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June 18, 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 Petition for Approval of a New Class for Very Large Customers Class and Associated Rate Schedule
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 Petition for approval of a new class for very large customers generally, and a rate schedule for data center loads, in the above-referenced matter.

Copies have been sent to you via USPS.

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

vjm
Enclosures
By electronic filing and U.S. mail

1 PU-26-215 Filed 06/18/2026 Pages: 137
Petition for Approval of Tiered Large General Service

Otter Tail Power Company
Amber Grenier, Mgr. Regulatory Economics

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Otter Tail Power Company's Application for Approval of a New Class for Very Large Customer Class and Associated Rate Schedules	**Case No. PU-26-** **Application**

I. APPLICATION SUMMARY

Otter Tail Power Company (OTP 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 Tariff. The proposed updates create a new class for very large customers with associated rate schedules and amendments, and a new rate schedule for high power compute loads. These changes are intended to ensure consistent application of tariff provisions across our jurisdictions and protect non-participating customers from costs associated with very large customer loads joining the system.

This filing includes:

- Section 10.04 – Large General Service – Tier I: Revises the name to indicate Tier I and clarifies that the size of customer load on this rate schedule is at least 200 kilowatts (kW) and less than 25,000 kW.
- Section 10.05 – Large General Service – Tier I – Time of Day: Revises the name to indicate Tier I, clarifies that the size customer load on this rate schedule is at least 200 kW and less than 25,000 kW.
- Section 10.06 – Large General Service – Tier II – Time of Day: Cancels the original 10.06 Super Large General Service and replaces it with a new rate schedule for customer load above 25,000 kW that sets forth the applicable rates and conditions of service. The rates and service conditions are identical to those in Section 10.05 (except for size) and will be updated in a future rate case.
- Section 10.07 – Large General Service – Tier III – High Power Compute: Creates a new rate schedule for high power compute customers with at least 75 MW of firm load and sets for the conditions of service.

- Section 10.08 – Large General Service – Marginal Rate: This rate schedule is technically a new tariff section but merely renames the former Super Large General Service rate schedule (formerly Section 10.06).
- Section 10.09 – Large General Service – Thermal Market Energy Pricing: this is technically a new tariff section but merely renames and renumbers the former Thermal Market Energy Pricing rate schedule (formerly Section 14.16).
- Sections 13.01, 13.04, 13.05, 13.06, 13.08, 13.11, 13.12, and 14.13 – Makes administrative changes to update the names and numbers of the rate schedules and indicate their inapplicability to the new rate schedules added.
- Section 14.16 – cancellation and reserve for future use (the old 14.16 becomes the new 10.09).

The proposed changes to the Company's rate schedule divide the Large General Service class into tiers and provide a new rate schedule for high power compute (HPC) customers, enhance cost accuracy, and ensure alignment between customer billing and the costs incurred to serve them. The proposed HPC rate schedule establishes a separate rate structure for very large customers whose size, load profile, and infrastructure requirements differ materially from existing retail customer classes. The HPC rate schedule is designed as a long-term, take-or-pay service construct that assigns to the data center, all costs attributable to serving data center load, separate and apart from OTP's traditional jurisdictional cost of service.

OTP filed a similar rate schedule creating a new class for very large customers and new rate schedule for data center loads at the Minnesota Public Utilities Commission on May 18, 2026, and will shortly file the same with the South Dakota Public Utilities Commission, to secure their respective approvals of our proposed methodology and approach to serving a very large HPC customer. OTP filed first in Minnesota, to comply with Minnesota's new statute regarding very large customers. We believe that these changes are in the best interests of all of our customers in all three jurisdictions.

The Company proposes an effective date for the new and amended rate schedules of January 1, 2027. 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) 739-8774
ldonoofrio@otpco.com

C. Title of utility employee responsible for filing

Amber Greiner
Manager, Regulatory Economics
Regulation & Retail Energy Solutions
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8728
agrenier@otpco.com

We request that all communications regarding this proceeding, including data request, 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 June 18, 2026. OTP proposes an effective date of January 1, 2027, for the new and updated rates.

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 OTP'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.

III. DESCRIPTION AND PURPOSE OF FILING

A. New class and rate schedule for very large customers

In recent years, the electric service industry has seen an influx of demand for high power compute (for example, AI or data center load). Recently, two of the states in which we serve have passed legislation related to this new demand for very large load additions. In 2025, the Minnesota Legislature passed legislation modifying various environmental and energy regulatory requirements governing data centers. That legislation included Minnesota Statute 216B.1622, which requires the Minnesota PUC to establish a new class for very large customers, and provides certain requirements for large load tariffs. In early 2026, South Dakota passed the "Data Center Bill of Rights for Citizens," Senate Bill 135, which will become effective July 1, 2026, and which sets forth similar requirements for serving data centers to Minnesota's requirements for serving very large loads. OTP has been considering internal policies around data centers and other large loads for some time, and Minnesota's and South Dakota's new laws informed OTP's proposed methodology for addressing very large load and data center-type load. OTP has already proposed its new methodology in Minnesota, and will shortly file in South Dakota.

OTP proposes to divide its Large General Service (LGS) class into tiers, largely by size, to better allow us to design future rates to more appropriately assign costs to cost causers. At present, our LGS class covers loads of at least 200 kW with no ceiling. We have begun to routinely see potential customers interested in service for loads above 500 MW. It is reasonable to expect that customers with less than a megawatt of demand will cause different types or different quantities of cost than customers with more than 500 MW of demand. To ensure fair cost allocation among new and existing customers alike, we propose dividing our LGS class into three tiers.

B. Appropriate characteristics of a very large customer class or subclass for Otter Tail Power.

OTP proposes to divide its existing LGS customer class into three tiers. Tier I will include customers with at least 200 kW and less than 25,000 kW (25 megawatts (MW)). Tier II will include customers with at least 25,000 kW. Tier III will include customers with at least 75,000 kW (75 MW) of firm data center load.

We selected 25 MW as a threshold for a very large load based on several considerations. A 25 MW threshold is consistent with our existing practices as both the Super Large General Service (10.06) and Thermal Market Energy Pricing (14.16) rate schedules apply to loads above 25 MW. It also balances the scale of typical customers with larger loads that may require incremental resources and higher connection costs. Tier III, proposed for data center loads, will have a minimum size of 75 MW. Loads at this level generally involve significant connection costs and require substantial investment in incremental generation resources.

These fairly low thresholds are appropriate given OTP's status as one of the smallest investor-owned public utilities in the nation. While larger utilities may adopt higher thresholds, those standards are not suitable for OTP. Further detail on the new proposed data center rate schedule threshold is provided below.

1. Required tariff amendments

To align existing rate schedules with this structure, certain rate schedules require renumbering, renaming, or minor changes to denote size thresholds. The table below presents the updated rate schedules and size limits we propose in tariff Section 10:

Section No.	Rate Schedule Name	Minimum Size	Maximum Size	Old Rate Schedule Name/No.
10.01	Small General Service		19kW	N/A
10.02	General Service	20 kW	199 kW	N/A
10.03	General Service – Time of Day	20 kW	199 kW	N/A
10.04	Large General Service – Tier I	200 kW	24,999 kW	Large General Services
10.05	Large General Service – Tier I – Time of Day	200 kW	24,999 kW	Large General Services – Time of Day
10.06	Large General Service – Tier II – Time of Day	25,000 kW		New
10.07	Large General Service – Tier III – High Power Compute	75,000 kW		New
10.08	Large General Service – Marginal Rate	25,000 kW		10.06 Super Large General Service
10.09	Large General Service – Thermal Market Energy Pricing	25,000 kW		14.16 Thermal Market Energy Pricing

There are three types of changes to tariff sections at issue here. First, there are the rate schedules that need minor changes to titles, changes to denote new maximums and/or minimum thresholds for applicability, and changes to reflect applicability of various riders to the new rate schedules. Second, there are new rate schedules where the section number is new, but the content has previously been approved by the Commission under the old rate schedule number. The third category is brand new rate schedules that the Commission has never seen before. A summary of the changes for each of these rate schedules is provided in Attachment 1. The legislative and non-legislative versions of each rate schedule are attached as Attachment 2.

a. Changes to existing rate schedules

In this Application, we propose minor changes to Sections Index, 10.04, 10.05, 13.00, 13.01, 13.02, 13.03, 13.04, 13.05, 13.07, 13.08, 13.10, 13.11, 13.12, and 14.00. The changes for each are set out in Attachments 1 (table with summary of changes) and 2, which have the proposed rate schedules (legislative and non-legislative). OTP is also using this opportunity to update the footers of these sections to reflect the name and title of Matthew J. Olsen, Vice President of Regulatory.

b. New Section numbers, previously approved content

There are two Commission-approved rate schedules that we propose renumbering and/or renaming in this Application. Because we plan to re-use existing tariff section numbers, for each rate schedule to be renumbered, we propose 3 versions. The first revision will cancel the rate schedule. The second revision is to reserve the section number for future use. The third revision will be the new rate section going into the section reserved for future use, but it will not have any substantive changes from the current version of the rate schedule, as it is only the section number and/or name that has changed.

The first is Section 10.06 Super Large General Service, which will ultimately be renumbered and renamed as a new rate schedule: Section 10.08 Large General Service – Marginal Rate. The substance of the rate schedule has not changed.

The second is Section 14.16 Thermal Market Energy Pricing, which will ultimately be renumbered and renamed as a new original rate schedule: Section 10.09 Large General Service – Thermal Market Energy Pricing. The substance of the rate schedule has not changed. In this instance there will only be two (2) versions as we are not replacing Section 14.16, so it will just be cancelled and reserved for future use.

c. Entirely new rate schedules

There are two completely new rate schedules for which OTP seeks approval in this Application. These are Section 10.06 Large General Service – Tier II – Time of Day and Section 10.07 Large General Service – Tier III – High Power Compute. These new rate schedules are discussed more fully below.

C. New Large General Service – Tier II – Time of Day Rate Schedule

The new Large General Service – Tier II – Time of Day rate schedule is functionally identical to OTP's existing Large General Service – Tier I – Time of Day rate schedule. Given that OTP does not currently have rates designed for this new rate schedule, OTP proposes to use the same rates applicable to Tier I for Tier II, until OTP's next rate case. This plan is reasonable because any customer who moved from Tier I to Tier II would not see any change in their rate.

D. Otter Tail Power's data center philosophy.

OTP takes a cautious approach to data center service by carefully considering how we can serve such a load without sacrificing reliability or raising costs for existing customers. We designed the proposed Large General Services – Tier III – High Power Compute rate schedule (HPC Rate) to provide competitively priced, reliable energy to potential new data center load, while protecting our customers and our business from the risks inherent to serving data center load.

This Application outlines a framework to serve a data center customer by assigning the incremental costs necessary to serve that customer to that customer. These costs include necessary incremental capacity and energy resources, as well as the incremental transmission and delivery facility infrastructure costs necessary to connect the HPC Rate customer. We also describe below the minimum qualifications, terms and conditions, cost recovery mechanisms, and proposed risk mitigation protections we would require to serve a new data center on the HPC Rate and protect customers from cross subsidies or stranded costs associated with the data center. Finally, we describe how the Company's approach would capture and return to existing legacy customers incremental benefits from adding such a significant load.

2. Otter Tail Power's Existing Service Territory demographics:

OTP is a very small investor-owned utility serving a large, sparsely populated region across North Dakota, Minnesota, and South Dakota. We provide retail electric service to approximately 134,000 customers – 59,000 in North Dakota, 63,000 in Minnesota, and 12,000 in South Dakota – across roughly 422 small communities and rural areas. Our 70,000 square-mile service territory spans the eastern two-thirds of

North Dakota, western Minnesota, and northeastern South Dakota, an area comparable to the size of Wisconsin.

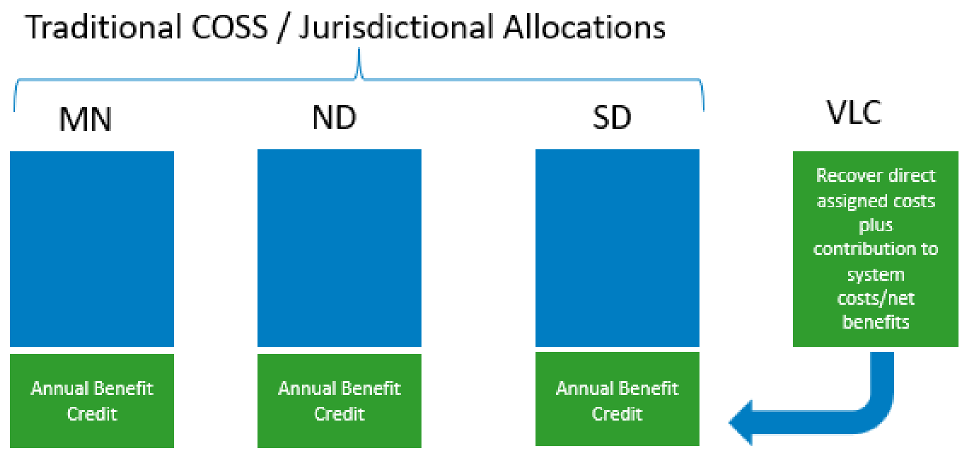
OTP's current system peak load across all jurisdictions is approximately 1,000 MW. Adding a several hundred megawatt, high-load-factor data center would require a significant amount of new capacity, energy, and delivery infrastructure. At the same time, we need to appropriately account for the costs to serve the new customer in a way that protects existing customers from cross-subsidization, negative impacts, and stranded asset risk.

3. Description of Proposed Service and Recovery Structure under the HPC Rate

OTP believes creating a new class for very large customers makes sense for the types of larger loads we have typically seen in our service territory. However, with regard to data center load of 75 MW or more, OTP proposes to take that concept one step further. Given the magnitude of the size of potential data center loads, especially relative to our small size, we propose creating a separate cost recovery structure under the HPC Rate that develops a separate cost of service specific to the Customer, and a customized rate structure that recovers the incremental costs to serve the customer, outside of OTP's traditional jurisdictionally allocated embedded system cost of service.

This new mechanism would be analogous to the modeling and cost recovery approach associated with a specific cost recovery rider. The same concept is being considered in this case, where within this mechanism, incremental costs to serve the HPC Rate customer would be captured, and specific rate designs and rates will be developed based on the cost characteristics unique to serving the load. The overall revenue requirement and associated rates would only be applicable to the individual HPC Rate customer.

OTP proposes that this mechanism will not be "state specific" from a traditional jurisdictional cost-of-service perspective. In other words, this load will not impact current, traditional jurisdictional allocations of existing system costs. Instead, the structure is designed to recover the HPC Rate customer's incremental cost of service while also incorporating rate elements that will capture and provide a benefit contribution to existing customers across all our jurisdictions, regardless of the HPC Rate customer's location. The illustration below helps visualize this concept:



OTP has proposed a similar rate schedule and associated mechanism in Minnesota and will do so in South Dakota as well. It is vital that all our jurisdictions support this approach as it is intended to protect all customers from any cross-subsidization of an HPC Rate customer and to equitably share the benefits of adding the HPC Rate customer with our legacy customers. Statutory provisions of the HPC Rate customer's host state (if any) will be considered within each state's HPC rate schedule, but the proposed cost tracking mechanism and benefit sharing would be consistent for each state.

A rider-type mechanism will allow rates to be established and updated as needed to facilitate recovery both during the buildout of facilities necessary to serve the HPC Rate customer, as well as when load begins to come on-line and grow to its final design levels, a process that can span multiple years. The mechanism will include true-up provisions to protect the HPC Rate customer, existing customers, and the Company.

For dedicated resources constructed and owned by OTP to serve the Customer, the mechanism shall recover all related revenue requirement components, including return on investment, depreciation, property taxes, insurance, and associated O&M costs. It will also capture costs for contracted energy and capacity, Midcontinent Independent System Operator (MISO)-related load and generation charges, and transmission-related costs including use of existing transmission facilities and any incremental transmission investments.

There are three main benefits associated with this approach. First, it reduces cross-subsidization risk. Second, it reduces regulatory lag on the front end by avoiding rates cases when adding an HPC Rate customer. Third, it also reduces regulatory lag in the case of an early exit. It also allows OTP to achieve allocation redistribution without filing multiple rate cases in separate jurisdictions.

This approach isolates the financial aspects of serving the new HPC Rate customer. Establishing a separate MISO asset owner for the customer and direct assigning or passing through all costs to serve the customer clearly identifies costs attributable to the new HPC Rate customer avoiding cross-subsidization and protecting existing customers from rate impacts associated with the new data center load.

This approach also mitigates risks associated with an early exit by an HPC Rate customer. By financially isolating a very large data center loads, we protect both our customers and our Company from potential impacts. For example, adding a 1,000 MW HPC Rate customer in North Dakota would effectively double OTP's load and significantly shift jurisdictional allocations – potentially increasing North Dakota's share from approximately 44 percent to 72 percent. Under a traditional approach, we would need to file three rate cases to re-allocate jurisdictional costs to avoid over-recovery of costs. Similarly, an early HPC Rate customer exit would require rate cases in all three jurisdictions to realign allocations, creating regulatory lag and under-recovery of costs.

In contrast, the proposed approach maintains existing jurisdictional allocations and allocates system benefits brought by the new HPC Rate customer according to current jurisdictional allocations. The HPC Rate customer will contribute to existing system costs as part of its revenue requirement, and that benefit will be shared across all states and customers regardless of the jurisdiction in which the HPC Rate customer is sited. If the HPC Rate customer exits early, the system benefit credit can be removed through the annual true-up, avoiding the need for multiple rate cases or disruption to existing rates.

4. Large General Service – High Power Compute rate schedule.

a. Eligibility

The HPC Rate will apply to a new customer expected to reach a Peak Contract Demand of at least 75 MW of firm (non-interruptible) demand at a single site or across multiple interconnected buildings on contiguous parcels operated as a single campus, with an expected annual load factor of at least 70 percent. Each customer will require a dedicated resource plan to meet its energy and capacity requirements from incremental generation. Both load ramp-up and resource development may take several years. This period, defined as the Buildout Period, begins when the customer first reaches commercial operation (the COD) and ends when the customer reaches full operability, and OTP has secured sufficient incremental resources. The Steady Period begins thereafter, with a minimum contract term of service of 15 years.

Eligibility is contingent on execution of a Commission-approved ESA, satisfaction of applicable credit and security requirements, and payment of all study and interconnection costs. The Customer will remain responsible for any statutory data-center fees or obligations established by Minnesota law.

b. Resource Plan to Serve Customer:

i. Dedicated Capacity and Energy Resources

OTP will develop a comprehensive capacity and energy resource plan, aligned with both the Company's and the HPC Rate customer's operational needs, which we will incorporate into the ESA. The HPC Rate customer will pay the full revenue requirement for dedicated resources, including Company-owned generation facilities and contracted costs (e.g. Purchase Power Agreements (PPAs)), covering fixed and variable O&M, fuel, property taxes, insurance, and carrying costs. In the alternative, the HPC Rate customer may negotiate to bring its own generation, on terms acceptable to the Company. The Company will establish separate MISO Asset Owner (AO) designations and Commercial Pricing Nodes (CP Nodes) for the HPC customer's load and the dedicated generation resources to isolate the load and dedicated generation resources from OTP's existing customers and resources.

