Redline Versions of Rate Schedules

LARGE GENERAL SERVICE – TIER I
(at least 200 kW but less than 25,000 kW~~or greater~~)

DESCRIPTION	RATE CODE
Secondary Service	S603
Primary Service	S602
Transmission Service	S632

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

APPLICATION OF SCHEDULE: This schedule is applicable to nonresidential Customers with a measured Demand of 200 kW or greater as further described in Terms and Conditions. This schedule is not applicable for Energy resale, nor for dusk to dawn outdoor lighting. Emergency and supplementary/standby service will be supplied only as allowed by law.

RATE:

SECONDARY SERVICE		
Customer Charge per Month:	$218.00	
Monthly Minimum Bill:	Customer + Facilities + Demand Charges	
Facilities Charge per Month per annual Maximum kW: (minimum 200 kW):		
<1000 kW	$0.75	/kW
>= 1000 kW	$0.65	/kW
Energy Charge per kWh:	$0.04309	/kWh
Demand Charge per kW/month: (minimum 200 kW)	$6.00	/kW

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PRIMARY SERVICE

Customer Charge per Month:	$282.00	
Monthly Minimum Bill:	Customer + Facilities + Demand Charges	
Facilities Charge per Month per annual Maximum kW: (minimum 200 kW)		
All kW	$0.45	/kW
Energy Charge per kWh:	$0.04190	/kWh
Demand Charge per kW/month: (minimum 200 kW)	$5.74	/kW

TRANSMISSION SERVICE

Customer Charge per Month:	$282.00	
Monthly Minimum Bill:	Customer + Facilities + Demand Charges	
Facilities Charge per Month per annual Maximum kW: (minimum 200 kW)		
All kW	$0.00	/kW
Energy Charge per kWh:	$0.04052	/kWh
Demand Charge per kW/month: (minimum 200 kW)	$3.60	/kW

(Continued)

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 schedule. See Sections 12.00, 13.00 and 14.00 of the South Dakota electric rates for the matrices of riders.

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 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 and does not exceed 25,000 kW for more than two of the most recent 12 months~~or the Customer is taking Transmission Service~~.

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 the General Service (Section 10.02) in the next billing month (unless the Customer requests to be on General Service – Time of Day (Section 10.03)).

~~2.~~3. If the Customer meets or exceeds 25,000 kW for more than two of the most recent 12 months, the Customer will be placed on Large General Service – Tier II – Time of Day (Section 10.06) in the next billing month.

DETERMINATION OF EXCESS REACTIVE DEMAND: For billing purposes, the Metered Demand may be increased by one kW for each whole 10 kVar of measured Reactive Demand in excess of 50% of the Metered Demand in kW.

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

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

LARGE GENERAL SERVICE – TIER I – TIME OF DAY

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

DESCRIPTION	RATE CODE
Secondary Service	S611
Primary Service	S610
Transmission Service	S639

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

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 ~~or greater~~ as further described in Terms and Conditions. This schedule is not applicable for Energy resale, nor dusk to dawn outdoor lighting. Emergency and supplementary/standby service will be supplied only as allowed by law.

RATE:

SECONDARY SERVICE		
Customer Charge per Month:	$218.00	
Monthly Minimum Bill:	Customer + Facilities + Demand Charges	
Facilities Charge per Month per annual Maximum kW: (minimum 200 kW)		
< 1000 kW	$0.80	/kW
>= 1000 kW	$0.70	/kW
Energy Charge per kWh:		
On-Peak	$0.04854	/kWh
Mid-Peak	$0.04220	/kWh
Off-Peak	$0.02811	/kWh
Demand Charge per kW/month:		
(minimum 200 kW)		
On-Peak	$7.75	/kW
Mid-Peak	$3.50	/kW
Off-Peak	N/A	

(Continued)

PRIMARY SERVICE		
Customer Charge per Month:	$282.00	
Monthly Minimum Bill	Customer + Facilities + Demand Charges	
Facilities Charge per Month per annual Maximum kW: (minimum 200 kW)	$0.47	/kW
Energy Charge per kWh:		
On-Peak	$0.04688	/kWh
Mid-Peak	$0.04081	/kWh
Off-Peak	$0.02716	/kWh
Demand Charge per kW/month:		
(minimum 200 kW)		
On-Peak	$7.40	/kW
Mid-Peak	$3.30	/kW
Off-Peak	$0.00	/kW

TRANSMISSION SERVICE		
Customer Charge per Month:	$282.00	
Monthly Minimum Bill:	Customer + Facilities + Demand Charges	
Facilities Charge per Month per annual Maximum kW: (minimum 200 kW)	$0.00	/kW
Energy Charge per kWh:		
On-Peak	$0.04555	/kWh
Mid-Peak	$0.03969	/kWh
Off-Peak	$0.02644	/kWh
Demand Charge per kW/month:		
(minimum 200 kW)		
On-Peak	$5.05	/kW
Mid-Peak	$1.90	/kW
Off-Peak	$0.00	/kW

(Continued)

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 schedule. See Sections 12.00, 13.00 and 14.00 of the South Dakota electric rates for the matrices of riders.

