.03	✓											✓
Controlled Service - Interruptible Load Self-Contained and CT Metering Rider (Dual Fuel)	14.04												
Reserved for Future Use	14.05												
Controlled Service Deferred Load Rider (Thermal Storage)	14.06												
Fixed Time of Service Rider	14.07												
Air Conditioning Control ~~Rider~~ Credit (**Cool***Savings*)	14.08												
Voluntary Renewable Energy Rider (**Tail***Winds*)	14.09												
WAPA Bill Crediting Program Rider	14.10												
Reserved for Future Use	14.11												
Bulk Interruptible Service	14.12												
Economic Development Rate Rider - Large General Service	14.13												
My Renewable Energy Credits (My RECs) Rider	14.14												
Key:	✓ = May apply	■ = Mandatory	☐ = Not Applicable										

Section 13.00 RESERVED FOR FUTURE USE

MANDATORY RIDERS - APPLICABILITY MATRIX (*Continued*)

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Applicability Matrix	Mandatory Riders	Energy Adjustment Rider	Reserved for Future Use	Reserved for Future Use	Renewable Resource Cost Recovery Rider	Transmission Cost Recovery Rider	Generation Cost Recovery Rider	Reserved for Future Use	Environmental Cost Recovery Rider	Reserved for Future Use	Reserved for Future Use	Metering & Distribution Technology Cost Recovery Rider	Interim Rate Rider
Base Tariffs	Section Numbers	13.01	13.02	13.03	13.04	13.05	13.06	13.07	13.08	13.09	13.10	13.11	13.12
VOLUNTARY RIDERS													
Water Heating Control Rider	14.01				✓	✓	✓		✓			✓	✓
Real Time Pricing	14.02								✓				
Large General Service Rider	14.03	✓											✓
Controlled Service - Interruptible Load Self-Contained and CT Metering Rider (Dual Fuel)	14.04												
Reserved for Future Use	14.05												
Controlled Service Deferred Load Rider (Thermal Storage)	14.06												
Fixed Time of Service Rider	14.07												
Air Conditioning Control Credit (**Cool***Savings*)	14.08												
Voluntary Renewable Energy Rider (**Tail***Winds*)	14.09												
WAPA Bill Crediting Program Rider	14.10												
Reserved for Future Use	14.11												
Bulk Interruptible Service	14.12												
Economic Development Rate Rider - Large General Service	14.13												
My Renewable Energy Credits (My RECs) Rider	14.14												
Key:	✓ = May apply	■ = Mandatory	☐ = Not Applicable										

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Section 13.00 RESERVED FOR FUTURE USE **N**

ENERGY ADJUSTMENT RIDER BY SERVICE CATEGORY

(Identified on the bill as Fuel & Purchase Power)

DESCRIPTION: Otter Tail Power Company's Energy Adjustment Rider (EAR) is a rate mechanism approved by the North Dakota Public Service Commission that allows for the recovery of the Company's variable fuel and purchased power costs that are not included in standard electric rates. These costs vary due to changes in fuel prices, wholesale market conditions, and system operating requirements.

ENERGY ADJUSTMENT CHARGE: There shall be added to each Customer's monthly bill an Energy Adjustment Charge calculated by multiplying the Ceustomer's applicable monthly billing Kilowatt--hours (kWh) by the Ceustomer's applicable billed Energy Adjustment Factor (EAF) per kWh. The billed EAF, expressed in cents amount per kWhKilowatt-hour and (rounded to the nearest 0.001¢), represents will be the average monthly cost of Energy per Kilowatt hourkWh as determined for thate Ceustomer's service category. The average cost of Energy per Kilowatt hour for the current period shall be calculated from data covering actual costs from the most recent four-month period as follows:

Energy costs from actual months 1, 2, 3, and 4 plus unrecovered (or less over recovered) prior cumulative Energy costs divided by retail sales for actual months 1, 2, 3, and 4 equals the cost of Energy adjustment for month 6.

ENERGY ADJUSTMENT FACTOR (EAF): A separate EAF will be determined for each Customer service category defined by Customer class. The EAF for each service category shall be calculated by multiplying is the sum of the Current Period Average Cost of Energy and applicable monthly true up, multiplied by the applicable EAF Ratio. The applicable EAF for each calendar month will be applied to that calendar month's daily pro-ration of Energy usage included on the bill.

The average costThe Current Period Average of Energy per kWh Kilowatt hour for the current period shall be calculated from data covering actual costs from the most recent four-month period as follows:

The sum of actual energy costs allocated to North Dakota during the most recent four-month period, adjusted for any net under- or over-recovered energy costs from prior periods,

divided by total North Dakota retail kWh sales, excluding kWh sales under Section 14.02 and Section 14.13, for the same four-month period.

The resultingapplicable EAF for each calendar month shallwill be applied to that calendar month's daily pro ration of Energy usage on the Customer's bill beginning with the first day of the next applicable billing monthincluded on the bill.

Service Category	Section	EAF Ratio
Residential	9.01, 9.02,	1.077
Farm	9.03	1.008
General Service	10.01, 10.02, 10.03	1.061
Large General Service	10.04, 10.05, 10.06, 11.01, 14.13	0.961
Irrigation Service	11.02	0.954
Outdoor Lighting	11.03, 11.04, 11.07	0.908
OPA	11.05	1.031
Controlled Service Deferred Load	14.01, 14.06	0.973
Controlled Service Interruptible	14.04, 14.12	0.985
Controlled Service Off-Peak	14.07	1.054

The average cost of Energy shall be determined as follows:

1. **Fuel Costs:** The cost of ~~fossil~~ fuel~~,~~ as recorded in Account 151, along ~~used in the Company's generating plants, and the~~with the cost~~s~~ of reagents, fuel additive, and emission allowances required for operation of ~~for~~ the Company's ~~to operate its~~ generating plants in compliance with the ~~associated~~ Federal Environmental Protection Agency rules and regulations. Energy generated by ~~from~~ the Company's hydroelectric ~~generating plants~~ facilities shall be included at zero cost.

2. **Purchased Power:** The Energy cost of purchased power ~~included in~~under Account 555 when such Energy ~~is~~ purchase~~d~~ occur on an economic--dispatch basis, excluding any~~exclusive of~~ Capacity or Demand charges. ~~This includes but is not limited to net costs linked to the utility's load serving obligation, associated with participation in wholesale electric Energy markets operated by Regional Transmission Organizations, Independent System Operators or similar entities that have received Federal Energy Regulatory Commission approval to operate the Energy markets. All Midcontinent Independent System Operator ("MISO") Energy and Ancillary service market charges and credits relating to retail sales and asset based sales, specifically including (but not limited to) Schedule 16 and 17 charges and credits shall be included in the calculation.~~

3. **Other Purchased Fuel Costs:** ~~The a~~Actual, identifiable fossil and nuclear fuel costs associated with Energy purchased for reasons other than ~~identified~~those described in item 2 above.

4. **Market-Energy-Related Costs:** ~~The net Energy cost of Energy purchases from a renewable Energy source, including hydropower, wood, windpower, and biomass~~. ~~This includes~~The net costs incurred to meet~~but is not limited to net costs linked to the~~ the utility's load~~-~~-serving obligation and the costs~~,~~ associated with participation in wholesale electric Energy markets and Ancillary Services Markets (ASM) operated by Regional Transmission Organizations, Independent System Operators, or similar entities ~~that have received~~approved by the Federal Energy Regulatory Commission ~~approval~~ to ~~operate the Energy~~administer such markets. This includes revenues and costs from wholesale energy market transactions for generators serving North Dakota customers.

Exclusions: Market-Energy-related costs under Section 14.02 and Section 14.16 are excluded.

5. **Renewable Energy Purchases:** The net Energy cost of Energy purchases from a renewable Energy sources, including hydropower, wood, wind power, and biomass.

6. Less the fuel-related costs recovered through intersystem sales.

7. The Energy cost of avoided purchased power resulting from Hoot Lake Solar output.

8.6. **Net MISO Planning Resourc Auction Costs:** Known MISO Planning Resource Auction capacity costs will be added to the energy adjustment rider or and revenues. will be credited (flow through) the energy adjustment rider.

9. All revenues and associated costs attributable to Asset-based Sales Margins, as defined below and in the amount calculated as described below, shall be included in the Energy adjustment calculation described in this schedule.