A HPC Rate customer's specific resource plan will need to meet each HPC Rate customer's energy and capacity requirements from incremental generation. For every MW of data center load, OTP will add a commensurate amount of incremental capacity and energy generation resources, either through new Company-owned resources or PPAs. Existing resources will not be used, preserving system reliability and compliance with MISO resource adequacy requirements during the Buildout and Steady Periods. This approach also maintains the ratio of load-to-available energy in the Zone mitigating impacts on locational marginal pricing (LMP) in our service area.

ii. Buildout Period Usage

While we expect the buildout of load and resources to align, there may be times during any Buildout Period when a customer's data center load exceeds the incremental resources we have brought online. If this occurs, OTP will limit the HPC Rate customer's capacity and energy to the amount of incremental capacity and energy resources added to serve the new customer. If the HPC Rate customer seeks additional usage during the Buildout Period, they may arrange temporary capacity through the Company or qualify as a MISO LMR.

If OTP anticipates that the HPC customer may have excess demand during the next planning year, OTP will require the customer to register its excess demand as an LMR. OTP would make a protective offer of the customer's LMR load to MISO in the PRA. A protective offer is one priced at the maximum price that still preserves MISO's reliability planning. If the PRA clears below that price, the Customer will not be an LMR. If MISO accepts OTP's offer, the Customer will be required to respond to MISO as an LMR.

OTP may also limit the Customer's energy usage to the output of the dedicated resources during periods of elevated LMP. The rate schedule includes a penalty if the customer ignores OTP's curtailment instructions.

OTP will schedule both load and generation into the MISO market daily. Separate settlement statements by AO will isolate all MISO related costs, with the HPC Rate customer responsible for all applicable MISO Day Ahead and Real Time market charges and credits, including losses, uplifts, and administrative charges attributable to the dedicated settlement account(s), net of dedicated resource output.

c. Delivery Facilities

The Company will construct and own, and the HPC Rate customer will be responsible for, all costs associated with building or upgrading necessary delivery facilities (Transmission and Distribution) to interconnect them. As noted earlier, the capital investment related to these incremental facilities will be captured within the recovery mechanism including the applicable return on and of those investments and associated costs.

d. Transmission Charges

Use of the Company's existing transmission system is implied with any customer taking service from OTP. We will require an HPC Rate customer to pay network transmission charges for the use of the existing transmission system based on the Company's Attachment O rate.

e. Other MISO Charges

The Customer shall pay, or reimburse the Company, for all other MISO charges including ancillary service charges attributable to the HPC Rate customer's load and as assessed by MISO on a load basis (Energy or Demand), including but not limited to Network Upgrades and Multi-Value-Project-type charges (Schedules 26/26A/26B/26C/26D/26E as applicable).

f. Rate Structure/Components

i. Fixed Administrative Charge.

A fixed charge per Customer per month to recover Customer-related costs including metering, billing, and customer account and services expenses. Escalates annually by CPI unless otherwise ordered.

ii. Demand-based Administrative Adder.

A charge per kW of Contract Capacity recovering OTP personnel, systems, and overheads to administer the Rate schedule, settlements, and reporting. Escalates annually by CPI unless otherwise ordered.

iii. Energy Charge.

The sum of levelized Dedicated PPA variable charges as determined in the PPA, plus fuel charges and variable O&M from any Company-owned Dedicated Generation Resources. The levelized energy charge to be paid by the Customer will be limited to the load that is covered by the Customer's Dedicated Resources that have been interconnected, energized and made available to offer into MISO as set out in the ESA.

iv. Energy and Operating Reserves Market charges ($/MWH).

Set to recover any MISO costs (net of MISO credits) associated with MISO load bids and MISO offers of Dedicated Resources. Initial MISO charges will be posted seven (7) days after the day on which the energy was delivered (Operating Day), which can be accessed via the MISO Portal.

v. Dedicated Generation Capacity Reservation Charge ($/contract MW/month):

Set at the weighted average of total levelized generation fixed costs including Company-owned plants and PPA fixed charges comprising Dedicated Resources to meet the Customer Contract Capacity and adjusted to include MISO's PRM. The charge will be inclusive of O&M expenses, and fuel costs associated with the dedicated resource, as well as PPA costs.

vi. Risk Adder:

Set at 2% of the monthly PPA (Company-contracted or Customer-contracted) revenues. If the Customer negotiates with the Company to bring its own generation, this adder will be based upon the Customer's locational monthly energy usage.

vii. MISO Interim Capacity Charge ($/MW/month):

Defined as the Grossed-up MISO Zone 1 Seasonal Planning Reserve Auction (PRA) Auction Clearing Price (ACP) in effect for the billing period according to the following formula:

PRA ACP x (1 + MISO Planning Reserve Margin) x (1 + MISO Otter Tail Power Transmission Loss Factor) x (1+ Distribution Loss Factor)

viii. Extra Facilities Expense:

A fixed charge for incremental distribution facilities necessary to serve the customer, calculated as set out in Section 5.02 of OTP's General Rules and Regulations.[1]

ix. Dedicated Transmission Facilities Demand Charge ($/on-peak MW-month):

Demand charges will recover Depreciation expense plus Return at the authorized weighted average cost of capital (WACC) plus O&M expense plus applicable taxes, per the ESA schedule to recover any Dedicated Transmission Line. An estimated incremental Administrative & General Expenses, and General Plant will be applied as loading factors, which will contribute to the share of existing embedded costs. A separate charge for O&M expense per MW will be added and updated annually by inflation.

x. MISO Transmission Charges (MISO Schedules).

Customer shall pay (or reimburse OTP for) all MISO charges attributable to the Project's load.

5. Customer Protections

In addition to procuring and providing adequate generation capacity and energy resources necessary to operationally serve the load, at the cost of the HPC Rate customer, OTP will require that, prior to any construction commitments, the HPC Rate customer shall post and maintain collateral sized to OTP's risk exposure under the ESA. The collateral will be in one or a combination of: irrevocable letter of credit, payment security bond, cash, or qualified parent guaranty from entities that are acceptable to OTP. If the Customer terminates the ESA before taking service, there will be liquidated damages and the HPC Rate customer will have to reimburse OTP for costs incurred. Similarly, if the HPC Rate customer takes service but terminates the ESA and before the minimum contract term ends, the HPC Rate customer shall pay exit fees as specified in either the rate schedule or as agreed to in the ESA, which will include exit fees sufficient to protect customers from stranded assets and incurred costs.

6. System Benefit Credit

As mentioned earlier, the proposed cost of service structure to be utilized for serving an HPC Rate customer is designed to eliminate cost-shifting and to share net system benefits with non-participating customers. The Company shall compute a

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[1] The new rate schedule references the version of Section 5.02 OTP proposed in Case No. PU-26-098, which is currently pending before the Commission.

jurisdictional System Benefit Credit annually following completion of the calendar year and credit it to all retail customers in Minnesota, North Dakota, and South Dakota through existing riders or a dedicated credit mechanism. The credit equals the net positive contribution/margins attributable to the Customer after full recovery of direct-assigned costs, including but not limited to margins from Dedicated Resource dispatch differentials (if any), incremental fixed-cost contributions, and any other defined components in the ESA, less incremental corporate costs required to support the Customer. OTP proposes that the allocation to each jurisdiction shall follow Commission-approved allocators using the most recent actual year E2 cost allocation factor.

IV. CONCLUSION

The influx of demand across our region from data center owners and developers is unprecedented and presents several new challenges for utilities. We believe that creating a new class for very large customers (25 MW or more) strikes the right balance between the old and the new. It takes into account the ordinary types of large loads we have traditionally seen on our system and separates these types of loads. We believe that further requiring very large data center load to take firm service at or above 75 MW, using a separate cost recovery structure, via a new rate schedule that addresses the unique challenges, risks, and benefits of adding new data center load onto our system is in all our customers' interests. Our cautious approach protects our customers, protects our company, and will provide safe, reliable and competitively priced power to new very large customers who may wish to join our system.

OTP therefore respectfully requests Commission approval of all proposed tariff updates and administrative refinements included in this filing.

Date: June 18, 2026

Respectfully submitted:

OTTER TAIL POWER COMPANY

/s/ AMBER GRENIER
Amber Grenier
Manager, Regulatory Economics
Regulation & Retail Energy Solutions
Otter Tail Power Company
Phone (218) 739-8728

Section	Old Name	New Name	Tariff Sheets	Changes
Index			All	Update names and sections, etc.
10.04	Large General Services	Large General Services – Tier I	All	name change & use limits
10.05	Large General Services – Time of Day	Large General Services – Tier I – Time of Day	All	name change & use limits
10.06	Super Large General Service	***Cancelled*** Super Large General Service	All	Cancelled Version
10.06	***Cancelled*** Super Large General Service	Reserved for Future Use	All	Reserved for Future Use Version
10.06	Reserved for Future Use	Large General Service – Tier II – Time of Day	All	New Schedule - new Content
10.07		Large General Services – Type III – High Power Compute	All	New schedule - New Content
10.08		Large General Service – Marginal Rate	All	New (old content from 10.06)
10.09		Large General Service – Thermal Market Energy Pricing	All	New (old content from 14.16)
13.00 Matrix	Matrix		All	updates to applicability & schedule changes
13.01	Energy Adjustment Rider		2	#14 - change 14.16 to 10.09 and add 10.07
13.04	Renewable Resource Cost Recovery Rider		1	Table at bottom of p. 1, under (a) - update names
13.05	Transmission Cost Recovery Rider		1	Table at bottom of p. 1, under (a) - update names
13.07	Uplift Program Rider		1	Applicability section, revise numbers, table at bottom of p. 1, under (a) - update names

13.08	Environmental Cost Recovery Rider		1	Applicability of section change 14.16 to 10.09
13.10	Revenue Decoupling Mechanism (RDM) Rider		1, 3	Update section numbers in Applicability on p.1, and under Components & Process, p.3.
13.11	Electric Utility Infrastructure Cost (EUIC) Recovery Rider		1, 2	In Applicability, chart p 1, and chart p 2, change 14.16 to 10.09
13.12	Interim Rate Rider		1	does not apply to 10.07
14.00	Matrix		All	updates to applicability & schedule changes
14.16	Thermal Market Energy Pricing	***Cancelled*** Thermal Market Energy Pricing	All	Cancelled Version
14.16	***Cancelled*** Thermal Market Energy Pricing	Reserved for Future Use	All	Reserved for Future Use Version

Attachment 2

Legislative and Non-Legislative Versions of Rate Schedules

OTTER TAIL POWER COMPANY
Fergus Falls, Minnesota

Rate Schedules & Riders

Rate Schedules & Riders

LARGE GENERAL SERVICE – Tier I
(at least 200 kW but less than 25,000 kW)

DESCRIPTION	**RATE CODE**
Secondary Service	N603
Primary Service	N602
Transmission Service	N632

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 is applicable to nonresidential Customers with a measured Demand of 200 kW but less than 25,000 kW as further described in ~~who meet~~ the Terms and Conditions. This schedule is not applicable for Energy for resale, nor for dusk to dawn or municipal outdoor lighting. Emergency and supplementary/standby services will be supplied only as allowed by law.

RATE:

Fergus Falls, Minnesota

SECONDARY SERVICE		
Customer Charge per Month:	$215.90	
Monthly Minimum Bill:	Customer + Facilities + Demand Charge	
Facilities Charge per Month per annual max. kW: (minimum 200 ~~80~~kW)		
< 1000 kW:	$0.76 /kW	
>= 1000 kW:	$0.56 /kW	
Energy Charge per kWh:	Summer	Winter
	2.606 ¢/kWh	2.798 ¢/kWh
Demand Charge per kW/month: (minimum 200~~80~~ kW)	Summer	Winter
	$13.75 /kW	$13.75 /kW

PRIMARY SERVICE		
Customer Charge per Month:	$282.00	
Monthly Minimum Bill:	Customer + Facilities + Demand Charge	
Facilities Charge per Month per annual max. kW: (minimum 200 ~~80~~kW) All kW:	$0.52 /kW	
Energy Charge per kWh:	Summer	Winter
	2.502 ¢/kWh	2.687 ¢/kWh
Demand Charge per kW/month: (minimum 200 ~~80~~ kW)	$13.25 /kW	$13.25 /kW

TRANSMISSION SERVICE		
Customer Charge per Month:	$282.00	
Monthly Minimum Bill:	Customer + Facilities + Demand Charge	
Facilities Charge per Month per annual max. kW: (minimum 200 ~~80~~kW) All kW:	$0.00 /kW	
Energy Charge per kWh:	Summer	Winter
	2.443 ¢/kWh	2.608 ¢/kWh
Demand Charge per kW/month: (minimum 200~~80~~ kW)	$12.75 /kW	$12.75 /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 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 applicability matrices of riders.

OTTER TAIL POWER COMPANY
Fergus Falls, Minnesota

DEFINITION OF SEASONS:

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

TERMS AND CONDITIONS:

1. A Customer with a Billing Demand of equal to or greater than 200 kW for more than two of the most recent 12 ~~consecutive~~ months will be required to take service under the Large General Service – Tier I (Section 10.04) or Large General Service ~~schedule~~ – Tier I - Time of Day (Section 10.05). The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 200 kW for more than two of the most recent 12 months.

2. If t~~T~~he Customer does not achieve an actual ~~must remain on this schedule if its maximum monthly~~ Billing Demand that meets or exceeds 200 kW for more than two of the most recent 12 months, the~~.~~ Customer~~s~~ will be placed on ~~on this schedule whose maximum monthly Billing Demand are less than 200 kW for less than 10 of the most recent 12 months, may take service on~~General Service (Section 10.02) in the next billing month (unless Customer requests to be on General Service – Time of Day (Section~~or~~ 10.03)). ~~If the Customer meets the criteria to take service on Section 10.02 or 10.03, they must direct the Company to the applicable rate schedule.~~

DETERMINATION OF METERED DEMAND: The maximum kW as measured by a Demand Meter for any period of 15 consecutive minutes during the month for which the bill is rendered.

DETERMINATION OF FACILITIES CHARGE: The Facilities Charge Demand will be based on the greater of 1) 200~~80~~ kW or 2) the largest of the most recent 12 monthly Billing Demands.

DETERMINATION OF BILLING DEMAND: The Billing Demand shall be the greater of 200~~80~~ kW or the Metered Demand adjusted for Excess Reactive Demand.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: For billing purposes, the Metered Demand shall be increased by 1 kW for each whole 10 kVar of measured Reactive Demand in excess of 50% of the Metered Demand in kW.

LARGE GENERAL SERVICE – Tier I C
(at least 200 kW but less than 25,000 kW) N

DESCRIPTION	RATE CODE
Secondary Service	N603
Primary Service	N602
Transmission Service	N632

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 is applicable to nonresidential Customers with C
a measured Demand of 200 kW but less than 25,000 kW as further described in the Terms and C
Conditions. This schedule is not applicable for Energy for resale, nor for dusk to dawn or municipal outdoor lighting. Emergency and supplementary/standby services will be supplied only as allowed by law.

RATE:

SECONDARY SERVICE			
Customer Charge per Month:	$215.90		
Monthly Minimum Bill:	Customer + Facilities + Demand Charge		
Facilities Charge per Month			
per annual max. kW: (minimum 200 kW)			C
< 1000 kW:	$0.76 /kW		
>= 1000 kW:	$0.56 /kW		
Energy Charge per kWh:	Summer	Winter	
	2.606 ¢/kWh	2.798 ¢/kWh	
Demand Charge per kW/month:	Summer	Winter	
(minimum 200 kW)	$13.75 /kW	$13.75 /kW	C

PRIMARY SERVICE			
Customer Charge per Month:	$282.00		
Monthly Minimum Bill:	Customer + Facilities + Demand Charge		
Facilities Charge per Month			
per annual max. kW: (minimum 200 kW)			C
All kW:	$0.52 /kW		
Energy Charge per kWh:	Summer	Winter	
	2.502 ¢/kWh	2.687 ¢/kWh	
Demand Charge per kW/month:	$13.25 /kW	$13.25 /kW	
(minimum 200 kW)			C

TRANSMISSION SERVICE			
Customer Charge per Month:	$282.00		
Monthly Minimum Bill:	Customer + Facilities + Demand Charge		
Facilities Charge per Month			
per annual max. kW: (minimum 200 kW)			
All kW:	$0.00 /kW		C
Energy Charge per kWh:	Summer	Winter	
	2.443 ¢/kWh	2.608 ¢/kWh	
Demand Charge per kW/month:	$12.75 /kW	$12.75 /kW	
(minimum 200 kW)			C

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 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 applicability matrices of riders.

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

TERMS AND CONDITIONS:

1. A Customer with a Billing Demand of equal to or greater than 200 kW for more than two of the most recent 12 months will be required to take service under the Large General Service – Tier I (Section 10.04) or Large General Service – Tier I - Time of Day (Section 10.05). The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 200 kW for more than two of the most recent 12 months. **C C C N N**

2. If the Customer does not achieve an actual Billing Demand that meets or exceeds 200 kW for more than two of the most recent 12 months, the Customer will be placed on General Service (Section 10.02) in the next billing month (unless Customer requests to be on General Service – Time of Day (Section 10.03)). **C C C C**

DETERMINATION OF METERED DEMAND: The maximum kW as measured by a Demand Meter for any period of 15 consecutive minutes during the month for which the bill is rendered.

DETERMINATION OF FACILITIES CHARGE: The Facilities Charge Demand will be based on the greater of 1) 200 kW or 2) the largest of the most recent 12 monthly Billing Demands. **C**

DETERMINATION OF BILLING DEMAND: The Billing Demand shall be the greater of 200 kW or the Metered Demand adjusted for Excess Reactive Demand. **C**

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: For billing purposes, the Metered Demand shall be increased by 1 kW for each whole 10 kVar of measured Reactive Demand in excess of 50% of the Metered Demand in kW.

LARGE GENERAL SERVICE ~~–~~– TIER I – TIME OF DAY

(at least 200 kW and less than 25,000 kW)

DESCRIPTION	RATE CODE
Secondary Service	N611
Primary Service	N610
Transmission Service	N639

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 is applicable to nonresidential Customers with a measured Demand of at least 200 kW and less than 25,000 kW as further described in the ~~, who meet the~~ Terms and Conditions. This schedule is not applicable for Energy for resale, nor for dusk to dawn or municipal outdoor lighting. Emergency and supplementary/standby services will be supplied only as allowed by law.

