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SCHEDULE 4
MULTIFAMILY RESIDENTIAL DEMAND RESPONSE WATER HEATER PILOT
NO NEW SERVICE (C)

PURPOSE

The Multifamily Residential Demand Response Water Heater Pilot is a demand response option for eligible Multifamily Properties. The objectives of the Multifamily Residential Demand Response Water Heater Pilot are:

- To quantify the energy consumption that can be shifted to different times from:
    - Water heaters equipped with a communication interface that supports Direct Load Control Events, or
    - Water heaters retrofitted with a control switch in the power supply to the tank
- To inform further the program design for a water heater demand response program;
- To determine an appropriate incentive level for Multifamily Property Owners and Residential Customers who choose to participate in a demand response program for water heaters;
- To integrate and test different technologies; and
- To implement different demand response dispatch strategies.

DEFINITIONS

Customer Override – The ability for the Residential Customer to temporarily suspend Direct Load Control for a period of 24 hours.

Direct Load Control – The means for a utility to remotely control an appliance. In terms of this pilot, direct load control allows the Company to control when the water heater uses electricity to heat water.

Direct Load Control Event – A period in which the Company will provide Direct Load Control.

Conventional Electric Resistance Water Heater – Multifamily Property Owners' existing electric resistant water heaters will be retrofitted to be demand response enabled. Water heaters that require replacement will be replaced with smart electric resistance water heaters with the approval of the Multifamily Property Owners.

Heat Pump Water Heater – Models compatible with the Company's available hardware, software, and communication technology that can engage in direct load control events.

AVAILABLE

In all territory served by the Company where the Company's demand response communication networks are available.

SCHEDULE 4 (Continued)

APPLICABLE

Subject to selection by the Company, Multifamily Property Owners may participate in the pilot. Residential Customers in multifamily residences (MFRs) will be the primary target of the pilot. In cases of rental properties, the pilot will be structured as an opt-out program, meaning Residential Customers will be automatically enrolled in the pilot if their Multifamily Property Owners enrolls in the pilot and the Residential Customer must withdraw from the program if they do not want to participate.

Residential Customers will be given notice about this pilot at the time of installation of the communication interface or at the start of their service. The Company will provide Residential Customers with information that they will be automatically enrolled in the pilot if they do not opt out. The notice will also provide the Residential Customer the contact information and instructions on how to opt out of the pilot at the time of installation or at the start of their service. If a Residential Customer chooses to opt out of this pilot, the installed communication interface and any other installed Company equipment will remain on the water heater. A Residential Customer that has elected to opt out will be removed from the dispatch of direct load control events. As new Residential Customers move into a participating MFR. The Company will be aware of a new Residential Customer based on customer data from the Company's Customer Information System (CIS). The number of eligible Residential Customers to participate in the pilot is 18,000 customer households. Residential Customers will remain on Schedule 7 and will be eligible for the incentives described in this schedule.

ELIGIBILITY

For MFRs, the Company will initially select large complexes, negotiating with Multifamily Property Owners or their property manager for the installation of retrofit devices as well as new demand response enabled water heaters. At the Company's discretion, the Company will select qualifying properties based on number of apartments, size of apartments, occupancy, and size of existing water heater.

DIRECT LOAD CONTROL EVENT

During the pilot there will be no limitation on the hours of Direct Load Control Events. This pilot will offer the ability for the Residential Customer to override a direct load control event, under the terms listed in Special Condition 4 of this pilot.

ENROLLMENT

Enrollment in this pilot will close to new participants after July 31, 2023. Unless this pilot is otherwise terminated, current MFRs and participating Residential Customers will remain enrolled in the pilot. **(C)**
(C)

SCHEDULE 4 (Continued)

INCENTIVES

Multifamily Property Owners or their property managers will receive an annual incentive in the form of: a monetary payment, and/or a specified number of replacement water heaters and/or, a monetary contribution toward water heater servicing/replacement costs. PGE will negotiate specifics with participating Multifamily Property Owners or their property managers based on their preferences. **(C)** **(C)** **(C)**

PGE will also incentivize the costs for new smart electric water heaters for Multifamily Property Owners or their property managers in situations when the existing water heater is too old to be retrofitted cost effectively and/or when an existing electric water heater fails. PGE will pay the incremental cost between a water heater with a standard six (6) year warranty and a qualifying smart water heater. Incentives should cover all or most of the cost difference between a standard electric water heater and a smart electric water heater. The incentive will substantially reduce the costs of making the water heater demand response enabled. **(C)** **(C)** **(T)**

The Residential Customer will also receive an incentive. The incentive that the Residential Customer receives may differ from the incentive of the Multifamily Property Owners or their property managers. The incentive amounts for each MFR, Multifamily Property Owners or their property managers will be determined based on the total number of demand response enabled water heaters installed or active participation levels in demand response events. **(C)** **(C)**

SCHEDULE 4 (Continued) (T)

SPECIAL CONDITIONS

Residential Customer (C)

1. The Residential Customer may terminate participation under this pilot voluntarily. The Residential Customer will not receive a participation incentive if they withdraw or are removed from the pilot. The Residential Customer must notify the Company to withdraw from the pilot. (C) (C)

2. If a Residential Customer withdraws or is removed from the pilot, the Residential Customer is not eligible for reenrollment during the pilot. (C)

3. If the Residential Customer moves from the enrolled residence during the term of the pilot, they are no longer eligible for the pilot. (C)

4. The Residential Customer may activate a 24-hour suspension from the pilot by notifying PGE through a pilot specific customer service phone number on the Company's website. A Residential Customer may be removed from the pilot if they implement the override option excessively; an example of excessive is override use for more than 100 days, or more than 15 days in any 30-day period. (C) (C)

5. To receive a participation incentive, the Residential Customer must respond to seasonal surveys regarding the pilot. (C) (C)

Company (C)

6. The Company has the right to remove a MFR or Residential Customer from the pilot at any time, for any reason. (C)

7. The Company is not responsible for any direct, consequential, incidental, punitive, exemplary, or indirect damages to the participating MFR, Multifamily Property Owners and their property managers, Residential Customer, or third parties that result from Direct Load Control Events. (C) (C)

8. Communication interfaces installed onto the water heater will remain the property of the Company before, during and after the conclusion of the pilot. (C)

9. The provisions of this schedule do not apply for any time period that the Company interrupts the Residential Customer's load for a system emergency or any other time that a Residential Customer's service is interrupted by events outside the control of the Company. (C) (C)

SCHEDULE 4 (Concluded)

DATA COLLECTION

In consideration for being allowed to participate in the Pilot, Multifamily Property Owners and Residential Customers agree that the Company or its representative may collect certain information from Multifamily Property Owners and Residential Customer's participation in the Pilot and use such information as described herein. Such information may include, but is not limited to, general energy usage and associated account and billing data (such information includes, but is not limited to, consumption and billing data, billing records, billing history, meter usage data, and rate information), name, email address, service address, account number, appliance serial number, activation date, runtime data, set-points, application and survey information. This data will be retained by the Company and its representatives for an indefinite amount of time. Multifamily Property Owners and Residential Customer agree that the Company and its Pilot representatives may use the information obtained through Pilot participation (a) to operate, administer, market, evaluate, analyze, change or improve the Pilot or utility services, (b) for the Company to prepare and present general, aggregated or anonymized results and information about the Pilot to third parties, including governmental entities such as the electricity system regulatory bodies, (c) for the Company to understand and evaluate participant habits and to inform the development and creation of utility programs and load planning, and (d) to inform Multifamily Property Owners and their property managers of irregularities associated with a given water heater. The Company and its Pilot representatives and agents will not use the data collected in the Pilot except as provided herein and will not otherwise disclose, transfer or sell this data.

TERM

The duration of this pilot is through July 31, 2025. **(C)**

SCHEDULE 5
RESIDENTIAL DIRECT LOAD CONTROL PILOT

PURPOSE

This direct load control pilot is a demand response option for eligible Residential Customers. The direct load control pilot offers incentives to allow the Company to control thermostats during Direct Load Control Events while providing a customer override. The Company provides advance notice to participating Customers for Direct Load Control Events. The pilot is expected to be conducted from December 1, 2015 through June 30, 2025. **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

This program is available to up to 80,000 eligible Residential (Schedule 7) Customers that elect to enroll and participate in the pilot. Customers will remain on Schedule 7 and will be eligible for the incentives described in this schedule. **(C)**

DEFINITIONS

<u>Central Air Conditioning</u> – Air conditioner tied into a central ducted forced air system.

<u>Direct Load Control</u> – A remotely controllable switch that allows the utility to operate an appliance, often by cycling. In terms of this pilot, direct load control allows the Company to change the set point or cycle the Customer's heating or cooling through the Customer's Qualified Thermostat to reduce the Customer's energy demand.

<u>Direct Load Control Event</u> – A period in which the Company will provide direct load control.

<u>Ducted Heat Pump</u> – Heat pump heating and cooling system hooked into a central ducted forced air system.

<u>Electric Forced Air Heating</u> – An electrical resistance heating system tied into a central ducted forced air system.

<u>Event Notification</u> – The Company will issue a notification of a Direct Load Control Event to participating Customers. Notification methods may include email, text, auto-dialer phone call, on thermostat display screen, or via mobile app notification. Notification may also be available on the Company's website. **(C)**

<u>Event Season</u> – The pilot has two event seasons: the Summer Event Season and the Winter Event Season.

SCHEDULE 5 (Continued)

DEFINITIONS (Continued)

Holidays – The following are holidays for purposes of the pilot: New Year’s Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

Qualified Thermostat – Thermostats that are Company-approved and listed on PortlandGeneral.com.

Summer Event Season – The summer event season includes the successive calendar months June through September.

Winter Event Season – The winter event season includes the successive calendar months December through February.

ELIGIBILITY

Eligible Customers must have a Network Meter and connectivity to the internet. To participate in the Winter Event Season, the Customer must have a Ducted Heat Pump or Electric Forced Air Heating. To participate in the Summer Event Season, the Customer must have Central Air Conditioning or a Ducted Heat Pump.

DELIVERY CHANNEL

BRING YOUR OWN THERMOSTAT

This delivery channel allows the Customer to use their Qualified Thermostat, which must be connected to the internet and the heating or cooling system, all at the Customers’ expense, to participate in Direct Load Control Events and receive incentives. Participating Customers receive a one-time payment of up to $105 for signing up for this delivery channel. In addition, Customers receive $25 for each Event Season they participate. A Customer participating in all Event Seasons receive up to $155 for the first participating year and $50 for additional years. Incentives are paid to the Customer with a check, bill credit, generic gift card, or credit. To receive payment for an Event Season, the Customer must participate in at least 50% of the event hours for which the Customer is eligible to participate in that Event Season. **(C)**

SCHEDULE 5 (Continued)

DELIVERY CHANNEL (Continued)

RESIDENTIAL THERMOSTAT DIRECT INSTALLATION – NO NEW SERVICE **(C)**

(N) As of May 30, 2022, this delivery channel will be closed to new Customers. Existing Customers enrolled in the pilot through this channel will continue to be governed by the incentive and participation structure defined below until they have successfully participated in Direct Load Control events for five years, at which time, they will be eligible to receive seasonal incentives. Thermostat installations will be warrantied for one year. **(N)**

This delivery channel allows Customers who own a qualifying Ducted Heat Pump, Electric Forced Air Heating, and/or Central Air Conditioner but do not own a Qualified Thermostat to participate by receiving one from the Company.

The Company will provide the following to Eligible Customers within the participation cap:

- For those Customers with a Ducted Heat Pump or Electric Forced Air, with or without Central Air Conditioner system, a connected thermostat that is installed, provisioned, and enrolled into PGE's demand response platform at no additional charge; or

- For those Customers with a Central Air Conditioner, for a fee up to $150, a connected thermostat that is installed, provisioned, and enrolled into PGE's demand response platform.

PGE may, at a later date, apply a mechanism to recover labor and materials costs if the Customer opts-out of more than 50% of the event hours in an Event Season or the Customer removes the enrolled thermostat. The Customer may be charged up to the following:

Participation Year Customer Opts-Out	Customer Payback of Thermostat Labor & Materials
1	100%
2	80%
3	60%
4	40%
5	20%
6	0%

If, a Customer returns the working qualified thermostat within 90 days of installation, they are not charged for the cost of the thermostat and are only charged for the labor associated with installing the thermostat.

SCHEDULE 5 (Continued)

DIRECT LOAD CONTROL EVENT

Direct Load Control Events occur for one to five hours. The Company may call two events per day but will not exceed five cumulative hours for the day. During Direct Load Control Events the Customer may allow the Company to control their thermostat for the duration of the event. The Customer has the option not to participate by overriding via the thermostat. The Company initiates Direct Load Control Events with Event Notification. The Company will call Direct Load Control Events only in the following months: December, January, February, June, July, August, and September. Direct Load Control Events will not be called on Holidays. Reasons for calling events may include but are not limited to: energy load forecasted to be in the top 1% of annual load hours, forecasted temperature above 90 or below 32, expected high generation heat rates and market power prices, and/or forecasted low or transitioning wind generation. The Company will call no more than 150 event hours per Event Season. **(C)**

SPECIAL CONDITIONS

1. The Customer may enroll at any time but must participate for the minimum number of hours described in the delivery channel section.

2. The Customer may notify PGE they wish to terminate enrollment in the pilot at any time. PGE will unenroll the customer from the program within approximately one week of the request. The Customer may be charged additional costs described in the participating Customers enrolled delivery channel section. **(C) | (C)**

3. The Customer may opt-out of any Direct Load Control Event; however, if the Customer does not participate in at least 50% of Direct Load Control Events in an Event Season, the Customer may be charged additional costs described in the participating Customer's enrolled delivery channel section.

4. If a participating Customer is eligible for an incentive, it will be provided at the next billing statement after the event season ends. **(C)**

5. The Company will defer and seek recovery of all pilot costs not otherwise included in rates.

(D)

6. The Company is not responsible for any direct, consequential, incidental, punitive, exemplary, or indirect damages to the participating Customer or third parties that result from AC Cycling or changing the thermostat set point. **(T)**

7. The Company shall have the right to select the cycling schedule and the percentage of the Customer's heating or cooling systems to cycle at any one time, up to 100%, at its sole discretion. **(T)**

SCHEDULE 5 (Concluded)

SPECIAL CONDITIONS (Continued)

8. The provisions of this schedule do not apply for any period that the Company interrupts the Customer's load for a system emergency or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular service associated with the Customer's Schedule 7 charges and associated charges. **(T)**

9. PGE has the right to remove a Customer from the pilot when good cause is shown including, but not limited to, for poor customer responsiveness, consistent customer non-participation in called events, or issues with customer equipment that impact customer's participation. **(T)**

PERTAINING TO BRING YOUR OWN THERMOSTAT

1. Customers that reenroll in the program are not eligible for a second payment for signing up. A Customer continuing service at a new residence is not considered a new enrollment.

2. If the participating Customer moves to a different residence, the Customer may continue participation if the new residence meets the eligibility requirements.

PERTAINING TO RESIDENTIAL THERMOSTAT DIRECT INSTALLATION

1. Customers in the residential thermostat direct installation delivery channel are excluded from receiving thermostat incentives by the Energy Trust.

2. Customers will be eligible for seasonal incentives after completion of five years of successful participation, as described in the delivery channel section, in Direct Load Control Events. **(C)**

TERM

This pilot began December 1, 2015 and ends June 30, 2025. **(C)**

SCHEDULE 7
RESIDENTIAL SERVICE

PURPOSE

This schedule provides Standard and Optional Service choices for residential customers. Optional Services include a time of use (TOU) portfolio option, Peak Time Rebate, and Green Future[SM] renewable portfolio options.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

DEFINITIONS

Peak Time Rebate (PTR) Program – Customers choosing the PTR program are eligible to receive a rebate for reducing Energy use during Company-called events, relative to each Customer's baseline Energy use, as determined by the Company. See details below.

ENERGY PRICE PLANS (DEFAULT PLAN AND TIME-OF-USE PORTFOLIO OPTION)

RESIDENTIAL SERVICE PRICE PLAN (DEFAULT PLAN)

This default plan is provided to Residential Customers who do not choose the TOU Portfolio option price plan.

Monthly Rate

The default plan is priced as the totals of the following charges per Service Point (SP)*, **:

Basic Charge			
Single-Family Home	$11.00		
Multi-Family Home	$8.00		
Transmission and Related Services Charge	0.585	¢ per kWh	
Distribution Charge	5.447	¢ per kWh	(I)
Energy Charge**			
First 1,000 kWh	6.642	¢ per kWh	
Over 1,000 kWh	7.002	¢ per kWh	

* See Schedule 100 for applicable adjustments.
** As defined in Section Rule B of this tariff.

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: DEFAULT PLAN (Continued)

Peak Time Rebate Event Participation

Residential Customers on the default plan can also enroll and participate in PTR events. This option is available for enrollment to the first 160,000 Residential Customers. Customer enrollment will close once the program has 160,000 Residential Customers.

Monthly Rate

Customers on the default plan plus PTR will pay the default plan monthly rate – which includes Basic Charge, transmission and related services, and distribution charges. Energy Charges may also include the following PTR credit:

PTR Credit	100.00	¢ per kWh

To receive the PTR Credit, the Customer must reduce Energy use during a PTR Event. Such event will be a two- to five-consecutive-hour window between the hours of 7:00 AM to 11:00 AM or 3:00 PM to 8:00 PM. Events will not be called on holidays. Holidays are New Year's Day on January 1; Memorial Day, the last Monday in May; Independence Day on July 4; Labor Day, the first Monday in September; Thanksgiving Day, the fourth Thursday in November; and Christmas Day on December 25. If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

The PTR program has two event seasons: summer (the successive calendar months of June through September) and winter (successive calendar months of November through February). The Company will call PTR events only in event seasons. Prior to each season, the Company will remind the enrolled Customers that they are on the program, that they may participate in PTR events, and ways to be successful.

The Company initiates PTR events with an event notification to participating Customers the day prior to the PTR event. Participating Customers must choose at least one method for receipt of notification: email, text, or another available option. The Company will not call PTR events for more than two consecutive days. Reasons for calling events may include but are not limited to: Energy load forecasted to be in the top 1% of annual load hours, forecasted temperature above 90 or below 32, expected high generation heat rates and market power prices, and/or forecasted low or transitioning wind generation.

Special Conditions Related to Peak Time Rebate Options (M)

1. To be eligible for a PTR credit, the Customer must agree to receive PTR notifications.

2. The Customer may unsubscribe from the PTR event notification at any time. If the Customer unsubscribes, they will receive credit only for those events for which they are enrolled and receive notifications. (M)

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: DEFAULT PLAN (Continued)

Special Conditions Related to Peak Time Rebate Options (Continued)

3. The PTR incentive may be provided in an on-bill credit on the Customer's next monthly billing statement or by check at the next billing statement after the event season ends.

4. Customers enrolled in Schedule 5 Direct Load Control are not eligible to participate in PTR on this schedule.
(D)
5. The Company will defer and seek recovery of all PTR costs not otherwise included in rates. (T)

TIME-OF-USE PORTFOLIO OPTION (WHOLE PREMISES OR ELECTRIC VEHICLE CHARGING) (Enrollment is necessary)

This option provides TOU pricing for transmission and related services, distribution and energy*.

Monthly Rate

Basic Charge		
Single-Family Home	$11.00	
Multi-Family Home	$8.00	
On-Peak Charge	32.800	¢ per kWh
Transmission and Related Services	1.800	¢ per kWh
Distribution	15.500	¢ per kWh
Energy	15.500	¢ per kWh
Mid-Peak Charge	11.915	¢ per kWh
Transmission and Related Services	0.520	¢ per kWh
Distribution	5.315	¢ per kWh
Energy	6.080	¢ per kWh
Off-Peak Charge	7.430	¢ per kWh
Transmission and Related Services	0.280	¢ per kWh
Distribution	2.700	¢ per kWh
Energy	4.450	¢ per kWh
Over 1,000 kWh block adjustment**	0.360	¢ per kWh

* See Schedule 100 for applicable adjustments.
** Not applicable to separately metered Electric Vehicle (EV) TOU option.

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: TOU PORTFOLIO OPTION (Continued)

On- and Off-Peak Hours

On-Peak	5:00 p.m. to 9:00 p.m. Monday-Friday
Mid-Peak	7:00 a.m. to 5:00 p.m. Monday-Friday;
Off-Peak	9:00 p.m. to 7:00 a.m. Monday-Friday;
	All day. Saturday, Sunday and holidays

Note: For Customers with Non-Network Meters, the time periods set forth above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November. Customers with Network Meters will observe the regular daylight-saving schedule.

Holidays are as follows: New Year's Day on January 1; Memorial Day, the last Monday in May; Independence Day on July 4; Labor Day, the first Monday in September; Thanksgiving Day, the fourth Thursday in November; and Christmas Day on December 25. If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

LEGACY TIME-OF-USE PORTFOLIO OPTION (WHOLE PREMISES OR ELECTRIC VEHICLE CHARGING)

This option provides TOU pricing for transmission and related services, distribution and Energy*.

Monthly Rate

Basic Charge			
Single-Family Home	$11.00		
Multi-Family Home	$8.00		
On-Peak Charge	22.261		(C)
Transmission and Related Services	0.960	¢ per kWh	
Distribution	8.934	¢ per kWh	
Energy	12.367	¢ per kWh	
Mid-Peak Charge	16.896		(C)
Transmission and Related Services	0.960	¢ per kWh	
Distribution	8.934	¢ per kWh	
Energy	7.002	¢ per kWh	
Off-Peak Charge	4.123		
Transmission and Related Services	0.000	¢ per kWh	
Distribution	0.000	¢ per kWh	
Energy	4.123	¢ per kWh	
First 1,000 kWh block adjustment**	(0.360)	¢ per kWh	

* See Schedule 100 for applicable adjustments.
** Not applicable to separately metered Electric Vehicle (EV) TOU option.

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: TOU PORTFOLIO OPTION (Continued)

On- and Off-Peak Hours **(M)**

Summer Months (begins May 1st of each year)

On-Peak	3:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	6:00 a.m. to 3:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and holidays

Winter Months (begins November 1st of each year)

On-Peak	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	10:00 a.m. to 5:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and holidays

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Note: For Customers with Non-Network Meters, the time periods set forth above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November. Customers with Network Meters will observe the regular daylight-saving schedule.

Holidays are as follows: New Year's Day on January 1; Memorial Day, the last Monday in May; Independence Day on July 4; Labor Day, the first Monday in September; Thanksgiving Day, the fourth Thursday in November; and Christmas Day on December 25. If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

Plug-In Electric Vehicle Time of Use Option

A Residential Customer wishing to charge Electric Vehicles (EVs) may do so either as part of Whole Premises Service (default plan or TOU Portfolio option) or as a separately metered service billed under the TOU option. In such cases, the applicable Basic, transmission and related services, and distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule (with the exception of the first 1000 kWh's block adjustment). Renewable Portfolio Options are also available under this EV option.

If the Customer chooses separately metered service for EV charging, the service shall be for the exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the Premises. Such service must be metered with a Network Meter as defined in Rule B (30) for the purpose of load research, and to collect and analyze data to characterize EV use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure. **(M)**

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: TOU PORTFOLIO OPTION (Continued)

Special Conditions Pertaining to Whole Premises and Electric Vehicle Time of Use Options

1. Service may be terminated at the next regularly scheduled meter reading provided the Company has received two weeks' notice prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. Participation requires a one-year commitment by the Customer. Generally, if a Customer requests removal from the TOU Option, the Customer will be required to wait 12 months before re-enrolling. However, a Customer may request to reinstate service within 90 days of termination, in which case the Portfolio Enrollment Charge will be waived.

3. The Customer must take service at 120/240 volts or greater.

4. The Customer must provide the Company access to the meter monthly.

5. After a Customer's initial 12 months of service on the TOU Option, the Company will calculate what the Customer would have paid under the default plan and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded the default plan Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount more than 10% either as a bill credit or refund check. No refund will be issued for Customers not meeting the 12-month requirement.

6. The Company may recover lost revenue from the TOU Option through Schedule 105.

7. Billing will begin for any Customer no later than the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date, assuming no meter exchange is required to enable the TOU rate.

8. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons.

GREEN FUTURE RENEWABLE PORTFOLIO OPTIONS

Customers can add any of the following Green Future Renewable Portfolio options to any service described in this schedule: renewable fixed option, renewable usage option, and renewable habitat option adder (Habitat Support). **(C)**

The Customer will be charged for the Green Future Renewable Portfolio option in addition to all other charges under this schedule for the term of enrollment in the Green Future Renewable Portfolio option.

SCHEDULE 7 (Continued)

GREEN FUTURE RENEWABLE PORTFOLIO OPTIONS (Continued) **(T)**

Energy or Renewable Energy Certificates (RECs), as defined in Rule B of this tariff, will be acquired by the Company such that by March 31 of the succeeding year, the Company will have received sufficient RECs or renewable energy to meet the purchases by Customers. For the renewable fixed and renewable usage options, the Company is not required to own renewables or to acquire Energy from renewable resources simultaneously with Customer usage. **(C)** **(C)**

For purposes of these options, renewable resources include wind, solar, biomass, low impact hydro (as certified by the Low Impact Hydro Institute) and geothermal energy sources used to produce electric power. All RECs will be Green-e® Energy certified by the Center for Resource Solutions (CRS).

RENEWABLE FIXED OPTION

The Company will use funds received under this option to cover program costs and purchase 200 kWh of RECs and/or renewable energy per block enrolled in the renewable fixed option. All RECs purchased under this option will come from new renewable resources.

The Company will also place any funds not spent after covering program and REC costs received from Customers enrolled in this option in a renewable resources development and demonstration fund ("Renewable Development Fund" or "RDF"). See Special Conditions for additional details on the RDF.

Monthly Rate

Renewable Fixed Option	$1.88	per month per block

SCHEDULE 7 (Continued)

GREEN FUTURE RENEWABLE PORTFOLIO OPTIONS (Continued)

RENEWABLE USAGE OPTION

Amounts received from Customers under the renewable usage option will be used to cover program costs and acquire RECs and/or Energy, all of which will come from new renewable resources.

The Company will place any funds received from Customers enrolled in this option that are not spent after covering program and REC costs in a renewable resources development and demonstration fund (“Renewable Development Fund” or “RDF”). See Special Conditions for additional details on the RDF.

Monthly Rate

Renewable Usage Option	0.940	¢ per kWh in addition to Energy Charge

(D)

SCHEDULE 7 (Continued)

GREEN FUTURE RENEWABLE PORTFOLIO OPTIONS (Continued)

RENEWABLE HABITAT OPTION ADDER (HABITAT SUPPORT)

The Company will distribute $2.50 per month as received from each Customer enrolled in habitat support to a nonprofit agency chosen by the Company who will use the funds for habitat restoration.

Available

Only Customers who are enrolled in a Green Future Renewable Portfolio option, described in this schedule, may choose habitat support.

Monthly Rate

Habitat Support	$2.50	per month

SPECIAL CONDITIONS RELATED TO GREEN FUTURE RENEWABLE PORTFOLIO OPTIONS

1. Service will become effective with the next regularly scheduled meter reading date provided the Customer has selected the option at least five days prior to their next scheduled meter read date. Absent the five-day notice, the change will become effective on the subsequent meter read date. Service may be terminated at the next regularly scheduled meter reading provided the Company has received two weeks' notice prior to the meter read date. Absent the two-week notice, the termination will occur with the subsequent meter reading date.

2. The Company, in its discretion, may accept participation from accounts that have a time payment agreement in effect, or have received two or more final disconnect notices. However, the Company will not accept participation from customers that have been **(C)**
involuntarily disconnected in the last 12 months due to non-payment. **(C)**

3. The Company will use reasonable efforts to ensure energy assistance dollars from the Oregon Low Income Home Energy Assistance Program (LIHEAP) and Oregon Energy Assistance Program (OEAP) assistance programs are not used to cover Green Future program participation during the time which participants receive these energy assistance funds. As such, PGE will unenroll Customers from the Green Future program if they receive energy assistance funds from LIHEAP and OEAP. If these energy assistance dollars are no longer applied to the bill, the Customer may re-enroll in the program subject to the above requirements.

SCHEDULE 7 (Concluded)

SPECIAL CONDITIONS RELATED TO GREEN FUTURE RENEWABLE PORTFOLIO OPTIONS (Continued) **(T)**

4. The Company will use reasonable efforts to acquire renewable energy but does not guarantee the availability of renewable energy sources to serve Green Future Renewable Portfolio Options. The Company makes no representations as to the impact on the development of renewable resources or habitat restoration projects of Customer's participation. **(T)**

(D)

5. Amounts in the RDF will be disbursed by the Company to non-residential renewable resource demonstration projects or projects that commit to supply Energy according to a contractually established timetable. The Company will report to the Commission annually by March 15th, pursuant to Order No. 16-156, on collections and disbursements for the preceding calendar year. The annual report will include a list of projects that received or were allocated RDF funding. **(T)**

6. Amounts placed in the RDF prior to July 6, 2016 will accrue interest at the Commission-authorized cost of capital until disbursed. Amounts placed in the fund on and after July 6, 2016 will accrue interest at the Commission-authorized rate for deferred accounts in amortization until disbursed. Amounts within the fund will be disbursed on a first-in-first-out basis. Once funds have been committed to projects, following the required OPUC review, they will be deemed disbursed. Funds deemed disbursed and still held by the Company, will accrue interest at the Commission-authorized rate for deferred accounts in amortization. **(T)**

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 8
RESIDENTIAL ELECTRIC VEHICLE CHARGING PILOT

PURPOSE

This Residential Electric Vehicle Charging Pilot (Pilot) is applicable to Residential Customers who own or lease an Electric Vehicle (EV). The Pilot offers rebates for the purchase, installation, and/or integration of technologies that help manage and increase the flexibility of load associated with residential EV Charging. The Pilot is expected to operate from October 23, 2020 to December 31, 2025. **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

This Pilot is available to all eligible Residential Customers that elect to enroll and participate in the Pilot. Qualifying Customers will remain on Schedule 7 and be eligible for rebates and incentives described in this schedule. **(C)**

DEFINITIONS

Active Charging Session – A period of time during which an EV is plugged into an EVSE for the purposes of having electricity supplied to the vehicle through the EVSE.

Direct Load Control – A remotely controllable communication device that allows the utility to operate an appliance/equipment, often by cycling.

Electric Vehicle Supply Equipment (EVSE) – The device, including the cable(s), coupler(s), and embedded software, installed for the purpose of transferring alternating current electricity at 208 or 240 volts between the electrical infrastructure and the EV.

Event Notification – The Company may issue a notification of a Managed Charging Event to participating Customers. Notification methods may include email, text, auto-dialer phone call, or via mobile app notification.

Holidays – The following are holidays for purposes of the Pilot: New Year's Day (January 1), Martin Luther King Day (third Monday in January), Memorial Day (last Monday in May), **(C)** Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

SCHEDULE 8 (Continued)

DEFINITIONS (Continued)

Income-Eligible Customer – A verified Residential Customer at 120% or below the state median income as defined by the US Department of Housing Urban Development, or the home qualifies for Section 8 housing.

Managed Charging Event – A period during which the utility will provide Direct Load Control by sending communication signals to a customer's vehicle or EVSE to adjust the rate or time of charge.

Participation Year – Twelve consecutive months from the anniversary date of a Qualifying Customer's enrollment in the Smart Charging Program.

Qualifying Customer – A Residential Customer in an existing single-family residence, including separately metered residences with assigned parking, with a Qualified L2 EVSE (excludes new construction or multifamily property).

Qualified Level 2 Electric Vehicle Supply Equipment (L2 EVSE) – A pre-approved L2 EVSE that meets the program's connectivity and controllability criteria.

Vehicle Telematics - Device installed in a vehicle that allows the sending, receiving, and storing of telemetry data.

ELIGIBILITY

Eligible Customers must comply with the terms of the participation agreement and be a Qualifying Customer with either of the following.

A. Qualified L2 EVSE and agree to the following minimum participation requirements:
   (1) the Qualified L2 EVSE is successfully connected to the Smart Charging Program for at least 50% of the participation year,
   (2) the Qualified L2 EVSE participates in six Managed Charging Events, and
   (3) the Qualified L2 EVSE completes 25 Active Charging Sessions.
   Or
B. EV with Vehicle Telematics connected to an approved vehicle telematics provider and agreement to the following minimum participation requirements:
   (1) the connected EV participates in six Managed Charging Events,
   (2) the connected EV completes 25 Active Charging Sessions, and
   (3) the vehicle telematics provider's participation agreement.

ENROLLMENT

Qualifying Customers can enroll in the Pilot at PortlandGeneral.com through July 31, 2025. **(C)** Unless PGE terminates this Pilot, customers will remain enrolled in the Smart Charging Program for the entire Pilot term. Qualifying Customers that reenroll in the Pilot are not eligible for a second payment for installation of a single Qualified L2 EVSE. A Qualifying Customer continuing service at a new residence is not considered a new enrollment.

SCHEDULE 8 (Continued)

INCENTIVES

Qualifying Customers with more than one Qualifying L2 EVSE are eligible for the following incentives per each unique EV and EVSE pair during their participation in the Pilot:

Incentive	Description	Amount	
Standard EVSE Installation Rebate	A one-time rebate for the purchase and installation of a Qualified L2 EVSE. PGE will automatically enroll Qualifying Customers into the Smart Charging Program. Upon approval of rebate qualification, Qualifying Customers will receive the rebate in a manner allowed by the Company, including by check, bill credit, ACH, electronic payment, or an invoice credit and or through a payment by the Company to an authorized designee.	Up to $300; capped at price paid	**(C)** **(C)** **(C)**
Income-Eligible EVSE Installation Rebate	A one-time rebate for Income-Eligible Qualifying Customers for the purchase and installation of a Qualified L2 EVSE. PGE will automatically enroll Qualifying Customers into the Smart Charging Program. Upon approval of rebate qualification, Qualifying Income-Eligible Customers will receive the rebate by check, bill credit, ACH, electronic payment, or an invoice credit and or through a payment by the Company to an authorized designee.	Up to $1,000; capped at price paid	**(C)** **(C)**
Bring Your Own Charger Rebate	A one-time rebate for Qualifying Customers with an existing Qualified L2 EVSE at a Qualifying Home, who enroll in the Smart Charging Program.	Up to $50	
Vehicle Telematics Participation Incentive	A one-time incentive for the integration with a Vehicle Telematics provider. PGE will automatically enroll Qualifying Customers into the Smart Charging Program. Qualifying Vehicle Telematics Customers will receive the incentive by check or bill credit from the Company upon approval of rebate qualification.	Up to $50	**(C)**
Smart Charging Participation Incentive	For Qualifying Customers enrolled in the Smart Charging Program who participate in the minimum number of Managed Charging Events and Active Charging Sessions as described in this schedule. This incentive will be sent by check or as a bill credit within two billing cycles following the end of the interval period.	Up to $50 per participation year	

(M)

SCHEDULE 8 (Continued)

INCENTIVES (Continued)

Smart Charging Program Reconnection Incentive	A one-time promotional incentive to encourage Qualifying Customers who unenrolled (intentionally or unintentionally) from the Smart Charging Program to re-enroll. This offer is available once per participant and at the discretion of the Company.	Up to $25	(M) (M)
Standard Panel Upgrade Rebate	A one-time incentive to aid in the materials and electrical work necessary to upgrade participating customers' home electrical panels to 200A service in order to install a Qualified Level 2 EVSE. Customers must also be applying for a Standard EVSE Installation Rebate. Upon approval of rebate qualification, Qualifying Customers will receive the rebate in a manner allowed by the Company, including by check, bill credit, ACH, electronic payment, an invoice credit, or through a payment by the Company to an authorized designee. This incentive is available until the designated Panel Upgrade Rebate funding is exhausted.	Up to $1,000; capped at price paid.	(C) (C)
Income-Eligible Panel Upgrade Rebate	A one-time incentive to aid in the materials and electrical work necessary to upgrade participating customers' home electrical panels to 200A service in order to install a Qualified Level 2 EVSE. Customers must also be applying for an Income-Eligible EVSE Installation Rebate. Upon approval of rebate qualification, Qualifying Income-Eligible Customers will receive the rebate in a manner allowed by the Company, including by check, bill credit, ACH, electronic payment, an invoice credit, or through a payment by the Company to an authorized designee. This incentive is available until the designated Panel Upgrade Rebate funding is exhausted.	Up to $5,000; capped at price paid.	(C) (C)

MANAGED CHARGING EVENTS

Customers will be randomly assigned into one of three groups: A, B, or C. Group A will be the control group and will have no demand response tactics scheduled. Group B will participate in load shifting events where charging times will be shifted away from system peak periods. Group C will have their charging slowed or stopped during event periods. The Company will strive to maintain the equal number of participants and EVSE models in each group. Managed Charged Events may be called at any hour and any weekday excluding Holidays. During Managed Charging Events, the Customer will allow the Company to control their Qualified L2 EVSE or connected EV for the duration of the event. The Customer has the option not to participate by overriding via the manufacturer's or third party mobile application or website. (C)

SCHEDULE 8 (Concluded)

SPECIAL CONDITIONS

1. If a Qualifying Customer moves to a different residence, the customer may continue participation in the Smart Charing Program at the new residence if the Customer meets the eligibility requirements.

2. The Company will defer and seek recovery of all Pilot costs not otherwise included in rates.

3. The provisions of this schedule do not apply for any period that the Company interrupts the Qualifying Customer's load for a system emergency or any other time that a Qualifying Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular service associated with the Qualifying Customer's Schedule 7 charges and associated charges.

TERM

This pilot began October 23, 2020 and expires December 31, 2025. **(C)**

SCHEDULE 13
SMART GRID TESTBED PILOT (C)

PURPOSE

The Smart Grid Testbed Pilot (SGTB) is a first-of-its-kind research project meant to advance Portland General Electric's (PGE) collective understanding and development of demand response (DR) to gain insight into how PGE could provide a demand-side resource at scale in lieu of traditional supply-side resources. The second phase (Phase II) of the SGTB seeks to expand upon the research and planning conducted in Phase I, which concluded on December 31, 2022, to increase PGE's understanding of how customers perceive and value DR so that PGE may more effectively engage customers in flexible load efforts. All Phase I activities concluded December 31, 2022. (C) (C) (D)

To achieve these goals, PGE is piloting both the Test Bed Smart Solar Study (Smart Solar Study) and Test Bed EV Charging Study (EV Charging Study) demonstration projects. (N)

> Smart Solar Study: PGE will leverage customer owned "smart inverters" (those equipped with the IEEE 1547-2018 Standard) to assess the value of inverter-based controls to deliver distribution operations value (e.g., Volt/VAR support); address hosting capacity issues; and support orchestration of Distributed Energy Resources (DER) together with distributed solar and storage to minimize grid export. PGE will recruit customers with qualifying equipment by offering an upfront incentive in addition to an ongoing monthly incentive for continued enrollment throughout the project duration (January 2023 – December 2024).
>
> EV Charging Study: PGE will communicate with qualifying customer-owned electric vehicles (EV) to control the time of EV charging, while ensuring that the vehicles meet the operational needs of participants, and will evaluate customer acceptance of charge rate, charge time and Location-based Price Signals. Research in this project area will focus on improving understanding of the technical paths for charge management, costs, performance, and limitations. Customers within the EV Charging Study test bed with qualifying electric vehicles will opt in to receive an ongoing monthly incentive throughout the project duration (January 2023 – December 2024). (N)

DEFINITIONS

IEEE 1547-2018 Standard – The standard that establishes the criteria and requirements for interconnection of distributed energy resources with electric power systems and associated interfaces. (N)(D)

Electric Vehicle Service Equipment (EVSE) - The device, including the cable(s), coupler(s), and embedded software, installed for the purpose of transferring alternating current electricity at 208 or 240 volts between the electrical infrastructure and the EV. (N)(D)

SCHEDULE 13 (Continued)

DEFINITIONS (Continued)

Location-based Price Signals – The notification that a specific utility rate is being offered to a customer determined by their location an eligible territory, allowing the utility to drive customer participation to achieve specific load shifting or load reduction goals of the area or feeder. **(N)(D)**

(N)(D)

AVAILABLE

Each demonstration area will have a different and distinct project boundary based on research conducted in Phase I. PGE customers may be eligible to enroll in the SGTB demonstration projects if located within a testbed's geographic region as defined on PGE's Smart Grid Test Bed webpage. **(N)**

Each SGTB Phase II demonstration project will have different and distinct applicability as is defined on PGE's Smart Grid Test Bed webpage. An overview of the customers eligible for the demonstration projects is as follows:

> Smart Solar Study: Eligible Schedule 7 and Schedule 32 customers with interconnected photovoltaic (PV) systems behind the meter with qualifying smart inverters as defined on the SGTB webpage may elect to enroll in the project.
>
> EV Charging Study: Eligible Schedule 7 customers with a qualifying EV as defined on the SGTB webpage and a Level 2 EVSE may elect to enroll in the project. **(N)**

(D)

ENROLLMENT **(N)**

Qualifying customers can enroll in the Smart Solar Study and EV Charging Study demonstration projects through the Smart Grid Test Bed webpage until December 31, 2024. Unless PGE terminates these demonstration projects, customers will remain enrolled for the entire project term. Each demonstration project within the SGTB Phase II will be subject to its own enrollment cap of a maximum of 500 participants for the Smart Solar Study and a maximum of 500 participants for the EV Charging Study. **(N)**

(D)

INCENTIVES **(N)**

Customers participating in a demonstration project within the SGTB will continue to pay all fees and charges associated with their currently enrolled rate schedule. Customers can qualify for the following incentives based on the demonstration project(s) enrolled: **(N)**

SCHEDULE 13 (Concluded) (T)

INCENTIVES (Continued) (N) (D)

Smart Solar Study

Eligible participants will receive a $250 incentive paid at time of enrollment and will receive an additional ongoing incentive of $10 per month while enrolled. The monthly incentive will begin at the month of enrollment after the tariff effective date and will continue through the end of the demonstration period (December 2024) unless the customer chooses to unenroll.

To remain enrolled in the project and to continue to receive monthly incentives, the customer must maintain the connection of their smart inverter to their WiFi network and must continue to allow PGE to communicate with their system via the manufacturer's interface.

EV Charging Study

Eligible participants will receive an incentive of $20 per month while enrolled. The monthly incentive will begin at the month of enrollment after the tariff effective date and will continue through the end of the demonstration period (December 2024) unless the customer chooses to unenroll. Customers must first enroll in Schedule 8 and remain enrolled in the EV Charging Study demonstration to continue to receive monthly incentives. (N)

SPECIAL CONDITIONS

1. The Customer may unenroll from the Smart Grid Test Bed demonstrations at any time. If a Customer unenrolls, the Customer is not eligible to re-enroll during the pilot period. (C)(M)
2. At any time, PGE can interact with customer-owned equipment with intention to remotely adjust the device settings in accordance with project goals.
3. The participant will retain ownership of the PV system equipment and is responsible for all maintenance, replacement, and disposal costs.
4. Customers already enrolled in the Solar Payment Option are not eligible for the Smart Solar Study demonstration.
5. Incentives may be provided in an on-bill credit on the Customer's next monthly billing statement or by check issued by Energy Trust of Oregon.
6. PGE is not responsible for any direct, consequential, incidental, punitive, exemplary, or indirect damages to the participating Customer or third parties that result from performing direct load control on a participating appliance.
7. PGE shall have the right to select the schedule and the percentage of the Customer's appliance(s) to cycle at any one time, up to 100%, at its sole discretion.
8. PGE will defer and seek recovery of all pilot costs not otherwise included in customer prices.

TERM

Phase II of the Smart Grid Test Bed concludes on December 31st, 2027. The Smart Solar Study and EV Charging Study pilots will conclude on December 31st, 2024. (C)(M)(D)

SCHEDULE 14
RESIDENTIAL BATTERY ENERGY STORAGE PILOT

PURPOSE

This residential battery energy storage pilot will evaluate the ability of residential batteries to deliver services in support of PGE's electrical system. The battery energy storage pilot offers incentives to allow the Company to manage the charging and discharging of customer batteries with the option for a customer override. The pilot is expected to be conducted from August 1, 2020 through July 31, 2025.

AVAILABLE

In all territory served by the Company.

APPLICABLE

This program is applicable to Residential (Schedule 7) Customers that own a qualifying battery[1] and elect to enroll and participate in the pilot. Customers will remain on Schedule 7 and will be eligible for the incentives described in this schedule. The pilot is optional and limited to a total of 9,480 kWh enrolled energy storage. **(C)** **(C)**

ELIGIBILTY

Customers must submit an interconnection application which must be approved by PGE, purchase or already own a qualifying battery, proceed with installation, and apply for acceptance into the pilot.

ENROLLMENT

Customers will be allowed to enroll in this pilot until the pilot reaches its maximum enrollment of 9,480 kWh of enrolled energy storage. Unless this pilot is otherwise terminated, participating Customers will be enrolled for the entire pilot term. **(C)**

INCENTIVES

Basic Offering

Available to customers who have a qualifying battery and allow PGE to manage the charging and discharging of such equipment for the benefit of PGE's electric system. A customer shall receive $1.70 per kWh that is dispatched by PGE. A customer shall inform PGE when they enroll in the program the maximum kWh PGE may dispatch from their device during an event. A customer may change their maximum nomination by contacting PGE in writing, allowing a minimum of three business days for the change to take effect. **(C)** **(C)**

1. A list of approved qualifying battery storage systems for this pilot is available on PortlandGeneral.com

SCHEDULE 14 (Continued)

INCENTIVES (Continued)

Test Bed Rebate **(D)**

1. Available only to customers who are participating in PGE's SALMON initiative or the Reeds Crossing Solarize campaign, both as defined on PGE's website regarding the "Smart Battery Pilot"; who purchase a new qualifying battery, and allow PGE to manage the charging and discharging of such equipment for the benefit of PGE's electric system. **(C)** **(C)**

2. PGE shall provide a rebate for the new purchase and installation of a qualifying battery storage system. The new purchase rebate is limited to 960 kWh of nominated energy storage. The rebate amount shall be $405 per kWh of energy storage nominated to PGE to be directly dispatchable by PGE. **(C)** **(C)**

3. The rebate level will be reserved for a customer for nine months from when the pilot application is approved to when the battery storage system is operable by PGE and enrolled in this pilot. If the battery storage system does not begin communications with PGE within nine months of pilot application approval, the customer's reserved rebate will be released. When communications are established the customer may receive the incentive, if still available. **(T)** **(C)**

4. A customer receiving a Test Bed Rebate is not eligible to also receive the Basic Offering. **(N)**

5. The Test Bed Rebate is based on the maximum kWh a customer elects to make available to PGE during a peak event dispatch (referred to as the "nomination.") The nomination may not exceed 80% of the customer's gross energy storage capacity.

6. A customer may change their maximum nomination by contacting PGE in writing, allowing a minimum of three business days for the change to take effect. However, reducing the nomination may result in customer partial repayment of the rebate. **(N)**

7. A developer or builder is eligible to receive the rebate if purchase and installation of a qualified battery storage system occurred prior to occupancy by a residential customer and enroll the battery in the Pilot. **(T)**

(M)

SCHEDULE 14 (Continued)

Income Qualified Rebate (M)

1. Available to customers receiving incentives from the Energy Trust of Oregon's Solar Within Reach program that purchase a new qualifying battery storage system and allow PGE to operate such equipment for the benefit of PGE's electric system.

2. In addition to the Basic Offering, PGE shall provide a rebate of $5,000 for the new purchase and installation of a qualified battery storage system. The rebate is limited to the first 25 customers. (M)

SPECIAL CONDITIONS

1. Participants are responsible for any equipment, installation, and associated costs of the battery storage system, including any upgrades identified in the PGE interconnection process and ensuring all installation complies with all applicable building code requirements. (C)

2. The participant will retain ownership of the battery storage system and is responsible for all maintenance, replacement, and disposal costs.

3. In the event of non-payment of electricity bill charges or disconnection for non-payment, for Electricity Service rendered, PGE will discontinue credit payments and battery storage system operation until the participant is current on all past-due balances. The participant will be removed from the pilot if basic service electricity charges are not current after two consecutive months.

4. The participant is required to maintain reliable communications with the battery storage system. If communications to the battery storage system are not restored in a timely manner PGE may discontinue paying the monthly incentive until communications are reestablished, or PGE may remove the customer from the pilot.

5. A participant that only receives the Basic Offering and did not receive a Test Bed or Income Qualified rebate may disenroll from the pilot at any time, upon which PGE will cease payments. (C)

6. If the participant has received a rebate, the customer may be required to repay the unamortized portion of the rebate in the event that the customer voluntarily disenrolls prior to the end of the pilot, reduces their dispatch nomination, or if the battery storage system is removed from the pilot due to lapses in communications. This is defined as the proportion of the months left until the end of the pilot divided by the months the customer has participated in the pilot. (C) (C)

7. Participants must agree to the contractual terms laid out in the Residential Battery Energy Storage Pilot agreement. (C)

(M)

SCHEDULE 14 (Concluded)

SPECIAL CONDITIONS (Continued) **(D)**

8. PGE will never discharge the battery storage system below 20% of capacity or below the manufacturer's warranty recommendation, whichever is higher. **(T)(M)** **(M)**

9. The participant may override PGE's control up to ten times per calendar year for a period of 24 hours per time. **(T)**

10. During times of severe weather, defined as any time PGE has placed emergency operators on Standby status, PGE will allow the battery storage system to fully charge. **(T)**

11. In the event of a power outage, the customer will have full use of the battery storage system until grid service is restored. Power outages are not considered a customer override. **(T)**

12. Customers enrolled in Solar Payment Option may not participate in this Pilot offering. **(T)**

13. A customer may not participate in both Peak Time Rebates as outlined in Schedule 7 and this Pilot offering. **(N)** **(N)**

(D)

TERM

This pilot began on August 1, 2020 and ends on July 31, 2025

SCHEDULE 15
OUTDOOR AREA LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer notifies the Company of the burn-out.

MONTHLY RATE

Included in the service rates for each installed luminaire are the following pricing components:

Transmission and Related Services Charge	0.441	¢ per kWh	
Distribution Charge	5.704	¢ per kWh	**(I)**
Cost of Service Energy Charge	5.175	¢ per kWh	

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate (1) Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$12.15 (2)	(I)
	400	21,000	147	21.81 (2)	
	1,000	55,000	374	47.44 (2)	
HPS	70	6,300	30	8.39 (2)	
	100	9,500	43	9.54	
	150	16,000	62	11.76	
	200	22,000	79	14.14	
	250	29,000	102	16.33	
	310	37,000	124	19.02 (2)	
	400	50,000	163	23.43	
Flood, HPS	100	9,500	43	9.59 (2)	
	200	22,000	79	15.01 (2)	
	250	29,000	102	17.73	
	400	50,000	163	24.63	
Shoebox, HPS (bronze color, flat	70	6,300	30	8.67	
lens or drop lens, multi-volt)	100	9,500	43	10.62	
	150	16,500	62	13.18	
Special Acorn Type, HPS	100	9,500	43	13.64	
HADCO Victorian, HPS	150	16,500	62	15.79	
	200	22,000	79	18.04	
	250	29,000	102	20.56	
Early American Post-Top, HPS					
Black	100	9,500	43	10.49	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	$11.91	**(I)**
	175	12,000	71	13.42	
Flood, Metal Halide	350	30,000	139	22.98	
	400	40,000	156	23.10	
Flood, HPS	750	105,000	285	41.04	
HADCO Independence, HPS	100	9,500	43	14.81	
HADCO Capitol Acorn, HPS	100	9,500	43	17.59	
	200	22,000	79	21.93	
	250	29,000	102	15.29	
HADCO Techtra, HPS	100	9,500	43	21.94	
	150	16,000	62	24.90	
HADCO Westbrooke, HPS	70	6,300	30	15.44	
	100	9,500	43	17.06	
	250	29,000	102	22.22	
Holophane Mongoose, HPS	150	16,000	62	18.04	**(I)**

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[(1)]	
Acorn					
LED	>35-40	3,262	13	$13.81	
	>40-45	3,500	15	14.04	**(I)**
	>45-50	5,488	16	12.01	
	>50-55	4,000	18	14.38	**(I)**
	>55-60	4,213	20	14.60	
	>60-65	4,273	21	14.72	**(I)**
	>65-70	4,332	23	14.91	
	>70-75	4,897	25	15.17	**(I)**
HADCO LED	70	5,120	24	19.24	**(I)**
Roadway LED	>20-25	3,000	8	5.50	**(I)**
	>25-30	3,470	9	5.61	
	>30-35	2,530	11	6.11	**(I)**
	>35-40	4,245	13	6.06	
	>40-45	5,020	15	6.42	**(I)**
	>45-50	3,162	16	6.64	
	>50-55	3,757	18	7.13	**(I)**
	>55-60	4,845	20	6.98	
	>60-65	4,700	21	7.10	**(I)**
	>65-70	5,050	23	7.91	
	>70-75	7,640	25	8.18	**(I)**
	>75-80	8,935	26	8.29	
	>80-85	9,582	28	8.52	**(I)**
	>85-90	10,230	30	8.75	
	>90-95	9,928	32	8.97	
	>95-100	11,719	33	9.09	
	>100-110	7,444	36	9.78	
	>110-120	12,340	39	9.76	
	>120-130	13,270	43	10.22	
	>130-140	14,200	46	11.51	
	>140-150	15,250	50	12.93	
	>150-160	16,300	53	13.27	
	>160-170	17,300	56	13.61	
	>170-180	18,300	60	13.95	
	>180-190	19,850	63	14.40	
	>190-200	21,400	67	15.06	**(I)**

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[(1)]	
Pendant LED (Non-Flare)	36	3,369	12	$15.19	
	53	5,079	18	16.65	**(I)**
	69	6,661	24	17.45	**(I)**
	85	8,153	29	18.58	**(I)**
Pendant LED (Flare)	>35-40	3,369	13	15.46	
	>40-45	3,797	15	15.69	**(I)**
	>45-50	4,438	16	15.80	
	>50-55	5,079	18	17.15	**(I)**
	>55-60	5,475	20	17.37	
	>60-65	6,068	21	17.49	**(I)**
	>65-70	6,661	23	18.48	
	>70-75	7,034	25	18.71	**(I)**
	>75-80	7,594	26	19.01	
	>80-85	8,153	28	19.24	**(I)**
CREE XSP LED	>20-25	2,529	8	5.35	**(I)**
	>30-35	4,025	11	5.69	**(I)**
	>40-45	3,819	15	6.14	**(I)**
	>45-50	4,373	16	6.50	
	>55-60	5,863	20	6.74	
	>65-70	9,175	23	7.43	
	>90-95	8,747	32	8.45	**(I)**
	>130-140	18,700	46	11.85	**(I)**

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Post-Top, American Revolution LED	>30-35	3,395	11	$7.64	(I)
	>45-50	4,409	16	8.55	
Flood LED	>80-85	10,530	28	9.59	(I)
	>120-130	16,932	43	11.82	(I)
	>180-190	23,797	63	15.15	(I)
	>370-380	48,020	127	26.89	(I)

Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$5.96
	40 to 55	7.07
Wood, Painted for Underground	35 or less	5.96 [3]
Wood, Curved Laminated	30 or less	7.09 [3]
Aluminum, Regular	16	4.56
	25	8.51
	30	9.82
	35	11.43
Aluminum, Fluted Ornamental	14	8.20
Aluminum, Fluted Ornamental	16	8.52

(1) See Schedule 100 for applicable adjustments.
(2) No pole charge for luminaires placed on existing Company-owned distribution poles.
(3) No new service.

SCHEDULE 15 (Continued) (T)

MONTHLY RATE (Continued)

Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Aluminum Davit	25	$9.11	(R)(M)
	30	10.30	(R)
	35	11.83	(R)
	40	15.22	(R)
Aluminum Double Davit	30	11.47	(R)
Aluminum, Smooth Techtra Ornamental	18	18.03	(R)
Aluminum, Fluted Ornamental	18	16.92	(R)(C)
Aluminum, Non-fluted Ornamental, Pendant	22	16.81	(R)(C)
Fiberglass Fluted Ornamental; Black	14	11.01	(R)
Fiberglass, Regular			
Black	20	4.94	(I)
Gray or Bronze	30	8.03	(I)
Black, Gray, or Bronze	35	7.90	(I)
Fiberglass, Anchor Base, Gray or Black	35	10.89	(R)
Fiberglass, Anchor Base (Color may vary)	25	11.46	(I)
	30	15.55	(I)
Fiberglass, Direct Bury with Shroud	18	6.70	(R)(M)
Aluminum, Regular with Breakaway Base	35	16.90	(N)
Aluminum, Double-Arm, Smooth Ornamental	25	13.82	(N)

INSTALLATION CHARGE (M)

See Schedule 300 regarding the installation of conduit on wood poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

(1) No pole charge for luminaires placed on existing Company-owned distribution poles. (M)

SCHEDULE 15 (Concluded)

SPECIAL CONDITIONS (M)

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Maintenance of outdoor area lighting poles includes replacement of accidentally or deliberately damaged poles and luminaires. If damage occurs more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will pay for future installations or may mutually agree with the Company and pay to have the pole either completely removed or relocated.

3. Electricity delivered to the Customer under this schedule may not be resold by the Customer.

4. If Company-owned area lighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned area lighting equipment or poles. (M)

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 17
COMMUNITY SOLAR - OPTIONAL

PROGRAM DESCRIPTION

In accordance with Senate Bill (SB) 1547, Division 88 of Chapter 860 of the Oregon Administrative Rules (OARs), and Oregon Public Utility Commission (Commission) Order Nos. 18-177 and 19-392, the Oregon Community Solar Program (CSP or Program) is an optional program that will provide Participants the opportunity to share in the costs and benefits associated with community solar. The Program rules and Customer participation requirements are described in detail in the Program Implementation Manual (PIM).

AVAILABLE

In all territory served by the Company.

APPLICABLE

The CSP is applicable to Customers that meet the eligibility requirements set forth in OAR 860-088-0090 and described in the PIM.

DEFINITIONS

Annual Billing Period – Period beginning on the first day of the April billing month and running through the close of the March billing month, unless the Company and the Program Manager agree otherwise.

Community Solar Program, CSP or Program – The program for the procurement of electricity by electric companies from Projects.

Low-income Participant – Participant meeting the low-income requirement set forth in the PIM, as identified by the Project Manager and verified by the Low-income Facilitator.

Bill Credit - The Company will apply a credit to each Participant's monthly utility bill in accordance with the process and calculations set forth in ORS 757.386(6), OAR 860-088-0170, and the PIM. Bill Credits will be applied to offset utility charges and participation fees. The Program Administrator will calculate the value of a Bill Credit based on the Participant's share in the total Project generation multiplied by the Project's Bill Credit Rate.

Bill Credit Rate – The rate, in dollars per kilowatt-hour, at which the Company provides credits to a Participant for energy produced based on Participation Interest in a Project. The Commission assigns the Bill Credit Rate to each Project at the time of Project pre-certification. A Projects' Bill Credit Rate will remain fixed for the term of the CSP Purchase Agreement.

CSP Purchase Agreement – The power purchase agreement between the Company and Project Manager as described in Schedule 204.

SCHEDULE 17 (Continued)

DEFINITIONS (Continued)

Participant – A subscriber or owner as defined in OAR 860-088-0010(6) and (15).

Participation Interest – A Participant's proportional share of a Project based on capacity.

Program Administrator – A third-party directed by the Commission to administer the CSP. The Commission has selected Energy Solutions as the Program Administrator.

Program Implementation Manual or PIM – The set of guidelines and requirements for implementing the CSP adopted by the Commission. The PIM can be found on the Oregon Community Solar website at https://www.oregoncsp.org/p/ProgramImplementationManual/

Program Fees - Program Fees include both the Program Administrator fee and the Utility Fee to administer various aspects of the CSP. Program Fees are added to a Participant's monthly bill and are expressed in $/kW-AC per month. Low-Income Participants are exempt from Program Fees.

Project – One or more solar photovoltaic energy systems that provide Participants the opportunity to share the costs and benefits associated with the generation of electricity by solar photovoltaic energy systems in the CSP.

Project Manager – The entity identified as having the responsibility for managing the operation of a Project and, if applicable, for maintaining contact with the electric company that procures electricity from the Project, as defined in ORS 757.386(1)(d).

Service Territory – The geographic area approved by the Commission for the Company to serve Customers.

Subscription - A Customer's subscription or ownership of a portion of a Project. When Customers subscribe to a Project, they are subscribing to a portion of the Project's capacity in kilowatts (kW-AC).

Subscription Agreement - A contractual agreement between a Participant and a registered Project Manager to enroll in a Project.

Subscription Fee - The Subscription Fee is a charge by the Project Manager that may be listed on a Participant's utility bill, or may be off-bill, and reflects monthly cost to subscribe to the Project. On-bill Subscription models may be either capacity-based ($/kW) or production based ($/kWh).

Utility Fee – Fee that the Company collects on each Participant's utility bill to fund the Company's administration of the Community Solar Program, in accordance with OAR 860-088-0160(2).

SCHEDULE 17 (Continued)

CUSTOMER ELIGIBILITY

To be a Participant, Customers must meet the requirements set forth in OAR 860-088-0090 and described in Chapter 3 (Requirements) of the PIM, enroll in a Project that has been pre-certified by the Commission, and sign a Subscription Agreement with a registered Project Manager of the Project.

Detailed program eligibility details are provided in the PIM, Chapter 3, starting at page 48.

Eligible Customer types - A list of eligible customer rate schedules and their accompanying customer type classifications is available on the program website at https://www.oregoncsp.org/p/ProjectManagerResources/. Direct access customers, lighting/traffic signals, cost of service opt-out customers, and customers who are receiving volumetric incentive rates (VIR) under the Solar Photovoltaic Volumetric Incentive Program are not eligible to participate.

COMMUNITY SOLAR ENERGY BILL CREDIT

1. Bill Credit Rate:
   The Commission establishes a Project's Bill Credit Rate at the time of Project pre-certification. The Commission has adopted Bill Credit Rates based on the capacity of pre-certified Projects to come online in PGE's Service Territory. The current Bill Credit Rate can be found on the Oregon Community Solar Website https://www.oregoncsp.org/p/SubscriberResources/

2. Bill Crediting Rules:
   A Participant's monthly Bill Credit is calculated by multiplying the Bill Credit Rate by the Participant's share of total Project generation in that month. This will be a dollar value.

   The value of the monthly Bill Credit will be applied to the Participant's total Company bill (in dollars), less any other on-bill repayment expenses, respecting the Company's established bill crediting hierarchy. Information on the crediting hierarchy of the Company is available on the program website under Project Manager Resources, https://www.oregoncsp.org/p/ProjectManagerResources/

   If the value of the monthly Bill Credit, minus any other on-bill repayment expenses, is greater than the total amount due on the Company's bill, an excess credit may appear. This excess credit may not be refunded, and will carry forward to subsequent months. If this excess credit is not consumed by monthly energy usage and charges by the end of the annual period, then, at the end of the annual period, PGE will donate the value of the amount carried forward to low income programs as required by the PIM.

3. Bill Credit Allowable Offsets:
   Bill Credits offset all Company charges and on-bill Subscription charges for Participant's electric bills. Bill Credits cannot offset non-Company charges, which may be collected on the Company bill, but are passed on to third parties, such as loans.

SCHEDULE 17 (Continued)

COMMUNITY SOLAR ENERGY BILL CREDIT (Continued)

If a Participant has multiple sites under one utility account, the Bill Credit will be applied separately to each site designated under the CSP. If a single site hosts multiple meters, the Bill Credit may offset the sum of all electric meters on the site.

4. Nonpayment and Underpayment:
In accordance with the PIM, the Company will recover any unpaid Participation or Program Fees on the Participant's next monthly utility bill. At the direction of the Program Administrator, the Company will suspend the application of Bill Credits or terminate a Participant's Participation Interest for failure to pay Participation and Program Fees in full.

5. Utility Disconnection:
If the Company disconnects a Participant's utility service temporarily, the Company will apply the Bill Credits, Participation Fees and Program Fees that accrue during the period of disconnection to the Participant's next monthly utility bill, in accordance with the PIM. Depending on the agreed terms between a Participant and the Project Manager, utility disconnection may result in the early termination of a Participant's Participation Interest by the Project Manager.

6. Timing:
In accordance with the PIM the Company will post a Participant's Bill Credit to their account on the ninth calendar day of each month, unless the ninth calendar day is a Sunday or holiday, in which case the Bill Credit will post on the following calendar day. If a Participant's billing period ends after the ninth calendar day of the month, their bill will reflect their Bill Credit for the previous month. If a Participant's billing period ends before or on the ninth calendar day of the month, their bill will reflect a one-month lag in the application of the Bill Credit.

7. Excess Credits:
If a Participant accrues Bill Credits that exceed the eligible expenses on their monthly utility bill, the excess Bill Credit amount will be carried forward and applied to the Participant's subsequent utility bills. In accordance with the PIM, a Participant may not cash out carryover Bill Credit amounts.

8. Annual Bill Credit Reconciliation:
Under OAR 860-088-0090(2) and OAR 860-088-0170(4), a Participant is not permitted to receive Bill Credits for more energy than they consume on an annual basis. If a Participant's Participation Interest in a Project generates more energy than their annual usage, the Company will apply a reconciliation charge to the Participant's next monthly bill based on calculations performed by the Program Administrator and in accordance with the process set forth in the PIM. A Participant's annual excess generation will be calculated based on the Participant's usage and their share of Project generation during the Annual Billing Period.