Asset-based Sales Margins:
Asset-based Sales Margins are defined as wholesale Energy and ancillary services sales revenues from Company-owned generation resources less the sum of fuel, Energy costs (including costs associated with MISO markets that are recorded in FERC Account 555), and any additional transmission or other costs incurred that are required to make such sales (referred to as "margins"). One hundred percent of these actual revenues and costs shall be included in the energy adjustment rider as they are incurred.

10.7. **Steam and Water Sales Impacts:** The costs of fuel and reagents associated with resulting from steam and water sales, as well as and the revenues received from steam and water sales shall be included in the energy adjustment rider.

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by

the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

ENERGY ADJUSTMENT RIDER BY SERVICE CATEGORY

(Identified on the bill as Fuel & Purchase Power)

DESCRIPTION: Otter Tail Power Company's Energy Adjustment Rider (EAR) is a rate mechanism approved by the North Dakota Public Service Commission that allows for the recovery of the Company's variable fuel and purchased power costs that are not included in standard electric rates. These costs vary due to changes in fuel prices, wholesale market conditions, and system operating requirements. **N N N N N**

ENERGY ADJUSTMENT CHARGE: There shall be added to each Customer's monthly bill an Energy Adjustment Charge calculated by multiplying the Customer's monthly billing Kilowatt-hours (kWh) by the Customer's applicable billed Energy Adjustment Factor (EAF) per kWh. The billed EAF, expressed in cents per kWh and rounded to the nearest 0.001¢, represents the average monthly cost of Energy per kWh for the Customer's service category. **C C C C C D**

ENERGY ADJUSTMENT FACTOR (EAF): A separate EAF will be determined for each Customer service category defined by Customer class. The EAF for each service category shall be calculated by multiplying the Current Period Average Cost of Energy the applicable EAF Ratio. **C C**

The Current Period Average of Energy per kWh shall be calculated as follows: **LC**

> The sum of actual energy costs allocated to North Dakota during the most recent four-month period, adjusted for any net under- or over-recovered energy costs from prior periods, divided by total North Dakota retail kWh sales**,** excluding kWh sales under Section 14.02 and Section 14.13**,** for the same four-month period. **N N N N**

The resulting EAF for each calendar month shall be applied to that month's daily Energy usage on the Customer's bill beginning with the first day of the next applicable billing month. **LC LC**

Service Category	Section	EAF Ratio	
Residential	9.01, 9.02,	1.077	L
Farm	9.03	1.008	L
General Service	10.01, 10.02, 10.03	1.061	L
Large General Service	10.04, 10.05, 10.06, 11.01, 14.13	0.961	L
Irrigation Service	11.02	0.954	L
Outdoor Lighting	11.03, 11.04, 11.07	0.908	L
OPA	11.05	1.031	L
Controlled Service Deferred Load	14.01, 14.06	0.973	L
Controlled Service Interruptible	14.04, 14.12	0.985	L
Controlled Service Off-Peak	14.07	1.054	L

The average cost of Energy shall be determined as follows:

1. **Fuel Costs:** The cost of fuel as recorded in Account 151, along with the cost of reagents, fuel additive, and emission allowances required for operation of the Company's generating plants in compliance with the Federal Environmental Protection Agency rules and regulations. Energy generated by the Company's hydroelectric facilities shall be included at zero cost. C C C C C

2. **Purchased Power:** The Energy cost of purchased power under Account 555 when such Energy purchase occur on an economic-dispatch basis, excluding any Capacity or Demand charges. C C C D

3. **Other Purchased Fuel Costs:** Actual, identifiable fossil and nuclear fuel costs associated with Energy purchased for reasons other than those described in item 2 above. C C C

4. **Market-Energy-Related Costs:**. The net costs incurred to meet the utility's load-serving obligation and the costs associated with participation in wholesale electric Energy markets and Ancillary Services Markets (ASM) operated by Regional Transmission Organizations, Independent System Operators, or similar entities approved by the Federal Energy Regulatory Commission to administer such markets. This includes revenues and costs from wholesale energy market transactions for generators serving North Dakota customers. LC LC LC LC LC LC

Exclusions: Market-Energy-related costs under Section 14.02 and Section 14.16 are excluded. **N N**

5. **Renewable Energy Purchases:** The net Energy cost of Energy purchases from renewable Energy sources, including hydropower, wood, wind power, and biomass. **LC LC D D D**

6. **Net MISO Planning Resourc Auction Costs:** Known MISO Planning Resource Auction capacity costs and revenues. **LC LC D D**

7. **Steam and Water Sales Impacts:** The costs of fuel and reagents associated with steam and water sales, as well as the revenues received from sales. **LC LC D**

RENEWABLE RESOURCE COST RECOVERY RIDER

DESCRIPTION	RATE CODE
All Services	NRRA

DESCRIPTION: The Renewable Resource Cost Recovery (RRCR) Rider is a rate mechanism approved by the North Dakota Public Service Commission that provides for the recovery of costs associated with eligible renewable energy facilities owned by the Company and used to serve North Dakota customers, to the extent such costs are not included in standard electric rates. Recovery under the Rider is subject to ongoing Commission review and approval.

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

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company's Retail Rate Schedules as described in the Mandatory Riders – Applicability Matrix.

COST RECOVERY CHARGE: There shall be included on each North Dakota Customer's monthly bill a ~~Renewable Resource Cost Recovery (~~RRCR~~)~~ charge based on the applicable cost recovery factor multiplied by the Customer's monthly bill. The Customer's monthly bill shall be based on all applicable charges and credits under the Company's retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Sections 14.09 (Tail*Winds*), 14.02 (Real-Time Pricing), and 14.16 (Thermal Market Energy Pricing). The RRCR charge will not apply to any Mandatory Riders or sales tax and any local assessments as provided in the General Rules and Regulations for the Company's electric service. The following charges are applicable in addition to all charges for service being taken under the Company's standard rate schedules.

Renewable Resource Cost Recovery Factor (2.950) percent

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

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

The annual revenue requirements associated with these investments eligible for recovery under NDCC 49-02, 49-05, and 49-06 that are determined by the Commission to be eligible for recovery under this RRCR Rider. A standard model will be used to calculate the total forecasted North Dakota revenue requirements for eligible measures for the designated period.

True-up: For each recovery period, a true-up adjustment to the RRCR Tracker account will be calculated reflecting the difference between actual prior period RRCR recoveries and actual prior period revenue requirements. Any resulting over/under recovery will be reflected as a carryover balance and included in calculating the next RRCR Factor plus carrying charges or credits accrued at the rate of return approved in Otter Tail Power Company's most recent general rate case.

All costs appropriately charged to the RRCR Tracker account shall be eligible for recovery through this Rider, and all revenues recovered from the applicable RRCR Factor shall be credited to the RRCR Tracker account.

Forecasted retail revenues used for calculating the RRCR Factor shall include the forecast of retail electric revenue collected through all applicable charges and credits under the Company's retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Sections 14.09 (**Tail***Winds*), 14.02 (Real-Time Pricing), and 14.16 (Thermal Market Energy Pricing). Retail revenue used for calculating the RRCR Factor will not include any Mandatory Riders.

The RRCR Factor may be adjusted annually (or other approved periods) with approval of the Commission.

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

RENEWABLE RESOURCE COST RECOVERY RIDER

DESCRIPTION	RATE CODE
All Services	NRRA

DESCRIPTION: The Renewable Resource Cost Recovery (RRCR) Rider is a rate mechanism approved by the North Dakota Public Service Commission that provides for the recovery of costs associated with eligible renewable energy facilities owned by the Company and used to serve North Dakota customers, to the extent such costs are not included in standard electric rates. Recovery under the Rider is subject to ongoing Commission review and approval. **N N N N N**

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

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company's Retail Rate Schedules as described in the Mandatory Riders – Applicability Matrix.