RATE:

SECONDARY SERVICE				
Customer Charge per Month:	$215.90			
Monthly Minimum Bill:	Customer + Facilities + Demand Charge			
Facilities Charge per Month per annual maximum kW: (minimum 200~~80~~ kW)				
< **1000 kW:**	$0.76 /kW			
>= **1000 kW:**	$0.57 /kW			
Energy Charge per kWh:	Summer		Winter	
On-Peak	5.977	¢/kWh	5.362	¢/kWh
Mid-Peak	4.869	¢/kWh	4.888	¢/kWh
Off-Peak	3.177	¢/kWh	4.206	¢/kWh
Demand Charge per kW/month: (minimum 200~~80~~ kW)	Summer		Winter	
On-Peak	$8.10	/kW	$7.75	/kW
Mid-Peak	$3.92	/kW	$4.20	/kW

Off-Peak	$1.74 /kW	$1.79 /kW

PRIMARY SERVICE				
Customer Charge per Month:	$282.00			
Monthly Minimum Bill:	Customer + Facilities + Demand Charge			
Facilities Charge per Month per annual maximum kW: (minimum 200~~80~~ kW)	$0.48 /kW			
Energy Charge per kWh:	Summer		Winter	
On-Peak	5.817	¢/kWh	5.187	¢/kWh
Mid-Peak	4.750	¢/kWh	4.740	¢/kWh
Off-Peak	3.104	¢/kWh	4.084	¢/kWh
Demand Charge per kW/month: (minimum 200~~80~~ kW)	Summer		Winter	
On-Peak	$7.83	/kW	$7.53	/kW
Mid-Peak	$3.76	/kW	$4.02	/kW
Off-Peak	$1.66	/kW	$1.70	/kW

TRANSMISSION SERVICE				
Customer Charge per Month:	$282.00			
Monthly Minimum Bill:	Customer + Facilities + Demand Charge			
Facilities Charge per Month per annual maximum kW: (minimum 200~~80~~ kW)	$0.00 /kW			
Energy Charge per kWh:	Summer		Winter	
On-Peak	5.672	¢/kWh	5.026	¢/kWh
Mid-Peak	4.637	¢/kWh	4.602	¢/kWh
Off-Peak	3.033	¢/kWh	3.969	¢/kWh
Demand Charge per kW/month: (minimum 200~~80~~ kW)	Summer		Winter	
On-Peak	$7.50	/kW	$7.34	/kW
Mid-Peak	$3.70	/kW	$3.84	/kW
Off-Peak	$0.00	/kW	$0.00	/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, 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.

DEFINITIONS OF SEASONS:

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

TERMS AND CONDITIONS:

1. A Customer with a Billing Demand equal to or ~~of~~ greater than 200 kW for more than two of the most recent 12 ~~consecutive~~ months will be required to take service under ~~the~~ Large General Service – Tier I – Time of Day (Section 10.05) or Large General Service – Tier I~~schedule~~ (Section 10.04). ~~or Large General Service schedule – Tier I – Time of Day (Section 10.05)~~ The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 200 kW and does not exceed 25,000 kW for more than two of the most recent 12 months.

2. If t~~T~~he Customer ~~must remain on this schedule if its maximum monthly~~does not achieve an actual Billing Demand of more than or equal to ~~meets or exceeds~~ 200 kW for more than two of the most recent 12 months, ~~.~~the Customer~~s~~ will be placed on General Service – Time of Day (Section 10.03) in the next billing month (unless the Customer requests to be on General Service (Section 10.02)). ~~on this schedule whose maximum monthly Billing Demand are less than 200 kW for less than 10 of the most recent 12 months, may take service on Section 10.02 or 10.03. If the Customer meets the criteria to take service on Section 10.02 or 10.03, they must direct the Company to the applicable rate schedule.~~

DETERMINATION OF FACILITIES CHARGE: The Facilities Charge Demand will be based on the greater of 1) 200~~80~~ kW, or 2) the largest of the most recent 12 monthly Billing Demand.

DETERMINATION OF METERED DEMAND: The maximum kW as measured for one hour during each of the On-Peak, Mid-Peak and Off-Peak periods during the month for which the bill is rendered.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: For billing purposes, the Metered Demand shall be increased by 1 kW for each whole 10 kVar of Reactive Demand in each period in excess of 50% of the Metered Demand in kW.

DETERMINATION OF BILLING DEMAND: The Billing Demand shall be the greater of 200~~80~~ kW or the Metered Demand adjusted for Excess Reactive Demand.

DEFINITION OF ON-PEAK, MID-PEAK AND OFF-PEAK PERIODS BY SEASON:

Winter:~~INTER SEASON –~~ October~~CTOBER~~ 1 through~~THROUGH~~ May~~AY~~ 31

On-Peak: For all kW and kWh used Monday through Friday between hours 7:00 a.m. to 10:00 a.m.

Mid-Peak: For all kW and kWh used Monday through Friday between hours 6:00 a.m. to 7:00 a.m. and 10:00 a.m. to 9:00 p.m.

Off-Peak: For all other kW and kWh used Monday through Friday between hours 9:00 p.m. to 6:00 a.m. and all weekend hours.

Summer:~~UMMER SEASON –~~ June~~UNE~~ 1 through~~THROUGH~~ September~~EPTEMBER~~ 30

On-Peak: For all kW and kWh used Monday through Friday between hours 1:00 p.m. to 7:00 p.m.

Mid-Peak: For all kW and kWh used Monday through Friday between hours 11:00 a.m. to 1:00 p.m., 7:00 p.m. to 9:00 p.m., and on weekends between hours 1:00 p.m. to 7:00 p.m.

Off-Peak: For all kW and kWh used Monday through Friday between hours 9:00 p.m. to 11:00 a.m. and on weekends between hours 7:00 p.m. to 1:00 p.m.

CONTRACT PERIOD & AGREEMENT: Contract period will be outlined in agreement.

OPTIONAL TRIAL SERVICE:

- Customers may elect Time of Day service for a trial period of three months.
- If a Customer chooses to return to non-time of day service after the trial period, the Customer will pay a charge of $60.00 for removal of time of day metering equipment.

- If a Customer chooses to change from this schedule after the three-month trial period, the customer must notify the Company within 15 days after the trial period ends. Otherwise, the Customer will remain on this schedule for the minimum of one year as described in the General Rules and Regulations Section 1.02.

- The Company will remove the time of day metering equipment and switch the customer to a different applicable rate within 45 days of receipt of written notice of termination of the trial period.

LARGE GENERAL SERVICE – TIER I – TIME OF DAY C
(at least 200 kW and less than 25,000 kW) N

DESCRIPTION	RATE CODE
Secondary Service	N611
Primary Service	N610
Transmission Service	N639

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 is applicable to nonresidential Customers
with a measured Demand of at least 200 kW and less than 25,000 kW as further described in the N
Terms and Conditions. This schedule is not applicable for Energy for resale, nor for dusk to dawn N
or municipal outdoor lighting. Emergency and supplementary/standby services will be supplied N
only as allowed by law. N

RATE:

SECONDARY SERVICE		
Customer Charge per Month:	$215.90	
Monthly Minimum Bill:	Customer + Facilities + Demand Charge	
Facilities Charge per Month per annual maximum kW: (minimum 200 kW)		
< **1000 kW:**	$0.76 /kW	
>= **1000 kW:**	$0.57 /kW	
Energy Charge per kWh:	Summer	Winter
On-Peak	5.977 ¢/kWh	5.362 ¢/kWh
Mid-Peak	4.869 ¢/kWh	4.888 ¢/kWh
Off-Peak	3.177 ¢/kWh	4.206 ¢/kWh
Demand Charge per kW/month: (minimum 200 kW)	Summer	Winter
On-Peak	$8.10 /kW	$7.75 /kW
Mid-Peak	$3.92 /kW	$4.20 /kW
Off-Peak	$1.74 /kW	$1.79 /kW

C

C

PRIMARY SERVICE

Customer Charge per Month: $282.00

Monthly Minimum Bill: Customer + Facilities + Demand Charge

Facilities Charge per Month per annual maximum kW: (minimum 200 kW) $0.48 /kW C

Energy Charge per kWh:	Summer	Winter
On-Peak	5.817 ¢/kWh	5.187 ¢/kWh
Mid-Peak	4.750 ¢/kWh	4.740 ¢/kWh
Off-Peak	3.104 ¢/kWh	4.084 ¢/kWh

C

Demand Charge per kW/month: (minimum 200 kW)	Summer	Winter
On-Peak	$7.83 /kW	$7.53 /kW
Mid-Peak	$3.76 /kW	$4.02 /kW
Off-Peak	$1.66 /kW	$1.70 /kW

TRANSMISSION SERVICE

Customer Charge per Month: $282.00

Monthly Minimum Bill: Customer + Facilities + Demand Charge

Facilities Charge per Month per annual maximum kW: (minimum 200 kW) $0.00 /kW C

Energy Charge per kWh:	Summer	Winter
On-Peak	5.672 ¢/kWh	5.026 ¢/kWh
Mid-Peak	4.637 ¢/kWh	4.602 ¢/kWh
Off-Peak	3.033 ¢/kWh	3.969 ¢/kWh

C

Demand Charge per kW/month: (minimum 200 kW)	Summer	Winter
On-Peak	$7.50 /kW	$7.34 /kW
Mid-Peak	$3.70 /kW	$3.84 /kW
Off-Peak	$0.00 /kW	$0.00 /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, 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.

DEFINITIONS OF SEASONS:

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

TERMS AND CONDITIONS:

1. A Customer with a Billing Demand equal to or greater than 200 kW for more than two of the most recent 12 months will be required to take service under Large General Service – Tier I – Time of Day (Section 10.05) or Large General Service – Tier I (Section 10.04). The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 200 kW and does not exceed 25,000 kW for more than two of the most recent 12 months. **C CN CN N N N**

2. If the Customer does not achieve an actual Billing Demand of more than or equal to 200 kW for more than two of the most recent 12 months, the Customer will be placed on General Service – Time of Day (Section 10.03) in the next billing month (unless the Customer requests to be on General Service (Section 10.02)). **C C C C**

DETERMINATION OF FACILITIES CHARGE: The Facilities Charge Demand will be based on the greater of 1) 200 kW, or 2) the largest of the most recent 12 monthly Billing Demand. **C**

DETERMINATION OF METERED DEMAND: The maximum kW as measured for one hour during each of the On-Peak, Mid-Peak and Off-Peak periods during the month for which the bill is rendered.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: For billing purposes, the Metered Demand shall be increased by 1 kW for each whole 10 kVar of Reactive Demand in each period in excess of 50% of the Metered Demand in kW.

DETERMINATION OF BILLING DEMAND: The Billing Demand shall be the greater of 200 kW or the Metered Demand adjusted for Excess Reactive Demand. **C**

DEFINITION OF ON-PEAK, MID-PEAK AND OFF-PEAK PERIODS BY SEASON:

Winter: October 1 through May 31

On-Peak: For all kW and kWh used Monday through Friday between hours 7:00 a.m. to 10:00 a.m.

Mid-Peak: For all kW and kWh used Monday through Friday between hours 6:00 a.m. to 7:00 a.m. and 10:00 a.m. to 9:00 p.m.

Off-Peak: For all other kW and kWh used Monday through Friday between hours 9:00 p.m. to 6:00 a.m. and all weekend hours.

Summer: June 1 through September 30

On-Peak: For all kW and kWh used Monday through Friday between hours 1:00 p.m. to 7:00 p.m.

Mid-Peak: For all kW and kWh used Monday through Friday between hours 11:00 a.m. to 1:00 p.m., 7:00 p.m. to 9:00 p.m., and on weekends between hours 1:00 p.m. to 7:00 p.m.

Off-Peak: For all kW and kWh used Monday through Friday between hours 9:00 p.m. to 11:00 a.m. and on weekends between hours 7:00 p.m. to 1:00 p.m.

CONTRACT PERIOD & AGREEMENT: Contract period will be outlined in agreement.

OPTIONAL TRIAL SERVICE:

- Customers may elect Time of Day service for a trial period of three months.
- If a Customer chooses to return to non-time of day service after the trial period, the Customer will pay a charge of $60.00 for removal of time of day metering equipment.

- If a Customer chooses to change from this schedule after the three-month trial period, the customer must notify the Company within 15 days after the trial period ends. Otherwise, the Customer will remain on this schedule for the minimum of one year as described in the General Rules and Regulations Section 1.02.

- The Company will remove the time of day metering equipment and switch the customer to a different applicable rate within 45 days of receipt of written notice of termination of the trial period.

CANCELLED

SUPER LARGE GENERAL SERVICE
APPLICATIONS AND ELIGIBILITY REQUIREMENTS

DESCRIPTION	RATE CODE
Primary Service	N618
Transmission Service	N620

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

APPLICATION OF SCHEDULE: This rate schedule is applicable to greenfield Customers who meet certain conditions described herein.

The rate schedule will be available to greenfield Customers who reasonably demonstrate to the Company (1) an expected Metered Demand of at least 25 MW at a single Metering point, (2) an expected load factor of at least 80%, and (3) expected annual Energy sales of at least 175,000 MWh's over 12 consecutive billing months. Customers seeking service under this rate schedule shall provide the Company data and written assurances supporting the Customer's application. Customers shall meet the above criteria to obtain and maintain service on this rate. Customers who are served on this rate and do not meet the above criteria will be moved to the most applicable rate schedule. The Company will require, a written electric service agreement ("ESA") between the Company and the Customer.

This schedule is not applicable for Energy for resale. Emergency and supplementary/standby service will be supplied only as allowed by law.

PURPOSE & SCOPE OF RATE SCHEDULE: To attract new large and high load factor Customer loads that provide net benefits the Company's North Dakota Customers and communities served by the Company.

The marginal cost estimates that form the basis of the Super Large General Service rate capture the marginal/incremental costs the utility expects to incur serving the Customer's load during the period the rate is in effect. There may be additional costs that were not anticipated when the rate was set. These incremental costs will be recovered through the corresponding Mandatory Rate Riders applied to the Customer.

COMMISSION-APPROVED PROCESS: This rate schedule requires that the Commission pre-approve a rate formula that allows the Company to respond to service inquiries by providing potential Customers Commission-approved rate quotes and final rates. This process enables potential Customers to make timely business decisions, protects the Company's ratepayers by ensuring net benefits, and allows the Company to plan service to the new load(s).

RATE DETERMINATION: The rate specified in each Customer's ESA shall be based upon and reflect either the marginal unit costs expected during the effective rate period, or the marginal unit costs plus an appropriate margin determined on a case-by-case basis. The marginal unit cost estimates will be consistent with those included in the Company's most recent marginal cost study for the corresponding voltage level of service, and adjusted for annual inflation as required. The marginal unit costs applied to the Customer's load requirements will determine the minimum incremental revenue collected under this rate. Any margin recovered on the incremental costs will collect a share of the Company's costs from the new Customer, thus reducing the fixed costs allocated to existing Customers.

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

TERMS AND CONDITIONS: The Company will offer the Customer the rate schedule under the following terms:

1. The minimum rate under this schedule shall recover at least the incremental cost of providing service, including any Energy-related marginal costs, the cost of additional Generation Capacity, the cost of network Capacity that is expected to be added while the rate is in effect, and any marginal Customer-related costs. The goal of this calculation is to establish a floor price to ensure that the revenue requirement of other Customers will not increase due to the addition of the new large load.

2. The final rate offered to the Customer under this rate schedule shall not exceed the Company's applicable Standard Tariff and all applicable riders, and shall not be lower than incremental costs as described in the preceding paragraph.

3. The Company will utilize its proprietary model to compare expected revenues from the prospective Customer and expected costs of serving the added load over the time period described in paragraph 4 of these terms and conditions. The model will be made available only

to the Commission to verify the calculations used to establish the rate quote and final rate offered to the Customer.

4. Service under this rate schedule requires an ESA with a term of at least five years, with the term commencing on the first day of commercial operations.

5. At the end of terms of the ESA, and any extensions thereof, Customers may elect to move from a full marginal cost-based rate to an embedded cost-based rate such as the applicable Standard Tariff offered to existing Customers, or a two-part market-based rate that would price a Customer- baseline load (CBL) at the embedded unit cost and any load above the CBL at marginal cost. Customers who elect to move away from the full marginal cost-based rate will not be able to return to it.

6. Changes to the ESA that impact Customer(s) revenue and/or other ratepayers will require approval from the Commission.

7. Customers who do not meet the 3-year minimum revenue guarantee as per OTP's line extension policy will not qualify for this rate schedule.

8. Customer will allow Company to undertake an Energy efficiency audit of the facility.

9. The Company will provide the Commission annual compliance updates to the trade-secret model and approved Customer rate while this rate schedule is in effect.

*****CANCELLED***** **N**
SUPER LARGE GENERAL SERVICE
APPLICATIONS AND ELIGIBILITY REQUIREMENTS

DESCRIPTION	RATE CODE
Primary Service	N618
Transmission Service	N620

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

APPLICATION OF SCHEDULE: This rate schedule is applicable to greenfield Customers who meet certain conditions described herein.

The rate schedule will be available to greenfield Customers who reasonably demonstrate to the Company (1) an expected Metered Demand of at least 25 MW at a single Metering point, (2) an expected load factor of at least 80%, and (3) expected annual Energy sales of at least 175,000 MWh's over 12 consecutive billing months. Customers seeking service under this rate schedule shall provide the Company data and written assurances supporting the Customer's application. Customers shall meet the above criteria to obtain and maintain service on this rate. Customers who are served on this rate and do not meet the above criteria will be moved to the most applicable rate schedule. The Company will require, a written electric service agreement ("ESA") between the Company and the Customer.

This schedule is not applicable for Energy for resale. Emergency and supplementary/standby service will be supplied only as allowed by law.

PURPOSE & SCOPE OF RATE SCHEDULE: To attract new large and high load factor Customer loads that provide net benefits the Company's North Dakota Customers and communities served by the Company.

The marginal cost estimates that form the basis of the Super Large General Service rate capture the marginal/incremental costs the utility expects to incur serving the Customer's load during the period the rate is in effect. There may be additional costs that were not anticipated when the rate was set. These incremental costs will be recovered through the corresponding Mandatory Rate Riders applied to the Customer.

COMMISSION-APPROVED PROCESS: This rate schedule requires that the Commission pre-approve a rate formula that allows the Company to respond to service inquiries by providing potential Customers Commission-approved rate quotes and final rates. This process enables potential Customers to make timely business decisions, protects the Company's ratepayers by ensuring net benefits, and allows the Company to plan service to the new load(s).

RATE DETERMINATION: The rate specified in each Customer's ESA shall be based upon and reflect either the marginal unit costs expected during the effective rate period, or the marginal unit costs plus an appropriate margin determined on a case-by-case basis. The marginal unit cost estimates will be consistent with those included in the Company's most recent marginal cost study for the corresponding voltage level of service, and adjusted for annual inflation as required. The marginal unit costs applied to the Customer's load requirements will determine the minimum incremental revenue collected under this rate. Any margin recovered on the incremental costs will collect a share of the Company's costs from the new Customer, thus reducing the fixed costs allocated to existing Customers.

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

TERMS AND CONDITIONS: The Company will offer the Customer the rate schedule under the following terms:

1. The minimum rate under this schedule shall recover at least the incremental cost of providing service, including any Energy-related marginal costs, the cost of additional Generation Capacity, the cost of network Capacity that is expected to be added while the rate is in effect, and any marginal Customer-related costs. The goal of this calculation is to establish a floor price to ensure that the revenue requirement of other Customers will not increase due to the addition of the new large load.