SCHEDULE 17 (Continued)

PROGRAM FEE

The Company will apply Program Fees, if applicable, to each Participant's utility bill based on Participants' Participation Interest. Program Fees will consist of a Program Administrator Fee and a Utility Fee. Program Fees may be subject to an annual adjustment, and are currently set at the following amounts:

Program Administrator Fee:	$0.85/kW/month
Utility Fee:	$0.11/kW/month
Program Fees (total)	$0.96/kW/month

Program Fees are subject to annual adjustments per the PIM Low-income Participants are exempt from Program Fees.

SUBSCRIPTION FEE

The Subscription Fee is a charge determined by the Project Manager that may be listed on a Participant's utility bill, or may be off-bill, and reflects monthly cost to subscribe to the CSP. Off-bill Subscriptions require Program Administrator approval as provided in PIM Chapter 3: Project Requirements.

SPECIAL CONDITIONS

1. A Participant's ownership interest in, or Subscription to, a Project may not exceed the retail electricity customer's average annual consumption of electricity in the Service Territory in which the Project is located.

2. Participant Interest may not exceed 40 percent interest in the Project.

3. With respect to Projects certified during the initial program capacity tiers:
   a. A Participant, and its affiliates, as defined in the PIM, may own or subscribe to no more than 4 MW-AC of capacity, in aggregate, across all participating utilities (i.e., PGE, PacifiCorp, and Idaho Power); and
   b. For the program interim capacity tier, a Participant may not own or subscribe to more than 2 MW-AC of capacity across all participating utilities.

4. These tariff terms apply to the Commission-approved initial capacity tier of the CSP. Any future program capacity tiers will be approved by the Commission and the Commission will then set participation requirements and the Bill Credit Rate.

5. SB 1547, Division 88 of Chapter 860 of the OARs, Commission Orders Nos. 18-177 and 19-392, and the PIM will govern to the extent this Schedule 17 may conflict with them.

SCHEDULE 17 (Concluded)

SPECIAL CONDITIONS (Continued)

6. Portability:
A Participant may retain their Participation Interest in a Project if they relocate to another site within the Company's Service Territory in accordance with the terms of the PIM and, if applicable, their agreement with the Project Manager.

7. Transferability:
A Participant may transfer their Participation Interest in a Project to another eligible customer of their choosing in accordance with the terms of the PIM and, if applicable, their agreement with the Project Manager. Any fees assessed by the Project Manager for the transferal of a Participant's Participation Interest will not be reflected on the Participant's utility bill. When a Participant transfers their Participation Interest to another customer, the Company will continue to apply any Excess Credit amounts to the Participant's utility bill.

   If the Participant terminates utility service with the Company, the Company will donate any Excess Credit amounts associated with the Participant's Participation Interest to the Company's low-income program.

8. Changes:
A Participant may change the size of their Participation Interest in accordance with the terms of the PIM and, if applicable, their agreement with the Project Manager. Any fees assessed by the Project Manager to change the size of a Participant's Participation Interest will not be reflected on the Participant's utility bill. Low Income Participants are not subject to change fees.

9. Early Termination:
A Participant or a Project Manager may terminate a Participant's Participation Interest before the end of their contract term, in accordance with the terms of the PIM, and, if applicable, their agreement with the Project Manager. Any early termination fees assessed by the Project Manager will not be reflected on the Participant's utility bill. When a Participant or Project Manager terminates a Participant's Participation Interest, the Company will donate any Excess Credit amounts associated with the Participant's Participation Interest to the Company's low-income program in accordance with the process described in the PIM.

10. Completion:
A Participant's Participation Interest is complete when the Company applies the final Bill Credit amounts to the Participant's monthly utility bill and the Company completes the final Annual Bill Credit Reconciliation.

11. Term:
This Schedule will apply for the term agreed to between a Participant and the Project Manager, not to extend beyond the end date of the Annual Billing Period following the termination of the Project Manager's CSP Purchase Agreement.

SCHEDULE 18
INCOME-QUALIFIED BILL DISCOUNT - OPTIONAL

PROGRAM DESCRIPTION

This is an optional bill discount for Income-Qualified Residential customers.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Income-Qualified Residential Customers, defined as Customers with gross household income at or below 60% of Oregon State Median Income (SMI), adjusted for household size. For Customers in single-person households, eligibility is extended to those with gross household incomes up to the greater of 60% SMI or $30,700.

MONTHLY DISCOUNT

Monthly bill discounts are calculated as a percentage of bill and are offered at three levels, based on the enrolled Customer's household income as a percentage of SMI. Tier 1 Customers with household incomes up to 30% of SMI will receive a 25% discount on their electricity bill; those in Tier 2 with household incomes between 31% and 45% of SMI will receive a 20% discount; and those in Tier 3 with household incomes between 46% and 60% of SMI (and single-person households up to $30,700) will receive a 15% discount.

Enrolled Customers with a verified Emergency Medical Certificate on their PGE account will be moved to the next highest discount level, if not already qualified for the highest discount level (25%).

The bill discount applies to most components of a Customer's bill, with a small number of charges not subject to the discount. Excluded charges include the following, where applicable:

- Green Future Solar, Fixed and Habitat Optional Charges
- Solar Customer Charge for Customers on Solar Payment Option
- Energy Efficiency Funding Adjustment (Schedule 109)
- Low Income Assistance Charge (Schedule 115)
- Meter Rental and Non-Network Meter Read Charges (Schedule 300)

SPECIAL CONDITIONS

1. Program participants must be the accountholder. **(C)**

2. Household size reflects all permanent residents in the home, including adults and children.

SCHEDULE 18 (Concluded)

SPECIAL CONDITIONS (Continued)

3. Qualifying income refers to total gross annual income, both taxable and nontaxable, from all sources for all persons in the applicant's household.

4. The discount applies only to bills associated with the Customer's permanent primary residence and only to new charges billed after enrollment. **(D)**

5. PGE Customers who have qualified for the federal Low-Income Home Energy Assistance Program (LIHEAP) or the Oregon Energy Assistance Program (OEAP) will be automatically enrolled in Tier 3. Those who also have a verified Emergency Medical Certificate on their PGE account will automatically be enrolled in Tier 2. Automatically enrolled Customers who believe they qualify for a larger discount are encouraged to submit an application and upon approval, will be moved to the appropriate tier. Should PGE be provided with detailed Customer eligibility information, automatically enrolled Customers will be placed directly in the appropriate tier. Customers who do not wish to receive the discount can contact PGE to be unenrolled. **(N)**

6. Customers not otherwise automatically enrolled may participate in the program after the approval of an application that includes a declaration of household size and income. Applications can be submitted directly by the Customer or a third-party on behalf of the Customer. Re-enrollment will be required every two years. **(N)**

7. Annually, beginning April 2023, PGE will require post-enrollment verification of need from a randomly selected 3% of enrolled Customers to continue receiving this discount. **(C)** If a Customer's discount is discontinued due to non-responsiveness or ineligibility, they may re-enroll upon providing verification of eligibility. Customers who were automatically **(N)** enrolled based on LIHEAP or OEAP eligibility are exempt from post-enrollment verification. **(N)**

SCHEDULE 25
NONRESIDENTIAL DIRECT LOAD CONTROL PILOT

PURPOSE

This Direct Load Control Pilot is a demand response option for eligible nonresidential Customers. The Direct Load Control Pilot offers incentives to allow the Company to control thermostats during Direct Load Control Events while providing a customer override. The Company provides advance notice to participating Nonresidential Customers for Direct Load Control Events. The Pilot is expected to be conducted from December 1, 2017 through May 31,2025. **(C)**

DEFINITIONS

Central Air Conditioning – Air conditioner tied into a central ducted forced air system.

Direct Installation – Thermostat delivery model in which a PGE technician, or implementation contractor technician representing PGE, installs thermostat(s) at a qualifying customer Site at a reduced cost to the Customer and enables the thermostat(s) to participate in the Pilot. **(N)** **(N)**

Direct Load Control – A remotely controllable switch that allows the utility to operate an appliance, often by cycling. In terms of this pilot, direct load control allows the Company to change the set point or cycle the Nonresidential Customer's heating or cooling through the Customer's Qualified Thermostat in order to reduce the Customer's energy demand.

Direct Load Control Event – A period of time in which the Company will provide direct load control.

Ducted Heat Pump – Heat pump heating and cooling system hooked into a central ducted forced air system.

Electric Forced Air Heating – An electrical resistance heating system tied into a central ducted forced air system.

Event Notification – The Company will issue a notification of a Direct Load Control Event to participating Customers. Participating Nonresidential Customers must choose at least one method for receipt of notification. Notification methods may include email, text, auto-dialer phone call, on thermostat display screen, or via mobile app notification. Notification may also be available on the Company's website.

Event Season – The pilot has two event seasons: the Summer Event Season and the Winter Event Season.

Holidays – The following are holidays for purposes of the pilot: New Year's Day (January 1), Martin Luther King Day (third Monday in January), President's Day (third Monday in February), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

SCHEDULE 25 (Continued)

DEFINITIONS (Continued)

Non-Ducted HVAC System Thermostat Demonstration – A demonstration within the smart grid test bed that meets Special Conditions 8 through 10. Demonstations are limited in scope and will not interfere with the operations of the Nonresidential DLC Pilot.

Summer Event Season – Includes the successive calendar months June through September.

Winter Event Season – Includes the successive calendar months November through February.

Qualified Site – Nonresidential Customer building served under qualifying PGE rate Schedule (as defined in Applicable section below) with a unique PGE service address and utility meter. Additionally, Qualified Sites meet HVAC system requirements defined in Eligibility section below. **(N)** | **(N)**

Qualified Thermostat – Thermostats that are Company-approved have been integrated with Company's demand response management system for event calling.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Nonresidential Customers served under Schedules 32, 38, 47, 49, 75, 83, 85, 89, and 90. The Company will limit participation to 7,000 Qualified Thermostats. Nonresidential Customers will remain on their base schedule and will be eligible for the incentives described in this schedule. **(C)**

ELIGIBILITY

Eligible Nonresidential Customers must have a Network Meter. Nonresidential Customers must have a Qualified Thermostat connected to the internet and the heating or cooling system at their expense, except as provided in the Incentives section of this schedule. To participate in the Winter Event Season, the Nonresidential Customer must have a Ducted Heat Pump or Electric Forced Air Heating. To participate in the Summer Event Season, the Nonresidential Customer must have Central Air Conditioning or a Ducted Heat Pump.

SCHEDULE 25 (Continued)

DIRECT LOAD CONTROL EVENT

Direct Load Control Events occur for one to five hours. The Company may call two events per day but will not exceed five cumulative hours for the day. During Direct Load Control Events the Customer may allow the Company to control their thermostat for the duration of the event. The Customer has the option not to participate by overriding the temperature setpoint via the thermostat. The Company initiates Direct Load Control Events with Event Notification. The Company will call Direct Load Control Events only during the Event Seasons. Direct Load Control Events will not be called on weekends or Holidays. Reasons for calling events may include but **(T)** are not limited to: energy load forecasted to be in the top 1% of annual load hours, forecasted temperature above 90 or below 32, expected high generation heat rates and market power prices, and/or forecasted low or transitioning wind generation. The Company will call no more than 150 event hours per Event Season.

ENROLLMENT

The Customer may enroll at any time but must participate for the minimum number of hours described in the incentive section.

INCENTIVE

Participating Customers receive a Qualified Thermostat for signing up for the Direct Load Control Pilot's Direct Installation channel. A Customer may receive multiple Qualified Thermostats for **(C)** separate spaces subject to verification by the Company. A Customer co-pay of up to $60 per installed thermostat is required for participation. Customers receive up to $60 per Qualified Site **(C)** for each Event Season they participate. A Customer participating in all Event Seasons receives up to $120 per Qualified Site per Pilot year. Incentives are paid to the Customer with an automated **(C)** clearing house (ACH,) check, bill credit, or generic gift card. To receive payment for an Event Season, all Qualifying Thermostats at the Qualified Site must participate in at least 50% of the **(C)** event hours for which the Customer is eligible to participate in that Event Season.

SPECIAL CONDITIONS

1. Customers that reenroll in the program are not eligible for additional Qualified Thermostats **(C)** for signing up. A Customer continuing service at a new location is not considered a new enrollment.

2. If the participating Customer moves to a different location, the Customer may continue participation if the new location meets the eligibility requirements.

3. The Company will defer and seek recovery of all pilot costs not otherwise included in rates.

4. The Company is not responsible for any direct, consequential, incidental, punitive, exemplary, or indirect damages to the participating Customer or third parties that result from Air Conditioning Cycling or changing the thermostat set point.

SCHEDULE 25 (Concluded)

SPECIAL CONDITIONS (Continued)

5. The Company shall have the right to select the cycling schedule and the percentage of the Customer's heating or cooling systems to cycle at any one time, up to 100%, at its sole discretion.

6. The Company shall have the right to pre-heat or pre-cool the Site as part of the Direct Load Control event in order to thermally condition the space to increase occupant comfort and site performance for the duration of the event. **(N) (N)**

7. The provisions of this schedule do not apply for any period that the Company interrupts the Customer's load for a system emergency or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular service schedule and associated charges and Customers will not be charged for energy not used or demand not set during Direct Load Control Events. **(T) (C) (C)**

8. The Company may engage with Customers who have existing qualified thermostats installed at their Sites to enroll them in the pilot. Customers with pre-existing thermostats that were not installed through the Direct Installation channel are eligible for seasonal incentives. **(N) (N)**

9. PGE has the right to remove a Customer from the pilot when good cause is shown including, but not limited to, poor customer responsiveness, consistent customer non-participation in called events, or issues with customer equipment that impact customer's participation. **(T) (T)**

TERM **(D)**

This pilot term is December 1, 2017 through May 31, 2025. **(C)**

SCHEDULE 26
NONRESIDENTIAL DEMAND RESPONSE PROGRAM

PURPOSE

This schedule is an optional supplemental service that provides participating Large Nonresidential Customers incentives for providing utility grid services when called for by the Company. Under this schedule, the Customer provides a Committed Load Reduction that the Company calls at any time according to the conditions detailed below. The Customer may also elect to receive incentives for providing other grid services from qualifying resources, as described below. (C)

DEFINITIONS

(D)

Baseline Load Profile – The average hourly load of the five highest load days in the last ten Typical Operational Days for the Winter Event Season or Summer Event Season. (C)

Commissioning Test – An optional test event conducted by the Customer upon initial program enrollment that confirms the Customer's load reduction potential results in the anticipated amount of load (kW) curtailment. (N)

Committed Load Reduction – A Customer nomination of load that represents the anticipated amount of load (kW) curtailed during an event. (C)

Contingency Reserve Event – A Load Reduction Event that is called by PGE with no advance notice in response to a critical need for power in the region. These events can occur at any time of year and at any time of day, including Holidays and weekends. (N)

Energy Payment – The payment made by the Company to the Customer, as determined by The Mid-Columbia Electricity Index (Mid-C) as reported by Powerdex, adjusted for losses based on the Customer's delivery voltage. The Energy Payment may be up to 120% of the Committed Load Reduction amount. (N)

Firm Load Reduction – The difference between the Baseline Load Profile and the Customer's measured hourly energy usage during the Load Reduction Event or the Measured Energy Output during the Load Reduction Event. (C)

(D)

SCHEDULE 26 (Continued)

DEFINITIONS (Continued)

Firm Load Reduction Options – Elections that determine the Customer's incentive levels; which include the maximum event hours per season option, the Notification Option, and the event windows (time period for an event) for which they want to participate. **(M)** **(C)** **(M)**

Frequency Response Event – An immediate reduction of site load or dispatch of energy at maximum power for a short duration by a Non-Emitting Firm Capacity Resource in response to a disruption that causes the frequency of the electrical system to deviate from a nominal 60 hertz (Hz). These can occur at any time of year and at any time of day, including Holidays and weekends. **(N)**

Grid Support - Frequency Response Events and Contingency Reserve Events are the two Grid Support functions that a Non-Emitting Firm Capacity Resource may elect to participate in. Grid Support functions will be dispatched with no advance notice in response to a disruption in the electrical grid or a critical need for power in the region. **(N)**

Holidays – The following are holidays for purposes of this schedule: New Year's Day (January 1), Martin Luther King Day (third Monday in January), President's Day (third Monday in February), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday. **(C)(M)**

Load Reduction Event – An event that is called during the Winter Event Season or the Summer Event Season, where customer incentives are offered in exchange for a Committed Load Reduction. **(C)** **(M)**

Load Reduction Plan – Document of record that defines the Committed Load Reduction, Firm Load Reduction Options, Customer payments based on Qualified Load Reductions during a Load Reduction Event, terms of any Grid Support in which the Customer has agreed to participate in, and participation instructions for each enrolled location. **(N)**

Measured Energy Output – An alternative measurement to using a Baseline Load Profile to determine a customer's Firm Load Reduction. Available for resources with their own metrology that can be made available to PGE for remote reading.

Non-Emitting Firm Capacity Resource – A continuously available electrical load or continuously available energy storage resource that can be dispatched with no notice and respond to a PGE signal within five seconds to provide Grid Support. This cannot be a resource identified in Special Condition 1. **(N)**

SCHEDULE 26 (Continued)

DEFINITIONS (Continued) (N)

Nonresidential Demand Response Program Agreement – An agreement between the Company and Customer that defines the enrollment terms by which each party agrees to participate.

Notification Option – The notification period in which the Company will alert the Customer prior to a Load Reduction Event; options include 18 hours, 4 hours, 10 minutes, and no notice. (N)

Participation Month – The current calendar month during a Winter Event Season or the Summer Event Season. (M)

Qualified Load Reduction – The average load reduction percentage for all Load Reduction Event hours during the Participation Month must be 70% of the Committed Load Reduction or greater to be qualified. (C) (C)

Reservation Payment – The payment made by the Company to the Customer, where the Customer's Qualified Load Reduction (kW) is multiplied by the sum of each applicable reservation price ($/kW) based on the options selected by the Customer adjusted for losses based on the Customer's delivery voltage.

Summer Event Season – Includes the successive calendar months June through September.

Typical Operational Days – Represents the 10 applicable days closest to the Load Reduction Event.

Winter Event Season – Includes the successive calendar months November through February.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Nonresidential Customers served under Schedules 32, 38, 47, 49, 75, 83, 85, 89, and 90. Participating Nonresidential Customers must execute a Nonresidential Demand Response Program Agreement to participate in this program. (C) (C)(M)

SCHEDULE 26 (Continued)

CUSTOMER ENROLLMENT

(M)
Customers must be fully enrolled at least five business days prior to the Participation Month. (C)

At the time of enrollment, the Customer chooses the Firm Load Reduction Options, which includes
the Firm Load Reduction Option, Grid Support Option, the maximum event hours per season, the (C)
Notification Option, and the event windows (time period for an event) for which they want to
participate. Customer elections are documented in the Load Reduction Plan. All options must
be agreed to by the Customer and the Company. First-time participants can also opt-in for a
Commissioning Test. (C)(M)

Customers wishing to opt into no notice dispatch or Grid Support with a Non-Emitting Firm (N)
Capacity Resource must utilize equipment or facilities that are directly dispatchable by PGE. (N)

Within five business days of enrollment, or for Customers completing a Commissioning Test, (C)(M)
within five days following the completion of such Commissioning Test, the Company will confirm (C)
receipt of the Service Point ID (SPID) the Customer intends to enroll under this schedule and the
Company or its representatives will send a signed Agreement to the Customer's representative.
The Customer may choose to aggregate SPIDs.

Upon completion of the initial term each Agreement will automatically renew for successive annual (C)
terms on January 1st of subsequent calendar years unless the Customer elects to terminate such Agreement by notifying PGE prior to January 1st or this Schedule is withdrawn, revoked or otherwise terminated.

CUSTOMER PARTICIPATION OPTIONS

Customers are offered three Firm Load Reduction Options for the contracted program year: (C)
Option 1, the Customer participates for both event seasons; Option 2, the Customer participates in only the Summer Event Season; and Option 3, the Customer participates in only the Winter Event Season.

Customer Option	Participation Months	Event Seasons
1	Nov, Dec, Jan, Feb, Jun, Jul, Aug, Sep	Both event seasons
2	Jun, Jul, Aug, Sep	Summer Event Season only
3	Nov, Dec, Jan, Feb	Winter Event Season only

FIRM LOAD REDUCTION OPTIONS

Several Firm Load Reduction Options are available to Customers in the reservation price section
of this schedule. Options include differing maximum event hours per season, Notification Options, (C)
and event windows. (C)(M)

SCHEDULE 26 (Continued)

RESERVATION PRICE (M)

20 Event Hours Maximum per Season
Monthly Payment per kW

	Notification Option				
	18 hours	4 hours	10 minutes	No Notice	(C) (N)
Summer (June – September)					
11 am – 4 pm	$1.68	$1.80	$1.91	$2.00	
4 pm – 8 pm	$1.95	$2.08	$2.22	$2.32	
8 pm – 10 pm	$0.39	$0.42	$0.45	$0.47	
All summer windows	$4.02	$4.30	$4.57	$4.78	
Winter (November – February)					
7 am – 11 am	$1.27	$1.35	$1.44	$1.51	
11 am -4 pm	$0.73	$0.78	$0.83	$0.87	
4 pm – 8 pm	$2.07	$2.22	$2.36	$2.47	
8 pm – 10 pm	$0.73	$0.78	$0.83	$0.87	
All winter windows	$4.80	$5.13	$5.46	$5.71	

40 Event Hours Maximum per Season
Monthly Payment per kW

	Notification Option				
Windows	18 hours	4 hours	10 minutes	No Notice	(C)
Summer (June – September)					
11 am – 4 pm	$2.52	$2.69	$2.87	$3.00	
4 pm – 8 pm	$2.92	$3.12	$3.32	$3.47	
8 pm – 10 pm	$0.59	$0.63	$0.67	$0.70	
All summer windows	$6.04	$6.45	$6.86	$7.17	
Winter (November – February)					
7 am – 11 am	$1.90	$2.03	$2.16	$2.26	
11 am – 4 pm	$1.09	$1.17	$1.24	$1.30	
4 pm – 8 pm	$3.11	$3.32	$3.54	$3.70	
8 pm – 10 pm	$1.09	$1.17	$1.24	$1.30	
All winter windows	$7.20	$7.70	$8.19	$8.56	(N)(M)

SCHEDULE 26 (Continued)

RESERVATION PRICE (Continued) (M)

80 Event Hours Maximum per Season
Monthly Payment per kW

	Notification Option				
	18 hours	**4 hours**	**10 minutes**	**No Notice**	(C) (N)
Summer (June – September)					
11 am – 4 pm	$3.35	$3.58	$3.81	$3.98	
4 pm – 8 pm	$3.89	$4.16	$4.42	$4.62	
8 pm – 10 pm	$0.79	$0.84	$0.89	$0.93	
All summer windows	$8.03	$8.58	$9.12	$9.53	
Winter (November – February)					
7 am – 11 am	$2.53	$2.70	$2.87	$3.00	
11 am - 4 pm	$1.46	$1.56	$1.65	$1.72	
4 pm - 8 pm	$4.14	$4.42	$4.70	$4.91	
8 pm - 10 pm	$1.46	$1.56	$1.65	$1.72	
All winter windows	$9.58	$10.23	$10.89	$11.36	(N)

COMMITTED LOAD REDUCTION

If a Customer has completed a test event, but not participated in actual events, their Committed Load Reduction will be based on committed load identified in the Load Reduction Plan. If Customer has completed only one event, their Committed Load Reduction will be the higher of either their committed load or their first event performance. If Customer has participated in more than one event, their Committed Load Reduction will be based on an average of actual load reductions during event hours. The Customer, at its discretion, may choose to increase its nomination above the levels described above. (C) (C)

QUALIFIED LOAD REDUCTION

If no events are called in a Participation Month, the Customer qualifies for the full Reservation Payment; the Qualified Load Reduction is the Committed Load Reduction.

In order to qualify for the full Reservation Payment during a month with Load Reduction Events, the Customer must provide a minimum of 90% of the Committed Load Reduction on average over each event for which the Customer is enrolled during events in that month. If the Customer qualifies for the full Reservation Payment; the Qualified Load Reduction is the Committed Load Reduction. (C)

(M)

SCHEDULE 26 (Continued)

QUALIFIED LOAD REDUCTION (Continued) (M)

To qualify for a proportional Reservation Payment during a month with Load Reduction Events, the Customer must deliver a minimum of 70% of the Committed Load Reduction on average over each Load Reduction Event for which the Customer is enrolled in that month. If the Customer qualifies for a reduced Reservation Payment; the Qualified Load Reduction is the average load reduction percentage for all Load Reduction Event hours during that month. (C) (C) (T) (C)

If the Customer fails to deliver a minimum of 70% of the Committed Load Reduction on average during any single event for which the Customer is enrolled during events in that month, the Customer is not eligible for the Energy Payment for that Load Reduction Event nor the Reservation Payment for that month. If other Load Reduction Events are called in the same month, and the Customer delivers a minimum of 70% of the Committed Load Reduction during such events, the corresponding Energy Reduction Payments are paid for each Load Reduction Event that the Customer delivers a minimum of 70% of the Committed Load Reduction on average over each event for which the Customer is enrolled during events in that month. (C) (C) (C) (C)

RESERVATION PAYMENTS

The Reservation Payment is the Qualified Load Reduction (kW) multiplied by the sum of each applicable Reservation Price ($/kW) based on the Firm Load Reduction Options selected by the Customer adjusted for losses based on the Customer's delivery voltage. For each event window (time period for an event) per season, only one price is applicable. The Reservation Payment is made to the Customer no later than 60 days after the month in which they participated. (C) (C) (M)

Customers meeting PGE's eligibility criteria as defined in a separate policy document and incorporated into the Agreement may be eligible to receive at the time of commissioning the net present value of any Reservation Payments and Grid Support options elected in the Load Reduction Plan for the duration of the Agreement with PGE. If a Customer fails to deliver a minimum of 70% of the Committed Load Reduction on average over each event during a month for which the Customer is enrolled, the Customer must reimburse PGE the Reservation Payment for that month. (N) (N)

* PGE will not call Load Reduction Events on Holidays. If a Holiday falls on Saturday, Friday is designated a Holiday. If a Holiday falls on Sunday, the following Monday is designated a Holiday. Grid Support events are in response to a grid emergency and may occur at any day or time, including Holidays. (C)(M) (C)(M)

SCHEDULE 26 (Continued)

ENERGY PAYMENTS

The Energy Payment is equal to the Mid-Columbia Electricity Index (Mid-C) as reported by the Powerdex, adjusted for losses based on the Customer's delivery voltage. The Firm Energy Reduction amount can be up to 120% of the Committed Load Reduction.

The monthly energy prices (per MWh) for the months in which the events are called* are:

Jan 2023	Feb 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Nov 2023	Dec 2023	
								(C)
$122.50	$105.00	$62.50	$175.20	$228.40	$186.80	$97.40	$111.20	(I)

The Energy Payment rates will be updated by December 1st for the next year beginning in January. Assessment and settlement of the Energy Payment will occur within 60 days of the Firm Load Reduction Event. Energy Payments are not eligible to be paid up-front at the time of commissioning.

LINE LOSSES

Losses will be included by multiplying the applicable price by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530
Secondary Delivery Voltage	1.0640

LOAD REDUCTION MEASUREMENT

Load reduction is measured as a reduction of load from a customer baseline load calculation during each hour of the Load Reduction Event. Although the Load Reduction Plan shall specify the customer baseline load calculation methodology to be used, PGE generally uses the following baseline methodology:

<u>Baseline Load Profile</u>

The Baseline Load Profile is based upon the average hourly load of the five highest load days in the last ten Typical Operational Days for the event season period. For Customers choosing the four-hour or 10-minute notification options there is an adjustment to the amounts above to reflect the day-of operational characteristics leading up to the Firm Load Reduction Event if the Firm Load Reduction Event starts at 11 am or later. This adjustment is the difference between the Firm Load Reduction Event day load and the average load of the five highest days used in the Baseline Load Profile during the two-hour period ending four hours prior to the start of the Firm Load Reduction Event.

SCHEDULE 26 (Continued) (T)

LOAD REDUCTION MEASUREMENT (Continued) (N)

Measured Energy Output (N)

For Firm Load Reduction provided by a resource that can be measured with its own metrology, load baselining is not required. Customers using devices with Measured Energy Output who opt out of a Baseline Load Profile must utilize equipment or facilities that are directly dispatchable by PGE so the Company can view the measured Firm Load Reduction. (N)

Typical Operational Days (M)

Typical Operational Days exclude days that a Customer has participated in a Load Reduction (C)
Event or pre-scheduled opt-out days as defined in the Special Conditions. Typical Operational
Days for the Baseline Load Profile calculation are defined as the ten applicable days closest to (C)
the Load Reduction Event. Typical Operational Days may include or exclude Saturdays, Sundays
and Western Electricity Coordinating Council (WECC) holidays. Grid Support events may occur (C)
at any day or time. (C)

The Company may decline the Customer's enrollment application if the Company determines the (T)
Customer's energy usage is highly variable and the Company is not able to verify that a reduction
will be made when called upon.

LOAD REDUCTION EVENT

The Company, at its discretion, initiates a Load Reduction Event by providing the participating
Customer with the appropriate notification consistent with the Customer's selected Firm Load
Reduction Option. The Customer reduces its load served by the Company, for each hour of the (C)
Load Reduction Event to achieve its Committed Load Reduction. Each Load Reduction Event
will last from one to five hours in duration and the Company will call at least one event per season.

The Company initiates Load Reduction Events during the Winter Event Season and Summer (C)
Event Season. (T)(M)

GRID SUPPORT EVENTS (N)

A Non-Emitting Firm Capacity Resource may elect to participate in Grid Support Events only, or in addition to, participating in Firm Load Reduction. A qualified resource for Grid Support must be available year-round and capable of responding to a signal from the Company with no advance notice within five seconds. The resource must be integrated with the Company's dispatch software. (N)

SCHEDULE 26 (Continued)

GRID SUPPORT EVENTS (Continued) **(N)**

Grid Support includes Frequency Response Events and Contingency Reserve Events, and are only dispatched in response to a grid disturbance or critical need for power in the region. Participating Customers will be compensated $29.38 per year per committed kW as a Reservation Payment. In addition, Energy Payments for load reduction will be paid to Customer for each Contingency Reserve Event. Due to the short duration of Frequency Response Events (less than 15 minutes), Energy Payments will not be paid to Customer if dispatched. **(N)**

EVENT NOTIFICATION **(M)**

The Company notifies the participating Customer of a Load Reduction Event using a mutually agreed upon method at the time of enrollment. The Company's notification includes a time and date by which the Customer must reduce the committed load for each period of the Load **(C)** Reduction Event. Customers enrolled in the "No Notice" option for Firm Load Reduction will still receive notification for events that are pre-planned. No Event Notification is required for Grid Support Events. **(C)**

The Customer is responsible to notify the Company if the Customer's contact information specified at the time of the enrollment changes as soon as such change occurs.

(D)

SPECIAL CONDITIONS

1. Customers cannot use on-site diesel, pipeline natural gas or propane or other carbon emitting generation equipment for load reductions to meet load reduction commitments under this schedule. **(C)**

2. Customers that choose to take service under Schedules 86, 485, 489, 490, 532, 538, 549, 575, 583, 585, 589, 590, or 689 will be withdrawn from this program.

3. Firm Load Reduction by Schedule 75 Customers will not exceed the Customer's baseline load **(C)** as specified in the Agreement between the Customer and the Company. Customer cannot use purchases under Schedule 76 to meet load reduction commitments under this schedule. **(C)**

4. In the case of Customers participating on Schedule 76R – Partial Requirements Economic Replacement Power Rider – at the time of the event, the energy imbalance will not apply during event hours and for the event energy amount.

5. This schedule is not applicable when the Company requests or initiates Load Reduction **(C)** affecting a Customer SPID under system emergency conditions described in Rule N or Rule C(2)(B). **(M)**

SCHEDULE 26 (Concluded)

SPECIAL CONDITIONS (Continued) **(N)**

6. The Company will not cancel or shorten the duration of a Firm Load Reduction Event once notification has been provided. **(C)(M)**

7. Participating Customers are required to have interval metering and meter communication in place prior to participation in this schedule. The Company will provide and install necessary equipment which allows the Company and the Customer to monitor the Customer's energy usage. **(C)**

8. If the Customer experiences operational changes or a service disconnection that impairs the ability of the Customer to provide the Firm Load Reduction as requested under this schedule, the Agreement will be terminated. **(T)** **(T)**

9. If the Company is not allowed to recover any costs of this program by the Commission, the Company may, at its option, and with 30-day notice, end service under this Schedule and terminate the Agreement. **(C)** **(C)**

10. The Customer may pre-schedule four opt-out days per season as indicated in the Agreement. If the Company calls a Firm Load Reduction Event on a pre-scheduled opt-out day, the Customer is exempt from providing Firm Load Reduction and will receive no Energy Payment, whether or not they choose to operate. The Customer will receive the Reservation Payment if otherwise eligible. An opt-out day will not be included in the calculation of the Baseline Load Profile. **(C)** **(C)** **(C)**

11. Customers who participate in this schedule may be placed on a calendar monthly billing cycle. **(C)(M)**

12. Inverter based Non-Emitting Firm Capacity Resources must be IEEE 1547-2018 compliant, built and installed in compliance with UL 1741SA with interoperability features unlocked. **(N)**

13. Non-Emitting Firm Capacity Resources capable of providing energy capacity in excess of the Customer's current site load that are not otherwise eligible for PGE Schedule 203 may receive a bi-directional meter and be credited at the Customer's retail rate of electricity for energy provided to the grid only when dispatched by PGE as part of this schedule. An interconnection agreement and approval by PGE's Interconnection Team is required prior to installation of such bi-directional meter. The terms and conditions for such credits will be set forth in the agreement.

14. Except as otherwise provided in this schedule, Customers nominating resources and receiving compensation through this schedule may participate in other schedules, but may not receive compensation for the resources nominated in this schedule through another schedule. **(N)**

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$29.00		
Transmission and Related Services Charge	0.471	¢ per kWh	
Distribution Charge			
First 5,000 kWh	5.244	¢ per kWh	(I)
Over 5,000 kWh	1.416	¢ per kWh	(I)
Energy Charge Options			
Standard Service	5.798	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.150	¢ per kWh	
Mid-Peak Period	5.798	¢ per kWh	
Off-Peak Period	3.385	¢ per kWh	

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

MONTHLY RATE (Continued)

Renewable Portfolio Options
(available upon enrollment in either
Energy Charge option)

Renewable Usage	0.940	¢ per kWh in addition to Energy Charge	
Renewable Fixed	$1.88	per month per block	(D)
	$2.50	per month	

* Only Customers who are enrolled in a Renewable Portfolio Option (Renewable Usage or Renewable Fixed Portfolio Options described herein) may choose the Renewable Habitat Portfolio Option Adder. (C)

RENEWABLE PORTFOLIO OPTIONS

The Customer will be charged for the Renewable Portfolio Option in addition to all other charges under this schedule for the term of enrollment in the Renewable Portfolio Option.

Renewable Fixed Option

The Company will use funds received under this option to cover program costs and purchase 200 kWhs of Renewable Energy Certificates (RECs) and/or renewable energy per block enrolled in the Renewable Fixed Option. All RECs purchased under this option will come from new renewable resources.

The Company will also place any funds not spent after covering program and REC costs received from Customers enrolled in this option in a renewable resources development and demonstration fund (“Renewable Development Fund” or “RDF”. See Special Conditions for additional details on the RDF.

Renewable Usage Option

Amounts received from Customers under the Renewable Usage Option will be used to cover program costs and acquire RECs and/or renewable energy, all of which will come from new renewable resources.

The Company will also place any funds received from Customers enrolled in this option not spent after covering program and REC costs in a renewable resources development and demonstration fund (“Renewable Development Fund” or “RDF”). See Special Conditions for additional details on the RDF.

SCHEDULE 32 (Continued)

RENEWABLE PORTFOLIO OPTIONS (Continued)

(D)

Renewable Habitat Adder

The Company will distribute $2.50 per month as received from each Customer enrolled in the Habitat Option to a nonprofit agency chosen by the Company who will use the funds for habitat restoration.

Energy or RECs supporting the Renewable Portfolio Options will be acquired by the Company such that by March 31 of the succeeding year, the Company will have received sufficient RECs or renewable energy to meet the purchases by Customers. For Renewable Fixed Option and Renewable Usage Option, the Company is not required to own renewables or to acquire energy from renewable resources simultaneously with Customer usage.

For purposes of these options, renewable resources include wind, solar, biomass, low impact hydro (as certified by the Low Impact Hydro Institute) and geothermal energy sources used to produce electric power. All RECs will be Green-e® Energy certified by the Center for Resource Solutions (CRS).

SCHEDULE 32 (Continued)

TIME OF USE PORTFOLIO OPTION

On- and Off-Peak Hours*

Summer Months (begins May 1st of each year)	
On-Peak	3:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	6:00 a.m. to 3:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**
Winter Months (begins November 1st of each year)	
On-Peak	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	10:00 a.m. to 5:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

* The time periods set forth above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November. Customers with AMI meters will observe the regular daylight saving schedule.

** Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on Saturday, Friday is designated a TOU holiday. If a holiday falls on Sunday, the following Monday is designated a TOU holiday.

DAILY PRICE

The Daily Price, applicable with Direct Access Service, is available to those Customers who were served under Schedule 532 and subsequently returned to this schedule before meeting the minimum term requirement of Schedule 532. The Customer will be charged the Daily Price charge of this schedule until the term requirement of Schedule 532 is met.

The Daily Price will consist of:

- the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index)
- plus 0.305¢ per kWh for wheeling **(R)**
- times a loss adjustment factor of 1.0640 **(R)**

If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported.

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 32 (Continued)

PLUG-IN ELECTRIC VEHICLE (EV) TOU OPTION (M)

A small Nonresidential Customer wishing to charge EV's may do so either as part of an integrated service (Standard service or TOU service) or as a separately metered service billed under the TOU option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule. Renewable Portfolio Options are also available under this EV option.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B (30) for the purpose of load research, and to collect and analyze data to characterize electric vehicle use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission.
Adjustments include those summarized in Schedule 100. (M)

SPECIAL CONDITIONS

Pertaining to Direct Access

1. Customers served under this schedule may at any time notify the Company of their intent to choose Direct Access Service. Notification must conform to the requirements established in Rule K.

2. Customers must enroll to receive service under any portfolio option. Customers may initially enroll or make one portfolio change per year without incurring the Portfolio Enrollment Charge as specified in Schedule 300.

Pertaining to Renewable Portfolio Options

1. Service will become effective with the next regularly scheduled meter reading date provided the Customer has selected the option at least five days prior to their next scheduled meter read date. Absent the five-day notice, the change will become effective on the subsequent meter read date. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date. (M)

SCHEDULE 32 (Continued)

SPECIAL CONDITIONS (Continued)

2. The Company, in its discretion, may accept enrollments on accounts that have a time payment agreement in effect, or have received two or more final disconnect notices. However, the Company will not accept enrollments from customers that have been **(C)**
involuntarily disconnected in the last 12 months due to non-payment. **(C)**

3. The Company will use reasonable efforts to acquire renewable energy, but does not guarantee the availability of renewable energy sources to serve Renewable Portfolio Options. The Company makes no representations as to the impact on the development of renewable resources or habitat restoration projects of Customer participation.

4. Amounts in the RDF will be disbursed by the Company to non-residential renewable resource demonstration projects or projects that commit to supply Energy according to a contractually established timetable. The Company will report to the Commission annually by March 15th, pursuant to Order No. 16-156, on collections and disbursements for the preceding calendar year. The annual report will include a list of projects that received or were allocated RDF funding.

5. Amounts placed in the RDF prior to July 6, 2016 will accrue interest at the Commission-authorized cost of capital until disbursed. Amounts placed in the fund on and after July 6, 2016 will accrue interest at the Commission-authorized rate for deferred accounts in amortization until disbursed. Amounts within the fund will be disbursed on a first-in-first-out basis. Once funds have been committed to projects, following the required OPUC review, they will be deemed disbursed. Funds deemed disbursed and still held by the Company, will accrue interest at the Commission-authorized rate for deferred accounts in amortization.

Pertaining to TOU Option

1. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. Participation requires a one-year commitment by the Customer. Generally, if a Customer requests removal from the TOU Option, the Customer will be required to wait 12 months before re-enrolling. However, a Customer may request to reinstate service within 90 days of termination, in which case the Portfolio Enrollment Charge will be waived.

SCHEDULE 32 (Concluded)

Pertaining to TOU Option (Continued)

3. The Customer must take service at 120/240 volts or greater. Single phase 2-wire grounded service is not eligible because of special metering requirements. **(M)**

4. The Customer must provide the Company access to the meter on a monthly basis.

5. At the end of the Customer's first 12 months of service under the TOU Option, the Company will calculate what the Customer would have paid under Standard Service and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded the Standard Service Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount in excess of 10% either as a bill credit or refund check. No refund will be issued for Customers not meeting the 12-month requirement. **(M)**

6. The Company will recover lost revenue from the TOU Option through Schedule 105.

7. Billing will begin for any Customer on the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date.

8. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 38
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers: 1) served at Secondary Demand Voltage whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW; or 2) who were receiving service on Schedule 38 as of December 31, 2015.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge	$30.00		
Transmission and Related Services Charge	0.415	¢ per kWh	
Distribution Charge	7.787	¢ per kWh	(I)
Energy Charge*			
On-Peak Period	6.027	¢ per kWh	
Off-Peak Period	4.527	¢ per kWh	

* See Schedule 100 for applicable adjustments.
** On-peak Period is Monday-Friday, 7:00 a.m. to 8:00 p.m. off-peak Period is Monday-Friday, 8:00 p.m. to 7:00 a.m.; and all day Saturday and Sunday.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 38 (Continued)

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window. **(C)** **(C)**

During the Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

November Election Window

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 38 (Continued)

DIRECT ACCESS DEFAULT SERVICE

A Customer returning to Schedule 38 service before completing the term of service specified in Schedule 538, must be billed at the Daily Price for the remainder of the term. This provision does not eliminate the requirement to receive service on Schedule 81 when notice is insufficient. The Daily Price under this schedule is as follows:

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0640	**(R)**

PLUG-IN ELECTRIC VEHICLE (EV) TIME OF DAY OPTION

A large Nonresidential Customer wishing to charge EV’s may do so either as part of an integrated service or as a separately metered service billed under the TOU Option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B (30) for the purpose of load research, and to collect and analyze data to characterize electric vehicle use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 38 (Concluded)

SPECIAL CONDITIONS (M)

Pertaining to Optional Time of Day Standard Service

1. Service under this schedule will begin on the first day of the Customer's regularly scheduled Billing Period.

2. In no case will the Company refund a Customer by retroactively adjusting the rate at which service was billed prior to the date the Customer begins service on this schedule.

TERM

Service will be for not less than one year or as otherwise provided under this schedule. (M)

SCHEDULE 47
SMALL NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge			
Summer Months**	$37.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.475	¢ per kWh	
Distribution Charge			
First 50 kWh per kW of Demand***	12.815	¢ per kWh	(I)
Over 50 kWh per kW of Demand	10.815	¢ per kWh	(I)
Energy Charge	6.434	¢ per kWh	

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 10 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 47 (Concluded)

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 49
LARGE NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Large Nonresidential Customer is defined as having a monthly Demand exceeding 30 kW at least twice within the preceding 13 months, or with seven months or less of service having exceeding 30 kW once.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge			
Summer Months**	$45.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.478	¢ per kWh	
Distribution Charge			
First 50 kWh per kW of Demand***	9.964	¢ per kWh	(I)
Over 50 kWh per kW of Demand	7.964	¢ per kWh	(I)
Energy Charge	6.586	¢ per kWh	

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 30 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 49 (Concluded)

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

NOVEMBER ELECTION WINDOW

Enrollment for the November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Enrollment Windows will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business (T)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 50
RETAIL ELECTRIC VEHICLE (EV) CHARGING

PURPOSE

This retail Electric Vehicle (EV) charging schedule is a supplemental service that governs the use of PGE's charging network for EVs. This schedule does not impact, replace, or otherwise modify any base retail service under which a customer is currently served by PGE. This schedule is designed solely for the retail sale of electricity as a transportation fuel.

DEFINITIONS

Direct Current Quick Chargers (DCQC) or Direct Current Fast Chargers (DCFC) – individual chargers that provide service at approximately 50 kW of peak demand or greater.

Electric Avenue Sites – Stations in PGE's service area that are listed as part of Electric Avenue **(N)**
on portlandgeneral.com. **(N)**

EV User – An EV driver or operator who uses the PGE charging Station. This does not have to be a PGE customer.

Holidays – refers to New Year's Day (December 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November, and Christmas Day (December 25). If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

Level 2 Chargers - individual chargers that are capable of providing service at approximately 7 kW.

Off-Peak – refers to all other hours outside of the On-Peak period.

On-Peak – refers to the hours of 3 PM to 8 PM on weekdays, excluding holidays.

Session – each unique charging event in which a customer connects a vehicle to a PGE charger.

Station – the location of a PGE charging facility, consisting of one or more DCQC and/or Level 2 Chargers.

AVAILABLE

The service described in this schedule is available – through a point-of-sale transaction or a monthly subscription, depending on EV User preference – as requested, and is intended for use at PGE's EV charging Stations.

This schedule is not available for any use other than the purchase of retail electricity as a transportation fuel.

SCHEDULE 50 (Concluded)

APPLICABLE

This schedule is available to all EV Users of PGE's EV charging Stations.

RATE

EV Users requesting service under this schedule may choose between a point-of-sale option, pre-pay, or a monthly subscription. EV Users may purchase a monthly subscription for use at Electric Avenue sites. Pricing is as follows: **(C)** **(C)**

	Flat Fee (all hours)*	On-Peak Charging Price
Direct Current Fast Charger	$5.00 per Session	Flat fee + $0.19 per kWh
Level 2 Charger	$3.00 per Session	Flat fee + $0.19 per kWh
Monthly Membership		
Single Purchase	$25.00 per month	$0.19 per kWh
Multiple Purchase**	$20.00 per month	$0.19 per kWh

* The flat fee is also the total charge during the Off-Peak period.
** Monthly memberships may be purchased at a discounted price of $20 per month when buying at least 50 memberships at once.

The monthly membership subscription replaces the pay per-Session flat fees at Electric Avenue sites, but does not include the peak-time price. **(C)** **(C)**

If an EV User has selected the per-Session option, payment will be made via credit card or other applicable payment method at the PGE charging Station. **(C)**

SPECIAL CONDITIONS

1. This schedule is designed for retail service to drivers or operators of EVs. EV User-owned EV chargers are not eligible for service under this retail charging rate.

2. The pricing listed in this tariff is part of a pilot program and is subject to change.

3. EV Users may not request service under this schedule for any purpose other than the purchase of electricity from PGE to fuel the customer's vehicle(s) at PGE's EV charging Stations.

SCHEDULE 52
NONRESIDENTIAL ELECTRIC VEHICLE CHARGING REBATE PILOT

PURPOSE

This Nonresidential Electric Vehicle (EV) Charging Rebate Pilot provides eligible Customers a rebate towards the purchase and installation of EV chargers or infrastructure, or both, that meets the defined eligibility criteria. The overarching goals of the pilot are to: (C) (C)

- Accelerate EV adoption by ensuring adequate charging infrastructure is available to meet customers' charging needs;
- Reduce the cost and complexity of installing EV Supply Equipment that can preclude Customers from deploying charging infrastructure; and
- Create a network of demand-side resources to reduce the costs of serving EV loads by supporting efficient grid operations and future renewables integration.

AVAILABLE

In all territory served by the Company.

APPLICABLE

This pilot is applicable to Nonresidential Customers and property managers/owners of multifamily residence(s) until the cap approved in OPUC Order No. 19-385 and the authorized HB 2165 Monthly Meter Charge budget have been reached. Temporary customers such as construction sites which have not received their certificate of occupancy are excluded.

DEFINITIONS

Direct Current Fast Charger (DCFC) EVSE – An EVSE that transfers direct current to the EV. (T)

Electric Vehicle Supply Equipment (EVSE) – The device, including the cable(s), coupler(s), and embedded software, installed for the purpose of transferring electricity between the electrical infrastructure and the EV.

Electric Vehicle Service Provider (EVSP) – The entity responsible for operating networked EVSEs. (N) (N)

Level 2 (L2) EVSE – An EVSE that transfers alternating current to the EV at 208 or 240 volts.

Make-Ready Infrastructure – The infrastructure at the Site to deliver electricity from the Service Point to the EVSE(s), including any panels, stepdown transformers, conduit, wires, connectors, meters, and any other necessary hardware. (N) | (N)

(M)

SCHEDULE 52 (Continued)

DEFINITIONS (Continued)

Operational – An EVSE installed on the premises that is able to transfer energy between the premises wiring and the EV, with all the applicable payment methods (e.g., credit card, phone app, subscription card), and transmit operational data (e.g., energy usage, session start/end times) to the EVSP. (M)

Port – The cable and coupler used to transfer energy from the EVSE to the EV. The number of Ports is defined by the number of EVs that can be charged simultaneously by a given EVSE. There are commonly one or two Ports per EVSE. (M)

Qualified EVSE –The list of qualified EVSE(s) that are available for rebate is determined by the Company and listed on PortlandGeneral.com.

ELIGIBILITY

Eligible Customers must own, lease, or demonstrate control over the site where the EVSE(s) are installed. The Customer will be responsible for procuring the Qualified EVSE(s) and are eligible for the pilot as follows: (C)

1. Qualified EVSEs are eligible for the following rebates, unless the EVSE cost is covered by PGE grant funding or installation of the EVSE's Make-Ready Infrastructure is provided by the Commercial Electric Vehicle Make Ready Pilot (Schedule 56):
    a. Standard L2 EVSE Rebate.
    b. Multi-Family (MF) L2 EVSE Rebate.
    c. L2 EVSE Installation Rebate.
    d. DCFC EVSE Rebate.
2. Qualified EVSEs installed by Fleet Customers using Make-Ready Infrastructure provided by the Commercial Electric Vehicle Make Ready Pilot (Schedule 56) are eligible for the following rebate:
    a. Standard L2 EVSE Rebate; limit of $8,000 per Customer.
3. Qualified EVSEs installed by Non-Fleet Customers using Make-Ready Infrastructure provided by the Commercial Electric Vehicle Make Ready Pilot (Schedule 56) are eligible for the following rebates:
    a. Standard L2 EVSE Rebate; limit is the lesser of either 12 rebates or number of chargers supported by infrastructure built per Customer.
    b. Multifamily L2 EVSE Rebate; limit of 12 rebates per Customer. (C)

ENROLLMENT

The customer enrollment period will be open until funds have been allocated. Eligible Customers may enroll at PortlandGeneral.com.

(M)

SCHEDULE 52 (Continued) (T)

REBATES (M)

Rebate	Description	Amount
Standard L2 EVSE Rebate	A one-time rebate for the purchase of a Qualified L2 EVSE.	Up to $1,000 per Port; capped at price paid. Customers are eligible for up to $50,000 in Standard L2 EVSE Rebates per site, unless otherwise noted.
Multifamily L2 EVSE Rebate	A one-time rebate for the purchase of a Qualified L2 EVSE installed at a multifamily dwelling.	Up to $2,300 per Port; capped at price paid. For customers who also participate in Schedule 56, the rebate will be issued in two parts – the first $1,000 will be issued at installation and the remaining $1,300 will be given after five years if the property owner maintains rates within 10% of Schedule 50. Customers are eligible for up to $50,000 in Multifamily L2 EVSE Rebates per site, unless otherwise noted.
L2 Installation Rebate	A one-time rebate for installing a L2 EVSE. Eligible covered costs include the cost of installing electrical infrastructure to support the EVSE, including but not limited to trenching, conduit, switchgear, equipment pads, line extension costs, site restoration, and EVSE installation.	Up to 80% of eligible costs paid or $6,000 per Port, whichever is less. Customers are eligible for up to $36,000 in L2 Installation Rebates per site.
DCFC EVSE Rebate	A one-time rebate for the purchase and installation of a Qualified DCFC EVSE.	Up to $350 per kW of maximum power output for the EVSE, up to a maximum of $25,000 per Port.

(C)
(C)
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(C)
(C)
(C)
(M)

Rebates are available for reservation on a first come-first serve basis per the reservation process identified on PortlandGeneral.com. Eligible Customers must comply with the application instructions and agree to the pilot Terms and Conditions on PortlandGeneral.com to receive the rebate.

SCHEDULE 52 (Concluded)

REBATES (Continued) **(M)**

Participating Customers will receive the one-time payment by check no later than 90 days from the Company receiving a complete application. All EVSE(s) installed under the pilot are subject to verification by PGE.

Participating Customers must meet the pilot requirements for 10 years. In the event the Participating Customer does not meet this commitment, the Participating Customer commits to reimburse PGE the pro-rata value of the rebate, calculated over the 10-year term.

SPECIAL CONDITIONS

1. Participation in this pilot is not mandatory to install EV charging equipment.

2. The Customer's charges for Electricity Service under any of the Company's Standard Service or Direct Access Service schedules are not changed or affected in any way by service under this schedule and are due and payable as specified in those schedules.

3. The Company will defer and seek recovery of all pilot costs not otherwise included in rates.

4. Participating Customers will maintain the EVSE(s) on a Standard Service Schedule. Customers on Direct Access Service must have the participating chargers separately metered and on a Standard Service Schedule.

5. Participating Customers will ensure the EVSE(s) are Qualified and Operational. If a property with EVSE(s) installed under the pilot changes ownership, lesseeship or management, participation in the pilot can be assumed by a new owner, lessee or manager that is willing to meet the pilot requirements.

6. Participating Customers will authorize the EVSP to provide operational data (e.g. energy usage, time of day usage and number of unique drivers) to PGE. Participating Customers agree to allow Company and its agents and representatives to use data gathered as part of the pilot in regulatory reporting, ordinary business use, industry forums, case studies or other similar activities, in accordance with applicable laws and regulations and to participate in Company-led research such as surveys.

7. Participating Customers may terminate participation in the pilot after providing PGE no less than 30 days' notice and are subject to the noncompliance reimbursement referenced in this Tariff. At the end of the 10-year term, Participating Customers have the option to continue to participate in the pilot if it is still active, but there is no obligation to do so.

(M)

SCHEDULE 53
NONRESIDENTIAL HEAVY-DUTY ELECTRIC VEHICLE CHARGING

PURPOSE

This Nonresidential Heavy-duty Electric Vehicle Charging offering aims to provide learnings about high-powered charging infrastructure, integrated energy storage and on-site generation technologies, and vehicle-to-grid technologies. This schedule is designed solely for the use of electricity as a transportation fuel for heavy duty vehicles. The objectives of this offering are:

- Provide unique opportunities to better understand grid impacts from heavy duty Electric Vehicle charging rates and how complementary grid edge technology (storage, solar, demand response) can help ensure infrastructure can be deployed in ways that benefit the grid
- Offer opportunities to actively engage and provide helpful guidance to customers in the design, deployment, commissioning, and operation of heavy-duty vehicle charging infrastructure
- Obtain heavy-duty Electric Vehicle usage data and gain insights to charging load profiles

AVAILABLE

In all territory served by the Company.

APPLICABLE

This offering is applicable to nonresidential heavy-duty Electric Vehicles manufacturers and operators that deploy high-powered charging infrastructure and also allows for public charging for light, medium and heavy-duty vehicles at the same site, and following conditions:

1. Where the site is made-ready to host or hosts at least one heavy-duty Electric Vehicle charging station capable of an output of at least one MW per port or greater;
2. Where the site is made-ready to host or hosts an energy storage system; and
3. Where the site is made-ready to host or hosts on-site generation.

DEFINITIONS

<u>Charging Infrastructure</u> – All infrastructure and equipment required to deliver energy to an Electric Vehicle, including all civil and electrical infrastructure or equipment located downstream of the Service Meter such as panelboards, switchboards, conductors, pathway, equipment foundations.

<u>Clean Fuels Credits</u> – Non-monetary asset generated by Electric Vehicle Charging Stations under Oregon's Clean Fuels Program

SCHEDULE 53 (Continued)

DEFINITIONS (Continued)

Electric Vehicle Charging Software - Software used to monitor, control, optimize, or perform other functions on Electric Vehicle Charging Stations, or other devices.

Electric Vehicle Charging Station – Equipment designed and installed specifically for the purposes of transferring energy to an Electric Vehicle.

High Power – Electric Vehicle charging rates in excess of 1 MW.

Vehicle Classes - The vehicle weight classes are defined by Federal Highway Administration (FHWA) and are used consistently throughout the industry. Vehicle classes, 1-8, are based on gross vehicle weight rating (GVWR), the maximum weight of the vehicle, as specified by the manufacturer. GVWR includes total vehicle weight plus fluids, passengers, and cargo. FHWA categorizes vehicles as Light Duty (Class 1-2), Medium Duty (Class 3-6), and Heavy Duty (Class 7-8).

Light Duty Vehicle – gross vehicle weight rating less than 10,000 lbs.
Medium Duty Vehicle – gross vehicle weight rating between 10,001 – 26,000 lbs.
Heavy Duty Vehicle – gross vehicle weight rating higher than 26,001 lbs.

ELIGIBILITY

Nonresidential customers that are heavy-duty electric vehicles manufactures and operators may participate in this offering if the following conditions are met:

1. Customer agrees to co-development of a large public charging site for medium- and heavy-duty electric commercial vehicles.
2. The large public charging site is designed to support customer's vehicle charging activities and give access to public to charge heavy-duty vehicles.
3. The site is made ready to host or hosts multiple grid edge technology such as: on-site energy storage, on-site energy generation, demand response capabilities, advanced grid edge controls, and/or other new and novel grid edge technologies.
4. Customer signs up for Oregon Clean Fuels Program
5. Customer will provide electric usage data and operational data to the Company upon request.
6. Customer has not been granted any transportation line extension allowance associated with the subject project.

COMPANY RESPONSIBILITY

Upon request from a Customer, the Company will contribute a portion of the project development costs including costs related to investments behind the customer meter. The total aggregate amount of Company contributions under this schedule is $10 million for all projects. Each customer participating in the program is limited to $5 million total. Due to the individualized nature of each project, specifics on the development of the project and payment responsibilities will be contained in a service agreement. Upon termination of the agreement, the Company may remove or abandon Company owned Charging infrastructure in place.

SCHEDULE 53 (Concluded)

SPECIAL CONDITIONS

1. The Customer's charges for Electricity Service under any of the Company's Standard Service or Direct Access Service schedules are not changed or affected in any way by service under this schedule and are due and payable as specified in those schedules.

2. Prior to receiving service on this schedule, the Customer and the Company must enter into a written agreement, signed by the Customer.

3. Customers receiving service under this schedule will agree to a multi-year term for the agreement. Should the Customer terminate the agreement before the end of the term, the Customer will reimburse the Company for a portion of the capital investment as specified in the service agreement.

TERM

Effective March 15, 2021 through December 31, 2027. **(C)**

SCHEDULE 54
LARGE NONRESIDENTIAL
RENEWABLE ENERGY CERTIFICATES RIDER

PURPOSE

This rider is an optional supplemental service that supports the development of New Renewable Energy Resources as defined in ORS 757.600. Under this Schedule, a Large Nonresidential Customer may purchase Renewable Energy Certificates (RECs), subject to a minimum purchase and availability of RECs for purchase.

AVAILABLE

In all territory served by the Company.

(D)

APPLICABLE

To all Customers taking service under any of the following PGE schedules: 38, 49, 83, 85, 89, 90, 91, 95, 485, 489, 490, 491, 495, 583, 585, 589, 590, 591, 595, and 689. Customers who are on one of these base schedules who also have schedule 15 area lighting may include those schedule 15 lights in this program. **(C)** | **(C)**

PRODUCT OFFERINGS

I. PGE Green Resource Mix

This product allows a Customer to purchase RECs, subject to minimum purchase. The product is Green-e® Energy certified, and as a result all RECs purchased on behalf of Green Resource Mix Customers will conform to the Green-e® Renewable Energy Standard for Canada and the United States and are either registered with Western Renewable Energy Generation Information System (WREGIS) or provided via third party audited Green-e attestation. **(T)** **(C)**

II. Specified Resource

This product allows a customer to purchase RECs from a specified facility, subject to a minimum purchase. Specified Resource provides the Customer with RECs obtained from specified resources and derived from the following fuels: **(T)** **(C)**

SCHEDULE 54 (Continued)

PRODUCT OFFERINGS
Specified Resource (Continued)

1. Wind;
2. Solar;
3. Certified low-impact hydroelectric;
4. Pipeline or irrigation hydroelectric systems;
5. Wave or tidal action;
6. Low emissions biomass (from digester methane from landfills, sewage or waste treatment plants, forest or field residues); **(T)**
7. Hydrogen derived from photovoltaic electrolysis or non-hydrocarbon derivation process; **(T)**
8. Geothermal. **(N)**

Upon customer request, PGE will make best efforts to assist the Customer in identifying a product mix or discrete generators matching the fuel types listed above. Any offering under Specified Resource must be 100% new renewable, which is defined as follows: **(C)** **(C)**

(1) a) Placed in operation (generating electricity) on or after January 28, 2000;

b) repowered on or after January 28, 2000 such that 80% of the fair market value of the project derives from new generation equipment installed as part of the repowering, or

c) a separable improvement to or enhancement of an operating existing facility that was first placed in operation prior to January 28, 2000 such that the proposed incremental generation is contractually available for sale and metered separately than existing generation at the facility.

(2) Any project that has been subject to an uprate meant solely to increase generation at a facility – without the construction of a new or repowered, separately metered generating unit – is not eligible for the specified resource offering.

Generation facilities solely owned by PGE (or included in the rate base of PGE) and constructed for the purpose of serving cost-of-service utility customers are not eligible for selection in the specified resource program.

III. DEQ Clean Fuels Compliant Resource

This product allows Customers to purchase qualifying RECs that meet the requirements to generate incremental clean fuels credits as part of the Oregon Clean Fuels Program administered by the Oregon Department of Environmental Quality (DEQ) under ORS 468A. Under this option, PGE only offers RECs that meet the Clean Fuels Program requirements.

SCHEDULE 54 (Continued)

RATE

1. With regard to Offering 1, PGE Green Resource Mix:

   a. The rate for this product is specified in the Green-e ® Energy required disclosure documents, a copy of which is provided to the Customer.

   b. The rate for Offering 1 shall be comprised of three components: the market price for the REC, selling, general, and administrative (SG&A) costs, and a risk premium fee.

   c. The market price for RECs may change but will be based on expected market conditions and program demand. The SG&A costs will be calculated to ensure that program participants bear the entirety of these costs, and these costs will be uniformly charged to customers. The risk premium accounts for PGE shareholder risk from entering a fixed price contract to supply RECs and will not exceed PGE's currently approved rate of return. The risk premium will be the same for all customers participating in this offering.

   d. A minimum REC purchase of 1,000 kWh per month, or annual equivalent, is required.

2. If a Customer chooses to participate in the Specified Resource or DEQ Clean Fuels Compliant Resource program, the same rate components as described in Offering 1 shall apply, but the price may differ and is subject to execution of a written contract. **(C)** **(C)**

SPECIAL CONDITIONS

1. The Customer may enroll to purchase any option outlined in this tariff after entering an agreement with the Company. Participation will commence within 60 days of the Company providing Customer with confirmation of a properly executed agreement that includes Customer's signature, which can be digital. **(C)** **(C)**

2. The Company will not accept enrollments from accounts with poor credit history. For the purposes of this offering, poor credit history is defined as: a) having received two or more final disconnect notices in the past 12 months; or b) having been involuntarily disconnected in the past 12 months.

3. The Company makes no representations as to the impact on the development of renewable resources from Customer participation.

SCHEDULE 54 (Concluded)

SPECIAL CONDITIONS (Continued)

4. The Company is not required to own renewables or to acquire energy from renewable resources simultaneously with Customer usage.

5. PGE will purchase RECs sufficient to meet all Customer commitments, and retire them annually.

6. The Company will charge or credit all incremental costs and revenues associated with the provision of services under this schedule to nonutility accounts.

7. PGE offers this product through a competitive operation and is provided in accordance with the Code of Conduct as set forth in OAR 860-038-0500 through 860-038-0640.

8. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other REC providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to allowing the Company's Large Nonresidential REC program to use the bill inserts.

9. PGE will limit the number of RECs that PGE offers for purchase under the PGE Green Resource Mix option, as well as the number of Green Resource Mix RECs bought by any individual customer based on RECs PGE has purchased. PGE reserves the right to change **(C)**
the limit based on the current program price and market price of RECs. The availability of **(C)**
Specified Resource and Clean Fuels Compliant RECs is also dependent on market supply and pricing and may be limited. In the event that RECs are limited in supply, there will be a waitlist for any new participants that will be served on a first come first served basis.