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 ~~the~~ 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~~ or the Customer is taking Transmission sService~~.

2. ~~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 the 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)).

~~2.~~3. If the Customer exceeds 25,000 kW for more than two of the most recent 12 months, the Customer will be placed on the Large General Service – Tier II – Time of Day (Section 10.06) in the next billing month.

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.

DETERMINATION OF EXCESS REACTIVE DEMAND: For billing purposes, the Metered Demand may be increased by one kW for each whole ten 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 1) 200kW or 2) the Metered Demand adjusted for Excess Reactive Demand.

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

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DEFINITION OF ON-PEAK, MID-PEAK AND OFF-PEAK PERIODS BY SEASON:
Summer and winter months are defined in the Glossary, Section 8.01.

Winter:

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 5:00 a.m. to 7:00 a.m. and, 10:00 a.m. to 9:00 p.m.

Off-Peak: For all kW and kWh used Monday through Friday between hours 9:00 p.m. to 5:00 a.m. and all weekend hours.

Summer:

On-Peak: For all kW and kWh used Monday through Friday between hours 2:00 p.m. to 8:00 p.m.

Mid-Peak: For all kW and kWh used Monday through Friday between hours 12:00 p.m. to 2:00 p.m., 8:00 p.m. to 10:00 p.m., and on weekends between hours 2:00 p.m. to 8:00 p.m.

Off-Peak: For all kW and kWh used Monday through Friday between hours 10:00 p.m. to 12:00 p.m. and on weekends between hours 8:00 p.m. to 2:00 p.m.

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~~SUPER~~ LARGE GENERAL SERVICE – TIER II – TIME OF DAY (at least 25,000kW)~~APPLICATIONS AND ELIGIBILITY REQUIREMENTS~~

DESCRIPTION	RATE CODE
Primary Service	S641~~18~~
Transmission Service	S665~~20~~

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 nonresidential~~greenfield~~ Customers with a measured Demand of at least 25,000 kW or greater as further described in Terms and Conditions~~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, nor dusk to dawn outdoor lighting. 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 South 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.~~

PRIMARY SERVICE					
-	-	-	-	-	-
Customer Charge per Month:			$282.00		

(Continued)

Monthly Minimum Bill	Customer + Facilities + Demand Charges	
Facilities Charge per Month per annual Maximum kW: (minimum 200 kW)	$0.47	/kW
Energy Charge per kWh:		
On-Peak	$0.04688	/kWh
Mid-Peak	$0.04081	/kWh
Off-Peak	$0.02716	/kWh
Demand Charge per kW/month: (minimum 25,000 kW)		
On-Peak	$7.40	/kW
Mid-Peak	$3.30	/kW
Off-Peak	$0.00	/kW

(Continued)

RATE:

TRANSMISSION SERVICE		
Customer Charge per Month:	$282.00	
Monthly Minimum Bill:	Customer + Facilities + Demand Charges	
Facilities Charge per Month per annual Maximum kW: (minimum 25,000 kW)	$0.00	/kW
Energy Charge per kWh:		
On-Peak	$0.04555	/kWh
Mid-Peak	$0.03969	/kWh
Off-Peak	$0.02644	/kWh
Demand Charge per kW/month: (minimum 25,000 kW)		
On-Peak	$5.05	/kW
Mid-Peak	$1.90	/kW
Off-Peak	$0.00	/kW

~~**COMMISSION APPROVAL PROCESS:** This rate schedule allows the Company to respond to service inquiries by providing potential Customers rate quotes and final rates based on a rate formula reviewed by Commission Staff. 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). However, Staff review of the rate formula and rate quotes does not preclude Commission review and approval. The Company will file the Customer's executed ESA as a contract with deviations for Commission approval.~~

~~**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.~~

(Continued)

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 schedule. See Sections 12.00, 13.00 and 14.00 of the South 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.~~ A Customer with a Billing Demand equal to or greater than 25,000 kW for more than two of the most recent 12 months will be required to take service under Large General Service Tier II – Time of Day (Section 10.06). The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 25,000 kW for more than two of the most recent 12 months or the Customer is taking Transmission or Primary Service.~~The minimum rate under this schedule shall recover 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 ensure that the revenue requirement of other Customers will not increase due to the addition of the new large load.~~

~~2.~~

~~3.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.~~

~~4.~~

~~5.~~1.~~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.~~

~~6.~~2.If the Customer does not achieve an actual Billing Demand of more than or equal to 25,000 kW for more than two of the most recent 12 months, the Customer will be placed on the Large General Service – Tier I - Time of Day (Section 10.05) in the next billing month.