2. The final rate offered to the Customer under this rate schedule shall not exceed the Company's applicable Standard Tariff and all applicable riders, and shall not be lower than incremental costs as described in the preceding paragraph.

3. The Company will utilize its proprietary model to compare expected revenues from the prospective Customer and expected costs of serving the added load over the time period described in paragraph 4 of these terms and conditions. The model will be made available only to the Commission to verify the calculations used to establish the rate quote and final rate offered to the Customer.

4. Service under this rate schedule requires an ESA with a term of at least five years, with the term commencing on the first day of commercial operations.

5. At the end of terms of the ESA, and any extensions thereof, Customers may elect to move from a full marginal cost-based rate to an embedded cost-based rate such as the applicable Standard Tariff offered to existing Customers, or a two-part market-based rate that would price a Customer- baseline load (CBL) at the embedded unit cost and any load above the CBL at marginal cost. Customers who elect to move away from the full marginal cost-based rate will not be able to return to it.

6. Changes to the ESA that impact Customer(s) revenue and/or other ratepayers will require approval from the Commission.

7. Customers who do not meet the 3-year minimum revenue guarantee as per OTP's line extension policy will not qualify for this rate schedule.

8. Customer will allow Company to undertake an Energy efficiency audit of the facility.

9. The Company will provide the Commission annual compliance updates to the trade-secret model and approved Customer rate while this rate schedule is in effect.

Section 10.06 RESERVED FOR FUTURE USE~~***CANCELLED***~~
~~SUPER LARGE GENERAL SERVICE~~
~~APPLICATIONS AND ELIGIBILITY REQUIREMENTS~~

~~DESCRIPTION~~	~~RATE CODE~~
~~Primary Service~~	~~N618~~
~~Transmission Service~~	~~N620~~

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

~~**APPLICATION OF SCHEDULE:** This rate schedule is applicable to greenfield Customers who meet certain conditions described herein.~~

~~The rate schedule will be available to greenfield Customers who reasonably demonstrate to the Company (1) an expected Metered Demand of at least 25 MW at a single Metering point, (2) an expected load factor of at least 80%, and (3) expected annual Energy sales of at least 175,000 MWh's over 12 consecutive billing months. Customers seeking service under this rate schedule shall provide the Company data and written assurances supporting the Customer's application. Customers shall meet the above criteria to obtain and maintain service on this rate. Customers who are served on this rate and do not meet the above criteria will be moved to the most applicable rate schedule. The Company will require, a written electric service agreement ("ESA") between the Company and the Customer.~~

~~This schedule is not applicable for Energy for resale. Emergency and supplementary/standby service will be supplied only as allowed by law.~~

~~**PURPOSE & SCOPE OF RATE SCHEDULE:** To attract new large and high load factor Customer loads that provide net benefits the Company's North Dakota Customers and communities served by the Company.~~

~~The marginal cost estimates that form the basis of the Super Large General Service rate capture the marginal/incremental costs the utility expects to incur serving the Customer's load during the period the rate is in effect. There may be additional costs that were not anticipated when the rate was set. These incremental costs will be recovered through the corresponding Mandatory Rate Riders applied to the Customer.~~

Section 10.06 RESERVED FOR FUTURE USE

~~**COMMISSION-APPROVED PROCESS:** This rate schedule requires that the Commission pre-approve a rate formula that allows the Company to respond to service inquiries by providing potential Customers Commission-approved rate quotes and final rates. This process enables potential Customers to make timely business decisions, protects the Company's ratepayers by ensuring net benefits, and allows the Company to plan service to the new load(s).~~

~~**RATE DETERMINATION:** The rate specified in each Customer's ESA shall be based upon and reflect either the marginal unit costs expected during the effective rate period, or the marginal unit costs plus an appropriate margin determined on a case-by-case basis. The marginal unit cost estimates will be consistent with those included in the Company's most recent marginal cost study for the corresponding voltage level of service, and adjusted for annual inflation as required. The marginal unit costs applied to the Customer's load requirements will determine the minimum incremental revenue collected under this rate. Any margin recovered on the incremental costs will collect a share of the Company's costs from the new Customer, thus reducing the fixed costs allocated to existing Customers.~~

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

~~**TERMS AND CONDITIONS:** The Company will offer the Customer the rate schedule under the following terms:~~

> ~~The minimum rate under this schedule shall recover at least the incremental cost of providing service, including any Energy-related marginal costs, the cost of additional Generation Capacity, the cost of network Capacity that is expected to be added while the rate is in effect, and any marginal Customer-related costs. The goal of this calculation is to establish a floor price to ensure that the revenue requirement of other Customers will not increase due to the addition of the new large load.~~
>
> ~~The final rate offered to the Customer under this rate schedule shall not exceed the Company's applicable Standard Tariff and all applicable riders, and shall not be lower than incremental costs as described in the preceding paragraph.~~

Section 10.06 RESERVED FOR FUTURE USE

~~The Company will utilize its proprietary model to compare expected revenues from the prospective Customer and expected costs of serving the added load over the time period described in paragraph 4 of these terms and conditions. The model will be made available only to the Commission to verify the calculations used to establish the rate quote and final rate offered to the Customer.~~

~~Service under this rate schedule requires an ESA with a term of at least five years, with the term commencing on the first day of commercial operations.~~

~~At the end of terms of the ESA, and any extensions thereof, Customers may elect to move from a full marginal cost-based rate to an embedded cost-based rate such as the applicable Standard Tariff offered to existing Customers, or a two-part market-based rate that would price a Customer- baseline load (CBL) at the embedded unit cost and any load above the CBL at marginal cost. Customers who elect to move away from the full marginal cost-based rate will not be able to return to it.~~

~~Changes to the ESA that impact Customer(s) revenue and/or other ratepayers will require approval from the Commission.~~

~~Customers who do not meet the 3-year minimum revenue guarantee as per OTP's line extension policy will not qualify for this rate schedule.~~

~~Customer will allow Company to undertake an Energy efficiency audit of the facility.~~

~~The Company will provide the Commission annual compliance updates to the trade-secret model and approved Customer rate while this rate schedule is in effect.~~

Section 10.06 RESERVED FOR FUTURE USE N
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Section 10.06 RESERVED FOR FUTURE USE **N**
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Section 10.06 RESERVED FOR FUTURE USE **N**
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OTTER TAIL POWER COMPANY
Fergus Falls, Minnesota

~~Section 10.06 RESERVED FOR FUTURE USE~~ LARGE GENERAL SERVICE – TIER II – TIME OF DAY

(at least 25 MW)

DESCRIPTION	RATE CODE
Primary Service	N615
Transmission Service	N616

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 is applicable to nonresidential Customers with a measured Demand of at least 25 MW, who meet the Terms and Conditions. This schedule is not applicable for Energy for resale, nor for dusk to dawn or municipal outdoor lighting. Emergency and supplementary/standby services will be supplied only as allowed by law.

RATE:

PRIMARY SERVICE		
Customer Charge per Month:	$282.00	
Monthly Minimum Bill:	Customer + Facilities + Demand Charge	
Facilities Charge per Month per annual maximum kW: (minimum 25,000 kW)	$0.48 /kW	
Energy Charge per kWh:	Summer	Winter
On-Peak	5.817 ¢/kWh	5.187 ¢/kWh
Mid-Peak	4.750 ¢/kWh	4.740 ¢/kWh
Off-Peak	3.104 ¢/kWh	4.084 ¢/kWh
Demand Charge per kW/month: (minimum 200 kW)	Summer	Winter
On-Peak	$7.83 /kW	$7.53 /kW
Mid-Peak	$3.76 /kW	$4.02 /kW
Off-Peak	$1.66 /kW	$1.70 /kW

~~**Section 10.06 RESERVED FOR FUTURE USE**~~

TRANSMISSION SERVICE				
Customer Charge per Month:	$282.00			
Monthly Minimum Bill:	Customer + Facilities + Demand Charge			
Facilities Charge per Month per annual maximum kW: (minimum 25,000 kW)	$0.00 /kW			
Energy Charge per kWh:	Summer		Winter	
On-Peak	5.672	¢/kWh	5.026	¢/kWh
Mid-Peak	4.637	¢/kWh	4.602	¢/kWh
Off-Peak	3.033	¢/kWh	3.969	¢/kWh
Demand Charge per kW/month: (minimum 25,000 kW)	Summer		Winter	
On-Peak	$7.50	/kW	$7.34	/kW
Mid-Peak	$3.70	/kW	$3.84	/kW
Off-Peak	$0.00	/kW	$0.00	/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, 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.

DEFINITIONS OF SEASONS:

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

TERMS AND CONDITIONS:

1. If the Customer does not achieve an actual Billing Demand of more than or equal to 200 kW for more than two of the most recent 12 months, the Customer will be placed on General Service – Time of Day (Section 10.03) in the next billing month (unless the Customer requests to be on General Service (Section 10.02)).

~~**Section 10.06 RESERVED FOR FUTURE USE**~~

2. If the Customer does not achieve an actual Billing Demand of more than or equal to 25 MW for more than two of the most recent 12 months, the Customer will be placed on Large General Service – Tier I – Time of Day (Section 10.05) in the next billing month (unless the Customer requests to be on Large General Service – Tier I (Section 10.04)). If the Customer meets the criteria to take service on Section 10.02 or 10.03, they must direct the Company to the applicable rate schedule.

DETERMINATION OF FACILITIES CHARGE: The Facilities Charge Demand will be based on the greater of 1) 25 MW, or 2) the largest of the most recent 12 monthly Billing Demand.

DETERMINATION OF METERED DEMAND: The maximum kW as measured for one hour during each of the On-Peak, Mid-Peak and Off-Peak periods during the month for which the bill is rendered.

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: For billing purposes, the Metered Demand shall be increased by 1 kW for each whole 10 kVar of Reactive Demand in each period in excess of 50% of the Metered Demand in kW.

DETERMINATION OF BILLING DEMAND: The Billing Demand shall be the greater of 25 MW or the Metered Demand adjusted for Excess Reactive Demand.

DEFINITION OF ON-PEAK, MID-PEAK AND OFF-PEAK PERIODS BY SEASON:

Winter: October 1 through May 31

On-Peak: For all kW and kWh used Monday through Friday between hours 7:00 a.m. to 10:00 a.m.

Mid-Peak: For all kW and kWh used Monday through Friday between hours 6:00 a.m. to 7:00 a.m. and 10:00 a.m. to 9:00 p.m.

Off-Peak: For all other kW and kWh used Monday through Friday between hours 9:00 p.m. to 6:00 a.m. and all weekend hours.

Summer: June 1 through September 30

On-Peak: For all kW and kWh used Monday through Friday between hours 1:00 p.m. to 7:00 p.m.

Mid-Peak: For all kW and kWh used Monday through Friday between hours 11:00 a.m. to 1:00 p.m., 7:00 p.m. to 9:00 p.m., and on weekends between hours 1:00 p.m. to 7:00 p.m.

Off-Peak: For all kW and kWh used Monday through Friday between hours 9:00 p.m. to 11:00 a.m. and on weekends between hours 7:00 p.m. to 1:00 p.m.

<u>CONTRACT PERIOD & AGREEMENT</u>: Contract period will be set out in an Electric Service Agreement.

OTTER TAIL POWER COMPANY
Fergus Falls, Minnesota

LARGE GENERAL SERVICE – TIER II – TIME OF DAY DN
(at least 25 MW) N

DESCRIPTION	RATE CODE	
Primary Service	N615	N
Transmission Service	N616	N

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

APPLICATION OF SCHEDULE: This schedule is applicable to nonresidential Customers with a measured Demand of at least 25 MW, who meet the Terms and Conditions. This schedule is not applicable for Energy for resale, nor for dusk to dawn or municipal outdoor lighting. Emergency and supplementary/standby services will be supplied only as allowed by law. N

RATE: N

PRIMARY SERVICE			
Customer Charge per Month:	$282.00		N
Monthly Minimum Bill:	Customer + Facilities + Demand Charge		N
Facilities Charge per Month per annual maximum kW: (minimum 25,000 kW)	$0.48 /kW		N
Energy Charge per kWh:	Summer	Winter	N
On-Peak	5.817 ¢/kWh	5.187 ¢/kWh	N
Mid-Peak	4.750 ¢/kWh	4.740 ¢/kWh	N
Off-Peak	3.104 ¢/kWh	4.084 ¢/kWh	N
Demand Charge per kW/month: (minimum 200 kW)	Summer	Winter	N
On-Peak	$7.83 /kW	$7.53 /kW	N
Mid-Peak	$3.76 /kW	$4.02 /kW	N
Off-Peak	$1.66 /kW	$1.70 /kW	N

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TRANSMISSION SERVICE			N
Customer Charge per Month:	$282.00		N
Monthly Minimum Bill:	Customer + Facilities + Demand Charge		N
Facilities Charge per Month per annual maximum kW: (minimum 25,000 kW)	$0.00 /kW		N N N
Energy Charge per kWh:	Summer	Winter	N
On-Peak	5.672 ¢/kWh	5.026 ¢/kWh	N
Mid-Peak	4.637 ¢/kWh	4.602 ¢/kWh	N
Off-Peak	3.033 ¢/kWh	3.969 ¢/kWh	N
Demand Charge per kW/month: (minimum 25,000 kW)	Summer	Winter	N N
On-Peak	$7.50 /kW	$7.34 /kW	N
Mid-Peak	$3.70 /kW	$3.84 /kW	N
Off-Peak	$0.00 /kW	$0.00 /kW	N N

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. N N N N

DEFINITIONS OF SEASONS: N

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

TERMS AND CONDITIONS: N

1. If the Customer does not achieve an actual Billing Demand of more than or equal to 200 kW for more than two of the most recent 12 months, the Customer will be placed on General Service – Time of Day (Section 10.03) in the next billing month (unless the Customer requests to be on General Service (Section 10.02)). N N N N

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2. If the Customer does not achieve an actual Billing Demand of more than or equal to 25 MW for more than two of the most recent 12 months, the Customer will be placed on Large General Service – Tier I – Time of Day (Section 10.05) in the next billing month (unless the Customer requests to be on Large General Service – Tier I (Section 10.04)). If the Customer meets the criteria to take service on Section 10.02 or 10.03, they must direct the Company to the applicable rate schedule. N N N N N N

DETERMINATION OF FACILITIES CHARGE: The Facilities Charge Demand will be based on the greater of 1) 25 MW, or 2) the largest of the most recent 12 monthly Billing Demand. N N

DETERMINATION OF METERED DEMAND: The maximum kW as measured for one hour during each of the On-Peak, Mid-Peak and Off-Peak periods during the month for which the bill is rendered. N N N

ADJUSTMENT FOR EXCESS REACTIVE DEMAND: For billing purposes, the Metered Demand shall be increased by 1 kW for each whole 10 kVar of Reactive Demand in each period in excess of 50% of the Metered Demand in kW. N N N

DETERMINATION OF BILLING DEMAND: The Billing Demand shall be the greater of 25 MW or the Metered Demand adjusted for Excess Reactive Demand. N N

DEFINITION OF ON-PEAK, MID-PEAK AND OFF-PEAK PERIODS BY SEASON: N

Winter: October 1 through May 31 N

On-Peak: For all kW and kWh used Monday through Friday between hours 7:00 a.m. to 10:00 a.m. N N

Mid-Peak: For all kW and kWh used Monday through Friday between hours 6:00 a.m. to 7:00 a.m. and 10:00 a.m. to 9:00 p.m. N N

Off-Peak: For all other kW and kWh used Monday through Friday between hours 9:00 p.m. to 6:00 a.m. and all weekend hours. N N

Summer: June 1 through September 30 N

On-Peak: For all kW and kWh used Monday through Friday between hours 1:00 p.m. to 7:00 p.m. N N

Mid-Peak: For all kW and kWh used Monday through Friday between hours 11:00 a.m. to 1:00 p.m., 7:00 p.m. to 9:00 p.m., and on weekends between hours 1:00 p.m. to 7:00 p.m. N N

Off-Peak: For all kW and kWh used Monday through Friday between hours 9:00 p.m. to 11:00 a.m. and on weekends between hours 7:00 p.m. to 1:00 p.m. N N

CONTRACT PERIOD & AGREEMENT: Contract period will be set out in an Electric Service Agreement. N N

LARGE GENERAL SERVICE – TIER III – HIGH POWER COMPUTE N

DESCRIPTION	RATE CODE	
Primary Service	N450	N
Transmission Service	N451	N

DESCRIPTION: The Large General Service – Tier III – High Power Compute rate schedule is structured for new non-controllable high power compute, for example data center or artificial intelligence (AI) load. Customers with firm steady state load of over 75 MW with an average annual load factor of not less than 70% joining the system. N

RULES AND REGULATIONS: Terms and conditions of this electric rate schedule and the General Rules and Regulations, as amended from time to time, govern use of this Tariff. 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 Tariff. See Section 13.00 of the electric rates for the matrices of rate schedules. N

AVAILABILITY: To be eligible for the Large General Services – Tier III – High Power Compute rate schedule, the Customer must meet the following criteria: N

1. Have new load at a new location not already being served by Company; N

2. Customer must intend to take firm electric service of at least 75 MW from the Company in North Dakota; N

3. Customer must have an aggregate minimum load forecasted to be at least 75 MW metered either at a single metering point, or at several metering points which are aggregated across multiple interconnected buildings on one or more physically contiguous parcels operated as a single campus; N

4. Customer shall maintain an average annual load factor of at least 70% except for scheduled outages; **N N**

5. The Customer will have no behind the Meter generation except for emergency backup purposes, or usage during the Build-Out Period as set out in the Electric Service Agreement (ESA); and **N N N**

6. To the extent applicable, the Customer has or will register with the North American Electric Reliability Corporation (NERC) as a large load. **N N**

<u>ELECTRIC SERVICE AGREEMENT</u>: The Customer must sign an ESA on terms acceptable to the Company consistent with this rate schedule. The ESA is subject to Commission approval. **N N**

<u>STUDY REQUIREMENTS</u>: The Customer shall fund all transmission, distribution, and resource adequacy studies, as deemed necessary by the Company, including any non-refundable system impact study fee specified in the ESA, and as may be required by the MISO, NERC, or other applicable governmental and/or regulatory entities. **N N N N**

<u>LENGTH OF CONTRACT FOR SERVICE</u>: Service under this rate schedule will be contracted for at minimum the following periods: (a) the Build-Out Period and (b) the Steady Period. The Build-Out Period begins when the initial generation resources dedicated to serving Customer's full firm load as identified in the ESA (Dedicated Resources) are commercially operable and made available to offer into MISO. The Build-Out Period ends when all planned Dedicated Resources, as identified in the ESA, are commercially operable and made available to offer into MISO. **N N N N N N N**

Upon completion of the Build-Out Period, the Customer will take retail electric service pursuant to the ESA for no less than 15 years (the Steady Period). The ESA shall contain specific terms regarding the term of the Build-Out Period and the term of the Steady Period. **N N N**