COST RECOVERY CHARGE: There shall be included on each North Dakota Customer's monthly bill a RRCR charge based on the applicable cost recovery factor multiplied by the Customer's monthly bill. The Customer's monthly bill shall be based on all applicable charges and credits under the Company's retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Sections 14.09 (Tail*Winds*), 14.02 (Real-Time Pricing), and 14.16 (Thermal Market Energy Pricing). The RRCR charge will not apply to any Mandatory Riders or sales tax and any local assessments as provided in the General Rules and Regulations for the Company's electric service. The following charges are applicable in addition to all charges for service being taken under the Company's standard rate schedules. **C N C**

Renewable Resource Cost Recovery Factor (2.950) percent

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

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

The annual revenue requirements associated with these investments eligible for recovery under NDCC 49-02, 49-05, and 49-06 that are determined by the Commission to be eligible for recovery under this RRCR Rider. A standard model will be used to calculate the total forecasted North Dakota revenue requirements for eligible measures for the designated period. **C**

True-up: For each recovery period, a true-up adjustment to the RRCR Tracker account will be calculated reflecting the difference between actual prior period RRCR recoveries and actual prior period revenue requirements. Any resulting over/under recovery will be reflected as a carryover balance and included in calculating the next RRCR Factor plus carrying charges or credits accrued at the rate of return approved in Otter Tail Power Company's most recent general rate case. **C** **C** **C**

All costs appropriately charged to the RRCR Tracker account shall be eligible for recovery through this Rider, and all revenues recovered from the applicable RRCR Factor shall be credited to the RRCR Tracker account. **C** **C** **C**

Forecasted retail revenues used for calculating the RRCR Factor shall include the forecast of retail electric revenue collected through all applicable charges and credits under the Company's retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Sections 14.09 (**Tail***Winds*), 14.02 (Real-Time Pricing), and 14.16 (Thermal Market Energy Pricing). Retail revenue used for calculating the RRCR Factor will not include any Mandatory Riders. **C** **C** **N** **C**

The RRCR Factor may be adjusted annually (or other approved periods) with approval of the Commission. **C**

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TRANSMISSION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Large General Service – Demand Charge	NTCRD
Large General Service – Energy Charge	NTCR
Controlled Service	NTCRC
Lighting	NTCRL
All Other Service	NTCRO

DESCRIPTION: The Transmission Cost Recovery (TCR) Rider is a rate mechanism approved by the North Dakota Public Service Commission that provides for the recovery of costs associated with eligible transmission facilities owned by the Company and used to serve North Dakota customers, to the extent such costs are not included in standard electric rates. Recovery under the Rider is subject to ongoing Commission review and approval.

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

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company's retail rate schedules as described in the Mandatory Rider – Applicability Matrix.

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

RATE:

TRANSMISSION COST RECOVERY

Energy Charge per kWh:		kWh	kW
Large General Service	**(a)**	N/A	$1.239
Controlled Service	**(b)**	$0.00	N/A
Lighting	**(c)**	$0.00213	N/A
All Other Service		$0.00387	N/A

(a) Rate schedules 10.04 Large General Service, 10.05 Large General Service – Time of Day, 10.06 Super Large General Service, 11.01 Standby Service, ~~14.02 Real Time Pricing Rider,~~ 14.03 Large General Service Rider, and 14.13 Economic Development Rate Rider.
(b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load Self-Contained and CT Metering, 14.06 Deferred Load, and 14.07 Fixed Time of Delivery.

(c) Rate Schedules 11.03 Outdoor Lighting (Energy only) and 11.04 Outdoor Lighting, and 11.07 LED Street and Area Lighting.

DETERMINATION OF DEMAND CHARGE (LARGE GENERAL SERVICE CLASS ONLY): The Demand charge shall be billed according to the Demand charge as defined in the applicable rate schedule the Customer is taking service.

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

TRANSMISSION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Large General Service – Demand Charge	NTCRD
Large General Service – Energy Charge	NTCR
Controlled Service	NTCRC
Lighting	NTCRL
All Other Service	NTCRO

DESCRIPTION: The Transmission Cost Recovery (TCR) Rider is a rate mechanism approved by the North Dakota Public Service Commission that provides for the recovery of costs associated with eligible transmission facilities owned by the Company and used to serve North Dakota customers, to the extent such costs are not included in standard electric rates. Recovery under the Rider is subject to ongoing Commission review and approval. **N N N N N**

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

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company's retail rate schedules as described in the Mandatory Rider – Applicability Matrix.

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

RATE:

TRANSMISSION COST RECOVERY

Energy Charge per kWh:		kWh	kW
Large General Service	**(a)**	N/A	$1.239
Controlled Service	**(b)**	$0.00	N/A
Lighting	**(c)**	$0.00213	N/A
All Other Service		$0.00387	N/A

(a) Rate schedules 10.04 Large General Service, 10.05 Large General Service – Time of Day, 10.06 Super Large General Service, 11.01 Standby Service, 14.03 Large General Service Rider, and 14.13 Economic Development Rate Rider. **C**

(b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load Self-Contained and CT Metering, 14.06 Deferred Load, and 14.07 Fixed Time of Delivery.

(c) Rate Schedules 11.03 Outdoor Lighting (Energy only) and 11.04 Outdoor Lighting, and 11.07 LED Street and Area Lighting.

DETERMINATION OF DEMAND CHARGE (LARGE GENERAL SERVICE CLASS ONLY): The Demand charge shall be billed according to the Demand charge as defined in the applicable rate schedule the Customer is taking service.

D

VOLUNTARY RIDERS - AVAILABILITY MATRIX

(Rate Schedules listed across the top in the first row are applicable to the Rate Schedules in the first column on the left.)

The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply, Voluntary Rate Riders selected by the Customer, and charges listed in the General Rules and Regulations.

Availability Matrix	Voluntary Riders	Water Heating Control Rider	Real Time Pricing ~~Rider~~	Large General Service Rider	Controlled Service - Interruptible Load Self-Contained and CT Metering Rider (Dual Fuel)	Reserved for Future Use	Controlled Service Deferred Load Rider (Thermal Storage)	Fixed Time of Service Rider	Air Conditioning Control ~~Rider~~ Credit (CoolSavings)	Voluntary Renewable Energy Rider (TailWinds)	WAPA Bill Crediting Program Rider	Reserved for Future Use	Bulk Interruptible Service	Economic Development Rate Rider - Large General Service	My Renewable Energy Credits (My RECs) Rider
Base Tariffs	Section Numbers	14.01	14.02	14.03	14.04	14.05	14.06	14.07	14.08	14.09	14.10	14.11	14.12	14.13	14.14
RESIDENTIAL & FARM SERVICES															
Residential Service	9.01	✓			✓		✓	✓	✓	✓	✓				
Residential Demand Control Service (RDC)	9.02	✓							✓	✓	✓				
Farm Service	9.03	✓			✓		✓	✓	✓	✓	✓				✓
Reserved for Future Use	9.04														
GENERAL SERVICES															
Small General Service (Under 20 kW)	10.01	✓			✓		✓	✓	✓	✓	✓				✓
General Service (20 kW or greater and less than 200 kW)	10.02	✓	✓		✓		✓	✓	✓	✓	✓				✓
General Service - Time of Use (20 kW or greater and less than 200 kW)	10.03	✓							✓		✓				✓
Large General Service	10.04	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓
Large General Service - Time of Day	10.05	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓
Super Large General Service	10.06	✓	✓	✓	✓		✓	✓		✓	✓		✓		✓
OTHER SERVICES															
Standby Service	11.01														✓
Irrigation Service	11.02									✓	✓				✓
Outdoor Lighting - Energy Only	11.03										✓				✓
Outdoor Lighting (CLOSED)	11.04										✓				
Municipal Pumping Service	11.05	✓	✓		✓		✓	✓		✓	✓				✓
Civil Defense - Fire Sirens	11.06												✓		
LED Street and Area Lighting	11.07										✓				✓

Key: ✓ = May apply ■ = Mandatory □ = Not Applicable

VOLUNTARY RIDERS - AVAILABILITY MATRIX

(Rate Schedules listed across the top in the first row are applicable to the Rate Schedules in the first column on the left.)

Availability Matrix	Voluntary Riders	Water Heating Control Rider	Real Time Pricing ~~Rider~~	Large General Service Rider	Controlled Service - Interruptible Load Self-Contained and CT Metering Rider (Dual Fuel)	Reserved for Future Use	Controlled Service Deferred Load Rider (Thermal Storage)	Fixed Time of Service Rider	Air Conditioning Control ~~Rider~~ Credit (CoolSavings)	Voluntary Renewable Energy Rider (TailWinds)	WAPA Bill Crediting Program Rider	Reserved for Future Use	Bulk Interruptible Service	Economic Development Rate Rider - Large General Service	My Renewable Energy Credits (My RECs) Rider
Riders	Section Numbers	14.01	14.02	14.03	14.04	14.05	14.06	14.07	14.08	14.09	14.10	14.11	14.12	14.13	14.14
VOLUNTARY RIDERS															
Water Heating Control Rider	14.01									✓					✓
Real Time Pricing ~~Rider~~	14.02									✓					✓
Large General Service Rider	14.03									✓					✓
Controlled Service - Interruptible Load CT Metering Rider	14.04									✓					✓
Controlled Service - Interruptible Load Self-Contained Metering Rider	14.05									✓					✓
Controlled Service Deferred Load Rider	14.06									✓					✓
Fixed Time of Service Rider	14.07									✓					✓
Air Conditioning Control ~~Rider~~ Credit	14.08														
Voluntary Renewable Energy Rider	14.09														
WAPA Bill Crediting Program Rider	14.10														
Reserved for Future Use	14.11														
Bulk Interruptible Service Application and Pricing Guidelines	14.12														
Economic Development Rate Rider - Large General Service	14.13														
My Renewable Energy Credits (My RECs) Rider	14.14														
Key:	✓ = May apply	■ = Mandatory	□ = Not Applicable												

VOLUNTARY RIDERS - AVAILABILITY MATRIX

(Rate Schedules listed across the top in the first row are applicable to the Rate Schedules in the first column on the left.)