SCHEDULE 55
LARGE NONRESIDENTIAL
GREEN ENERGY AFFINITY RIDER (GEAR)

PURPOSE

This tariff is an optional supplemental service that supports the development of local new renewable resources as defined in Oregon Revised Statute (ORS) 469A.025. Under this Schedule, a Nonresidential Customer may purchase a subscription share of a new renewable facility matched to the preference of the Subscribing Customer (with a maximum subscription of **(C)**
the Customer's yearly consumption). **(C)**

DEFINITIONS

"Local" means that the facility that generates the qualifying electricity for which the bundled renewable energy certificate is issued is located in the United States and within the geographic boundary of the Western Electricity Coordinating Council (WECC). This definition is consistent with ORS 469A.135. Portland General Electric Company (PGE) may seek specific resource locations at the Subscribing Customer's request.

"Bundled Renewable Energy" or "Bundled Renewable Energy Certificates" means a renewable energy certificate (REC) for qualifying electricity that is acquired by an electric utility or electricity service supplier by a trade, purchase, or other transfer of electricity, or by an electric utility by generation of the electricity for which the REC was issued. This definition is consistent with ORS 469A.005.

"Energy Value" means the energy value calculated using the AURORA model and the same methodologies and assumptions described in the Integrated Resource Plan (IRP) or IRP update, at the time the resource contract is executed.

"Capacity Value" means the value of capacity, calculated as described in PGE's IRP, at the time the resource contract is executed.

"Company-Owned Resource" means a resource developed or purchased by the Company. Should the Company propose to own a resource serving this program, that proposed ownership is subject to meeting the requirements of Public Utility Commission of Oregon (OPUC) Order 21-091 regarding company ownership, and OPUC Order 21-263.

"Customer Supply Option (CSO)" means a resource identified and selected by the Customer, with assistance from PGE in identifying a resource if requested by the Customer, and contracted as a Power Purchase Agreement (PPA), or Company-Owned Resource, or other means consistent with the Minimum Requirements. CSO eligible Customers, are Customers with greater than 10 aMW in load or as otherwise approved by the Public Utility Commission of Oregon (OPUC).

SCHEDULE 55 (Continued)

DEFINITIONS (Continued)

"Minimum Requirements" means the minimum requirements for available commercial structures. The minimum requirements may be found at this link: https://portlandgeneral.com/energy-choices/renewable-power/green-future-impact The minimum requirements may be updated from time to time to reflect PGE's criteria from its latest Commission accepted renewable request for proposals.

"PGE Supply Option (PSO)" means the renewable resource(s) for Subscribing Customer(s) is identified and procured by PGE to meet aggregate Subscribing Customers loads in the program. The PSO resource could be contracted as a PPA, a Company Owned Resource, or other means consistent with the Minimum Requirements.

"Power Purchase Agreement (PPA)" means a long-term electricity supply agreement between a power producer and PGE. The PPA is one means of procuring renewable energy for Subscribing Customers in this voluntary supplemental service program.

"Subscribing Customer" means a PGE Nonresidential Customer served by retail base service, who elects to receive voluntary supplemental service through this program.

AVAILABLE

In all territory served by the Company.

APPLICABLE

This schedule is available – subject to capacity approved by the Oregon Public Utility Commission (OPUC) from time to time – to all Nonresidential Customers each of whose aggregate demand across all retail schedules exceeds 30kW. In the event that a Subscribing Customer has multiple accounts – some of which may fall under 30kW of demand – the Subscribing Customer will be allowed to aggregate all Nonresidential accounts.

GENERAL PROVISIONS

1. Customers enrolling in this schedule commit to a subscription share of a new renewable facility, matched to the preference of the Subscribing Customer (with a maximum **(C)**
subscription of the Customer's yearly consumption). **(C)**

SCHEDULE 55 (Continued)

GENERAL PROVISIONS (Continued)

2. The Company will ensure that renewable energy resources utilized under this schedule are new, meaning they are or have been operational no earlier than one year prior to the resource being included in the program, and may include energy storage associated with Renewable Portfolio Standard (RPS)-eligible resources as defined in ORS469A.120(2)(a). A Subscribing Customer using the CSO shall ensure that renewable energy resources utilized under this schedule are or have been operational no earlier than one year prior to the resource being included in the program, and may include energy storage associated with RPS-eligible resources as defined in ORS469A.120(2)(a).

3. The Company shall procure Bundled Renewable Energy on the Subscribing Customer's behalf – or through collaborative sourcing with a customer for the CSO – from a new renewable energy facility. In the event of yearly under-generation from the renewable energy resource, the Company will purchase RECs on the Subscribing Customer's behalf to ensure that the Customer's subscribed amount is covered under this tariff. In the event that the renewable energy supplier is no longer able to supply bundled renewable energy to the Subscribing Customer, the Company, at the election of the Subscribing Customer, shall make reasonable efforts to procure a new resource on behalf of the Subscribing Customer as soon as practicable with the cost of the renewable energy to the Subscribing Customer revised accordingly.

4. This schedule is for supplemental retail service, and will be served solely as a supplement to retail base rates by the Company. Subscribing Customers who leave PGE's retail supply service, or who are not on PGE's retail supply service, are ineligible for this program. **(C)**

5. The Company will retire the RECs associated with the energy procured on behalf of the Subscribing Customer, or the Subscribing Customer may retire the RECs itself.

6. Should the Company propose to own a resource serving this program, the Company will follow Commission direction including proposing accounting safeguards for separate accounting for the Company owned GEAR resource. The renewable energy GEAR resource may be included in rate base so long as the asset(s) can be accounted for separately from the Company's general rate base. The proposed safeguards will prevent the commingling of renewable resources serving this program with other assets that are in rate base for the purpose of serving non-GEAR customers[1].

1.This requirement is found in Commission Order 21-091 at page 12.

SCHEDULE 55 (Continued)

ENROLLMENT PROCESS

When the Company opens the queues for Customer enrollment, Customers can elect to enter either the CSO or PSO queue. The Company will maintain separate and distinct queues for the CSO and PSO options. Customers will be allowed to enter one queue and will not be allowed to be simultaneously enrolled in both the CSO and PSO queues. Customer placement in the program option queue they elect will be based on the timestamp that the Company receives electronically when the Customer returns the signed, non-binding letter of interest. Customers will submit their letter of interest and the amount of load. Enrollment will remain open and PGE will maintain each respective queue order until all available capacity is fully subscribed by Customer contracts. Subject to the program eligibility requirements, a Customer may withdraw their election in writing and return a signed non-binding letter of interest to be placed in the other queue, and their new queue position will be based on the timestamp that the Company receives electronically when the Customer returns the new signed non-binding letter of interest received by the Company. **(C)** **(C)**

1. The Customer shall independently make the selection of the CSO resource for enrollment in the program.

2. The Customer will determine when to engage PGE in the CSO resource identification and solicitation process. Should the Customer approach PGE for help during the identification and/or solicitation process for a CSO resource, PGE will assist the Customer. The Company will provide written notice of the Customer's request to the Staff of the OPUC.

3. If a CSO Customer elects to seek PGE's help for resource identification or solicitation, the Company will ensure the costs of such efforts are separately tracked and collected via the Customer's program administration fee to avoid cost shifting. **(C)**

4. Given that the resource will be interconnected and delivering energy into PGE's system, the Company will be the entity contracting for the resource to serve the CSO Customer and must be provided the opportunity, in the course of the development of an agreement between a CSO Customer and a third-party to review and address contract terms that would shift costs or risks to other Customers or PGE shareholders. The Subscribing Customer may determine the appropriate point in time to involve PGE during contract negotiations, but must allow PGE sufficient time to review and address contract terms. **(T)** **(T)**

5. The Company will not help with CSO resource identification or design a CSO resource solicitation if the Company plans to submit a Company provided resource into such solicitation. Any submission of a utility developed resource to a CSO Customer would be in the form of a formal response to a Customer's solicitation.

6. The same renewable energy project may support both the CSO and PSO; however, contracts for the CSO and PSO will be separately negotiated.

7. The Company will accept the commercial structure of the resource that is selected by the CSO Customer, subject to the allowable commercial structures and applicable requirements as identified in the posted Minimum Requirements. **(C)**

SCHEDULE 55 (Continued)

ENROLLMENT PROCESS (Continued)

8. Should PGE propose a Company Owned Resource for this program, PGE will submit to all applicable Commission processes, including the Commission's competitive bidding rules unless such rules are waived, and initiate a Commission process to determine appropriate segregation of the asset. If no processes under the competitive bidding rules are required for the acquisition of a project by the Company for the GEAR program, the Company nevertheless commits to provide for a process that would allow Commission review into the acquisition before it is completed. **(T)**

9. PGE will not establish capacity limits with regard to Customers enrolling in the CSO option. **(N)**

10. If PGE anticipates customer demand for the PSO offering exceeds 100% of the offered capacity, PGE will limit each participants allowable capacity. The limit will restrict subscription so that no customer can subscribe to more than 20% of the total offered capacity for the upcoming offering. In the event remaining capacity is available, PGE will allocate this remaining available capacity to customers requesting an amount in excess of the limit in the order of the Customer's queue position. In advance of the enrollment queue opening to Customers, PGE will publish the 20% limit on capacity and the date when it will allocate any available remaining capacity on the Company's website. **(N)**

PRICING STRUCTURE

1. While enrolled in this Rider, the Subscribing Customer shall continue to take service under – and pay the components of – their applicable base rate schedule and all supplemental schedules and riders.

2. The Rider rate will pass to Subscribing Customers the costs of acquiring the renewable energy resource and operating this supplemental program. The Subscribing Customer will be credited with the Energy Value and Capacity Value (as applicable). These charges and credits will be determined and billed as follows:

   - The cost for each MWh of the applicable resource generated and delivered to the Subscribing Customer;
   - An administrative charge to account for program costs, integration, shaping, firming, and other relevant program expenses;
   - A risk adjustment, if applicable;
   - Credit for Energy Value and Capacity Value, as defined in the "Definitions" section above.

3. Non-subscribing Customers will not be subject to resource costs, administrative costs, or any cost associated with this program, except for the crediting of Energy Value and Capacity Value, as applicable.

(M)

SCHEDULE 55 (Concluded)

CREDITS (T)

1. The bill credit amount, the sum of the Capacity and Energy Values, represents the amount that cost of service Customers are paying to the Subscribing Customer(s), for the resource. (M)

2. The bill credit amount is determined by the Company, using the Company's IRP methodology to determine the Capacity and Energy Values. The credit values for energy and/or capacity will be determined at the time of resource procurement, fixed over the contract period. (M)

3. The Company shall submit for regulatory review the rate and credit calculations agreed upon by the Company and the Subscribing Customer through a filing to the Staff of the OPUC.

4. For the CSO option, Customers may apply to the PUC for a floating credit on a case by case basis. A floating credit is one that updates in a predictable way periodically and while it does not guarantee net savings to a participant, it may result in participant net savings[1].

CONTRACT PERIOD

The Subscribing Customer may elect to subscribe to this Rider for a term between 5 and 20 years, as agreed upon between the Company and the Subscribing Customer. The Subscribing Customer shall enter into a contract for service under this Rider for a term and with terms and conditions consistent with the terms and conditions of the contract with the renewable energy supplier or the life of the resource, or as agreed upon between Company and Subscribing Customer (and subject to regulatory review). If the Subscribing Customer requests an amendment to or termination of the subscription agreement, or defaults on the subscription agreement before the expiration of the term of the agreement, the Subscribing Customer shall be subject to termination and default provisions as contained within the subscription agreement between the Subscribing Customer and the Company.

1.For Commission discussion of the floating credit approach, see Order 19-075 at pages 5-6.

SCHEDULE 56
COMMERCIAL ELECTRIC VEHICLE MAKE-READY PILOT **(C)**

PURPOSE

This Commercial Electric Vehicle (EV) Make-Ready Pilot provides eligible Fleet and Non-Fleet Customers with incentives to install Electric Vehicle charging infrastructure to support fleet and personal electric vehicles at fleet, commercial, workplace, and multifamily sites. The overarching goals of the pilot for both Fleet and Non-Fleet Customers are to: **(C)**

- Evaluate the methods and incentives used to support both Fleet and Non-Fleet Customers' electric transportation transition;
- Create a network of demand side resources to reduce the costs of serving EV loads by supporting efficient grid operation and future renewables integration; and
- Generate empirical data that can be used to inform existing utility analyses, support customers transitioning to electric vehicles, and develop future products and programs.

The primary goals of the pilot for Fleet Customers are to:

- Enable and support the electrification of commercial, public (municipal, county, state, federal), school, non-profit and transit fleets by reducing customer cost and complexity associated with transitioning to electric fuel;
- Better understand the Fleet Customer and barriers and opportunities in the fleet electrification market; and
- Identify areas for utility process improvement with respect to fleet electrification.

The primary goals of the pilot for Non-Fleet Customers are to:

- Support the equitable electric transportation transition at commercial, workplace, and multifamily locations by reducing costs and complexity for property owners;
- Gain insight and information to better understand the barriers for Non-Fleet Customers and users of public and semi-public charging infrastructure; and
- Identify areas of utility process improvement for non-fleet commercial electrification and make ready infrastructure deployment. **(C)**

AVAILABLE

In all territory served by PGE.

APPLICABLE

This pilot is applicable to nonresidential customers within PGE's service area. **(C)**

(M)

SCHEDULE 56 (Continued)

DEFINITIONS **(M)**

Activation Date – date that PGE first determines an EVSE is Operational.

Electric Vehicle Supply Equipment (EVSE) – the device, including the cable(s), coupler(s), and embedded software, installed for the purpose of transferring electricity between the electrical infrastructure at the Site and the EV.

Electric Vehicle Service Provider (EVSP) – provider of connectivity across a network of EVSE(s).

Fleet Customer – A nonresidential customer installing EVSEs for the purpose of the use or operation of their fleet of vehicles. **(N)** **(N)**

Line Extension – has the same meaning as set forth in Rule I.

Line Extension Allowance – has the same meaning as set forth in Rule I and is calculated per Schedule 300.

Line Extension Cost – has the same meaning as set forth in Rule I. **(M)**

Make-Ready Cost – the cost to design and construct and/or upgrade the Make-Ready Infrastructure and Line Extension, excluding those accounted for in the Line Extension Cost. **(C)**

Make-Ready Infrastructure – the infrastructure at the Site to deliver electricity from the Service Point to the EVSE(s), including any panels, stepdown transformers, conduit, wires, connectors, meters, and any other necessary hardware.

Make-Ready Port – Make-Ready Infrastructure constructed in a way that supports the future installation of EVSEs with the corresponding number of ports. For example, a site constructed with Make-Ready Infrastructure for five dual-port EVSEs would have ten (10) Make-Ready Ports. **(N)**

Non-Fleet Customer – A nonresidential customer installing EVSEs at commercial, workplace, multifamily, or other sites for use by EVs owned or leased by Residential Customers. **(N)**

Operational – an EVSE installed at the Site is able to transfer energy between the Site wiring and the EV, with any applicable payment methods (e.g., credit card, phone app, subscription card), and transmitting operational data (e.g. energy usage, session start/end times) to the Qualified EVSP.

Qualified EVSE – list of qualified EVSE(s), determined by PGE.

Qualified Level 2 EVSE – An EVSE on PGE's qualified list that provides Alternating Current (AC) electricity to the EV at 208 or 240 volts. **(N)** **(N)**

Qualified EVSP – list of qualified EVSP(s), determined by PGE.

(M)

SCHEDULE 56 (Continued)

(M)

DEFINITIONS (Continued)

Qualified Service Schedule – list of qualified service schedules, including Schedules 32, 38, 83, 85, and 89. The list of qualified service schedules may be expanded to include new rates in the future.

Service Point – has the same meaning as set forth in Rule B.

Site – has the same meaning as set forth in Rule B.

Site Owner – entity holding title to the Site.

ELIGIBILITY

Eligible Fleet Customers are nonresidential customers that use or operate fleets (including, but not limited to, commercial, non-profit, public, school or transit fleets) within PGE's service territory installing a minimum of 70 kW of EV charging. Eligible Fleet Customers must own or lease the Site. (C) (C)

Eligible Non-Fleet Customers are nonresidential customers that are installing a minimum of 8 Qualified Level 2 EVSE Ports at existing commercial, workplace, or multi-family properties and are intended to be used by EVs owned or leased by Residential Customers. Eligible Non-Fleet Customers must own, lease, or manage the Site, and not have any active construction occurring at the site at the time of installation. (C) (C)

ENROLLMENT

The customer enrollment period for eligible Fleet Customers will be open through December 2025, or until available funds for the pilot have been fully reserved. Eligible customers may apply at PortlandGeneral.com and enroll by signing a participation agreement. (C) (C) (M)

The enrollment period for eligible Non-Fleet Customers will be open through December 2025, or until available funds for the pilot have been fully reserved. Eligible customers may apply at PortlandGeneral.com and enroll by signing a participation agreement. (C) (C)

INCENTIVE

Fleet Customers will pay for the Make-Ready Cost, less a custom incentive. The custom incentive will be calculated as the lower of the following amounts: (C)

- Estimated Year 5 EVSE annual energy use x Line Extension Allowance x 7.5; or (C)
- The participant's Make-Ready Costs; or
- $400,000. (C)

(M)

SCHEDULE 56 (Continued) **(T)**

INCENTIVE (Continued) **(C)**

Non-Fleet Customers will pay for Make-Ready Cost and Line Extension costs less an incentive not to exceed $17,000 per Make Ready Port. Non-Fleet Customers receiving the incentive cannot also receive a Line Extension Allowance for the same project. The incentive will be calculated as the lower of the following amounts:

- $17,000 per Make-Ready Port;
- The participant's Make-Ready Costs; or
- $204,000. **(C)**

SPECIAL CONDITIONS **(M)**

1. Participation in this pilot is not mandatory to install EV charging equipment.

2. Any chargers installed as a part of this pilot must receive service on one of PGE's Standard Service Schedules. The customer's charges for electricity service under any of PGE's Standard Service or Direct Access Service schedules are not changed or affected in any way by participating in this schedule and are due and payable as specified in those schedules. **(C)** **(C)**

3. For both Fleet and Non-Fleet Customers, PGE will locate, design, install, own, operate and maintain the Make-Ready Infrastructure. For Fleet Customers, EVSE(s) will be separately metered from any other load at the Site. EVSE(s) may be separately metered at Non-Fleet Customer sites. **(C)** **(C)**

4. The Site Owner may be required to grant an easement to PGE to maintain PGE-owned facilities.

5. If the final design of the Make-Ready Infrastructure is estimated to cost in excess of $15,000, PGE may require the customer to submit a deposit prior to proceeding to final design and enrollment. The deposit will be the amount of the estimated final design costs and will be applied to the Make-Ready Costs or refunded upon the participating customer's enrollment in the Pilot. If the customer does not enroll, the deposit will not be refunded.

6. If the final design of the Make-Ready Infrastructure has been completed and the Customer does not enroll in the Pilot, the Customer may be required to reimburse PGE for final design costs and any other associated expenses that PGE incurs due to the cancellation of the project. **(C)** **(C)**

7. If the participating Fleet Customer's custom incentive is in excess of $250,000, the participating Fleet Customer agrees that PGE may verify its creditworthiness at any time and seek financial security to ensure the participating Fleet Customer is able to meet its obligations as set forth in the participation agreement. **(C)** **(C)** **(M)**

SCHEDULE 56 (Concluded)

SPECIAL CONDITIONS (Continued)

(M)

8. The participating Fleet Customer is responsible for the procurement and installation of at **(C)** least one new Qualified EVSE(s) within 6 months of PGE's completion of the Make-Ready Infrastructure. The participating Non-Fleet Customer is responsible for the procurement **(C)** and installation of all Qualified Level 2 EVSE(s) within 12 months of PGE's completion of the Make-Ready Infrastructure. **(C)**

9. The participating customer must maintain the EVSE(s) on a Qualified Service Schedule for **(T)** 10 years following the Activation Date of the first Qualified EVSE installed at the Site.

10. The participating customer will ensure the EVSE(s) remain Qualified EVSE(s) and **(T)** Operational for 10 years following the Activation Date of the first Qualified EVSE installed at the Site.

11. The participating Fleet Customer will adhere to an energy usage plan that sets forth the **(C)** minimum amount of energy the participating customer commits to using over the 10 years following the Activation Date of the first Qualified EVSE installed at the Site, but in no event will the minimum energy usage amount be less than the Estimated Year 5 energy use x 6.

12. The participating customer will authorize and require the Qualified EVSP to provide operational data (e.g. charging session data, energy interval data) to PGE. The **(T)** participating customer agrees to allow PGE and its agents and representatives to use data gathered as part of the pilot in regulatory reporting, ordinary business use, industry forums, case studies or other similar activities, in accordance with applicable laws and regulations and to participate in PGE-led research such as surveys.

13. If the Site changes ownership or lesseeship, participation in the pilot may be assumed by the new owner or lessee if it is willing to meet the pilot requirements. The participating Fleet **(T)** Customer will be responsible for any pro-rata reimbursement for estimated minimum usage deficiencies between the participating customer's original energy usage plan and the new **(C)** customer's energy usage plan.

14. In the event the participating customer breaches or terminates the participation agreement, the participating customer will reimburse PGE the pro-rata value of the custom incentive, **(T)** calculated over the 10-year term.

(M)

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$5,290.00	$3,640.00	$5,580.00	
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$1.77	$1.75	$1.72	
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.33	$1.32	$1.32	
Over 4,000 kW	$1.02	$1.01	$1.01	
per kW of monthly On-Peak Demand	$1.47	$1.46	$0.46	
Generation Contingency Reserves Charges				
Spinning Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.251 ¢	0.250 ¢	0.248 ¢	(I)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned by the Customer. Initially, the Customer's Baseline Demand will be the Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations. Subsequently, Customer may select its Baseline Demand in accordance with the applicable notice requirements set forth in this schedule adjusted for changes in load and planned generator operations. Planned generator operations include the Electricity planned to be produced by the generator as well as the Customer's plans to sell Electricity produced by the generator to the Company or third parties. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable. Any modification to the Baseline Demand must be consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 76R, monthly Demand charges under Schedule 75 will be based on Demand up to the Baseline Demand.

FACILITY CAPACITY

For the first three months of service under this schedule, the Facility Capacity will be equal to the Customer's Baseline Demand. Starting with the fourth month, the Facility Capacity will be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Period, but will not be less than the Customer's Baseline Demand.

RESERVED CAPACITY

The Reserved Capacity is the lesser of the nameplate rating of the Customer's generation or the maximum kW of Customer load supplied by the Customer's generation. Additionally, upon agreement with the Customer, the Company will reduce the Reserved Capacity by the Customer's demonstrated, instantaneous load reduction capability in kW associated with generation output reductions.

The Customer and Company will enter into a written agreement that specifies the Reserved Capacity in kW, the load reduction capability in kW (if any), the requirements for Customer notification to the Company of any changes in the Reserved Capacity, the Company's ability to request a demonstration of load reduction capability annually, additional metering requirements and any other necessary notification requirements.

Except during the first three months of operation, if the Customer's operations result in an actual Reserve Capacity requirement above the level specified by the agreement, the Reserved Capacity will immediately be adjusted to the actual kW level for that month and the following three months. Thereafter, the Reserved Capacity will remain at that increased kW level until the Customer has demonstrated to the Company's reasonable satisfaction that the Reserved Capacity should be revised.

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

Spinning Reserves

Spinning Reserves provide Electricity immediately after a Customer's generator output falls below the Reserved Capacity. Spinning Reserves in combination with Supplemental Reserves, transition a Customer's load to Unscheduled Power. A Customer on Schedule 75 must take Spinning Reserves in all Billing Periods that its generator is expected to operate. Spinning Reserves are not required for a Customer with Reserved Capacity of 2,000 kW or less, or when the Customer's generator is not normally scheduled to operate during an entire Billing Period.

Supplemental Reserves

Supplemental Reserves provide Electricity within the first 10 minutes after a Customer's generator output falls below the Reserved Capacity. In lieu of purchasing Supplemental Reserves, a Customer may choose to reduce load within the 10 minutes of generator failure. The Customer's Load Reduction Plan must be approved by the Company.

Self-Supplied Reserves

Customers with nameplate Generation of 15 MW or greater may self-supply needed Generation Contingency Reserves upon agreement between Customer and the Company. The agreement will specify the kW of Contingency Reserves provided by the Customer at 7% of Reserved Capacity, the notification processes for delivery of reserve Energy, the requirements for Customer delivery of requested reserves, the requirements for Customer notification to the Company of any changes in the ability to self-supply reserves, the settlement process to be used when Contingency Reserves are supplied by the Customer, the provisions for an annual demonstration of such capability, any additional metering requirements and other necessary notification requirements. Customers who self-supply Generation Contingency Reserves will not be charged for Spinning and Supplemental Reserves under this schedule.

Supplemental Reserves Load Reduction Plan

In lieu of self supplying Supplemental Reserves through a self-supply agreement, a Customer may provide Supplemental Reserves through the submittal to the Company of a Load Reduction Plan that demonstrates the ability to reduce load within the first ten minutes of generator failure and specifies a kW amount of load reduction equal to 3.5% of the Reserved Capacity.

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES (Continued)

Supplemental Reserves Load Reduction Plan (Continued)

The Load Reduction Plan also will specify the notification processes for delivery of Supplemental Reserves, the requirements for Customer delivery of requested Supplemental Reserves, the requirements for Customer notification to Company of any changes in the ability to supply Supplemental Reserves, the settlement process to be used when Supplemental Reserves are supplied by the Customer, the provisions for a demonstration of such capability, any additional metering requirements and other necessary notification, plant and financial requirements. The Customer Load Reduction Plan must be approved by the Company. If approved by the Company, and adhered to by the Customer, a credit to the Supplemental Reserves charges will be applied to Customer's bill based on the Supplemental Reserves Level as specified in the Load Reduction Plan.

If Customer fails to follow the Company-approved Load Reduction Plan, all Supplemental Reserves credits for the subsequent three months (Penalty Period) will be forfeited. If the Customer satisfactorily follows the Company-approved Load Reduction Plan during the Penalty Period, the Load Reduction Plan kW credit will be reinstated at the end of the three month Penalty Period.

If the Customer fails to follow the Company-approved Load Reduction Plan a second time during the Penalty Period and the following three months, the Load Reduction Plan will be terminated.

The duration of the Penalty Period will not be limited by the establishment of a new service agreement under this schedule.

Following termination or contract expiration, Customer may submit a new Load Reduction Plan to the Company. Company will approve the new Load Reduction Plan if the Customer is able to demonstrate the load reduction capability of the Plan to Company's satisfaction.

Notwithstanding the above, Customer may terminate the Company-approved Load Reduction Plan upon giving 6 month written notice to Company.

ENERGY CHARGE

The Energy Charge is comprised of the following:

Baseline Energy

Unless otherwise agreed to, the Baseline Energy is the Energy normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned. Usage on an hourly basis up to and including the Baseline Demand will be considered Baseline Energy. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Energy when the Customer is new to the Company's system or has changed operations from the previous year.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable.

Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Powerdex Mid-Columbia Hourly Firm Electricity Price Index (Powerdex-Mid-C Hourly Firm Index) plus 0.305¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, plus losses. **(R)**

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Unscheduled Energy (Continued)

If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported.

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

The Company may request that a Customer taking Unscheduled Energy during more than 1,000 hours during a calendar year provide information detailing the reasons that the generator was not able to run during those hours in order to determine the appropriate Baseline Demand.

LOSSES

Losses will be included by multiplying the applicable Energy Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

A Customer served under this schedule may elect to receive Direct Access Partial Requirements Service from an Electricity Service Supplier (ESS) under the terms of Schedule 575 provided it has given notice consistent with any Baseline Energy option requirements. A Customer may return to Schedule 75 provided it has met any term requirements of Schedule 575 and any requirements needed to purchase Baseline Energy if needed.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Transmission, Distribution, Demand and Generation Contingency Reserves Charges, when applicable. In addition, the Company may require a higher Minimum Charge, if necessary, to justify the Company's investment in service Facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 75 (Continued)

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline Energy and Scheduled Maintenance Energy with the exception of Schedules 108 and 115, which are applied to factors other than usage as required by statute.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written service agreement specifying the terms and conditions of service, the Customer's Baseline Demand and Energy Pricing Option under Schedule 89, the Customer's Reserved Capacity, the Company's and Customer's contact information, and any other information necessary for implementation of service under this schedule. The term of the service agreement will be one calendar year (except that the term of the first service agreement will be the remainder of the year when signed plus the next calendar year) and will renew annually thereafter for successive one year terms, unless the Customer gives 90 days prior written notice. These terms and conditions will be consistent with this schedule.

2. A Customer must inform the Company within 30 minutes of taking Unscheduled Energy at a rate of five MW or greater and inform the Company of the anticipated time that the generator will return to normal operations.

3. Customers must have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Service Point and total Generator output.

4. If the Customer is served at Primary or Subtransmission Voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment and wiring will be of types and characteristics approved by the Company and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. If during a Billing Period the Customer is billed for Transmission and Related Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8), Regulation and Frequency Response Service will be credited to the **(C)** Transmission and Related Services Charge under this schedule. The credit will be the actual OATT demand incurred but will not exceed the Monthly Demand for the Schedule 75 monthly Transmission Demand multiplied by the applicable OATT (OATT Schedules 7 or 8) **(C)** and such credit will not exceed the Transmission and Related Services Charge incurred under this schedule.

SCHEDULE 75 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Customer will not use Electricity sold by the Company to directly or indirectly make or continue a delivery of Electricity to another Customer or wholesale power purchaser.

7. A Customer's failure to inform the Company of the use of on-site generation will not relieve the Customer of responsibility for the charges and requirements under this schedule.

8. The Customer's Baseline Demand may be increased or decreased as requested by the Customer for planned, long-term load changes including changes resulting from the addition of long-term energy efficiency measures, load shedding, the addition or removal of equipment or the permanent removal of generating capacity from the Customer location. Such changes will be effective upon verification of the change by the Company. "Long-term" or "permanent" mean changes that are implemented with the purpose of being in place indefinitely. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the Customer's generating capacity. **(N)** **(N)**

9. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Company or Customer provides the following notice: **(C)**
   a) for a change to Baseline Demand that within a one calendar year period does not exceed 5 MW, the Company or Customer may make one such request per calendar year and will provide at least 6 months written notice; **(C)**

   b) for a change in Baseline Demand that is greater than 5 MW, the Company or Customer must provide at least 13 months written notice with such change effective on January 1 of the applicable year. Any subsequent notice by the Company or Customer under this special condition must be made consistent with these notice requirements. **(C)** **(C)** **(C)**

10. If the Customer's Baseline Demand is increased, any Energy used above the initial Baseline Demand, and below the revised Baseline Demand will be priced at the Daily Price Option contained in Schedule 89 unless the Customer has given the required notice to change the applicable Schedule 89 Energy Charge Option.

11. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council guidelines.

12. If the Customer is receiving service under this schedule and Schedule 76R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 76R Special Conditions.

13. A Customer may not change service options until it has satisfied any Baseline Energy term provisions as established in Schedule 89.

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:*

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Transmission and Related Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.069	$0.068	$0.067	**(I)(R)**
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.057	$0.057	$0.018	**(R)(I)**
Transaction Fee per Energy Needs Forecast (ENF)	$50.00	$50.00	$50.00	
Energy Charge* per kWh of ERP	See below for ERP Pricing			

* See Schedule 100 for applicable adjustments.
** Peak hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours (also called light load hours "LLH") are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 76R (Continued)

ENERGY NEEDS FORECAST (ENF) AND ECONOMIC REPLACEMENT POWER (ERP)

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF). The ENF specifies the amount of Electricity in mWh for each hour that ERP is requested to serve some or all of the Customer's load normally supplied by the Customer's generation (amounts in excess of the Baseline Energy under Schedule 75) pursuant to the requirements of the applicable ERP Supply Option.

Each ENF will be based on the Customer's expected Energy requirements and the Customer will use best efforts to conform Actual Energy usage to the ENF and utilize Energy imbalances to the minimum extent reasonably possible.

The ENF will specify the expected ERP needed by hour. The Customer will deliver the ENF to the Company in accordance with Company procedures. The Company will inform the Customer as to the availability of ERP at the time of the ENF request. The Company can choose to provide all or a portion of the ENF and will inform the Customer of any such adjustment to the submitted ENF. Customer acceptance of such modification of the ENF by the Company will be confirmed within 15 minutes of the proposed ENF revision by the Company. If the Company does not inform the Customer that it is modifying the submitted ENF within 30 minutes of receipt of the ENF, the ENF will be deemed accepted by the Company.

The Customer may utilize only one of the ERP supply options on any day.

ERP Supply Options

Each request for ERP will originate from the requesting Customer and requires an ENF from the customer. At the time of an ENF submittal, Customer must designate which of the available ERP pricing options the ENF applies to for purposes of pricing and price quotes. Customer is solely responsible for the accuracy of an ENF and the acceptance or rejection of a price quote.

<u>ENF Options for ERP</u>

Short Notice ENF: The Customer must provide the ENF to the Company a minimum of 90 minutes prior to the first hour that Short-Notice ERP is requested.

Daily ENF: At the Customer's option, between 0600 and 0615 of a Pre-Schedule Day, the customer will communicate with PGE in an agreed-to manner the customer's interest in purchasing ERP power for delivery the next day or days (as required by the daily day-ahead pre-scheduling protocols of Western Electricity Coordinating Council ("WECC")). Customer will at this time provide the Company with the ENF for HLH or LLH or both for the day or days of delivery. The ENF may differentiate between HLH and LLH hours but will be a flat (constant) MW amount for the each HLH or LLH or both.

Monthly ENF: Not less than 7 business days prior to the last trading day for the upcoming quote month, the customer may submit an ENF for the next month. The ENF may be differentiated into HLH or LLH for the entire month.

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ENF Options for ERP (Continued)

The Daily ENF pre-scheduling protocols will conform to the standard practices, applicable definitions, requirements and schedules of the WECC. Pre-Schedule Day means the trading day immediately preceding the day of delivery consistent with WECC practices for Saturday, Sunday, Monday or holiday deliveries.

ERP Pricing

The following ERP Energy Charges are applied to the applicable hourly ENF and summed for the hours for the monthly billing:

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported. **(R)**

Daily ERP: The Daily ERP Energy Charge will be determined in accordance with a commodity energy price quote from the Company accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.305¢ per kWh for wheeling, plus losses. Customer will communicate with PGE between hour 0615 and 0625 to receive the PGE commodity energy price quote based on the customer’s submitted ENF for the day of delivery. Customer will state acceptance of quote within 5 minutes of receipt of quote from the Company. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place. **(R)**

Monthly ERP: The Monthly ERP Energy Charge will be determined in accordance with a price quote accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.305¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. **(R)**

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ERP Pricing (Continued)

The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

On-peak hours (Heavy Load Hours, HLH) are between 6:00 a.m. and 10:00 p.m. PPT (hours ending 0700 through 2200), Monday through Saturday. Off-peak hours (Light Load Hours, LLH) are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all hours Sunday.

Losses will be included by multiplying the ERP Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 75 Baseline Energy.

IMBALANCE ENERGY SETTLEMENT

Imbalance Settlement Amounts are bill credits or charges resulting from hourly Imbalance Energy multiplied by the applicable hourly Settlement Price and summed for all hours in the billing period. Imbalance Energy is the kWh amount determined hourly as the deviation between Actual Energy for such hour and the ENF for such hour (i.e., Imbalance Energy = Actual Energy less ENF).

For any Imbalance Energy in any hour up to 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive Imbalance Energy (where Customer receives more ERP than the ENF), the Imbalance Energy multiplied by the Settlement Price of the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 0.305¢ per kWh for wheeling, plus losses. **(R)**
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the Powerdex-Mid-C Hourly Index plus 0.305¢ per kWh for wheeling, plus losses. **(R)**

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

For any Imbalance Energy in any hour in excess of 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 10%, plus 0.305¢ per kWh for wheeling, plus losses. **(R)**

For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the Powerdex-Mid-C Hourly Index, less 10%, plus 0.305¢ per kWh for wheeling, **(R)**
plus losses.
The Imbalance Settlement Amount may be a credit or charge in any hour.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 76R (Concluded)

SPECIAL CONDITIONS (Continued)

3. All charges and requirements of Schedule 75 will apply except as provided for under this schedule.

4. ERP supplied will not be resold.

5. The Company may interrupt ERP due to transmission constraints.

6. The Customer must notify the Company's Merchant Power Operations, at a specified phone number, as soon as practical of otherwise unplanned load deviations greater than 5 MW that are expected to last one hour or longer.

7. If Customer is unable to use or accept delivery of ERP due to circumstances beyond its control, the difference between Actual Energy and the ENF will be treated as Imbalance Energy.

8. Upon mutual agreement between the Company and Customer, the otherwise applicable Schedule 75 monthly Basic and Facility Capacity Charges will be replaced by a flat monthly Basic and Facility Capacity Charge billed under this schedule. The flat monthly Basic and Facility Capacity Charge will be set to maximize the economic value of sales under this schedule.

9. The Company is not responsible for providing market information to Customer.

10. The Company has no obligation to provide the Customer with ERP except as explicitly agreed to by both parties.

11. Each day of flow will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

In all territory served by the Company. The Company may restrict Customer loads returning to this schedule in accordance with Rule N Curtailment Plan and Rule C (Section 2).

APPLICABLE

To existing Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule.

MONTHLY RATE

All charges for Emergency Default Service except the energy charge will be billed at the Customer's applicable Standard Service rate schedule for five business days after the Customer's initial purchase of Emergency Default Service.

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh **(R)** for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

Losses will be included by multiplying the Energy Charge Daily Rate by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 81 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service under this schedule will terminate five business days from initial purchase.

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. Service under this Schedule is available for Secondary Delivery Voltage only.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge		
Single Phase Service	$35.00	
Three Phase Service	$45.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$1.77	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$4.75	
Over 30 kW	$4.65	
per kW of monthly On-Peak Demand	$1.47	
Energy Charge		
On-Peak Period per kWh***	4.824 ¢	
Off-Peak Period per kWh***	3.324 ¢	
Generation Demand Charge		
per kW of monthly On-Peak Demand	$4.68	
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	1.031 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.
*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 83 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage 1.0640 **(R)**

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer’s Electricity usage will be billed as 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 83 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 83 (Continued)

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window. **(C)** **(C)**

During the Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

November Election Window

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 83 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service will be for not less than one year or as otherwise provided under this schedule. **(C)**

SCHEDULE 85
LARGE NONRESIDENTIAL
STANDARD SERVICE
(201 – 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Secondary Delivery Voltage Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. To each Primary Delivery Voltage Large Nonresidential Customer whose Demand has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$810.00	$770.00	
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$1.77	$1.75	
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.24	$3.21	
Over 200 kW	$2.04	$2.01	
per kW of monthly On-Peak Demand	$1.47	$1.46	
Energy Charge			
On-Peak Period per kWh***	4.684 ¢	4.639 ¢	
Off-Peak Period per kWh***	3.184 ¢	3.139 ¢	
Generation Demand Charge			
per kW of monthly On-Peak Demand	$5.17	$5.15	
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.287 ¢	0.285 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 85 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 85 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate Schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

NON COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer’s Electricity usage will be billed as 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

SCHEDULE 85 (Continued)

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window. **(C)** **(C)**

During the Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

November Election Window

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities. The minimum monthly on-peak Demand (in kW) will be 100 kW for primary voltage service.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 85 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 86
DEMAND BUY BACK RIDER
NONRESIDENTIAL

PURPOSE

This rider is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce their Electricity usage in return for a payment, at times and prices determined by the Company.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Industrial, Commercial and General Service electric Customers served under Schedules 38, 83, 85, 89, 90 and 99 who satisfy the conditions contained in this rider. **(C)**
Customers must execute a Demand Buy Back Agreement prior to receiving service and have the capability to reduce not less than 250 kW aggregated from one or more points of delivery for each hour during a Buy Back Event.

BUY BACK CREDIT DETERMINATION

Energy Price

The Energy Price will be a price or prices quoted by the Company for a specified Buy Back Event, subject to requirements and other conditions described in Special Conditions.

Hourly Credit

Buy Back Amount (kWh) **X** Energy Price **=** Hourly Credit

The Hourly Credit is the amount owed to the Customer for each hour of the Buy Back Event. The Hourly Credit is determined by multiplying the Buy Back Amount by the Energy Price. The Hourly Credit will not be less than zero.

Buy Back Credit

The Buy Back Credit is the amount paid to the Customer for its Electricity reduction during a Buy Back Event and is the sum of each Hourly Credit during such event (minus any amounts owed as a result of failure to comply during an Extended Buy Back Event).

PAYMENTS

The Company will pay the Buy Back Credit to the Customer within 60 days of the Buy Back Event.

SCHEDULE 86 (Continued)

BUY BACK AMOUNT

The Buy Back Amount will be the difference between the Customer's Baseline Usage and the Customer's measured hourly load during the term of the Buy Back Event. The Customer will participate by operating below its Baseline Usage for the length of the requested Buy Back Event. A participating Customer's measured load for purposes of determining a Buy Back Amount must be zero kW or greater. The Company at its discretion may limit the Buy Back Amount to the Buy Back Pledge.

BASELINE USAGE

The Customer's Baseline Usage is dynamic and is defined as the average Energy usage for each hour for a minimum of approximately 14 typical operational days prior to the Buy Back Event. Typical operational days exclude days that a Customer has participated in a Buy Back Event. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Usage when the Customer's Energy usage is highly variable.

BUY BACK PLEDGE

The Buy Back Pledge is the amount of Energy the Customer commits to curtail when it agrees to participate in a Buy Back Event. The Buy Back Pledge must be at least 250 kW and can vary by hour. The Customer must submit to the Company the amount of the Buy Back Pledge prior to the Buy Back Event through the specified notification method. The Customer will receive an acceptance confirmation for its pledge prior to the start of the Event. A Buy Back Pledge cannot exceed Baseline Usage and is the expected Buy Back Amount for the Buy Back Event.

NOTIFICATIONS

The Company will utilize a secure Internet web site as the primary method to notify participants of Buy Back Events and to receive Customer notification of participation in a Buy Back Event. The Company's notification will include a time and date by which the participating Customers must submit a Buy Back Pledge. The Company will provide the Customer with access codes to the secure Internet web site. Other methods of notification such as facsimile, telephone and electronic mail, may be utilized at the discretion of the Company.

BUY BACK EVENT

A Buy Back Event specifies the dates, times and duration of a Company requested load reduction and will be for one or more consecutive hours. A Buy Back Event with a duration of more than 24 consecutive hours is an Extended Buy Back Event. An Extended Buy Back Event may include requirements for a single, continuous Buy Back Pledge to which the participant must comply for the duration of the event. More than one Buy Back Event may occur in one day and more than one Buy Back Event may be in effect simultaneously.

SCHEDULE 86 (Continued)

BUYBACK EVENT (Continued)

The Company is not obligated to call a Buy Back Event, and the Customer is not obligated to reduce Energy upon being advised of a Buy Back Event. The Company will not be liable for failure to advise a Customer of a Buy Back Event.

FAILURE TO COMPLY WITH BUY BACK PLEDGE

Single Day Buy Back Event

If a Customer's Buy Back Amount for any hour is less than 90% of the Customer's Buy Back Pledge, the Company may refuse to accept future pledges from the Customer until the capability to meet their pledge is demonstrated in a manner acceptable to the Company.

Extended Buy Back Event

If a Customer's actual Buy Back Amount for any hour of an Extended Buy Back Event (as defined in Special Condition 3 below) is less than the Buy Back Pledge, the Customer will pay to the Company an amount equal to the applicable Intercontinental Exchange Mid-Columbia Daily Electricity Firm On-Peak Price Index, plus 5%, multiplied by the difference between the Buy Back Pledge and the actual hourly Buy Back Amount for all of the hours during the Extended Buy Back Event that the pledge is not met. The Company may for any Extended Buy Back Event establish other lesser consequences for noncompliance. **(C)**

SPECIAL CONDITIONS

1. The Customer and Company must execute a Demand Buy Back Agreement prior to receiving service on this rider.

2. The Customer may not participate in this rider until the Company has installed metering that records usage in 15 minute intervals. The Customer will provide communication service to the meter if requested by the Company. Service under this rider is subject to meter availability.

3. The Company is not responsible for any load reduction that has not been confirmed and accepted by the Company.

4. The Company is not responsible for any consequences to the participating Customer that result from a Buy Back Event or the Customer's effort to reduce Energy in response to a Buy Back Event.

5. This schedule is not applicable when the Company requests or initiates load interruptions affecting a Customers meter for a system emergency.

SCHEDULE 86 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Company may utilize a third party to provide program management support for this rider. The Company has the right to provide the Customer's Energy consumption data to a third party for the purpose of providing service under this rider. Such information will be provided to a third party subject to confidentiality requirements.

7. The Company may quote a separate Energy Price for Customers that shift load in conjunction with a Buy Back Event. Load shifting is the change in a Customer's Energy usage during non-Buy Back Event hours to compensate for reduced Energy usage during the Buy Back Event. For purposes of this rider, load shifting occurs when the Customer's Energy usage during the 24 hours preceding or following a Buy Back Event (or any day of an extended Buy Back Event) increases from the applicable hourly Baseline Usage by more than 50% of the Buy Back Amount.

8. The Company and the Customer will test the Customer's ability to reduce Energy usage prior to the Customer's participation in a Buy Back Event.

9. If a Customer takes service under a direct access schedule (when available), it is no longer eligible to participate in this rider.

10. Should an error occur in the calculation of the Buy Back Credit or any of the underlying components, the Company will provide written notice to the Customer detailing the circumstances and amount of adjustment. The Customer will return the overpayment to the Company or the Company will pay the underpayment to the Customer, as applicable, within a period of time agreed to by the Customer and the Company after notice has been given.

11. The Company will not cancel or shorten the duration of a Buy Back Event once notification has been given.

TERM

Service under this schedule will not be for less than a one-year term.

SCHEDULE 88
LOAD REDUCTION PROGRAM

PURPOSE

The Load Reduction Program is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce Electricity usage to a Company-determined level during an Emergency Curtailment as described in Rule C(2)(B) in exchange for partial exemption from Emergency Curtailments.

AVAILABLE

In all territory served by the Company but total pledges will not exceed 5% of Company primary voltage circuits.

APPLICABLE

To an individual or a group of Large Nonresidential Customers receiving Electricity Service under Schedules 83, 85, 89, 90, 485, 489, 490, 583, 585, 589, 590 and/or 689 from one or more Service Point(s) (SPs) but from the same dedicated primary circuit and able to reduce Baseline Usage from the primary circuit by a minimum of 15%. Customers applying as a group must be represented by a Lead Customer. A group may consist of multiple SPs under one Customer name that are all located on the same primary circuit. Participation is dependent upon satisfaction of all conditions contained in this schedule. **(C)**

BASELINE USAGE

The Baseline Usage is defined as the average usage for each hour for a minimum of 14 typical operational days prior to the Emergency Curtailment. Typical operational days exclude days that a Customer has participated in either an Emergency Curtailment or a Demand Buy Back Event (Schedule 86). Holidays and weekends will be excluded when determining the Baseline Usage except when the Emergency Curtailment includes weekends or holidays. The Customer may request that specific days be excluded from the 14-day baseline calculation upon demonstrating to the Company's satisfaction that the specific days are not similar days. The Company and Customer may mutually agree to use an alternate method to determine Baseline Usage when the Customer's usage is highly variable.

LOAD REDUCTION DETERMINATION

During an Emergency Curtailment, the individual Customer or group of Customers will be required to reduce Baseline Usage to a Company-determined Maximum Circuit Load (MCL). The MCL is the Customer's or group of Customer's Baseline Usage minus the necessary load reduction of 5, 10 or 15%.

Schedule 88 (Continued)

LOAD REDUCTION DETERMINATION (Continued)

The Company may choose at any time during an Emergency Curtailment to increase the load reduction percentage. Upon notification of an MCL change, the Customer/Lead Customer has one-half hour (30 minutes) to meet the new MCL. The Company may only make one notification of an increased increment of reduction per hour.

If the Customer is participating in Demand Buy Back Rider (Schedule 86), Baseline Usage will be determined after subtracting the Buy Back amount stipulated under that schedule. State mandated curtailments as defined under Rule N will also be subtracted before determining Baseline Usage.

LOAD REDUCTION PLAN

Participation depends upon the Company approval of a single submitted Load Reduction Plan. A renewed plan is due annually on March 15th.

A Lead Customer will submit one Load Reduction Plan for the group of Customers served on the same dedicated primary circuit and jointly participating. The Lead Customer assumes responsibility for submitting the group's Load Reduction Plan, managing the load reduction and paying all noncompliance charges.

The Load Reduction Plan must include the following:

1) Customer or Lead Customer's name;
2) A list of all other participating Customers, their account numbers, service and mailing addresses, and contact information;
3) The Customer or Lead Customer's alphanumeric pager and facsimile numbers to be used for notification of an Emergency Curtailment;
4) A Company and Customer mutually agreed upon Baseline Usage;
5) An estimated MCL for the 5, 10 and 15% load reduction levels. The MCL for the 5% load reduction is equal to the Baseline Usage times 0.95; 10% load reduction is Baseline Usage times 0.90; 15% reduction is Baseline Usage times 0.85; and
6) Specific quantifiable measures to be utilized by the Customer to reduce load to or below each MCL.

NOTIFICATION

The Company will notify the Customer/Lead Customer as to the percent of load reduction needed by alphanumeric pager and/or facsimile. The Customer/Lead Customer is responsible for keeping the pager and facsimile functioning and able to receive notification.

Schedule 88 (Continued)

NOTIFICATION (Continued)

Upon notification, the Lead Customer will be responsible for contacting all other Customers participating under that plan. Upon notification, the Customer/Lead Customer will have 30 minutes to establish the determined MCL.

METERING EQUIPMENT

Customers on a dedicated circuit with one SP will have load reduction compliance audited by an interval meter with remote access capacity. The Company will install metering that records usage in 15-minute intervals. The Customer will provide communication service to the meter if requested by the Company. Participation under this schedule is subject to meter availability. **(C)**

Customers on a dedicated circuit with more than one SP will have compliance monitored from individual meters or electronic recording equipment located at Company substations. Where the circuit does not have electronic recording equipment to monitor its load, the Company will install such equipment subject to availability. The Customer/Lead Customer will provide communication service when requested by the Company. **(C)**

A Customer/Lead Customer will not be allowed to participate in any Load Reduction Programs until the proper monitoring equipment is installed and operational.

FAILURE TO COMPLY

Failure to meet the required MCL, to maintain the MCL for the duration of the Emergency Curtailment or to meet the required MCL within the required 30 minutes after notification will result in a noncompliance penalty. The penalty is equal to two times the baseline circuit load (BCL) on the applicable circuit, less the required MCL by hour, times the market price (MP) for power during the Emergency Curtailment as determined by an appropriate index such as the Intercontinental Exchange Mid-Columbia Daily Electricity Firm Price Index:

$$\text{Penalty} = 2[MP(BCL - MCL)]$$

Such penalties will be in addition to all other Company charges for Electricity Service.

After two noncompliance penalties, the Customer/Lead Customer will be removed from the program. Failure to pay noncompliance penalties may result in the termination of the Customer's/Lead Customer's Electricity Service.

Schedule 88 (Concluded)

ADJUSTMENTS

Supplemental adjustment schedules are applicable to the Customer's underlying rate schedule and not applicable to this schedule unless approved by the Commission.

SPECIAL CONDITIONS

1. The Company may not be able to supply advance notice of an Emergency Curtailment. Participation in this program does not guarantee that the Customer or group of Customers will not be subject to outages related to maintenance, storms or system emergencies caused by natural catastrophes.

2. The Company is not liable for any damage to Customer's property resulting from participation in this program.

TERM

Service under this schedule will be for a term of one year. Service thereafter may be extended after Company review of Customer's/Lead Customer's annually updated Load Reduction Plan. Customer/Lead Customer's decision to leave the program at any time may limit its eligibility to participate in the program in the future.

SCHEDULE 89
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	5,290.00	$3,640.00	$5,580.00	
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$1.77	$1.75	$1.72	
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.33	$1.32	$1.32	
Over 4,000 kW	$1.02	$1.01	$1.01	
per kW of monthly On-Peak Demand	$1.47	$1.46	$0.46	
Energy Charge (per kWh)				
On-Peak Period***	5.968 ¢	5.910 ¢	5.851 ¢	
Off-Peak Period***	4.468 ¢	4.410 ¢	4.351 ¢	
See below for Daily Pricing Option description.				
System Usage Charge				
per kWh	0.251 ¢	0.250 ¢	0.248 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 89 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 89 (Continued)

ELECTION WINDOWS

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window. **(C)** **(C)**

During the Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

November Election Window

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and Subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 89 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service will be for not less than one year or as otherwise provided under this schedule. **(C)**

SCHEDULE 90
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

	Delivery Voltage		
	Primary	Subtransmission	
Basic Charge	$21,000.00	$21,000.00	
Transmission and Related Services Charge per kW of monthly On-Peak Demand	$1.75	1.72	
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.64	$1.64	
Over 4,000 kW	$1.33	$1.33	
per kW of monthly on-peak Demand	$1.46	$0.46	
Energy Charge (per kWh)			
Usage (30MWa – 250MWa)			
On-Peak Period***	5.716¢	5.652¢	
Off-Peak Period***	4.216¢	4.152¢	
Usage (greater than 250MWa)			
On-Peak Period***	5.600¢	5.537¢	
Off-Peak Period***	4.100¢	4.037¢	
System Usage Charge			
Usage (30MWa – 250MWa) per kWh	0.137¢	0.137¢	(I)
Usage (greater than 250MWa) per kWh	0.176¢	0.134¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.
*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 90 (Continued)

MONTHLY RATE (Continued)
Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus **(R)** losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 90 (Continued)

ELECTION WINDOWS

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

During the Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

November Election Window

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and Subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 90 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

(D)

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 91
STREET AND HIGHWAY LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity generally are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually. **(C)**

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services [1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option A - Luminaire (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer. **(N)**

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation and luminaire replacement schedule.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs [(1)], in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Maintenance under Option B luminaires specifically does not include replacement of failed or failing ballasts or replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. This exclusion does not include replacements of Power Doors where the Customer is qualified and paying the applicable Cobrahead Power Door rate. In addition, maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to page 91-8 of this Schedule.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)

Option B – Luminaire:

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable.

Without obligation or notice to the Customer, individual lamps will be replaced on burnout as soon as reasonably possible subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services [1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff. (C)

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of certain failed parts including the lamp, power door (if applicable), photoelectric controller, starter and lens. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company's schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. (N)

1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company. **(C)**

Maintenance Service under Option C

The Company does not maintain Customer-purchased lighting when mounted on Customer-owned poles. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Option B to Option C Luminaire Conversion and Future Maintenance Election

1. The Company will, with not less than 180 days written notice from the Customer (the requesting municipality) and subject to completion of all conditions necessary to finalize such election, convert the entirety of the Customer's lighting service under Option B luminaire lighting rates to the equivalent Option C luminaires lighting rates (with respect to Monthly kWh usage) including Option B luminaires attachment to Company-owned poles.

2. Upon such conversion, the Customer will assume all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires. The Customer may not require that the Company provide new Option B lighting following the conversion to Option C luminaires. The Customer must notify and inform all affected residents of the conversion that all maintenance and repair services are the sole responsibility of the Customer, and not the Company.

3. The Customer may choose the Schedule 91 Option B to Schedule 95 Option C Luminaire Conversion and Future Maintenance Election as described in Schedule 95 if converting to Schedule 95 Option C luminaires and the above notice has not been given.

SCHEDULE 91 (Continued)

STREETLIGHT POLES SERVICE OPTIONS **(N)**

Option A – Poles

Option A provides for Company purchased and owned streetlight poles at the applicable rate.

Pole Maintenance under Option A

Maintenance of Option A poles includes straightening of leaning poles, the replacement of rotted wood poles no longer structurally sound or any pole, which by definition, has reached its natural end of life at no additional charge to the customer. Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles

Emergency Pole Replacement and Repair

The Company will repair or replace structurally unsound poles at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is and subject to the Company's operating schedules and requirements and at no additional charge to the Customer.

Option B - Poles

Option B provides for Customer purchased and owned streetlight poles. The Company does not, at any time, assume ownership of Option B streetlight poles.

Maintenance Service under Option B

The Company provides for maintenance only as defined herein to Customer purchased and owned poles and related equipment at the applicable monthly Option B rate and subject to the Company's operating schedules and requirements.

Maintenance of Option B poles includes straightening of leaning poles.

Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles, nor does maintenance of Option B poles include replacement of rotted wood poles no longer structurally sound, or any pole which by definition has reached its natural end of life. **(N)**

SCHEDULE 91 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued) **(N)**
Option B – Pole maintenance (Continued)

Upon Customer request, the Company may install and replace Option B poles that have reached their natural end of life. All costs associated to the installation and removal of any pole is the sole responsibility of the Customer, in addition to the applicable monthly Option B rate.

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company’s discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment. **(N)**

SCHEDULE 91 (Continued)

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.357 ¢ per kWh	
Distribution Charge	5.788 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	4.884 ¢ per kWh	

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0640.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

Enrollment for Service

To begin service under the Daily Price Option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

SCHEDULE 91 (Continued)

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

During the Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

November Election Window

Enrollment for the November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate	Straight Time	Overtime [(1)]	
	\$132.00 per hour	\$170.00 per hour	**(I)**

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING

High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead Power Doors **	70	6,300	30	*	$0.81	(R)
	100	9,500	43	*	0.93	(R)
	150	16,000	62	*	0.81	(R)
	200	22,000	79	*	0.97	(R)
	250	29,000	102	*	0.81	(R)
	400	50,000	163	*	0.99	(R)
Cobrahead	70	6,300	30	$4.99	1.10	(I)
	100	9,500	43	4.67	1.05	(R)
	150	16,000	62	4.74	1.06	(R)
	200	22,000	79	5.42	1.13	(R)
	250	29,000	102	5.01	1.07	(R)
	400	50,000	163	5.21	1.10	(R)
Flood	250	29,000	102	6.40	1.27	(I)(R)
	400	50,000	163	6.40	1.27	(I)(R)
Early American Post-Top	100	9,500	43	5.62	1.20	(I)(R)
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	5.27	1.15	(R)
	100	9,500	43	*	1.22	(C)(R)
	150	16,000	*	*	1.28	(C)(R)

* Not offered.
** Service is only available to Customers with total power door luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black, Bronze, or Gray	20	$5.16	$0.17	(I)
Fiberglass, Black or Bronze	30	8.40	0.28	(I)
Fiberglass, Gray	30	8.40	0.28	(I)
Fiberglass, Smooth, Black or Bronze	18	5.48	0.19	(I)
Fiberglass, Regular Black, Bronze, or Gray	18	4.80	0.16	(I)
	35	8.20	0.28	(I)
Aluminum, Regular with Breakaway Base	35	16.90	0.57	(N)

SCHEDULE 91 (Continued)

RATES FOR STANDARD POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Wood, Standard	30 to 35	$6.26	$0.21	**(I)**
Wood, Standard	40 to 55	7.37	0.25	**(I)**

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Acorn-Types						
HPS	100	9,500	43	$8.99	$1.67	**(I)(R)**
HADCO Victorian, HPS	150	16,000	62	8.99	1.67	**(I)(R)**
	200	22,000	79	9.33	1.72	**(I)(R)**
	250	29,000	102	9.24	1.70	**(I)(R)**
HADCO Capitol Acorn, HPS	100	9,500	43	12.95	2.23	**(I)(R)**
	150	16,000	62	*	2.19	**(C)(R)**
	200	22,000	79	*	2.27	**(C)(I)**
	250	29,000	102	*	0.89	**(C)(R)**
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	10.16	1.81	**(I)(R)**
	150	16,000	62	*	1.53	**(C)(R)**
HADCO Techtra, HPS	100	9,500	43	17.29	2.84	**(I)(R)**
	150	16,000	62	18.11	2.96	**(I)(R)**
	250	29,000	102	*	2.73	**(C)(R)**
HADCO Westbrooke, HPS	70	6,300	30	12.27	2.11	**(I)(R)**
	100	9,500	43	12.42	2.13	**(I)(R)**
	150	16,000	62	*	2.42	**(C)(R)**
	200	22,000	79	*	0.95	**(C)(R)**
	250	29,000	102	10.89	1.91	**(I)(R)**

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Types						
Flood, Metal Halide	350	30,000	139	*	$1.45	**(C)(R)**
Flood, HPS	750	105,000	285	$9.00	1.78	**(R)**
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	
Ornamental Acorn	55	2,800	21	*	*	
Ornamental Acorn Twin	55	5,600	42	*	*	
Composite, Twin	140	6,815	54	*	*	
	175	9,815	66	*	*	

* Not offered.
** Rates are based on current kWh energy charges.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$8.88	$0.30	**(R)**
	30	10.19	0.34	**(R)**
	35	11.80	0.40	**(R)**
Aluminum Davit	25	9.48	0.32	**(R)**
	30	10.67	0.36	**(R)**
	35	12.20	0.41	**(R)(I)**
	40	15.67	0.53	**(R)(I)**
Aluminum Double Davit	30	11.84	0.40	**(R)**

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Fluted Ornamental	14	$8.42	$0.28	
Aluminum, Smooth Techtra Ornamental	18	18.40	0.62	
Aluminum, Fluted Ornamental	16	8.74	0.30	
Aluminum, Double-Arm, Smooth Ornamental	25	14.19	0.48	(C)
Aluminum, Fluted Westbrooke	18	17.29	0.58	
Aluminum, Non-Fluted Ornamental, Pendant	22	17.18	0.58	
Fiberglass, Fluted Ornamental Black	14	11.78	0.40	
Fiberglass, Anchor Base, Gray or Black	35	11.19	0.38	
Fiberglass, Anchor Base (Color may vary)	25	9.94	0.34	
	30	12.15	0.41	

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Cobrahead, Metal Halide	150	10,000	60	*	$1.16
Cobrahead, Mercury Vapor	100	4,000	39	*	*
	175	7,000	66	$4.68	1.06
	250	10,000	94	*	*
	400	21,000	147	5.39	1.10
	1,000	55,000	374	5.33	1.22
Holophane Mongoose, HPS	150	16,000	62	*	1.98
	250	29,000	102	*	1.99
Special Box Similar to GE "Space-Glo"					
HPS	70	6,300	30	5.69	*
Mercury Vapor	175	7,000	66	5.69	1.16

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Box, Anodized Aluminum						
Similar to GardCo Hub						
HPS - Twin	70	6,300	60	*	*	
HPS	70	6,300	30	*	*	
	100	9,500	43	*	$1.49	**(R)**
	150	16,000	62	*	0.89	**(R)**
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	0.90	**(R)**
	400	40,000	156	*	0.90	**(R)**
Cobrahead, Metal Halide	175	12,000	71	*	1.17	**(R)**
Flood, Metal Halide	400	40,000	156	$5.66	1.20	**(R)**
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	0.89	**(R)**
100/150 Watt Ballast	100	9,500	43	*	0.89	**(R)**
100/150 Watt Ballast	150	16,000	62	*	0.89	**(R)**
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.33	**(R)**
	165	12,000	60	*	0.97	**(I)**
HADCO Techtra, QL	165	12,000	60	*	1.28	**(C)(I)**
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	0.89	**(R)**
KIM Archetype, HPS	250	29,000	102	*	2.01	**(R)**
	400	50,000	163	*	2.45	**(I)**
Special Acorn-Type, HPS	70	6,300	30	8.89	1.57	**(I)(R)**
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Early American Post-Top, HPS						
Black	70	6,300	30	$5.46	$1.04	**(I)(R)**
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	5.52	1.10	**(I)(R)**
Flood, HPS	70	6,300	30	4.71	1.09	**(R)**
	100	9,500	43	4.72	1.07	**(R)**
	200	22,000	79	6.29	1.16	**(I)(R)**
Cobrahead, HPS						
Power Door	310	37,000	124	*	1.27	**(C)(R)**
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Fluorescent	28	N/A	12	*	*	

* Not offered.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Option A	Option B	
Aluminum Post	30	$4.78	*	**(R)**
Aluminum, Painted Ornamental	35	*	*	**(C)**
Aluminum, Regular	16	4.78	$0.16	**(R)**
Bronze Alloy GardCo	12	*	0.23	**(I)**
Concrete, Ornamental	35 or less	8.88	0.30	**(R)**
Fiberglass, Direct Bury with Shroud	18	7.06	0.24	**(R)**
Steel, Painted Regular **	25	8.88	0.30	**(R)**
Steel, Painted Regular **	30	10.19	0.34	**(R)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	**(R)**
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.41	**(I)**
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41	**(I)**
Wood, Laminated without Mast Arm	20	5.16	0.17	**(I)**
Wood, Laminated Street Light Only	20	5.16	*	**(I)**
Wood, Curved Laminated	30	7.17	0.28	**(I)**
Wood, Painted Underground	35	6.26	0.21	**(I)**

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 91 (Continued)

SPECIAL CONDITIONS

1. The Company may offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one-year at which time the lighting service equipment will either be removed at Customer expense or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new Option C **(C)**
installations. **(C)**

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimated usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

SCHEDULE 91 (Continued)

SPECIAL CONDITIONS (Continued)

(N)

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

10. Indemnification:

    a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

    b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule. (N)

SCHEDULE 91 (Continued)

SPECIAL CONDITIONS (Continued)

c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer. (N)

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer.