At the end of the Steady Period, the ESA shall automatically renew for an additional five-year term unless either party gives at least twenty-four (24) months' written notice of an intent not to renew. **N N N**

CONTRACT CAPACITY: Through the contract term, the Customer's retail electric peak load is limited to the maximum Demand approved by MISO for the load, as set out in the ESA (the Contract Capacity). **N**

The Customer's Planning Reserve Margin Requirement (PRMR) is set annually on a seasonal basis by MISO and shall also be met by new Dedicated Resources. Dedicated Resources shall be a combination of incremental Company-owned generation, contracted-for generation (either by Company or Customer, or both, as agreed to in the ESA), and a *de minimus* amount of Planning Resource Auction (PRA) market capacity. **N**

In the event of the loss or partial loss of an in-service Dedicated Resource, Customer will also pay for any Zonal Resource Credits required to be purchased by Company to backstop any shortfall in capacity accreditation of the Dedicated Resources (including derates, changes in capacity accreditation methodology, or loss of a Dedicated Resource) until such time as such shortfall can be mitigated through the procurement of new Dedicated Resources. **N**

During the Build-Out Period, the Customer's retail electric peak load is limited to the accredited capacity of the in-service Dedicated Resources. Parties may negotiate terms for the Customer becoming a MISO Load Modifying Resource (LMR) for all load above the accredited capacity of the in-service Dedicated Resources. **N**

During any period where the Customer is required under this Tariff or its ESA to be a MISO LMR, Customer must reduce its load to the requested amount within 30 minutes (or other applicable response time specified in the MISO tariff) of receiving a curtailment directive from Company. If Customer does not do so, Customer is responsible for all MISO costs and penalties incurred by the Company due to the non-compliance and the Customer shall pay a penalty equal to MISO's Value of Lost Load (VOLL) as defined in the MISO tariff at the time of the event for each MWh of Energy consumption above the Company's curtailment directive. **N**

CONTRACT ENERGY: The Company may impose reasonable limits to Energy consumption of Customer to ensure that Energy consumption does not exceed 100% of Contract Capacity in any hour. **N**

During the Build-Out Period, the Customer's Energy usage is limited to the hourly output of the in-service Dedicated Resources. If the Customer's Energy usage in any hour exceeds the output of the in-service Dedicated Resources, the Company may impose operational limitations, including curtailment, to address any systemic impacts of Customer's load due to market **N** dynamics, location, basis risk, or other factors that would reasonably require operational controls to mitigate economic or physical impacts on other Company Customers or the overall MISO system. If the Customer is requested to reduce its load pursuant to this section and the ESA and does not do so within 30 minutes of receiving a curtailment directive from the Company, the Customer shall pay a penalty equal to MISO's VOLL as defined in the MISO tariff at the time of the event for each MWh of Energy consumption above the Company's curtailment directive. In addition, the Customer is responsible for all costs incurred by the Company due to non-compliance. **N**

GENERATION RESOURCE PROCUREMENT: The Company will provide for the procurement of the Dedicated Resources, which will provide Capacity and Energy necessary to serve the Customer, commensurate with the agreed upon Contract Capacity on terms set forth in the ESA. Such Dedicated Resources shall be incremental and may be owned by the Company, contracted from third-parties (either by Company, or Customer, or by both, as may be agreed upon in the ESA), or include market purchases or capacity and/or Energy by Company, Customer, or both, as agreed upon in an ESA. **N**

The Company will consult with the Customer in selecting the Dedicated Resources. **N**

SETTLEMENT OF DEDICATED RESOURCES: The Company will bid and settle the load and offer and settle Dedicated Resources in the MISO market, and the Customer will pay or receive credits accordingly unless otherwise agreed to in the ESA. Any MISO credits and charges associated with Customer load will be passed through to the participating Customer including: all MISO day-ahead and real-time Energy market charges/credits, losses, penalties, make whole payments, uplifts, and administrative charges attributable to the new Asset Owner/LSE settlement account(s), net of any Dedicated Resources, Energy market charges/credits, losses, penalties, make whole payments, uplifts, and administrative charges. This includes a pass-through of actual costs and credits based on the MISO energy and operating reserves market charges for the Customer's MISO Load Zone and Dedicated Resources, which includes point of withdrawal, day-ahead LMP and real-time LMP imbalance. The Company will meet any shortfalls of generation required to meet the Customer's full Energy needs, up to its Contract Capacity as set out in the ESA, on an hourly basis with purchases in the MISO day-ahead/ real-time Energy market (or load curtailment if operational constraints are instituted) including any MISO scarcity prices that may be triggered in hours of MISO generation alerts. **N**

CREDIT SUPPORT: The Customer shall post and maintain credit support sized equal to the cost of the Extra Facilities, plus the Exit Fee set out in the Customer's ESA discounted at the Company's weighted average cost of capital, plus cash or cash equivalent in an amount sufficient to cover any accounts receivable and other costs prior to disconnection (the Credit Support Amount). N N N N N

The Credit Support shall be for the full Credit Support Amount. The Credit Support shall be at least upper-medium grade rated and commensurate with the size, complexity and risk associated with serving the Customer's load. Credit Support may be provided in one or a combination of the following forms, subject to approval by the Company, and on terms satisfactory to the Company: standby irrevocable letter of credit, financial guarantee bond, parent or affiliate payment guarantee, or cash deposit. Cash provided as a cash deposit under this section shall not accrue interest while held by the Company. N N N N N N N

OTP may require Credit Support and/or Credit Support Amount adjustments for material credit events or material ESA changes. The Credit Support Amount may be reduced over time based on the Customer's financial performance, load history, and timely payments, with reductions approved at the Company's discretion. The Company may also require updated financial information from the Customer or guarantor to re-evaluate the Credit Support during the term of the ESA. In the event of a default, uncured breach of the ESA, or failure to maintain the required Credit Support, the Company may draw upon any form of Credit Support and exercise all rights and remedies available under the ESA and applicable regulations. N N N N N N N N

PRICING METHODOLOGY: The Customer shall be liable for the full cost (incremental and embedded) of the Company serving Customer. The Customer will pay costs of connecting its load to the system plus any network upgrades identified by MISO. Customer will hold-harmless Company for any costs incurred but not otherwise provided for due to Customer's obligation with respect to serving Customer as Network Load under the MISO Tariff. N N N N N

The Customer will pay all costs associated with Dedicated Resources. For those Dedicated Resources under Company ownership, rates will reflect Company's return of and on such investment. N N N

The Customer shall pay the annual authorized return associated with the Company-owned plant, annual fixed and variable costs from Power Purchase Agreements (PPAs) and any other costs associated with Dedicated Resources used to serve the Customer including Energy and capacity outputs, fixed/variable operation and maintenance expenses, fuel (if any), property taxes, and insurance. Should Company and Customer agree to alterative procurement methods for Dedicated Resources, the ESA shall provide terms and conditions for ensuring Company is held harmless for any additional costs incurred. Ad valorem taxes associated with the gross plant will be included in the computed generation and transmission revenue requirement and updated annually; and income taxes associated with the transmission cost of service, including expenses recorded in FERC account 565, will be updated annually. **N**

The Customer will be required to pay for all incremental resource costs dedicated to meeting its firm Demand, including an adjustment to include PRMR as set by MISO. The Customer will also pay for all incremental Energy costs, and applicable transmission charges. The Customer will need to provide sufficient Credit Support for these activities. **N**

The Customer will also be required to pay a System Benefit Contribution. The Company will refund to its other customers in all of its jurisdictions on a load share ratio all revenues received from Customer that are a contribution to Company's embedded system costs pursuant to the pricing methodology all as set forth in the ESA. ESA shall set forth the amount of System Benefit Contribution, which shall be subject to True Up to maintain an appropriate level of net system benefits. **N**

Annual Adjustment and True Up: The Customer's pricing will be subject to an annual adjustment and true-up cost adjustment to ensure that all costs directly attributable to the Customer are recovered. Annual adjustment will include escalations for Consumer Price Index (CPI), updates to reflect current MISO rates, and estimated System Benefit Contribution. Annual True Up will reconcile estimated System Benefit Contribution with actuals. The Credit Support Amount will adjust to cover any additional amounts determined in the annual adjustment and true-up cost adjustment. **N**

Escalations included in the annual adjustment are measured by the CPI, published by the U.S. Department of Labor, Bureau of Labor Statistics in January of each year, and shall be the 12-month Consumer Price Index for all Urban Consumers (CPI-U). **N**

Monthly Charges: Total Monthly Charges = Σ [Charges in Sections 1–9 (subject to annual adjustment and true-up)] + Taxes, any applicable riders, and statutory fees. N N

Pricing Components of Monthly Charges: N

1. **Administrative Charge:** A fixed charge per kW of Contract Capacity recovering OTP personnel, systems, and overheads including metering, billing, customer account and services expenses, administration of the Tariff, settlements, and reporting. Expenses escalate annually by CPI unless otherwise ordered. N N N N

2. **System Benefit Charge ($/MWH):** Set in the ESA, which will also include a minimum charge, and provides an appropriate amount of net benefits to non-participating Customers. Updated annually to reflect current MISO rates. The System Benefit Charge is a component of the System Benefit Contribution. N N N N

3. **Energy Charge:** The sum of levelized Dedicated Resource PPA variable charges as determined in the PPA, plus fuel charges and variable operations and maintenance charges from any Company-owned Dedicated Resources. The levelized Energy Charge to be paid by the Customer will be limited to the load that is covered by the Customer's Dedicated Resources that have been interconnected, energized, and made available to offer into MISO, as set out in the ESA. N N N N N N

4. **Energy and Operating Reserves Market charges ($/MWH):** Set to recover any MISO costs (net of MISO credits) associated with MISO load bids and MISO offers of Dedicated Resources. Initial MISO charges will be posted seven (7) days after the day in which the Energy was delivered (operating day), which can be accessed via the MISO Portal. N N N N N

5. **Dedicated Generation Capacity Reservation Charge ($/contract MW/month):** Set at the weighted average of total levelized generation fixed costs including Company-owned plants and PPA fixed charges comprising Dedicated Resources to meet the Customer Contract Capacity and adjusted to include MISO's PRMR. The charge will be inclusive of operation and maintenance expenses, and fuel costs associated with the Dedicated Resource(s), as well as PPA costs. N N N N N N

6. **Risk Adder:** A percentage, to be set in the ESA, of the net book value of any Dedicated Resources, Incremental Transmission, and Incremental Distribution, plus 2% of any monthly PPA revenues or charge equivalent thereto should Company and Customer agree to allow for Customer to contract directly for some or all Dedicated Resources. N N N N

7. **MISO Interim Capacity Charge ($/MW/month):** Defined as the grossed-up MISO Zone 1 seasonal PRA Auction Clearing Price (ACP) in effect for the billing period according to the following formula: N N N

   [PRA ACP] x ([MISO PRMR] – [ZRCs from Dedicated Resources] – [Customer Zone 1 ZRCs]) N N

8. **Incremental Delivery Facilities Demand Charge ($/MW/month/Contract Capacity):** Demand charges will recover depreciation expense, plus return at the authorized weighted average cost of capital, plus operation and maintenance expense, plus applicable taxes, per the ESA schedule, to recover any Incremental Transmission and/or Distribution Facility costs. An estimated incremental administrative and general expense, and general plant will be applied as loading factors. The charge for operation and maintenance and administrative and general expense per MW will be updated annually to reflect current MISO rates. N N N N N N N N

9. **MISO Transmission Charges (MISO Schedules).** Customer shall pay (or reimburse OTP for) all MISO charges, under all applicable MISO schedules, attributable to the Customer's load. N N N

<u>BILLING</u>: The Customer may choose either weekly billing, or monthly billing with estimated advance payment. N N

Minimum Bill: The Customer's Minimum Bill will include all fixed charges, all actual MISO charges, risk adder, system benefit charge, and Demand charges subject to a monthly Billing Demand that will differentiate between a Generation and a Transmission billing component, as follows: N N N N

1. The Generation Billing Demand charge: 85% of the Contract Capacity (Contract Demand); and N N

2. The Transmission Billing Demand charge: set at the highest of the following: N
   a. the actual metered on-peak kW use during the transmission system monthly coincident peaks; N N
   b. 85% of the Contract Capacity, specified for the applicable time period of the ESA term (Minimum Demand); or N N
   c. 85% of Demand during the current month and previous 11 months. N

<u>SPECIAL PROVISIONS</u>: If there is a change in the legal identity of the Customer receiving service under this Tariff, service shall be terminated unless the Company and the Customer make other mutually agreeable arrangements. N N N

<u>COST ALLOCATION</u>: Customers taking service under this Tariff will not be included with other retail customers for purposes of class cost of service studies. Each Customer will have costs directly assigned to it individually based upon cost causation and the characteristics of the electric service provided for that Customer pursuant to this rate schedule and the ESA. N N N N

Dedicated Resources shall be excluded from general jurisdictional cost of service unless the Commission approves future integration when deemed not detrimental to non-participating customers. N N N

<u>INCREMENTAL FACILITIES</u>: New Transmission and Distribution Facilities necessary to serve the Customer will be considered part of the Company's rate base but associated costs will be directly assigned to the specific Customer and recovered through the Incremental Delivery Facilities Demand Charge. N N N N

SEPARATE ACCOUNTING STRUCTURE: The Company will maintain separate accounting/ratemaking for Customers provided service pursuant to this rate schedule to ensure exclusion of Dedicated Resources and Dedicated Transmission and Distribution Facility costs from the general cost of service absent Commission approval, and to implement the System Benefit Credit. **N**

ESA GENERAL TERMS: Service under this Tariff requires an ESA approved by the Commission, with conforming informational filings in other OTP jurisdictions, as applicable. In furtherance of the requirements of this rate schedule, and not in limitation thereof, the ESA shall contain such terms and conditions as are deemed reasonably necessary by the Company to provide retail electric service to Customer and shall include at least the following terms: **N**

1. Pricing as set forth elsewhere in this rate schedule, including any additional terms not specifically reflected in this rate schedule, necessary to ensure that Customer bears all the costs (incremental and embedded) associated with the Company serving Customer. **N**

2. The Dedicated Resources the Company procures for the Customer's Contract Capacity, which may include all or a combination of Company-owned resources, power purchase agreements (Capacity-only contracts, and contracts for both Energy and Capacity). **N**

3. Any alternative resource procurement arrangements as may be agreed to by Company and Customer. **N**

4. The ESA shall provide that if the Company needs to purchase seasonal Capacity via MISO's PRA to address a shortfall to serve Customer, that Customer shall pay the full cost of such purchases. **N**

5. The ESA shall contain terms regarding the Build-Out Period, including the schedule for load additions, Dedicated Resources, and Customer's Contract Capacity. Load additions shall be tied to the in-servicing of Dedicated Resources, except that there shall be provisions for the Customer to have non-firm service (and be accredited as an LMR) for the difference and for the Company to seek short-term capacity via MISO's PRA using price sensitive bids (with Customer being charged an interim capacity surcharge). The ESA shall provide for curtailment in appropriate situations, including emergencies and hourly use in excess of Energy from Dedicated Resources. **N**

a. During the Build-Out period, there shall be provisions allowing for behind-the-meter generation for resiliency reasons subject to applicable requirements and Customer ensuring no operational or economic detriment to the Company or its system. **N N N N**

6. The ESA shall contain provisions regarding the length, in years, of the Steady Period (minimum of 15 years) and allowable Energy and Demand during the Steady Period. **N N**

7. The ESA shall allow for suspension of service or amendment of the ESA if there are repeated events of excess Demand. **N N**

8. The ESA shall contain provisions for curtailment of Customer load under certain conditions during the Build-Out period including: **N N**
   a. Use of Energy exceeding accredited capacity of the Dedicated Resources; **N**
   b. Energy Emergencies; and **N**
   c. Maximum hours of curtailment of Customer load for economic curtailment purposes when Dedicated Resources don't cover Customer's load. **N N**

9. The ESA shall provide terms for the use of behind the meter generation by Customer including terms for emergency/back-up operations; curtailment; dedicated Energy resources and impact to Demand and Energy requirements; and such other terms as may be necessary to ensure that no costs of serving Customer are borne by other Company Customers. **N N N N N**

10. The ESA shall contain detailed provisions regarding the offer and settlement of the Dedicated Resources on the MISO market, including MISO credits and charges. The ESA shall also provide for the Company's purchases to meet generation shortfalls, a forecast of purchases expected under normal weather conditions, and terms requiring a pass through of costs of such purchases to Customer. **N N N N N**

11. The ESA shall include terms establishing who will be responsible for fuel procurement, and the nature of the fuel procurement procedures; **N N**

12. The ESA must also include the following terms: N
    a. Size of monthly Contract Demand; N
    b. A change in law provision; N
    c. Provisions conditioning service obligations on receipt of all necessary regulatory approvals; N N
    d. Customer’s responsibility for all applicable taxes, franchise fees, and governmental charges; N N
    e. Non-binding confidential expectations of market Energy and capacity purchases; N
    f. The connection point(s) of the Company’s and Customer’s equipment at which Customer takes service; N N
    g. A binding forecast of Contract Capacity, expected load factor, and binding estimated schedule of load additions in both the Build-Out Period and the Steady Period; N N N
    h. Schedule of all components comprising the revenue requirement; N
    i. The voltage level(s) at which service will be supplied; N
    j. Monthly minimum on-peak Demand for Transmission; N
    k. Rate levels of each component; N
    l. Credit Support consistent with this rate schedule; N
    m. Exit fee consistent with this rate schedule; N
    n. Transmission and Distribution loss factors; and N
    o. Terms for termination consistent with this rate schedule. N

ESA TERMINATION: The ESA shall provide that it remains in effect unless cancelled or modified pursuant to its terms. N N

The ESA shall provide that if the Customer wishes to terminate the ESA prior to the end of the Steady Period, it must provide written notice thirty-six (36) months prior to its requested termination date. In addition, Customer will be subject to an Exit Fee. N N N

The Exit Fee provided for in the ESA shall cover at least the following: N

1. All stranded costs of all Dedicated Resource owned by the Company that were built to serve the Customer; N N

2. Any and all costs incurred including termination fees for cancellation of contracts with third parties including Dedicated Resource PPAs; N N

3. Any remaining minimum monthly Incremental Delivery Facilities Demand Charges for unrecovered costs of Incremental Transmission and/or Distribution Facilities; and N N

4. All liabilities of the Company to MISO arising from service to Customer including Transmission service pass-through charges or credits from MISO Schedule 9 after termination of the ESA due to transmission charges and credits being based on historical usage. N N N N

An additional fee shall apply if the Customer seeks to terminate with less than thirty-six (36) months' notice (the Early Termination Penalty). In such case, the Early Termination Penalty shall be equal to the Exit Fee plus one and a half (1.5) times the nominal value of the Minimum Bill corresponding to the number of months less than the thirty-six (36) months' notice required for termination. N N N N N

The Exit Fee and Early Termination Penalty (if applicable) shall be due in full within thirty (30) days of the date the Customer receives an invoice from the Company for such fees. N N