The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply, Voluntary Rate Riders selected by the Customer, and charges listed in the General Rules and Regulations.

Availability Matrix	Voluntary Riders	Water Heating Control Rider	Real Time Pricing	Large General Service Rider	Controlled Service - Interruptible Load Self-Contained and CT Metering Rider (Dual Fuel)	Reserved for Future Use	Controlled Service Deferred Load Rider (Thermal Storage)	Fixed Time of Service Rider	Air Conditioning Control Credit (CoolSavings)	Voluntary Renewable Energy Rider (TailWinds)	WAPA Bill Crediting Program Rider	Reserved for Future Use	Bulk Interruptible Service	Economic Development Rate Rider - Large General Service	My Renewable Energy Credits (My RECs) Rider	
Base Tariffs	Section Numbers	14.01	14.02	14.03	14.04	14.05	14.06	14.07	14.08	14.09	14.10	14.11	14.12	14.13	14.14	
RESIDENTIAL & FARM SERVICES																
Residential Service	9.01	✓			✓		✓	✓	✓	✓	✓					
Residential Demand Control Service (RDC)	9.02	✓							✓	✓	✓					
Farm Service	9.03	✓			✓		✓	✓	✓	✓	✓				✓	
Reserved for Future Use	9.04															
GENERAL SERVICES																
Small General Service (Under 20 kW)	10.01	✓			✓		✓	✓	✓	✓	✓				✓	C
General Service (20 kW or greater and less than 200 kW)	10.02	✓	✓		✓		✓	✓	✓	✓	✓				✓	C
General Service - Time of Use (20 kW or greater and less than 200 kW)	10.03	✓							✓		✓				✓	C
Large General Service	10.04	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓	
Large General Service - Time of Day	10.05	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓	
Super Large General Service	10.06	✓	✓	✓	✓		✓	✓		✓	✓		✓		✓	
OTHER SERVICES																
Standby Service	11.01														✓	
Irrigation Service	11.02									✓	✓				✓	
Outdoor Lighting - Energy Only	11.03										✓				✓	
Outdoor Lighting (CLOSED)	11.04										✓					
Municipal Pumping Service	11.05	✓	✓		✓		✓	✓		✓	✓				✓	
Civil Defense - Fire Sirens	11.06												✓			
LED Street and Area Lighting	11.07										✓				✓	
Key:	✓ = May apply	■ = Mandatory	☐ = Not Applicable													

VOLUNTARY RIDERS - AVAILABILITY MATRIX

(Rate Schedules listed across the top in the first row are applicable to the Rate Schedules in the first column on the left.)

Availability Matrix	Voluntary Riders	Water Heating Control Rider	Real Time Pricing	Large General Service Rider	Controlled Service - Interruptible Load Self-Contained and CT Metering Rider (Dual Fuel)	Reserved for Future Use	Controlled Service Deferred Load Rider (Thermal Storage)	Fixed Time of Service Rider	Air Conditioning Control cREDIT (*CoolSavings*)	Voluntary Renewable Energy Rider (*TailWinds*)	WAPA Bill Crediting Program Rider	Reserved for Future Use	Bulk Interruptible Service	Economic Development Rate Rider - Large General Service	My Renewable Energy Credits (My RECs) Rider	
Riders	Section Numbers	14.01	14.02	14.03	14.04	14.05	14.06	14.07	14.08	14.09	14.10	14.11	14.12	14.13	14.14	
VOLUNTARY RIDERS																
Water Heating Control Rider	14.01									✓					✓	
Real Time Pricing	14.02									✓					✓	C
Large General Service Rider	14.03									✓					✓	
Controlled Service - Interruptible Load CT Metering Rider	14.04									✓					✓	
Controlled Service - Interruptible Load Self-Contained Metering Rider	14.05									✓					✓	
Controlled Service Deferred Load Rider	14.06									✓					✓	
Fixed Time of Service Rider	14.07									✓					✓	
Air Conditioning Control Credit	14.08															C
Voluntary Renewable Energy Rider	14.09															
WAPA Bill Crediting Program Rider	14.10															
Reserved for Future Use	14.11															
Bulk Interruptible Service Application and Pricing Guidelines	14.12															
Economic Development Rate Rider - Large General Service	14.13															
My Renewable Energy Credits (My RECs) Rider	14.14															
Key:	✓ = May apply	■ = Mandatory	□ = Not Applicable													

C

REAL TIME PRICING ~~RIDER~~ CLOSED TO NEW SERVICE

DESCRIPTION	RATE CODE
Transmission Service ~~CLOSED TO NEW CUSTOMERS~~	N660
Primary Service ~~CLOSED TO NEW CUSTOMERS~~	N662
Secondary Service ~~CLOSED TO NEW CUSTOMERS~~	N664

DESCRIPTION: The Real-Time Pricing (RTP) Tariff is structured for Large General Service customers with operational flexibility to adjust their energy usage in response to changing market conditions. By curtailing or shifting consumption during periods of high market prices, participating customers may better manage energy costs and contribute to overall system efficiency.

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

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

TERM OF SERVICE: Service under this Tariff~~rider~~ requires a minimum term of ~~shall be for a period not less than~~ one year. ~~The~~ Customers must provide at least six months advance written notice before initiating service unless otherwise agreed upon with the Company~~shall take service under this rider by either signing a new electric service agreement with the Company or by entering into amendments of existing electric service agreements. A Customer who voluntarily cancels service under this rider is not eligible to receive service again under this rider for a period of one year~~.

AVAILABILITY: ~~This rider is available on a~~Participation in this Tariff is voluntary and limited~~basis~~ to Customers who have received service on past versions of this Tariff and who are currently taking service under Section 10.04 (Large General Service) or Section 10.05 (Large General Service – Time of Day).

To be eligible, such Customers must maintain~~ed~~ a measured Demand of at least 2.5MW~~00 kW during the historical period used for Customer Baseline Load (CBL) development. Priority~~

~~will be established based on the date that an agreement is executed by both the Customer and the Company~~.

The Customer will have no behind the meter generation or battery energy storage system (BESS) except for emergency backup purposes.

ADMINISTRATIVE CHARGE: An Administrative Charge in the amount of $500~~282~~.00 will be applied to each monthly bill to cover billing, administrative, metering, and communication costs associated with real-time pricing, plus any other applicable tariff charges.

PRICING METHODOLOGY: The Day-Ahead Energy prices are determined for each day based on hourly Day-Ahead MISO Location Marginal Pricing (LMP) at the OTP. OTP MISO pricing node, losses according to voltage level, generation capacity costs, transmission costs, a system contribution price, and other MISO charges incurred by the Company caused by the Customer's load ~~Hourly prices are determined for each day based on projections of the hourly system incremental costs, losses according to voltage level, hourly outage costs (when applicable), and profit margin~~.

The Real-Time Market Energy prices are determined for each day based on hourly Real-Time LMP at the OTP.OTP MISO pricing node, losses according to voltage level, generation capacity costs, transmission costs, a system contribution price, and other MISO charges incurred by the Company caused by the Customer's load.

DAY-AHEAD REQUIREMENTS~~PRICE NOTIFICATION~~: By 7:00 a.m. (Central Time) the preceding day, the ~~The Company shall make available to~~ Customer~~s~~ will provide the Company its expected hourly load~~, no later than 4:00 p.m. (Central Time) of the preceding day, hourly RTP prices~~ for the next business day. The Customer's expected loads for Saturday through Monday will be provided to the Company by 7 a.m. the previous Friday. By 7 a.m. preceding a holiday, the Customer will provide its expected hourly load for the holiday and the next business day ~~Except for unusual periods where an outage is at high risk, the Company will make prices for Saturday through Monday available to Customers on the previous Friday. More than one-day-ahead pricing may also be used~~ for the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas Eve and Christmas Day.