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance. (N)

SCHEDULE 91 (Concluded)

SPECIAL CONDITIONS (Continued)

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action. **(N)**

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments. **(N)**

(M)

TERM

A Customer served under the Daily Pricing option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made. **(M)**

SCHEDULE 92
TRAFFIC SIGNALS
(NO NEW SERVICE)
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments where funds for payment of Electricity are provided through taxation or property assessment for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Transmission and Related Services Charge	0.359	¢ per kWh	
Distribution Charge	1.580	¢ per kWh	**(I)**
Energy Charge	5.156	¢ per kWh	

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

SCHEDULE 92 (Concluded)

ELECTION WINDOW (Continued)

November Election Window

Enrollment for the November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day. **(C)** | **(C)**

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

The Customer will furnish the Company with a complete list each month of all traffic-signal intersections and their respective estimated monthly kWh usage. The method of estimating usage will be established by the Company. The Customer will be responsible for updating the list of intersections and corresponding estimated usages each month as new installations are made, as existing installations are removed, or as wattages are increased or decreased.

1. The Customer will conduct an independent audit of all traffic-signal intersections once every three years and provide the Company with a copy of such audit. The audit must contain a listing of each light and its corresponding monthly kWh usage installed at all intersections.

2. The Company may, whenever it deems it to be advisable, conduct a field inventory of a Customer's electrical equipment being supplied under this schedule, using sampling techniques to determine whether in the Company's opinion the Customer's list of estimated usages is being properly maintained. If the Customer's list is improperly maintained, or in the event the Customer does not furnish such a list, the Company may institute such other means of estimating the Customer's Electricity use as it may deem to be satisfactory or discontinue service to the Customer under this schedule.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 95
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments for lighting service utilizing Company approved new technology streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity generally are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services[1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff. **(C)**

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option A (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer.

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation.

(M)

Option B - Luminaire (N)

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs(1), in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services(2) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to page 95-7 of this Schedule.
(2) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight. (N)

(M)

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued) (M)
Maintenance Service under Option B (Continued) (N)

Maintenance under Option B luminaires specifically does not include replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. In addition, maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

Emergency Luminaire Replacement and Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable

Without obligation or notice to the Customer, luminaire repair or replacement shall occur as soon as reasonably possible subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE’s Customer Service or PGE’s Outdoor Lighting Services(1) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of the photoelectric controller. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company’s schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

(N)
(M)

(1) Contact PGE’s Outdoor Lighting Services at 503-736-5710, PGE’s Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 95 (Continued)

(M)

LUMINAIRE SERVICE OPTIONS (Continued) (N)
Special Provisions for Option B Luminaire Maintenance (Continued)

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. (N)

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on non-Company owned poles or Company-owned distribution poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company.

Maintenance Service under Option C

The Company has no obligation to maintain Customer-purchased lighting if the Customer selects this option. Such maintenance and service is the sole responsibility of the Customer.

(C)

Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election

(C)

1. If Customer elects to convert any of its luminaires from Schedule 91/95 Option B to Schedule 95 Option C, the Customer must at the same time commit to convert the (C) entirety of Customer's Schedule 91/95 Option B luminaires to Schedules 91 Option C and Schedule 95 Option C using one of two methods: (A) within five years following PGE's group lamp replacement cycle or (B) within three years on a schedule mutually agreed upon between the Company and Customer. Customer may elect to have some of its luminaires on Schedule 91 Option C and some on Schedule 95 Option C.

(M)

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election (Continued)

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91/95 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires.

STREETLIGHT POLES SERVICE OPTIONS

See Schedule 91 for Streetlight poles service options.

MONTHLY RATE

In addition to the service rates for Option A and Option B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.357 ¢ per kWh	
Distribution Charge	5.788 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	4.884 ¢ per kWh	

NON-COST OF SERVICE OPTION

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

SCHEDULE 95 (Continued)

NON-COST OF SERVICE OPTION (Continued)

For Customers billed on the Daily Price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0640. **(R)**

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

Enrollment for Service

To begin service under the Daily Price Option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

Balance-of-year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Balance-of-Year Election Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

During the Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. The move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to either the Cost of Service or Daily Price Option during the Balance-of-Year Election Window.

November Election Window

Enrollment for the November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Enrollment Windows will remain open until 5:00 p.m. of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change to eligible service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 95 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate	Straight Time	Overtime	
	$132.00 per hour	$170.00 per hour	**(I)**

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Roadway LED	>20-25	3,000	8	$4.81	$0.41
	>25-30	3,470	9	4.81	0.41
	>30-35	2,530	11	5.09	0.41
	>35-40	4,245	13	4.81	0.41
	>40-45	5,020	15	4.95	0.41
	>45-50	3,162	16	5.06	0.41
	>50-55	3,757	18	5.31	0.42
	>55-60	4,845	20	4.95	0.41
	>60-65	4,700	21	4.95	0.41
	>65-70	5,050	23	5.53	0.42
	>70-75	7,640	25	5.58	0.43
	>75-80	8,935	26	5.58	0.43
	>80-85	9,582	28	5.58	0.43
	>85-90	10,230	30	5.58	0.43
	>90-95	9,928	32	5.58	0.43
	>95-100	11,719	33	5.58	0.43
	>100-110	7,444	36	5.92	0.43
	>110-120	12,340	39	5.58	0.43
	>120-130	13,270	43	5.58	0.43
	>130-140	14,200	46	6.52	0.45
	>140-150	15,250	50	7.49	0.48
	>150-160	16,300	53	7.49	0.48
	>160-170	17,300	56	7.49	0.48
	>170-180	18,300	60	7.38	0.47
	>180-190	19,850	63	7.49	0.48
	>190-200	21,400	67	7.70	0.48

SCHEDULE 95 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

		Nominal	Monthly	Monthly Rates		
Type of Light	Watts	Lumens	kWh	Option A	Option B	
Acorn						
LED	>35-40	3,262	13	$12.57	$0.61	(C)
	>40-45	3,500	15	12.57	0.61	
	>45-50	5,488	16	10.43	0.55	
	>50-55	4,000	18	12.57	0.61	
	>55-60	4,213	20	12.57	0.61	
	>60-65	4,273	21	12.57	0.61	
	>65-70	4,332	23	12.53	0.61	
	>70-75	4,897	25	12.57	0.61	
HADCO LED	70	5,120	24	16.74	0.72	(C)(D)
Pendant LED (Non-Flared)	36	3,369	12	14.05	0.65	(R)(C)
	53	5,079	18	14.83	0.67	
	69	6,661	24	14.96	0.67	
	85	8,153	29	15.52	0.69	(R)
						(D)
Pendant LED (Flared)	>35-40	3,369	13	14.22	0.65	(C)
	>40-45	3,797	15	14.22	0.65	
	>45-50	4,438	16	14.22	0.65	
	>50-55	5,079	18	15.33	0.68	
	>55-60	5,475	20	15.33	0.68	
	>60-65	6,068	21	15.33	0.68	
	>65-70	6,661	23	16.11	0.70	
	>70-75	7,034	25	16.11	0.70	
	>75-80	7,594	26	16.30	0.71	
	>80-85	8,153	28	16.30	0.71	
Post-Top, American Revolution						
LED	>30-35	3,395	11	6.61	0.45	
	>45-50	4,409	16	6.96	0.46	
Flood LED	>80-85	10,530	28	6.64	0.45	
	>120-130	16,932	43	7.17	0.47	
	>180-190	23,797	63	8.25	0.50	
	>370-380	48,020	127	12.73	0.61	(C)

SCHEDULE 95 (Continued)

Light-Emitting Diode (LED) Only – Option C Energy Use **(M)**

Type of Light	Watts*	Monthly kWh**
LED	5 - 10	3
LED	>10 - 15	4
LED	>15 - 20	6
LED	>20 - 25	8
LED	>25 - 30	9
LED	>30 - 35	11
LED	>35 - 40	13
LED	>40 - 45	15
LED	>45 - 50	16
LED	>50 - 55	18
LED	>55 - 60	20
LED	>60 - 65	21
LED	>65 - 70	23
LED	>70 - 75	25
LED	>75 - 80	26
LED	>80 - 85	28
LED	>85 - 90	30
LED	>90 - 95	32
LED	>95 - 100	33
LED	>100 - 110	36
LED	>110 - 120	39
LED	>120 - 130	43
LED	>130 - 140	46
LED	>140 - 150	50
LED	>150 - 160	53
LED	>160 - 170	56

(N) (N)

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh. **(M)**
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

SCHEDULE 95 (Continued)

Light-Emitting Diode (LED) Only – Option C Energy Use (Continued) **(M)**

Type of Light	Watts*	Monthly kWh**
LED	>170 - 180	60
LED	>180 - 190	63
LED	>190 - 200	67
LED	>200 - 210	70
LED	>210 - 220	73
LED	>220 - 230	77
LED	>230 - 240	80
LED	>240 - 250	84
LED	>250 - 260	87
LED	>260 - 270	91
LED	>270 - 280	94
LED	>280 - 290	97
LED	>290 - 300	101

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

. Trimming of trees adjacent to streetlight equipment and circuits.
. Arterial patrols to ensure correct operation of streetlights.
. Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100. **(M)**

SCHEDULE 95 (Continued)

SPECIAL CONDITIONS (M)

1. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

2. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

3. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

4. If circuits or poles not already covered under Special Conditions 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

5. For Option C lights: The Company does not provide the circuit on new installations. (C)

6. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

7. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work. (M)

SCHEDULE 95 (Continued) **(T)**

SPECIAL CONDITIONS (Continued) **(M)**

8. Indemnification:

a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

(N)

b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that **(N)** arise under this Schedule.

c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 8.c. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer. **(M)**

SCHEDULE 95 (Continued)

SPECIAL CONDITIONS (Continued) **(M)**

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer. **(C)**

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

9. The conversion of existing Schedule 91 luminaires to Schedule 95 Option A luminaires is subject to the Company's operating schedule.

(M)

SCHEDULE 95 (Concluded)

SPECIAL CONDITIONS (Continued) **(M)**

10. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

11. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

A Customer served under the Daily Pricing Option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made. **(M)**

SCHEDULE 99
SPECIAL CONTRACTS

PURPOSE

This schedule describes contracts between the Company and Customers at rates other than those contained in standard schedules. These descriptions do not include all terms and conditions in the contracts and are intended only as summaries. If there are any conflicts between these summaries and provisions in the contracts, the contracts will be controlling. The Company maintains for public inspection copies of special contracts at offices where the Tariff is available.

APPLICABLE

To those Customers that can meet the eligibility criteria established in Commission Order 87-402 and ORS 757.230, as well as the eligibility criteria listed below.

CONTRACTS

Port of Portland/Cascade General, Inc. (Portland)

Effective Date

February 21, 1996.

Term

Effective as long as Customer purchases Electricity Service under a mutually agreed to Tariff. **(C)**

Rate

Schedule 89 - General Service, Primary Voltage.

Special Conditions

Customer to supply Electricity for resale to his/her "Customers" at his/her Repair Facility. Customer will be allowed to reflect charges over and above the Company's price for electricity in order to recover the costs of the Customer's electrical distribution system as outlined in the Portland Ship Repair Yard Price Schedule. As a result, bills received by his/her "Customers" may show a kWh charge above that which is charged by the Company.

Eligibility Criteria

1. Customer engaged in sales for resale prior to November 5, 1973.

2. Customer has significant investment in distribution facilities requiring additional cost recovery from its "Customers".

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules.

Schs.	102[1]	103[3]	105	106[1]	108[3]	109[1]	110[1]	112	115	118	122	123[1]	125[1]	126	128[4]	129[1]
7	x	x	x	x	x	x	x	x	x	x	x	x	x	x		
15	x	x	x	x	x	x	x	x	x	x	x	x	x	x		
32	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
38	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
47	x	x	x	x	x	x	x	x	x	x	x	x	x	x		
49	x	x	x	x	x	x	x	x	x	x	x	x	x	x		
75	x[2]	x	x[2]	x	x	x[2]	x[2]	x	x	x	x[2]	x	x[2]	x[2]	x	
76	x	x		x	x			x	x	x						
83	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
85	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
89	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
90	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
91		x	x	x	x	x	x	x	x	x	x	x	x	x	x	
92		x	x	x	x	x	x	x	x	x	x	x	x	x		
95		x	x	x	x	x	x	x	x	x	x	x	x	x	x	
485	x	x	x	x	x	x	x	x	x	x		x		x[5]		x
489	x	x	x	x	x	x	x	x	x	x		x		x[5]		x
490	x	x	x	x	x	x	x	x	x	x		x		x		x
491		x	x	x	x	x	x	x	x	x		x		x		x
492		x	x	x	x	x	x	x	x	x		x		x		x
495		x	x	x	x	x	x	x	x	x		x		x		x
515	x	x	x	x	x	x	x	x	x	x		x		x[5]	x	
532	x	x	x	x	x	x	x	x	x	x		x		x[5]	x	
538	x	x	x	x	x	x	x	x	x	x		x		x[5]	x	
549	x	x	x	x	x	x	x	x	x	x		x		x[5]	x	
575	x[2]	x	x[2]	x	x	x	x	x	x	x		x		x[2]	x	
576	x	x		x	x			x	x	x						
583	x	x	x	x	x	x	x	x	x	x		x		x[5]	x	
585	x	x	x	x	x	x	x	x	x	x		x		x[5]	x	
589	x	x	x	x	x	x	x	x	x	x		x		x[5]	x	
590	x	x	x	x	x	x	x	x	x	x		x		x	x	
591		x	x	x	x	x	x	x	x	x		x		x[5]	x	
592		x	x	x	x	x	x	x	x	x		x		x[5]	x	
595		x	x	x	x	x	x	x	x	x		x		x[5]	x	
689	x	x	x	x	x	x	x	x	x	x		x				

(N)

(N)

1. Where applicable.
2. These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
3. Schedule 108 applies to the sum of all charges less taxes, Schedule 109 and 115 charges and one-time charges such as deposits.
4. Applicable to Nonresidential Customer who receive service at Daily pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 485, 489, 490, 491, 492 and 495).
5. Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 100 (Concluded)

SUMMARY OF APPLICABLE ADJUSTMENTS (Continued)

(N)

Schs.	131	134	135	136	137	138	139	142	143	145	146	149	150	151	152	153
7	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
15	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
32	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
38	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
47	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
49	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
75	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
76	x	x						x				x		x		
83	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
85	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
89	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
90	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
91	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
92	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
95	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
485	x	x			x	x		x	x			x	x	x	x	x
489	x	x			x	x		x	x			x	x	x	x	x
490	x	x			x	x		x	x			x	x	x	x	x
491	x	x			x	x		x	x			x	x	x	x	x
492	x	x			x	x		x	x			x	x	x	x	x
495	x	x			x	x		x	x			x	x	x	x	x
515	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
532	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
538	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
549	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
575	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
576	x	x						x				x		x		
583	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
585	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
589	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
590	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
591	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
592	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
595	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
689	x	x		x	x	x	x	x	x			x	x	x	x	x

(N)

1. Where applicable.
2. These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
3. Schedule 108 applies to the sum of all charges less taxes, Schedule 109 and 115 charges and one-time charges such as deposits.
4. Applicable to Nonresidential Customer who receive service at Daily pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 485, 489, 490, 491, 492 and 495).
5. Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 102
REGIONAL POWER ACT EXCHANGE* CREDIT

PURPOSE

Each Customer's bill rendered under schedules providing Residential Service, Farm Service and Nonresidential Farm Irrigation and Drainage Pumping Service will include the Regional Power Act Exchange Credit applied to each kWh sold when the Customer qualifies for the adjustment according to the definitions and limitations set forth in this schedule. Where Customers are served by Electricity Service Suppliers (ESSs), the ESS will agree to pass through the credit to the Customer.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Direct Access Service, Emergency Default Service, Standard Service and Residential Service where the Customer meets the definition of Residential Service, Farm Service or Farm Irrigation and Drainage Pumping Service as specified in this schedule. Consistent with the requirements of the Bonneville Power Administration (BPA), if, in the course of doing business, a utility discovers that one of its existing Customers is growing Cannabis using power provided by the utility, such customer is not eligible for the Regional Power Act Exchange Credit under this Schedule.

REGIONAL POWER ACT EXHANGE CREDIT

The credit will be the value of power and other benefits inclusive provided in accordance with the terms of the Settlement Agreement between the Company and the BPA.

The credit inclusive of interest is:

All schedules	(0.676)	¢ per kWh	**(R)**

RESIDENTIAL SERVICE

Residential Service means Electricity Service provided for residential purposes including service to master-metered apartments, apartment utility rooms, common areas, and other residential uses.

* Short title for "Pacific Northwest Electric Power Planning and Conservation Act".

SCHEDULE 102 (Concluded)

FARM IRRIGATION AND DRAINAGE PUMPING SERIVE

Farm Irrigation and Drainage Pumping Service means Electricity Service to a parcel of land used for the raising of crops, livestock, or pasturage and includes service to irrigation pumps.

FARM SERVICE

Farm Service means Electricity Service furnished to Premises employed for the purpose of obtaining a profit in money by raising, harvesting and selling crops; or by the feeding, breeding, management and sale of, or the produce of, livestock, poultry, fur-bearing animals, or honeybees; or for dairying and the sale of dairy products; or any other agricultural or horticultural use, animal husbandry, or any combination thereof. Farm Service includes the use of Energy to prepare and store the products raised on the Premises for human use and animal use and his/her disposal by marketing or otherwise. Farm Service does not include the use of Energy for commercial treatment, storage, or distribution of agricultural or horticultural products and does not include the use of land subject to the provisions of ORS Chapter 321 concerning commercial forestry.

SPECIAL CONDITIONS

1. The Credit will be applied to residential and farm usage; however, irrigation for farm use is limited to the first 400 horsepower per farm. The 400-horsepower limitation will be converted to maximum monthly kWh usage according to the following formula:

   400 hp x .746 x (24 hrs x days in Billing Period) = maximum kWh but not to exceed 222,000 kWh in any month

2. The credit is no longer applicable upon determination that the service no longer constitutes residential or farm usage. The Customer or ESS will notify the Company of any change of the type of service on the Customer's Premises. The credit and eligibility for the adjustment are subject to review and approval by BPA and the Commission.

SCHEDULE 103
METRO SUPPORTIVE HOUSING SERVICES BUSINESS INCOME TAX RECOVERY

PURPOSE

To recover from Customers inside Metro's jurisdiction in Clackamas, Multnomah and Washington Counties the Metro Supportive Housing Services (MSHS) Business Income Tax paid by the Company in accordance with Measure 26-210 OAR 860-022-0045 and to establish an associated Automatic Adjustment Clause and balancing account.

APPLICABLE

All Customers receiving Electricity Service within Metro's jurisdiction in Clackamas, Multnomah and Washington Counties.

BALANCING ACCOUNT

The MSHS Balancing Account will be maintained to accrue any difference between the Company's actual local income tax liability and the amount collected from Customers under this Schedule. Any over or under-collection reflected in this account will be considered when the Metro Supportive Housing Services Rate is established. This Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts.

METRO SUPPORTIVE HOUSING SERVICES RATE DETERMINATION

The MSHS Rate is determined by dividing the sum of forecast MSHS tax liability plus or minus any amount in the Balancing Account divided by forecast Retail Revenue from Customers in Metro's jurisdiction in Clackamas, Multnomah or Washington Counties for each tax year or other applicable recovery period.

MSHS RATE

The MSHS Rate is:

> 0.024% of the total billed amount to the Customer excluding the Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes. **(I)**

SCHEDULE 105
REGULATORY ADJUSTMENTS

PURPOSE

The purpose of this schedule is to reflect the effects of regulatory adjustments such as net gains from nonrecurring property transactions, and costs associated with the implementation of SB 1149, and miscellaneous nonrecurring items.

APPLICABLE

To all bills for Electricity Service calculated under all schedules and contracts, except those Customers explicitly exempted.

PART A – MISCELLANEOUS ADJUSTMENTS

Part A will be adjusted annually as necessary to recover nonrecurring Regulatory Adjustments.

PART B – LARGE NON-RESIDENTIAL LOAD TRUE-UP

Part B consists of costs associated with the Schedule 128 Large Nonresidential Load Shift True-up after the November annual open enrollment window.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Schedule	Part A	Part B	Adjustment Rate		
7	0.016	0.000	0.016	¢ per kWh	(I)
15	0.019	0.000	0.019	¢ per kWh	
32	0.010	0.000	0.010	¢ per kWh	
38	0.010	0.009	0.019	¢ per kWh	
47	0.015	0.000	0.015	¢ per kWh	
49	0.013	0.009	0.022	¢ per kWh	
75					
Secondary	0.017	0.009	0.026	¢ per kWh(1)	
Primary	0.017	0.009	0.026	¢ per kWh(1)	
Subtransmission	0.017	0.009	0.026	¢ per kWh(1)	(I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 105 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
83	0.007	0.009	0.016	¢ per kWh	(I)
85					
Secondary	0.006	0.009	0.015	¢ per kWh	
Primary	0.006	0.009	0.015	¢ per kWh	
89					
Secondary	0.017	0.009	0.026	¢ per kWh	
Primary	0.017	0.009	0.026	¢ per kWh	
Subtransmission	0.017	0.009	0.026	¢ per kWh	(I)
90					
Primary	0.016	0.009	0.025	¢ per kWh	(C)(I)
Subtransmission	0.016	0.009	0.025	¢ per kWh	(N)
91	0.019	0.009	0.028	¢ per kWh	(I)
92	0.005	0.009	0.014	¢ per kWh	
95	0.019	0.009	0.028	¢ per kWh	
485					
Secondary	0.002	0.000	0.002	¢ per kWh	
Primary	0.002	0.000	0.002	¢ per kWh	
489					
Secondary	0.013	0.000	0.013	¢ per kWh	
Primary	0.013	0.000	0.013	¢ per kWh	
Subtransmission	0.013	0.000	0.013	¢ per kWh	(I)
490					
Primary	0.016	0.000	0.016	¢ per kWh	(C)(I)
Subtransmission	0.016	0.000	0.016	¢ per kWh	(N)
491	0.019	0.000	0.019	¢ per kWh	(I)
492	0.005	0.000	0.005	¢ per kWh	
495	0.019	0.000	0.019	¢ per kWh	(I)

SCHEDULE 105 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
515	0.019	0.000	0.019	¢ per kWh	(I)
532	0.010	0.000	0.010	¢ per kWh	
538	0.010	0.009	0.019	¢ per kWh	
549	0.013	0.009	0.022	¢ per kWh	
575					
Secondary	0.017	0.009	0.026	¢ per kWh(1)	
Primary	0.017	0.009	0.026	¢ per kWh(1)	
Subtransmission	0.017	0.009	0.026	¢ per kWh(1)	
583	0.007	0.009	0.016	¢ per kWh	
585					
Secondary	0.006	0.009	0.015	¢ per kWh	
Primary	0.006	0.009	0.015	¢ per kWh	
589					
Secondary	0.017	0.009	0.026	¢ per kWh	
Primary	0.017	0.009	0.026	¢ per kWh	
Subtransmission	0.017	0.009	0.026	¢ per kWh	(I)
590					
Primary	0.016	0.009	0.025	¢ per kWh	(C)(I)
Subtransmission	0.016	0.009	0.025	¢ per kWh	(N)
591	0.019	0.009	0.028	¢ per kWh	(I)
592	0.005	0.009	0.014	¢ per kWh	
595	0.019	0.009	0.028	¢ per kWh	
689					
Secondary	0.013	0.000	0.013	¢ per kWh	
Primary	0.013	0.000	0.013	¢ per kWh	
Subtransmission	0.013	0.000	0.013	¢ per kWh	(I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 106
MULTNOMAH COUNTY BUSINESS INCOME TAX RECOVERY

PURPOSE

To recover from Customers in Multnomah County the Multnomah County Business Income Tax (MCBIT) paid by the Company in accordance with Multnomah County Code § 12.610 and OAR 860-022-0045 and to establish an associated Automatic Adjustment Clause and balancing account.

APPLICABLE

All Customers receiving Electricity Service within Multnomah County.

BALANCING ACCOUNT

A MCBIT Balancing Account will be maintained to accrue any difference between the Company's actual local income tax liability and the amount collected from Customers under this Schedule. Any over or under-collection reflected in this account will be considered when the MCBIT Rate is established. This Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts.

MCBIT RATE DETERMINATION

The MCBIT Rate is determined by dividing the sum of forecast MCBIT tax liability plus or minus any amount in the Balancing Account divided by forecast Retail Revenue from Customers in Multnomah County for each tax year or other applicable recovery period.

MCBIT RATE

The MCBIT Rate is:

> 0.00% of the total billed amount to the Customer excluding the Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes. **(R)**

SCHEDULE 108
PUBLIC PURPOSE CHARGE

PURPOSE

To collect funds associated with activities mandated for the benefit of the general public pursuant to OAR 860-038-0480. Activities include new energy, related investments in schools, new renewable energy resources and customer investments in technologies supporting reliability, resilience and the integration of renewable energy resources with the Company's distribution system, low-income housing resources and new low-income weatherization. **(C)** **(C)**

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except Nonresidential Customers qualifying as a Self-Directing Customer may be partially exempt.

PUBLIC PURPOSE CHARGE

The Public Purpose Charge will be 1.5% of total revenue billed to the Customer "for electricity services, distribution, ancillary services, metering and billing, transition charges and other types of costs that were included in electric rates on July 23, 1999" as specified in OAR 860-038-0480(2). **(C)**

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be a Self-Directing Customer (SDC), the Large Nonresidential Customer must have a load that exceeds one aMW and receive certification from the Oregon Department of Energy (ODOE) as an SDC. Beginning November 30, 2004, the Company will include the credits due, as reported by the ODOE, to the applicable portions of the SDCs monthly Public Purpose Charge.

SPECIAL CONDITIONS

1. Electricity Service Suppliers (ESS) – Each ESS that provides Direct Access Service in the Company's service territory will collect a Public Purpose Charge from its Direct Access Customers. The ESS will remit monthly to the Company the Public Purpose Charges it collects from Customers and provide calculations of the Public Purpose Charge for each Service Point enrolled in Direct Access. The ESS will supply the Company with this information, so the Company can correctly allocate the applicable portions of the Direct Access SDC's monthly Public Purpose Charge and ensure Disbursement of Funds collected are allocated as required. **(C)** **(C)**

SCHEDULE 108 (Concluded)

SPECIAL CONDITIONS (Continued)

2. Disbursement of Funds – The Company will distribute monthly, Public Purpose funds collected, minus reasonable administrative costs, as outlined in OAR 860-038-0480 and required by ORS 757.612:

- The funds for energy related investments in schools to the education service districts located in the Company's service territory = 0.30% of revenues (20% of total); **(C)** **(C)** **(D)**

- The funds for renewable energy resources and customer investments in technologies supporting reliability, resilience, and the integration of renewable energy resources will be allocated as directed by the Commission = 0.51% of revenues (34% of total); **(C)** **(C)**

- The funds for low-income weatherization will be allocated to the Housing and Community Services Department = 0.55% of revenues (36.67% of total); and **(C)** **(C)**

- The funds for low-income housing will be allocated to the Housing and Community Services Department Revolving Account = 0.14% of revenues (9.33% of total). **(C)** **(C)**

TERM

This Schedule will terminate on January 1, 2036. **(C)**

SCHEDULE 109
ENERGY EFFICIENCY FUNDING ADJUSTMENT

PURPOSE

To fund the acquisition of additional Energy Efficiency Measures (EEMs) for the benefit of the Company's Customers pursuant to ORS 757.054. **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory. **(C)** Nonresidential Customers whose load exceeded one aMW at a Service Point (SP) during the prior calendar year or those Nonresidential Customers qualifying as a Site certified by Oregon Department of Energy (ODOE) will not be charged an amount in rates that exceeds 1.7% of the total revenue received from the sale of electricity serviced to the Site from any source. **(C)**

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the ODOE as a SDC. The Company will include the credits due, as reported by the **(C)** ODOE, to the applicable portions of the SDCs monthly Schedule 109 Charge. **(C)**

DISBURSEMENT OF FUNDS

All funds collected under this schedule less an allowance for uncollectible expenses will be distributed to the ETO on a monthly basis.

(M)

SCHEDULE 109 (Continued)

ENERGY EFFICIENCY ADJUSTMENT **(M)**

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be: **(T)**

Standard Pricing **(N)**

Schedule	Adjustment Rate	
7	0.579 ¢ per kWh	**(I)**
15/515	0.794 ¢ per kWh	**(I)(C)**
32/532	0.576 ¢ per kWh	
38/538	0.635 ¢ per kWh	
47	0.922 ¢ per kWh	
49/549	0.635 ¢ per kWh	**(I)(C)**
75/575		**(M)**
Secondary	0.125 ¢ per kWh	**(R)**
Primary	0.121 ¢ per kWh	
Subtransmission	0.123 ¢ per kWh	**(R)**
83/583	0.464 ¢ per kWh	**(I)(C)**
85/485/585		
Secondary	0.400 ¢ per kWh	
Primary	0.413 ¢ per kWh	**(I)(C)**
89/489/589/689		**(C)**
Secondary	0.125 ¢ per kWh	**(R)**
Primary	0.121 ¢ per kWh	
Subtransmission	0.123 ¢ per kWh	
90/490/590	0.113 ¢ per kWh	
91/491/591	0.553 ¢ per kWh	**(R)**
92/492/592	0.409 ¢ per kWh	**(I)**
95/495/595	0.553 ¢ per kWh	**(R)**

(D)

SCHEDULE 109 (Concluded)

ENERGY EFFICIENCY ADJUSTMENT (Continued)

Over One Average Megawatt or Site Price Adjustment (D)
(N)

Schedule	Adjustment Rate
15/515 >1aMW	0.140 ¢ per kWh
32/532 >1aMW	0.214 ¢ per kWh
38/538 >1aMW	0.243 ¢ per kWh
47 >1aMW	0.353 ¢ per kWh
49/549 >1aMW	0.243 ¢ per kWh
75/575 >1aMW	
Secondary	0.125 ¢ per kWh
Primary	0.121 ¢ per kWh
Subtransmission	0.123 ¢ per kWh
83/583 >1aMW	0.149 ¢ per kWh
85/485/585 >1aMW	
Secondary	0.132 ¢ per kWh
Primary	0.126 ¢ per kWh
89/489/589/689 >1aMW	
Secondary	0.125 ¢ per kWh
Primary	0.121 ¢ per kWh
Subtransmission	0.123 ¢ per kWh
90/490/590 >1aMW	0.113 ¢ per kWh
91/491/591/95/495/595 >1aMW	0.223 ¢ per kWh

TERM

This Schedule will terminate on January 1, 2036. (N)

SCHEDULE 110
ENERGY EFFICIENCY CUSTOMER SERVICE

PURPOSE

To fund Company activities associated with enabling Customers to achieve energy efficiency including, but not limited to project facilitation, technical assistance, education and assistance to support programs administered by the Energy Trust of Oregon (ETO).

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Service Point (SP) during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer (SDC). Customers so exempted will not be charged the prices contained in this Schedule. **(C)**

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

> **Energy Efficiency Measures (EEMs)** – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the ODOE as a SDC.

BALANCING ACCOUNT

Effective June 1, 2010, the Company will establish a balancing account to record the differences between the actual fully loaded qualifying expenses (which may not exceed $1.3 million in any year) and the revenues collected under this schedule adjusted for allowance for uncollectibles, franchise fees, and other revenue sensitive costs. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

SCHEDULE 110 (Continued)

ENERGY EFFICIENCY CUSTOMER SERVICE ADJUSTMENT

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Schedule	Adjustment Rate		
7	0.004	¢ per kWh	**(R)**
15	0.008	¢ per kWh	
32	0.004	¢ per kWh	
38	0.004	¢ per kWh	
47	0.007	¢ per kWh	
49	0.005	¢ per kWh	
75			
Secondary	0.003	¢ per kWh	
Primary	0.003	¢ per kWh	
Subtransmission	0.003	¢ per kWh	
83	0.003	¢ per kWh	
85			
Secondary	0.003	¢ per kWh	
Primary	0.003	¢ per kWh	
89			
Secondary	0.003	¢ per kWh	
Primary	0.003	¢ per kWh	
Subtransmission	0.003	¢ per kWh	
90			**(R)**
Primary	0.003	¢ per kWh	**(C)(R)**
Subtransmission	0.003	¢ per kWh	**(N)**
91	0.008	¢ per kWh	**(R)**
92	0.002	¢ per kWh	**(R)**

SCHEDULE 110 (Continued)

ENERGY EFFICIENCY CUSTOMER SERVICE ADJUSTMENT (Continued)

Schedule		Adjustment Rate	
95		0.008 ¢ per kWh	(R)
485			
	Secondary	0.003 ¢ per kWh	
	Primary	0.003 ¢ per kWh	
489			
	Secondary	0.003 ¢ per kWh	
	Primary	0.003 ¢ per kWh	
	Subtransmission	0.003 ¢ per kWh	(R)
490			
	Primary	0.003 ¢ per kWh	(C)(R)
	Subtransmission	0.003 ¢ per kWh	(N)
491		0.008 ¢ per kWh	(R)
492		0.002 ¢ per kWh	
495		0.008 ¢ per kWh	
515		0.008 ¢ per kWh	
532		0.004 ¢ per kWh	
538		0.004 ¢ per kWh	
549		0.005 ¢ per kWh	
575			
	Secondary	0.003 ¢ per kWh	
	Primary	0.003 ¢ per kWh	
	Subtransmission	0.003 ¢ per kWh	
583		0.003 ¢ per kWh	(R)

SCHEDULE 110 (Concluded)

ENERGY EFFICIENCY CUSTOMER SERVICE ADJUSTMENT (Continued)

Schedule		Adjustment Rate	
585			
	Secondary	0.003 ¢ per kWh	(R)
	Primary	0.003 ¢ per kWh	
589			
	Secondary	0.003 ¢ per kWh	
	Primary	0.003 ¢ per kWh	
	Subtransmission	0.003 ¢ per kWh	(R)
590			
	Primary	0.003 ¢ per kWh	(C)(R)
	Subtransmission	0.003 ¢ per kWh	(N)
591		0.008 ¢ per kWh	(R)
592		0.002 ¢ per kWh	
595		0.008 ¢ per kWh	
689			
	Secondary	0.003 ¢ per kWh	
	Primary	0.003 ¢ per kWh	
	Subtransmission	0.003 ¢ per kWh	(R)

SCHEDULE 112
CUSTOMER ENGAGEMENT TRANSFORMATION ADJUSTMENT

PURPOSE

This schedule recovers the unamortized 2014-2016 deferred costs and the estimated 2017 and 2018 operations and maintenance costs related to PGE's Customer Engagement Transformation (CET) project consistent with OPUC Order No. 17-511.

APPLICABLE

To all bills for Electricity Service.

ADJUSTMENT RATES

Schedule 112 Adjustment Rates will be set based on the relevant cost allocations determined in the Company's most recent general rate proceeding, updated for more recent billing determinants, if necessary.

Schedule	Adjustment Rate	
7	0.030	¢ per kWh
15/515	0.025	¢ per kWh
32/532	0.021	¢ per kWh
38/538	0.039	¢ per kWh
47	0.050	¢ per kWh
49/549	0.015	¢ per kWh
75/575/76R/576R		
Secondary	0.001	¢ per kWh
Primary	0.001	¢ per kWh
Subtransmission	0.001	¢ per kWh
83/583	0.006	¢ per kWh
85/485/585		
Secondary	0.004	¢ per kWh
Primary	0.004	¢ per kWh

SCHEDULE 112 (Concluded)

ADJUSTMENT RATE (Concluded)

Schedule	**Adjustment Rate**	
89/489/589/689		
Secondary	0.001	¢ per kWh
Primary	0.001	¢ per kWh
Subtransmission	0.001	¢ per kWh
90/490/590	0.001	¢ per kWh
91/491/591	0.025	¢ per kWh
92/492/592	0.023	¢ per kWh
95/495/595	0.025	¢ per kWh

ACCOUNTING

The Company will maintain an account to track the stipulated CET expenses and the actual Schedule 112 revenues. The account will accrue interest at the Commission-authorized rate for deferred accounts.

TERM

This schedule will terminate on January 31, 2023. **(C)**

SCHEDULE 115
LOW-INCOME ASSISTANCE

PURPOSE

The purpose of this rate schedule is to implement the low-income bill payment assistance provisions in accordance with ORS 757.612(7)(b) and reflective of adjustments made via House Bill 2739 (2021 regular session). The latter directs electric companies to collect an additional $10 million annually for two years, starting in 2022, bringing the statewide total to approximately $30 million annually. **(C)** **(C)**

APPLICABLE

To all Retail Electricity Customers, including Customers receiving electricity from other sources and Customers who do not purchase distribution services from PGE per ORS 757.612(8), except those Customers explicitly exempted. **(C)** **(C)**

ADJUSTMENT RATES

The applicable Adjustment Rates are listed below. As specified in House Bills 2134 and 2739, Customers will not be required to pay more than $500 per month per Site for low-income bill payment assistance. **(C)** **(C)**

Schedules	Adjustment Rate	
7	$1.04 per month	**(I)**
All other Schedules, including DSIs	0.104¢ per kWh for the first 480,769 kWh	**(I)** **(C)**

SPECIAL CONDITION **(T)**

1. On a monthly basis, on or before the last day of the month, the Company will forward an amount to the Oregon Housing and Community Services Department (OHCS) based on billings to Customers for the previous month less a reserve for uncollectable amounts.

SCHEDULE 118
BILL ADJUSTMENT
COST RECOVERY MECHANISM

PURPOSE

The purpose of this schedule is to recover the costs associated with PGE's Income-Qualified Bill Discount, an offering to eligible Residential Customers designed to increase bill affordability (operationalized in Schedule 18). This discount is enabled by House Bill 2475 (2021 regular session), which calls for differentiated rates for "low-income customers and other economic, social equity or environmental justice factors that affect affordability for certain classes of utility customers." This adjustment schedule is implemented as an automatic adjustment clause as provided for in ORS 757.210.

APPLICABLE

To all bills for Electricity Service.

ADJUSTMENT RATES

The applicable Adjustment Rates are listed below. Customers will not be required to pay more than $1,000 per month per Site for cost recovery of the Income-Qualified Bill Discount.

Schedules	Adjustment Rate	
7	$1.14 per bill	**(I)**
All other Schedules	0.114¢ per kWh for the first 877,193 kWh	**(I)** **(C)**

SCHEDULE 122
RENEWABLE RESOURCES AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource and energy storage projects associated with renewable energy resources (including associated transmission) not otherwise included in rates. Additional new renewable and energy storage projects associated with renewable energy resources may be incorporated into this schedule as they are placed in service. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210 and Section 13 of the Oregon Renewable Energy Act (OREA).

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76, 485, 489, 490, 491, 492, 495, 576 and 689. This schedule is not applicable to direct access customers after December 31, 2010.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule		Adjustment Rate		
7		0.000	¢ per kWh	(R)
15		0.000	¢ per kWh	
32		0.000	¢ per kWh	
38		0.000	¢ per kWh	
47		0.000	¢ per kWh	
49		0.000	¢ per kWh	
75				
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	
	Subtransmission	0.000	¢ per kWh	
83		0.000	¢ per kWh	
85				
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	(R)

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

Schedule		Adjustment Rate		
89				(R)
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	
	Subtransmission	0.000	¢ per kWh	
90				
	Primary	0.000	¢ per kWh	(R)
	Subtransmission	0.000	¢ per kWh	(N)
91		0.000	¢ per kWh	(R)
92		0.000	¢ per kWh	
95		0.000	¢ per kWh	(R)

ANNUAL REVENUE REQUIREMENTS

The Annual Revenue Requirements of a qualifying project will include the fixed costs of the renewable resource or energy storage project associated with renewable energy resources and associated transmission (including return on and return of the capital costs), operation and maintenance costs, income taxes, property taxes, and other fees and costs that are applicable to the renewable resource or energy storage project associated with renewable energy resources or associated transmission. Until the dispatch benefits are included in the Annual Power Cost Update Schedule 125, the net revenue requirements of each project (fixed costs less market value of the energy produced by the renewable resource or energy storage project associated with renewable energy resources plus any power costs such as fuel, integration and wheeling costs) will be deferred and included in the Schedule 122 rates. By no later than April 1 of each year following the resource's on-line date, the Company will file an update to the revenue requirements of resources included in this schedule to recognize projected changes for the following calendar year. Should the final determination of a Schedule 122 filing for a new resource not allow for inclusion of its net variable power costs (NVPC) in the AUT, these will be included in the Schedule 122 revenue requirement used to set initial prices. In this circumstance, the resource's NVPC impacts will subsequently be removed from Schedule 122 prices and included in the AUT at the next available opportunity.

DEFERRAL MECHANISM

For each calendar year that the Company anticipates that a new renewable resource or energy storage project associated with renewable energy resources will commence operation, the Company may file a deferral request the earlier of the resource online date or April 1. The deferral amount will be for the fixed revenue requirements of the resource less net dispatch benefits. For purposes of determining dispatch benefits, the forward curves used to set rates for the year under the Annual Power Cost Update will be used. The deferral will be amortized over the next calendar year in Schedule 122 unless otherwise approved by the Oregon Public Utility Commission (OPUC). The balancing account will accrue interest at the Commission-authorized rate for deferred accounts, and the amortization of the deferred amount will not be subject to the provisions of ORS 757.259(5).

SCHEDULE 122 (Continued)

TIME AND MANNER OF FILING

When the Company proposes to include a new resource under this schedule and, by no later than April 1 of each calendar year that the Company is required to update the Annual Revenue Requirements for an existing resource, the Company will file the following: (C)

1. Revised rates under this schedule and a transmittal letter that summarizes the proposed revenue requirements and charges for both the new resource(s) and the updated revenue requirements and charges for applicable resources previously approved for recovery under this schedule. In addition, the filing will include revised income taxes and associated ratios to calculate "taxes authorized to be collected in rates" under ORS 757.268.

2. Within the Company's Annual Power Cost Update (Schedule 125) filing, the Company will include for the following year the expected generation of resources included in this schedule and the power costs of these resources.

3. Work papers that support the calculation of revenue requirements for all applicable resources and demonstrate how the proposed prices are calculated.

With respect to a Schedule 122 rate change for the initial inclusion of the allowable costs of a new resource, and in compliance with the Commission's findings in the proceeding(s) regarding the initial cost recovery of the new resource, the Company will file updated Schedule 122 rates by noless than 30 days prior to the rate effective date. (C)

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

2. Each renewable resource project (and associated transmission) included in this adjustment schedule must be separately identified and be a new resource defined as "renewable" in the OREA.

3. The costs for projects included under this schedule will be updated annually as provided above, and will continue to be recovered under Schedule 122 until such time as the costs are included in base rates or the project is no longer in service.

4. The in-service date for the new renewable resource project or energy storage project associated with renewable energy resources or each separately identifiable project segment will be verified by an attestation from the Company stating that the specific renewable resource project or energy storage project associated with renewable energy resources, or project segment, has met requirements for being commercially operational and is in service. (C)

SCHEDULE 122 (Concluded)

SPECIAL CONDITIONS (Continued)

5. If the actual costs of an eligible new resource cannot be verified by the final round of testimony in the proceeding reviewing the filing for its initial cost recovery, the Company will include in its compliance filing for initial cost recovery an update to reflect then-current actual resource costs, or forecasted costs where appropriate. If the updated costs are lower than the projected costs in the record of the proceeding, the update will contain sufficient information to support a reduction in the proposed adjustment charges before the effective date. If updated costs are higher than the projected costs in the proceeding's record or if actual costs cannot be verified prior to the compliance filing, the Company may file for deferred accounting under the OREA to allow an opportunity for recovery of the cost differences between the projected costs in the record and the prudently incurred actual costs. For purposes of Schedule 126 (Annual Power Cost Variance Mechanism), actual NVPC will be adjusted to remove the impact of any power produced by a new renewable resource or energy storage project associated with renewable energy resources qualifying for treatment under this schedule but not otherwise included in rates. The following adjustments will be made: **(C)** **(C)** **(C)** **(C)** **(C)** **(C)**

    a) Actual NVPC will be increased by the value of any renewable or energy storage resource energy. The value of such energy will be determined by employing the forward curves used to set rates for the year under the Annual Power Cost Update. Actual NVPC will be reduced by applicable fuel costs and supply integration costs for the resource.

    b) Actual NVPC will also be increased or decreased as appropriate for any other credits or charges specifically identifiable with the new renewable or energy storage resource.

6. For Schedule 122 filings made on and after April 2009, the Commission may condition approval of a proposed change in Schedule 122 charges on PGE making a filing under ORS 757.210 within six months after the Commission order approving the proposed change. Through this filing, the Company will roll into the generation component of its rates all of the costs, or a portion thereof identified by the Commission, that are being collected through the then existing Schedule 122 charges. The Commission's order for conditional approval must be based upon: (1) a finding that the costs, or a portion thereof, specified by the Commission have been collected through Schedule 122 for a reasonable period of years, as determined by the Commission; or (2) for good cause, as determined by the Commission.

SCHEDULE 123
DECOUPLING ADJUSTMENT

PURPOSE

This Schedule establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Service Point (SP) **(C)** during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer. Customers so exempted will not be charged the prices contained in this schedule.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

Energy Efficiency Measures (EEMs) – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.

Self-Directing Customer (SDC) - Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy as an SDC.

SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, differences between:

a) the monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) to weather-normalized kWh Energy sales; and

b) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer to the numbers of active Customers for each applicable SNA rate schedule, respectively, for each month. For Schedule 7, a Secondary Fixed Charge equal to 69% of the Monthly Fixed Charge will be used to calculate Fixed Charge Revenues for actual customer counts that exceed the projected customer counts used to establish base rates in a general rate review.

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

The SNA will calculate monthly as the Fixed Charge Revenue less actual revenues and will accrue to the SNA Balancing Account. The monthly amount accrued may be positive (an under-collection) or negative (an over-collection). The SNA is divided into sub-accounts so that net accruals for each rate schedule will track separately. (C)

(C)

The SNA is applicable to the following rate schedules:

(N)

Schedule	Fixed Charge Energy Rate (¢ per kWh)	Monthly Fixed Charge	Monthly Secondary Fixed Charge
7	8.870	$71.45	$49.30
32	7.693	$111.66	
83*	3.790	$790.34	

*Applicable beginning in 2019. The Fixed Charge Energy Rate for Schedule 83 includes fixed generation charges only. (N)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA)

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32, 83 (starting in 2019), and 532 or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. Also included are differences in actual energy savings from a test year forecast associated with the conversion to LED streetlighting in Schedule 95 reported by the Company. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates. (C)

The Lost Revenue Recovery Adjustment may be positive or negative. A negative Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are less than those estimated in setting base rates. A positive Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are greater than those estimated for the test year in setting base rates. The LRRA for each year subsequent to the test year will incorporate incremental kWh savings reported by the Energy Trust of Oregon for that year.

(M)

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA) (Continued)

For the purposes of this Schedule, the Lost Revenue Recovery Adjustment is the product of: (1) the reduction in kWh sales resulting from ETO-reported EEMs plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, and (2) the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule-weighted average of transmission, distribution, and fixed generation charges; including those contained in Schedule122 and other applicable schedules. System usage or distribution charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. Franchise fee recovery is not included in the Lost Revenue Rate. The applicable Lost Revenue Rate is 5.548 cents per kWh. **(C)**

SNA and LRRA BALANCING ACCOUNTS

The Company will maintain a separate balancing account for the SNA applicable rate schedules and for the Nonresidential LRRA applicable rate schedules. Each balancing account will record over- and under-collections resulting from differences as determined, respectively, by the SNA and LRRA mechanisms. The accounts will accrue interest at the Commission-authorized Modified Blended Treasury Rate established for deferred accounts.

DECOUPLING ADJUSTMENT

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate		
7	(0.222)	¢ per kWh	**(I)**
15	0.100	¢ per kWh	
32	0.301	¢ per kWh	
38	0.100	¢ per kWh	
47	0.100	¢ per kWh	
49	0.100	¢ per kWh	
75			
Secondary	0.100	¢ per kWh	
Primary	0.100	¢ per kWh	
Subtransmission	0.100	¢ per kWh	**(I)**
83	0.088	¢ per kWh	**(R)**

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued)

Schedule	Adjustment Rate	
85		
Secondary	0.100 ¢ per kWh	(I)
Primary	0.100 ¢ per kWh	
89		
Secondary	0.100 ¢ per kWh	
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
90		
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
91	0.100 ¢ per kWh	
92	0.100 ¢ per kWh	
95	0.100 ¢ per kWh	
485		
Secondary	0.017 ¢ per kWh	
Primary	0.017 ¢ per kWh	
489		
Secondary	0.017 ¢ per kWh	
Primary	0.017 ¢ per kWh	
Subtransmission	0.017 ¢ per kWh	
490		
Primary	0.017 ¢ per kWh	
Subtransmission	0.017 ¢ per kWh	
491	0.017 ¢ per kWh	
492	0.017 ¢ per kWh	
495	0.017 ¢ per kWh	
515	0.100 ¢ per kWh	
532	0.301 ¢ per kWh	
538	0.100 ¢ per kWh	
549	0.100 ¢ per kWh	(I)

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued)

Schedule	Adjustment Rate	
575		
Secondary	0.100 ¢ per kWh	(I)
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	(I)
583	0.088 ¢ per kWh	(R)
585		
Secondary	0.100 ¢ per kWh	(I)
Primary	0.100 ¢ per kWh	
589		
Secondary	0.100 ¢ per kWh	
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
590		
Primary	0.100 ¢ per kWh	
Subtransmission	0.100 ¢ per kWh	
592	0.100 ¢ per kWh	
591	0.100 ¢ per kWh	(N)
595	0.100 ¢ per kWh	
689		
Secondary	0.012 ¢ per kWh	
Primary	0.012 ¢ per kWh	
Subtransmission	0.012 ¢ per kWh	(I)

TIME AND MANNER OF FILING

Commencing in 2014, the Company will submit to the Commission the following information by November 1 of each year:

SCHEDULE 123 (Concluded)

TIME AND MANNER OF FILING (Continued) **(T)**

1. The proposed price changes to this Schedule to be effective on January 1st of the subsequent year based on a) the amounts in the SNA Balancing Accounts and b) the amount in the LRRA Balancing Account. **(M)**

2. Revisions to this Schedule which reflect the new proposed prices and supporting work papers detailing the calculation of the new proposed prices and the SNA weather-normalizing adjustments. **(M)**

SPECIAL CONDITIONS

1. The Fixed Charge Energy Rate, Monthly Fixed Charge per Customer and the Lost Revenue Rate will be updated concurrently with a change in the applicable base revenues used to determine the rates.

2. Weather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that used for determining the forecasted loads used to establish base rates.

3. No revision to any SNA or LRRA Adjustment Rate will result in an estimated average annual rate increase greater than 2% to the applicable SNA or LRRA rate schedule, based on the net rates in effect on the effective date of the Schedule 123 rate revisions. Rate revisions resulting in a rate decrease are not subject to the 2% limit.

4. The LRRA prices for Customers served under the provisions of Schedules 485, 489, 490, 491, 492, 495 and 689 will be calculated to apply to distribution services only.

5. The SNA and LRRA mechanisms will terminate on May 8, 2022. Balances accrued up to that point will be subject to subsequent adjustment.

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all Cost-of-Service bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 90, 91, 92, and 95. Customers served under the daily price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 90, 91, and 95 are exempt from Schedule 125.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Wind energy forecast based on a five-year rolling average.
- Costs associated with wind integration. The battery portion of wind and solar projects that have a battery storage component may be included if the battery is charged solely by wind and solar generation. **(N)**
- Dispatch of energy storage systems. **(N)**
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Emission control chemical costs.
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- Reciprocating engine lubrication oil costs.
- Projections of State and Federal Production Tax Credits.
- No other changes or updates will be made in the annual filings under this schedule.

SCHEDULE 125 (Continued)

CHANGES IN NET VARIABLE POWER COSTS

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0331. **(I)**

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On or before November 6th of each calendar year, the Company will file estimates with the final planned maintenance outages from the October 1st filing, load forecasts from the October 1st filings, load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the inal change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) new market power and fuel contracts entered into since the previous updates, 3) the final planned maintenance outages and load forecast from the October 1st filing, 4) final update to Qualifying Facilities online dates, and 5) final price for the energy generation at the Priest Rapids and Wanapum hydro facilities, as provided in the power contract between PGE and Grant County.

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES

Schedule		¢ per kWh	
7		1.007	(I)
15		0.777	
32		0.870	
38		0.796	
47		0.966	
49		0.989	
75			
	Secondary	0.807 [1]	
	Primary	0.796 [1]	
	Subtransmission	0.810 [1]	
83		0.855	
85			
	Secondary	0.826	
	Primary	0.791	
89			
	Secondary	0.807	
	Primary	0.796	
	Subtransmission	0.810	
90			
	Primary	0.745	
	Subtransmission	0.745	
91		0.733	
92		0.774	
95		0.733	(I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all Customers for Electricity Service except those who were served on Schedule 76R and 576R, 485, 489, 490, 491, 492, 495, 515, 532, 538, 549, 583, 585, 589, 591, 592, 595 and 689, or served under Schedules 83, 85, 89 or 90 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 590, 591, 592 and 595 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE

Subject to the Earnings Test, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record Annual Variance amounts. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. This account will accrue interest at the Commission-authorized rate for deferred accounts. At the end of each year the Adjustment Amount for the calendar year will be adjusted by 50% of the annual interest calculated at the Commission-authorized rate. This amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0331 to account for franchise fees, uncollectibles, and OPUC fees. (I)

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount to the extent that such recovery will not cause the Company's Actual Return on Equity (ROE) for the year to exceed its Authorized ROE minus 100 basis points. The Company will refund the Adjustment Amount to the extent that such refunding will not cause the Company's Actual Return on Equity (ROE) for the year to fall below its Authorized ROE plus 100 basis points.

Schedule 126 (Continued)

DEFINITIONS

Actual Loads

Actual loads are total annual calendar retail loads adjusted to exclude loads of Customers to whom this adjustment schedule does not apply.

Actual NVPC

Incurred cost of power based on the definition for NVPC described here in. Actual NVPC will be increased by the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.

Actual Unit NVPC

The Actual Unit NVPC is the Actual NVPC divided by Actual Loads.

Annual Variance (AV)

The Annual Variance (AV) is the dollar amount calculated annually based on the following formula:

(Actual Unit NVPC – Adjusted Base Unit NVPC) * Actual Loads

Base Unit NVPC

The Base Unit NVPC is the NVPC used to develop rate schedules for the applicable year divided by the associated calendar basis retail loads. Base NVPC are updated annually in accordance with Schedule 125.

Adjusted Base Unit NVPC

The Adjusted Base Unit NVPC is the NVPC used to calculate the Annual Variance. The Adjusted Base Unit NVPC is the Base Unit NVPC (determined in accordance with Schedule 125) adjusted for load and cost changes resulting from non-residential customers choosing service under Schedule 515 through 595 after the November update for the applicable year. **(C)**

Negative Annual Power Cost Deadband

The Negative Annual Power Cost Deadband is ($15.0 million).

Positive Annual Power Cost Deadband

The Positive Annual Power Cost Deadband is $30.0 million.

Schedule 126 (Continued)

DEFINITIONS (Continued)

Net Variable Power Costs (NVPC)

The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the deferral period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- Include Energy Charge revenues from Schedules 76R, 38, 83, 85, 89, 90, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485, 489, 490, 491, 492, 495 and 689 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.
- Actual NVPC will be increased to include the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.
- Include reciprocating engine lubrication oil expenses.
- Include actual State and Federal Production Tax Credits.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0331 to account for franchise fees, uncollectables, and OPUC fees. (I)

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

Schedule 126 (Continued)

TIME AND MANNER OF FILING (Continued)

Included in this filing will be the following information:

1) A transmittal letter that summarizes the proposed changes.
2) Revised Power Cost Variance Rates.
3) Work papers supporting the calculation of the revised PCV rates.

If the Company finds that the PCV Rates may over or under collect revenues in a particular year, the Company may recommend a modification of the Adjustment Rates to the Commission. The Company may also recommend that the Commission consider Adjustment Rates based on a collection or refund period different than one year based on the balance in the PCV Account.

POWER COST VARIANCE RATES

The PCV Rates will be determined on an equal cents per kWh basis. The PCV Rates are:

Schedule	Adjustment Rate	
7	0.080 ¢ per kWh	(I)
15	0.080 ¢ per kWh	
32	0.080 ¢ per kWh	
38	0.080 ¢ per kWh	
47	0.080 ¢ per kWh	
49	0.080 ¢ per kWh	
75		
Secondary	0.080 ¢ per kWh(1)	
Primary	0.080 ¢ per kWh(1)	
Subtransmission	0.080 ¢ per kWh(1)	
83	0.080 ¢ per kWh	
85		
Secondary	0.080 ¢ per kWh	
Primary	0.080 ¢ per kWh	
89		
Secondary	0.080 ¢ per kWh	
Primary	0.080 ¢ per kWh	
Subtransmission	0.080 ¢ per kWh	(I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

Schedule 126 (Continued)

POWER COST VARIANCE RATES (Continued)

Schedule	Adjustment Rate	
90		
Primary	0.080 ¢ per kWh	(C)(I)
Subtransmission	0.080 ¢ per kWh	(N)
91	0.080 ¢ per kWh	(I)
92	0.080 ¢ per kWh	
95	0.080 ¢ per kWh	
485		
Secondary	0.080 ¢ per kWh[(2)]	
Primary	0.080 ¢ per kWh[(2)]	
489		
Secondary	0.080 ¢ per kWh[(2)]	
Primary	0.080 ¢ per kWh[(2)]	
Subtransmission	0.080 ¢ per kWh[(2)]	(I)
490		
Primary	0.080 ¢ per kWh	(C)(I)
Subtransmission	0.080 ¢ per kWh	(N)
491	0.080 ¢ per kWh	(I)
492	0.080 ¢ per kWh	
495	0.080 ¢ per kWh	
515	0.080 ¢ per kWh[(2)]	
532	0.080 ¢ per kWh[(2)]	
538	0.080 ¢ per kWh[(2)]	
549	0.080 ¢ per kWh[(2)]	
575		
Secondary	0.080 ¢ per kWh[(1)]	
Primary	0.080 ¢ per kWh[(1)]	
Subtransmission	0.080 ¢ per kWh[(1)]	
583	0.080 ¢ per kWh[(2)]	
585	0.080 ¢ per kWh[(2)]	
Seconday	0.080 ¢ per kWh[(2)]	
Primary	0.080 ¢ per kWh[(2)]	(I)

(M)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 126 (Concluded)

POWER COST VARIANCE RATES (Continued) **(M)**

589			
Secondary	0.080	¢ per kWh[2]	**(I)**
Primary	0.080	¢ per kWh[2]	
Subtransmission	0.080	¢ per kWh[2]	
590			
Primary	0.080	¢ per kWh	**(C)(I)**
Subtransmission	0.080	¢ per kWh	**(N)**
591	0.080	¢ per kWh[2]	**(I)**
592	0.080	¢ per kWh[2]	
595	0.080	¢ per kWh[2]	**(I)** **(M)**
689			**(N)**
Secondary	0.080	¢ per kWh[2]	
Primary	0.080	¢ per kWh[2]	
Subtransmission	0.080	¢ per kWh[2]	

(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued. **(N)**

TERM

Effective for service on and after January 17, 2007 and continuing until terminated by the Commission.

This schedule may only be terminated upon approval or order of the Commission. If this schedule is terminated for any reason, the Company will determine the remaining Adjustment Amount on a prorated basis consistent with the principles of this schedule. In such case, any balance in the PCV Account will be amortized to rates over a period to be determined by the Commission.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 85, 89, 90, 91 or 95 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 590, 591, 592 and 595. This Schedule is not applicable to Customers served on Schedules 485, 489, 490, 491, 492 and 495.

SHORT-TERM TRANSITION ADJUSTMENT

The Short-Term Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service in 2022, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2023: **(C)** **(C)**

Schedule		Annual Part A ¢ per kWh [1]	Annual Part B $ per KW of On-Peak Demand	
				(N) **(C)** **(N)**
32		(4.012)		**(R)**
38		(4.731)		
75	Secondary	(4.286) [2]		
	Primary	(4.241) [2]		
	Subtransmission	(4.323) [2]		
83		(5.667)	4.68	**(N)**
85	Secondary	(5.830)	5.17	
	Primary	(5.695)	5.15	**(R)** **(N)**

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual Part A ¢ per kWh [1]	Annual Part B $ per KW of On-Peak Demand	
				(C) (N)
89	Secondary	(4.286)		(R)
	Primary	(4.241)		
	Subtransmission	(4.323)		
90	Primary	(4.531)		(C)
91		(3.059)		
95		(3.059)		
515		(2.686)		
532		(4.012)		
538		(4.731)		
549		(5.248)		
575	Secondary	(4.286) [2]		
	Primary	(4.241) [2]		
	Subtransmission	(4.323) [2]		
583		(5.667)	4.68	(N)
585	Secondary	(5.830)	5.17	
	Primary	(5.695)	5.15	(N)
589	Secondary	(4.286)		
	Primary	(4.241)		
	Subtransmission	(4.323)		
590	Primary	(4.531)		(C)
591		(3.059)		
592		(4.346)		
595		(3.059)		(R)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT REVISIONS

The Annual Short-Term Transition Adjustment rate will be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. Indicative, non-binding estimates for the Annual Short-Term Transition Adjustment and Cost-of-Service Energy Prices will be posted by the Company by September 1 and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

SCHEDULE 128 (Continued)

LARGE NONRESIDENTIAL LOAD SHIFT TRUE-UP

For the November window, the Company will compute the Load Shift True-Up as the difference between the market prices used to establish the Schedule 128 Transition Adjustment and the average of the corresponding projected market prices during the first full week in December times the load leaving Cost of Service pricing. For the Balance of Year Transition Adjustment windows, the Company will compute the True-Up as the difference between the market prices used to establish the Schedule 128 Transition Adjustments and the corresponding projected market prices during the first full week after the close of the window times the amount of load leaving Cost of Service pricing. For the November election window, the Company will file for a deferral after the close of the window if the True-Up is greater than $240,000. The filing threshold for each of the quarterly windows will be $60,000.

BALANCING ACCOUNT

The Company will maintain a Balancing Account to accrue any deferred load shift true-up amounts. This Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts. These monies will be recovered from or refunded to all direct-access eligible Large Nonresidential Customers in a manner approved by the Commission.

CHANGES TO TRANSITION ADJUSTMENT RATES

The Short-Term Transition Adjustment is subject to modification to reflect any changes to the Energy Charge(s) of the Cost of Service Option that serve as the basis for the calculation of the Transition Adjustment. No change will be made, however, to the market price of power used to determine the applicable adjustment rate.

BALANCE-OF-YEAR TRANSITION ADJUSTMENT RATE

Eligible customers who have elected to receive service on a rate other than Cost of Service during a Balance-of-Year Election Window, will have the applicable Short-Term Balance-of-Year Transition Adjustment Rate applied to their bills. **(C)**

The Balance-of-Year Transition Adjustment Rate will be filed, posted on the Company's website and incorporated into this Schedule effective as follows:

- February 15th for an April 1st effective date

Where the date above is a weekend or state-recognized holiday, the filing date will be the next business day. The Short-Term Balance-of-Year Transition Adjustment will be posted by the Company on its website PortlandGeneral.com/business on the day the rate is filed with the Commission.

SCHEDULE 128 (Concluded)

Second Quarter – April 1st Balance of Year Adjustment Rate [1]

Schedule		9-Month Part A ¢ per kWh [2]	9-Month Part B $ per KW of On-Peak Demand	
				(N)
				(N)
38		(5.092)		(R)
75	Secondary	(4.539) [3]		
	Primary	(4.492) [3]		
	Subtransmission	(4.634) [3]		
83		(5.996)	4.68	(N)
85	Secondary	(6.155)	5.17	
	Primary	(6.012)	5.15	(N)
89	Secondary	(4.539)		
	Primary	(4.492)		
	Subtransmission	(4.634)		
90	Primary	(4.771)		
	Subtransmission	(4.771)		(N)
91		(2.887)		
95		(2.887)		
538		(5.092)		
575	Secondary	(4.539) [3]		
	Primary	(4.492) [3]		
	Subtransmission	(4.634) [3]		
583		(5.996)	4.68	(N)
585	Secondary	(6.155)	5.17	
	Primary	(6.012)	5.15	(N)
589	Secondary	(4.539)		
	Primary	(4.492)		
	Subtransmission	(4.634)		
590	Primary	(4.771)		
	Subtransmission	(4.771)		
591		(2.887)		(N)
592		(4.581)		
595		(2.887)		(R)

(1) Applicable April 1, 2023 through December 31, 2023. (C)
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 129
LONG-TERM TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected service under Schedules 485, 489, 490, 491, 492, and 495.

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Periods A - P: 0.000 ¢ per kWh (C)

The Schedule 129 Transition Cost Adjustment will be updated to reflect OPUC-approved changes in fixed generation costs during the five-year period.