The Company will make commercially reasonable efforts to mitigate the Exit Fee amount owed by the Customer, subject to Commission approval. N N

Pre-Service Termination: If the Customer terminates the ESA prior to when it is scheduled to begin to take service from the Company, Customer shall reimburse the Company for all actual costs incurred or committed to serve the Customer, including engineering, construction, equipment, carrying costs, and third-party obligations, subject to the Company taking commercially reasonable steps to mitigate such costs; and it shall pay a pre-service termination penalty in the amount of 10% of the value of the Incremental Transmission and Distribution Facilities planned to serve the Customer. N N N N N N N

ATTACHMENT NO. 1 N
DEFINITIONS AND USEFUL TERMS N

Asset Owner is a designation used within MISO's commercial model to represent resources such as generation units, load zones, or other market-related assets. This role allows a market participant to manage and submit bids, offers, and other market activities associated with these resources, even if the participant does not physically own the asset. N N N N

Auction Clearing Price (ACP) is the price at which the annual MISO PRA clears for MISO Zone 1 for each season. N N

Build-Out Period is the period that begins when the initial Dedicated Resources are commercially operable and made available to offer into MISO and ends when all planned Dedicated Resources, as identified in the ESA, are commercially operable and made available to offer into MISO. N N N

Consumer Price Index (CPI) is a percentage published monthly by the U.S. Department of Labor, Bureau of Labor Statistics that denotes the rate of inflation. N N

Consumer Price Index for all Urban Consumers (CPI-U) is a specific index that denotes the rate of inflation experienced by consumers in urban areas published monthly by the U.S. Department of Labor, Bureau of Labor Statistics. N N N

Contract Capacity is the maximum Demand approved by MISO for the load, as set out in the ESA. N N

Contract Demand is 85% of the Contract Capacity. N

Credit Support is a standby irrevocable letter of credit, financial guarantee bond, parent or affiliate payment guarantee, or cash deposit. N N

Credit Support Amount is the total of the cost of the Extra Facilities, plus the Exit Fee set out in the Customer's ESA discounted at the Company's weighted average cost of capital, plus an amount sufficient to cover any accounts receivable. N N N

Dedicated Resources are generation resources that the Company has dedicated to serving Customer's full firm load, and for which the Company has assigned all associated costs to the Customer, as identified in the ESA. N N N

Incremental Delivery Facilities Demand Charge is a charge on a Customer's bill that recovers depreciation expense, plus return at the authorized weighted average cost of capital, plus operation and maintenance expense, plus applicable taxes, per the ESA schedule to recover any Incremental Transmission or Distribution Facility costs. An estimated incremental administrative and general expense, and general plant will be applied as loading factors. A separate charge for operation and maintenance expense per MW will be added and updated annually to reflect current MISO rates. **N N N N N N**

Incremental Transmission/Distribution Facilities are Transmission or Distribution Facilities that the Company has built to serve the Customer and for which all of the costs and expenses associated with the facilities have been directly assigned to the Customer. **N N N**

Early Termination Penalty is an additional fee that shall apply if the Customer seeks to terminate the ESA with less than thirty-six (36) months' notice. **N N**

Electric Service Agreement (ESA) is a contract between a Customer and the Company that sets out the terms of service. **N N**

Energy Emergency is a situation where the bulk electric system in MISO's service territory faces a shortage of available electricity generation or transmission capacity that threatens reliability. **N N**

Exit Fee is a charge imposed when a Customer ends a contract or service agreement before the agreed-upon term is completed. **N N**

Load Modifying Resource (LMR) is a demand response resource at MISO that reduces electricity consumption during emergencies to help maintain grid stability. **N N**

Load Serving Entity (LSE) is an entity, often a public utility, that serves load in MISO. Otter Tail Power Company is an LSE in MISO. **N N**

Minimum Bill is the minimum amount due each month for service to the Customer regardless of the Customer's usage, as set out in the Customer's ESA. **N N**

Minimum Demand is 85% of the Contract Capacity, specified for the applicable time period of the ESA term. **N N**

MISO Load Zone is a geographical area used to organize electricity load and resource data for operational and market purposes. Otter Tail Power Company serves in Zone 1. **N N**

MISO Locational Marginal Pricing (LMP) is the price of electricity at a specific location (node) on the grid, reflecting energy, congestion, and losses. N N

North American Electric Reliability Corporation (NERC) is a not-for-profit, international regulatory authority dedicated to effectively and efficiently reducing risks to the reliability and security of the bulk power system. N N N

Planning Reserve Margin Requirement (PRMR) is the number of MW in ZRCs required to meet an LSE's resource adequacy requirements as set by MISO. The MISO established resource adequacy requirements to ensure that LSEs have enough planning resources to reliably serve load. N N N

Planning Resource Auction (PRA) is an annual seasonal auction to ensure sufficient electricity capacity to meet peak demand in MISO. LSE like the Company both offer capacity resources and bid load into the PRA. N N N

Power Purchase Agreements (PPAs) is a contract for the purchase of energy, capacity, or both, typically from an independent power producer who must deliver the agreed amount of energy, capacity, or both to MISO. PPAs must be for physical assets located in MISO Zone 1, unless otherwise agreed in the ESA. N N N N

Steady Period is the period that begins once all planned Dedicated Resources, as identified in the ESA, are commercially operable and made available to offer into MISO. N N

System Benefit Charge is a charge set in a Customer's ESA that is a part of the Customer's System Benefit Contribution. This charge assures an appropriate amount of net benefits to non-participating Customers. N N N

System Benefit Contribution is revenue received from the Customer that is a contribution to the Company's embedded system costs. The System Benefit Contribution includes the System Benefit Charge as well as any other contributions to system costs, for example, operations and maintenance, administrative and general, and certain MISO Schedules. N N N N

Value of Lost Load (VOLL) is a key metric used in the MISO wholesale electricity markets to quantify the economic cost of losing a given amount of electricity supply. VOLL represents the monetary value of the energy that would have been delivered to customers if a generation or transmission resource had been available. N N N N

Zonal Resource Credit (ZRC) a ZRC in the MISO market is a unit of capacity accreditation that represents the dependable capacity a generation or demand resource can provide to meet the PRMR for a specific Local Resource Zone. N N N

LARGE GENERAL SERVICE – MARGINAL RATE N

DESCRIPTION	RATE CODE
Primary Service	N618
Transmission Service	N620

N
N
N
N

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

APPLICATION OF SCHEDULE: This rate schedule is applicable to greenfield Customers who meet certain conditions described herein. N N

The rate schedule will be available to greenfield Customers who reasonably demonstrate to the Company (1) an expected Metered Demand of at least 25 MW at a single Metering point, (2) an expected load factor of at least 80%, and (3) expected annual Energy sales of at least 175,000 MWh's over 12 consecutive billing months. Customers seeking service under this rate schedule shall provide the Company data and written assurances supporting the Customer's application. Customers shall meet the above criteria to obtain and maintain service on this rate. Customers who are served on this rate and do not meet the above criteria will be moved to the most applicable rate schedule. The Company will require, a written electric service agreement (ESA) between the Company and the Customer. N N N N N N N N N

This schedule is not applicable for Energy for resale. Emergency and supplementary/standby service will be supplied only as allowed by law. N N

PURPOSE & SCOPE OF RATE SCHEDULE: To attract new large and high load factor Customer loads that provide net benefits the Company's North Dakota Customers and communities served by the Company. N N N

The marginal cost estimates that form the basis of the Large General Service – Marginal Rate captures the marginal/incremental costs the utility expects to incur serving the Customer's load during the period the rate is in effect. There may be additional costs that were not anticipated when the rate was set. These incremental costs will be recovered through the corresponding Mandatory Rate Riders applied to the Customer. N N N N N

COMMISSION-APPROVED PROCESS: This rate schedule requires that the Commission pre-approve a rate formula that allows the Company to respond to service inquiries by providing potential Customers Commission-approved rate quotes and final rates. This process enables potential Customers to make timely business decisions, protects the Company's ratepayers by ensuring net benefits, and allows the Company to plan service to the new load(s). N N N N N

RATE DETERMINATION: The rate specified in each Customer's ESA shall be based upon and reflect either the marginal unit costs expected during the effective rate period, or the marginal unit costs plus an appropriate margin determined on a case-by-case basis. The marginal unit cost estimates will be consistent with those included in the Company's most recent marginal cost study for the corresponding voltage level of service and adjusted for annual inflation as required. The marginal unit costs applied to the Customer's load requirements will determine the minimum incremental revenue collected under this rate. Any margin recovered on the incremental costs will collect a share of the Company's costs from the new Customer, thus reducing the fixed costs allocated to existing Customers. N N N N N N N N N

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

TERMS AND CONDITIONS: The Company will offer the Customer the rate schedule under the following terms: N N

1. The minimum rate under this schedule shall recover at least the incremental cost of providing service, including any Energy-related marginal costs, the cost of additional Generation Capacity, the cost of network Capacity that is expected to be added while the rate is in effect, and any marginal Customer-related costs. The goal of this calculation is to establish a floor price to ensure that the revenue requirement of other Customers will not increase due to the addition of the new large load. N N N N N N

2. The final rate offered to the Customer under this rate schedule shall not exceed the Company's applicable Standard Tariff and all applicable riders and shall not be lower than incremental costs as described in the preceding paragraph. N N N

3. The Company will utilize its proprietary model to compare expected revenues from the prospective Customer and expected costs of serving the added load over the time period described in paragraph 4 of these terms and conditions. The model will be made available only to the Commission to verify the calculations used to establish the rate quote and final rate offered to the Customer. **N**

4. Service under this rate schedule requires an ESA with a term of at least five (5) years, with the term commencing on the first day of commercial operations. **N**

5. At the end of terms of the ESA, and any extensions thereof, Customers may elect to move from a full marginal cost-based rate to an embedded cost-based rate such as the applicable Standard Tariff offered to existing Customers, or a two-part market-based rate that would price a Customer- baseline load (CBL) at the embedded unit cost and any load above the CBL at marginal cost. Customers who elect to move away from the full marginal cost-based rate will not be able to return to it. **N**

6. Changes to the ESA that impact Customer(s) revenue and/or other ratepayers will require approval from the Commission. **N**

7. Customers who do not meet the 3-year minimum revenue guarantee as per OTP's line extension policy will not qualify for this rate schedule. **N**

8. Customer will allow Company to undertake an Energy efficiency audit of the facility. **N**

9. The Company will provide the Commission annual compliance updates to the trade-secret model and approved Customer rate while this rate schedule is in effect. **N**

LARGE GENERAL SERVICE - THERMAL MARKET ENERGY PRICING N

DESCRIPTION	RATE CODE	
		N N
Transmission Service	N657	N
Primary Service	N658	N
Secondary Service	N659	N

<u>RULES AND REGULATIONS</u>: Terms and conditions of this electric rate schedule and the N
General Rules and Regulations govern use of this rider. N

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

<u>TERM OF SERVICE</u>: Service under this rider shall be for a period not less than one year. N
The Customer shall take service under this rider by either signing a new electric service N
agreement (ESA) with the Company or by entering into amendments of existing ESA that N
covers new Energy requirements that sets forth, among other things, the Customer's Billing N
Demand(s), firm Demand, and Baseline Demand(s). The ESA must address incremental fixed N
and/or variable service costs necessary to provide service to the Customer and maintain net N
benefits. A Customer who voluntarily cancels service under this rider is not eligible to receive N
service again under this rider for a period of one year. N

<u>AVAILABILITY</u>: This rider is available on a voluntary basis only to new greenfield N
customers and locations that use thermal storage technology, have a Demand of at least 25 N
MW, and have a load factor less than 50 percent. The Customer's entire thermal load must be N
registered as a load modifying resource in Midcontinent Independent System Operator (MISO) N
and take service coincident with and not to exceed the hourly generating output of a nearby N
specifically identified wind and/or solar generation resource that is not owned by the Company. N
MISO must have established a new Asset Owner and Commercial Pricing Load Node (CP N
Node) associated with the Customer's load for market settlement purposes. N

The Customer will have no behind the Meter generation except for emergency backup N
purposes. N

METERING REQUIREMENTS: Company approved metering equipment capable of providing load interval information is required for Rider participation. The Customer agrees to pay for the additional cost of such metering when not provided in conjunction with existing retail electric service. **N**

CUSTOMER EQUIPMENT: Customers taking service under this Rider shall provide equipment to maintain a power factor at a level no less than the level at which power factor penalties would be invoked under the Tariff, if applicable. **N**

LIABILITY: The Company and the Customer agree that the Company has no liability for indirect, special, incidental, or consequential loss or damages to the Customer, including but not limited to the Customer's operations, site, production output, or other claims by the Customer as a result of participation in this Rider. **N**

BASELINE DEMAND(S): The Baseline Demand(s) is used to produce the Standard Bill and from which to measure changes in consumption for purposes of billing under the Thermal Market Energy Pricing Rider. It is specific to each Thermal Market Energy Pricing Rider Customer and is a representation of its typical pattern of electricity consumption. The Customer Baseline Demand(s) is designated through a Customer's ESA and allows the Company to curtail the participating Customer's load to an established Firm Demand. **N**

The Customer's Baseline Demand(s) must be agreed to in writing by the Customer as a precondition of receiving service under this rider. **N**

CUSTOMER CHARGE: A customer charge in the amount of $282.00 will be applied to each monthly bill to cover billing, administrative, metering, and communication costs associated with market pricing, plus any other applicable Tariff charges. **N**

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 7:00 a.m. the previous Friday. By 7:00 a.m. on the last business day 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, Veterans Day, Thanksgiving, Christmas Eve, and Christmas Day. **N**

No later than 4:00 p.m. (Central Time) of the preceding day, the Company shall give its best efforts to make available to Customers the Day-Ahead Thermal Market Energy prices for the next business day. The Day-Ahead Thermal 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 **N N N N N**

The Company is not responsible for the Customer's failure to receive or obtain and act upon Day-Ahead Thermal 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 Thermal Market Energy prices at any time prior to the Customer's acceptance and will be responsible for notifying the Customer of such revised prices. **N N N N N N**

Because high-outage-risk circumstances may prevent the Company from projecting prices more than one day in advance, the Company reserves the right to revise and make available to the Customer 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. **N N N N N**

PRICING METHODOLOGY: The Day-Ahead Thermal Market Energy prices will be determined for each day based on hourly MISO LMP at the Customer's CP Node, Network Integration Transmission Service (NITS) costs, customer charge, and other MISO charges incurred by the Company caused by the Customer's load. **N N N N**

The Company is not responsible for providing the Real-Time Thermal Market Energy prices to the Customer. **N N**

BILL DETERMINATION: **N**

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

The monthly bill for Energy consumed up to and including the Baseline Demand(s) will be determined by multiplying the Customer's metered Energy consumption by the Energy rate provided in the rate schedule applicable to the Customer. **N N N**

The monthly bill for Energy consumed above the Baseline Demand(s) will be determined by the MISO market settlements that occur at the Customer specific CP Node plus associated NITS charges and applicable riders. **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**

ESA Components: Incremental fixed and/or variable service costs to maintain net benefits as set in ESA. **N**

PENALTY FOR INSUFFICIENT LOAD CONTROL: Upon notification from the Company, the Customer shall curtail its Demand to its Firm Demand. In the event the Customer fails to curtail its load as requested by the Company, the Customer shall be responsible for any and all costs and/or penalties incurred by the Company as a result of the Customers' failure to curtail. The duration and frequency of curtailments shall be at the sole discretion of the Company unless otherwise provided in the ESA between the Company and the Customer. **N**

ENERGY ADJUSTMENT RIDER: Energy consumed up to and including the Baseline Demand(s) is subject to the Energy Adjustment Rider as provided in Section 13.01, or any amendments or superseding provisions applicable thereto. Because Energy consumed above the Baseline Demand(s) is subject to the Thermal Market Energy prices, it is not subject to the Energy Adjustment Rider as provided for in Mandatory Riders – Applicability Matrix, Section 13.00. **N**

SPECIAL PROVISIONS: If there is a change in the legal identity of the Customer receiving service under this Thermal Market Energy Pricing Rider, service shall be terminated unless the Company and the Customer make other mutually agreeable arrangements. **N**

MANDATORY RIDERS - APPLICABILITY MATRIX

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.

OTTER TAIL POWER COMPANY 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
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 - Tier I	10.04	■			■	■	■		■			■	■
Large General Service - Tier I - Time of Day	10.05	■			■	■	■		■			■	■
~~Super~~ Large General Service - Tier II - Time of Day	10.06	■			■	■	■		■			■	■
Large General Service - Tier III - High Power Compute	10.07											■	
Large General Service - Marginal Rate	10.08	■			■	■	■		■			■	■
Large General Service - Thermal Market Energy Pricing	10.09												
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

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				■	■	■		■				
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 (**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												
~~Thermal Market Energy Pricing Rider~~ Reserved for Future Use	14.16												

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

MANDATORY RIDERS - APPLICABILITY MATRIX

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.

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	
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	10.01	■			■	■	■		■			■	■	C
General Service	10.02	■			■	■	■		■			■	■	C
General Service - Time of Use	10.03	■			■	■	■		■			■	■	C
Large General Service - Tier I	10.04	■			■	■	■		■			■	■	C
Large General Service - Tier I - Time of Day	10.05	■			■	■	■		■			■	■	C
Large General Service - Tier II - Time of Day	10.06	■			■	■	■		■			■	■	C
Large General Service - Tier III - High Power Compute	10.07											■		N
Large General Service - Marginal Rate	10.08	■			■	■	■		■			■	■	N
Large General Service - Thermal Market Energy Pricing	10.09													N
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

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				■	■	■		■				
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 (**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												
Reserved for Future Use	14.16												
Key:	✓ = May apply	■ = Mandatory	☐ = Not Applicable										

C

ENERGY ADJUSTMENT RIDER BY SERVICE CATEGORY
(Identified on the bill as Fuel & Purchase Power)

ENERGY ADJUSTMENT CHARGE: There shall be added to the monthly bill an Energy Adjustment Charge calculated by multiplying the customers applicable monthly billing Kilowatt hours (kWh) by the customers applicable billed Energy Adjustment Factor (EAF) per kWh. The billed EAF amount per Kilowatt-hour (rounded to the nearest 0.001¢) will be the average monthly cost of Energy per Kilowatt-hour as determined for that customers 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 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.

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 – Tiers I & II	10.04, 10.05, 10.06, 11.01, 14.13	0.961
Large General Service – Marginal Rate	10.08	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

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.

9. The costs of fuel and reagents resulting from steam and water sales and the revenues from steam and water sales shall be included in the energy adjustment rider.

10. Excluding any Market Energy related costs under Sections 10.07 and 10.09~~ 14.16~~.

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)

ENERGY ADJUSTMENT CHARGE: There shall be added to the monthly bill an Energy Adjustment Charge calculated by multiplying the customers applicable monthly billing Kilowatt hours (kWh) by the customers applicable billed Energy Adjustment Factor (EAF) per kWh. The billed EAF amount per Kilowatt-hour (rounded to the nearest 0.001¢) will be the average monthly cost of Energy per Kilowatt-hour as determined for that customers 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 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.