~~Because high-outage-risk circumstances prevent the Company from projecting prices more than one day in advance, the Company reserves the right to revise and make available to Customers prices for Sunday, Monday, any of the holidays mentioned above, or for the day following a holiday. Any revised prices shall be made available by the usual means no later than 4:00 p.m. of the day prior to the prices taking effect.~~
No later than 4:00 p.m. (Central Time) of the preceding day, the Company shall make available to Customers the Day-Ahead Market Energy prices for the next business day. The Day-Ahead Market Energy prices for Saturday through Monday will be made available, whenever possible, the previous Friday. The Company may deviate from this procedure in abnormal operating conditions and for the holidays mentioned above.

If a Customer does not receive or obtain the prices made available by the Company, it is the Customer's responsibility to notify the Company by 4:30 p.m. (Central Time) of the business day preceding the day ~~that~~ the prices are to take effect. The Company reserves the right to revise its Day-Ahead Market Energy prices at any time prior to the Customer's acceptance and will be responsible for notifying the Customer of such revised prices~~if prices are revised~~.

The Company is not responsible for providing the Real-time hourly prices to the Customer~~a Customer's failure to receive or obtain and act upon the hourly RTP prices~~.

~~CUSTOMER~~ BASELINE DEMAND~~LOAD~~: The Customer Baseline Demand~~Load~~ is used to produce the Standard Bill and from which to measure changes in consumption for purposes for billing under the ~~specific to each Real Time Pricing (“~~RTP Tariff.~~”)~~ It is specific to each RTP Customer and is a representation of its typical annual load using ~~developed using~~ a twelve ~~12~~-month period~~. of hourly (8,760) Energy levels (kWh) as well as the corresponding twelve monthly Billing Demands based on the Customer's rate schedule under which it was being billed immediately prior to taking service under the RTP Rider.~~ The Baseline Demand~~Customer's CBL~~ must be agreed to in writing by the Customer as a precondition of receiving service under this Tariff~~rider~~.

The Customer’s Baseline Demand~~CBL~~ will be reevaluated every two years to ensure that the Customer’s Baseline Demand remains accurate~~. is a representation of its typical pattern of electricity consumption and is derived from historical usage data. The CBL is used to produce the Standard Bill and from which to measure changes in consumption for purposes of billing under the RTP rider.~~

BILL DETERMINATION: ~~A Real Time Pricing bill will be rendered after each monthly billing period. The bill consists of an Administrative Charge, a Standard Bill, a charge (or credit) for consumption changes from the CBL, and an excess Reactive Demand charge/credit. The monthly bill is calculated using the following formula:~~

Energy: A Customer’s monthly bill for energy will be determined in two parts: (1) energy consumed up to and including the Baseline Demand, and (2) energy consumed above the Baseline Demand.

The monthly bill for energy consumption up to and including the Baseline Demand will be determined by multiplying the Customer’s metered energy consumption by the energy rate provided in the Large General Service rate schedule applicable to the Customer.

The monthly bill for energy consumed above the Baseline Demand will be determined by multiplying the Customer’s expected hourly load by the hourly Day-Ahead prices plus the difference between the Customer’s expected hourly load and its realized hourly load (above Baseline Demand) multiplied by hourly Real-Time prices.

Demand: A Customer’s monthly bill for demand shall be determined by multiplying the Customer’s Baseline Demand by the demand rate provided in the Large General Service rate

schedule applicable to the Customer.

Facilities Demand Charge: A Customer's monthly bill for Facilities Demand shall be determined by multiplying the Customer's metered Demand by the Facilities Demand rate provided in the rate schedule applicable to the Customer.

~~**$RTP\ Bill_{Mo} = Adm.\ Charge + Std\ Bill_{Mo} + Consumption\ Changes\ from\ CBL_{Hr} + Excess\ Reactive\ Demand$**~~

~~**Where:**~~

~~$RTP\ Bill_{Mo}$ = Customer's monthly bill for service under this Rider~~
~~Adm. Chg. = See Administrative Charge section below~~
~~$Std.\ Bill_{Mo}$ = See Standard Bill section above~~
~~Consumption Changes From CBL = $\Sigma\ \{Price_{Hr} \times \{Load_{Hr} - CBL_{Hr}\}\}$~~
~~Excess Reactive Demand = See Excess Reactive Demand section below~~
~~Σ = Sum over all hours of the monthly billing period~~
~~$Price_{Hr}$ = Hourly RTP price as defined under Pricing Methodology~~
~~$Load_{Hr}$ = Customer's actual load for each hour of the billing period~~
~~CBL_{Hr} = Customer's CBL Energy usage for each hour of the billing period~~

DETERMINATION OF THE BASELINE DEMAND~~CBL~~:

For a Customer who elects to take service under this RTP Tariff~~rider~~, the Company shall determine ~~and~~ the Customer's ~~will develop a~~ Baseline Demand ~~CBL~~ using hourly load data from the most~~a~~ representative twelve~~12~~-month period. The most representative hourly load data to be used will be historical data that originates within two years (24 months) of the date that the Customer begins receiving service under the RTP Tariff~~rider~~.

BASELINE DEMAND~~CBL~~ ADJUSTMENTS: In order to assure that the Baseline Demand~~CBL~~ accurately reflects the Energy that the Customer would consume on its otherwise applicable rate schedule, adjustments to the Baseline Demand~~CBL~~ shall be made for:

1. The installation of permanent Energy efficiency measures or other verifiable conservation or technology efficiency improvement measures. At any time during the RTP service year, Customers can request that Baseline~~CBL~~ adjustments be made to reflect efficiency improvements and that the adjustment coincide with the time of the installation or change-out.

2. The permanent removal of Customer equipment or a change to operating procedures that results in a significant and permanent reduction of electrical load. At any time before or during the RTP service year, the Company will make adjustments to the Baseline Demand~~CBL~~ to coincide with the time that the equipment is removed or changes to operating procedures.

3. The permanent addition of Customer equipment that has been or will be made prior to the *initial* RTP service year is based upon known changes in Customer usage and/or Demand that are not directly related to the introduction of RTP.

4. One-time, extraordinary events such as a tornado or other natural causes or disasters outside the control of the Customer or the Company. In these cases, the Company will make adjustments to the Baseline Demand~~CBL~~ as warranted by the circumstance.

5. The permanent addition of Customer equipment after the initial RTP service year that requires the Company to install additional distribution capacity such as a larger or additional substation transformer, larger or additional distribution transformers, or larger distribution feeders, or other equipment changes needed to accommodate the new Customer load to be added. The Customer must make a formal request for additional contracted kVA capacity. The Company will determine the appropriate size of the new equipment to be installed. The Company will determine the total kW Demand to be added to the Customer's Baseline Demand~~CBL~~ that results from the request for additional kVA capacity. The Baseline Demand~~CBL~~ increase includes both a higher kW demand and additional energy that will be billed through the Customer's Standard Bill portion of the monthly RTP Bill. The amount of energy to be added will be determined by taking the annual load factor of the customer times the increased kW Demand.

SPECIAL PROVISIONS:

~~1.~~ If there is a change in the legal identity of the Customer receiving service under this RTP rider, service shall be terminated unless the Company and the Customer make other mutually agreeable arrangements.

~~2.~~ All equipment to be served must be of such voltage and electrical characteristics so that it can be served from the circuit provided for the main part of the load and so that the electricity used can be properly measured by the meter ordinarily installed on such a circuit. If the equipment is such that it is impossible to serve from existing circuits, the Customer must provide any necessary transformers, auto transformers, or any other devices so that connection can be made to the circuit provided by the Company.

~~3.~~ If the Customer's actual load exceeds the Baseline Demand~~CBL~~ by an amount that requires the Company to install additional facilities to serve the Customer, or the Customer requests additional Capacity greater than the capability of the system at the time the Customer signed up for the RTP Tariff~~Rider~~, the Customer's Baseline Demand~~CBL~~ will be increased by the amount of the excess capacity as used or requested by the Customer that is in excess of the capability of the System. Excess Capacity is the Capacity above our System capability at the time the Customer initially took service under the RTP Tariff~~Rider~~ or the most recent Baseline Demand~~CBL~~ adjustment as required by this Special Provision or any Baseline Demand~~CBL~~ Adjustments made through the Baseline Demand~~CBL~~ Adjustment

Section of this tariff.