(D)

For Enrollment Period Q (2018), the current Transition Cost Adjustments are: (M)

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2019	2.972	2.958	2.625	2.576	2.493	2.540	2.511
2020	2.972	2.958	2.625	2.576	2.493	2.540	2.511
2021	2.972	2.958	2.625	2.576	2.493	2.540	2.511
2022	2.412	2.424	2.162	2.144	2.086	2.095	2.078
2023	2.412	2.424	2.162	2.144	2.086	2.095	2.078
After 2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(M)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

(M)

For Enrollment Period R (2019), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2020	2.376	2.359	2.042	2.004	1.918	1.960	1.968
2021	2.376	2.359	2.042	2.004	1.918	1.960	1.968
2022	1.816	1.825	1.579	1.572	1.511	1.515	1.535
2023	1.816	1.825	1.579	1.572	1.511	1.515	1.535
2024	1.816	1.825	1.579	1.572	1.511	1.515	1.535
After 2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(M)

For Enrollment Period S (2020), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2021	3.167	3.137	2.801	2.749	2.770	2.704	2.666
2022	2.475	2.474	2.216	2.197	2.247	2.144	2.119
2023	2.475	2.474	2.216	2.197	2.247	2.144	2.119
2024	2.475	2.474	2.216	2.197	2.247	2.144	2.119
2025	2.475	2.474	2.216	2.197	2.247	2.144	2.119
After 2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(M)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

(M)

For Enrollment Period T (2021), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2022	0.851	0.845	0.590	0.602	0.606	0.564	0.669
2023	0.851	0.845	0.590	0.602	0.606	0.564	0.669
2024	0.851	0.845	0.590	0.602	0.606	0.564	0.669
2025	0.851	0.845	0.590	0.602	0.606	0.564	0.669
2026	0.851	0.845	0.590	0.602	0.606	0.564	0.669
After 2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000

For Enrollment Period U (2022), the current Transition Cost Adjustments are: (M)

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2023	(1.985)	(1.799)	(0.766)	(0.758)	(0.798)	(0.825)	(0.769)
2024	(1.985)	(1.799)	(0.766)	(0.758)	(0.798)	(0.825)	(0.769)
2025	(1.985)	(1.799)	(0.766)	(0.758)	(0.798)	(0.825)	(0.769)
2026	(1.985)	(1.799)	(0.766)	(0.758)	(0.798)	(0.825)	(0.769)
2027	(1.985)	(1.799)	(0.766)	(0.758)	(0.798)	(0.825)	(0.769)
After 2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(M)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out (Continued)

(M)

For Enrollment Period U (2022), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. $ per kW of On-Peak Demand	Sch. 485 Pri. Vol. $ per kW of On-Peak Demand	Sch. 489 Sec. Vol. $ per kW of On-Peak Demand	Sch. 489 Pri. Vol. $ per kW of On-Peal Demand	Sch. 489 Sub. Vol. $ per kW of On-Peak Demand	Sch. 490 Pri. Vol. $ per kW of On-Peak Demand	Schs. 491/492/495 $ per kW of On-Peak Demand
2023	5.17	5.15	0.000	0.000	0.000	0.000	0.000
2024	5.17	5.15	0.000	0.000	0.000	0.000	0.000
2025	5.17	5.15	0.000	0.000	0.000	0.000	0.000
2026	5.17	5.15	0.000	0.000	0.000	0.000	0.000
2027	5.17	5.15	0.000	0.000	0.000	0.000	0.000
After 2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000

For Enrollment Period V (2023), the current Transition Cost Adjustments are: (N)

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2024	(4.685)	(4.263)	(2.422)	(2.397)	(2.532)	(2.418)	(2.019)
2025	(4.685)	(4.263)	(2.422)	(2.397)	(2.532)	(2.418)	(2.019)
2026	(4.685)	(4.263)	(2.422)	(2.397)	(2.532)	(2.418)	(2.019)
2027	(4.685)	(4.263)	(2.422)	(2.397)	(2.532)	(2.418)	(2.019)
2028	(4.685)	(4.263)	(2.422)	(2.397)	(2.532)	(2.418)	(2.019)
After 2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(N)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out (Continued) **(N)**

For Enrollment Period V (2023), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. $ per kW of On-Peak Demand	Sch. 485 Pri. Vol. $ per kW of On-Peak Demand	Sch. 489 Sec. Vol. $ per kW of On-Peak Demand	Sch. 489 Pri. Vol. $ per kW of On-Peal Demand	Sch. 489 Sub. Vol. $ per kW of On-Peak Demand	Sch. 490 Pri. Vol. $ per kW of On-Peak Demand	Schs. 491/492/495 $ per kW of On-Peak Demand
2024	9.32	9.22	0.000	0.000	0.000	0.000	0.000
2025	9.32	9.22	0.000	0.000	0.000	0.000	0.000
2026	9.32	9.22	0.000	0.000	0.000	0.000	0.000
2027	9.32	9.22	0.000	0.000	0.000	0.000	0.000
2028	9.32	9.22	0.000	0.000	0.000	0.000	0.000
After 2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(N)

<u>Three Year Opt-Out</u>

This option was not available during Enrollment Periods A and B

For Enrollment Periods C - Q, No Longer Available

For Enrollment Period R (2019), the Transition Cost Adjustment will be:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2020	2.655	2.589	2.273	2.231	2.266	1.992	2.157
2021	2.655	2.589	2.273	2.231	2.266	1.992	2.157
2022	2.655	2.589	2.273	2.231	2.266	1.992	2.157

(M)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out (Continued)

For Enrollment Period S (2020), the Transition Cost Adjustment will be: **(M)**

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2021	3.170	3.085	2.770	2.718	2.624	2.476	2.612
2022	3.170	3.085	2.770	2.718	2.624	2.476	2.612
2023	3.170	3.085	2.770	2.718	2.624	2.476	2.612

For Enrollment Period T (2021), the Transition Cost Adjustment will be:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2022	1.376	1.312	1.002	0.983	1.046	0.770	1.125
2023	1.376	1.312	1.002	0.983	1.046	0.770	1.125
2024	1.376	1.312	1.002	0.983	1.046	0.770	1.125

(M)

For Enrollment Period U (2022), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2023	(3.779)	(3.703)	(2.249)	(2.226)	(2.292)	(2.567)	(1.954)
2024	(2.172)	(2.142)	(0.655)	(0.649)	(0.586)	(1.021)	(0.645)
2025	(1.266)	(1.294)	0.246	0.242	0.425	(0.170)	(0.140)

(M)

SCHEDULE 129 (Continued) (T)

TRANSITION COST ADJUSTMENT (Continued) (T)
Three Year Opt-Out (Continued) (T)

For Enrollment Period U (2022), the Generation Demand Charge are: (M)

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2023	5.17	5.15	0.000	0.000	0.000	0.000	0.000
2024	5.17	5.15	0.000	0.000	0.000	0.000	0.000
2025	5.17	5.15	0.000	0.000	0.000	0.000	0.000

(M)

For Enrollment Period V (2023), the current Transition Cost Adjustments are: (N)

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2024	(5.205)	(5.134)	(2.870)	(2.840)	(2.905)	(3.116)	(2.398)
2025	(4.724)	(4.696)	(2.351)	(2.327)	(2.336)	(2.615)	(1.978)
2026	(4.532)	(4.508)	(2.147)	(2.125)	(2.094)	(2.442)	(2.094)

For Enrollment Period V (2023), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2024	9.32	9.22	0.000	0.000	0.000	0.000	0.000
2025	9.32	9.22	0.000	0.000	0.000	0.000	0.000
2026	9.32	9.22	0.000	0.000	0.000	0.000	0.000

(N)

(M)

SCHEDULE 129 (Continued)

SPECIAL CONDITIONS **(M)**

1. Annually, the total amount paid in Schedule 129 Long-Term Transition Cost Adjustments associated with Enrollment Periods A through K will be collected through applicable Large Nonresidential rate schedules (Schedules 75, 85, 89, 90, 485, 489, 490, 575, 585, 589 and 590), through either the System Usage or Distribution Charges. Commencing with Enrollment Period L, the Schedule 129 amounts paid or received will be collected from all rate schedules, through either System Usage Charges or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedules 485, 489, 490, 491, 492, and 495 customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges or Distribution Charges of all rate schedules. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage or Distribution Charges resulting from changes in fixed generation revenues shall not result in an overall rate increase or decrease of more than 2 percent except as noted below. For those Enrollment Periods in which the first-year Schedule 129 Transition Adjustments are expected to be positive charges to participants, the projected first-year revenues from Schedule 129 will be netted against the changes in fixed generation costs for purposes of calculating the proposed overall rate increase or decrease. Should the rate increase or decrease exceed 2 percent, the amounts exceeding 2 percent will be deferred for future recovery through a balancing account. This balancing account will be considered an "Automatic Adjustment Clause" as defined in ORS 757.210. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased participating load will be determined.

3. In determining changes in fixed generation revenues from movement to or from Schedules 485, 489, 490, 491, 492, and 495, the following factors will be used:

Schedule		¢ per kWh	
85	Secondary	2.858	(I)
	Primary	2.829	
89	Secondary	2.714	
	Primary	2.684	
	Subtransmission	2.655	
90		2.653	
91		2.582	
92		2.582	
95		2.582	(I)

(M)

SCHEDULE 129 (Concluded)

TERM

(M)

The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 485, 489, 490, 491, 492 or 495.

(M)

SCHEDULE 131
OREGON CORPORATE ACTIVITY TAX RECOVERY

PURPOSE

To recover from Customers the Oregon Corporate Activity Tax (CAT) paid by the Company for "commercial activity" in accordance with House Bill 3427 and to establish an associated Automatic Adjustment Clause and balancing account.

APPLICABLE

To all bills for Electricity Service.

BALANCING ACCOUNT

A CAT Balancing Account will be maintained to accrue any difference between the Company's actual commercial activity tax liability and the amount collected from Customers under this Schedule. Any over or under-collection reflected in this account will be considered when the CAT Rate is established. The Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts.

CAT RECOVERY RATE DETERMINATION

The CAT Recovery Rate is determined by dividing the sum of forecast commercial activity tax liability plus or minus any amount in the Balancing Account divided by forecast Retail Revenue from Customers for each tax year or other applicable recovery period. Forecast Retail Revenue excludes Schedule 102, Schedule 108, Schedule 109, and Schedule 115, and all other separately stated taxes.

CAT RECOVERY RATE

The CAT Recovery Rate is:

> 0.000% of the total billed amount to the Customer excluding the RPA Credit (Schedule 102), Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes. **(R)**

SPECIAL CONDITIONS

1. Actual commercial activity tax liability is subject to audit. Any adjustments to the commercial activity tax liability will be included in the balancing account.

SCHEDULE 134
GRESHAM RETROACTIVE PRIVILEGE TAX PAYMENT ADJUSTMENT

PURPOSE

To recover from Customers in the City of Gresham the privilege taxes and court-ordered, associated interest amounts assessed retroactively by the City of Gresham following an Oregon Supreme Court decision in 2016.

APPLICABLE

All Customers receiving Electricity Service within the City of Gresham.

BALANCING ACCOUNT

The Company will establish a Balancing Account to record the difference between amounts collected under this schedule, net of uncollectible accounts and amounts authorized to be recovered. This Balancing Account will accrue interest at the Commission-authorized rate for deferred accounts. The disposition of any over- or under-recovery amount will be subject to Commission approval.

GRESHAM PRIVILEGE TAX SETTLEMENT RECOVERY RATE

The Rate is:

> 0.0% of the total billed amount to the Customer excluding the Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes. Certain Large Nonresidential Customers with existing limitations on privilege tax obligations will be billed in accordance with these existing limitations. **(C)**

SCHEDULE 135
DEMAND RESPONSE COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with demand response pilots not otherwise included in rates. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 576R and 689.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate		
7	0.094	¢ per kWh	(I)
15/515	0.073	¢ per kWh	
32/532	0.081	¢ per kWh	
38/538	0.074	¢ per kWh	
47	0.090	¢ per kWh	
49/549	0.092	¢ per kWh	
75/575			
Secondary	0.075	¢ per kWh(1)	
Primary	0.074	¢ per kWh(1)	
Subtransmission	0.076	¢ per kWh(1)	
83/583	0.080	¢ per kWh	
85/585			
Secondary	0.077	¢ per kWh	
Primary	0.074	¢ per kWh	(I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 135 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
89/589			
Secondary	0.075	¢ per kWh	(I)
Primary	0.074	¢ per kWh	|
Subtransmission	0.076	¢ per kWh	(I)
90/590			
Primary	0.070	¢ per kWh	(C)(I)
Subtransmission	0.070	¢ per kWh	(N)
91/591	0.068	¢ per kWh	(I)
92/592	0.072	¢ per kWh	|
95/595	0.068	¢ per kWh	(I)

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with automated demand response and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the implementation and administration of demand response pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of demand response pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

SPECIAL CONDITION

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule’s forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

SCHEDULE 136
OREGON COMMUNITY SOLAR PROGRAM
COST RECOVERY MECHANISM

PURPOSE

The purpose of this Schedule is to recover costs incurred during and for the development (or modification) of the Oregon Community Solar Program (Oregon CSP) including the costs associated with the State of Oregon's Program Administrator, Low Income Facilitator, the company's prudently incurred costs associated with implementing the Community Solar Program that are not otherwise included in rates, and payments to participants in the Oregon CSP. Company incurred costs to implement the state program do not include costs associated with the company developing a community solar project. This cost recovery mechanism is authorized by ORS 757.386 (7)(c) and OAR 860-088-0160. The Oregon CSP is an optional program that will provide PGE customers the opportunity to voluntarily subscribe to the generation output of eligible community solar projects. This adjustment schedule is implemented as an automatic adjustment clause as provided under ORS 757.210 to allow recovery of operations and maintenance start-up costs as soon as the cost data is approved by the Commission.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76Rand 576R.

ADUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate		
7	0.021	¢ per kWh	(I)
15/515	0.017	¢ per kWh	
32/532	0.019	¢ per kWh	
38/538	0.021	¢ per kWh	
47	0.032	¢ per kWh	
49/549	0.025	¢ per kWh	
75/575			
Secondary	0.020	¢ per kWh	
Primary	0.010	¢ per kWh	
Subtransmission	0.010	¢ per kWh	(I)

SCHEDULE 136 (Continued)

ADJUSTMENT RATE (Continued)

83/583	0.015	¢ per kWh	(I)
85/485/585			
Secondary	0.013	¢ per kWh	
Primary	0.011	¢ per kWh	
89/489/589/689			
Secondary	0.020	¢ per kWh	
Primary	0.010	¢ per kWh	
Subtransmission	0.010	¢ per kWh	(I)
90/490/590			(C)
Primary	0.010	¢ per kWh	(I)
Subtransmission	0.010	¢ per kWh	(N)
91/491/591	0.017	¢ per kWh	(I)
92/492/592	0.011	¢ per kWh	
95/495/595	0.017	¢ per kWh	(I)

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between incremental costs associated with the Oregon CSP and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the Oregon CSP.

SPECIAL CONDITION

1. Pursuant to OAR 860-088-0160 (1), Oregon CSP start-up costs are:

   - Costs associated with the Program Administrator and Low-Income Facilitator; and
   - Each utility's prudently incurred start-up costs associated with implementing the Community Solar Program. These costs include, but are not limited to, costs associated with customer account information transfer and on-bill crediting and payment, but exclude any costs associated with the electric utility developing a project.

(M)

SCHEDULE 136 (Concluded)

SPECIAL CONDITION (Continued)

2. PGE will remit payments to the Program Administrator on a monthly basis for program costs including performing work as provided in OAR 860-088-0020 and OAR 860-088-0030 within 15 days receipt of the Commission's approval of eligible costs. **(M)** **(M)**

3. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule.

SCHEDULE 137
CUSTOMER-OWNED SOLAR PAYMENT OPTION
COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the costs associated with the Solar Payment Option pilot not otherwise included in rates. This adjustment schedule is implemented as an "automatic adjustment clause" as provided for under ORS 757.210, and defined in Renewable Portfolio Standards.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76Rand 576R. **(C)**

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate		
7	0.005	¢ per kWh	
15	0.003	¢ per kWh	
32	0.004	¢ per kWh	
38	0.005	¢ per kWh	(I)
47	0.007	¢ per kWh	(I)
49	0.005	¢ per kWh	
75			
Secondary	0.002	¢ per kWh[(1)]	(R)
Primary	0.002	¢ per kWh[(1)]	
Subtransmission	0.003	¢ per kWh[(1)]	
83	0.003	¢ per kWh	
85			
Secondary	0.003	¢ per kWh	
Primary	0.003	¢ per kWh	(R)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 137 (Continued)

ADJUSTMENT RATES (Continued)

Schedule		Adjustment Rate		
89				
	Secondary	0.002	¢ per kWh	(R)
	Primary	0.002	¢ per kWh	
	Subtransmission	0.003	¢ per kWh	
90				
	Primary	0.002	¢ per kWh	(R)
	Subtransmission	0.002	¢ per kWh	(N)
91		0.003	¢ per kWh	
92		0.003	¢ per kWh	(R)
95		0.003	¢ per kWh	
485				(N)
	Secondary	0.003	¢ per kWh	
	Primary	0.003	¢ per kWh	
489				
	Secondary	0.002	¢ per kWh	
	Primary	0.002	¢ per kWh	
	Subtransmission	0.003	¢ per kWh	
490				
	Primary	0.002	¢ per kWh	
	Subtransmission	0.002	¢ per kWh	
491		0.003	¢ per kWh	
492		0.003	¢ per kWh	
495		0.003	¢ per kWh	(N)
515		0.003	¢ per kWh	
532		0.004	¢ per kWh	
538		0.005	¢ per kWh	(I)
549		0.005	¢ per kWh	
575				
	Secondary	0.002	¢ per kWh(1)	(R)
	Primary	0.002	¢ per kWh(1)	
	Subtransmission	0.003	¢ per kWh(1)	(R)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy. (M)

SCHEDULE 137 (Concluded)

ADJUSTMENT RATES (Continued) **(T)**

583		0.003	¢ per kWh	**(R)(M)**
585				
	Secondary	0.003	¢ per kWh	
	Primary	0.003	¢ per kWh	
589				
	Secondary	0.002	¢ per kWh	
	Primary	0.002	¢ per kWh	
	Subtransmission	0.003	¢ per kWh	**(M)**
590				
	Primary	0.002	¢ per kWh	**(R)**
	Subtransmission	0.002	¢ per kWh	**(N)**
591		0.003	¢ per kWh	
592		0.003	¢ per kWh	**(R)**
595		0.003	¢ per kWh	**(R)**
689				**(N)**
	Secondary	0.002	¢ per kWh	
	Primary	0.002	¢ per kWh	
	Subtransmission	0.003	¢ per kWh	**(N)**

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with the Solar Payment Option pilot and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request. The deferral will be amortized over one year in this schedule unless otherwise directed by the Oregon Public Utility Commission.

SPECIAL CONDITION

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule. **(C)** **(C)**

SCHEDULE 138
ENERGY STORAGE COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with HB 2193 energy storage pilots not otherwise included in rates. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495 and 576R and 689.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.012 ¢ per kWh	(I)
15/515	0.009 ¢ per kWh	
32/532	0.011 ¢ per kWh	
38/538	0.010 ¢ per kWh	
47	0.012 ¢ per kWh	
49/549	0.012 ¢ per kWh	
75/575		
Secondary	0.010 ¢ per kWh	
Primary	0.010 ¢ per kWh	
Subtransmission	0.010 ¢ per kWh	
83/583	0.010 ¢ per kWh	
85/585		
Secondary	0.010 ¢ per kWh	
Primary	0.010 ¢ per kWh	(I)

SCHEDULE 138 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
89/589		
Secondary	0.010 ¢ per kWh	(I)
Primary	0.010 ¢ per kWh	
Subtransmission	0.010 ¢ per kWh	
90/590		
Primary	0.009 ¢ per kWh	
Subtransmission	0.009 ¢ per kWh	
91/591	0.009 ¢ per kWh	
92/592	0.009 ¢ per kWh	
95/595	0.009 ¢ per kWh	(I)

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with energy storage pilots and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the implementation and administration of the energy storage pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of energy storage pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

SPECIAL CONDITION

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

SCHEDULE 139
NEW LARGE LOAD TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected New Large Load Cost-of-Service Opt-Out service under Schedule 689. This transition adjustment will be paid when the Customer begins service under Schedule 689. This transition adjustment represents 20 percent of the Company's fixed generation costs and is subject to change annually during the Customer's five-years enrolled in Schedule 689. At the end of the Customer's five-year payment term of these transition adjustments, the Customer will no longer be subject to the charges in this rate schedule. The Customer will not be subject to the charges in this rate schedule with at least three years of notification to the Company of a return to cost-of-service pricing.

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Period 1 (2020), the Transition Cost Adjustment will be:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	
2020	0.679	0.667	0.658	
2021	0.702	0.689	0.680	
2022	0.587	0.580	0.576	
2023	0.655	0.648	0.645	
2024	0.655	0.648	0.645	(I)
2025*	0.655	0.648	0.645	(I)
After 2026	0.000	0.000	0.000	

For Period 2 (2021), the Transition Cost Adjustment will be:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	
2021	0.702	0.689	0.680	
2022	0.587	0.580	0.576	
2023	0.655	0.648	0.645	(I)
2024	0.655	0.648	0.645	
2025	0.655	0.648	0.645	
2026*	0.655	0.648	0.645	(I)
After 2027	0.000	0.000	0.000	

*Applicable pricing only to completion of five-year period and zero thereafter.

SCHEDULE 139 (Continued) (T)

TRANSITION COST ADJUSTMENT (Continued)

For Period 3 (2022), the Transition Cost Adjustment will be:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	
2022	0.587	0.580	0.576	
2023	0.655	0.648	0.645	(I)
2024	0.655	0.648	0.645	
2025	0.655	0.648	0.645	
2026	0.655	0.648	0.645	
2027*	0.655	0.648	0.645	(I)
After 2028	0.000	0.000	0.000	

For Period 4 (2023), the Transition Cost Adjustment will be: (N)

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	
2023	0.655	0.648	0.645	
2024	0.655	0.648	0.645	
2025	0.655	0.648	0.645	
2026	0.655	0.648	0.645	
2027	0.655	0.648	0.645	
2028*	0.655	0.648	0.645	
After 2029	0.000	0.000	0.000	(N)

*Applicable pricing only to completion of five-year period and zero thereafter.

SPECIAL CONDITIONS

1. Annually, the total amount collected in Schedule 139 New Large Load Transition Cost Adjustments will be incorporated into all rate schedules, through either System Usage Charges or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

(M)

SCHEDULE 139 (Concluded)

SPECIAL CONDITIONS (Continued)

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedules 689 Customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges or Distribution Charges of all rate schedules. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage or Distribution Charges resulting from changes in fixed generation revenues shall not result in an overall rate increase or decrease of more than 2 percent except as noted below. For those Enrollment Periods in which the first-year Schedule 139 Transition Adjustments are expected to be positive charges to participants, the projected first-year revenues from Schedule 139 will be netted against the changes in fixed generation costs for purposes of calculating the proposed overall rate increase or decrease. Should the rate increase or decrease exceed 2 percent, the amounts exceeding 2 percent will be deferred for future recovery through a balancing account. This balancing account will be considered an "Automatic Adjustment Clause" as defined in ORS 757.210. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased participating load will be determined. (M)

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 689 but will not exceed 60 months. (M)

SCHEDULE 142
UNDERGROUND CONVERSION COST RECOVERY ADJUSTMENT

PURPOSE

To recover costs incurred by the Company to convert electric facilities from overhead to underground from customers within the boundaries of the local government requiring such conversion at the Company's expense, as required by OAR 860-022-0046.

APPLICABLE

To all bills for electric service supplied by the Company within the boundaries of the local government requiring the conversion of electric facilities from overhead to underground at the Company's expense.

ADJUSTMENT RATE

The Adjustment Rate is the applicable percentage as listed below of the total bill amount to each Customer located within the applicable local government's boundaries excluding the Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes.

Municipality	Ordinance Number	Effective Date	Projected Term	Adjustment Rate

(C)

SPECIAL CONDITIONS

1. For each local government underground conversion project, the Company will establish a tracking mechanism that will track the receipts from each listed Adjustment Rate.

2. In accordance with OAR 860-022-0046, the Company will accrue interest for the unamortized conversion costs at the effective rate of the senior security issue that most recently preceded the incurrence of the conversion cost for the local government.

3. The Company will terminate the collection of the Adjustment Rate at the time when the conversion costs associated with each local government underground conversion project listed above are fully recovered.

4. The Adjustment Rate will be separately stated on the Customer bills rendered within the boundaries of the applicable local government.

SCHEDULE 143
SPENT FUEL ADJUSTMENT

PURPOSE

The purpose of this schedule is to implement in rates the amortization of the excess funds previously contained in the Trojan Nuclear Decommissioning Trust Fund and any ongoing refunds from the United States Department of Energy. Also included are pollution control tax credits associated with the Independent Spent Fuel Storage Installation at the Trojan nuclear plant.

APPLICABLE

To all bills for Electricity Service calculated under all schedules and contracts, except those Customers explicitly exempted.

PART A – TROJAN NUCLEAR DECOMMISSIONING TRUST FUND

Part A consists of the amortization of the excess funds previously contained in the Trojan Nuclear Decommissioning Trust Fund and any ongoing refunds from the United States Department of Energy.

PART B – ISFSI ADJUSTMENT

Part B consists of the amortization of the payments from the Oregon Department of Energy related to state pollution control tax credits for the Independent Spent Fuel Storage Installation at Trojan.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Schedule	Part A	Part B	Adjustment Rate	
7	0.000	0.000	0.000 ¢ per kWh	(I)
15	0.000	0.000	0.000 ¢ per kWh	
32	0.000	0.000	0.000 ¢ per kWh	
38	0.000	0.000	0.000 ¢ per kWh	
47	0.000	0.000	0.000 ¢ per kWh	
49	0.000	0.000	0.000 ¢ per kWh	
75				
Secondary	0.000	0.000	0.000 ¢ per kWh(1)	
Primary	0.000	0.000	0.000 ¢ per kWh(1)	
Subtransmission	0.000	0.000	0.000 ¢ per kWh(1)	(I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 143 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
83	0.000	0.000	0.000 ¢ per kWh	(I)
85				
Secondary	0.000	0.000	0.000 ¢ per kWh	
Primary	0.000	0.000	0.000 ¢ per kWh	
89				
Secondary	0.000	0.000	0.000 ¢ per kWh	
Primary	0.000	0.000	0.000 ¢ per kWh	
Subtransmission	0.000	0.000	0.000 ¢ per kWh	
90				
Primary	0.000	0.000	0.000 ¢ per kWh	
Subtransmission	0.000	0.000	0.000 ¢ per kWh	
91	0.000	0.000	0.000 ¢ per kWh	
92	0.000	0.000	0.000 ¢ per kWh	
95	0.000	0.000	0.000 ¢ per kWh	
485				
Secondary	0.000	0.000	0.000 ¢ per kWh	
Primary	0.000	0.000	0.000 ¢ per kWh	
489				
Secondary	0.000	0.000	0.000 ¢ per kWh	
Primary	0.000	0.000	0.000 ¢ per kWh	
Subtransmission	0.000	0.000	0.000 ¢ per kWh	
490				
Primary	0.000	0.000	0.000 ¢ per kWh	
Subtransmission	0.000	0.000	0.000 ¢ per kWh	
491	0.000	0.000	0.000 ¢ per kWh	
492	0.000	0.000	0.000 ¢ per kWh	
495	0.000	0.000	0.000 ¢ per kWh	
515	0.000	0.000	0.000 ¢ per kWh	
532	0.000	0.000	0.000 ¢ per kWh	(I)

SCHEDULE 143 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
538	0.000	0.000	0.000 ¢ per kWh	(I)
549	0.000	0.000	0.000 ¢ per kWh	
575				
Secondary	0.000	0.000	0.000 ¢ per kWh(1)	
Primary	0.000	0.000	0.000 ¢ per kWh(1)	
Subtransmission	0.000	0.000	0.000 ¢ per kWh(1)	
583	0.000	0.000	0.000 ¢ per kWh	
585				
Secondary	0.000	0.000	0.000 ¢ per kWh	
Primary	0.000	0.000	0.000 ¢ per kWh	
589				
Secondary	0.000	0.000	0.000 ¢ per kWh	
Primary	0.000	0.000	0.000 ¢ per kWh	
Subtransmission	0.000	0.000	0.000 ¢ per kWh	
590				
Primary	0.000	0.000	0.000 ¢ per kWh	
Subtransmission	0.000	0.000	0.000 ¢ per kWh	
591	0.000	0.000	0.000 ¢ per kWh	
592	0.000	0.000	0.000 ¢ per kWh	
595	0.000	0.000	0.000 ¢ per kWh	
689				
Secondary	0.000	0.000	0.000 ¢ per kWh	
Primary	0.000	0.000	0.000 ¢ per kWh	
Subtransmission	0.000	0.000	0.000 ¢ per kWh	(I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

BALANCING ACCOUNT

The Company will maintain balancing accounts to track the difference between the Trojan Nuclear Decommissioning Trust Fund refund, ongoing refunds, and the ISFSI payments and the actual Schedule 143 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts.

SCHEDULE 145
BOARDMAN POWER PLANT
DECOMMISSIONING ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the revenue requirement effect of the decommissioning expenses related to the Boardman power plant. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 576R and 689.

ADJUSTMENT RATES

Schedule 145 Adjustment Rates will be set based an equal percent of Energy Charge revenues applicable at the time of any filing that revises rates pursuant to this schedule.

Schedule	Adjustment Rate	
7	0.000 ¢ per kWh	(R)
15	0.000 ¢ per kWh	
32	0.000 ¢ per kWh	
38	0.000 ¢ per kWh	
47	0.000 ¢ per kWh	
49	0.000 ¢ per kWh	
75		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
83	0.000 ¢ per kWh	
85		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	(R)

SCHEDULE 145 (Continued)

ADJUSTMENT RATE (Continued)

Schedule		Adjustment Rate		
89				
	Secondary	0.000	¢ per kWh	(R)
	Primary	0.000	¢ per kWh	
	Subtransmission	0.000	¢ per kWh	
90		0.000	¢ per kWh	
91		0.000	¢ per kWh	
92		0.000	¢ per kWh	
95		0.000	¢ per kWh	
515		0.000	¢ per kWh	
532		0.000	¢ per kWh	
538		0.000	¢ per kWh	
549		0.000	¢ per kWh	
575				
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	
	Subtransmission	0.000	¢ per kWh	
583		0.000	¢ per kWh	
585				
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	
589				
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	
	Subtransmission	0.000	¢ per kWh	
590		0.000	¢ per kWh	
591		0.000	¢ per kWh	
592		0.000	¢ per kWh	
595		0.000	¢ per kWh	(R)

SCHEDULE 145 (Concluded)

DETERMINATION OF ADJUSTMENT AMOUNT

(D)

The Adjustment Amount is the revenue requirements related to decommissioning of the Boardman Power Plant using a plant end of life assumption of year-end 2020. The decommissioning revenue requirement computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return and return on equity rates. Only changes to decommissioning expense are included in the revenue requirements. **(C)** **(C)**

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Boardman Power Plant decommissioning revenue requirement. **(T)**

(D)

BALANCING ACCOUNT

The Company will maintain a balancing account to track the difference between the Schedule 145 Decommissioning Revenue Requirements and the actual Schedule 145 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts. **(T)**

TIME AND MANNER OF FILING

Commencing in 2011, the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the following year based on the updated revenue requirements described above.

2. Work papers supporting the Schedule 145 prices, the updated decommissioning revenue requirements, the projected applicable billing determinants, and the projected balancing account activity. **(T)**

SCHEDULE 146
COLSTRIP POWER PLANT
OPERATING LIFE ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the Company's share of the full revenue requirement for the Colstrip Power Plant Units 3 and 4 and associated common facilities. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 576R and 689.

ADJUSTMENT RATES

Schedule 146 Adjustment Rates will be set based on an equal percent of Energy Charge revenues applicable at the time of any filing that revises rates pursuant to this schedule.

Schedule	Adjustment Rate		
7	0.393	¢ per kWh	(R)
15/515	0.279	¢ per kWh	
32/532	0.336	¢ per kWh	
38/538	0.308	¢ per kWh	
47	0.374	¢ per kWh	
49/549	0.385	¢ per kWh	
75/575			
Secondary	0.312	¢ per kWh	
Primary	0.308	¢ per kWh	
Subtransmission	0.313	¢ per kWh	
83/583	0.332	¢ per kWh	
85/585			
Secondary	0.321	¢ per kWh	
Primary	0.314	¢ per kWh	
89/589			
Secondary	0.312	¢ per kWh	
Primary	0.308	¢ per kWh	
Subtransmission	0.313	¢ per kWh	(R)

SCHEDULE 146 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
90/590		
Primary	0.287 ¢ per kWh	(R)
Subtransmission	0.287 ¢ per kWh	
91/591	0.283 ¢ per kWh	
92/592	0.300 ¢ per kWh	
95/595	0.283 ¢ per kWh	(R)

PART A- DECOMMISSIONING AMOUNTS

Part A consists of the revenue requirements related to decommissioning of the Colstrip Power Plant Units 3 and 4. The decommissioning revenue requirement computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return and return on equity rates.

PART B- DEPRECIATION AMOUNTS

Part B consists of the revenue requirements related to depreciation of the Colstrip Power Plant Units 3 and 4. The depreciation revenue requirement computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return and return on equity rates.

PART C- REMAINING AMOUNTS

Part C consists of the full revenue requirement associated with the Colstrip Power Plant Units 3 and 4 and associated common facilities (including all identifiable capital- and expense-related costs and other revenues), excluding associated transmission facilities, costs allowable for recovery through PGE’s existing Schedule 125 (Annual Power Cost Update), and amounts identified in Parts A and B above. The revenue requirement computation will use the Commission-authorized tax rates, revenue sensitive cost rates, rate of return, and return on equity rates.

SCHEDULE 146 (Concluded)

DETERMINATION OF ADJUSTMENT AMOUNTS (M)

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 revenue requirement (Parts A, B and C). (C)(M)

BALANCING ACCOUNT (N)

The Company will maintain a balancing account to track the difference between the Schedule 146 Part A only amounts and the actual Schedule 146 revenues for Part A. This difference will accrue interest at the Commission-authorized rate for deferred accounts. No other amounts included within Schedule 146 will be subject to balancing account treatment.

TIME AND MANNER OF FILING

Commencing in 2022, the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the following year based on the updated revenue requirements described above.

2. Work papers supporting the Schedule 146 prices, the updated depreciation and decommissioning revenue requirements, the projected applicable billing determinants, and the projected balancing account activity.

With respect to a Schedule 146 rate change for the inclusion or update of costs outside of revised decommissioning or operating life adjustments and in compliance with the Commission's findings in separate cost recovery proceeding(s), the Company will file updated Schedule 146 rates by no less than 30 days prior to the rate effective date.

(N)

SCHEDULE 149
ENVIRONMENTAL REMEDIATION COST RECOVERY ADJUSTMENT
AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the costs and revenues associated with the Portland Harbor Superfund site ("Portland Harbor"), the Natural Resource Damage obligation, the Downtown Reach portions of the Willamette River, and the Harborton Restoration Project. This adjustment schedule is implemented as an automatic adjustment clause as provided under ORS 757.210.

AVAILABLE

In all territory served by Portland General Electric Company ("PGE").

APPLICABLE

To all Schedules.

ANNUAL ACCOUNT & BALANCING ACCOUNT

By Order No. 17-071, the Commission approved a deferral of environmental-related costs and revenues, effective July 15, 2016, that flow into the Portland Harbor Environmental Remediation Account ("PHERA"). The PHERA Annual Account records Environmental Remediation Costs ("ERC"), the costs of developing the Harborton Restoration Project, and Environmental Remediation Revenues ("ERR"). The balance in the Annual Account that has not been reviewed by the Commission for prudence shall accrue interest at the authorized rate of return approved in PGE's most recent general rate case. Costs and revenues in the Annual Account that have been reviewed for prudency and remain following the earnings test will be transferred to the PHERA Balancing Account and will accrue interest at the average of the five-year U.S. Treasury rate plus 100 basis points (the "PURE Rate").

EARNINGS TEST

Subject to the conditions stated below, the recovery from customers of certain ERC is subject to an earnings review and test for the year that the costs were paid. Following a prudence review, PGE will be allowed to place prudent expenses and proceeds into the Balancing Account to the extent that PGE's Actual Regulated Return on Equity ("ROE") does not exceed its ROE authorized by the Commission in PGE's most recent general rate case. A fixed $6.0 million each year in ERC and Harborton Restoration Project development costs, currently estimated at $10-$12 million, are not subject to the earnings test. Proceeds from insurance companies and DSAY ("Discount Service Acre Year") sales will not be subject to an earnings review, but will be subject to a prudency review.

SCHEDULE 149 (Continued)

DEFINITIONS

Annual Allocated Revenue (“AAR”)

The Annual Allocated Revenue is the sum of annual revenue from this Tariff plus DSAY revenues (net of prudent Harborton Restoration Project development costs), insurance proceeds, $3.56 million currently in base rates (subject to revision by the Commission), AAR balances carried forward, and accumulated interest. The $3.56 million per year currently in base rates will be credited to the PHERA Annual Account on a monthly basis, in the amount of $0.2967 million, until PGE’s next general rate case when the appropriate amount to be included in rates, if any, will be re-examined. For the month of July 2016, a prorated amount of $0.1627 million shall be credited to the PHERA Annual Account. The amount of insurance proceeds and net DSAY revenues to be included in the AAR is calculated as total proceeds divided by the expected remaining life of the projects, inclusive of the year in which they are received (so that such proceeds are equally allocated). The initial assumption is that the remaining life is through 2028, and may be revised by the Commission (on a going-forward basis) in any subsequent Commission review process.

Downtown Reach

The segment of the Willamette River between River Miles 12 and 16 is known as the “Downtown Reach.”

DSAY

Discount Service Acre Year (“DSAY”) obligations or credits measure damage or mitigation to natural resources.

SCHEDULE 149 (Continued)

DEFINITIONS (Continued)

Environmental Remediation Costs ("ERC")

Environmental Remediation Costs are costs related to remediation of the Portland Harbor and Downtown Reach sites that include, but are not limited to, the design, permitting, construction, on-going monitoring, and trustee financial requirements necessary for habitat restoration development, investigation, testing, sampling, monitoring, removal, disposal, storage, remediation, or other treatment of residues, litigation costs/expenses or other liabilities, disposal sites, sites that otherwise contain contamination that requires remediation for which PGE is responsible, or sites to which material may have migrated; the Natural Resource Damage obligation; Harborton Restoration Project O&M and endowment costs; and costs related to pursuing insurance recoveries. ERC do not include Harborton Restoration Project development costs, which include, but are not limited to, costs incurred as of the date of the UM 1789 Stipulation, development and construction costs, permitting costs, costs paid to the Trustees for participation in the NRD restoration project, and future termination-related costs if applicable. Further, the remediation sites eligible for inclusion as ERCs are limited to those sites identified in Appendix A to the UM 1789 Stipulation.

Environmental Remediation Revenues

Environmental Remediation Revenues include: (1) DSAY revenues net of prudent Harborton Restoration Project development costs; (2) insurance proceeds; (3) the amount included in base rates for environmental remediation activities at Portland Harbor or Downtown Reach; (4) the Schedule 149 tariff revenue; and (5) interest.

Harborton Restoration Project

PGE intends to design, construct, monitor and maintain the Harborton Restoration Project at 12500 NW Marina Way, Portland, Multnomah County, Oregon. PGE will restore and enhance approximately 62 acres of the 78.51 acres of the overall property.

Natural Resource Damage

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 ("CERCLA" or "Superfund") and Oil Pollution Act ("OPA") Programs require the cleanup for contaminants that are released and pose a threat to human health and the environment. In addition to the requirements for cleanup under these cleanup programs, the Superfund and OPA cleanup programs also require that natural resources be restored to the state that they were at before injury from environmental contaminants. If natural resources are not restored, then Trustees will seek compensation for the injury, quantified as Natural Resource Damages ("NRD") from parties responsible for the release of the contaminants. NRD in this tariff refers to NRD obligations assessed against PGE.

SCHEDULE 149 (Continued)

Portland Harbor Superfund

The Superfund designation is pursuant to CERCLA. 42 U.S.C Section 9601 et seq. The CERCLA and OPA programs require the cleanup for contaminants that are released and pose a threat to human health and the environment.

PURE

The Prudence-Reviewed Unamortized Environmental Remediation Expense ("PURE") rate that is established early each year by Staff and represents the average of the 5-year US Treasury rate plus 100 basis points.

SCHEDULE 149 (Continued)

ADJUSTMENT RATES

Schedule	Adjustment Rate	
7	0.000	¢ per kWh
15/515	0.000	¢ per kWh
32/532	0.000	¢ per kWh
38/538	0.000	¢ per kWh
47	0.000	¢ per kWh
49/549	0.000	¢ per kWh
75/575		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh
76R/576R		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh
83/583	0.000	¢ per kWh
85/485/585		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
89/489/589/689		(C)
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh
90/490/590	0.000	¢ per kWh
91/491/591	0.000	¢ per kWh
92/492/592	0.000	¢ per kWh
95/495/595	0.000	¢ per kWh

SCHEDULE 149 (Continued)

SPECIAL CONDITIONS

1. By March 15 of each year, PGE will submit a prudence review filing that includes a report of all activity associated with Harborton Restoration Project development costs, ERC, ERR, and other related third-party proceeds recorded in the PHERA Annual Account. Staff and other Parties will complete the prudence review, and Staff will submit its report and recommendation to the Commission within 120 days of submittal. Only cash expenditures will be included in the PHERA Annual Account for recovery under the PHERA mechanism. PGE shall defer, separately track, and capitalize as a regulatory asset, contingent environmental liability accruals. This regulatory asset shall not be included in rate base and PGE shall not earn a return on the balance.

2. The amount of costs and revenues that is transferred to the Balancing Account is determined on an annual basis and subject to an earnings test. The amount transferred is calculated as the current year's ERC and any remaining Harborton Restoration Project development costs not offset by that year's DSAY revenues, less the AAR. Harborton Restoration Project development costs incurred prior to the first year with DSAY revenues may be netted against those revenues.

3. The earnings test in this schedule will be applied after the Power Cost Adjustment Mechanism ("PCAM") earnings test. The amount subject to the earnings test is prudently incurred ERC that exceed $6.0 million. In addition, Harborton Restoration Project development costs are not subject to an earnings test.

4. The amount of annual ERC recoverable post-application of the earnings test is reduced by the AAR and then the remaining balance, if any, is transferred to the Balancing Account for recovery across the following five years.

5. If ERC in any year are less than the AAR, then the remaining ARR balance will be used to offset accumulated costs in the Balancing Account that were allocated to that year. Any remaining positive balances (more AAR revenues than current and accumulated costs) will roll forward as an addition to the next year's AAR.

6. Functionalized costs recoverable through Schedule 149 will be allocated to each rate schedule according to relative use of generation, distribution, and transmission service. Long-Term Direct Access customers will be priced at Cost-of-Service for purposes of allocating costs.

SCHEDULE 149 (Concluded)

SPECIAL CONDITIONS (Continued)

7. In the event that the amount in the PHERA Balancing Account results in a potential refund to customers, subject to approval by the Commission, PGE will determine if the refund should be applied to Customer bills, or if the credit balance should carry to a future period. A credit balance may be carried to a future period if it is determined by the Commission that the credit balance is best used to offset future expected ERC not yet recorded in the deferral account, or for such other reasons as the Commission may determine.

8. Adjustments under this Schedule shall continue for a period of five years following the date that the last remediation expenses are incurred and paid, or such other date that the Commission may decide.

9. Development costs associated with the creation of DSAYs from the Harborton Restoration Project shall be deferred as regulatory assets.

10. PGE shall defer and capitalize, as a regulatory asset, incurred costs associated with environmental liabilities accrued according to Accounting Standards Codification (“ASC”) 410, *Environmental Obligations* and pursuant to Generally Accepted Accounting Principles (“GAAP”). Any GAAP accounting accruals recorded would not be subject to interest computation or earnings test as no cash amounts have been paid or received.

11. The PHERA is subject to review no less frequently than every two years, when significant new information becomes available, or during a general rate case. All aspects of the mechanism are subject to review and revision, including but not limited to, the earnings test, the exempt ERC amount, and incentives for cost management such as sharing.

12. If Harborton Restoration Project development costs, currently estimated at $10-$12 million, exceed DSAY revenues, PGE will not recover development costs from customers in excess of DSAY revenues retained by PGE. Harborton Restoration Project development costs include all costs associated with the Harborton Restoration Project development, including but not limited to, costs incurred as of the date of the UM 1789 Stipulation, development and construction costs, permitting costs, costs paid to the Trustees for participation in the NRD restoration project, and future termination-related costs if applicable.

SCHEDULE 150
TRANSPORTATION ELECTRIFICATION COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the costs to support the statewide decarbonization goals and long-term load growth through transportation electrification not otherwise included in rates. Expenditure of the revenue collected under this schedule will be made pursuant to ORS 757.357. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, and 576R.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule		Adjustment Rate		
7		0.074	¢ per kWh	(I)
15/515		0.058	¢ per kWh	(R)
32/532		0.070	¢ per kWh	(I)
38/538		0.089	¢ per kWh	
47		0.141	¢ per kWh	
49/549		0.112	¢ per kWh	
75/575				
	Secondary	0.038	¢ per kWh	
	Primary	0.019	¢ per kWh	(I)
	Subtransmission	0.014	¢ per kWh	(R)
83/583		0.029	¢ per kWh	(I)
85/585				
	Secondary	0.025	¢ per kWh	(I)
	Primary	0.021	¢ per kWh	(R)
89/589				
	Secondary	0.038	¢ per kWh	(I)
	Primary	0.019	¢ per kWh	(I)
	Subtransmission	0.014	¢ per kWh	(R)

SCHEDULE 150 (Continued)

ADJUSTMENT RATE (Continued)

Schedule		Adjustment Rate		
90/490/590				
	Primary	0.018	¢ per kWh	**(I)**
	Subtransmission	0.018	¢ per kWh	**(I)**
91/491/591		0.068	¢ per kWh	**(R)**
92/492/592		0.030	¢ per kWh	**(I)**
95/495/595		0.068	¢ per kWh	**(R)**
485				
	Secondary	0.025	¢ per kWh	**(I)**
	Primary	0.021	¢ per kWh	**(R)**
489				
	Secondary	0.038	¢ per kWh	**(I)**
	Primary	0.019	¢ per kWh	**(I)**
	Subtransmission	0.014	¢ per kWh	**(R)**
689				
	Secondary	0.038	¢ per kWh	**(I)**
	Primary	0.019	¢ per kWh	**(I)**
	Subtransmission	0.014	¢ per kWh	**(R)**

Part A collects a charge to support transportation electrification in accordance with Section 2(2) of House Bill 2165.

Part B recovers costs associated with transportation electrification pilots not otherwise included in rates.

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with transportation electrification and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the implementation and administration of transportation electrification pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of transportation electrification pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

SCHEDULE 150 (Concluded)

SPECIAL CONDITIONS (M)

1. For part A, the adjustment rate of the transportation electrification charges will be updated every year. The forecasted total retail revenue will be based on the rates in effect on January 1 of each year. (C)

2. For part B, the costs associated with Docket No. UM 1938 and UM 2003 will be created for each schedule using applicable schedule's forecasted energy on the basis of an equal percent of distribution revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule. (C) (C)(M)

3. For part B, any future costs associated with transportation electriciation pilots will be created for each schedule using applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule. (N) (N)

SCHEDULE 151
WILDFIRE MITIGATION COST RECOVERY

PURPOSE

This schedule recovers the costs associated with wildfire mitigation, implemented to reduce wildfire risks and enhance safety, reliability, and energy system resilience. This adjustment schedule is implemented as an automatic adjustment clause as provided under ORS 757.210 and ORS 757.963(8).

AVAILABLE

In all territory served by Portland General Electric Company (“PGE”).

APPLICABLE

To all bills for Electricity Service.

ADJUSTMENT RATES

Schedule	Adjustment Rate
7	0.209 ¢ per kWh
15/515	0.176 ¢ per kWh
32/532	0.204 ¢ per kWh
38/538	0.249 ¢ per kWh
47	0.429 ¢ per kWh
49/549	0.297 ¢ per kWh
75/575	
Secondary	0.030 ¢ per kWh
Primary	0.029 ¢ per kWh
Subtransmission	0.031 ¢ per kWh
83/583	0.118 ¢ per kWh
85/485/585	
Secondary	0.073 ¢ per kWh
Primary	0.057 ¢ per kWh

SCHEDULE 151 (Concluded)

ADJUSTMENT RATES (Continued)

89/489/589/689		
Secondary	0.030	¢ per kWh
Primary	0.029	¢ per kWh
Subtransmission	0.031	¢ per kWh
90/490/590		
Primary	0.026	¢ per kWh
Subtransmission	0.026	¢ per kWh
91/491/591	0.176	¢ per kWh
92/492/592	0.056	¢ per kWh
95/495/595	0.176	¢ per kWh

ANNUAL REVENUE REQUIREMENTS

The Annual Revenue Requirements will include all reasonable operating costs plus investment and associated capital-related costs to develop, implement and/or operate a wildfire mitigation plan under ORS 757.963.

BALANCING ACCOUNT

The Company will maintain a balancing account to track the difference between the actual incremental Schedule 151 revenue requirement and Schedule 151 revenues. The balancing account will accrue interest at the Commission-authorized rate.

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule’s forecasted energy on the basis of an equal percent of non-generation revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule. The fixed revenue for all lighting schedules is removed from the non-generation revenue and is not used as the basis for the allocation.

2. The costs for projects included under this schedule will be updated annually and will continue to be recovered under Schedule 151 until such time as the costs are included in base rates.

SCHEDULE 152
MAJOR EVENT COST RECOVERY

PURPOSE

The purpose of this schedule is to recover costs incurred relating to the 2020 and 2021 wildfire and 2021 ice storm emergencies and the COVID-19 pandemic and refund previous collections associated with the Boardman Coal Plant after its closure. **(C)** **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, and 576R.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate		
7	0.242	¢ per kWh	**(R)**
15/515	0.188	¢ per kWh	
32/532	0.216	¢ per kWh	
38/538	0.255	¢ per kWh	
47	0.439	¢ per kWh	
49/549	0.304	¢ per kWh	
75/575			
Secondary	0.022	¢ per kWh	
Primary	0.022	¢ per kWh	
Subtransmission	0.022	¢ per kWh	
83/583	0.136	¢ per kWh	
85/585			**(C)**
Secondary	0.094	¢ per kWh	
Primary	0.074	¢ per kWh	**(R)**

SCHEDULE 152 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
89/589			(C)
Secondary	0.022	¢ per kWh	(R)
Primary	0.022	¢ per kWh	
Subtransmission	0.022	¢ per kWh	
90/590			(C)
Primary	0.020	¢ per kWh	
Subtransmission	0.020	¢ per kWh	
91/591	0.186	¢ per kWh	(C)
92/592	0.076	¢ per kWh	
95/595	0.186	¢ per kWh	
485			
Secondary	0.110	¢ per kWh	
Primary	0.090	¢ per kWh	
489			
Secondary	0.038	¢ per kWh	
Primary	0.038	¢ per kWh	
Subtransmission	0.038	¢ per kWh	
490			
Primary	0.035	¢ per kWh	
Subtransmission	0.035	¢ per kWh	
491	0.201	¢ per kWh	
492	0.091	¢ per kWh	
495	0.201	¢ per kWh	
689			
Secondary	0.038	¢ per kWh	
Primary	0.038	¢ per kWh	
Subtransmission	0.038	¢ per kWh	(R)(C)

BALANCING ACCOUNT

The Company will maintain balancing accounts to track the residual balances caused by differences between expected and actual Schedule 152 revenues.

SCHEDULE 153
COMMUNITY BENEFITS AND IMPACT ADVISORY GROUP
COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the costs associated with the Community Benefits and Impact Advisory Group (CBAIG) not otherwise included in rates. This adjustment schedule is implemented as an "automatic adjustment clause" as provided for under ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R and 576R.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule		Adjustment Rate	
7		0.003	¢ per kWh
15		0.003	¢ per kWh
32		0.003	¢ per kWh
38		0.003	¢ per kWh
47		0.005	¢ per kWh
49		0.004	¢ per kWh
75			
	Secondary	0.003	¢ per kWh(1)
	Primary	0.002	¢ per kWh(1)
	Subtransmission	0.002	¢ per kWh(1)
83		0.002	¢ per kWh
85			
	Secondary	0.002	¢ per kWh
	Primary	0.002	¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 153 (Continued)

ADJUSTMENT RATES (Continued)

Schedule		Adjustment Rate	
89			
	Secondary	0.003	¢ per kWh
	Primary	0.002	¢ per kWh
	Subtransmission	0.002	¢ per kWh
90			
	Primary	0.002	¢ per kWh
	Subtransmission	0.002	¢ per kWh
91		0.003	¢ per kWh
92		0.002	¢ per kWh
95		0.003	¢ per kWh
485			
	Secondary	0.002	¢ per kWh
	Primary	0.002	¢ per kWh
489			
	Secondary	0.003	¢ per kWh
	Primary	0.002	¢ per kWh
	Subtransmission	0.002	¢ per kWh
490			
	Primary	0.002	¢ per kWh
	Subtransmission	0.002	¢ per kWh
491		0.003	¢ per kWh
492		0.002	¢ per kWh
495		0.003	¢ per kWh
515		0.003	¢ per kWh
532		0.003	¢ per kWh
538		0.003	¢ per kWh
549		0.004	¢ per kWh
575			
	Secondary	0.003	¢ per kWh(1)
	Primary	0.002	¢ per kWh(1)
	Subtransmission	0.002	¢ per kWh(1)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 153 (Concluded)

ADJUSTMENT RATES (Continued)

583	0.002	¢ per kWh
585		
Secondary	0.002	¢ per kWh
Primary	0.002	¢ per kWh
589		
Secondary	0.003	¢ per kWh
Primary	0.002	¢ per kWh
Subtransmission	0.002	¢ per kWh
590		
Primary	0.002	¢ per kWh
Subtransmission	0.002	¢ per kWh
591	0.003	¢ per kWh
592	0.002	¢ per kWh
595	0.003	¢ per kWh
689		
Secondary	0.003	¢ per kWh
Primary	0.002	¢ per kWh
Subtransmission	0.002	¢ per kWh

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with the Community Benefits and Impact Advisory Group and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request. The deferral will be amortized over one year in this schedule unless otherwise directed by the Oregon Public Utility Commission.

SCHEDULE 200
DISPATCHABLE STANDBY GENERATION

PURPOSE

To provide the Company with additional generation capacity by contracting with Large Nonresidential Customers for the right to operate their Generation Resource(s) for the purpose of providing Grid Services and averting situations that could lead to power quality problems for the power supply in the local region. (C) (C)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers with 250 kW or greater of permanently installed Generation Resource(s) in place or planned for installation within 24 months. (C) (C)

DEFINITIONS (N)

Aid in Construction Allowance - The amount of funding PGE may contribute to an individual project to enable the Generation Resource to be integrated with PGE for dispatch to support Grid Services.

Ancillary Services - Includes Contingency Reserve and Frequency Response for the purposes of this program.

Battery Energy Storage System (BESS) - An electrochemical device that charges (or collects energy) from the grid or on-site power generation sources and then discharges that energy at a later time to provide electricity or other grid services when needed.

Contingency Reserve - The ability to dispatch an enrolled Generation Resource in response to a critical need for replacement power in the region.

Demand Response - The dispatch of a qualified enrolled Generation Resource for the purpose of strategically reducing energy usage during times of peak demand and/or high energy market pricing.

Dispatchable Standby Generation Agreement (Agreement) - An agreement between the Company and Customer that defines the length of the Agreement, amount of capacity nominated to PGE, number of hours PGE may dispatch the Generation Resource, the terms of the Customer's usage of the Generation Resource, and amount of the Aid in Construction Allowance.

Frequency Response - An immediate reduction of site load or dispatch of power at a predetermined level for a short duration in response to a disruption that causes the frequency of the electrical system to fall below a nominal 60 hertz (Hz). (N)

SCHEDULE 200 (Continued)

DEFINITIONS (Continued) (N)

Generation Resource - An Internal Combustion Generator or a Battery Energy Storage System integrated with PGE pursuant to this Schedule.

Grid Services - For the purposes of this Schedule includes the dispatch of Generation Resources for Ancillary Services or Demand Response.

Internal Combustion Generator - A mechanical engine used to generate electricity.

Reserve Status - Indicates a resource is available for dispatch by PGE. (N)

CUSTOMER RESPONSIBILITIES (M)

The Customer will grant the Company access to its Generation Resource(s) such that the (C) Company can operate the Generation Resource(s) at the site or remotely operate the Generation Resource(s) in parallel with the Company's distribution system. (C)

The Customer may operate the Generation Resource(s) at the site as specified in the (C) Dispatchable Standby Generation Agreement (Agreement). (C)

COMPANY RESPONSIBILITIES

The Company will conduct an analysis of the Customer's Generation Resource and develop a (C) cost estimate for the installation of the equipment necessary for participation under this schedule. (C) The Company will be responsible for providing engineering and funding based on the cost estimate not to exceed the Aid in Construction Allowance. The Company will pay for and own all (C) communications and metering equipment.

The Company will normally pay for all fuel used to operate the Customer's Internal Combustion (C) Generator (s) throughout the term of the Agreement. To the extent the Customer operates the Internal Combustion Generator(s) more than 15 (fifteen) hours per operating year during non-outage periods, the Customer shall be responsible for paying fuel costs, per the Agreement. (C)

In, addition, the Company is responsible for routine maintenance as described in the Agreement. (C) The Company will perform regular testing of the Customer's Generation Resource(s) and control (C) system and testing of the Company's dispatch control and interconnection facilities. The Company will provide power quality monitoring and data reporting of the Customer's facility and Generation Resource(s). (C)

The Company's design will be such that during outage situations, the Customer's Generation (C) Resource(s) will automatically start and provide backup power to the Customer. (C)
(M)

SCHEDULE 200 (Continued) (T)

AID IN CONSTRUCTION ALLOWANCE (C)(M)

The Company's Aid in Construction Allowance is based on the cost of Company owned equipment necessary for parallel operations, system protection, safety provisions and communications, related administrative costs and the Generation Resource and switchgear modifications, wiring and conduit necessary to permit Customer's Generation Resource(s) to run in parallel with the Company's system. (C) (C) (C)

PGE shall contribute $39.50 per nominated kW year for Ancillary Services, or $82.40 per nominated kW year for participating in both Demand Response and Ancillary Services. Only BESS resources are eligible to participate in Demand Response. The Customer will be responsible for cost components that bring the total project costs above the Company's Aid in Construction Allowance. Due to the individual nature of each Generation Resource, specifics on Company Funding and Customer payment responsibilities will be contained in the Agreement. (C) (C)

Upon termination of the Agreement, the Company may remove its equipment. (T)

SPECIAL CONDITIONS

1. The Customer's charges for Electricity Service under any of the Company's Standard Service or Direct Access Service schedules are not changed or affected in any way by service under this schedule and are due and payable as specified in those schedules.

2. Parallel operation of Generation Resources must satisfy Company interconnection requirements. (C)

3. The Customer will ensure that the Generation Resource(s), communications equipment, switchgear and metering equipment are accessible to the Company at all times. (C)

4. Prior to receiving service pursuant to this schedule, the Customer and the Company must enter into a written Agreement, signed by the Customer. (C) (C)

5. The Customer must obtain all required permits prior to service initiation to allow all planned operations as specified in the Agreement. The Company will reimburse the Customer for any permits specifically required for this service, including permit renewals during the term of the Agreement up to $10,000 annually. (C) (C)(M)

SCHEDULE 200 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Company may operate the Generation Resource(s) at any time without notice when the Generation Resources are placed on Reserve Status. When advance notice is possible, PGE will notify the Customer as specified in the Agreement. **(C)(M)** **(C)**

7. Customers receiving service under this schedule will agree to an initial multi-year term for the Agreement, with options to renew. Should the Customer terminate the Agreement before the end of the initial term, the Customer will reimburse the Company for a portion of the capital investment plus a removal fee as specified in the Agreement. **(C)** **(C)(M)**

8. The customer is responsible for maintaining the nominated capacity of the BESS, the details of which are described in the Agreement. **(N)** **(N)**

9. PGE may request that the Customer allow PGE to use the Generation Resource(s) in Reserve Status. The decision to allow PGE to use the Generation Resource(s) for any given period of time in Reserve Status is up to the Customer, as specified in the Agreement. **(C)(M)** **(C)**

10. The Company will have the right to refuse to fund projects for any reason; including, but not limited to projects deemed high-risk, not cost effective, of poor equipment quality, or an excessive environmental risk. Reasons for funding denial will be provided in writing to the Customer upon request. **(T)** **(M)**

SCHEDULE 203
NET METERING SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This schedule is applicable to a Customer with installed generating equipment that qualifies as a Net Metering Facility defined in ORS 757.300(1)(d). Such Customer is referred to as a Customer-generator and defined in OAR 860-039-0005(2)(e). Service under this schedule is provided pursuant to the requirements of OAR 860-039-0005 through 0080 and ORS 757.300. **(C)** **(C)**

DEFINITION

Net metering measures the difference between the Electricity supplied by the Company and the Electricity generated by a Customer-generator that is fed back to the Company over an applicable Billing Period. Net Metered generation is supplied to the Company from a Customer that operates an interconnected power production facility using solar power, wind power, fuel cells, hydroelectric power, landfill gas, digester gas, waste, dedicated energy crops available on a renewable basis or low-emission, nontoxic biomass based on solid organic fuels from wood, forest or field residues where the generating nameplate capacity is 2 MW or less for Non-residential Customers and 25 kW or less for Residential Customers. The facility must operate in parallel with the Company's existing Facilities and be primarily intended to offset part or all of the Customer's own electrical requirements.

MONTHLY BILLING

Each Customer-generator will pay monthly charges (including Basic, Demand, Facilities, and Reactive Demand charges) as applicable in accordance with the Customer's service option selection and receive kWh credits as described below.

During a monthly Billing Period when the Company supplies a Customer-generator more energy than the Customer-generator supplies to the Company, the Customer-generator will be charged for the net energy supplied in accordance with the Customer's service option selection.

During a monthly Billing Period when the Customer-generator supplies to the Company more Energy than the Company supplies to the Customer-generator, ("Excess Generation", that is, there is net excess kWh that is delivered to the Company), the Customer will be billed the appropriate monthly charges (including Basic, Demand, Facilities, and Reactive Demand charges as applicable) and will be credited for the net Excess Generation on the next monthly bill as provided for in OAR 860-039-0055(1). **(T)** **(T)**

SCHEDULE 203 (Continued)

EXCESS ANNUAL KILOWATT-HOUR CREDITS

In accordance with OAR 860-039-0060, at the end of the last monthly Billing Period of the Customer's-generator annual billing cycle, any excess kWh credits accumulated will be transferred to the Company's low income assistance program at the average annual Schedule 201 Avoided Cost rate. The Customer's excess kWh credits are set to zero for the beginning of the subsequent annual billing cycle. The annual billing cycle begins with the Customer-generator's regularly scheduled April Billing Period (which typically begins in March) and ends with completion of the March Billing Period of the following year unless a different annual billing cycle is mutually agreed to by the Customer-generator and Company and such agreement is provided to the Commission within 30 days.

AGGREGATION AND CREDITING OF EXCESS KILOWATT-HOUR CREDITS WITHIN ANNUAL BILLING CYCLE (N)

As provided in OAR 860-039-0065, upon request from the Customer-generator, the Company will aggregate for billing purposes the monthly kWh usage of the Customer's designated meter and any additional meters of the Customer-generator, where all meters are located on the Customer's contiguous property and are served by the same primary feeder. A 60 day advance notice is required for requests to aggregate meters.

Meters will be aggregated as follows: Generation will first be credited to the designated meter. If there is more generation than consumption at the designated meter, netting will continue with the next meter in the rank order chosen by the Customer. Aggregated meters subject to the same rate schedule as the designated meter must be ranked above any other meters. A change in the rank order used for netting calculations of already aggregated meters is allowed at the beginning of the next annual billing period only and requires a 60 day advance notice.

TIME OF USE

Meters subject to Time of Use rates will be credited as follows: First, generation will be credited in the time period in which it was generated. If there is more generation than consumption in any time period, crediting will continue beginning with the highest rate period first and then continue to lower rate periods, until all generation has been credited. If any generation remains after the crediting process for a meter, it will be applied to lower ranked meters within that month and then to the following month, subject to the processes and annual billing cycle limitations described previously. (N)

(M)

(D)

SCHEDULE 203 (Concluded)

SPECIAL CONDITIONS **(T)**

1. Prior to the interconnection of a Net Metering Facility the Customer-generator must submit an application for interconnection review, execute a written Net Metering Agreement and Interconnection Agreement with the Company, and remit any applicable fees and charges as described in Special Condition 8. The Company will review the application in accordance with the requirements of the applicable interconnection facility review set out in OAR 860-039-0030, 0035 and 0040. An applicant may contact the Company's Net Metering Coordinator at (503) 464-8000 or via email at netmetering@pgn.com for net metering service information, applications and agreements. **(M)** **(T)**

2. The Customer-generator is responsible for obtaining all necessary government approvals relating to its Net Metering Facility and must meet all applicable building codes and standards including standards specified in OAR 860-039-0020.

3. The Customer-generator is responsible for all costs associated with its Net Metering Facility and is also responsible for all costs related to any modifications to the facility that may be required by the Company resulting from the reviews as provided for in OAR 860-039-0030, 0035 or 0040, as applicable.