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 – Tiers I & II	10.04, 10.05, 10.06, 11.01, 14.13	0.961	**C**
Large General Service – Marginal Rate	10.08	0.961	**N**
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	

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.

9. The costs of fuel and reagents resulting from steam and water sales and the revenues from steam and water sales shall be included in the energy adjustment rider.

10. Excluding any Market Energy related costs under Sections 10.07 and 10.09. **CN**

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.

RENEWABLE RESOURCE COST RECOVERY RIDER

DESCRIPTION	RATE CODE
All Services	NRRA

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 (RRC) 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*), 10.07 (Large General Service – Tier III – High Power Compute), and 10.09~~14.16~~ (Large General Service – Thermal Market Energy Pricing). The RRC 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 (0.812) percent

DETERMINATION OF RENEWABLE RESOURCE COST CHARGE: The RRC Factor shall be determined by dividing the forecasted *balance of the RRC Tracker account* by the *forecasted retail revenues subject to the RRC Factor.* The forecasted RRC 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 RRC Factor shall be rounded to the nearest 0.001 percent.

The *balance of the RRC Tracker account* for determination of the RRC 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 RRC 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 RRC Tracker account will be calculated reflecting the difference between actual prior period RRC 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 RRC 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 RRC Tracker account shall be eligible for recovery through this Rider, and all revenues recovered from the applicable RRC Factor shall be credited to the RRC Tracker account.

Forecasted retail revenues used for calculating the RRC 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*), 10.07 (Large General Service – Tier III – High Power Compute), and 10.09 (Large General Service – ~~and 14.16 (~~Thermal Market Energy Pricing). Retail revenue used for calculating the RRC Factor will not include any Mandatory Riders.

The RRC 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

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 (RRC) 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*), 10.07 (Large General Service – Tier III – High Power Compute), and 10.09 (Large General Service – Thermal Market Energy Pricing). The RRC 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. **N** **C**

Renewable Resource Cost Recovery Factor (0.812) percent

DETERMINATION OF RENEWABLE RESOURCE COST CHARGE: The RRC Factor shall be determined by dividing the forecasted *balance of the RRC Tracker account* by the *forecasted retail revenues subject to the RRC Factor.* The forecasted RRC 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 RRC Factor shall be rounded to the nearest 0.001 percent.

The *balance of the RRC Tracker account* for determination of the RRC 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 RRC 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 RRC Tracker account will be calculated reflecting the difference between actual prior period RRC 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 RRC 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 RRC Tracker account shall be eligible for recovery through this Rider, and all revenues recovered from the applicable RRC Factor shall be credited to the RRC Tracker account.

Forecasted retail revenues used for calculating the RRC 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*), 10.07 (Large General Service – Tier III – High Power Compute), and 10.09 **NC**
(Large General Service – Thermal Market Energy Pricing). Retail revenue used for **C**
calculating the RRC Factor will not include any Mandatory Riders.

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

<u>MANDATORY AND VOLUNTARY RIDERS</u>: 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

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 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– Tier I, 10.05 Large General Service – Tier I – Time of Day, 10.06 ~~Super~~ Large General Service– Tier II – Time of Day, Large General Service – Marginal Rate, 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.

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

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 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– Tier I, 10.05 Large General Service – Tier I – Time of Day, 10.06 Large General Service– Tier II – Time of Day, Large General Service – Marginal Rate, 11.01 Standby Service, 14.02 Real Time Pricing Rider, 14.03 Large General Service Rider, and 14.13 Economic Development Rate Rider. C 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.

GENERATION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
All Services	NGCR

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 Generation Cost Recovery (GCR) 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 10.07 (Large General Service – Tier III – High Power Compute), 10.09 (Large General Service – Thermal Market Energy Pricing), and 14.09 (**Tail***Winds*) ~~and 14.16 (Thermal Market Energy Pricing~~. The GCR 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.

Generation Cost Recovery Factor 0.000 percent

DETERMINATION OF GENERATION COST RECOVERY CHARGE: The GCR Factor shall be determined by dividing the forecasted *balance of the GCR Tracker account* by the *forecasted retail revenues subject to the GCR Factor.* The forecasted GCR 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 GCR Factor shall be rounded to the nearest 0.001 percent.

The *balance of the GCR Tracker account* for determination of the GCR 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 GCR 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 GCR Tracker account will be calculated reflecting the difference between actual prior period GCR 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 GCR 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 GCR Tracker account shall be eligible for recovery through this Rider, and all revenues recovered from the applicable GCR Factor shall be credited to the GCR Tracker account.

Forecasted retail revenues used for calculating the GCR 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 10.07 (Large General Service – Tier III – High Power Compute), 10.09 (Large General Service – Thermal Market Energy Pricing), and 14.09 (**Tail***Winds*) ~~and 14.16 (Thermal Market Energy Pricing)~~. Retail revenue used for calculating the GCR Factor will not include any Mandatory Riders.

The GCR 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.

GENERATION COST RECOVERY RIDER

DESCRIPTION	**RATE CODE**
All Services	NGCR

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 Generation Cost Recovery (GCR) 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 10.07 (Large General Service – Tier III – High Power Compute), 10.09 (Large General Service – Thermal Market Energy Pricing), and 14.09 (**Tail***Winds*). The GCR 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. **N** **N** **C**

Generation Cost Recovery Factor 0.000 percent

DETERMINATION OF GENERATION COST RECOVERY CHARGE: The GCR Factor shall be determined by dividing the forecasted *balance of the GCR Tracker account* by the *forecasted retail revenues subject to the GCR Factor.* The forecasted GCR 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 GCR Factor shall be rounded to the nearest 0.001 percent.

The *balance of the GCR Tracker account* for determination of the GCR 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 GCR 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 GCR Tracker account will be calculated reflecting the difference between actual prior period GCR 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 GCR 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 GCR Tracker account shall be eligible for recovery through this Rider, and all revenues recovered from the applicable GCR Factor shall be credited to the GCR Tracker account.

Forecasted retail revenues used for calculating the GCR 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 10.07 **N**
(Large General Service – Tier III – High Power Compute), 10.09 (Large General Service – **N**
Thermal Market Energy Pricing), and 14.09 (**Tail***Winds*). Retail revenue used for **C**
calculating the GCR Factor will not include any Mandatory Riders.

The GCR 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.

ENVIRONMENTAL COST RECOVERY RIDER

DESCRIPTION	RATE CODE
All Service – Environmental Cost Recovery	NECR

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

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company's retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Sections 10.07 (Large General Service – Tier III – High Power Compute), 10.09 (Large General Service – Thermal Market Energy Pricing), and 14.09 (**Tail***Winds*) ~~and 14.16 (Thermal Market Energy Pricing)~~.

ENVIRONMENTAL COST RECOVERY CHARGE: There shall be included on each North Dakota Customer's monthly bill an Environmental Cost Recovery (ECR) Charge, based on the applicable ECR Factor multiplied by the Customer's monthly bill. The Customer's monthly bill shall be based on all applicable charges and credits under the Company's retail rate schedules in Sections 9, 10, 11, 12 and 14, except for Sections 10.07 (Large General Service – Tier III – High Power Compute), 10.09 (Large General Service – Thermal Market Energy Pricing), and 14.09 (**Tail***Winds*) ~~and Section 14.16 (Thermal Market Energy Pricing)~~. The ECR Factor will not apply to any Mandatory Riders. The ECR charge will be included as part of the charge reflected on the Customer's bill on the line labeled "EPA Req Environmental Cst."

Environmental Cost Recovery Factor - 0.000 percent

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

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

The annual revenue requirements associated with environmental measures eligible for recovery under NDCC 49-05-04.2 that are determined by the Commission to be eligible for recovery under this ECR 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 ECR Tracker account will be calculated reflecting the difference between actual prior period ECR 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 ECR Factor plus carrying charges or credits accrued at the rate of return approved in Otter Tail Power's most recent general rate case.

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

Forecasted retail revenues used for calculating the ECR 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 10.07 (Large General Service – Tier III – High Power Compute), 10.09 (Large General Service – Thermal Market Energy Pricing), and 14.09 (**Tail***Winds*~~) and 14.16 (Thermal Market Energy Pricing)~~. Retail revenue used for calculating the ECR Factor will not include any Mandatory Riders.

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

ENVIRONMENTAL COST RECOVERY RIDER

DESCRIPTION	RATE CODE
All Service – Environmental Cost Recovery	NECR

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

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company's retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Sections 10.07 (Large General Service – Tier III – High Power Compute), 10.09 (Large General Service – Thermal Market Energy Pricing), and 14.09 (**Tail***Winds*). **N N C**

ENVIRONMENTAL COST RECOVERY CHARGE: There shall be included on each North Dakota Customer's monthly bill an Environmental Cost Recovery (ECR) Charge, based on the applicable ECR Factor multiplied by the Customer's monthly bill. The Customer's monthly bill shall be based on all applicable charges and credits under the Company's retail rate schedules in Sections 9, 10, 11, 12 and 14, except for Sections 10.07 (Large General Service – Tier III – High Power Compute), 10.09 (Large General Service – Thermal Market Energy Pricing), and 14.09 (**Tail***Winds*). The ECR Factor will not apply to any Mandatory Riders. The ECR charge will be included as part of the charge reflected on the Customer's bill on the line labeled "EPA Req Environmental Cst." **N N C**

Environmental Cost Recovery Factor - 0.000 percent

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

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

The annual revenue requirements associated with environmental measures eligible for recovery under NDCC 49-05-04.2 that are determined by the Commission to be eligible for recovery under this ECR 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 ECR Tracker account will be calculated reflecting the difference between actual prior period ECR 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 ECR Factor plus carrying charges or credits accrued at the rate of return approved in Otter Tail Power's most recent general rate case.

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

Forecasted retail revenues used for calculating the ECR 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 10.07 (Large General Service – Tier III – High Power Compute), 10.09 (Large General Service – Thermal Market Energy Pricing), and 14.09 (**Tail***Winds*). Retail revenue used for calculating the ECR Factor will not include any Mandatory Riders. **N** **N** **C**

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

METERING & DISTRIBUTION TECHNOLOGY (MDT)
COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Residential	NAMRS
Residential RDC	NAMRC
Farm	NAMFM
Small General Service ~~(Under 20 kW)~~	NAMGS
General Service ~~(20 kW and Greater)~~	NAMG1
General Service – TOD	NAMGU
Large General Service – Tier I – Primary / Transmission	NAMLP
Large General Service – Tier II – Secondary	NAMLS
Large General Service – Tier II – Primary / Transmission	NAMPT
Large General Service – Tier III – High Power Compute	NAMHP
Large General Service – Marginal Rate	NAMMR
Irrigation Service	NAMIR
Outdoor Lighting (Metered)	NAMLT
OPA (Metered)	NAMOP
Controlled Service Deferred Load	NAMWH
Controlled Service Interruptible – Self Contained	NAMCS
Controlled Service Interruptible – CT Metering	NAMCT
Controlled Service Off Peak	NAMCD

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 metered retail rate schedules.

COST RECOVERY CHARGE: There shall be included on each North Dakota Customer's monthly bill a Metering & Distribution Technology (MDT) Cost Recovery Per Meter 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:

Service Category	Section	Per Meter Charge
Residential	9.01	$2.28
Residential RDC	9.02	$5.38
Farm	9.03	$6.74
Small General Service ~~(Under 20 kW)~~	10.01	$3.60
General Service ~~(20 kW or Greater)~~	10.02	$13.72
General Service -TOD~~U~~	10.03	$23.19
Large General Services - Primary / Transmission	10.04, 10.05, 10.06, 10.07, 10.08, 11.01	$117.14
Large General Services - Secondary	10.04, 10.05, 11.01	$21.29
Irrigation Service	11.02	$12.21
Outdoor Lighting (Metered)	11.03	$2.45
OPA (Metered)	11.05	$5.89
Controlled Service Deferred Load	14.01, 14.06	$5.38
Controlled Service Interruptible – Self-Contained	14.04	$5.47
Controlled Service Interruptible – CT Metering	14.04, 14.12	$24.34
Controlled Service Off Peak	14.07	$6.84

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.

METERING & DISTRIBUTION TECHNOLOGY (MDT) COST RECOVERY RIDER

DESCRIPTION	RATE CODE	
Residential	NAMRS	
Residential RDC	NAMRC	
Farm	NAMFM	
Small General Service	NAMGS	C
General Service	NAMG1	C
General Service – TOD	NAMGU	C
Large General Service – Tier I – Primary / Transmission	NAMLP	C
Large General Service – Tier II – Secondary	NAMLS	C
Large General Service – Tier II – Primary / Transmission	NAMPT	N
Large General Service – Tier III – High Power Compute	NAMHP	N
Large General Service – Marginal Rate	NAMMR	N
Irrigation Service	NAMIR	
Outdoor Lighting (Metered)	NAMLT	
OPA (Metered)	NAMOP	
Controlled Service Deferred Load	NAMWH	
Controlled Service Interruptible – Self Contained	NAMCS	
Controlled Service Interruptible – CT Metering	NAMCT	
Controlled Service Off Peak	NAMCD	

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 metered retail rate schedules.

COST RECOVERY CHARGE: There shall be included on each North Dakota Customer's monthly bill a Metering & Distribution Technology (MDT) Cost Recovery Per Meter 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.

<u>RATE</u>:

Service Category	Section	Per Meter Charge	
Residential	9.01	$2.28	
Residential RDC	9.02	$5.38	
Farm	9.03	$6.74	
Small General Service	10.01	$3.60	C
General Service	10.02	$13.72	C
General Service -TOD	10.03	$23.19	C
Large General Services - Primary / Transmission	10.04, 10.05, 10.06, 10.07, 10.08, 11.01	$117.14	C N N
Large General Services - Secondary	10.04, 10.05, 11.01	$21.29	C
Irrigation Service	11.02	$12.21	
Outdoor Lighting (Metered)	11.03	$2.45	
OPA (Metered)	11.05	$5.89	
Controlled Service Deferred Load	14.01, 14.06	$5.38	
Controlled Service Interruptible – Self-Contained	14.04	$5.47	
Controlled Service Interruptible – CT Metering	14.04, 14.12	$24.34	
Controlled Service Off Peak	14.07	$6.84	

<u>MANDATORY AND VOLUNTARY RIDERS</u>: 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.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Case No. PU-26-
Approved by order dated

EFFECTIVE with bills rendered on
and after January 1, 2027, in North Dakota

APPROVED: Matthew J. Olsen
Vice President, Regulatory

INTERIM RATE RIDER

DESCRIPTION	RATE CODE
All Services	NINTM

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, excluding Section 10.07 (Large General Service – High Power Compute) and 10.09~~14.16~~ (Large General Service – Thermal Market Energy Pricing)~~- Rider~~, as described in the Mandatory Riders – Applicability Matrix.

INTERIM RATE ADJUSTMENT: There shall be included on each North Dakota Customer's monthly bill a percent increase to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge. The following charge is applicable in addition to all charges for service being taken under the Company's standard rate schedules.

Interim Rate Adjustment – 0.00 percent

DETERMINATION OF INTERIM RATE ADJUSTMENT: As described in § 49-05-06 of the North Dakota Century Code, the Interim Rate Adjustment must be calculated using the proposed test year cost of capital, rate base, and expenses, except that the schedule must include:

a. A rate of return on common equity for the public utility equal to that authorized by the commission in the public utility's most recent rate proceeding.
b. Rate base or expense items the same in nature and kind as those allowed by a currently effective Commission order in the public utility's most recent rate proceeding.
c. No change in existing rate design.

The Interim Rate Adjustment shall be rounded to the nearest 0.001 percent.

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.

INTERIM RATE RIDER

DESCRIPTION	RATE CODE
All Services	NINTM

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, excluding Section 10.07 (Large General Service – High Power Compute) and 10.09 (Large General Service – Thermal Market Energy Pricing), as described in the Mandatory Riders – Applicability Matrix. **C CN**

INTERIM RATE ADJUSTMENT: There shall be included on each North Dakota Customer's monthly bill a percent increase to the sum of the following, as applicable: Customer Charge, Energy Charge, Demand Charge, Fixed Charge, Facilities Charge, and the monthly Minimum Charge. The following charge is applicable in addition to all charges for service being taken under the Company's standard rate schedules.

Interim Rate Adjustment – 0.00 percent

DETERMINATION OF INTERIM RATE ADJUSTMENT: As described in § 49-05-06 of the North Dakota Century Code, the Interim Rate Adjustment must be calculated using the proposed test year cost of capital, rate base, and expenses, except that the schedule must include:

a. A rate of return on common equity for the public utility equal to that authorized by the commission in the public utility's most recent rate proceeding.
b. Rate base or expense items the same in nature and kind as those allowed by a currently effective Commission order in the public utility's most recent rate proceeding.
c. No change in existing rate design.

The Interim Rate Adjustment shall be rounded to the nearest 0.001 percent.

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.

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 (Cool *Savings*)	Voluntary Renewable Energy Rider (Tail *Winds*)	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	~~Thermal Market Energy Pricing Rider~~ Rerserved for Future Use
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	14.16
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 - Tier I	10.04	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓	~~✓~~
Large General Service - Tier I - Time of Day	10.05	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓	~~✓~~
~~Super~~ Large General Service - Tier II - Time of Day	10.06	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓	
Large General Service - Tier III - High Power Compute	10.07															
Large General Service - Marginal Rate	10.08	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓	
Large General Service - Thermal Market Energy Pricing	10.09															
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.)

OTTER TAIL POWER COMPANY 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 (**Cool** *Savings*)	Voluntary Renewable Energy Rider (**Tail** *Winds*)	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	~~Thermal Market Energy Pricing Rider~~ Reserved for Future Use
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	14.16
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	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															
~~Thermal Market Energy Pricing Rider~~ Reserved for Future Use	14.16															
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.

OTTER TAIL POWER COMPANY 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 (Cool Savings)	Voluntary Renewable Energy Rider (Tail Winds)	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	Reserved for Future Use	
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	14.16	C
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	10.01	✓			✓		✓	✓		✓	✓				✓		C
General Service	10.02	✓	✓		✓		✓	✓		✓	✓				✓		C
General Service - Time of Use	10.03	✓									✓				✓		C
Large General Service - Tier I	10.04	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓		C
Large General Service - Tier I - Time of Day	10.05	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓		C
Large General Service - Tier II - Time of Day	10.06	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓		C
Large General Service - Tier III - High Power Compute	10.07																N
Large General Service - Marginal Rate	10.08	✓	✓	✓	✓		✓	✓		✓	✓		✓	✓	✓		N
Large General Service - Thermal Market Energy Pricing	10.09																N
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 (Cool Savings)	Voluntary Renewable Energy Rider (Tail Winds)	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	Reserved for Future Use	C
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	14.16	
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	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																
Reserved for Future Use	14.16																C
Key:	✓ = May apply	■ = Mandatory	☐ = Not Applicable														

ECONOMIC DEVELOPMENT RATE RIDER

DESCRIPTION	RATE CODE
Secondary Service	N690
Primary Service	N691
Transmission Service	N692

RULES AND REGULATIONS: The use of this electric rate schedule is also governed by the General Rules and Regulations.