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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.~~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.~~

DETERMINATION OF EXCESS REACTIVE DEMAND: For billing purposes, the Metered Demand may be increased by one kW for each whole ten 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 1) 25,000kW or 2) the Metered Demand adjusted for Excess Reactive Demand.

DETERMINATION OF FACILITIES CHARGE: The Facilities Charge Demand will be based on the greater of 25,000 kW or the largest kW of the most recent 12 monthly Billing Demand.

DEFINITION OF ON-PEAK, MID-PEAK AND OFF-PEAK PERIODS BY SEASON: Summer and winter months are defined in the Glossary, Section 8.01.

Winter:

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

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Mid-Peak: For all kW and kWh used Monday through Friday between hours 5:00 a.m. to 7:00 a.m. and, 10:00 a.m. to 9:00 p.m.

Off-Peak: For all kW and kWh used Monday through Friday between hours 9:00 p.m. to 5:00 a.m. and all weekend hours.

Summer:

On-Peak: For all kW and kWh used Monday through Friday between hours 2:00 p.m. to 8:00 p.m.

Mid-Peak: For all kW and kWh used Monday through Friday between hours 12:00 p.m. to 2:00 p.m., 8:00 p.m. to 10:00 p.m., and on weekends between hours 2:00 p.m. to 8:00 p.m.

Off-Peak: For all kW and kWh used Monday through Friday between hours 10:00 p.m. to 12:00 p.m. and on weekends between hours 8:00 p.m. to 2:00 p.m.

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

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~~SUPER~~ LARGE GENERAL SERVICE – MARGINAL RATE
APPLICATIONS AND ELIGIBILITY REQUIREMENTS

DESCRIPTION	RATE CODE
Primary Service	S618
Transmission Service	S620

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 South Dakota Customers and communities served by the Company.

The marginal cost estimates that form the basis of the ~~Super~~ Large General Service – Marginal ~~r~~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.

(Continued)

COMMISSION-APPROVAL PROCESS: This rate schedule allows the Company to respond to service inquiries by providing potential Customers rate quotes and final rates based on a rate formula reviewed by Commission Staff. 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). However, Staff review of the rate formula and rate quotes does not preclude Commission review and approval. The Company will file the Customer's executed ESA as a contract with deviations for Commission approval.

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 South 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 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 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.

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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.

LARGE GENERAL SERVICE – TIER III – HIGH POWER COMPUTE

DESCRIPTION	RATE CODE
Primary Service	S450
Transmission Service	S451

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.

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.

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.

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

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

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

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;

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

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

~~4.~~6. To the extent applicable, the Customer has or will register with the North American Electric Reliability Corporation (NERC) as a large load.

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

STUDY REQUIREMENTS: 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.

LENGTH OF CONTRACT FOR SERVICE: 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.

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.

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.

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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).

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.

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.

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.

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.

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.

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 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.

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.

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

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.

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).

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.

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.

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.

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.

(Continued)

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.

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.

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.

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.

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).

(Continued)

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.

Pricing Components of Monthly Charges:

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.

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.

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.

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.

~~1.~~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.

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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.

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:

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

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.

~~2.~~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.

(Continued)

BILLING: The Customer may choose either weekly billing, or monthly billing with estimated advance payment.

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:

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

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

~~1.~~3. 85% of Demand during the current month and previous 11 months.

SPECIAL PROVISIONS: 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.

COST ALLOCATION: 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.

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.

INCREMENTAL FACILITIES: 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.

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.

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:

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.

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).

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

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.

~~1.~~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.

(Continued)

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.

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.

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

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

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.

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.

~~2.~~11. The ESA shall include terms establishing who will be responsible for fuel procurement, and the nature of the fuel procurement procedures;

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

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

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.

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

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

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

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

~~1.~~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.

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.

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.

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

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.

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ATTACHMENT NO. 1
DEFINITIONS AND USEFUL TERMS

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.

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

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.

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.

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.

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

Contract Demand is 85% of the Contract Capacity.

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

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.

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.

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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.

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.

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.

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

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.

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

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

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.

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.

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

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.

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

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.

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.

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.

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.

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.

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.

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.

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.

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.

THERMAL MARKET ENERGY PRICING RIDER

DESCRIPTION	RATE CODE
Transmission Service	S657
Primary Service	S658
Secondary Service	S659

RULES AND REGULATIONS: Terms and condition of this tariff 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 South Dakota 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 specific 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.

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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.

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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.

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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.

ENERGY EFFICIENCY PARTNERSHIP RIDER: Energy consumed up to and including the Baseline Demand(s) is subject to the Energy Efficiency Partnership Rider as provided in Section 13.04, or any amendments or superseding provisions applicable thereto. Energy consumed above the Baseline Demand(s) is exempt from the Energy Efficiency Partnership 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.