4. As provided in OAR 860-039-0015 where applicable, a manual disconnect switch capable of isolating the Net Metering Facility from the Company's system must be provided by the Customer-generator and must be accessible to the Company at all times. **(T)**

5. The Company maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of day.

6. The Company maintains the right to disconnect, without liability, the Customer-generator for issues relating to safety and reliability. **(M)**

7. The Company will not be liable directly or indirectly for permitting or continuing to allow an attachment of a Net Metering Facility, or for the acts or omissions of the Customer-generator that cause loss or injury, including death, to any third party. **(D)**

8. The Company will apply the following fees to each Net Metering Facility interconnection application as provided in OAR 860-039-0045: **(T)**
   a) For Level 2 interconnection review, $50.00 plus $1.00 per kW of a Net Metering Facilities capacity.
   b) For Level 3 interconnection review, $100.00 plus $2.00 per kW of a Net Metering Facilities capacity.
   c) For Level 2 and 3 interconnections, the reasonable costs for additional engineering and Company system modifications.

SCHEDULE 204
COMMUNITY SOLAR PROGRAM INTERCONNECTION
AND POWER PURCHASE SCHEDULE

AVAILABLE

Service under this schedule is available throughout the Company's Service Territory.

DEFINITIONS

As-Available Rate is the rate at which PGE will purchase a Project's Net Output that is Unsubscribed Energy as a Qualifying Facility pursuant to PURPA. The As-Available Rate is set forth in PGE's Schedule 201.

Certified Projects are CSP Projects that have been certified by the Oregon Public Utility Commission of Oregon under OAR 860-088-0050.

Community Solar Program (CSP) is the program established for the procurement of electricity from CSP Projects pursuant to ORS 757.386, the CSP Rules, and the Program Implementation Manual.

Company means Portland General Electric Company or PGE.

CSP Interconnection Service is the interconnection service offered by the Company to qualifying CSP Projects pursuant to this schedule.

CSP Interconnection Application is the application that a Project Manager must submit to the Company in order to request CSP Interconnection Service.

CSP Project means a solar photovoltaic energy facility used to generate electric energy on behalf of CSP Participants and for which Participants receive Renewable Energy Credits and credit on their electric bills as provided in the CSP rules, Program Implementation Manual, and this schedule.

CSP Purchase Agreement means the power purchase agreement between Company and Project Manager that establishes the terms and conditions of the Project Manager's sale and Company's purchase of Net Output from a Certified Project in accordance with this schedule and the CSP.

CSP Rules means the administrative rules governing the CSP set forth in OAR Chapter 860, Division 88.

Losses are the loss of electric energy occurring as a result of the transformation and transmission of electric energy from the Project to the Point of Delivery.

SCHEDULE 204 (Continued)

DEFINITION (Continued)

Low-side Metering means loss-compensated revenue metering located on the low voltage side of the CSP Project's generator step up transformer.

Net Output means all energy expressed in kWhs generated by the CSP Project, less station and other onsite use and less Losses, delivered to the Company in accordance with the conditions of this schedule and the CSP Purchase Agreement. Net Output does not include any environmental attributes. Net Output is comprised of both Subscribed Energy and Unsubscribed Energy.

Participant means a customer of the Company that is either a subscriber or owner of a CSP Project as those terms are defined in ORS 757.386(1), OAR 860-088-0010 and the Program Implementation Manual.

Pre-certified Project is a Project that is pre-certified by the Oregon Public Utility Commission (Commission) under the CSP and in accordance with OAR 860-088-0040 and the Program Implementation Manual.

Program Administrator means the third-party entity directed by the Commission to administer the CSP.

Program Fees are fees that the Company collects on each Participant's utility bill to fund the administration of the CSP in accordance with OAR 860-088-0160(2) and the Program Implementation Manual. Program Fees include a Program Administrator Fee and a Utility Administration Fee. Program Fees, expressed in terms of $/kW/month, are subject to Commission approval and adjusted annually.

Program Implementation Manual means the set of guidelines and requirements for implementing the CSP adopted by the Commission in Order No. 19-438 and which may be changed by the Commission from time to time in future orders.

Project Manager is the entity having responsibility for managing the operation of a CSP Project, as defined in ORS 757.386(1)(d).

PURPA means the Public Utility Regulatory Policies Act of 1978.

Point of Delivery means the high side of the CSP Project's step-up transformer(s) located at the point of interconnection between the CSP Project and the Company's distribution/transmission system.

SCHEDULE 204 (Continued)

DEFINITION (Continued)

Qualifying Facility is a solar photovoltaic facility that meets the PURPA criteria for qualification set forth in Subpart B of Part 292, Subchapter K, Chapter I, Title 18, of the Code of Federal Regulations.

Schedule means this Community Solar Program Interconnection and Power Purchase Schedule, including all exhibits attached hereto or incorporated by reference.

Service Territory means the geographic area within which the Company provides electricity to retail customers, as defined in OAR 806-088-0010(13).

Station Use is electric energy used to operate the CSP Project that is auxiliary to or directly related to the generation of electricity and which, but for the generation of electricity, would not be consumed by the CSP Project.

Subscribed Energy means the portion of the Net Output from a CSP Project delivered to the Point of Delivery for which the Project Manager of the CSP Project has subscribed to Participants and for which the Company must therefore credit the Participants' electric bills as provided in this schedule, the CSP, and the CSP Purchase Agreement.

Supplementary Power is electric energy or capacity supplied by the Company that is regularly used by the CSP Project in addition to the Station Use that the CSP Project supplies itself.

Term means the length of the CSP Purchase Agreement.

Unsubscribed Energy means the portion of the Net Output from a CSP Project delivered to the Point of Delivery for which the Project Manager has not subscribed to Participants and for which the Company must therefore purchase from the Project Manager at the As-Available Rate as provided in this schedule and the CSP Purchase Agreement.

SCHEDULE 204 (Continued)

PART 1: CSP INTERCONNECTION

A. Applicable

To a CSP Project that:

1. Is located within the Company's Service Territory;

2. Meets the eligibility requirements of the Community Solar Program Rules and the Program Implementation Manual;

3. Together with all other interconnected and requested generation in the local area, is less than 100 percent of minimum daytime load (MDL), as determined by the Company. If a measure of MDL is not available for the feeder, Company will use 30 percent of summer peak load; and

4. Submits a valid CSP Interconnection Application through the Company's interconnection application online system.

B. CSP Interconnection Process

1. Requesting CSP Interconnection. To request CSP Interconnection, an applicant must submit online through PGE's PowerClerk platform ((https://pgeqf.powerclerk.com) a valid CSP Interconnection Application The Company will process the CSP Interconnection Application in accordance with the CSP Interconnection Procedures provided as Exhibit A to this schedule.

2. CSP Interconnection Study Process. The Company will study CSP Interconnection requests in accordance with its CSP Interconnection Procedures and using an Energy Resource Interconnection Service study process, as defined in the Company's Open Access Transmission Tariff. However, the Company will also perform a non-binding, informational analysis of the requirements associated with interconnecting the CSP project using its Network Resource Interconnection Service study process, as defined in the Company's Open Access Transmission Tariff. This non-binding Network Resource Interconnection Service analysis will be provided in the same system impact study report as the CSP Interconnection analysis, along with good-faith estimates of both costs and timing of any system upgrades necessary for both types of service.

3. CSP Interconnection Queue. The Company will process CSP Interconnection Applications for prospective CSP Projects in a CSP Interconnection queue, separate from the traditional serial queue. The Company will process all CSP Interconnection Applications in the order received. Requests for CSP Interconnection will be assigned CSP Interconnection queue positions in the order in which the request, and all associated requirements, are received.

SCHEDULE 204 (Continued)

SP Interconnection Process (Continued)

4. Low-side Metering. An applicant may request Low-side Metering for a CSP Project 360 kW and smaller.

5. Joint Study. If an applicant for CSP Interconnection has multiple CSP Projects eligible for interconnection, it can request that the Company study the CSP Projects jointly if the CSP Interconnection Applications are submitted in back to back queue order. Such projects shall equally share in the costs for CSP interconnection study purposes in accordance with the process described in the Interconnection Procedures for CSP Projects, attached as Exhibit A to this Schedule.

C. CSP Interconnection Exhibits

1. The Interconnection Procedures for CSP Projects are set forth in Exhibit A to this Schedule.

2. The System Impact Study Agreement for CSP Projects is set forth in Exhibit B to this Schedule.

3. The Facilities Study Agreement for CSP Projects is set forth in Exhibit C to this Schedule.

4. The CSP Project Completion Form is set forth in Exhibit D to this Schedule.

5. The CSP Project Interconnection Agreement is set forth in Exhibit E to this Schedule.

PART 2: CSP PURCHASE AGREEMENT

A. Applicable

To CSP Projects that:

1. Are located within the Company's Service Territory;

2. Are certified or exempt from certification as a Qualifying Facility;

3. Are pre-certified or Certified as a CSP Project by the Commission under Oregon Administrative Rule (OAR) 860-088-0050; and

4. Except for CSP Projects that have otherwise received consent from the Company, or as otherwise legally required by the Commission, have not already sold, leased assigned, contracted for (including pursuant to the execution of a power purchase agreement under PURPA) or otherwise disposed of the Net Output of the CSP Project, except for the sale of subscriptions for Subscribed Energy to Participants consistent with the CSP.

SCHEDULE 204 (Continued)

B. Contracting Process

Upon request by a CSP Manager, the Company will enter into a CSP Purchase Agreement for the procurement and purchase of Net Output from the Project under and with the following conditions:

1. To obtain a draft CSP Purchase Agreement, the Project Manager must notify the Company of its intent to enter into a CSP Purchase Agreement and provide the Company, in writing, with the general Project information listed below:

   (a) confirmation of Qualifying Facility status (e.g., filed FERC Form 556 certification);
   (b) design capacity (MW), Station Use requirements, and Net Output of power to be delivered to the Company's electric system;
   (c) solar generation technology and other related technology;
   (d) site location;
   (e) anticipated schedule of monthly power deliveries;
   (f) calculation or determination of minimum and maximum annual deliveries;
   (g) proposed on-line date;
   (h) status of interconnection arrangements; and
   (i) Point of delivery.

2. Upon receipt of complete CSP Project information, the Company will provide a draft CSP Purchase Agreement to the Project Manager for review.

3. When both Company and Project Manager are in full agreement as to all terms and conditions of the draft CSP Purchase Agreement, the Company will prepare and forward to the Project Manager within fifteen (15) business days, a final executable version of the agreement. Following the Project Manager and Company's execution, a completely executed copy of the CSP Purchase Agreement will be returned to the Project Manager.

SCHEDULE 204 (Concluded)

C. CSP Administration

1. Energy Delivery: Once a Certified Project has commenced commercial operation, not later than the second day of each month, the Company shall report to the Program Administrator the amount of Net Output received from the Certified Project at the Point of Delivery for the preceding month.

2. Compensation: As provided in the Program Implementation Manual and the CSP Purchase Agreement, the Company shall provide compensation monthly for each kWh of Net Output accepted at the Point of Delivery as follows:

a. Subscribed Energy: For all Subscribed Energy delivered by the CSP Project to the Company at the Point of Delivery, the Company will apply a bill credit to each Participant's utility bill in accordance with the process and calculations set forth in ORS 757.386(6), OAR 860-088-0170, the Program Implementation Manual, and the CSP Purchase Agreement.

b. Unsubscribed Energy: The Company will pay the Program Administrator on a monthly basis for each kWh of Unsubscribed Energy in the manner described in OAR 860-088-0140, the Program Implementation Manual, and the CSP Purchase Agreement.

3. Program Fees: The Company will apply Program Fees to each Participant's monthly utility bill in the manner described in ORS 757.386, OAR 860-088-0120, the Program Implementation Manual, and PGE's CSP Operational Tariff.

4. Term: The Term of the CSP Purchase Agreement is up to twenty (20) years from the Facility's Commercial Operation Date, in accordance with ORS 757.386(2)(a)(D) and OAR 860-088-0140(1)(a).

D. CSP Purchase Agreement

The form of the CSP Purchase Agreement is provided as Exhibit F of this Schedule.

SCHEDULE 215
SOLAR PAYMENT OPTION PILOT
SMALL SYSTEMS
(10 kW or LESS)

PURPOSE

This schedule establishes a photovoltaic volumetric incentive rate (VIR) pilot program as required by HB 3039 (Chapter 748, Oregon Laws 2009), HB 3690 (Chapter 78, Oregon Laws 2010 Special Session), HB 2893 (Chapter 244, Oregon Laws 2013), and OAR 860-084-0100. The pilot provides payments to retail electricity Customers for electricity generated by permanently installed solar photovoltaic energy systems.

AVAILABLE

To Customers with Qualifying Systems (QSs), as defined in ORS 757.360(3)(b), connected to retail Customers' facilities in territory served by the Company.

APPLICABLE

To Customers that have QSs not purchased with state or ETO incentives with installed nameplate generating capacity 10 kW DC or less where the output is not paid for pursuant to another tariff schedule, that meet the eligibility requirements in OAR 860-084-0120, and where the monthly generation does not exceed Total Monthly Use pursuant to a Solar Photovoltaic Pilot Program and Interconnection Services Agreement (Agreement).

MONTHLY RATE

Customer Charge

The Customer pays the Company a $10.00 Customer Charge per month for each separately metered QS. This is in addition to the Basic Charge for providing Electricity Service to the Customer.

Volumetric Incentive Rate

The Company pays the applicable gross VIR to the QS Customer for eligible generation from the participating Customer with a capacity reservation awarded on or after August 25, 2015. **(C)**

Description	Hood River County	All Other Counties		
Small : 10 kW or less*	22.7	31.6	¢ per kWh	**(R)**

* DC nameplate capacity

The gross VIR applies up to the Total Monthly Use and consists of two components: (1) a retail bill offset based on applicable volumetric (kWh) charges, and (2) a net VIR payment. Kilowatt-hours generated in excess of the Total Monthly Use will be carried forward to the next month as provided in OAR 860-084-0360. Total Monthly Use is defined as net kWh from the retail meter (may be positive or negative) plus kWh from the QS meter.

SCHEDULE 215 (Continued)

MONTHLY RATE (Continued)
Volumetric Incentive Rate

The rate in place at the time of the Reservation Start Date, defined in OAR 860-084-0010(17), applies to the entire 15 year life of the Agreement.

RATE ADJUSTMENT

The Commission may adjust the rate to be effective on October 1 and April 1 of each year consistent with Commission Order Nos. 11-280 and 11-339. For Spring 2015, consistent with Commission Order No 15-092, the Commission adjusted the rate effective date to May 1, 2015. Pursuant to Commission Order No. 15-250, the Commission directs that any remaining capacity (C) be distributed to applicants that are already on the waiting list as part of the May 2015 window. Distribution of any remaining capacity of the VIR program will continue until the earlier of March 31, 2016, or the installation of all program capacity (27.5 MW). (C)

EXCESS ANNUAL KILOWATT-HOUR CREDITS

In accordance with OAR 860-084-0360, at the end of the last monthly Billing Period ending on or before the last day of each generation year, any excess generation kWh credits accumulated will be transferred to the Company's low income assistance program at the average annual Schedule 201 Avoided Cost rate. The default generation year is April 1 through March 31. The Customer's excess kWh credits are set to zero for the beginning of the subsequent annual billing cycle.

SOLAR PHOTOVOLTAIC PILOT PROGRAM AND INTERCONNECTION SERVICES AGREEMENT

The Customer must execute a Solar Photovoltaic Pilot Program and Interconnection Services Agreement with the Company and meet all criteria under OAR Division 84 – Solar Photovoltaic Programs prior to delivery of power to the Company.

In accordance with terms set out in this schedule and the Commission's Rules as applicable, the Customer will receive monthly payment for energy from the Customer's QS based on kWh output, up to Total Monthly Use.

VIR PAYMENTS

VIR payments under this pilot occur no later than 45 days from the last day of the Customer's billing period. The VIR payment will be reduced by the amount of the retail bill offset for a net VIR payment. The Customer may choose among three payment options for the net VIR payment: (1) receive a direct payment, (2) have payments netted against the Customer's retail bill, or (3) assign the payment to a single assignee. A one-time assignment fee of $25 applies for each payment assignment or reassignment.

The Customer is responsible for the minimum monthly charge and all non-volumetric charges related to the retail electricity rate schedule.

SCHEDULE 215 (Continued)

METERING REQUIREMENTS

The Company will install and own the required QS metering equipment at its expense.

Customers served on this schedule must have a PGE-owned meter that measures QS generation net of parasitic load. This meter must be located on the Customer side of the retail meter and on the AC (output) side of the inverter in a location that measures the entire output of the system. The additional meter does not change the Customer's Service Point (SP). **(C)**

SEMIANNUAL CAPACITY RESERVATION

A customer must apply during the capacity reservation enrollment window beginning at 8 a.m. on April 1 and October 1 of each pilot year. If the 1st occurs on a weekend or holiday, the Company will accept applications on the following business day. For Spring 2015, per OPUC Order 15-092, the enrollment window begins at 8 a.m. on May 1, 2015. Capacity is initially allocated by a 24-hour lottery as directed by Commission Order. After capacity fills, remaining customers will be placed on a waitlist in the order of their reservation. In the event capacity becomes available during the enrollment window, Customers on the waitlist will be offered capacity in that order. The waitlist expires at the end of each enrollment period. The enrollment window is open for three months.

If capacity is not filled in the lottery, then capacity is reserved on a first-come, first-served basis.

A capacity reservation deposit of a $500 minimum or $20 per kW of the proposed system DC nameplate capacity is required with the capacity reservation application. The deposit is refundable unless the capacity reservation expires or the customer cancels the reservation, in each case the applicant forfeits the deposit.

A capacity reservation expires one year from the Reservation Start Date if the system has not been installed or, if an interconnection application is not filed, two months from the Reservation Start Date. See OARs 860-084-0195 through 860-084-0230 for additional capacity reservation rules.

SPECIAL CONDITIONS

1. Division 84 of the Oregon Administrative Rules (OAR) Chapter 860 contains additional details that apply to this pilot.

2. The QS must be constructed from new components and operational no sooner than July 1, 2010.

SCHEDULE 215 (Continued)

SPECIAL CONDITIONS (Continued)

3. The Customer-generator is responsible for obtaining all necessary government approvals relating to its QS facility and must meet all applicable building codes and standards including standards specified in OAR 860-084-0260.

4. The Customer-generator is responsible for all costs associated with its QS facility, including interconnection costs incurred by the Company, and is also responsible for all costs related to any modifications to the facility that may be required by the Company resulting from the reviews as provided for in OAR 860-084-0310, 0320 or 0330, as applicable.

5. As provided in OAR 860-084-0340 and where applicable, a manual disconnect switch capable of isolating the QS from the Company's system and accessible to the Company at all times must be provided by the Customer-generator.

6. The estimated kWh output of any QS must not exceed 90% of the actual usage in the most recent 12 billing periods at the premise where the eligible system will be installed. If less than 12 billing periods of actual usage is available at the existing premise or new **(T)** construction, then the annual usage by a similarly situated Customer may be used or a Customer may submit PGE's load estimation document. The Customer is responsible to determine the appropriate size of the QS.

7. The Customer is not eligible for service under both this schedule and Schedule 203, Net Metering Service for each separately metered account. Each separately metered retail account may only have one QS meter. A Customer is eligible for additional QSs only if the VIR for the additional QS is the same as the first QS.

8. All renewable energy credits (RECs) or other benefits or allowances for which the QS qualifies or creates under current or future law relating to renewable energy are property of the Company.

9. The Company maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of day.

10. The Company maintains the right to disconnect, without liability, the Customer-generator for issues relating to safety or reliability.

SCHEDULE 215 (Concluded)

SPECIAL CONDITIONS (Continued)

11. The Company will not be liable directly or indirectly for permitting or continuing to allow an attachment of a QS, or for the acts or omissions of the Customer-generator that cause loss or injury, including death, to any third party.

12. Participants are required to meet general liability insurance requirements set forth in applicable Solar Photovoltaic Pilot Program and Interconnection Services Agreements in order to protect against injuries to property or persons caused by the QS. The applicable Agreements contain insurance limits and provisions, as well as the basis for making representations of equivalence.

(D)

TERM

Each Solar Photovoltaic Pilot Program and Interconnection Services Agreement will have a term of 15 years at the applicable VIR. In accordance with OPUC Order No. 14-025, the pilot will **(T)**
close to new capacity reservations on March 31, 2016, or when the cumulative capacity of |
contracted systems in the pilot reaches 27.5 MW AC statewide per OAR 860-084-0150, **(T)**
whichever comes first.

SCHEDULE 216
SOLAR PAYMENT OPTION PILOT
MEDIUM SYSTEMS (GREATER THAN 10 kW to 100 kW)

PURPOSE

This schedule establishes a photovoltaic volumetric incentive rate (VIR) pilot program as required by HB 3039 (Chapter 748, Oregon Laws 2009), HB 3690 (Chapter 78, Oregon Laws 2010 Special Session), HB 2893 (Chapter 244, Oregon Laws 2013), and OAR 860-084-0100. **(C)** The pilot provides payments to retail electricity Customers for electricity generated by permanently installed solar photovoltaic energy systems.

AVAILABLE

To Customers with Qualifying Systems (QSs), as defined in ORS 757.360(3)(b), connected to retail Customers' facilities in territory served by the Company.

APPLICABLE

To Customers that have QSs not purchased with state or ETO incentives with installed nameplate generating capacity greater than 10 kW up to and including 100 kW DC where the output is not paid for pursuant to another tariff schedule, that meet the eligibility requirements in OAR 860-084-0120, and where the monthly generation does not exceed Total Monthly Use pursuant to a Solar Photovoltaic Pilot Program and Interconnection Services Agreement (Agreement).

PARTICIPATION

As determined by Commission Order 11-339, the allocated capacity will be divided between the net metering and competitive bidding options. The enrollment windows will alternate between the net metering and bid options.

A Customer who expects to install a medium system under this schedule has the option to submit a bid in the RFP or a capacity application during corresponding open enrollment periods. Submission of a bid or a capacity application does not guarantee participation in the pilot. Successful bidders and Customers awarded capacity will be notified.

(A) Competitive Bid Option – Request for Proposal

The Company will announce an RFP no later than 30 business days before October 1 for each pilot year or as directed by Commission Order 11-339. Participants will have at least 30 days to submit proposals for a QS including the proposed VIR.

SCHEDULE 216 (Continued)

PARTICIPATION (Continued)

(B) Net Metering Option – Capacity Reservation Enrollment

The Company will accept new capacity reservation applications for program participation on April 1 for each pilot year pursuant to Commission Order 11-339 except in 2015 when the enrollment period starts on May 1. Customers may apply online beginning at 8 a.m. If the 1st occurs on a weekend or holiday, the Company will accept applications on the following business day.

Capacity is initially allocated by a 24-hour lottery or as directed by the Commission. After capacity fills remaining Customers will be placed on a waitlist. The waitlist expires at the end of each enrollment period. The enrollment window is open for three months.

If capacity is not filled in the lottery, then capacity is reserved on a first-come, first-served basis.

VOLUMETRIC INCENTIVE RATE

(A) Competitive Bid Option

The Company pays applicable rates to the QS Customer for eligible generation based on a successful bid from the competitive bidding process.

(B) Net Metering Option

If the customer is awarded capacity during open enrollment, the Company pays the applicable gross VIR for eligible generation from the participating Customer with a capacity reservation awarded on or after August 25, 2015. **(C)**

Description	Hood River County	All Other Counties		
Medium is >10 kW - 100 kW DC Nameplate Capacity	26.81	25.26	¢ per kWh	**(I)**

Under the net metering option, the gross VIR applies up to the Total Monthly Use and consists of two components: (1) a retail bill offset based on applicable volumetric (kWh) charges, and (2) a net VIR payment. Kilowatt-hours generated in excess of the Total Monthly Use will be carried forward to the next month as provided in OAR 860-084-0360. Total Monthly Use is defined as net kWh from the retail meter (may be positive or negative) plus kWh from the QS meter.

The rate in place at the time of the Reservation Start Date, defined in OAR 860-084-0010(17), applies to the entire 15-year life of the Agreement.

SCHEDULE 216 (Continued)

VOLUMETRIC INCENTIVE RATE (Continued)
Net Metering Option (Continued)

VIR Adjustment

The Commission may adjust the VIR to be effective on April 1 of each year Consistent with Commission Order Nos. 11-280 and 11-339. For Spring 2015, per OPUC Order 15-092, the enrollment window begins at 8 a.m. on May 1, 2015. Pursuant to Commission Order No. 15-250, the Commission directs that any remaining capacity be distributed to applicants that are already on the waiting list as part of the May 2015 window. Distribution of any remaining capacity of the VIR program will continue until the earlier of March 31, 2016, or the installation of all program capacity (27.5 MW). **(C)** **(C)**

VIR Payments

VIR payments under this pilot occur no later than 45 days from the last day of the Customer's billing period. The VIR payment will be reduced by the amount of the retail bill offset for a net VIR payment. The Customer may choose among three payment options for the net VIR payment:

(1) receive a direct payment,
(2) have payments netted against the Customer's retail bill, or
(3) assign the payment to a single assignee.

Excess Annual Kilowatt-hour Credits

In accordance with OAR 860-084-0360, at the end of the last monthly Billing Period ending on or before the last day of each generation year, any excess generation kWh credits accumulated will be transferred to the Company's low income assistance program at the average annual Schedule 201 Avoided Cost rate. The default generation year is April 1 through March 31. The Customer's excess kWh credits are set to zero for the beginning of the subsequent annual billing cycle.

CUSTOMER COSTS

Capacity Reservation Deposit

The Customer pays a deposit of $500 minimum or $20 per kW of the proposed system capacity at the time of enrollment or bid submission. The deposit is refundable unless the capacity reservation expires or the Customer cancels the reservation, in each case the applicant forfeits the deposit.

Customer Charge

The Customer pays the Company a $10.00 Customer Charge per month for each separately metered QS. This is in addition to the Basic Charge for providing Electricity Service to the Customer. The VIR payment will be reduced by the Customer Charge under this schedule.

SCHEDULE 216 (Continued)

CUSTOMER COSTS (Continued)

Assignment Fee

The Customer may assign the net VIR payment each month to a single assignee and the Company will make the payment to the assignee. A one-time assignment fee of $25 applies for each payment assignment or reassignment.

Interconnection Review Fee

For an interconnection review, a fee may apply as provided in OAR 860-084-0320 and 0330. Other costs may apply for modifications to the electric distribution system or for additional review.

Level 1	No charge applies
Level 2	up to $50.00 plus $1.00 per kW of the Qualifying System's capacity
Level 3	up to $100.00 plus $2.00 per kW of the Qualifying System's capacity

SOLAR PHOTOVOLTAIC PILOT PROGRAM AND INTERCONNECTION SERVICES AGREEMENT

The Customer must execute a Solar Photovoltaic Pilot Program and Interconnection Services Agreement with the Company and meet all criteria under OAR Division 84 – Solar Photovoltaic Programs prior to delivery of power to the Company.

METERING REQUIREMENTS

The Company will install and own the required QS metering equipment at its expense.

(A) Competitive Bid Option

Customers served under this option must be separately metered from all other load and generation and operate in parallel with the Company's distribution system.

(B) Net Metering Option

Customers served under this option must have a PGE-owned meter that measures QS generation net of parasitic load. This meter must be located on the Customer side of the retail meter and on the AC (output) side of the inverter in a location that measures the entire output of the system. The additional meter does not change the Customer's Service Point (SP). **(C)**

SCHEDULE 216 (Continued)

SPECIAL CONDITIONS

1. Division 84 of the Oregon Administrative Rules (OAR) Chapter 860 contains additional details that apply to this pilot.

2. The QS must be constructed from new components and operational no sooner than July 1, 2010.

3. The Customer-generator is responsible for obtaining all necessary government approvals relating to its QS facility and must meet all applicable building codes and standards including standards specified in OAR 860-084-0260.

4. The Customer-generator is responsible for all costs associated with its QS facility, including interconnection costs incurred by the Company, and is also responsible for all costs related to any modifications to the facility that may be required by the Company resulting from the reviews as provided for in OAR 860-084-0310, 0320 or 0330, as applicable.

5. As provided in OAR 860-084-0340 and where applicable, a manual disconnect switch capable of isolating the QS from the Company's system and accessible to the Company at all times must be provided by the Customer-generator.

6. Under the net metering option the estimated kWh output of any QS must not exceed 90% of the actual usage in the most recent 12 billing periods at the premise where the eligible system will be installed. If less than 12 billing periods of actual usage is available at existing premise or new construction, then the annual usage by a similarly situated Customer may be used or a Customer may submit PGE's load estimation document. (T)

7. The Customer is not eligible for service under both this schedule and Schedule 203, Net Metering Service for each separately metered account. Each separately metered retail account may only have one QS meter. A Customer is eligible for additional QSs only if the VIR for the additional QS is the same as the first QS.

8. All renewable energy credits (RECs) or other benefits or allowances for which the QS qualifies or creates under current or future law relating to renewable energy are property of the Company.

9. The Company maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of day.

SCHEDULE 216 (Concluded)

SPECIAL CONDITIONS (Continued)

10. The Company maintains the right to disconnect, without liability, the Customer-generator for issues relating to safety or reliability.

11. The Company will not be liable directly or indirectly for permitting or continuing to allow an attachment of a QS, or for the acts or omissions of the Customer-generator that cause loss or injury, including death, to any third party.

12. Participants are required to meet general liability insurance requirements set forth in applicable Solar Photovoltaic Pilot Program and Interconnection Services Agreements in order to protect against injuries to property or persons caused by the QS. The applicable Agreements contain insurance limits and provisions, as well as the basis for making representations of equivalence.

(D)

TERM

Each Solar Photovoltaic Pilot Program and Interconnection Services Agreement will have a term of 15 years at the applicable VIR. In accordance with OPUC Order No. 14-025, the pilot will (T)
close to new capacity reservations on March 31, 2016, or when the cumulative capacity of
contracted systems in the pilot reaches 27.5 MW AC statewide per OAR 860-084-0150, (T)
whichever comes first.

SCHEDULE 217
SOLAR PAYMENT OPTION PILOT
LARGE SYSTEMS (GREATER THAN 100 kW to 500 kW)

PURPOSE

This schedule establishes a photovoltaic volumetric incentive rate (VIR) pilot program as required by HB 3039 (Chapter 748, Oregon Laws 2009), HB 3690 (Chapter 78, Oregon Laws 2010 Special Session), HB 2893 (Chapter 244, Oregon Laws), and OAR 860-084-0100. The pilot provides payments to retail electricity Customers for electricity generated by permanently installed solar photovoltaic energy systems. Capacity under this schedule is awarded based on an annual competitive bidding process. **(C)**

AVAILABLE

To Customers with Qualifying Systems (QSs), as defined in ORS 757.360(3)(b) located on retail Customers' property in territory served by the Company.

APPLICABLE

To Customers that have QSs not purchased with state or ETO incentives with installed nameplate generating capacity over 100 kW up to and including 500 kW DC where the output is not paid for pursuant to another tariff schedule and that meet the eligibility requirements in OAR 860-084-0120.

MONTHLY RATE

Customer Charge

The Customer pays the Company a $10.00 Customer Charge per month for each separately metered QS.

Volumetric Incentive Rate

The Company pays applicable rates to the QS Customer for eligible generation based on a successful bid from the competitive bidding process.

SOLAR PHOTOVOLTAIC PILOT PROGRAM AND INTERCONNECTION SERVICES AGREEMENT

The Customer must have a successful bid in the Request for Proposal (RFP) process, execute a Solar Photovoltaic Pilot Program and Interconnection Services Agreement with the Company, and meet all criteria under OAR Division 84 – Solar Photovoltaic Programs prior to delivery of power to the Company. The Customer must certify that they eligible to make wholesale sales of energy at market-based rates.

In accordance with terms set out in this schedule and the Commission's Rules as applicable, the Company will provide the Customer with a photovoltaic VIR payment for energy made available from the Customer's QS.

SCHEDULE 217 (Continued)

VIR PAYMENTS

The VIR payment will be reduced by the Customer Charge under this schedule. The Customer may assign the net VIR payment each month to a single assignee and the Company will make the payment to the assignee. A one-time assignment fee of $25 applies for each payment assignment or reassignment.

METERING AND INTERCONNECTION REQUIREMENTS

Customers served on this schedule must be separately metered from all other load and generation and operate in parallel with the Company's distribution system.

REQUEST FOR PROPOSAL

The Company will announce an RFP for each pilot program year. Participants will have at least 30 days to submit proposals for a QS including the proposed VIR.

ANNUAL CAPACITY RESERVATION

The Customer must submit an application package meeting the requirements of OAR 860-084-0230(2). A capacity reservation deposit of $20 per kW of the proposed system DC nameplate capacity is required with the capacity reservation application. The deposit is refundable unless the capacity reservation expires or the Customer cancels the reservation, in each case the applicant forfeits the deposit.

Capacity reservations under this schedule are awarded annually based on competitive bidding. The capacity reservation begins when the bidder is notified of a successful bid. Notification will occur within 15 business days after the bidding response deadline based on least bid VIRs and available capacity.

A capacity reservation expires two months from the Reservation Start Date if an interconnection application is not filed. If an interconnection application has been filed, the capacity reservation expires six months from when the interconnection application is filed or one year from the Reservation Start Date if the system has not been installed, whichever is longer. See OARs 860-084-0195 through 860-084-0230 for additional capacity reservation rules.

ANNUAL CAPACITY RESERVATION LIMITS

The Company will award bids annually up to the periodic available capacity, pursuant to Commission Order 10-198.

SCHEDULE 217 (Continued)

INSURANCE

Participants are required to meet general liability insurance requirements set forth in the applicable Solar Photovoltaic Pilot Program and Interconnection Service Agreements in order to protect against injuries to property or persons caused by the QS. The applicable Agreements contain insurance limits and provisions, as well as the basis for making representations of equivalence.

SPECIAL CONDITIONS

1. Division 84 of the Oregon Administrative Rules (OAR) Chapter 860 contains additional details that apply to this pilot.

2. The QS must be constructed from new components and operational no sooner than July 1, 2010.

3. The Customer-generator is responsible for obtaining all necessary government approvals relating to its QS facility and must meet all applicable building codes and standards including standards specified in OAR 860-084-0260.

4. The Customer-generator is responsible for all costs associated with its QS facility, including interconnection costs incurred by the Company, and is also responsible for all costs related to any modifications to the facility that may be required by the Company resulting from the reviews as provided for in OAR 860-084-0310, 0320 or 0330, as applicable. The Company provides the QS meter.

5. As provided in OAR 860-084-0340 and where applicable, a manual disconnect switch capable of isolating the QS facility from the Company's system must be provided by the Customer-generator and will be accessible to the Company at all times.

6. All renewable energy credits (RECs) or other benefits or allowances for which the QS qualifies or creates under current or future law relating to renewable energy are property of the Company.

7. The Company maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of day.

8. The Company maintains the right to disconnect, without liability, the Customer-generator for issues relating to safety or reliability.

SCHEDULE 217 (Concluded)

SPECIAL CONDITIONS (Continued)

9. The Company will not be liable directly or indirectly for permitting or continuing to allow an attachment of a QS, or for the acts or omissions of the Customer-generator that cause loss or injury, including death, to any third party.

10. The Company will apply the following fees to each QS interconnection application as provided in OAR 860-084-0320, 0330:
    a) For Level 2 interconnection review, $50.00 plus $1.00 per kW of a QS facility capacity.
    b) For Level 3 interconnection review, $100.00 plus $2.00 per kW of a QS facility capacity.
    c) For Level 2 and 3 interconnections, the reasonable costs for additional engineering and Company system modifications.

11. Pursuant to Commission Order No. 14-025, there is no enrollment window in October 2014. However, a new window will start May 1, 2015 to “clean up” the remaining capacity. **(N)**

TERM

Each Solar Photovoltaic Pilot Program and Interconnection Services Agreement will have a term of 15 years at the applicable VIR. In accordance with OPUC Order No. 14-025 The VIR pilot program will close to new capacity reservations March 31, 2016 or when the cumulative capacity of contracted systems in the pilot reaches 27.5 MW AC statewide per OAR 860-084-0150, whichever comes first. **(C)**

SCHEDULE 300
CHARGES AS DEFINED BY THE RULES AND REGULATIONS
AND MISCELLANEOUS CHARGES

PURPOSE

The purpose of this schedule is to list the charges referred to in the General Rules and Regulations.

AVAILABLE

In all territory served by the Company.

APPLICABLE

For all Customers utilizing the services of the Company as defined and described in the General Rules and Regulations.

INTEREST ACCRUED ON NON-RESIDENTIAL CUSTOMER DEPOSITS (See Rules E and K)

4.5% per annum.

BILLING RATES (Rules E, F, H and J)
Trouble call, cause in Customer-owned equipment

Scheduled Crew Hours [(1)]	No charge	
Other than Scheduled Crew Hours [(1)]	$270.00	(I)
Returned Payment Charge	$ 25.00	
Special Meter Reading Charge (non-network)	$ 17.00	
Meter Test Charge	$ 75.00	
Late Payment Charge (monthly)	2.2% of delinquent balance	
Field Visit Charge [(2)]	$ 20.00	
Bill History Information Service Charge (Not applicable when a billing dispute is filed with the Commission - see Rule F)	$ 32.00	
Portfolio Enrollment Charge	$ 5.00	
Customer Interval Data (12 months) to Customers	$100.00	
Customer Interval Data (12 months, formatted and analyzed)	Mutually agreed price	
Switching Fee	$20.00	
Unauthorized Connection of Service / Tamper Fee	$75.00	

(1) Scheduled Crew Hours - The Company's Scheduled Crew Hours for the above listed services are from 7:00 a.m. to 3:30 p.m., Monday through Friday, except for Company-recognized holidays. The Customer will be informed of and agree to the charges before Company personnel are dispatched.
(2) See Rule H, Section 2 for applicable conditions.

SCHEDULE 300 (Continued)

CREDIT RELATED DISCONNECTION AND RECONNECTION RATES (Rule H)

Disconnects		
Monday through Friday	No charge	
Reconnection		
Standard Reconnection		
At Meter Base	$ 27.00	(R)
Other than Meter Base	$ 75.00	
After Hours Reconnection[1]		
At Meter Base	$ 80.00	
Other than Meter Base	$160.00	

CUSTOMER REQUESTED DISCONNECTION AND RECONNECTION RATES (Rule H)[2][3]

Disconnects		
Standard		
At Meter Base	No charge	
Other than Meter Base	No charge	
		(D)
Reconnects		
Standard		
Safety related	No charge	
Non-safety related		
At Meter Base	$ 27.00	(R)
Other than Meter Base	$ 75.00	
		(D)

(1) PGE representatives will be dispatched to reconnect service until 7:00 p.m., Monday through Friday. As such, crews dispatch up to and including 7:00 p.m. may be reconnecting service after 7:00 p.m. State- and utility-recognized holidays are excluded from the after hours provision.

(2) These rates apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In other cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.

(3) No charge for disconnects / reconnects completed to ensure safe working conditions that meet the guidelines in Rule H(4).

SCHEDULE 300 (Continued)

PULSE OUTPUT METERING (Rule M) **(N)**

Installation of Standard Meter Option (1 or 2 outputs)	$ 350.00
Installation of Complex Meter Option (1 – 4 outputs)	$1,300.00 **(N)**

NON-NETWORK RESIDENTIAL METER RATES (Rule M)

Installation of non-network meter (one time charge)	$80.00
Non-network Meter Read	$17.00 per month

METER RELOCATION RATES (Rule M)

Single meter relocation	Estimated Actual Costs
Single meter relocation with Pole	Estimated Actual Costs

MISCELLANEOUS EQUIPMENT RENTAL (Rule C)

Rental of transformers, single-phase to three-phase inverters, capacitors, and other related equipment	1-2/3% per month of current replacement cost at time of installation

TRANSFORMERS (Rule I Section 3)

Submersible Transformers[(1)]

Subdivision - eight dwelling units or more	$ 250.00 per lot $1,970.00 minimum
Mobile Home - eight spaces or more	$ 250.00 per space $1,970.00 minimum
Multi-Family Units - twenty units or more	$ 100.00 per family unit $1,970.00 minimum

(1) For all other applications, which include but are not limited to network service areas and densely populated urban areas, that require submersible transformers, the charge will be the calculated difference in cost between submersible and pad-mount transformer installations including the costs of future maintenance.

SCHEDULE 300 (Continued)

TRANSFORMERS

Transformer Content

Upon request, PGE will research its records to provide a customer with Polychlorinated Biphenyls (PCB) content of a PGE transformer. Records searches could reveal the PCB content in specified transformer or that the PCB content is unknown. In the situation where the PCB content is unknown, an additional request can be made to test the PCB concentration.

Research Transformer PCB Content		
PCB Content-Specific Transformer	$75.00 per Transformer(1)	
Additional Request		
Concentration Test	site-by-site basis(2)	**(T)**

PCB Records Request

To request a records search to determine the PCB content of PGE equipment, please contact PGE's Environmental Services to request a PCB Inquiry form. The form can be sent electronically or by postal service, if needed. Complete the form and return it, along with payment to: PGE PCB Inquiry, 121 SW Salmon Street, WTCBR05, Portland, OR 97204. Checks are made payable to PGE PCB Inquiry and submitted with the PCB Inquiry form.

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(1) PGE transformers often have stickers which indicate the PCB concentration of the oil within that transformer. The Customer may determine the content by observing the sticker. The PCB content of equipment with green stickers is unknown. However, blue stickers indicate <1 parts per million (PPM) PCB, red stickers indicate <15 ppm PCB, and black stickers indicate <48 ppm PCB.

(2) The additional cost of testing PCB concentration is determined on a site-by-site basis, and based on whether the following activities are required: de-energizing equipment, collecting samples, contracting sample analyses, and preparation of a summary report. In some instances, a proposal from a contractor may be required.

SCHEDULE 300 (Continued)

LINE EXTENSIONS (Rule I)

Line Extension Allowance (Section 1)[(1)]

Residential Service All Electric[(2)]	$2260.00 / dwelling unit	
Residential Service Primary Other[(3)]	$1590.00 / dwelling unit	
Schedule 32	$0.2564 / estimated annual kWh	(I)
Schedules 38 and 83	$0.1050 / estimated annual kWh	
Schedules 85 and 89 Secondary Voltage Service	$0.0778 / estimated annual kWh	
Schedules 85 and 89 Primary Voltage Service	$0.0429 / estimated annual kWh	
Schedules 15, 91 and 95 Outdoor Lighting	$0.1529 / estimated annual kWh	(I)
Schedule 92 Traffic Signals	$0.0424 / estimated annual kWh	(R)
Schedules 47 and 49	$0.0980 / estimated annual kWh	(I)

Trenching or Boring (Section 2)

Trenching and backfilling associated with Service Installation except where General Rules and Regulations require actual cost.

In Residential Subdivisions:

Short-side service connection up to 30 feet	$ 100.00
Otherwise:	
First 75 feet or less	$ 219.00
Greater than 75 feet	$ 3.80 /foot

Mainline trenching, boring and backfilling — Estimated Actual Cost

Lighting Underground Service Areas[(4)]

Installation of conduit on a wood pole for lighting purposes — $ 75.00 per pole

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(1) Estimated annual kWh values used to calculate non-Residential Customer line extension allowances do not reflect onsite generation.

(2) Residential All Electric Service is a dwelling where the primary heating is provided by an active electric HVAC-system. Common qualifying system include but are not limited to stand-alone ducted heat pumps, ducted heat pumps with auxiliary electric resistant heat strips, ductless mini-splits, and packaged terminal air conditioners. Electric resistant heat strips, baseboards, and electric resistant in-wall heaters are allowed as back-up heat source. Dwellings heated solely by electric resistance heating systems without a primary qualifying electric heating system are excluded from the Residential All Electric Service Line extension allowance.

(3) Residential Service Primary Other is a dwelling where the primary heating source is provided by an alternative HVAC-system that uses heating fuels such as natural gas, propane, oil, and biodiesel. Common qualifying HVAC-systems include but are not limited to stand-alone combustion furnaces, combustion furnaces with air conditioners, combustion furnaces with heat pumps, as well as gas boilers. Dwellings heated primarily by electric resistance heating and passive means also fall into this category.

(4) Applies only to 1-inch conduit without brackets.

SCHEDULE 300 (Concluded)

LINE EXTENSIONS (Rule I) Continued

Additional Services (Section 3)
(applies solely to Residential Subdivisions in Underground Service Areas)

Service Guarantee	$ 100.00
Wasted Trip Charge	$ 100.00
Service Locate Charge	$ 30.00
Long-Side Service Connection	$ 120.00

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$1077.00	(I)
Permanent Customer obtained		
Overhead Service	$607.00	(I)
Underground Service	$632.00	(I)
Existing service	$819.00	(I)

Enhanced Temporary Service

Fixed fee for initial 6-month period	$865.00	(C)
Fixed fee per 6-month renewal	$354.00	(C)

Temporary Area Lights — Estimated Actual Cost(1)

PGE TRAINING

Educational and Energy Efficiency (EE) training available to:

PGE Business Customer	No Charge(2)
Non-PGE Business Customer	Estimated Actual Cost(3)

(1) Based on install, removal and energy for pole and luminaire. Energy will be calculated based on burning hours used for Option C Schedule 91, 95
(2) Charges may be assessed for training courses registered through the states of Oregon and Washington for electrical licensees.
(3) Based on the cost associated with instructor, facility, food, and materials per attendee.

SCHEDULE 307
RESIDENTIAL BILL ASSISTANCE PROGRAM

PURPOSE

The purpose of this schedule is to implement the Residential Bill Assistance Program consistent with Commission Order No. 20-401. The Order directs Utilities to establish a program to identify and manage residential customer arrearages associated with the COVID-19 pandemic to proactively assist residential customers prior to resuming disconnections and prevent bad debt accumulating on utility accounts.

The program may identify and waive residential arrearages at an initial total amount of $17,557,000. This amount represents one percent of the Company's 2019 Oregon retail revenues, not to be increased without prior Commission approval. The Company is seeking Commission approval to add an additional amount of $6 million in program funds to continue offering the Customer Assistance and Reconnect Assistance, and the revised Extended Match programs described below. **(C)** | **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

This program is only available to Residential Customers.

ELIGIBILITY

The PGE Bill Assistance Program will be eligible to Residential Customers at least 31 days in arrears.

ENROLLMENT

Eligible Residential Customers may enroll in a bill assistance plan by calling PGE Customer Service, Monday through Friday, 7 a.m. to 7 p.m. at 503-228-6322 or 800-542-8818. **(C)**

BILL ASSISTANCE OPTIONS

Several options are available to assist Residential Customers manage bills regardless of account status. The program's intent is to help customers catch up on past due balances or get reconnected if they've been disconnected for non-payment. Programs are designed to match Customer payments anywhere from a one-time match up to a match for 12-months as well as **(C)** provide one-time assistance for those unable to make a payment. The maximum amount of bill **(C)** assistance per Customer is $1,000 for all programs combined, including Customer Assistance. All programs will be available for a limited time based on funding availability. Programs are outlined below:

SCHEDULE 307 (Continued) **(T)**

BILL ASSISTANCE OPTIONS (Continued)

1. 50/50 Plan – One-time Company bill payment to match Customer payment of an equal amount. To qualify, the Customer must be at least 31 days past due on payments. The Company match will not leave a credit on the Customer account. This program will be closed to new entrants after the initial $17.5 million in funding is fully subscribed. **(C)** **(C)**

2. Payment Match –Three-month Company bill payment plan to match Customer payments of equal amounts. To qualify, the Customer must be at least 31 days past due on payments. Matching stops after three months or when total account balance reaches $0. This program will be closed to new entrants after the initial $17.5 million in funding is fully subscribed. **(C)** **(C)**

3. Extended Match Program – Company bill payment plan to match Customer payments for up to 12 months. Customer must enroll in a Time Payment Arrangement (TPA) plan, up to 24-months, to match payments up to the first 12 months of a TPA. To qualify, the Customer must be at least 31 days past due on payments. Matching stops after 12 months, when total account balance reaches $0 or if the Customer is disconnected. Extended Match Program enrollments will end once up to 50% of the additional $6 million funding is allocated or October 31, 2021 which ever happens sooner. **(C)** **(C)**

4. Customer Assistance – One-time Company bill payment, up to $500, to help Customers get current on their balance utilizing an instant grant. This assistance will be made available to Customers who are unable to get current without assistance. This assistance will also cover any remaining Customer balance after receiving energy assistance, up to $500. Customer Assistance funds will not leave a credit on the account. **(C)** **(C)**

5. Reconnect Assistance – One-time Company bill payment, up to $500, to assist in reconnecting disconnected Customers. Company will also offer enrollment in TPA plan up to one year. Customers that used one of the other options previously are eligible. **(C)**

(M)

SCHEDULE 307 (Concluded)

SPECIAL CONDITIONS **(M)**

1. The Company will defer and seek recovery of all associated program costs not otherwise included in rates in accordance of Commission Order No. 20-376. The additional $6 million in funding is also subject to deferred accounting and will be added to the balance of COVID-related deferred costs. **(C)** **(C)**

2. Additional programs or adjustments to the programs listed above may occur as we develop experience in operating these programs, upon Commission approval.

3. In addition to the reporting requirements outlined in Commission Order No. 20-401, the Company will provide quarterly reporting on the amount of assistance that has been provided and the number of customers enrolled by program, including cost to operate the program. Additional reporting may be provided as determined by the Commission.

TERM

The duration of this program is through December 31, 2022, until the Company reaches the spending limit, or until the Commission closes the program. **(M)**

SCHEDULE 320
METER INFORMATION SERVICES

PURPOSE

This schedule provides Meter Information Services to Nonresidential Customers, and with customer permission, to Energy Trust of Oregon (ETO). (T) (T)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers and ETO. (T)

PROGRAM DESCRIPTION

Meter Information Services provides Nonresidential Customers with interval usage data. By enrolling in the Company's meter information services program, customers have 24/7 access to a technology platform that enables visualization, exporting, analyzing, and reporting on energy use information. Nonresidential Customers can compare their current usage with historic data, identify anomalies in their usage, track savings from energy efficiency projects and understand their energy usage. Additionally, PGE offers utility billing information within the same software platform. (C) (C)

Nonresidential Customers requesting service under this schedule must have the ability to access the appropriate website URL. The Company will advise the Customer and ETO on equipment specifications and subsequent changes necessary to meet these service requirements. (C) (C)

BILLING RATES

Meter Information Services is billed monthly on the Customer's bill for Electricity Service. Energy Trust will be billed through the Company's miscellaneous Accounts Payable process for FTP meter services rendered. (C) (C)

SCHEDULE 320 (Continued)

BILLING RATES (Continued)

Standard Package

Set Up Fee*:	$350.00 for the first meter	
	$160.00 for each additional meter	(I)
	$80.00 for 50 or more meters	(I)
	Set-up fees are waived for ETO or if a customer is transferring from a product that is no longer offered.	(C) (C)

Monthly Fees per meter:		
1 to 5 meters	$75.00	(I)
6 to 10 meters	$70.00	
11 to 15 meters	$65.00	
16 to 20 meters	$60.00	
21 to 49 meters	$55.00	
50 or more meters	$50.00	(I)

Additional Customer Support or Training: $125.00 per hour

Customized service, data, and hardware, including but not limited to Data loggers, Data Recorders, Energy Kiosks, Natural gas data, Interval Data via File Transfer Protocol (FTP) to Third Party*, and Raw Feeder Data may be provided at a mutually agreed, cost-based price. (T)

SPECIAL CONDITIONS

1. Customers who request service both inside and outside of the service territory will have all Service Points (SPs) receiving service on this Schedule, added together to determine the appropriate monthly rate per meter.

2. Service under this schedule requires interval metering and meter communications be in place prior to the initiation of Meter Information Services.

3. Because of the meter and/or software installation required for this service, if a meter needs to be replaced, installed, or otherwise modified, delays can occur from the time a Customer requests service under this Schedule, until the Company can provide it. (C)

(M)

* No set-up fees are charged for Interval Data via FTP to Third Party. FTP is used to send/receive files from a remote computer. See Special Condition 10. (C)

SCHEDULE 320 (Concluded)

SPECIAL CONDITIONS (Continued)

4. Meter Information Services requires that the Customer have certain minimum computer system requirements and an ability to capture and transmit interval usage data. Specifications will be provided upon request. The Customer will, at its expense, provide the necessary communications equipment. **(M)** **(M)**

5. ETO will be supplied data only after the Customer provides to the Company a signed release form by the Customer giving ETO access to interval data, account information, and software application. ETO will also complete a Data Share Request Form specifying price, billing, and duration of service. **(T)** **(T)** **(C)** **(C)**

6. ETO purchases meter data made available via FTP and is not enrolled in the Company's Meter Information Services program. ETO does not pay set-up fees, only monthly meter fees for usage data. **(N)** **(N)**

7. Customers may request a submeter be installed for the purpose of receiving Meter Information Services from a specified location behind the Company meter. However, the feasibility of installing a submeter will be at the Company's discretion. Customers choosing submetering will incur charges for all associated labor and materials needed to install the meter. The Customer is responsible for ownership and maintenance of the submeter. **(T)**

8. This product is provided in accordance with the Code of Conduct as set forth in OAR 860-038-0500 through 860-038-0640 with the exception of OAR 860-38-0540 with which the Company received a waiver from the Commission. The waiver will be reconsidered, if justified, based on an examination of inquiries from competitors or potential competitors. **(T)**

9. The Company will disclose to Customers, in any written or electronic marketing communications of more than minor length, that the Customer may procure similar services from other providers. **(T)** **(T)**

10. Interval Data via FTP to Third Party, with the exception of ETO, is not being offered at this time. The Interval Data via FTP will still be available to those customers receiving service as of September 29, 2017. The Interval Data is closed to new service during the implementation of the new Customer Information System (CIS) and meter data management system (MDMS). **(C)**

SCHEDULE 328
CLEAN FUELS CREDIT MONETIZATION OPTIONAL SERVICE

PURPOSE

To support customer participation in Transportation Electrification and facilitate access to State of Oregon’s Clean Fuels Program (CFP) administered under Oregon Administrative Rules Chapter 340, Division 253 by offering CFP credit monetization services.

AVAILABILE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers who are eligible CFP credit generators under Oregon Department of Environmental Quality (DEQ) rules.

CHARACTER OF SERVICE

The Company, or its representative, will monetize CFP credits (credits) for Customers. The service includes: calculation of carbon intensity of fuel supply; equipment registration; as well as credit aggregation, credit claiming, credit transfer, credit tracking, and credit reporting for base credits, incremental credits, and advance credits in compliance with Oregon’s CFP rules and regulations.

RATES FOR SERVICE

PGE will charge the participating Customer all applicable transaction fees, plus an administrative fee that covers the utility's administrative costs associated with DEQ compliance and monetizing credits. The administrative fee is calculated based on fleet vehicle size, vehicle type, number of chargers, charger utilization, and quantity of credits sold, and will be charged on a nondiscriminatory basis to participating customers, based on those factors.

SPECIAL CONDITIONS

1. PGE will monetize credits on behalf of the Nonresidential customer that has signed a contract, by leveraging PGE’s existing market and Clean Fuels compliance infrastructure.

2. PGE makes no guarantee as to a certain monetized value of the CFP credits. PGE is not responsible for market fluctuations which may affect credit value or amounts.

SCHEDULE 328 (Concluded)

SPECIAL CONDITIONS (Continued)

3. The administrative fee is designed to include all administration expenses, including, but not limited to: DEQ registration, data pulls, data reporting, market transaction cost, record keeping, billing, management and providing Internal Revenue Service tax reporting information. PGE will update fees as needed to appropriately reflect the costs associated with this service.

4. The administrative fee will be applied after CFP credit sales, and on no less than an annual basis. PGE will remit to the customer the net amount after the administrative fee is deducted.

SCHEDULE 339
ON-BILL LOAN REPAYMENT SERVICE
CLEAN ENERGY WORKS OF OREGON PROGRAM

PURPOSE

This schedule describes the general terms of the On-Bill Loan Repayment Service that PGE will provide in support of the Energy Efficiency and Sustainable Technologies Act of 2009 (EEAST) legislation (HB2626) and offered by Clean Energy Works Oregon (CEWO). The program will enable homeowners to access low-interest; long-term financing for energy efficiency measures with repayment of the Loan using PGE's On-Bill Loan Repayment Service. Loan repayment amounts will be included and separately stated on the participating Customer's Electricity bill.

AVAILABLE

To all participating Customers served by the Company within its Service Territory.

APPLICABLE

To the primary Customer of Record of any owner-occupied electrically heated single family premises participating in the Clean Works of Oregon program and agreeing to utilize the Company's Electricity bill for repayment of the Loan amount. Participation is dependent on the Customer having continuous Electricity Service with the Company during the period the bill is used for repayment of the loan.

SERVICE DESCRIPTION

CEWO will act as a coordinator between utilities, Energy Trust of Oregon, and financing organizations. PGE will exchange data, submit invoices for services rendered, and remit loan payments received to CEWO. CEWO will in turn communicate with the various financing organizations.

The On-Bill Loan Repayment Service provides limited billing and remittance activity as described in this Schedule.

The On-Bill Loan Repayment Service:

The Company will add to a participating Customer's Electricity bill a separately stated fixed Loan repayment amount as determined by CEWO and communicated to the Company. The On-Bill Loan Repayment Service will remain in effect on a Customer's account until such time that the Company receives notice from CEWO to discontinue the repayment item, or that the repayment obligation is satisfied, or if Electricity Service at the premises is terminated (whether such termination is initiated by the Company or by the Customer of Record), or if payment for this On-Bill Loan Repayment Service is not received by the Company.

SCHEDULE 339 (Continued)

SERVICE DESCRIPTION (Continued)

CEWO is responsible for qualifying Customers for loans and establishing a contractual relationship with the Customer for repaying the Loan. CEWO will obtain and provide upon request to the Company, the participating Customer's written authorization that allows the repayment amount to be placed on the Customer's Electricity bill and authorizes the Company to share the participating Customer's account payment history and credit activity with CEWO on an as needed, ongoing basis.

The On-Bill Loan Repayment Service program is offered with the following understanding:

Related to the Participating Customer:

1. The Customer's decision to enter into a Loan agreement with CEWO will not affect his/her ability to establish credit with the Company; nor impact the deposit amount that the Customer may be required to pay, or affect the Customer's ability to receive reliable Electricity Service.

2. Customer payments remitted to the Company shall first be applied to those charges related to the provision of Electricity Service and other related services billed to the Customer consistent with the Company's tariff[1]. Any underpayment of the monthly loan amount will be added to the subsequent bill. Overpayments received by the Company will not be applied to the CEWO Loan balance, nor will refunds be issued. The overpayment will be applied towards Electricity Service charges in the same posting priority as defined within the Company's tariff[2].

3. The Company will not disconnect a Customer's service for non-payment of the CEWO Loan amount. The Company retains all rights and responsibilities regarding the provision of Electricity Service separate from the CEWO Loan Repayment including disconnection for non-payment of Electricity Service charges.

4. Time Payment Agreements or other payment arrangements will not be available for the CEWO Loan amount, nor will Energy Assistance payments be applied to this Service.

5. Delinquency Conditions: The Company will not provide a collections service for delinquent CEWO Loan amounts, provide past due notices or disconnection of service for non-payment or late payment of these loans, nor will the Company assess, or collect, late fees on the Loan balance for CEWO. A return check charge as provided in Schedule 300 will be applied to any payment returned by a financial institution.

1) Rule F, Billings, (5), Presentation and Payment of Bills
2) Should the overpayment be equal to that of the remaining CEWO Loan balance, the Company may issue a refund and advise the Customer to contact the lending agent CEWO on proper loan pay-off procedures.

SCHEDULE 339 (Continued)

SERVICE DESCRIPTION (Continued)

6. If the Customer sells the property, the loan will revert to CEWO and its financing organization. CEWO may work with the new homeowner to continue the loan; if the new homeowner is willing to continue the loan CEWO and PGE will treat this as a new loan for future use.

Related to the CEWO:

1. The Company will not seek to recover incremental costs associated with this program from its Customers. All programming costs, credit searches, loan set up costs and marketing costs that the Company incurs are the sole responsibility of CEWO.

2. The Company will transfer to CEWO on-going remittance via an agreed means not less than on a monthly basis that includes the aggregate amount of all CEWO repayment amounts received during the previous month, a listing of participating Customers, payment amounts and dates of payment and other information as agreed to between the Company and CEWO.

3. Any Customer payment transferred by the Company to CEWO that is later returned by the Customer's financial institution will be withheld from the subsequent payment to CEWO. CEWO may not assess a return payment fee to the Company.

4. The Company will not transfer a CEWO Loan to another Customer without first receiving notification from CEWO that a new qualifying Customer at the premises has established a contract with CEWO for repayment of the CEWO Loan and has authorized the Company to provide the On-Bill Loan Repayment Service.

5. Dispute Resolution: CEWO must provide the Company with a toll-free customer service phone number to which the Company can refer Customers who have questions or concerns about their CEWO Loan. The Company is not responsible for responding to Customer questions and disputes related to CEWO or for any misinformation provided by CEWO.

SPECIAL CONDITIONS

1. Participating Customers shall acknowledge that the Company will be held harmless from any cost, liability, claim, suit and expense arising out of any act or omission of the CEWO, its financing organizations or contractors related to the installation of energy efficiency measures, the effectiveness of such installations or resulting energy or financial savings, any representations made directly or indirectly to Customers concerning energy usage, environmental impacts, property values or other effects or savings related to the energy efficiency measures, including but not limited to the negligent or wrongful acts or omissions of contractors with regard to the installation of energy efficiency upgrades resulting from or related to this repayment activity.

SCHEDULE 339 (Concluded)

SPECIAL CONDITIONS (Continued)

2. The provision of repayment services provided by the Company will not affect the Company's adherence to Utility Regulation and law, Oregon Administrative Rules or Division 21 rules and regulation.

3. The Company may withdraw from providing repayment loan activity at any time after receiving three months written notice by CEWO. If notice to terminate has not been provided, service under this Tariff will automatically terminate once CEWO has terminated their Operating Agreement with the Company.

4. The standards and requirements under PGE's Customer Service and Billing Service Quality Measures shall not apply with respect to bills and remittances related to this repayment loan activity.

TERM

This tariff will be in effect through December 31, 2012 or through such time that Legislation either terminates or changes the requirements regarding this Service.

SCHEDULE 340
ON-BILL REPAYMENT SERVICE
ENERGY EFFICIENCY AND SUSTAINABLE TECHNOLOGIES (EEAST)

PURPOSE

This Schedule describes the general terms of the On-Bill Repayment Service that PGE provides in compliance with the Energy Efficiency and Sustainable Technologies (EEAST) legislation codified as ORS 470.500 through ORS 470.720. This Service will enable Customers access to low-cost, long-term financing for installed energy efficiency measures with repayment on the Customer's PGE Electricity bill. Financing for the Customer's energy efficiency measures is provided by a third party financial institution. The Customer's repayment amount will be included and separately stated on the participating Customer's Electricity bill.

AVAILABLE

To participating Customers of owner occupied buildings where the primary source of heat is Electricity provided by the Company.

APPLICABLE

To Customers who have obtained an energy efficiency loan offered through programs managed by the Energy Trust of Oregon (Energy Trust) that include PGE's On Bill Repayment Service (EEAST loan).

SERVICE DESCRIPTION

Energy Trust of Oregon will offer financing to participating Customers and will act as a program coordinator. PGE will bill repayment of the EEAST loan offered by the Energy Trust on the participating Customer's Electricity bill. PGE will then remit the collected Customer repayments received to Energy Trust of Oregon or financial institution designated by the Energy Trust and communicated to PGE in writing.

Energy Trust of Oregon, through its contracted financial institution, is responsible to qualify Customers for the repayment service and establish a contract with the Customer for repaying the EEAST loan. Energy Trust of Oregon will obtain and provide to the Company, the participating Customer's written authorization that allows the repayment amount to be placed on the Customer's Electricity bill and for the Company to share the participating Customer's account payment and credit history with Energy Trust of Oregon as needed, on an ongoing basis.

SCHEDULE 340 (Continued)

SERVICE DESCRIPTION (Continued)

The On-Bill Repayment Service program is offered with the following understanding:

Related to the Participating Customer:

1. A Customer's participation in the On Bill Repayment Service will not affect the Customer's OAR Chapter 860, Division 21 rights and responsibilities or the Company's compliance with Division 21 rules. For example, the Company will not disconnect a Customer's service for non-payment of the EEAST loan repayment amount. The Customer's participation in the On Bill Repayment Service will not affect the Customer's ability to establish credit, impact the deposit amount the Customer may be required to pay, or otherwise affect the Customer's ability to receive reliable Electricity Service with the Company.

2. By securing an EEAST loan, the Customer will be responsible to remit the monthly EEAST loan repayment amount to PGE with the monthly bill payment for Electricity Service.

3. Customer payments remitted to the Company shall first be applied to those charges related to the provision of Electricity Service and other related services billed to the Customer consistent with the Company's tariff[1]. Overpayments received by the Company will not be applied to the EEAST loan balance, nor will refunds be issued. The overpayment will be applied towards Electricity Service charges in the same posting priority as defined within the Company's tariff[2].