APPLICATION OF RIDER: This rider is applicable to the following Large General Service customers served on Section 10.04, ~~&~~ 10.05, 10.06, or 10.08:

(i) Greenfield customers with: expected metered demand of at least 500 kW at a single metering point, and Seasonal Load Factor that is above the seasonal system average load factor and above the seasonal class average load factor corresponding to existing customers under the otherwise applicable rate code.

(ii) Existing customers with: metered demands of at least 1,000 kW that increase measured demand by at least 500 kW at a single new metering point, and Seasonal Load Factor above the seasonal system average load factor and above the seasonal class average load factor under the otherwise applicable rate code.

SCOPE OF RIDER: To attract, by offering a Rate Discount, new customer load that provides net benefits to ratepayers.

RATE DISCOUNT: To be specified in each Customer's contract, in the form of a discount percentage from the applicable rate code (Section 10.04, ~~or~~ 10.05, 10.06, or 10.08), plus Mandatory Riders.

TERMS AND CONDITIONS: The Company will offer the Customer the Rate Discount under the following terms:

1. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including any energy-related marginal costs plus the cost of additional generation capacity or network capacity that is to be added while the rate is in effect, and any marginal

ECONOMIC DEVELOPMENT RATE RIDER

DESCRIPTION	RATE CODE
Secondary Service	N690
Primary Service	N691
Transmission Service	N692

RULES AND REGULATIONS: The use of this electric rate schedule is also governed by the General Rules and Regulations.

APPLICATION OF RIDER: This rider is applicable to the following Large General Service customers served on Section 10.04, 10.05, 10.06, or 10.08: **N**

(i) Greenfield customers with: expected metered demand of at least 500 kW at a single metering point, and Seasonal Load Factor that is above the seasonal system average load factor and above the seasonal class average load factor corresponding to existing customers under the otherwise applicable rate code.

(ii) Existing customers with: metered demands of at least 1,000 kW that increase measured demand by at least 500 kW at a single new metering point, and Seasonal Load Factor above the seasonal system average load factor and above the seasonal class average load factor under the otherwise applicable rate code.

SCOPE OF RIDER: To attract, by offering a Rate Discount, new customer load that provides net benefits to ratepayers.

RATE DISCOUNT: To be specified in each Customer's contract, in the form of a discount percentage from the applicable rate code (Section 10.04, 10.05, 10.06, or 10.08), plus Mandatory Riders. **N**

TERMS AND CONDITIONS: The Company will offer the Customer the Rate Discount under the following terms:

1. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including any energy-related marginal costs plus the cost of additional generation capacity or network capacity that is to be added while the rate is in effect, and any marginal

CANCELLED
THERMAL MARKET ENERGY PRICING RIDER

DESCRIPTION	RATE CODE
Transmission Service	N657
Primary Service	N658
Secondary Service	N659

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

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

TERM OF SERVICE: Service under this rider shall be for a period not less than one year. The Customer shall take service under this rider by either signing a new electric service agreement (ESA) with the Company or by entering into amendments of existing ESA that covers new Energy requirements that sets forth, among other things, the Customer's Billing Demand(s), firm Demand, and Baseline Demand(s). The ESA must address incremental fixed and/or variable service costs necessary to provide service to the Customer and maintain net benefits. 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 voluntary basis only to new greenfield customers and locations that use thermal storage technology, have a Demand of at least 25 MW, and have a load factor less than 50 percent. The Customer's entire thermal load must be registered as a load modifying resource in Midcontinent Independent System Operator (MISO) and take service coincident with and not to exceed the hourly generating output of a nearby specifically identified wind and/or solar generation resource that is not owned by the Company. MISO must have established a new Asset Owner and Commercial Pricing Load Node (CP Node) associated with the Customer's load for market settlement purposes.

The Customer will have no behind the Meter generation except for emergency backup purposes.

METERING REQUIREMENTS: Company approved metering equipment capable of providing load interval information is required for Rider participation. The Customer agrees to pay for the additional cost of such metering when not provided in conjunction with existing retail electric service.

CUSTOMER EQUIPMENT: Customers taking service under this Rider shall provide equipment to maintain a power factor at a level no less than the level at which power factor penalties would be invoked under the Tariff, if applicable.

LIABILITY: The Company and the Customer agree that the Company has no liability for indirect, special, incidental, or consequential loss or damages to the Customer, including but not limited to the Customer's operations, site, production output, or other claims by the Customer as a result of participation in this Rider.

BASELINE DEMAND(S): The Baseline Demand(s) is used to produce the Standard Bill and from which to measure changes in consumption for purposes of billing under the Thermal Market Energy Pricing Rider. It is specific to each Thermal Market Energy Pricing Rider Customer and is a representation of its typical pattern of electricity consumption. The Customer Baseline Demand(s) is designated through a Customer's ESA and allows the Company to curtail the participating Customer's load to an established Firm Demand.

The Customer's Baseline Demand(s) must be agreed to in writing by the Customer as a precondition of receiving service under this rider.

CUSTOMER CHARGE: A customer charge in the amount of $282.00 will be applied to each monthly bill to cover billing, administrative, metering, and communication costs associated with market pricing, plus any other applicable Tariff charges.

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 7:00 a.m. the previous Friday. By 7:00 a.m. on the last business day 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, Veterans Day, Thanksgiving, Christmas Eve, and Christmas Day.

No later than 4:00 p.m. (Central Time) of the preceding day, the Company shall give its best efforts to make available to Customers the Day-Ahead Thermal Market Energy prices for the next business day. The Day-Ahead Thermal 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

The Company is not responsible for the Customer's failure to receive or obtain and act upon Day-Ahead Thermal 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 Thermal Market Energy prices at any time prior to the Customer's acceptance and will be responsible for notifying the Customer of such revised prices.

Because high-outage-risk circumstances may prevent the Company from projecting prices more than one day in advance, the Company reserves the right to revise and make available to the Customer 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.

PRICING METHODOLOGY: The Day-Ahead Thermal Market Energy prices will be determined for each day based on hourly MISO LMP at the Customer's CP Node, Network Integration Transmission Service (NITS) costs, customer charge, and other MISO charges incurred by the Company caused by the Customer's load.

The Company is not responsible for providing the Real-Time Thermal Market Energy prices to the Customer.

BILL DETERMINATION:

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

The monthly bill for Energy consumed up to and including the Baseline Demand(s) will be determined by multiplying the Customer's metered Energy consumption by the Energy rate provided in the rate schedule applicable to the Customer.

The monthly bill for Energy consumed above the Baseline Demand(s) will be determined by the MISO market settlements that occur at the Customer specific CP Node plus associated NITS charges and applicable riders.

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.

ESA Components: Incremental fixed and/or variable service costs to maintain net benefits as set in ESA.

PENALTY FOR INSUFFICIENT LOAD CONTROL: Upon notification from the Company, the Customer shall curtail its Demand to its Firm Demand. In the event the Customer fails to curtail its load as requested by the Company, the Customer shall be responsible for any and all costs and/or penalties incurred by the Company as a result of the Customers' failure to curtail. The duration and frequency of curtailments shall be at the sole discretion of the Company unless otherwise provided in the ESA between the Company and the Customer.

ENERGY ADJUSTMENT RIDER: Energy consumed up to and including the Baseline Demand(s) is subject to the Energy Adjustment Rider as provided in Section 13.01, or any amendments or superseding provisions applicable thereto. Because Energy consumed above the Baseline Demand(s) is subject to the Thermal Market Energy prices, it is not subject to the Energy Adjustment Rider as provided for in Mandatory Riders – Applicability Matrix, Section 13.00.

SPECIAL PROVISIONS: If there is a change in the legal identity of the Customer receiving service under this Thermal Market Energy Pricing Rider, service shall be terminated unless the Company and the Customer make other mutually agreeable arrangements.

<u>*CANCELLED***</u>** N
THERMAL MARKET ENERGY PRICING RIDER

DESCRIPTION	RATE CODE
Transmission Service	N657
Primary Service	N658
Secondary Service	N659

<u>RULES AND REGULATIONS</u>: Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this rider.

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

<u>TERM OF SERVICE</u>: Service under this rider shall be for a period not less than one year. The Customer shall take service under this rider by either signing a new electric service agreement (ESA) with the Company or by entering into amendments of existing ESA that covers new Energy requirements that sets forth, among other things, the Customer's Billing Demand(s), firm Demand, and Baseline Demand(s). The ESA must address incremental fixed and/or variable service costs necessary to provide service to the Customer and maintain net benefits. 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.

<u>AVAILABILITY</u>: This rider is available on a voluntary basis only to new greenfield customers and locations that use thermal storage technology, have a Demand of at least 25 MW, and have a load factor less than 50 percent. The Customer's entire thermal load must be registered as a load modifying resource in Midcontinent Independent System Operator (MISO) and take service coincident with and not to exceed the hourly generating output of a nearby specifically identified wind and/or solar generation resource that is not owned by the Company. MISO must have established a new Asset Owner and Commercial Pricing Load Node (CP Node) associated with the Customer's load for market settlement purposes.

The Customer will have no behind the Meter generation except for emergency backup purposes.

METERING REQUIREMENTS: Company approved metering equipment capable of providing load interval information is required for Rider participation. The Customer agrees to pay for the additional cost of such metering when not provided in conjunction with existing retail electric service.

CUSTOMER EQUIPMENT: Customers taking service under this Rider shall provide equipment to maintain a power factor at a level no less than the level at which power factor penalties would be invoked under the Tariff, if applicable.

LIABILITY: The Company and the Customer agree that the Company has no liability for indirect, special, incidental, or consequential loss or damages to the Customer, including but not limited to the Customer's operations, site, production output, or other claims by the Customer as a result of participation in this Rider.

BASELINE DEMAND(S): The Baseline Demand(s) is used to produce the Standard Bill and from which to measure changes in consumption for purposes of billing under the Thermal Market Energy Pricing Rider. It is specific to each Thermal Market Energy Pricing Rider Customer and is a representation of its typical pattern of electricity consumption. The Customer Baseline Demand(s) is designated through a Customer's ESA and allows the Company to curtail the participating Customer's load to an established Firm Demand.

The Customer's Baseline Demand(s) must be agreed to in writing by the Customer as a precondition of receiving service under this rider.

CUSTOMER CHARGE: A customer charge in the amount of $282.00 will be applied to each monthly bill to cover billing, administrative, metering, and communication costs associated with market pricing, plus any other applicable Tariff charges.

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 7:00 a.m. the previous Friday. By 7:00 a.m. on the last business day 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, Veterans Day, Thanksgiving, Christmas Eve, and Christmas Day.

No later than 4:00 p.m. (Central Time) of the preceding day, the Company shall give its best efforts to make available to Customers the Day-Ahead Thermal Market Energy prices for the next business day. The Day-Ahead Thermal 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

The Company is not responsible for the Customer's failure to receive or obtain and act upon Day-Ahead Thermal 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 Thermal Market Energy prices at any time prior to the Customer's acceptance and will be responsible for notifying the Customer of such revised prices.

Because high-outage-risk circumstances may prevent the Company from projecting prices more than one day in advance, the Company reserves the right to revise and make available to the Customer 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.

PRICING METHODOLOGY: The Day-Ahead Thermal Market Energy prices will be determined for each day based on hourly MISO LMP at the Customer's CP Node, Network Integration Transmission Service (NITS) costs, customer charge, and other MISO charges incurred by the Company caused by the Customer's load.

The Company is not responsible for providing the Real-Time Thermal Market Energy prices to the Customer.

BILL DETERMINATION:

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

The monthly bill for Energy consumed up to and including the Baseline Demand(s) will be determined by multiplying the Customer's metered Energy consumption by the Energy rate provided in the rate schedule applicable to the Customer.

The monthly bill for Energy consumed above the Baseline Demand(s) will be determined by the MISO market settlements that occur at the Customer specific CP Node plus associated NITS charges and applicable riders.

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.

ESA Components: Incremental fixed and/or variable service costs to maintain net benefits as set in ESA.

PENALTY FOR INSUFFICIENT LOAD CONTROL: Upon notification from the Company, the Customer shall curtail its Demand to its Firm Demand. In the event the Customer fails to curtail its load as requested by the Company, the Customer shall be responsible for any and all costs and/or penalties incurred by the Company as a result of the Customers’ failure to curtail. The duration and frequency of curtailments shall be at the sole discretion of the Company unless otherwise provided in the ESA between the Company and the Customer.

ENERGY ADJUSTMENT RIDER: Energy consumed up to and including the Baseline Demand(s) is subject to the Energy Adjustment Rider as provided in Section 13.01, or any amendments or superseding provisions applicable thereto. Because Energy consumed above the Baseline Demand(s) is subject to the Thermal Market Energy prices, it is not subject to the Energy Adjustment Rider as provided for in Mandatory Riders – Applicability Matrix, Section 13.00.

SPECIAL PROVISIONS: If there is a change in the legal identity of the Customer receiving service under this Thermal Market Energy Pricing Rider, service shall be terminated unless the Company and the Customer make other mutually agreeable arrangements.

Section 14.16 RESERVED FOR FUTURE USE~~***CANCELLED***~~
~~THERMAL MARKET ENERGY PRICING RIDER~~

~~DESCRIPTION~~	~~RATE CODE~~
~~Transmission Service~~	~~N657~~
~~Primary Service~~	~~N658~~
~~Secondary Service~~	~~N659~~

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

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

~~**TERM OF SERVICE:** Service under this rider shall be for a period not less than one year. The Customer shall take service under this rider by either signing a new electric service agreement (ESA) with the Company or by entering into amendments of existing ESA that covers new Energy requirements that sets forth, among other things, the Customer's Billing Demand(s), firm Demand, and Baseline Demand(s). The ESA must address incremental fixed and/or variable service costs necessary to provide service to the Customer and maintain net benefits. 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 voluntary basis only to new greenfield customers and locations that use thermal storage technology, have a Demand of at least 25 MW, and have a load factor less than 50 percent. The Customer's entire thermal load must be registered as a load modifying resource in Midcontinent Independent System Operator (MISO) and take service coincident with and not to exceed the hourly generating output of a nearby specifically identified wind and/or solar generation resource that is not owned by the Company. MISO must have established a new Asset Owner and Commercial Pricing Load Node (CP Node) associated with the Customer's load for market settlement purposes.~~

~~The Customer will have no behind the Meter generation except for emergency backup purposes.~~

Section 14.16 RESERVED FOR FUTURE USE

~~**METERING REQUIREMENTS:** Company approved metering equipment capable of providing load interval information is required for Rider participation. The Customer agrees to pay for the additional cost of such metering when not provided in conjunction with existing retail electric service.~~

~~**CUSTOMER EQUIPMENT:** Customers taking service under this Rider shall provide equipment to maintain a power factor at a level no less than the level at which power factor penalties would be invoked under the Tariff, if applicable.~~

~~**LIABILITY:** The Company and the Customer agree that the Company has no liability for indirect, special, incidental, or consequential loss or damages to the Customer, including but not limited to the Customer's operations, site, production output, or other claims by the Customer as a result of participation in this Rider.~~

~~**BASELINE DEMAND(S):** The Baseline Demand(s) is used to produce the Standard Bill and from which to measure changes in consumption for purposes of billing under the Thermal Market Energy Pricing Rider. It is specific to each Thermal Market Energy Pricing Rider Customer and is a representation of its typical pattern of electricity consumption. The Customer Baseline Demand(s) is designated through a Customer's ESA and allows the Company to curtail the participating Customer's load to an established Firm Demand.~~

~~The Customer's Baseline Demand(s) must be agreed to in writing by the Customer as a precondition of receiving service under this rider.~~

~~**CUSTOMER CHARGE:** A customer charge in the amount of $282.00 will be applied to each monthly bill to cover billing, administrative, metering, and communication costs associated with market pricing, plus any other applicable Tariff charges.~~

~~**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 7:00 a.m. the previous Friday. By 7:00 a.m. on the last business day 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, Veterans Day, Thanksgiving, Christmas Eve, and Christmas Day.~~

Section 14.16 RESERVED FOR FUTURE USE

~~No later than 4:00 p.m. (Central Time) of the preceding day, the Company shall give its best efforts to make available to Customers the Day-Ahead Thermal Market Energy prices for the next business day. The Day-Ahead Thermal 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~~

~~The Company is not responsible for the Customer's failure to receive or obtain and act upon Day-Ahead Thermal 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 Thermal Market Energy prices at any time prior to the Customer's acceptance and will be responsible for notifying the Customer of such revised prices.~~

~~Because high-outage-risk circumstances may prevent the Company from projecting prices more than one day in advance, the Company reserves the right to revise and make available to the Customer 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.~~

~~**PRICING METHODOLOGY:** The Day-Ahead Thermal Market Energy prices will be determined for each day based on hourly MISO LMP at the Customer's CP Node, Network Integration Transmission Service (NITS) costs, customer charge, and other MISO charges incurred by the Company caused by the Customer's load.~~

~~The Company is not responsible for providing the Real-Time Thermal Market Energy prices to the Customer.~~

~~**BILL DETERMINATION:**~~

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

~~The monthly bill for Energy consumed up to and including the Baseline Demand(s) will be determined by multiplying the Customer's metered Energy consumption by the Energy rate provided in the rate schedule applicable to the Customer.~~

Section 14.16 RESERVED FOR FUTURE USE

~~The monthly bill for Energy consumed above the Baseline Demand(s) will be determined by the MISO market settlements that occur at the Customer specific CP Node plus associated NITS charges and applicable riders.~~

~~**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.~~

~~**ESA Components:** Incremental fixed and/or variable service costs to maintain net benefits as set in ESA.~~

~~**PENALTY FOR INSUFFICIENT LOAD CONTROL:** Upon notification from the Company, the Customer shall curtail its Demand to its Firm Demand. In the event the Customer fails to curtail its load as requested by the Company, the Customer shall be responsible for any and all costs and/or penalties incurred by the Company as a result of the Customers' failure to curtail. The duration and frequency of curtailments shall be at the sole discretion of the Company unless otherwise provided in the ESA between the Company and the Customer.~~

~~**ENERGY ADJUSTMENT RIDER:** Energy consumed up to and including the Baseline Demand(s) is subject to the Energy Adjustment Rider as provided in Section 13.01, or any amendments or superseding provisions applicable thereto. Because Energy consumed above the Baseline Demand(s) is subject to the Thermal Market Energy prices, it is not subject to the Energy Adjustment Rider as provided for in Mandatory Riders – Applicability Matrix, Section 13.00.~~

~~**SPECIAL PROVISIONS:** If there is a change in the legal identity of the Customer receiving service under this Thermal Market Energy Pricing Rider, service shall be terminated unless the Company and the Customer make other mutually agreeable arrangements.~~

Section 14.16 RESERVED FOR FUTURE USE **N**
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Section 14.16 RESERVED FOR FUTURE USE

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Section 14.16 RESERVED FOR FUTURE USE

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