Section 14.02 RESERVED FOR FUTURE USE

REAL TIME PRICING- CLOSED TO NEW SERVICE C

DESCRIPTION	RATE CODE	
Transmission Service	N660	C
Primary Service	N662	C
Secondary Service	N664	C

DESCRIPTION: The Real-Time Pricing (RTP) Tariff is structured for Large General Service customers with operational flexibility to adjust their energy usage in response to changing market conditions. By curtailing or shifting consumption during periods of high market prices, participating customers may better manage energy costs and contribute to overall system efficiency. N N N N N

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

MANDATORY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply. See Section 13.00 of the North Dakota electric rates for the Mandatory Riders – Applicability Matrix. C C C

TERM OF SERVICE: Service under this Tariff requires a minimum term of one year. Customers must provide at least six months advance written notice before initiating service unless otherwise agreed upon with the Company. C C C

AVAILABILITY: Participation in this Tariff is voluntary and limited to Customers who have received service on past versions of this Tariff and who are currently taking service under Section 10.04 (Large General Service) or Section 10.05 (Large General Service – Time of Day). C C C C

To be eligible, such Customers must maintain a measured Demand of at least 2.5MW . C

The Customer will have no behind the meter generation or battery energy storage system (BESS) except for emergency backup purposes. N N

ADMINISTRATIVE CHARGE: An Administrative Charge in the amount of $500.00 will be applied to each monthly bill to cover billing, administrative, metering, and communication costs associated with real-time pricing, plus any other applicable tariff charges. R

D

PRICING METHODOLOGY: The Day-Ahead Energy prices are determined for each day based on hourly Day-Ahead MISO Location Marginal Pricing (LMP) at the OTP. OTP MISO pricing node, losses according to voltage level, generation capacity costs, transmission costs, a system contribution price, and other MISO charges incurred by the Company caused by the Customer's load.

The Real-Time Market Energy prices are determined for each day based on hourly Real-Time LMP at the OTP.OTP MISO pricing node, losses according to voltage level, generation capacity costs, transmission costs, a system contribution price, and other MISO charges incurred by the Company caused by the Customer's load.

DAY-AHEAD REQUIREMENTS: By 7:00 a.m. (Central Time) the preceding day, the Customer will provide the Company its expected hourly load for the next business day. The Customer's expected loads for Saturday through Monday will be provided to the Company by 7 a.m. the previous Friday. By 7 a.m. preceding a holiday, the Customer will provide its expected hourly load for the holiday and the next business day for the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas Eve and Christmas Day.

D

No later than 4:00 p.m. (Central Time) of the preceding day, the Company shall make available to Customers the Day-Ahead Market Energy prices for the next business day. The Day-Ahead Market Energy prices for Saturday through Monday will be made available, whenever possible, the previous Friday. The Company may deviate from this procedure in abnormal operating conditions and for the holidays mentioned above.

If a Customer does not receive or obtain the prices made available by the Company, it is the Customer's responsibility to notify the Company by 4:30 p.m. (Central Time) of the business day preceding the day the prices are to take effect. The Company reserves the right to revise its Day-Ahead Market Energy prices at any time prior to the Customer's acceptance and will be responsible for notifying the Customer of such revised prices.

The Company is not responsible for providing the Real-time hourly prices to the Customer.

BASELINE DEMAND: The Customer Baseline Demand is used to produce the Standard Bill and from which to measure changes in consumption for purposes for billing under the RTP Tariff. It is specific to each RTP Customer and is a representation of its typical annual load using a twelve -month period. The Baseline Demand must be agreed to in writing by the Customer as a precondition of receiving service under this Tariff. **C C C C C**

The Customer's Baseline Demand will be reevaluated every two years to ensure that the Customer's Baseline Demand remains accurate. **C C**

BILL DETERMINATION: **D**

Energy: A Customer's monthly bill for energy will be determined in two parts: (1) energy consumed up to and including the Baseline Demand, and (2) energy consumed above the Baseline Demand. **N N N**

The monthly bill for energy consumption up to and including the Baseline Demand will be determined by multiplying the Customer's metered energy consumption by the energy rate provided in the Large General Service rate schedule applicable to the Customer. **N N N**

The monthly bill for energy consumed above the Baseline Demand will be determined by multiplying the Customer's expected hourly load by the hourly Day-Ahead prices plus the difference between the Customer's expected hourly load and its realized hourly load (above Baseline Demand) multiplied by hourly Real-Time prices. **N N N N**

Demand: A Customer's monthly bill for demand shall be determined by multiplying the Customer's Baseline Demand by the demand rate provided in the Large General Service rate schedule applicable to the Customer. **N N N**

Facilities Demand Charge: A Customer's monthly bill for Facilities Demand shall be determined by multiplying the Customer's metered Demand by the Facilities Demand rate provided in the rate schedule applicable to the Customer. **N N N**

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DETERMINATION OF THE BASELINE DEMAND: C D

For a Customer who elects to take service under this RTP Tariff, the Company shall determine the Customer's Baseline Demand using hourly load data from the most representative twelve-month period. The most representative hourly load data to be used will be historical data that originates within two years (24 months) of the date that the Customer begins receiving service under the RTP Tariff. C C C C D D

BASELINE DEMANDADJUSTMENTS: In order to assure that the Baseline Demand accurately reflects the Energy that the Customer would consume on its otherwise applicable rate schedule, adjustments to the Baseline Demand shall be made for: C C

1. The installation of permanent Energy efficiency measures or other verifiable conservation or technology efficiency improvement measures. At any time during the RTP service year, Customers can request that Baseline adjustments be made to reflect efficiency improvements and that the adjustment coincide with the time of the installation or change-out. C

2. The permanent removal of Customer equipment or a change to operating procedures that results in a significant and permanent reduction of electrical load. At any time before or during the RTP service year, the Company will make adjustments to the Baseline Demand to coincide with the time that the equipment is removed or changes to operating procedures. C

3. The permanent addition of Customer equipment that has been or will be made prior to the initial RTP service year is based upon known changes in Customer usage and/or Demand that are not directly related to the introduction of RTP.

4. One-time, extraordinary events such as a tornado or other natural causes or disasters outside the control of the Customer or the Company. In these cases, the Company will make adjustments to the Baseline Demand as warranted by the circumstance. C

5. The permanent addition of Customer equipment after the initial RTP service year that requires the Company to install additional distribution capacity such as a larger or additional substation transformer, larger or additional distribution transformers, or larger distribution feeders, or other equipment changes needed to accommodate the new Customer load to be added. The Customer must make a formal request for additional contracted kVA capacity. The Company will determine the appropriate size of the new equipment to be installed. The Company will determine the total kW Demand to be added to the Customer's Baseline Demand that results from the request for additional kVA capacity. The Baseline Demand increase includes both a higher kW demand and additional energy that will be billed through the Customer's Standard Bill portion of the monthly RTP Bill. The amount of energy to be added will be determined by taking the annual load factor of the customer times the increased kW Demand. **C C**

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SPECIAL PROVISIONS:

If there is a change in the legal identity of the Customer receiving service under this RTP rider, service shall be terminated unless the Company and the Customer make other mutually agreeable arrangements. **C**

All equipment to be served must be of such voltage and electrical characteristics so that it can be served from the circuit provided for the main part of the load and so that the electricity used can be properly measured by the meter ordinarily installed on such a circuit. If the equipment is such that it is impossible to serve from existing circuits, the Customer must provide any necessary transformers, auto transformers, or any other devices so that connection can be made to the circuit provided by the Company. **C**

If the Customer's actual load exceeds the Baseline Demand by an amount that requires the Company to install additional facilities to serve the Customer, or the Customer requests additional Capacity greater than the capability of the system at the time the Customer signed up for the RTP Tariff, the Customer's Baseline Demand will be increased by the amount of the excess capacity as used or requested by the Customer that is in excess of the capability of the System. Excess Capacity is the Capacity above our System capability at the time the Customer initially took service under the RTP Tariff or the most recent Baseline Demand adjustment as required by this Special Provision or any Baseline Demand Adjustments made through the Baseline Demand Adjustment Section of this tariff. **C C C C C**

Section 14.02 RESERVED FOR FUTURE USE **N**

CONTROLLED SERVICE - INTERRUPTIBLE LOAD SELF-CONTAINED AND CT METERING RIDER

(Commonly identified as Dual Fuel Riders)

DESCRIPTION	RATE CODE
Self-Contained Metering	
without Penalty	N190
with Penalty	N190P
Self-Contained Metering (with short-duration cycling)	
without Penalty	N185
with Penalty	N185P
CT Metering without ancillary load	
without Penalty	N170
with Penalty	N170P
CT Metering without ancillary load (short-duration cycling)	
without Penalty	N165
with Penalty	N165P
CT Metering with ancillary load	N168C
CT Metering with ancillary load (short-duration cycling)	N169C

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

AVAILABILITY: This rider Tariff is available for Residential or nonresidential service to any approved permanently connected interruptible load; such loads are primarily the electric heating portion of dual fuel heating systems and may include approved Energy storage loads. Electric heating systems may include heat pumps used for heating and/or cooling. Domestic electric water heating, and/or other permanently connected approved loads other than the exceptions noted below in CT with ancillary load, will be interrupted during control periods. When service to the electric equipment on this rate is interrupted, the back-up system cannot be electric.