4. Time Payment Agreements or other payment arrangements will not be available for the EEAST loan repayment amount, nor will Energy Assistance payments be applied to the EEAST loan repayment amount.

5. Delinquency Conditions: If a customer is seventy five (75) calendar days past due on their EEAST loan payment, the Company will notify the Energy Trust and no longer provide the On Bill Repayment Service to the customer if the EEAST loan remains past due. If the EEAST loan payment is more that ninety (90) calendar days past due, the Company will remove the Customer from the On Bill Repayment Service without notice to the Energy Trust or the Customer. A return check charge as provided in Schedule 300 will be applied to any payment returned by a financial institution.

1) Rule F, Billings, (5), Presentation and Payment of Bills
2) Should the overpayment be equal to that of the remaining EEAST Loan balance, the Company may issue a refund and advise the Customer to contact the Energy Trust on proper loan pay-off procedures.

SCHEDULE 340 (Continued)

SERVICE DESCRIPTION (Continued)

6. As the EEAST loan is specific to the Customer and the premises, if the Customer sells the property, the loan will revert to Energy Trust, and/or its financing organization. Energy Trust may work with the new owner to continue the repayment obligation; if the new owner is willing to continue the EEAST loan repayment obligation, the Energy Trust and PGE will treat this as a new EEAST loan.

<u>Related to the Energy Trust of Oregon:</u>

1. Energy Trust will reimburse Company for all costs related to Company's administration of this On Bill Repayment Service. The Company will bill Energy Trust for ongoing administrative costs, including costs associated with programming, credit searches, repayment set up, repayment termination, and other incremental activities related to processing bill payments, accounting and reporting. The Company will not seek to recover any incremental costs associated with this program from Customers. The business relationship between the Energy Trust and Company will be governed by an executed operating agreement.

2. The Company will transfer to the Energy Trust, on a monthly basis, a remittance that includes the aggregate amount of all EEAST loan repayment amounts received during the previous month, a listing of participating Customers, payment amounts and dates of payment and other information as agreed to between the Company and Energy Trust.

3. If any Customer payment transferred by the Company to Energy Trust or its designee is later reversed or payment declined because the Customer has insufficient funds with its bank or financial institution, the Company shall not be responsible for a return payment fee to the Energy Trust or its designee.

4. Upon receipt of written notice of a change in ownership of the premises of a participating Customer, the Company will not include repayment amounts on the Electricity bill for the new owner of the premises without first receiving written notification from Energy Trust of the following: a) a new qualifying Customer at the premises has established a contract for repayment of the payment obligation, b) written authorization from the new owner of the premises that allows the repayment amount to be placed on the new qualifying Customer's Electricity bill, and c) authorization for the Company to share the new qualifying Customer's account payment history and credit activity with the Energy Trust.

5. Dispute Resolution: Energy Trust must provide the Company with a toll-free Customer Service phone number to which the Company can refer Customers who have questions or concerns about their EEAST loan repayment obligation. The Company is not responsible for responding to Customer questions and disputes related to EEAST loan or for any misinformation provided by Energy Trust.

SCHEDULE 340 (Concluded)

SPECIAL CONDITIONS

1. PGE is acting as a billing agent for Energy Trust. By participating as billing agent, Customer agrees to hold the Company harmless from any cost, liability, claim, suit and expense arising out of any act or omission of Energy Trust, or its designee, its financing institutions, or contractors related to the installation of energy efficiency measures or upgrades, the effectiveness of such installations or resulting energy or financial savings, or any representations made directly or indirectly to Customer concerning energy usage, environmental impacts, property values or other effects or savings related to the energy efficiency measures. In addition, Customer agrees to hold the Company harmless from any action the Company may take in reliance on information provided to the Company by Energy Trust or associated financing institutions.

2. The service quality standards and requirements under the Oregon Administrative Rules for Customer Service shall not apply with respect to bills and remittances related to this EEAST On Bill Repayment service.

3. As a condition of participation in this Schedule 340 On Bill Repayment Service, participating customers must participate in the Company's auto pay program in which the Customer's electricity bill is automatically paid from the Customer's bank account. The Customer receives a monthly statement noting charges due, in advance of the due date, and the amount due is automatically withdrawn from the Customer's bank account when due. For more information, Customer is directed to http://www.portlandgeneral.com/ebill/autopay.aspx.

TERM

This Schedule will be in effect until one of the following occurs: the Energy Trust /PGE operating agreement is terminated; all participating Customers have fully repaid their respective repayment obligations; or OPUC waiver, legislation, or judicial order terminates or materially changes the requirements of this Service.

SCHEDULE 341

ENERGY EFFICIENCY UPGRADE
VOLUNTARY ON-BILL REPAYMENT SERVICE

PURPOSE

This Schedule describes the general terms of the On-Bill Repayment Service that allows Customers, who have obtained energy efficiency upgrade financing offered through programs managed by the Energy Trust of Oregon, with repayment of the financed amount on the Customer's Electricity bill. This Service enables Customers access to low-cost, long-term financing provided by a third party financial institution for installed energy efficiency measures with the repayment amount included and separately stated on the participating Customer's Electricity bill as "Energy Upgrade Loan."

AVAILABLE

To Owners, who are the Customer of Record, of dwellings and/or buildings where Electricity is provided by the Company.

APPLICABLE

To Customers who have obtained an energy efficiency loan offered through programs managed by Energy Trust.

SERVICE DESCRIPTION

Energy Trust, will offer financing provided by a third party financial institution to participating Customers and will act as a program coordinator. PGE will bill repayment of the loan offered by the Energy Trust on the participating Customer's Electricity bill. PGE will then remit the collected Customer repayments received to Energy Trust or financial institution, designated by the Energy Trust, and communicated to PGE in writing.

Energy Trust through a third party with which Energy Trust contracts, is responsible to qualify Customers for the loan and repayment service and establish a contract with the Customer for repaying the loan. Energy Trust will obtain and provide to the Company, the participating Customer's written authorization that allows the repayment amount to be placed on the Customer's Electricity bill and for the Company to share the participating Customer's account payment and credit history with Energy Trust as needed, on an ongoing basis.

SCHEDULE 341 (Continued)

The On-Bill Repayment Service program is offered with the following understanding:

Related to the Participating Customer:

1. A Customer's participation in the On-Bill Repayment Service will not affect the Customer's OAR Chapter 860, Division 21 rights and responsibilities or the Company's compliance with Division 21 rules. For example, the Company will not disconnect a Customer's service for non-payment of the loan repayment amount. The Customer's participation in the On-Bill Repayment Service will not affect the Customer's ability to establish credit with the Company, impact the deposit amount the Customer may be required to pay, or otherwise affect the Customer's ability to receive reliable Electricity Service provided by the Company.

2. By participating in this service, the Customer is responsible to remit the monthly loan repayment amount to PGE in addition to the monthly Electricity Service payment.

3. Customer payments remitted to the Company shall first be applied to those charges related to the provision of Electricity Service and other related services billed to the Customer consistent with the Company's tariff[1]. Overpayments received by the Company will not be applied to the loan balance, nor will refunds be issued. The overpayment will be applied toward Electricity Service charges in the same posting priority as defined within the Company's tariff[2].

4. Time Payment Agreements or other payment arrangements are not available for the repayment amount, nor will Energy Assistance payments be applied to the repayment amount.

5. Delinquency Conditions: If a customer is seventy-five (75) calendar days past-due on their loan payment, the Company will notify the Energy Trust through the third party with which Energy Trust contracts as their designated on-bill administer that the Company will no longer provide the On-Bill Repayment Service to the customer if the loan remains past due. If the loan payment is more that ninety (90) calendar days past due, the Company will remove the Customer from the On-Bill Repayment Service without notice to the Energy Trust or the Customer. A return check charge as provided in Schedule 300 will be applied to any payment returned by a financial institution.

6. As the loan is specific to the Customer and the premises, if the Customer sells the property, the loan will revert to Energy Trust, and/or the third party with which Energy Trust contracts. Energy Trust may work with the new owner to continue the repayment obligation; if the new owner is willing to continue the loan repayment obligation, the Energy Trust and PGE will treat this as a new loan.

1) Rule F, Billings, (5), Presentation and Payment of Bills
2) Should the overpayment be equal to that of the remaining Loan balance, the Company may advise the Customer to contact the Energy Trust on proper loan pay-off procedures.

SCHEDULE 341 (Continued)

Related to the Energy Trust of Oregon:

1. Energy Trust will reimburse Company for all costs related to Company's administration of this On-Bill Repayment Service. The Company will bill Energy Trust for ongoing administrative costs, including costs associated with programming, credit searches, repayment set up, repayment termination, and other incremental activities related to processing bill payments, accounting and reporting. The Company will not seek to recover any incremental costs associated with this program from Customers. The business relationship between the Energy Trust and Company will be governed by the On-Bill Repayment Service Operating Agreement for non-EEAST Programs between Portland General Electric and the Energy Trust of Oregon.

2. The Company will, on a monthly basis, transfer to the Energy Trust or its designated third party on-bill repayment administrator, a remittance that includes the aggregate amount of loan repayments received during the previous month. The remittance will include a list of participating Customers, payment amounts, dates of payment, and other information as agreed by the Company and Energy Trust.

3. If any Customer payment transferred by the Company to Energy Trust or its designee is later reversed or payment declined because the Customer has insufficient funds with its bank or financial institution, the Company shall not be responsible for a return payment fee to the Energy Trust or its designee.

4. Upon receipt of written notice of a change in ownership of the premises of a participating Customer, the Company will not include repayment amounts on the Electricity bill for the new owner of the premises without first receiving written notification from Energy Trust of the following: a) a new qualifying Customer at the premises has established a contract for repayment of the payment obligation, b) written authorization from the new owner of the premises that allows the repayment amount to be placed on the new qualifying Customer's Electricity bill, and c) authorization for the Company to share the new qualifying Customer's account payment history and credit activity with the Energy Trust.

5. Dispute Resolution: Energy Trust must provide the Company with a toll-free Customer Service phone number to which the Company can refer Customers with questions or concerns. The Company is not responsible for responding to Customer questions and disputes related to the loan or for any misinformation provided by Energy Trust.

SCHEDULE 341 (Concluded)

SPECIAL CONDITIONS

1. PGE is acting as a billing agent for Energy Trust. By participating as billing agent, Customer agrees to hold the Company harmless from any cost, liability, claim, suit and expense arising out of any act or omission of Energy Trust, or its designee, its financing institutions, or contractors related to the installation of energy efficiency measures or upgrades, the effectiveness of such installations or resulting energy or financial savings, or any representations made directly or indirectly to Customer concerning energy usage, environmental impacts, property values or other effects or savings related to the energy efficiency measures. In addition, Customer agrees to hold the Company harmless from any action the Company may take in reliance on information provided to the Company by Energy Trust or associated financing institutions.

2. The service quality standards and requirements under the Oregon Administrative Rules for Customer Service shall not apply with respect to bills and remittances related to this On-Bill Repayment Service described herein.

3. As a condition of participation in this Schedule 341 On-Bill Repayment Service, participating Customers must participate in the Company's auto pay program in which the Customer's electricity bill is automatically paid from the Customer's bank account when due. The Customer receives a monthly statement noting charges due in advance of the due date and that amount automatically withdrawn from the Customer's bank account when due. For more information, Customer is directed to http://www.portlandgeneral.com/ebill/autopay.aspx.

TERM

This Schedule will be in effect until one of the following occurs: the On-Bill Repayment Service Operating Agreement for the non-EEAST Programs between Portland General Electric and the Energy Trust of Oregon is terminated; all participating Customers have fully satisfied their respective loan obligations; or OPUC waiver, legislation, or judicial order terminates or materially changes the requirements of this Service.

SCHEDULE 402
PROMOTIONAL CONCESSIONS
RESIDENTIAL PRODUCTS AND SERVICES

PURPOSE

This schedule describes the Company's promotional concession program for enhancing the purchase of products and services.

APPLICABLE

To Residential Customers, qualified engineers, equipment vendors, installers, builders, contractors, and to commercial Customers for residential-type appliances, products, and services.

DESCRIPTION OF CONCESSION

From time to time, the Company will provide incentives to promote the purchase and installation of selected electrical appliances, products, and services. Incentives may include, but are not limited to, contests, discounts, rebates, gift certificates, free merchandise, etc.

In compliance with OAR 860-026-0025, the Company will submit a description of each concession to the Commission. In addition, the Company will furnish a copy of the description to any other energy utility providing service in any portion of the Company's service territory.

EXPIRATION / REVIEW DATE

This program will be offered as necessary to encourage installation of energy-efficient appliances and products, and support the introduction of new products and services.

ACCOUNTING TREATMENT

Project costs associated with selling and promoting Company products and services will be assigned to FERC Account 416.0 (Costs and Expenses of Merchandising). Other costs will be **(T)**
assigned to FERC Account 426.5 (Other Income Deductions). **(T)**

SCHEDULE 485
LARGE NONRESIDENTIAL
COST OF SERVICE OPT-OUT
(201 - 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per SP*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$810.00	$770.00	
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.24	$3.21	
Over 200 kW	$2.04	$2.01	
per kW of monthly On-Peak Demand	$1.47	$1.46	
System Usage Charge			
per kWh	0.144 ¢	0.144 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 485 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's SPs under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

SCHEDULE 485 (Continued)

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that their facility capacity falls below 201 kW, the customer will be moved to an otherwise applicable rate schedule.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly On-Peak Demand (in kW) will be 100 kW for primary voltage service.

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

LOSSES

The following adjustment factors will be used where losses are to be included in the Energy Charges:

Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments applicable to this schedule are summarized in Schedule 100.

SCHEDULE 485 (Continued)

(T)

SPECIAL CONDITIONS (M)

Customers selecting this schedule must enter into a written service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the minimum Five-Year Option during Enrollment Periods* A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service under the minimum Five-Year Option subsequent to Enrollment Period* L must provide not less than three years notice to terminate service under this schedule. Such notices will be binding. (T) (T)

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule. (M)

(N)

* A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 485 (Concluded) **(T)**

SPECIAL CONDITIONS (Continued) **(M)**

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. **(T)**
Customers enrolled for service during Enrollment Periods* A through L must give the Company not less than two years notice to terminate service under this schedule. **(T)**
Customers enrolled for service subsequent to Enrollment Period* L must give the Company not less than three years notice to terminate service under this schedule. Such notices will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule. **(M)**

(N)

* A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 489
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW more than once within the preceding 13 months and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per SP*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$5,290.00	$3,640.00	$5,580.00	
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.33	$1.32	$1.32	
Over 4,000 kW	$1.02	$1.01	$1.01	
per kW of monthly On-Peak Demand	$1.47	$1.46	$0.46	
System Usage Charge				
per kWh	0.111 ¢	0.112 ¢	0.112 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's SPs under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

SCHEDULE 489 (Continued)

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option during Enrollment Periods* A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service under the minimum Five-Year Option subsequent to Enrollment Period* L must provide not less than three years notice to terminate service under this schedule. Such notices will be binding.

* A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 489 (Continued)

(D)
(M)

SPECIAL CONDITIONS (Continued)

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill. (M)

(T)

SCHEDULE 489 (Concluded)

TERM (M)

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers enrolled for service during Enrollment Periods* A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service subsequent to Enrollment Period* L must give the Company not less than three years notice to terminate service under this schedule. Such notices will be binding. (T) (T)

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule. (M)

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* A list of Enrollment Periods can be found in Schedule 129. (N)

SCHEDULE 490
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window*** enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to this and Schedules 485, 489, 490, 491, 492, and 495. Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges per SP*:

	Delivery Voltage		
	Primary	Subtransmission	
Basic Charge	\$21,000.00	\$21,000.00	
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	\$1.64	\$1.64	
Over 4,000 kW	\$1.33	\$1.33	
per kW of monthly on-peak Demand	\$1.46	\$0.46	
System Usage Charge			
per kWh	0.038 ¢	0.038¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 490 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's SPs under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

SCHEDULE 490 (Continued)

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Subtransmission Delivery Voltage	1.0416	(I)
Primary Delivery Voltage	1.0530	(I)
Secondary Delivery Voltage	1.0640	(R)

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

SCHEDULE 490 (Concluded) (T)

SPECIAL CONDITIONS (Continued) (T)

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer. (M)

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule. (M)

SCHEDULE 491
STREET AND HIGHWAY LIGHTING
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments with no fewer than 30,000 lights purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE’s Customer Service or PGE’s Outdoor Lighting Services [1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE’s Outdoor Lighting Services at 503-736-5710, PGE’s Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 491 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option A - Luminaire (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer.

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation and luminaire replacement schedule.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs (1), in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Maintenance under Option B luminaires specifically does not include replacement of failed or failing ballasts or replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. This exclusion does not include replacements of Power Doors where the Customer is qualified and paying the applicable Cobrahead Power Door rate. In addition, Maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to page 591-6 of this Schedule.

SCHEDULE 491 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option B - Luminaire (continued):

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable.

Without obligation or notice to the Customer, individual lamps will be replaced on burnout as soon as reasonably possible subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services [1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of certain failed parts including the lamp, power door (if applicable), photoelectric controller, starter and lens. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company's schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 491 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company.

Maintenance Service under Option C

The Company does not maintain Customer-purchased lighting when mounted on Customer-owned poles. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Option B to Option C Luminaire Conversion and Future Maintenance Election

1. The Company will, with not less than 180 days written notice from the Customer (the requesting municipality) and subject to completion of all conditions necessary to finalize such election, convert the entirety of the Customer's lighting service under Option B luminaire lighting rates to the equivalent Option C luminaires lighting rates (with respect to Monthly kWh usage) including Option B luminaires attachment to Company-owned poles.

2. Upon such conversion, the Customer will assume all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires. The Customer may not require that the Company provide new Option B lighting following the conversion to Option C luminaires. The Customer must notify and inform all affected residents of the conversion that all maintenance and repair services are the sole responsibility of the Customer, and not the Company.

The Customer may choose the Schedule 91 Option B to Schedule 95 Option C Luminaire Conversion and Future Maintenance Election as described in Schedule 95 if converting to Schedule 95 Option C luminaires and the above notice has not been given.

SCHEDULE 491 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

Option A provides for Company purchased and owned streetlight poles.

Pole Maintenance under Option A

Maintenance of Option A poles includes straightening of leaning poles, the replacement of rotted wood poles no longer structurally sound or any pole, which by definition, has reached its natural end of life at no additional charge to the customer. Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles

Emergency Pole Replacement and Repair

The Company will repair or replace structurally unsound poles at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is and subject to the Company's operating schedules and requirements and at no additional charge to the Customer.

Option B - Poles

Option B provides for Customer purchased and owned streetlight poles. The Company does not, at any time, assume ownership of Option B streetlight poles.

Maintenance Service under Option B

The Company provides for maintenance only as defined herein to Customer purchased and owned poles and related equipment at the applicable monthly Option B rate and subject to the Company’s operating schedules and requirements.

Maintenance of Option B poles includes straightening of leaning poles.

Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles, nor does maintenance of Option B poles include replacement of rotted wood poles no longer structurally sound, or any pole which by definition has reached its natural end of life.

Upon Customer request, the Company may install and replace Option B poles that have reached their natural end of life. All costs associated to the installation and removal of any pole is the sole responsibility of the Customer, in addition to the applicable monthly Option B rate.

SCHEDULE 491 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 5.649 ¢ per kWh **(I)**

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's Service Points (SPs) under this schedule.

SCHEDULE 491 (Continued)

MARKET BASED PRICING OPTION (Continued)

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Secondary Delivery Voltage	1.0640	**(R)**

SCHEDULE 491 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)	
	$132.00 per hour	$170.00 per hour	(I)

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Cobrahead Power Doors **						
	70	6,300	30	*	$2.50	$1.69
	100	9,500	43	*	3.35	2.42
	150	16,000	62	*	4.30	3.49
	200	22,000	79	*	5.41	4.44
	250	29,000	102	*	6.54	5.73
	400	50,000	163	*	10.15	9.16
Cobrahead, Non-Power Door	70	6.300	30	$6.68	2.79	2.42
	100	9,500	43	7.09	3.47	2.42
	150	16,000	62	8.23	4.55	3.49
	200	22,000	79	9.86	5.57	4.44
	250	29,000	102	10.74	6.80	5.73
	400	50,000	163	14.37	10.26	9.16
Flood	250	29,000	102	12.13	7.00	5.73
	400	50,000	163	15.56	10.43	9.16
Early American Post-Top	100	9,500	43	8.04	3.62	2.42
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	6.96	2.84	1.69
	100	9,500	43	*	3.64	2.42
	150	16,000	62	*	4.77	3.49

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 491 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black, Bronze or Gray	20	$5.16	$0.17	**(I)**
Fiberglass, Black or Bronze	30	8.40	0.28	**(I)**
Fiberglass, Gray	30	8.40	0.28	**(I)**
Fiberglass, Smooth, Black or Bronze	18	5.48	0.19	**(I)**
Fiberglass, Regular	18	4.80	0.16	**(I)**
Black, Bronze, or Gray	35	8.20	0.28	**(I)**
Aluminum, Regular with Breakaway Base	35	16.90	0.57	**(N)**
Wood, Standard	30 to 35	6.26	0.21	**(I)**
Wood, Standard	40 to 55	7.37	0.25	**(I)**

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Types							
HPS	100	9,500	43	$11.41	$4.09	$2.42	**(I)(R)**
HADCO Victorian, HPS	150	16,000	62	12.48	5.16	3.49	**(I)(R)**
	200	22,000	79	13.77	6.16	4.44	**(R)(I)**
	250	29,000	102	14.97	7.43	5.73	**(R)**
HADCO Capitol Acorn, HPS	100	9,500	43	15.37	4.65	2.42	**(R)**
	150	16,000	62	*	5.68	3.49	**(C)(R)**
	200	22,000	79	*	6.71	4.44	**(C)(R)**
	250	29,000	102	*	6.62	5.73	**(C)(R)**
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	12.58	4.23	2.42	**(I)(R)**
	150	16,000	62	*	5.02	3.49	**(C)(R)**
HADCO Techtra, HPS	100	9,500	43	19.71	5.26	2.42	**(I)(R)**
	150	16,000	62	21.60	6.45	3.49	**(R)**
	250	29,000	102	*	8.46	5.73	**(C)(R)**
HADCO Westbrooke, HPS	70	6,300	30	13.96	3.80	*	**(I)(R)**
	100	9,500	43	14.84	4.55	2.42	**(I)(R)**

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	*	$5.91	$3.49	**(C)(R)**
	200	22,000	79	*	5.39	4.44	**(C)(R)**
	250	29,000	102	$16.62	7.64	5.73	**(R)**
Special Types							
Flood, Metal Halide	350	30,000	139	*	9.26	7.81	**(C)(R)**
Flood, HPS	750	105,000	285	25.02	17.80	16.02	**(R)(R)**
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	3.60	**(R)**
Ornamental Acorn	55	2,800	21	*	*	1.18	**(R)**
Ornamental Acorn Twin	55	5,600	42	*	*	2.36	**(R)**
Composite, Twin	140	6,815	54	*	*	3.04	**(R)**
	175	9,815	66	*	*	3.71	**(R)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$8.88	$0.30	**(R)**
	30	10.19	0.34	**(R)**
	35	11.80	0.40	**(R)**
Aluminum Davit	25	9.48	0.32	**(R)**
	30	10.67	0.36	**(R)**
	35	12.20	0.41	**(R)(I)**
	40	15.67	0.53	**(R)(I)**
Aluminum Double Davit	30	11.84	0.40	**(R)**
Aluminum, Fluted Ornamental	14	8.42	0.28	**(R)**

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, Smooth Techtra Ornamental	18	$18.40	$0.62	**(R)**
Aluminum, Fluted Ornamental	16	8.74	0.30	**(R)**
Aluminum, Double-Arm, Smooth Ornamental	18	14.19	0.48	**(I)**
Aluminum, Fluted Westbrooke	18	17.29	0.58	**(R)**
Aluminum, Non-Fluted Ornamental, Pendant	22	17.18	0.58	**(C)(R)**
Fiberglass, Fluted Ornamental Black	14	11.78	0.40	**(I)**
Fiberglass, Anchor Base, Gray or Black	35	11.19	0.38	**(R)**
Fiberglass, Anchor Base (Color may vary)	25	9.94	0.34	**(R)(I)**
	30	12.15	0.41	**(I)**

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Cobrahead, Metal Halide	150	10,000	60	*	$4.53	$3.37	**(C)(R)**
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.19	**(R)**
	175	7,000	66	$8.39	4.77	3.71	**(R)**
	250	10,000	94	*	*	5.28	**(R)**
	400	21,000	147	13.65	9.36	8.26	**(R)**
	1,000	55,000	374	26.36	22.25	21.03	**(R)**
Holophane Mongoose,	150	16,000	62	*	5.47	3.49	**(C)(R)**
HPS	250	29,000	102	*	7.72	*	**(C)(R)**

* Not offered.

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$7.38	*	*	**(R)**
Mercury Vapor	175	7,000	66	9.40	$4.87	$3.71	**(R)**
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	3.37	**(R)**
	70	6,300	30	*	*	1.69	**(R)**
	100	9,500	43	*	3.91	2.42	**(R)**
	150	16,000	62	*	4.38	3.49	**(R)**
	250	29,000	102	*	*	5.73	**(R)**
	400	50,000	163	*	*	9.16	**(R)**
Metal Halide	250	20,500	99	*	6.47	5.57	**(R)**
	400	40,000	156	*	9.67	*	**(R)**
Cobrahead, Metal Halide	175	12,000	71	*	5.16	3.99	**(R)**
Flood, Metal Halide	400	40,000	156	14.43	9.97	8.77	**(R)**
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.31	*	**(R)**
100/150 Watt Ballast	100	9,500	43	*	3.31	*	**(R)**
100/150 Watt Ballast	150	16,000	62	*	4.38	3.49	**(R)**
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	4.38	3.49	**(R)**
KIM Archetype, HPS	250	29,000	102	*	7.74	5.73	**(R)**
	400	50,000	163	*	11.61	9.16	**(R)**

* Not offered

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$10.58	$3.26	*	**(I)(R)**
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	$1.69	**(R)**
Mercury Vapor	175	7,000	66	*	*	3.71	**(R)**
Early American Post-Top, HPS							
Black	70	6,300	30	7.15	2.73	1.69	**(R)**
Rectangle Type	200	22,000	79	*	*	4.44	**(R)**
Incandescent	92	1,000	31	*	*	1.74	**(R)**
	182	2,500	62	*	*	3.49	**(R)**
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	9.23	4.81	3.71	**(R)**
Flood, HPS	70	6,300	30	6.40	2.78	*	**(R)**
	100	9,500	43	7.14	3.49	2.42	**(R)**
	200	22,000	79	10.73	5.60	4.44	**(R)**
Cobrahead, HPS							
Power Door	310	37,000	124	*	8.24	6.97	**(C)(R)**
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.42	**(R)**
Twin ornamental, HPS	Twin 100	9,500	86	*	*	4.83	**(R)**
Compact Fluorescent	28	N/A	12	*	*	0.67	**(R)**

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$4.78	*	(R)
Aluminum, Painted Ornamental	35	*	*	(C)
Aluminum, Regular	16	4.78	0.16	(R)
Bronze Alloy GardCo	12	*	0.23	(R)
Concrete, Ornamental	35 or less	8.88	0.30	(R)
Fiberglass, Direct Bury with Shroud	18	7.06	0.24	(R)
Steel, Painted Regular **	25	8.88	0.30	(R)
Steel, Painted Regular **	30	10.19	0.34	(R)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.41	(I)
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41	(I)
Wood, Laminated without Mast Arm	20	5.16	0.17	(I)
Wood, Laminated Street Light Only	20	5.16	*	(I)
Wood, Curved Laminated	30	7.17	0.28	(I)
Wood, Painted Underground	35	6.26	0.21	(I)

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$2.13	$1.80	(R)
	165	12,000	60	*	1.81	0.84	(R)
	165	12,000	60	*	4.65	3.37	(R)

SCHEDULE 491 (Continued)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer’s selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

SCHEDULE 491 (Continued)

SPECIAL CONDITIONS (Continued)

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new installations.

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

SCHEDULE 491 (Continued)

SPECIAL CONDITIONS (Continued)

10. Indemnity:

   a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

   b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule.

   c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer.

SCHEDULE 491 (Continued)

SPECIAL CONDITIONS (Continued)

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer.

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

SCHEDULE 491 (Continued)

SPECIAL CONDITIONS (Continued)

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

13. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

14. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

15. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

16. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

17. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

18. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

SCHEDULE 491 (Concluded) (T)

SPECIAL CONDITIONS (Continued)

19. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. Where applicable, a Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

20. All lights corresponding to an individual municipal department must choose service under this schedule and/or Schedule 495.

21. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 492
TRAFFIC SIGNALS
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 500 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Service Point (SP)* is:

Distribution Charge	1.436 ¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's SPs under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

SCHEDULE 492 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Secondary Delivery Voltage	1.0640	**(R)**

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 492 (Continued)

SPECIAL CONDITIONS

1. The Customer or ESS will furnish the Company with a complete list each month of all traffic-signal intersections and their respective estimated monthly kWh usage. The method of estimating usage will be established by the Company. The Customer will be responsible for updating the list of intersections and corresponding estimated usages each month as new installations are made, as existing installations are removed, or as wattages are increased or decreased.

2. The Customer will conduct an independent audit of all traffic-signal intersections once every three years and provide the Company with a copy of such audit. The audit must contain a listing of each light and its corresponding monthly kWh usage installed at all intersections.

3. The Company may, whenever it deems it to be advisable, conduct a field inventory of a Customer's electrical equipment being supplied under this schedule using sampling techniques to determine, whether in the Company's opinion, the Customer's list of estimated usages is being properly maintained. If the Customer's list is improperly maintained, or in the event the Customer does not furnish such a list, the Company may institute such other means of estimating the Customer's Energy use as it may deem to be satisfactory or remove the Customer from service under this schedule.

4. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

5. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

6. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

7. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer’s election of service under this schedule.

8. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

SCHEDULE 492 (Concluded)

SPECIAL CONDITIONS (Continued)

9. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

10. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. Where applicable, a Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

11. All intersections corresponding to an individual municipal department must choose service under this schedule.

12. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 495
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments with no fewer than 30,000 lights purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services[1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 495 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option A (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer.

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation.

Option B - Luminaire (M) (N)

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs(1), in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services(2) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

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(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to page 495-7 of this Schedule.
(2) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight. (N) (M)

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option B (Continued) **(M)**

(N)

Maintenance under Option B luminaires specifically does not include replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. In addition, maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

Emergency Luminaire Replacement and Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable

Without obligation or notice to the Customer, luminaire repair or replacement shall occur as soon as reasonably possible subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services[1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of the photoelectric controller. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company's schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight. **(N)**

(M)

SCHEDULE 95 (Continued)

(M)

LUMINAIRE SERVICE OPTIONS (Continued) (N)
Special Provisions for Option B Luminaire Maintenance (Continued)

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. (N)

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on non-Company owned poles or Company-owned distribution poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company.

Maintenance Service under Option C

The Company has no obligation to maintain Customer-purchased lighting if the Customer selects this option. Such maintenance and service is the sole responsibility of the Customer.

(C)

Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election

(C)

1. If Customer elects to convert any of its luminaires from Schedule 91/95 Option B to Schedule 95 Option C, the Customer must at the same time commit to convert the entirety of Customer's Schedule 91/95 Option B luminaires to Schedules 91 Option C and Schedule 95 Option C using one of two methods: (A) within five years following PGE's group lamp replacement cycle or (B) within three years on a schedule mutually agreed upon between the Company and Customer. Customer may elect to have some of its luminaires on Schedule 91 Option C and some on Schedule 95 Option C. (C)

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91/95 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires. (C) (M)

SCHEDULE 495 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/491/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A and Option B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 5.649 ¢ per kWh (I)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's Service Points (SPs) under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

SCHEDULE 495 (Continued)

MARKET BASED PRICING OPTION (Continued)

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Secondary Delivery Voltage	1.0640	**(R)**

SCHEDULE 495 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [1]	Straight Time	Overtime	
	$132.00 per hour	$170.00 per hour	(I)

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Roadway LED	>20-25	3,000	8	$5.26	$0.86
	>25-30	3,470	9	5.32	0.92
	>30-35	2,530	11	5.71	1.03
	>35-40	4,245	13	5.54	1.14
	>40-45	5,020	15	5.79	1.25
	>45-50	3,162	16	5.96	1.31
	>50-55	3,757	18	6.32	1.43
	>55-60	4,845	20	6.07	1.53
	>60-65	4,700	21	6.13	1.59
	>65-70	5,050	23	6.82	1.71
	>70-75	7,640	25	6.99	1.84
	>75-80	8,935	26	7.04	1.89
	>80-85	9,582	28	7.15	2.00
	>85-90	10,230	30	7.27	2.12
	>90-95	9,928	32	7.38	2.23
	>95-100	11,719	33	7.44	2.29
	>100-110	7,444	36	7.94	2.45
	>110-120	12,340	39	7.77	2.62
	>120-130	13,270	43	8.00	2.85
	>130-140	14,200	46	9.11	3.04
	>140-150	15,250	50	10.30	3.29
	>150-160	16,300	53	10.47	3.46
	>160-170	17,300	56	10.64	3.63
	>170-180	18,300	60	10.75	3.84
	>180-190	19,850	63	11.03	4.02
	>190-200	21,400	67	11.47	4.25

SCHEDULE 495 (Continued)

RATES FOR STANDARD LIGHTING (Continued) **(M)**

Light-Emitting Diode (LED) Only – Option C Energy Use

Type of Light	Watts*	Monthly kWh**	
LED	5 - 10	3	**(N)**
LED	>10 - 15	4	
LED	>15 - 20	6	**(N)**
LED	>20 - 25	8	**(C)**
LED	>25 - 30	9	
LED	>30 - 35	11	
LED	>35 - 40	13	
LED	>40 - 45	15	
LED	>45 - 50	16	
LED	>50 - 55	18	
LED	>55 - 60	20	
LED	>60 - 65	21	
LED	>65 - 70	23	
LED	>70 - 75	25	
LED	>75 - 80	26	
LED	>80 - 85	28	
LED	>85 - 90	30	
LED	>90 - 95	32	
LED	>95 - 100	33	
LED	>100 - 110	36	
LED	>110 - 120	39	
LED	>120 - 130	43	
LED	>130 - 140	46	
LED	>140 - 150	50	
LED	>150 - 160	53	
LED	>160 - 170	56	

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request. **(M)**
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

SCHEDULE 495 (Continued)

(M)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option C Energy Use (Continued)

Type of Light	Watts*	Monthly kWh**
LED	>170 - 180	60
LED	>180 - 190	63
LED	>190 - 200	67
LED	>200 - 210	70
LED	>210 - 220	73
LED	>220 - 230	77
LED	>230 - 240	80
LED	>240 - 250	84
LED	>250 - 260	87
LED	>260 - 270	91
LED	>270 - 280	94
LED	>280 - 290	97
LED	>290 - 300	101

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

(M)

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Acorn						
LED	>35-40	3,262	13	$13.30	$1.34	(C)
	>40-45	3,500	15	13.41	1.45	
	>45-50	5,488	16	11.33	1.45	
	>50-55	4,000	18	13.58	1.62	
	>55-60	4,213	20	13.69	1.73	
	>60-65	4,273	21	13.75	1.79	
	>65-70	4,332	23	13.82	1.90	
	>70-75	4,897	25	13.98	2.02	
HADCO LED	70	5,120	24	18.09	2.07	(C)
Pendant LED (Non-Flared)	36	3,369	12	14.72	1.32	(R)(C)
	53	5,079	18	15.84	1.68	
	69	6,661	24	16.31	2.02	
	85	8,153	29	17.15	2.32	(R)
						(D)
Pendant LED (Flared)	>35-40	3,369	13	14.95	1.38	(C)
	>40-45	3,797	15	15.06	1.49	
	>45-50	4,438	16	15.12	1.55	
	>50-55	5,079	18	16.34	1.69	
	>55-60	5,475	20	16.45	1.80	
	>60-65	6,068	21	16.51	1.86	
	>65-70	6,661	23	17.40	1.99	
	>70-75	7,034	25	17.52	2.11	
	>75-80	7,594	26	17.76	2.17	
	>80-85	8,153	28	17.87	2.28	(C)
Post-Top, American Revolution LED	>30-35	3,395	11	7.23	1.07	(C)
	>45-50	4,409	16	7.86	1.36	
Flood LED	>80-85	10,530	28	8.21	2.02	
	>120-130	16,932	43	9.59	2.89	
	>180-190	23,797	63	11.79	4.04	
	>370-380	48,020	127	19.87	7.75	(C)

(M)

SCHEDULE 495 (Continued)

SPECIALTY SERVICES OFFERED (M)

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

. Trimming of trees adjacent to streetlight equipment and circuits.
. Arterial patrols to ensure correct operation of streetlights.
. Painting or staining of wood and steel streetlight poles. (M)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer’s selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer’s request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request. (M)

SCHEDULE 495 (Continued)

SPECIAL CONDITIONS (Continued)

6. For Option C lights: The Company does not provide the circuit on new installations. **(M)**

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage. **(M)**

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A “Qualified Worker” means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a “qualified person” or “qualified employee” with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

10. Indemnification:

    a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

SCHEDULE 495 (Continued) **(T)**

SPECIAL CONDITIONS (Continued) **(M)**

(N)

b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule. **(N)**

c. Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.c. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer. **(C)**

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer. **(M)**

(M)

SCHEDULE 495 (Continued)

SPECIAL CONDITIONS (Continued) (M)

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

13. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding. (M)

SCHEDULE 495 (Concluded)

SPECIAL CONDITIONS (Continued) **(M)**

14. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

15. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

16. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

17. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

18. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

19. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. Where applicable, a Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

20. All lights corresponding to an individual municipal department must choose service under this schedule and/or Schedule 491.

21. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

(M)

SCHEDULE 515
OUTDOOR AREA LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Nonresidential Customers purchasing Direct Access Service for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer or Electricity Service Supplier (ESS) notifies the Company of the burn-out.

MONTHLY RATE

The service rates below include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 5.565 ¢ per kWh (I)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$8.35[2]	(I)
	400	21,000	147	13.35[2]	
	1,000	55,000	374	25.91[2]	
HPS	70	6,300	30	6.66[2]	
	100	9,500	43	7.06	
	150	16,000	62	8.19	
	200	22,000	79	9.60	
	250	29,000	102	10.46	
	310	37,000	124	11.88[2]	
	400	50,000	163	14.05	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Flood , HPS	100	9,500	43	$7.11[2]	(I)
	200	22,000	79	10.47[2]	
	250	29,000	102	11.86	
	400	50,000	163	15.25	
Shoebox, HPS (bronze color, flat lens,	70	6,300	30	6.94	
or drop lens, multi-volt)	100	9,500	43	8.14	
	150	16,500	62	9.61	
Special Acorn Type, HPS	100	9,500	43	11.16	
HADCO Victorian, HPS	150	16,500	62	12.22	
	200	22,000	79	13.50	
	250	29,000	102	14.69	
Early American Post-Top, HPS, Black	100	9,500	43	8.01	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	8.46	
Cobrahead, Metal Halide	175	12,000	71	9.33	
Flood, Metal Halide	350	30,000	139	14.99	
Flood, Metal Halide	400	40,000	156	14.12	
Flood, HPS	750	105,000	285	24.64	
HADCO Independence, HPS	100	9,500	43	12.33	
HADCO Capitol Acorn, HPS	100	9,500	43	15.11	
	200	22,000	79	17.39	
	250	29,000	102	9.42	
HADCO Techtra, HPS	100	9,500	43	19.46	
	150	16,000	62	21.33	
HADCO Westbrooke, HPS	70	6,300	30	13.71	
	100	9,500	43	14.58	
	250	29,000	102	16.35	
Holophane Mongoose, HPS	150	16,000	62	14.47	(I)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[(1)] Per Luminaire	
Acorn					
LED	>35-40	3,262	13	$13.06	
	>40-45	3,500	15	13.17	
	>45-50	5,488	16	11.09	
	>50-55	4,000	18	13.34	
	>55-60	4,213	20	13.45	
	>60-65	4,273	21	13.51	(I)
	>65-70	4,332	23	13.59	
	>70-75	4,897	25	13.73	
HADCO LED	70	5,120	24	17.86	
Roadway LED	>20-25	3,000	8	5.04	(I)
	>25-30	3,470	9	5.09	
	>30-35	2,530	11	5.47	
	>35-40	4,245	13	5.31	
	>40-45	5,020	15	5.55	
	>45-50	3,162	16	5.72	
	>50-55	3,757	18	6.09	
	>55-60	4,845	20	5.83	
	>60-65	4,700	21	5.89	(I)
	>65-70	5,050	23	6.59	
	>70-75	7,640	25	6.74	
	>75-80	8,935	26	6.80	
	>80-85	9,582	28	6.91	
	>85-90	10,230	30	7.02	
	>90-95	9,928	32	7.13	
	>95-100	11,719	33	7.19	
	>100-110	7,444	36	7.70	
	>110-120	12,340	39	7.52	
	>120-130	13,270	43	7.74	
	>130-140	14,200	46	8.86	
	>140-150	15,250	50	10.05	
	>150-160	16,300	53	10.22	
	>160-170	17,300	56	10.39	
	>170-180	18,300	60	10.50	
	>180-190	19,850	63	10.78	
	>190-200	21,400	67	11.21	(I)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Pendant LED (Non-Flare)	36	3,369	12	$14.50	**(I)**
	53	5,079	18	15.61	
	69	6,661	24	16.07	**(I)**
	85	8,153	29	16.91	
Pendant LED (Flare)	>35-40	3,369	13	14.71	
	>40-45	3,797	15	14.82	
	>45-50	4,438	16	14.88	
	>50-55	5,079	18	16.11	
	>55-60	5,475	20	16.22	
	>60-65	6,068	21	16.28	**(I)**
	>65-70	6,661	23	17.16	
	>70-75	7,034	25	17.27	
	>75-80	7,594	26	17.52	
	>80-85	8,153	28	17.63	
CREE XSP LED	>20-25	2,529	8	4.89	**(I)**
	>30-35	4,025	11	5.05	
	>40-45	3,819	15	5.27	
	>45-50	4,373	16	5.58	
	>55-60	5,863	20	5.59	
	>65-70	9,175	23	6.11	**(I)**
	>90-95	8,747	32	6.61	**(I)**
	130-140	18,700	46	9.20	**(I)**
Post-Top, American Revolution LED	>30-35	3,395	11	7.00	
	>45-50	4,409	16	7.63	
Flood LED	>80-85	10,530	28	7.98	**(I)**
	120-130	16,932	43	9.34	**(I)**
	180-190	23,797	63	11.53	**(I)**
	370-380	48,020	127	19.58	**(I)**

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued) **(T)**
Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$ 5.96	**(I)(M)**
	40 to 55	7.07	**(I)**
Wood, Painted Underground	35 or less	5.96 [3]	**(I)**
Wood, Curved laminated	30 or less	7.09 [3]	**(I)**
Aluminum, Regular	16	4.56	**(I)**
	25	8.51	**(R)**
	30	9.82	**(R)**
	35	11.43	**(R)**
Aluminum, Fluted Ornamental	14	8.20	**(R)**
Aluminum, Fluted Ornamental	16	8.52	**(R)**
			(D)(M)
Aluminum Davit	25	9.11	**(R)**
	30	10.30	**(R)**
	35	11.83	**(R)**
	40	15.22	**(R)**
Aluminum Double Davit	30	11.47	**(R)**
Aluminum, Smooth Techtra Ornamental	18	18.03	**(R)**
Aluminum, Fluted Ornamental	18	16.92	**(C)(R)**
Aluminum, Non-Fluted Ornamental, Pendant	22	16.81	**(C)**
			(D)
Fiberglass Fluted Ornamental; Black	14	11.01	**(R)**
Fiberglass, Regular			
Black	20	4.94	**(I)**
Gray or Bronze	30	8.03	**(I)**
Black, Gray, or Bronze	35	7.90	**(I)**
Fiberglass, Anchor Base, Gray or Black	35	10.89	**(R)**
Fiberglass, Anchor Base (Color may vary)	25	11.46	**(I)**
	30	15.55	**(I)**
Fiberglass, Direct Bury with Shroud	18	6.70	**(R)**
Aluminum, Regular with Breakaway Base	35	16.90	**(N)**
Aluminum, Double-Arm, Smooth Ornamental	25	13.82	**(N)**

(2) No pole charge for luminaires placed on existing Company-owned distribution poles.
(3) No new service.

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles

SCHEDULE 515 (Concluded)

ESS CHARGES (M)

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file to add the luminaire type to this rate schedule.

2. Maintenance of outdoor area lighting poles includes replacement of accidentally or deliberately damaged poles and luminaires. If damage occurs more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will pay for future installation or may mutually agree with the Company and pay to have the pole either completely removed or relocated.

3. If Company-owned area lighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned area lighting equipment or poles.

TERM

Service under this schedule will not be for less than one year.

(M)

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge		
Single Phase	$20.00	
Three Phase	$29.00	
Distribution Charge		
First 5,000 kWh	5.081 ¢ per kWh	(I)
Over 5,000 kWh	1.253 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 532 (Concluded)

SPECIAL CONDITION

Unmetered service may be provided under this schedule to fixed loads with fixed periods of operation, including, but not limited to, telephone booths and television amplifiers, which are unmetered for the convenience and mutual benefit of the Customer and the Company. The average monthly usage to be used for billing will be determined by test or estimated from equipment ratings and will be mutually agreed upon by the Customer and the Company.

TERM

Service will be for not less than one year or as otherwise provided under this schedule. **(C)**

SCHEDULE 538
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers who have chosen to receive service from an Electricity Service Supplier (ESS), and: 1) served at Secondary Demand Voltage whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW; or 2) who were receiving service on Schedule 38 as of December 31, 2015.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge	$30.00		
Distribution Charge	7.637	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 538 (Concluded)

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day. **(C)** **(C)**

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SPECIAL CONDITION

In no case will the Company refund a Customer by retroactively adjusting the rate at which service was billed prior to the date the Customer begins service on this schedule.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 549
IRRIGATION AND DRAINAGE PUMPING
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS) for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

Basic Charge		
Summer Months**	$45.00	
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	9.780 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	7.780 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

** Summer Months and Winter Months commence with meter readings as defined in Rule B.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 549 (Concluded)

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following **(C)**
business day if the 15th falls on a weekend or holiday). The November Election Window will **(C)**
remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SPECIAL CONDITION

The Customer is also responsible for notification to the Company of any change in type of service provided to the Customer's premises.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who receive Electricity Service from an Electricity Service Supplier (ESS) and who supply all or some portion of their load by self generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$5,290.00	$3,640.00	$5,580.00	
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.33	$1.32	$1.32	
Over 4,000 kW	$1.02	$1.01	$1.01	
per kW of monthly On-Peak Demand**	$1.47	$1.46	$0.46	
Generation Contingency Reserves Charges***				
Spinning Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.111 ¢	0.112 ¢	0.112 ¢	(I)

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.
*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 575 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand of the Large Nonresidential Customer when the Customer's generator is operating as planned by the Customer. Initially, the Customer's Baseline Demand will be the Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations. Subsequently, Customer may select its Baseline Demand in accordance with the applicable notice requirements set forth in this schedule adjusted for changes in load and planned generator operations. Planned generator operations include the Electricity planned to be produced by the generator as well as the Customer's plans to sell Electricity produced by the generator to the Company or third parties. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable. Any modification to the Baseline Demand must be consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 576R, monthly Demand charges under Schedule 575 will be based on Demand up to the Baseline Demand.

FACILITY CAPACITY

For the first three months of service under this schedule, the Facility Capacity will be equal to the Customer's Baseline Demand. Starting with the fourth month, the Facility Capacity will be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Period, but will not be less than the Customer's Baseline Demand.

RESERVED CAPACITY

The Reserved Capacity is the lesser of the nameplate rating of the Customer's generation or the maximum kW of Customer load supplied by the Customer's generation. Additionally, upon agreement with the Customer, the Company will reduce the Reserved Capacity by the Customer's demonstrated instantaneous load reduction capability in kW associated with generation output reductions.

The Customer and Company will enter into a written agreement that specifies the Reserved Capacity in kW, the load reduction capability in kW (if any), the requirements for Customer notification to the Company of any changes in the Reserved Capacity, the Company's ability to request a demonstration of load reduction capability annually, additional metering requirements and any other necessary notification requirements.

Except during the first three months of operation, if the Customer's operations result in an actual Reserve Capacity requirement above the level specified by the agreement, the Reserved Capacity will immediately be adjusted to the actual kW level for that month and the following three months. Thereafter, the Reserved Capacity will remain at that increased kW level until the Customer has demonstrated to the Company's reasonable satisfaction that the Reserved Capacity should be revised.

SCHEDULE 575 (Continued)

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

Spinning Reserves

Spinning Reserves provide Electricity immediately after a Customer's generator output falls below the Reserved Capacity. Spinning Reserves in combination with Supplemental Reserves, transition a Customer's load to Unscheduled Power. A Customer on Schedule 575 must take Spinning Reserves in all Billing Periods that their generator is expected to operate either provided by their ESS or the Company. Spinning Reserves are not required for Customers with Reserved Capacity of 2,000 kW or less, or when the Customer's generator is not normally scheduled to operate during an entire Billing Period.

Supplemental Reserves

Supplemental Reserves provide Electricity within the first 10 minutes after a Customer's generator output falls below the Reserved Capacity. In lieu of purchasing Supplemental Reserves, a Customer may choose to reduce load within the 10 minutes of generator failure. The Customer's Load Reduction Plan must be approved by the Company.

Self-Supplied Reserves

Customers with Nameplate Generation of 15 MW or greater may self-supply needed Generation Contingency Reserves upon agreement between Customer and the Company. The agreement will specify the kW of Contingency Reserves provided by the Customer at 7% of Reserved Capacity, the notification processes for delivery of reserve Energy, the requirements for Customer delivery of requested reserves, the requirements for Customer notification to Company of any changes in the ability to self-supply reserves, the settlement process to be used when Contingency Reserves are supplied by the Customer, the provisions for an annual demonstration of such capability, any additional metering requirements and other necessary notification requirements. Customers who self-supply Generation Contingency Reserves will not be charged for Spinning and Supplemental Reserves under this schedule.

Supplemental Reserves Load Reduction Plan

In lieu of self supplying Supplemental Reserves through a self-supply agreement, a Customer may provide Supplemental Reserves through the submittal to the Company of a Load Reduction Plan that demonstrates the ability to reduce load within the first ten minutes of generator failure and specifies a kW amount of load reduction equal to 3.5% of the Reserved Capacity.

SCHEDULE 575 (Continued)

GENERATION CONTINGENCY RESERVES (Continued)

Supplemental Reserves Load Reduction Plan (Continued)

The Load Reduction Plan also will specify the notification processes for delivery of Supplemental Reserves, the requirements for Customer delivery of requested Supplemental Reserves, the requirements for Customer notification to Company of any changes in the ability to supply Supplemental Reserves, the settlement process to be used when Supplemental Reserves are supplied by the Customer, the provisions for a demonstration of such capability, any additional metering requirements and other necessary notification, plant and financial requirements. The Customer Load Reduction Plan must be approved by the Company. If approved by the Company, and adhered to by the Customer, a credit to the Supplemental Reserves charges will be applied to Customer's bill based on the Supplemental Reserves Level as specified in the Load Reduction Plan.

If Customer fails to follow the Company-approved Load Reduction Plan, all Supplemental Reserves credits for the subsequent three months (Penalty Period) will be forfeited. If the Customer satisfactorily follows the Company-approved Load Reduction Plan during the Penalty Period, the Load Reduction Plan kW credit will be reinstated at the end of the three month Penalty Period.

If the Customer fails to follow the Company-approved Load Reduction Plan a second time during the Penalty Period and the following three months, the Load Reduction Plan will be terminated.

The duration of the Penalty Period will not be limited by the establishment of a new service agreement under this schedule.

Following termination or contract expiration, Customer may submit a new Load Reduction Plan to the Company. Company will approve the new Load Reduction Plan if the Customer is able to demonstrate the load reduction capability of the Plan to Company's satisfaction.

Notwithstanding the above, Customer may terminate the Company-approved Load Reduction Plan upon giving 6 month written notice to Company.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission, and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 575 (Continued)

MINIMUM CHARGE

The Minimum Charge will be the Basic, Ancillary Services, Distribution, and Contingency Generation Reserves Charges, where applicable. In addition, the Company may require the Customer to specify a higher Minimum Charge, if necessary to justify the Company's investment in service facilities.

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the Actual Monthly Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline Energy with the exception of Schedules 108 and 115, which are applied to factors other than usage as required by statute.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written service agreement specifying the terms and conditions of service, the Customer's Baseline Demand, the Customer's Reserved Capacity, the Company's and Customer's contact information, and any other information necessary for implementation of service under this schedule. The term of the service agreement will be one calendar year (except that the term of the first service agreement will be the remainder of the year when signed plus the next calendar year) and will renew annually thereafter for successive one year terms, unless the Customer gives 90 days prior written notice. These terms and conditions will be consistent with this schedule.

2. Customers must have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Service Point (SP) and total Generator output. **(C)**

3. Direct Access Service is available only upon acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the SP and total Generator output. **(C)**

SCHEDULE 575 (Continued)

SPECIAL CONDITIONS (Continued)

4. If the Customer is served at Primary or Subtransmission Voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. If during a Billing Period, the Customer or its ESS is billed for Ancillary Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8), Regulation and Frequency Response Service will be credited to the **(C)**
Ancillary Services Charge under this schedule. The credit will be the actual OATT charges incurred but will not to exceed the Monthly Demand for the Schedule 575 monthly Ancillary Services Demand multiplied by the applicable OATT (OATT Schedules 7 or 8) and such **(C)**
credit will not exceed the Ancillary Services Charge incurred under this schedule. No credit will be provided against any Energy Imbalance Service charges.

6. A Customer's failure to inform the Company of use of on-site generation will not relieve the Customer of responsibility for the charges and requirements under this schedule.

7. The Customer's Baseline Demand may be increased or decreased as requested by the Customer for planned, long-term load changes including changes resulting from the addition of long-term energy efficiency measures, load shedding, the addition or removal of equipment or the permanent removal of generating capacity from the Customer location. Such changes will be effective upon verification of the change by the Company. "Long-term" or "permanent" mean changes that are implemented with the purpose of being in place indefinitely. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the Customer's generating capacity.

8. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Company or Customer provides the following notice:

   a) for a change to Baseline Demand that within a one calendar year period does not exceed 5 MW, the Company or Customer may make one such request per calendar year and will provide at least 6 months written notice;

   b) for a change in Baseline Demand that is greater than 5 MW, the Company or Customer must provide at least 13 months written notice with such change effective on January 1 of the applicable year. Any subsequent notice by the Company or Customer under this special condition must be made consistent with these notice requirements.

SCHEDULE 575 (Concluded)

SPECIAL CONDITIONS (Continued)

9. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council guidelines.

10. If the Customer is receiving service under this schedule and Schedule 576R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 576R Special Conditions.

SCHEDULE 576R
ECONOMIC REPLACEMENT POWER RIDER
DIRECT ACCESS SERVICE

PURPOSE

To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 575.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 575:*

	Secondary	Primary	Subtransmission	
Daily Economic Replacement Power (ERP) Demand Charge				
per kW of Daily ERP Demand during On-Peak hours per day**	$0.057	$0.057	$0.018	(R)
Transaction Fee				
per Energy Needs Forecast (ENF) submission or revision	$50.00	$50.00	$50.00	

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 576R (Continued)

ENERGY NEEDS FORECAST (ENF) AND ECONOMIC REPLACEMENT POWER (ERP)

Economic Replacement Power (ERP) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF). The ENF specifies the amount of Electricity in mWh for each hour that ERP is requested to serve some or all of the Customer's load normally supplied by the Customer's generation (amounts in excess of the Baseline Energy under Schedule 575). The Customer, or its agent, must provide the ENF to the Company a minimum of 90 minutes prior to the first hour that ERP is requested.

Each ENF will be based on the Customer's expected energy requirements and the Customer will use best efforts to conform actual Energy usage to the ENF.

The ENF will specify the expected ERP needed by hour. The Customer, or its agent, will deliver the ENF to the Company in accordance with Company procedures. The Company can choose to allow delivery of all or a portion of the ENF and will inform Customer of any such adjustment to the submitted ENF. Customer acceptance of such modification of the ENF by the Company will be confirmed within 15 minutes of the proposed ENF revision by the Company. If the Company does not inform the Customer that it is modifying the submitted ENF within 30 minutes of receipt of the ENF, the ENF will be deemed accepted by the Company.

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 575 Baseline Energy.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Customer is taking ERP less the sum of the Customer's Schedule 575 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Customer is taking ERP.

If the sum of the Customer's Unscheduled and Schedule 575 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for any power cost adjustment for costs incurred while the Customer is taking Service under this schedule and Schedule 128.

SCHEDULE 576R (Concluded) **(T)**

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied to the Customer pursuant to this schedule and agreement. All other Energy delivered will be made under the terms of Schedule 575. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. Customer is required to maintain Schedule 575 service unless otherwise agreed to by the Company.

3. All charges and requirements of Schedule 575 will apply except as provided for under this schedule.

4. ERP supplied will not be resold.

5. The Company may interrupt ERP due to Transmission constraints.

6. The Customer, or its agent, must notify the Company's Merchant Power Operations, at a specified phone number, as soon as practical of otherwise unplanned load deviations greater than 5 MW that are expected to last one hour or longer. The Company may require the Customer to change its forecast if the Company believes the forecast does not adequately represent the expected load.

7. Upon mutual agreement between the Company and Customer, the otherwise applicable Schedule 575 monthly Basic and Facility Capacity Charges will be replaced by a flat monthly Basic and Facility Capacity Charge billed under this schedule. The flat monthly Basic and Facility Capacity Charge will be set to maximize the economic value of sales under this schedule.

8. The Company is not responsible for providing market information to Customer.

9. The Company has no obligation to provide the Customer with ERP except as explicitly agreed to by both parties.

10. Each day of flow will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

Basic Charge		
Single Phase Service	$35.00	
Three Phase Service	$45.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$4.75	
Over 30 kW	$4.65	
per kW of monthly On-Peak Demand	$1.47	
System Usage Charge		
per kWh	0.870 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 583 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity shall be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. **(C)**

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

Enrollment for the November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Enrollment Windows will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 583 (Concluded)

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service will be for not less than one year or as otherwise provided under this schedule. **(C)**

SCHEDULE 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$810.00	$770.00	
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.24	$3.21	
Over 200 kW	$2.04	$2.01	
per kW of monthly On-Peak Demand	$1.47	$1.46	
System Usage Charge			
per kWh	0.144 ¢	0.144 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 585 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity shall be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly on-peak Demand (in kW) will be 100 kW for primary voltage service.

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

Enrollment for the November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Enrollment Windows will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 585 (Concluded)

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 589
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW, and who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$5,290.00	$3,640.00	$5,580.00	
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.33	$1.32	$1.32	
Over 4,000 kW	$1.02	$1.01	$1.01	
per kW of monthly on-peak Demand	$1.47	$1.46	$0.46	
System Usage Charge				
per kWh	0.111 ¢	0.112 ¢	0.112 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 589 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (ESS) for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business **(C)**
day if the 15th falls on a weekend or holiday). The November Election Window will remain open **(C)**
until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 589 (Concluded)

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service will be for not less than one year or as otherwise provided under this schedule. **(C)**

SCHEDULE 590
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Service Point (SP)*:

	Delivery Voltage		
	Primary	Subtransmission	
Basic Charge	$21,000.00	$21,000.00	
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.64	$1.64	
Over 4,000 kW	$1.33	$1.33	
per kW of monthly on-peak Demand	$1.46	$0.46	
System Usage Charge			
per kWh	0.038 ¢	0.038 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 590 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (ESS) for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 590 (Concluded)

SPECIAL CONDITIONS

(D)

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule. (T)

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company. (T)

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 591
STREET AND HIGHWAY LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually. **(C)**

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services [1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option A - Luminaire (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer. **(N)**

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation and luminaire replacement schedule.

Option B - Luminaire

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs [(1)], in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Maintenance under Option B luminaires specifically does not include replacement of failed or failing ballasts or replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. This exclusion does not include replacements of Power Doors where the Customer is qualified and paying the applicable Cobrahead Power Door rate. In addition, Maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to page 591-6 of this Schedule.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Option B - Luminaire (continued):

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable.

Without obligation or notice to the Customer, individual lamps will be replaced on burnout as soon as reasonably possible subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services [1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff. (C)

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of certain failed parts including the lamp, power door (if applicable), photoelectric controller, starter and lens. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer. (N)

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company's schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on Customer-owned poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company. **(C)**

Maintenance Service under Option C

The Company does not maintain Customer-purchased lighting when mounted on Customer-owned poles. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Option B to Option C Luminaire Conversion and Future Maintenance Election

1. The Company will, with not less than 180 days written notice from the Customer (the requesting municipality) and subject to completion of all conditions necessary to finalize such election, convert the entirety of the Customer's lighting service under Option B luminaire lighting rates to the equivalent Option C luminaires lighting rates (with respect to Monthly kWh usage) including Option B luminaires attachment to Company-owned poles.

2. Upon such conversion, the Customer will assume all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires. The Customer may not require that the Company provide new Option B lighting following the conversion to Option C luminaires. The Customer must notify and inform all affected residents of the conversion that all maintenance and repair services are the sole responsibility of the Customer, and not the Company.

(T)

3. The Customer may choose the Schedule 91 Option B to Schedule 95 Option C Luminaire Conversion and Future Maintenance Election as described in Schedule 95 if converting to Schedule 95 Option C luminaires and the above notice has not been given.

SCHEDULE 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS **(N)**

Option A – Poles

Option A provides for Company purchased and owned streetlight poles.

Pole Maintenance under Option A

Maintenance of Option A poles includes straightening of leaning poles, the replacement of rotted wood poles no longer structurally sound or any pole, which by definition, has reached its natural end of life at no additional charge to the customer. Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles

Emergency Pole Replacement and Repair

The Company will repair or replace structurally unsound poles at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is and subject to the Company's operating schedules and requirements and at no additional charge to the Customer.

Option B - Poles

Option B provides for Customer purchased and owned streetlight poles. The Company does not, at any time, assume ownership of Option B streetlight poles.

Maintenance Service under Option B

The Company provides for maintenance only as defined herein to Customer purchased and owned poles and related equipment at the applicable monthly Option B rate and subject to the Company's operating schedules and requirements.

Maintenance of Option B poles includes straightening of leaning poles.

Pole maintenance does not include painting of fiberglass, or painting, staining, treating or testing wood poles, nor does maintenance of Option B poles include replacement of rotted wood poles no longer structurally sound, or any pole which by definition has reached its natural end of life.