CT without ancillary load: Electric fans, pumps and other ancillary equipment used in the distribution of conditioned air and/or water shall be wired for service through the Customer's firm service tariff.

CT METERING WITHOUT ANCILLARY LOAD		
Customer Charge per Month:	$20.20	
Monthly Minimum Bill:	Customer + Facilities Charge	
Facilities Charge per Month per annual maximum kW:	$1.42 /kW	
	Summer	Winter
Energy Charge per kWh:	1.637 ¢/kWh	1.419 ¢/kWh
Penalty:	18.412 ¢/kWh	20.847 ¢/kWh

During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above.

CT METERING WITH ANCILLARY LOAD		
Customer Charge per Month:	$20.20	
Monthly Minimum Bill:	Customer + Facilities Charge	
Facilities Charge per Month per annual maximum kW:	$1.42 /kW	
	Summer	Winter
Energy Charge per kWh:	1.637 ¢/kWh	1.419 ¢/kWh
Control Period Demand Charge per kW:	$14.50 /kW	$14.45 /kW

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

DEFINITIONS OF SEASONS:

Summer: June 1 through September 30.

Winter: October 1 through May 31.

PENALTY PERIODS – CT METERING WITHOUT ANCILLARY LOAD: Penalty periods are defined as periods when the Company signals to interrupt the Customer's load and the Customer's equipment does not shed the load. Installation of a dual register Meter will be at the option of the Company. When a dual register Meter is installed, penalty usage will be recorded on the peak register and the total register of the dual register Meters.

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

CONTROL CRITERIA: Service may be controlled up to a total of 24 hours during any 24-hour period, as measured from midnight to midnight. Exceptions to this control are a) Short-duration cycling ~~is approximately 15 minutes off/15 minutes on~~ of appropriate cooling equipment ~~during the extended Summer Cooling Season (May–October)~~, and b) Domestic water heating may be controlled up to 14 hours in the 24-hour period.

DETERMINATION OF FACILITIES CHARGE – ALL CT METERING: The monthly measured Demand will be based on the maximum 15 consecutive minute period measured by a suitable Demand Meter for the month for which the bill is rendered. The Facilities Charge Demand shall be based on the greatest of the current and preceding 11 monthly measured Demands.

DETERMINATION OF CONTROL PERIOD DEMAND – ONLY CT METERING WITH ANCILLARY LOAD: The Billing Demand measured during the control period for which the bill is rendered shall be the maximum metered kW for any period of 15 consecutive minutes during the control period.

EQUIPMENT SUPPLIED: The Company will supply and maintain the necessary standard metering and control equipment.

CONTROLLED SERVICE - INTERRUPTIBLE LOAD
SELF-CONTAINED AND CT METERING C
(Commonly identified as Dual Fuel) C

DESCRIPTION	RATE CODE
Self-Contained Metering	
without Penalty	N190
with Penalty	N190P
Self-Contained Metering (with short-duration cycling)	
without Penalty	N185
with Penalty	N185P
CT Metering without ancillary load	
without Penalty	N170
with Penalty	N170P
CT Metering without ancillary load (short-duration cycling)	
without Penalty	N165
with Penalty	N165P
CT Metering with ancillary load	N168C
CT Metering with ancillary load (short-duration cycling)	N169C

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

AVAILABILITY: This Tariff is available for Residential or nonresidential service to any approved permanently connected interruptible load; such loads are primarily the electric heating portion of dual fuel heating systems and may include approved Energy storage loads. Electric heating systems may include heat pumps used for heating and/or cooling. Domestic electric water heating, and/or other permanently connected approved loads other than the exceptions noted below in CT with ancillary load, will be interrupted during control periods. When service to the electric equipment on this rate is interrupted, the back-up system cannot be electric. C

CT without ancillary load: Electric fans, pumps and other ancillary equipment used in the distribution of conditioned air and/or water shall be wired for service through the Customer's firm service tariff.

CT METERING WITHOUT ANCILLARY LOAD

Customer Charge per Month:	$20.20
Monthly Minimum Bill:	Customer + Facilities Charge
Facilities Charge per Month per annual maximum kW:	$1.42 /kW

	Summer	Winter
Energy Charge per kWh:	1.637 ¢/kWh	1.419 ¢/kWh
Penalty:	18.412 ¢/kWh	20.847 ¢/kWh

During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above.

CT METERING WITH ANCILLARY LOAD

Customer Charge per Month:	$20.20
Monthly Minimum Bill:	Customer + Facilities Charge
Facilities Charge per Month per annual maximum kW:	$1.42 /kW

	Summer	Winter
Energy Charge per kWh:	1.637 ¢/kWh	1.419 ¢/kWh
Control Period Demand Charge per kW:	$14.50 /kW	$14.45 /kW

MANDATORY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply. See Section 13.00 of the North Dakota electric rates for the matrix of riders. **C C C**

DEFINITIONS OF SEASONS:

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

PENALTY PERIODS – CT METERING WITHOUT ANCILLARY LOAD: Penalty periods are defined as periods when the Company signals to interrupt the Customer's load and the Customer's equipment does not shed the load. Installation of a dual register Meter will be at the option of the Company. When a dual register Meter is installed, penalty usage will be recorded on the peak register and the total register of the dual register Meters.

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

CONTROL CRITERIA: Service may be controlled up to a total of 24 hours during any 24-hour period, as measured from midnight to midnight. Exceptions to this control are a) Short-duration cycling of appropriate cooling equipment , and b) Domestic water heating may be controlled up to 14 hours in the 24-hour period. C

DETERMINATION OF FACILITIES CHARGE – ALL CT METERING: The monthly measured Demand will be based on the maximum 15 consecutive minute period measured by a suitable Demand Meter for the month for which the bill is rendered. The Facilities Charge Demand shall be based on the greatest of the current and preceding 11 monthly measured Demands.

DETERMINATION OF CONTROL PERIOD DEMAND – ONLY CT METERING WITH ANCILLARY LOAD: The Billing Demand measured during the control period for which the bill is rendered shall be the maximum metered kW for any period of 15 consecutive minutes during the control period.

EQUIPMENT SUPPLIED: The Company will supply and maintain the necessary standard metering and control equipment.

CONTROLLED SERVICE
DEFERRED LOAD RIDER
(Commonly identified as Thermal Storage)

DESCRIPTION	RATE CODE
Deferred Loads	N197
Deferred Loads with Penalty	N197P
Deferred Loads (short duration cycling)	N195
Deferred Loads (short duration cycling) with Penalty	N195P

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

AVAILABILITY: This rider Tariff is available for both Residential and nonresidential service to any approved permanently connected deferred loads that can be served under the limited conditions provided; such loads are primarily electric water heating, thermal storage, and Energy storage.

Deferred loads may include heat pumps, domestic electric water heating, and other permanently connected loads that can be interrupted. Subject to the exception below, electric fans, pumps, and other ancillary equipment used in the distribution of heat shall be wired through the Customer's firm service Meter.

The Company retains the authority to allow a portion of the load to remain on during control periods in situations where 1) it is unfeasible to separately serve the equipment's control systems, or other critical ancillary equipment associated with this load, or 2) if the separation would violate the manufacturer's Underwriters Laboratory (UL) approval or other industry recognized operating standards. Although a minimal amount of fan and pump load may be allowed under this provision, it is not intended to be applied to larger loads such as the fan load on low temperature grain drying.

RATE:

CONTROLLED SERVICE - DEFERRED LOAD		
Customer Charge per Month:	$10.00	
Monthly Minimum Bill:	Customer + Facilities Charge	
Facilities Charge per Month:	$11.60	
	Summer	Winter
Energy Charge per kWh:	4.545 ¢/kWh	3.336 ¢/kWh
Penalty	17.726 ¢/kWh	18.221 ¢/kWh
During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above.		

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

DEFINITIONS OF SEASONS:

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

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

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

CONTROL CRITERIA: Service, including domestic water heating, may be controlled for up to a total of 14 hours during any 24-hour period, as measured from midnight to midnight. Under normal circumstances the Company will schedule recovery time following control periods that approach 14 continuous hours. An exception to this control includes Short-duration cycling, approximately 15 minutes off/15 minutes on, of appropriate cooling equipmentduring the extended Summer Cooling Season (May-October).

EQUIPMENT SUPPLIED: The Company will supply and maintain the necessary standard metering and control equipment.

CONTROLLED SERVICE
DEFERRED LOAD C
(Commonly identified as Thermal Storage)

DESCRIPTION	RATE CODE
Deferred Loads	N197
Deferred Loads with Penalty	N197P
Deferred Loads (short duration cycling)	N195
Deferred Loads (short duration cycling) with Penalty	N195P

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

AVAILABILITY: This Tariff is available for both Residential and nonresidential service to any approved permanently connected deferred loads that can be served under the limited conditions provided; such loads are primarily electric water heating, thermal storage, and Energy storage. C

Deferred loads may include heat pumps, domestic electric water heating, and other permanently connected loads that can be interrupted. Subject to the exception below, electric fans, pumps, and other ancillary equipment used in the distribution of heat shall be wired through the Customer's firm service Meter.

The Company retains the authority to allow a portion of the load to remain on during control periods in situations where 1) it is unfeasible to separately serve the equipment's control systems, or other critical ancillary equipment associated with this load, or 2) if the separation would violate the manufacturer's Underwriters Laboratory (UL) approval or other industry recognized operating standards. Although a minimal amount of fan and pump load may be allowed under this provision, it is not intended to be applied to larger loads such as the fan load on low temperature grain drying.

RATE:

CONTROLLED SERVICE - DEFERRED LOAD		
Customer Charge per Month:		$10.00
Monthly Minimum Bill:		Customer + Facilities Charge
Facilities Charge per Month:		$11.60
	Summer	Winter
Energy Charge per kWh:	4.545 ¢/kWh	3.336 ¢/kWh
Penalty	17.726 ¢/kWh	18.221 ¢/kWh
During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above.		

MANDATORY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply. See Section 13.00 of the North Dakota electric rates for the matrix of riders. **C C C**

DEFINITIONS OF SEASONS:

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

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

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

CONTROL CRITERIA: Service, including domestic water heating, may be controlled for up to a total of 14 hours during any 24-hour period, as measured from midnight to midnight. Under normal circumstances the Company will schedule recovery time following control periods that approach 14 continuous hours. An exception to this control includes Short-duration cycling of appropriate cooling equipment. **C C C**

EQUIPMENT SUPPLIED: The Company will supply and maintain the necessary standard metering and control equipment.

AIR CONDITIONING CONTROL ~~RIDER~~CREDIT

(Commonly identified as **Cool***Savings*)

DESCRIPTION	RATE CODE
Air Conditioning Control ~~Rider~~ Credit	N760
Commercial Air Conditioning Control ~~Rider~~Credit	N762

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

AVAILABILITY: This ~~rider~~ credit is voluntary, available to Residential, Residential service associated with a Farm, and Commercial Customers who have qualifying ~~only with~~ central cooling equipment, including heat pumps. For Commercial Customers, eligibility for ~~T~~the ~~Commercial~~ Air Conditioning Control ~~Rider~~ Credit is ~~available~~ limited to Customers taking service under Sections 10.01 and 10.02. See Section 14.00 of the North Dakota electric rates for the applicability matrix of the credit.

The ~~rider will not be available to Customers, as determined by the~~ Company may determine that the credit is unavailable ~~,~~ when~~n~~re ~~the~~ installation of load management devices is impractical. ~~Such reasons for not installing the equipment~~ Circumstances ~~b~~may include, but are not limited to, ~~oversized/undersized central air conditioning~~improperly sized cooling equipment or locations with abnormal ~~utilization of~~ equipment use patterns, such as ~~including~~ vacation homes or other limited~~-~~-occupancy ~~situations~~buildings.

~~COMPENSATION~~CREDIT:

~~AIR CONDITIONING CONTROL CREDIT – N760~~
~~Monthly Credit: – $8.25 (Extended Summer Cooling Season Only)~~

~~COMMERCIAL AIR CONDITIONING CONTROL CREDIT – N762~~
~~Monthly Credit: – $6.00 per ton (Extended Summer Cooling Season only)~~

Residential (N760):
The Customer will be compensated for taking service on this program by receiving a $7.00 per month bill credit during the billing months May through October. The credit will be applied on the Customer's Account.

Commercial (N762):
The customer will be compensated for taking service on this program by receiving a $5.00 credit per ton per month during the billing months May through October. The credit will be applied on the Customer's Account.

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

TERMS AND CONDITIONS:

1. ~~Extended Summer Cooling Season hours~~Hours of interruptions per year shall not exceed 300, except during periods of Company system emergencies. ~~Central cooling equipment will be cycled approximately 15 minutes on/15 minutes off.~~ Cycling of equipment within a control period may occur during expected cooling equipment operation. Cycling patterns will be determined by the Company based on system needs. ~~Extended Summer Cooling Season is the months of May through October. Customers will be compensated for only 5 of the 6 months during the extended cooling season.~~

2. The Company will install, own, and maintain the standard load management devices controlling the Customer's central cooling equipment. The Customer shall be responsible for any additional costs for the installation of non-standard facilities associated with the Company's load management control devices.

3. The Customer is required to remain on ~~the Electric Rate Schedule~~~~rider~~this program ~~-~~for 12 consecutive months unless given special approval by the Company. If the Customer leaves the program, they may not participate for another 12 months and may not receive any form of compensation as determined by the Company.

4. The Company has the right to test the function of the load management devices at any time.

5. The Customer must agree to allow the Company to control all central cooling equipment at the location of service.

6. Commercial Only (N762): Single and dual stage central air conditioning will be cycled ~~on a 15 minute on/off schedule~~ to achieve a ~~50%~~ reduction in the building air conditioning requirements during a load management period. Dual stage air conditioners will be allowed to have the first stage run without interruption while the second stage will be shut off for the entire load management period.

AIR CONDITIONING CONTROL CREDIT C

(Commonly identified as **Cool***Savings*)

DESCRIPTION	RATE CODE	
Air Conditioning Control Credit	N760	C
Commercial Air Conditioning Control Credit	N762	C

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

AVAILABILITY: This credit is voluntary, available to Residential, Residential service associated with a Farm, and Commercial Customers who have qualifying central cooling equipment, including heat pumps. For Commercial Customers, eligibility for the Air Conditioning Control Credit is limited to Customers taking service under Sections 10.01 and 10.02. See Section 14.00 of the North Dakota electric rates for the applicability matrix of the credit. C C C C N N

The Company may determine that the credit is unavailable where installation of load management devices is impractical. Circumstances may include, but are not limited to, improperly sized cooling equipment or locations with abnormal equipment use patterns, such as vacation homes or other limited-occupancy buildings. C C C C

CREDIT: C D D N

Residential (N760):
The Customer will be compensated for taking service on this program by receiving a $7.00 per month bill credit during the billing months May through October. The credit will be applied on the Customer's Account. NR N N

Commercial (N762):
The customer will be compensated for taking service on this program by receiving a $5.00 credit per ton per month during the billing months May through October. The credit will be applied on the Customer's Account. N NR N N

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TERMS AND CONDITIONS:

1. Hours of interruptions per year shall not exceed 300, except during periods of Company system emergencies. Cycling of equipment within a control period may occur during expected cooling equipment operation. Cycling patterns will be determined by the Company based on system needs. **C C C C**

2. The Company will install, own, and maintain the standard load management devices controlling the Customer's central cooling equipment. The Customer shall be responsible for any additional costs for the installation of non-standard facilities associated with the Company's load management control devices.

3. The Customer is required to remain on this program for 12 consecutive months unless given special approval by the Company. If the Customer leaves the program, they may not participate for another 12 months and may not receive any form of compensation as determined by the Company. **C**

4. The Company has the right to test the function of the load management devices at any time.

5. The Customer must agree to allow the Company to control all central cooling equipment at the location of service.

6. Commercial Only (N762): Single and dual stage central air conditioning will be cycled to achieve a reduction in the building air conditioning requirements during a load management period. Dual stage air conditioners will be allowed to have the first stage run without interruption while the second stage will be shut off for the entire load management period. **C C**