Upon Customer request, the Company may install and replace Option B poles that have reached their natural end of life. All costs associated to the installation and removal of any pole is the sole responsibility of the Customer, in addition to the applicable monthly Option B rate. **(N)**

SCHEDULE 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	5.649 ¢ per kWh	**(I)**
Energy Charge	Provided by Electricity Service Supplier	

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)	
	$132.00 per hour	$170.00 per hour	(I)

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Cobrahead Power Doors **						
	70	6,300	30	*	$2.50	$1.69
	100	9,500	43	*	3.35	2.42
	150	16,000	62	*	4.30	3.49
	200	22,000	79	*	5.41	4.44
	250	29,000	102	*	6.54	5.73
	400	50,000	163	*	10.15	9.16
Cobrahead, Non-Power Door	70	6.300	30	$6.68	2.79	2.42
	100	9,500	43	7.09	3.47	2.42
	150	16,000	62	8.23	4.55	3.49
	200	22,000	79	9.86	5.57	4.44
	250	29,000	102	10.74	6.80	5.73
	400	50,000	163	14.37	10.26	9.16
Flood	250	29,000	102	12.13	7.00	5.73
	400	50,000	163	15.56	10.43	9.16
Early American Post-Top	100	9,500	43	8.04	3.62	2.42
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	6.96	2.84	1.69
	100	9,500	43	*	3.64	2.42
	150	16,000	62	*	4.77	3.49

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 591 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black, Bronze or Gray	20	$5.16	$0.17	**(I)**
Fiberglass, Black or Bronze	30	8.40	0.28	**(I)**
Fiberglass, Gray	30	8.40	0.28	**(I)**
Fiberglass, Smooth, Black or Bronze	18	5.48	0.19	**(I)**
Fiberglass, Regular	18	4.80	0.16	**(I)**
Black, Bronze, or Gray	35	8.20	0.28	**(I)**
Aluminum, Regular with Breakaway Base	35	16.90	0.57	**(N)**
Wood, Standard	30 to 35	6.26	0.21	**(I)**
Wood, Standard	40 to 55	7.37	0.25	**(I)**

RATES FOR CUSTOM LIGHTINGm

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Types							
HPS	100	9,500	43	$11.41	$4.09	$2.42	**(I)(R)**
HADCO Victorian, HPS	150	16,000	62	12.48	5.16	3.49	**(I)(R)**
	200	22,000	79	13.77	6.16	4.44	**(R)(I)**
	250	29,000	102	14.97	7.43	5.73	**(R)(I)**
HADCO Capitol Acorn, HPS	100	9,500	43	15.37	4.65	2.42	**(I)(R)**
	150	16,000	62	*	5.68	3.49	**(C)(R)**
	200	22,000	79	*	6.71	4.44	**(C)(I)(R)**
	250	29,000	102	*	6.62	5.73	**(C)(R)**
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	12.58	4.23	2.42	**(I)(R)**
	150	16,000	62	*	5.02	3.49	**(C)(R)**
HADCO Techtra, HPS	100	9,500	43	19.71	5.26	2.42	**(I)(R)**
	150	16,000	62	21.60	6.45	3.49	**(I)(R)**
	250	29,000	102	*	8.46	5.73	**(C)(R)**
HADCO Westbrooke, HPS	70	6,300	30	13.96	3.80	*	**(I)(R)**
	100	9,500	43	14.84	4.55	2.42	**(I)(R)**

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	*	$5.91	$3.49	**(C)(R)**
	200	22,000	79	*	5.39	4.44	**(C)(R)**
	250	29,000	102	$16.62	7.64	5.73	**(R)(R)**
Special Types							
Flood, Metal Halide	350	30,000	139	*	9.26	7.81	**(C)(R)**
Flood, HPS	750	105,000	285	25.02	17.80	16.02	**(R)**
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	3.60	**(R)**
Ornamental Acorn	55	2,800	21	*	*	1.18	**(R)**
Ornamental Acorn Twin	55	5,600	42	*	*	2.36	**(R)**
Composite, Twin	140	6,815	54	*	*	3.04	**(R)**
	175	9,815	66	*	*	3.71	**(R)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$8.88	$0.30	**(R)**
	30	10.19	0.34	**(R)**
	35	11.80	0.40	**(R)**
Aluminum Davit	25	9.48	0.32	**(R)**
	30	10.67	0.36	**(R)**
	35	12.20	0.41	**(R)(I)**
	40	15.67	0.53	**(R)(I)**
Aluminum Double Davit	30	11.84	0.40	**(R)**
Aluminum, Fluted Ornamental	14	8.42	0.28	**(R)**

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Smooth Techtra Ornamental	18	$18.40	$0.62	**(R)**
Aluminum, Fluted Ornamental	16	8.74	0.30	**(R)**
Aluminum, Double-Arm, Smooth Ornamental	18	14.19	0.48	**(I)**
Aluminum, Fluted Westbrooke	18	17.29	0.58	**(R)**
Aluminum, Non-Fluted Ornamental, Pendant	22	17.18	0.58	**(C)(R)**
Fiberglass, Fluted Ornamental Black	14	11.78	0.40	**(I)**
Fiberglass, Anchor Base, Gray or Black	35	11.19	0.38	**(R)**
Fiberglass, Anchor Base (Color may vary)	25	9.94	0.34	**(R)(I)**
	30	12.15	0.41	**(I)**

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Metal Halide	150	10,000	60	*	$4.53	$3.37	**(C)(R)**
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.19	**(R)**
	175	7,000	66	$8.39	4.77	3.71	**(R)**
	250	10,000	94	*	*	5.28	**(R)**
	400	21,000	147	13.65	9.36	8.26	**(R)**
	1,000	55,000	374	26.36	22.25	21.03	**(R)**
Holophane Mongoose,	150	16,000	62	*	5.47	3.49	**(C)(R)**
HPS	250	29,000	102	*	7.72	*	**(C)(R)**

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$7.38	*	*	**(R)**
Mercury Vapor	175	7,000	66	9.40	$4.87	$3.71	**(R)**
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	3.37	**(R)**
	70	6,300	30	*	*	1.69	**(R)**
	100	9,500	43	*	3.91	2.42	**(R)**
	150	16,000	62	*	4.38	3.49	**(R)**
	250	29,000	102	*	*	5.73	**(R)**
	400	50,000	163	*	*	9.16	**(R)**
Metal Halide	250	20,500	99	*	6.47	5.57	**(R)**
	400	40,000	156	*	9.67	*	**(R)**
Cobrahead, Metal Halide	175	12,000	71	*	5.16	3.99	**(R)**
Flood, Metal Halide	400	40,000	156	14.43	9.97	8.77	**(R)**
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.31	*	**(R)**
100/150 Watt Ballast	100	9,500	43	*	3.31	*	**(R)**
100/150 Watt Ballast	150	16,000	62	*	4.38	3.49	**(R)**
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	4.38	3.49	**(R)**
KIM Archetype, HPS	250	29,000	102	*	7.74	5.73	**(R)**
	400	50,000	163	*	11.61	9.16	**(R)**

* Not offered

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$10.58	$3.26	*	**(I)(R)**
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	$1.69	**(R)**
Mercury Vapor	175	7,000	66	*	*	3.71	**(R)**
Early American Post-Top, HPS							
Black	70	6,300	30	7.15	2.73	1.69	**(I)(R)**
Rectangle Type	200	22,000	79	*	*	4.44	**(R)**
Incandescent	92	1,000	31	*	*	1.74	**(R)**
	182	2,500	62	*	*	3.49	**(R)**
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	9.23	4.81	3.71	**(R)**
Flood, HPS	70	6,300	30	6.40	2.78	*	**(R)**
	100	9,500	43	7.14	3.49	2.42	**(R)**
	200	22,000	79	10.73	5.60	4.44	**(R)**
Cobrahead, HPS							
Power Door	310	37,000	124	*	8.24	6.97	**(C)(R)**
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.42	**(R)**
Twin ornamental, HPS	Twin 100	9,500	86	*	*	4.83	**(R)**
Compact Fluorescent	28	N/A	12	*	*	0.67	**(R)**

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$4.78	*	**(R)**
Aluminum, Painted Ornamental	35	*	*	**(C)**
Aluminum, Regular	16	4.78	0.16	**(R)**
Bronze Alloy GardCo	12	*	0.23	**(I)**
Concrete, Ornamental	35 or less	8.88	0.30	**(R)**
Fiberglass, Direct Bury with Shroud	18	7.06	0.24	**(R)**
Steel, Painted Regular **	25	8.88	0.30	**(R)**
Steel, Painted Regular **	30	10.19	0.34	**(R)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.41	**(I)**
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41	**(I)**
Wood, Laminated without Mast Arm	20	5.16	0.17	**(I)**
Wood, Laminated Street Light Only	20	5.16	*	**(I)**
Wood, Curved Laminated	30	7.17	0.28	**(I)**
Wood, Painted Underground	35	6.26	0.21	**(R)(I)**

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$2.13	$1.80	**(R)**
	165	12,000	60	*	1.81	0.84	**(R)**
	165	12,000	60	*	4.65	3.37	**(C)(R)**

SCHEDULE 591 (Continued)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights. (D)
- Painting or staining of wood and steel streetlight poles.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS (M)

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, (M) less salvage value, plus removal cost. This provision does not pertain to the sale of (C) Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or (C) poles.

SCHEDULE 591 (Continued)

SPECIAL CONDITIONS (Continued)

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new installations. **(C)**

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

SCHEDULE 591 (Continued)

SPECIAL CONDITIONS (Continued)

10. Indemnity: **(N)**

a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule.

c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer. **(N)**

SCHEDULE 591 (Continued)

SPECIAL CONDITIONS (Continued)

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer. (N)

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action. (N)

SCHEDULE 591 (Concluded)

SPECIAL CONDITIONS (Continued)

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule. **(N)**

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments. **(N)**

TERM **(M)**

Service under this schedule will not be for less than one year. **(M)**

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Service Point (SP)* is:

Distribution Charge	1.436 ¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 592 (Concluded)

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day. **(C)** **(C)**

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SPECIAL CONDITIONS

1. The Customer or ESS will furnish the Company with a complete list each month of all traffic-signal intersections and their respective estimated monthly kWh usage. The method of estimating usage will be established by the Company. The Customer will be responsible for updating the list of intersections and corresponding estimated usages each month as new installations are made, as existing installations are removed, or as wattages are increased or decreased.

2. The Customer will conduct an independent audit of all traffic-signal intersections once every three years and provide the Company with a copy of such audit. The audit must contain a listing of each light and its corresponding monthly kWh usage installed at all intersections.

3. The Company may, whenever it deems it to be advisable, conduct a field inventory of a Customer's electrical equipment being supplied under this schedule using sampling techniques to determine, whether in the Company's opinion, the Customer's list of estimated usages is being properly maintained. If the Customer's list is improperly maintained, or in the event the Customer does not furnish such a list, the Company may institute such other means of estimating the Customer's Energy use as it may deem to be satisfactory or remove the Customer from service under this schedule.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 595
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services[1] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff. (C)

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1- 800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 595 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option A (Continued)

The Customer is responsible for repair or replacement of luminaires and circuits damaged as a result of rotted wood poles owned by the Customer.

The Company may remove or discontinue service to any luminaire and related equipment that has become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, and lightning, proximity to interference by trees or structures, or other causes as determined by the Company. The Company will notify the Customer as soon as reasonably practical of any such service discontinuation.

(M)

Option B - Luminaire (N)

Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light.

The Company does not at any time assume ownership of Option B luminaires.

As defined herein, the Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate. The Company will replace non-repairable Option B luminaires for which the Customer is charged and billed the appropriate replacement costs[(1)], in addition to the applicable monthly Option B rate.

Maintenance Service under Option B

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services[(2)] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Replacement costs include: Installation Labor + Material costs and loading + Removal Labor = total billable charges. For applicable labor rates, refer to page 595-5 of this Schedule.
(2) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight. (N)

(M)

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Maintenance Service under Option B (Continued) (M)

(N)

Maintenance under Option B luminaires specifically does not include replacement of luminaires that are deemed inoperable due to general deterioration, lack of replacement parts, or replacement of parts associated with Emergency Repair that will not bring the unit into operable status. Such inoperable luminaires will be designated as non-repairable luminaires. In addition, maintenance under Option B luminaires excludes maintenance related to vegetation management, luminaire relocation or modification of the luminaire (such as adding light shields).

Emergency Luminaire Replacement and Repair

The Company will repair or replace damaged luminaires that have been deemed inoperable due to the acts of vandalism, damage claim incidences and storm related events that cause a luminaire to become inoperable

Without obligation or notice to the Customer, luminaire repair or replacement shall occur as soon as reasonably possible subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services[(1)] department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

Non-operating luminaires will be repaired by the Company without additional charge to the Customer only when the luminaire can be restored to operable status by repair or replacement of the photoelectric controller. If repair efforts by the Company do not result in an operable luminaire, the luminaire will be designated as non-repairable and replaced, the cost of such replacement is the responsibility of the Customer.

Special Provisions for Option B Luminaire Maintenance

1. Non-repairable luminaires will be replaced with in-kind equipment, except as provided below, by the Company on the Company's schedule. Replacement is limited to Company-approved equipment at the date of installation, for which the Customer is charged and billed the appropriate prevailing costs upon completion of the work. The Company will provide to the Customer, subsequent to the luminaire replacement, a cost itemization of amounts to be paid by the Customer and additional information specifying luminaire location, age, repair history, replacement luminaire type, and reason for designation as non-repairable luminaire. The Company is not obligated to notify the Customer prior to replacement nor retain the replaced non-repairable luminaire.

(1) Contact PGE's Outdoor Lighting Services at 503-736-5710, PGE's Customer Service 503-228-6322 or 1-800-542-8818, or www.portlandgeneral.com to report an inoperable streetlight. (N)

(M)

SCHEDULE 95 (Continued)

(M)

LUMINAIRE SERVICE OPTIONS (Continued) (N)
Special Provisions for Option B Luminaire Maintenance (Continued)

2. The Company may discontinue service to Option B luminaires and related equipment, which in the opinion of the Company have become unsafe or unsatisfactory for further service by reason of deterioration, storm, flood, lightning, proximity to or unsafe interference by trees or structures or other causes. The Company will notify the Customer of such discontinuance of service.

3. If damage occurs to any streetlight more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. (N)

Option C – Luminaire

Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on non-Company owned poles or Company-owned distribution poles. As a condition to the election of Option C, Customer is responsible for ensuring that all new underground service installations of Option C luminaires are isolated by a disconnect switch or fuse. Both the equipment used to isolate the luminaire and its location must be approved by the Company. The Company may provide necessary circuits for an additional charge.

Maintenance Service under Option C

The Company has no obligation to maintain Customer-purchased lighting if the Customer selects this option. Such maintenance and service is the sole responsibility of the Customer.

Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election (C)

1. If Customer elects to convert any of its luminaires from Schedule 91/95 Option B to Schedule 95 Option C, the Customer must at the same time commit to convert the entirety of Customer's Schedule 91/95 Option B luminaires to Schedules 91 Option C and Schedule 95 Option C using one of two methods: (A) within five years following PGE's group lamp replacement cycle or (B) within three years on a schedule mutually agreed upon between the Company and Customer. Customer may elect to have some of its luminaires on Schedule 91 Option C and some on Schedule 95 Option C. (C) (C)

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91/95 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires. (C) (M)

SCHEDULE 595 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A and Option B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	5.649 ¢ per kWh
Energy Charge	Provided by Electricity Service Supplier

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)	
	$132.00 per hour	$170.00 per hour	(I)

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

SCHEDULE 595 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option A and Option B Service Rates **(M)**

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Roadway LED	>20-25	3,000	8	$5.26	$0.86	**(C)**
	>25-30	3,470	9	5.32	0.92	
	>30-35	2,530	11	5.71	1.03	
	>35-40	4,245	13	5.54	1.14	
	>40-45	5,020	15	5.79	1.25	
	>45-50	3,162	16	5.96	1.31	
	>50-55	3,757	18	6.32	1.43	
	>55-60	4,845	20	6.07	1.53	
	>60-65	4,700	21	6.13	1.59	
	>65-70	5,050	23	6.82	1.71	
	>70-75	7,640	25	6.99	1.84	
	>75-80	8,935	26	7.04	1.89	
	>80-85	9,582	28	7.15	2.00	
	>85-90	10,230	30	7.27	2.12	
	>90-95	9,928	32	7.38	2.23	
	>95-100	11,719	33	7.44	2.29	
	100-110	7,444	36	7.94	2.45	
	110-120	12,340	39	7.77	2.62	
	120-130	13,270	43	8.00	2.85	
	130-140	14,200	46	9.11	3.04	
	140-150	15,250	50	10.30	3.29	
	150-160	16,300	53	10.47	3.46	
	160-170	17,300	56	10.64	3.63	
	170-180	18,300	60	10.75	3.84	
	180-190	19,850	63	11.03	4.02	
	190-200	21,400	67	11.47	4.25	**(C)**

(M)

SCHEDULE 595 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option C Energy Use (Continued)

(M)

Type of Light	Watts*	Monthly kWh**
LED	5 - 10	3
LED	>10 - 15	4
LED	>15 - 20	6
LED	>20 - 25	8
LED	>25 - 30	9
LED	>30 - 35	11
LED	>35 - 40	13
LED	>40 - 45	15
LED	>45 - 50	16
LED	>50 - 55	18
LED	>55 - 60	20
LED	>60 - 65	21
LED	>65 - 70	23
LED	>70 - 75	25
LED	>75 - 80	26
LED	>80 - 85	28
LED	>85 - 90	30
LED	>90 - 95	32
LED	>95 - 100	33
LED	>100 - 110	36
LED	>110 - 120	39
LED	>120 - 130	43
LED	>130 - 140	46
LED	>140 - 150	50
LED	>150 - 160	53
LED	>160 - 170	56

(M)

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

SCHEDULE 595 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option C Energy Use (Continued) (M)

Type of Light	Watts*	Monthly kWh**
LED	>170 - 180	60
LED	>180 - 190	63
LED	>190 - 200	67
LED	>200 - 210	70
LED	>210 - 220	73
LED	>220 - 230	77
LED	>230 - 240	80
LED	>240 - 250	84
LED	>250 - 260	87
LED	>260 - 270	91
LED	>270 - 280	94
LED	>280 - 290	97
LED	>290 - 300	101

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

(M)

SCHEDULE 595 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates (M)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Acorn						
LED	>35-40	3,262	13	$13.30	$1.34	(C)
	>40-45	3,500	15	13.41	1.45	
	>45-50	5,488	16	11.33	1.45	
	>50-55	4,000	18	13.58	1.62	
	>55-60	4,213	20	13.69	1.73	
	>60-65	4,273	21	13.75	1.79	
	>65-70	4,332	23	13.82	1.90	
	>70-75	4,897	25	13.98	2.02	(C)
HADCO LED	70	5,120	24	18.09	2.07	(R)
Pendant LED (Non-Flared)	36	3,369	12	14.72	1.32	(R)(C)
	53	5,079	18	15.84	1.68	
	69	6,661	24	16.31	2.02	
	85	8,153	29	17.15	2.32	(R)
						(D)
Pendant LED (Flared)	>35-40	3,369	13	14.95	1.38	(C)
	>40-45	3,797	15	15.06	1.49	
	>45-50	4,438	16	15.12	1.55	
	>50-55	5,079	18	16.34	1.69	
	>55-60	5,475	20	16.45	1.80	
	>60-65	6,068	21	16.51	1.86	
	>65-70	6,661	23	17.40	1.99	
	>70-75	7,034	25	17.52	2.11	
	>75-80	7,594	26	17.76	2.17	
	>80-85	8,153	28	17.87	2.28	(C)
Post-Top, American Revolution						
LED	>30-35	3,395	11	7.23	1.07	(C)
	>45-50	4,409	16	7.86	1.36	
Flood LED	>80-85	10,530	28	8.21	2.02	
	>120-130	16,932	43	9.59	2.89	
	>180-190	23,797	63	11.79	4.04	
	>370-380	48,020	127	19.87	7.75	(C)

(M)

SCHEDULE 595 (Continued)

SPECIALTY SERVICES OFFERED (M)

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting. (M)

SCHEDULE 595 (Continued)

SPECIAL CONDITIONS (Continued)

(M)

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned streetlighting equipment or poles.

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

6. For Option C lights: The Company does not provide the circuit on new installations.

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

(M)

SCHEDULE 595 (Continued)

SPECIAL CONDITIONS (Continued) **(M)**

10. Indemnification:

a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule.

c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.c. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer. **(M)**

SCHEDULE 595 (Continued) (T)

SPECIAL CONDITIONS (Continued)

(M)

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer.

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule.

(M)

SCHEDULE 595 (Concluded)

SPECIAL CONDITIONS (Continued) **(M)**

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

TERM

Service under this schedule will not be for less than one year. **(M)**

SCHEDULE 600
ELECTRICITY SERVICE SUPPLIER CHARGES

AVAILABLE

In all territory served by the Company.

APPLICABLE

To any Electricity Service Supplier (ESS), including an applicant ESS, providing service to Customers. To receive service under this schedule, the ESS must sign an ESS Service Agreement and abide by all provisions of the Company's Tariff.

SERVICES

The following services are offered to an ESS providing Electricity to one or more Direct Access Service Customers.

Transmission Services (Applicable to Scheduling ESS only)

Transmission services are provided to an ESS pursuant to the Company's Open Access Transmission Tariff (OATT), Original Volume No. 8 (PGE-8). **(D)**

ESS Provided Regulation and Imbalance Service

An ESS that self-provides Regulation and Frequency Response and Energy Imbalance Services must provide the Company with a real-time load and power factor signal via electronic metering from the Customer load to the location designated by the Company, consistent with PGE's OATT and business practices. **(C)**

SCHEDULE 600 (Continued)

ESS SUPPORT SERVICES

The following charges are applicable to Scheduling and Non-Scheduling ESSs:

(1)	Application Processing Fee	$400.00 with Application
(2)	Registration Renewal Fee	$200.00
(3)	Electronic Data Interchange Testing	$100.00 per man-hour for all hours in excess of 16 hours annually
(4)	Change of Effective Date Request (Rule K)	$ 35.00
(5)	Switching Fee (Rule K) (Applicable for each Enrollment or Drop DASR, not applicable for Rescind or Change DASRs)	$ 20.00
(6)	Customer Change of Location (Rule K)	$5,000.00

ESS BILLING SERVICES

(1)	ESS Consolidated Bill Billing Credit	$ 0.63 per bill	
(2)	Late Pay Charge	2.2 % of delinquent balances for products and services purchased under this Tariff.	**(I)**

CUSTOMER INFORMATION

ESS Web Portal Historical Usage Download for Interval Data Charge	$ 20.00 per Service Point Identification (SPID)

BILLING AND PAYMENT

Charges incurred for Schedule 600 services are the responsibility of the ESS for which service was provided and are due and payable as described in the Company's General Rules and Regulations.

SCHEDULE 600 (Concluded)

SPECIAL CONDITION

The ESS must purchase firm Transmission Service under the Company’s OATT for not less than one-month duration and will be charged at the OATT monthly rate for firm transmission.

PGE DISTRIBUTION LOSSES (C)

The ESS will schedule sufficient Energy to provide for the following losses on the Company’s distribution system: (C)

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Losses:	2.34%	1.25%	0.14%	(C)

SCHEDULE 689
NEW LARGE LOAD
COST-OF-SERVICE OPT-OUT
(>10 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer with new load requirements that are expected to constitute "New Large Load" as that term is defined below, and that has contractually opted out such New Large Load from PGE's cost-of-service based pricing. Participation in this program means Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. **(C)** **(C)**

New Large Load must be separately metered from an existing facility or measured separately with comparable accuracy in a mutually agreed upon form between the Customer and PGE, as specified within the opt-out agreement for this program. Any New Large Load being served under this Schedule 689 must meet a minimum load of 10 MWa over a consecutive 12-month period within the first 36 months of receiving service. **(C)** **(C)**

New Large Load is defined in OAR 860-038-0710 as: any load associated with a new facility, an existing facility, or an expansion of an existing facility which (1) has never been contracted for or committed to receiving electric service in writing by a cost-of-service Customer with the Company and (2) is expected to result in a 10 MWa or more increase in the Customer's power requirements during the first three years after new operations begin. **(T)** **(C)**

Service under this rate schedule begins at the time that the new meter is energized, or at a mutually agreed upon date between the Customer and PGE. The Company and Customer will identify the SP(s) that qualifies for service under this rate schedule, which SP(s) will be referenced within the previously executed opt-out agreement between the Customer and the Company once the SP(s) is known. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule. Construction meters and energy supplied during construction will not apply to this rate schedule. **(T)** **(C)** **(T)**

Service under this schedule is limited to 119 MWa (hereafter referred to as the "cap") and is available on a first-come, first-served basis to those who apply for service under this Schedule 689 and are deemed eligible; provided, however, that capacity must be available under the cap and such cap shall not be exceeded by those who are served under this Schedule 689. Likewise, the timing of service under this schedule may be impacted by the availability of existing transmission capacity on the system at the time service is requested and any planning requirements, consistent with the requirements of the Company's Open Access Transmission Tariff. **(C)** **(C)**

(M)

SCHEDULE 689 (Continued)

APPLICABLE (Continued)

Load served under Schedule 689 will not be counted under the Long Term Direct Access cap that applies to Schedules 485, 489, 490, 491, 492 and 495. The expected load of the Customer, defined as the “Contracted Load” in the opt out agreement between the Customer and the Company, will be the amount of load that is initially counted toward the New Load Direct Access cap for the first 60 months, unless a Customer is earlier de-enrolled under the terms of this Schedule 689 or the terms of the opt-out agreement.

The Contracted Load for each Customer will be counted toward the cap limit for up to the first 60 months of service. Following 60 months of service on Schedule 689, the Customer’s actual load factor (LF) will be applied to the contracted demand (MW) to calculate a Customer’s MWa to be captured and counted toward the New Large Load Program cap thereafter, and the total amount of load under the cap will be adjusted at such time of inquiry, in accordance with actual loads.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	\$5,290.00	\$3,640.00	\$5,580.00	
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	\$1.33	\$1.32	\$1.32	
Over 4,000 kW	\$1.02	\$1.01	\$1.01	
per kW of monthly On-Peak Demand	\$1.47	\$1.46	\$0.46	
System Usage Charge				
per kWh	0.111 ¢	0.112 ¢	0.112 ¢	**(I)**
Administrative Fee	\$0.00	\$0.00	\$0.00	

* See Schedule 100 for applicable adjustments.

** The Customer’s load, as reflected in the opt-out agreement executed between the Customer and PGE, may be higher than that reflected in a minimum load agreement for purposes of calculating the minimum monthly Facility Capacity and monthly Demand for the SP, for any Customer with dedicated substation capacity and/or redundant distribution facilities.

SCHEDULE 689 (Continued)

ENERGY SUPPLY

The Customer may elect to purchase Energy from an Electric Service Supplier (ESS) certified by the PUC to do business in PGE's service territory,(Direct Access Service) or from the Company (Company Supplied Energy). Election of energy supply from an ESS or from the Company applies toward the cap of this program.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the agreement between the Customer and the ESS.

Company Supplied Energy

The Company Daily Market Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.
Upon not less than five business days' notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

Additional charges to meet the state of Oregon's Renewable Portfolio Standard may apply following future Commission determination.

Wheeling Charge
The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

SCHEDULE 689 (Continued)

RETURN TO COST OF SERVICE PRICING

Except when disenrolled for failure to meet the threshold load standard established in this schedule, Customers must provide not less than three years notice to terminate service under this schedule. If a Customer's return to cost-of-service increases rates for existing cost-of-service **(T)** Customers by more than 0.5%, the Customer returning to cost-of-service will be subject to the forward looking rate adder, hereafter referred to as the "Energy Supply Return Charge" noted **(C)** below, for three years beginning from the date of notice to return to cost-of-service. **(C)**

Energy Supply Return Charge
$0.00 per kWh

TRANSMISSION CHARGE

Transmission and Ancillary Service charges will be as specified in the Company's OATT, as specified and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly On-Peak Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

SCHEDULE 689 (Continued)

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

LOSSES

The following adjustment factors will be used where losses are to be included in the Energy Charges:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments applicable to this schedule are summarized in Schedule 100.

EXISTING LOAD SHORTAGE TRANSITION ADJUSTMENT

The Existing Load Shortage Transition Adjustment will be applied to the Existing Load Shortage of the Customer and to the Existing Load Shortage of the Customer’s Affiliated Customers. An Affiliated Customer is a controlling interest which is held by another Customer, engaged in the same line of business as the holder of the controlling interest. Existing Load Shortage is the larger of zero or a Customer’s average historic cost-of-service load plus Incremental Demand Side Management less the average cost-of-service eligible load during the previous 60 months. Average Historical Cost-of-Service Load is the average monthly Cost-of-Service Eligible Load during the preceding 60 months prior to signing of the service agreement between the Customer and the Company for service on this rate schedule. Incremental Demand Side Management is the effective net impact of energy efficiency measures after the Customer has entered a written and binding agreement with the Company through the service agreement between the Customer and the Company.

SCHEDULE 689 (Continued)

The Existing Load Shortage Transition Adjustment for the first 60 months is equal to 75 percent of fixed generation costs plus net variable power cost transition adjustments during the first 60 months after enrollment in this rate schedule. The Existing Load Shortage Transition Adjustment after 60 months of service on this rate schedule is equal to 100 percent of fixed generation costs plus net variable power cost transition adjustments.

The Customer may be exempted from the Existing Load Transition Adjustment if the Customer can demonstrate that the change in load in question is not due to load shifting activity described in OAR 860-038-0740. The Company will provide written notification to the Customer at least 30 days prior to charging the Existing Load Shortage Transition Adjustment. The Customer must demonstrate the change in load by providing a written request for exemption that includes explanation for the change in load and support from available documentation. The Company will approve or deny the request of the Customer within 90 days and will not charge the Existing Load Transition Adjustment within this time period.

ENROLLMENT

The prospective NLDA program participant with New Large Load and any current Large **(C)**
Nonresidential Customer with New Large Load, must notify the Company of its interest to enroll
in this Schedule 689 and execute an opt out agreement at the earlier of one year prior to the **(C)**
expected energization date of the new meter or upon entering a written and binding service
agreement for distribution service with the Company. The date of energization will be agreed upon **(C)**
between the Customer and the Company within a written and binding agreement for service under
this Schedule, to be provided by the Company to the Customer. Upon energization, the Customer **(C)**
will begin service on PGE daily market energy option and will remain on daily market energy
option unless and until PGE is notified that Customer has chosen an ESS and the ESS **(C)**
commences service. Customer enrollment may be contingent upon additional agreements
between the Company and the Customer, including but not limited to Minimum Load Agreements.
The Company will not accept applications for service that exceed the current program cap or any **(C)**
remaining load available under the cap. Customer applications with expectations of load to grow **(C)**
beyond the program cap will require separate application and approval by the Commission.

A Customer will have ten (10) business days to sign the NLDA service agreement once tendered **(T)**
by PGE. If a Customer executes an opt out agreement for service under this schedule, and if a **(C)**
Customer is working with an ESS, the Company will notify the ESS when to send the enrollment
Direct Access Service Request (DASR). Prerequisites and notification requirements are as **(C)**
contained in Rule K.

Applicants that do not meet the conditions above, or that are found in breach of the opt out agreement between the Company and the Customer are not eligible for enrollment/continued enrollment under this rate schedule. If the Customer or the Customer's selected ESS cannot
demonstrate creditworthiness, the Customer will not be eligible for service under this rate **(T)**
schedule and will be enrolled in an applicable cost-of-service based rate. **(T)**

SCHEDULE 689 (Continued)

ENROLLMENT (Continued) **(N)**

Prior to receiving service, the existing or prospective Customer must agree to only purchase energy from a resource mix consistent with the specifications of OAR 860-038-0730(1), which does not include coal-fired generation. Prior to taking service under this program, the existing or prospective Customer must provide a signed affidavit to PGE representing that their energy supply will meet the requirements of OAR 860-038-0730 (1). Customers found in violation of the provision--that no coal will be delivered by wire after January 1, 2030--will be enrolled in the general cost-of-service opt out program in the next direct access opt out window and subject to transition adjustments as a new enrollment. **(C)** **(C)** **(C)** **(T)**

DE-ENROLLMENT

At the conclusion of 36 months of service, if Customer's actual load enrolled under this Schedule 689 does not meet the minimum load requirements for service under this rate schedule, the Company may de-enroll the Customer from this rate schedule. The Company will provide the Customer and the Commission with written notification of its decision prior to moving the Customer to the applicable cost-of-service rate schedule. The Customer may respond to the Company's notice in accordance with OAR 860-038-0750. A Customer that is de-enrolled will no longer be served by an ESS and will be served by the Company at an applicable cost-of-service rate. Once de-enrolled, the Customer is subject to all notice requirements and provisions of the applicable cost-of-service rate schedule under which the Customer is served. The Customer may elect to opt-out of cost-of-service in a subsequent direct access window, and in accordance with the Company's tariff requirements. Customers that opt out of cost of service in the September direct access window will be subject to Schedule 129 transition adjustment schedule charges. **(C)** **(C)**

The Customer must provide written notification, within 60 days of PGE's notification of de-enrollment, to the Company and the Commission to demonstrate that its reduction in load to less than 10 MWa was the result of equipment failure, incremental demand side management, load curtailment or load control, or other causes outside the control of the Customer. The Customer must provide documentation to demonstrate this. **(C)** **(T)**

The Company will not transition a Customer to a new rate schedule before 90 days has passed since initial notification from the Company.

TERM

Service under this rate schedule will be for the minimum of 36 months to determine if the minimum load required for service under this rate schedule, 10 MWa for 12 consecutive months, is met. Upon completion of this term, if 10 MWa for 12 consecutive months is met, service will continue under this schedule. If the minimum load requirement is not met, the Customer will be de-enrolled and transitioned to the applicable cost-of-service rate and subject to all notice requirements and provisions of the applicable rate schedule under which the Customer is served. **(C)**

SCHEDULE 689 (Continued) (T)

QUEUE MANGEMENT PLAN (N)

Pending an investigation of its NLDA tariff, PGE opened a non-binding queue to start the one-year notification period for any prospective NLDA program participant who wished to provide PGE with notice of its intent to participate in the New Load Direct Access program. In recognition of the program cap, the process for entry into the queue was posted on PGE's website, in advance of the opening of the queue, and prospective NLDA program participants were advised that queue positions would be established on a first-come, first-served basis, once the queue was opened. The purpose of the temporary queue process is to provide nondiscriminatory and transparent management of those interested in NLDA.

The opening of the queue and the start of the one-year notification period for all those who entered the queue on that date, was on April 15, 2019. Thus, any load energized prior to April 15, 2020 is deemed ineligible for NLDA.

PGE anticipates that once the program cap is reached or all prospective NLDA program participants who entered the queue on April 15, 2019 have been processed, whichever comes first, PGE will close its temporary queue. Thereafter, any prospective NLDA program participant will have their request for NLDA processed on a first-come, first-served basis, at any time any capacity is or may become available under the program cap, provided the Customer load fits within the available capacity under the cap. A new NLDA queue will be established if such should become necessary.

Once PGE tenders an opt out agreement under this schedule, the prospective NLDA program participant has ten (10) business days to sign and return the agreement to PGE, or the offer will be withdrawn.

Beyond the one-year notification period, a prospective NLDA program participant has up to one additional year to energize the new service (by April 15, 2021 for initial program participants) or two years if substation construction and/or substation upgrades are required to serve the Contracted Load (by April 15, 2022 for initial program participants), known as the "Timely Energization Date." Temporary power will not be considered "energization" for the purposes of determining a program participant's Timely Energization Date. Allowances will be made if delays in construction are outside of the NLDA program participant's control, such as materiel delays, or delays caused by PGE. The Customer must notify PGE at least 30 days prior to the Timely Energization Date to qualify for an allowance for additional time. Failure to meet the Timely Energization Date will result in automatic disenrollment from the NLDA program and termination of the New Large Load Cost of Service Opt-Out Agreement.

PGE will calculate, in demand (kW), the New Large Load that is to be referenced in the New Large Load Cost of Service Opt-Out Agreement ("Contracted Load") and used for the purposes of determining remaining capacity available under the program cap, if any. This calculation will generally be based on the capacity of service currently being requested by the prospective NLDA program participant. PGE will design and construct facilities to serve the Contracted Load stated in the NLDA contract. (N)

SCHEDULE 689 (Continued)

QUEUE MANGEMENT PLAN (Continued) **(N)**

Provided any capacity is available under the program cap, such capacity will be offered serially, to the next prospective NLDA program participant in the queue, provided such prospective NLDA program participant's New Large Load can be served without exceeding the program cap. For example, if there is 25MWa available under the cap and the next prospective NLDA program participant in the queue with a 50MWa load seeks enrollment, that participant will be denied participation, as their New Large Load does not fit under the cap. **(N)**

SPECIAL CONDITIONS **(M)**

1. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar Customers not taking service under this schedule, including competitors to the Customer.

2. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

3. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it energy experts that assisted in making this decision.

4. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and arrangement and operation of such equipment will be subject to the approval of the Company.

5. Customers selecting service under this schedule will be limited to a Company/ESS Split Bill. **(T)**

6. Customers under this schedule are put on notice through Commission Order No. 20-002, that the Commission intends that all system participants including NLDA Customers, will **(T)** be required to support resource adequacy. Should a change be justified in the future, it may be imposed on all NLDA Customers. Further, when the Commission considers any **(T)** future proposed changes or requirements, the Commission stated that it intends to disfavor grandfathering. **(M)**

SCHEDULE 689 (Concluded)

SPECIAL CONDITIONS (Continued)

7. Customers selecting service under this schedule are put on notice that PGE may be proposing changes to its curtailment schedules applicable to NLDA Customers, consistent with the invitation extended in Commission Order No. 20-002. If proposed, PGE would describe when and how NLDA Customers would be curtailed so that cost of service Customers are less likely to face cost shifts if and when any ESS supplying NLDA Customers fails to perform. (C)(M) (T) (T) (C) (T)(M)

SCHEDULE 715
ELECTRICAL EQUIPMENT SERVICES

PURPOSE

To provide construction and maintenance to Customer or utility owned electrical equipment (other than equipment owned by the Company).

AVAILABLE

In the State of Oregon.

APPLICABLE

To all Nonresidential Customers and utilities.

CHARACTER OF SERVICE

The Company provides engineering, electrical design and construction, equipment maintenance and repair, preventative diagnostic and prevention maintenance, electrical oil containment and compliance with the Environmental Protection Agency's Spill Prevention Control and Countermeasure Oil Program (SPCC), equipment leasing, Energy recovery and revenue protection and electrical equipment refurbishing and disposal services.

BILLING RATES

Service will be contractually negotiated.

SPECIAL CONDITIONS

1. All fully distributed costs and revenues associated with the provision of Electrical Equipment Services will be charged or credited to non-utility accounts.

2. Electrical Equipment Services will be provided in accordance with the Code of Conduct as set forth in OAR 860-038-0500 through 806-038-0640.

3. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other electrical equipment services providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Electrical Equipment Services.

SCHEDULE 750
INFORMATIONAL ONLY: FRANCHISE FEE RATE RECOVERY

PURPOSE

To inform customers regarding the level of franchise fee rate recovery contained in each schedule's system usage or distribution charges.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory.

FRANCHISE FEE RATE RECOVERY

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate	Included in:	
7	0.358 ¢ per kWh	Distribution Charge	**(I)**
15	0.640 ¢ per kWh	Distribution Charge	**(I)**
32	0.330 ¢ per kWh	Distribution Charge	**(I)**
38	0.360 ¢ per kWh	Distribution Charge	**(I)**
47	0.540 ¢ per kWh	Distribution Charge	**(I)**
49	0.408 ¢ per kWh	Distribution Charge	**(I)**
75			
Secondary	0.167 ¢ per kWh	System Usage Charge	**(I)**
Primary	0.165 ¢ per kWh	System Usage Charge	**(I)**
Subtransmission	0.163 ¢ per kWh	System Usage Charge	**(I)**

DO NOT BILL

SCHEDULE 750 (Continued)

FRANCHISE FEE RATE RECOVERY (Continued)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate	Included in:	
83	0.249 ¢ per kWh	System Usage Charge	**(I)**
85			
Secondary	0.199 ¢ per kWh	System Usage Charge	**(I)**
Primary	0.196 ¢ per kWh	System Usage Charge	**(I)**
89			
Secondary	0.167 ¢ per kWh	System Usage Charge	**(I)**
Primary	0.165 ¢ per kWh	System Usage Charge	**(I)**
Subtransmission	0.163 ¢ per kWh	System Usage Charge	**(I)**
90			
Primary	0.149 ¢ per kWh	System Usage Charge	**(I)**
Subtransmission	0.149 ¢ per kWh	System Usage Charge	**(N)**
91	0.699 ¢ per kWh	Distribution Charge	**(I)**
92	0.181 ¢ per kWh	Distribution Charge	**(R)**
95	0.699 ¢ per kWh	Distribution Charge	**(I)**
485			
Secondary	0.056 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.055 ¢ per kWh	System Usage Charge	**(R)**
489			
Secondary	0.028 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.027 ¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.027 ¢ per kWh	System Usage Charge	**(R)**
490			
Primary	0.011 ¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.011 ¢ per kWh	System Usage Charge	**(N)**
491	0.563 ¢ per kWh	Distribution Charge	**(I)**
492	0.037 ¢ per kWh	Distribution Charge	**(R)**
495	0.563 ¢ per kWh	Distribution Charge	**(I)**

SCHEDULE 750 (Concluded)

FRANCHISE FEE RATE RECOVERY (Concluded)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate		Included in:	
515	0.494	¢ per kWh	Distribution Charge	**(I)**
532	0.167	¢ per kWh	Distribution Charge	**(I)**
538	0.209	¢ per kWh	Distribution Charge	**(I)**
549	0.224	¢ per kWh	Distribution Charge	**(I)**
575				
Secondary	0.028	¢ per kWh	System Usage Charge	**(R)**
Primary	0.027	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.027	¢ per kWh	System Usage Charge	**(R)**
583	0.088	¢ per kWh	System Usage Charge	**(I)**
585				
Secondary	0.056	¢ per kWh	System Usage Charge	**(R)**
Primary	0.055	¢ per kWh	System Usage Charge	**(R)**
589				
Secondary	0.028	¢ per kWh	System Usage Charge	**(R)**
Primary	0.027	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.027	¢ per kWh	System Usage Charge	**(R)**
590				
Primary	0.011	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.011	¢ per kWh	System Usage Charge	**(N)**
591	0.563	¢ per kWh	Distribution Charge	**(I)**
592	0.037	¢ per kWh	Distribution Charge	**(R)**
595	0.563	¢ per kWh	Distribution Charge	**(I)**
689				
Secondary	0.028	¢ per kWh	System Usage Charge	**(R)**
Primary	0.027	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.027	¢ per kWh	System Usage Charge	**(R)**

SCHEDULE 800
SERVICE MAPS

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers, third parties and Competitive Operations as defined in OAR 860-038-0005(8), but not to Company employees classified as "Merchant" according to FERC Standards of Conduct.

DESCRIPTION

The Company offers Public GIS data and maps at no cost through ArcGIS Online. This spatial data is not designed to help fulfill engineering, surveying or legal needs and is for informational purposes only. Direct requests to PGE's GIS Department for additional assistance or more detailed maps. Additional data or map requests are subject to the fees listed below. **(C)**

ArcGIS Online data and maps are available for no cost at this URL: https://arcg.is/0fvGTL **(C)**

PRICE LIST

GEOSPATIAL (GIS) PRODUCTS

<u>Hardcopy Maps – by Quarter Section</u>	<u>Price</u>	
11 X 17 Standard Format Map	$25.00[1]	
24 X 36 Large Format Map	$50.00	
<u>Electronic Maps or Data Files by Quarter Section</u>		
Static Plot file (.pdf)	$25.00[2]	
Active plot files (.dgn, .dwg)	$50.00[2]	
Google Earth Files (.kmz)	$50.00	
Geodata Files (.shp, .gdb)	$50.00	
<u>Customized Hard Copy or Electronic Map or Data File</u>		
Special Order (e.g., Boundary Map)	$150.00	One Hour Minimum
	$75.00	per hour for additional hours

MAP REQUESTS

Maps may be requested by calling PGE Customer Service at 503-228-6322 or contacting PGE's GIS department at GISDepartment@pgn.com.

SCHEDULE 800 (Concluded)

PAYMENT

Payment is required at the time of ordering. Electronic maps or data files may be refreshed three times at no extra cost for up to one year after the initial purchase. **(C)(M)**
(C)

(1) The first 5 copies are free when new service is being installed at the site.
(2) One electronic copy is free when new service is being installed at the site.

(M)

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RULE A
INTRODUCTION

1. General

These General Rules and Regulations provide the terms and conditions related to services offered by the Company under this Tariff.

2. Territory Served

The Company supplies Electricity Service in incorporated and unincorporated portions of Clackamas, Columbia, Hood River, Marion, Multnomah, Polk, Washington, and Yamhill counties, Oregon. The Company may also provide certain non-utility services in other **(T)** parts of Oregon.

3. Commission Rules, Regulations and Orders

Existing and future lawful rules, regulations, and orders of the Commission will be considered a part of this Tariff.

4. Tariff Compliance

Service and rates are subject to all applicable General Rules and Regulations contained in the Tariff of which each schedule is a part.

5. Relationship to Rate Schedules

If a rate schedule provision conflicts with a provision in these General Rules and Regulations, the rate schedule provision will apply.

RULE A (Concluded)

RULE B
DEFINITIONS

The terms listed below, which are used frequently in the Tariff, have the stated meanings:

1. Ancillary Services

Services necessary or incidental to the transmission and delivery of Electricity from resources to retail Electricity Customers, including but not limited to scheduling, frequency regulation, load shaping, load following, spinning reserves, supplemental reserves, reactive power, voltage control and energy balancing services.

2. Applicant

A person or business applying to the Company for Electricity Service or reapplying for service at a new or existing location after service has been discontinued.

3. Basic Charge

A monthly amount, specified in certain rate schedules, which is charged regardless of the amount of Energy consumed. The charge represents a part of the Company's fixed costs of making service available, such as meter reading and billing costs.

4. Billing Period

A time interval, which may vary between 27 and 34 days, between successive billing dates.

5. Commission

The Public Utility Commission of Oregon.

6. Company

Portland General Electric Company.

7. Customer

An individual, partnership, corporation, organization, government, governmental agency, political subdivision, municipality, or other entity who has applied for, been accepted, and is currently receiving Electricity Service at a Service Point (SP). A Customer who **(C)**
voluntarily terminates service and subsequently requests service with the Company at a new or existing location within 20 days after terminating service retains Customer status. For purposes of Schedule 201, a Customer may not be receiving Electricity Services from the Company.

8. **Customer Service Agreement**

An Agreement with a Customer that specifies Utility Provided Service or Direct Access Service terms and conditions for service under this Tariff.

9. **Day of Flow**

The day in which Electricity deliveries are made; measured as the time period beginning immediately after midnight for the hour ending 0100 and ending at exactly the end of the 2400 hour Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable, "PPT").

10. **Demand**

The maximum rate of delivery of Electricity metered for purposes of billing, measured in whole kilowatts (kW) registered over a nominal 30-minute interval.

11. **Demand Charge**

A charge for registered Demand normally assessed to Customers with Demands greater than 30 kW.

12. **Direct Access Service**

The delivery by the Company of Electricity and applicable Ancillary Services by the Company that a Nonresidential Customer has purchased from an Electricity Service **(T)**
Supplier (ESS). **(T)**

13. **Direct Access Service Request (DASR)**

Electronic notification provided by an ESS to the Company that a Customer has selected the notifying ESS as its supplier of Electricity Service. DASRs are also required for a Customer to terminate Direct Access Service and begin or resume receiving Electricity Service from the Company, rescind a previously submitted DASR, change the effective date of the enrollment DASR, or update the Customer's account information when the Customer is receiving Direct Access Service.

14. **Electricity**

Electric energy, measured in kilowatt-hours (kWh) or megawatt-hours (MWh); or electric capacity, measured in kilowatts (kW) or megawatts (MW), or both.

15. Electricity Schedule

A Scheduling ESS's projection of its hourly Electricity deliveries, measured in megawatt-hours (MWh) that are necessary to meet the aggregate hourly load of its Customers and the Customers of any Non-Scheduling ESS for which it provides scheduling service. The Electricity Schedule is for a Day of Flow and is provided to the Company in accordance with Western Electricity Coordinating Council (WECC) and National Energy Reliability Council (NERC) operating standards.

16. Electricity Service

The provision of Electricity to Customers by the Company or by an ESS using the Company's Facilities.

17. Electricity Service Supplier (ESS)

A provider of Electricity Service including a Large Nonresidential Customer that has obtained all necessary approvals to do business in the State of Oregon, is certified by the Commission if applicable, has met the Company's requirements for providing service and executed an ESS Service Agreement with the Company. The Company, when supplying Electricity to Nonresidential Customers in its own service territory, is not considered an ESS. The Company will classify ESSs as one of the following:

Scheduling ESS

An ESS that provides its own Electricity Schedule to the Company.

Non-Scheduling ESS

An ESS that does not provide the Company with a Schedule and relies on a Scheduling ESS for services related to scheduling and settlement.

18. Electric Vehicle: An electric vehicle is any vehicle propelled in whole or in part by electric energy stored on board for the purpose of propulsion, and where charging of the on-board electrical storage is provided in whole or in part, through a connection to the utility distribution system. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles (PHEV) and battery electric vehicles (BEV). **(N)**

(N)

19. Energy **(T)**

Electric energy commonly measured in kilowatt-hours (kWh) or megawatt-hours (MWh).

20. Energy Charge **(T)**

A variable charge billed on the basis of a Customer's metered or estimated kilowatt-hours (kWh) usage.

21. **Emergency Default Service** (T)

A service option provided by the Company to a Nonresidential Customer that requires Utility Provided Service with less than five business days' notice to the Company by the Customer or its ESS. This service is available to the Customer for a maximum of five consecutive days from initial purchase.

22. **ESS Service Agreement** (T)

An agreement between the Company and an ESS specifying terms and conditions for service under this Tariff.

23. **Facilities** (T)

Transmission and distribution plant and equipment owned and operated by the Company.

24. **Facility Capacity** (T)

The Facility Capacity is the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

25. **Farm Service** (T)

Nonresidential electric service furnished to Premises employed for the purpose of obtaining a profit in money by raising, harvesting, and selling crops; or by the feeding, breeding, management and sale of, or the producing of, livestock, poultry, fur-bearing animals, or honeybees; or for dairying and the sale of dairy products; or any other agricultural or horticultural use, animal husbandry, or any combination thereof. Farm Service includes the use of Energy to prepare and store the products raised on the Premises for human use and animal use and their disposal by marketing or otherwise. Farm Service does not include the use of Energy for commercial treatment, storage, or distribution of agricultural or horticultural products and does not include the use of land subject to the provisions of ORS Chapter 321 concerning commercial forestry. (T)

26. **Kilovar (kVAr)** A unit of reactive power equal to 1,000 reactive volt amperes. (T)
27. **Kilowatt (kW)** A unit of power equal to 1,000 watts. (T)
28. **Kilowatt-Hour (kWh)** The amount of Energy delivered in one hour when power is delivered at a constant rate of 1 kW.

29. Large Nonresidential Customer

A Nonresidential Customer whose monthly Demand has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service whose Demand has exceeded 30 kW.

30. Losses **(N)**

The difference between the amount of electricity generated and the amount sold to Customers within a given period of time. Losses largely reflect the electricity lost as a result transformation and transmission, but also include Company use and potentially electricity theft.

31. Multi-Family Dwelling

A residential building that contains three or more dwelling units. **(N)**

32. Network Meter **(T)**

Metered service that is the basis of PGE's Smart Grid (Advanced Metering Infrastructure) Technology Program with functionality to collect, receive and transmit meter-related data remotely.

33. Nonresidential Customer **(T)**

A Customer that does not meet the definition of a Residential Customer.

34. Non-Network Meter (Residential only) **(T)**

Metered service not part of PGE's Smart Grid (Advanced Metering Infrastructure) Technology Program with functionality to collect and receive meter-related data for manual collection.

35. Operational Order to Deliver Electricity **(T)**

An order issued by the Company to scheduling ESSs to deliver additional Electricity for purposes of maintaining the integrity of the Company's facilities.

36. Portfolio **(T)**

A set of product and pricing options provided to Residential Customers and Small Nonresidential Customers.

37. Premises **(T)**

Real and personal property owned and/or used by a Customer at a single location, which contains a Service Point.

38. Reactive Demand **(T)**

The maximum rate of delivery of kilovolt-amperes reactive (kVars) measured over a nominal 30-minute interval. Reactive Demand must be supplied to most types of magnetic equipment, such as motors. It is supplied by generators or by electrostatic equipment, such as capacitors, motors or transformers. It is recognized as a necessary Ancillary Service.

39. Reactive Demand Charge **(T)**

A charge for Reactive Demand assessed to Customers with loads that are supplied Reactive Demand on the Company's system.

40. Residential Customer **(T)**

A Customer that has applied for and been accepted to receive service at a dwelling primarily used for residential purposes, including, but not limited to, single family dwellings, separately metered apartment units, mobile homes, and houseboats, but excluding dwellings employed for Transient Occupancy, such as hotels, motels, camps, lodges, and clubs.

For purposes of this rule, a dwelling must contain permanent facilities for sleeping, bathing, and cooking.

Boarding houses with no more than four separate sleeping quarters for use by people who are not members of the Residential Customer’s family and “adult foster homes” (defined in ORS 443.705 as a home or facility in which residential care is provided for five or fewer adults who are not related to the Residential Customer by blood or marriage) are residential dwellings.

When there is nonresidential use of Electricity at a dwelling used primarily for residential purposes, the Company will classify the Customer as residential if the Company determines that Electricity consumed in a typical month for residential use exceeds that consumed for nonresidential use, and if the nonresidential use is carried out primarily by the occupants of the dwelling.

Individual dwelling units in newly constructed multi-family residential buildings will be individually metered and billed as Residential Customers.

Service through one meter to two dwelling units will be classified as one Residential Customer where an existing dwelling unit is or has been divided into two dwelling units, provided the ampacity of the service equipment is not increased. In the case where service is supplied through one meter to two or more new dwelling units, or to three or more existing dwelling units, service will be classified as nonresidential service.

With the exception of the separately metered Residential Electric Vehicle Time of Use (EV TOU) Option under Schedule 7, service through additional meters to other than dwellings on residential premises will be classified as nonresidential.

41. Scheduled Crew Hours **(T)**

Those times that Company service crew personnel are working at their regular rate of pay. Scheduled Crew Hours may vary by location and type of work.

42. Service Point (SP) **(T)**

Unless otherwise designated by agreement, the first point of connection of the Company's service drop, service lateral or bus to the Customer's service entrance conductors or equipment determined without regard to the location of the meter or metering equipment.

43. Service Point Identification (SPID) **(T)**

A code that identifies each unique Service Point and associated Company meter location (if applicable).

44. Single-Family Dwelling **(N)**

A residential building that contains less than three dwelling units. **(N)**

45. Site **(T)**

A. Buildings and related structures that are interconnected by facilities owned by a single retail electricity Customer and that are served through a single electric meter; or

B. A single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, such that

1) Each building or structure included in the site is no more than 1,000 feet from at least one other building or structure in the site;

(M)

2) Buildings and structures in the Site, and land containing and connecting buildings and structures in the Site, are owned by a single retail electricity Customer who is billed for electricity use at the buildings and structures; and **(M)** **(M)**

3) Land will be considered to be contiguous even if there is an intervening public or railroad right of way, provided that rights of way land, on which municipal infrastructure facilities exist (such as streetlighting, sewerage transmission, and roadway controls), will not be considered contiguous.

46. **Small Nonresidential Customer** **(T)**

A Nonresidential Customer who does not meet the definition of a Large Nonresidential Customer, which means the Nonresidential Customer has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service had not exceeded 30 kW.

47. **Standard Service** **(T)**

A service option provided by the Company to a Nonresidential Customer who elects to purchase Electricity from the Company rather than from an ESS.

48. **Summer Months** **(T)**

Summer Months are the six regular Billing Periods from May through October.

49. **Tariff** **(T)**

This Tariff, including all schedules, rules and regulations as they may be modified or amended from time to time.

50. **Theft of Service** **(T)**

Theft of Service occurs when an Applicant or Customer initiates or maintains Electricity Service through fraudulent means, including but not limited to providing false identification or false information to establish an account or credit, paying for Electricity Service with a stolen financial account, tampering with Company equipment including but not limited to the meter, or diverting service.

51. **Renewable Energy Certificates** **(T)**

Renewable Energy Certificates (RECs) consist of the non-power attributes resulting from the generation of Energy by a qualified renewable resource. Such attributes may be fuel, emissions, or other environmental characteristics deemed of value by a REC purchaser.

Non-power attributes include, but are not limited to, any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and any other pollutant that is now or may in the future be regulated under the pollution control laws of the United States; and further include any avoided emissions of carbon dioxide (CO2) and any other greenhouse gas (GHG) that contributes to the actual or potential threat of altering the Earth's climate. These non-power attributes are expressed in MWh.

Non-power attributes do not include any energy, reliability, scheduling, shaping or other power attributes.

52. <u>Transient Occupancy</u> **(T)**

Tenancy at a Premise for a duration of less than 30 days.

53. <u>Utility Provided Service</u> **(T)**

The provision of Electricity Service to a Customer by the Company.

54. <u>Winter Months</u>

Winter Months are the six regular Billing Periods from November through April. **(T)**

RULE B (Concluded)

RULE C
CONDITIONS GOVERNING CUSTOMER ATTACHMENT TO FACILITIES

1. Acceptance of Electricity Service

By establishing or requesting a Service Point (SP) or by continuing an existing SP to the Company's Facilities, an owner or tenant of the property agrees to the following: **(C)**

A. To be bound by the conditions of this Tariff including payment of costs for Electricity Service delivered at the rates and under the terms and conditions of this Tariff as in effect from time to time and all applicable Commission rules;

B. To pay any costs incurred by the Company to provide Electricity Service if Electricity is taken and there is no Customer; and

C. To have Electricity Service discontinued by the Company if there is no Customer.

2. Continuity of Electricity Service

A. **Generally**

Unless otherwise specified in a Customer Service Agreement, the Company intends to make Electricity Service available continuously at standard voltages on the Company's distribution system. The Company does not guarantee constant or uninterrupted delivery of Electricity, the constancy of its voltage or frequency, or against the loss or reversal of one or more phases in a three-phase service. The Company's obligation to provide or continue to provide Electricity Service is subject to the applicable provisions of this Tariff. During periods of imminent or actual system emergencies, the Company may curtail or interrupt service to the Customer in order to maintain system integrity.

B. **Short Term Emergency Curtailment** (C)

During short term curtailment emergencies, the Company may find it necessary or prudent to protect the performance, integrity, reliability, or stability of the Company's electrical system or any electrical system with which it is interconnected by initiating an Emergency Curtailment. A system emergency includes, but is not limited to, events caused by extreme weather, the temporary loss of a major generating plant or transmission facilities, or conditions that violate the North American Reliability Corporation (NERC) standards, or conditions that violate the operating requirements set forth by the Company's Reliability Coordinator. , The Company will contact the Commission prior to an Emergency Curtailment unless circumstances deem prior notice impracticable. Upon the instigation of an Emergency Curtailment, the Company will begin complying with its Curtailment Operating Plan to restore system stability.

The Company's Curtailment Plan and underlying operating procedures include, but are not limited to, steps for implementing rotating outages. During rotating outages the Company would discontinue Electricity Service to a specific number of circuits for approximately one-hour periods. If, after the first hour, system integrity were still in jeopardy, the circuits initially curtailed would have service restored while a second block of circuits would simultaneously have service discontinued. This cycle would continue until the Company determined that system emergency conditions no longer existed. Facilities deemed necessary to public health, safety and welfare are excluded from the rotating outage, as well as feeders serving Customers participating in the Schedule 88, Load Reduction Program. (C)

During system emergencies, Customers having their own generation facilities or access to Electricity from non-utility power sources may choose to use energy from those other sources.

The Company will not initiate its Curtailment Plan to avoid the purchase of high priced power. The Curtailment Plan is periodically updated and submitted to the Commission. (C) (C)

C. **Limitation of Liability**

The Company is not liable to Customers, ESSs or any other person or entity for any interruption, suspension, curtailment or fluctuation in Electricity Service, or for any loss or damage caused thereby, resulting from:

1) Causes beyond the Company's reasonable control;
2) Repair, maintenance, improvement, renewal, or replacement of Facilities, or any discontinuance of service that the Company determines is necessary to permit repairs or changes to its Facilities or to eliminate the possibility of injuries to persons or damage to the Company's property or property of others. To the extent practical, such work will be done in a manner that will minimize inconvenience to the Customer, and whenever practical and applicable, the Customer will be given reasonable notice of such work, repairs, or changes;
3) An ESS's failure to abide by the terms of the ESS Service Agreement or the Tariff;
4) Automatic or manual actions taken by the Company, including but not limited to Emergency Curtailments, that in its opinion, are necessary or prudent to protect the performance, integrity, reliability, or stability of the Company's electrical system or any electrical system with which it is interconnected; and
5) Actions taken by the Company to curtail Electricity use at times of anticipated resource deficiency in accordance with the applicable provisions of this Tariff.

D. **Company's Right to Remove Facilities**

The Company may remove its Facilities as specified in a Customer Service Agreement or when no longer used.

E. **No Customer**

The Company may refuse to maintain Facilities in place or to continue the availability of Electricity Service at any Premises for which the Company has No Customer.

3. Delivery Voltages

A. **Generally**

Electricity delivered under this Tariff is provided at alternating current, 60 hertz, single- or three-phase, at one of the following standard voltages:

B. **Secondary Voltages**

1) **Generally**

Single-phase, 120/240 volts, 3-wire, grounded
Single-phase, 240/480 volts, 3-wire, grounded
Three-phase, 208/120 volts, 4-wire, grounded wye
Three-phase, 240/120 volts, 4-wire, grounded delta
Three-phase, 480/277 volts, 4-wire, grounded wye
Three-phase, 480/240 volts, 4-wire, grounded delta

2) **In Some Locations**

Single-phase, 480 volts, 2-wire (no new service)
Single-phase, 120/208 volts, 3-wire
Three-phase, 240 volts, 3-wire (no new service)
Three-phase, 480 volts, 3-wire (no new service)

C. **Primary Voltages**

1) **Generally**

Three-phase, 12,470/7,200 volts, 4-wire, grounded

2) **In Some Locations**

Three-phase 34,500/19,918 volts, 4-wire grounded service

11,400/6,660 volts, 4-wire, grounded service and 11,100/6,480 volts, 4-wire grounded service

(New installations will not be supplied at 2,400 or 4,160/2,400 volts.)

D. **Subtransmission Voltage**

At 59.8-kV, voltage range is: 57.62-kV to 63.68-kV

At 115-kV, voltage range is: 112.10-kV to 123.90-kV

E. **Selection of Voltage Furnished**

The voltage to be furnished is at the Company's option and will depend upon the characteristics of the Company's distribution system near the SP, the applicable **(C)** rate schedule and the Customer's service requirements.

4. Conditions for Receiving Service

A. **Generally**

This section describes the physical and technical requirements necessary to interconnect the Company's Facilities with the SP.

B. **Rights-of-Way and Access**

The Customer must provide, without cost to the Company, all rights-of-way and easements on the Premises to be served for the construction, maintenance, repair, replacement, or use of any or all Facilities necessary or convenient for the supply of Electricity. The Customer must grant the Company free and unrestricted access to the Premises at all reasonable times for purposes of reading meters, trimming trees, and inspecting, testing, repairing, removing or replacing any or all Facilities of the Company.

C. **Customer-Supplied Equipment**

1) **Customer's Responsibility**

The Customer will, at the Customer's risk and expense, furnish, install, inspect, and maintain in a safe condition all wiring, equipment, apparatus, protective devices, raceways, and enclosures which may be required beyond the SP for receiving and using Electricity. The Company may, at its option, install and maintain Facilities beyond the SP where deemed necessary to provide adequate Electricity Service. For service(s) that **(C)** relate to Transportation Electrification (TE) and Electric Vehicle (EV), the Company may install and operate assets beyond the SP in order to facilitate the expansion of TE across the Company's service territory. **(C)**

2) **Conformance with Codes**

Before the Company will provide Electricity Service, the Customer's wiring and equipment must conform to applicable municipal, county and state requirements, and to accepted standards of the National Electrical Safety Code, the National Electric Code, the Company's published "Electric Service Requirements and Guidelines," and Company standards and practices. As required by law, the Customer or its agent must obtain a certificate of electrical inspection before the Company will provide Electricity Service.

3) **Company's Right to Inspect**

The Company has the right, but is not obligated, to inspect any Customer-owned installation, including all wiring, conduit, meter-bases or supporting equipment up to the electric meter and/or SP, at any reasonable time. **(C)**

4) **Effect of Customer's Load**

The Customer must reasonably balance load between phases of a three-phase service or between ungrounded conductors of a single-phase, three-wire service. The Customer’s equipment must not cause excessive voltage fluctuations on the Company's lines. The Company has the right to refuse, discontinue or to regulate hours of Electricity Service to loads that could, in the Company's opinion, impair Electricity Service to other Customers.

5) **Notice of Changes in Customer Load**

A Customer must give the Company prior written notice before making any material change in either the amount or character of the Customer’s electrical appliances, apparatus or equipment, thereby allowing the Company to ascertain whether any changes are needed in its Facilities and to make such alterations in the charges for Electricity Service as may be required by this Tariff for the changed installation. If damage results to Facilities owned by the Company through failure of the Customer to notify the Company, the repair and, or replacement costs of such Facilities will be paid by the Customer.

6) **Trouble Calls**

When the Company, in responding to a report of an outage or other continuity of Electricity Service problem, determines the cause of the service problem to be solely in the Customer's equipment, the Company will bill the Customer for charges as listed under Schedule 300.

7) **Miscellaneous Equipment Rental**

When available, the Customer may elect to rent equipment from the Company including, but not limited to, transformers, single-phase to three-phase inverters, capacitors, and other related equipment in accordance with charges specified under Schedule 300 and the terms and conditions of the equipment rental agreement.

D. **Hazardous Substances**

1) **Evaluation of Job Sites**

The Company reserves the right, but is not obligated, to evaluate the job site of any new line extension request or of any required maintenance or repairs of existing Facilities for the purpose of identifying any hazardous wastes, hazardous substances or contaminants ("hazards") in soils or surface at the job site, as such hazards are defined under state or federal law.

2) **Information About Hazards**

Information about hazards may include the following:

a) The job site is within an area designated or listed as a hazardous site by a state or federal environmental agency; or

b) The Customer, Applicant or an employee of the Company or agent of the Company, Customer or Applicant reports unusual or inappropriate odor, color or material in, or adverse physical reaction to, soil or surfaces at the job site.

3) **Treatment of Information About Hazards**

If the Company receives information that hazards may exist at a job site, and such hazards may, in the Company's determination based upon applicable state, federal and industry standards, cause a risk to the health or safety of its employees or agents or the viability of equipment in the installation, maintenance, or repair of service, the Company will specify mandatory conditions for the protection of its employees, agents, or equipment. The Company also may require that the Customer or Applicant indemnify the Company against future claims related to the existence of the hazard. The cost of complying with the Company's conditions and with following state and federal regulations for the handling of the hazard, including, but not limited to, the cost of testing, handling, transporting and disposing of contaminated soil will be borne by the Customer or Applicant.

4) **Remediation of Hazardous Conditions**

The Company may require the Customer or Applicant to bear the cost of remediation or relocation of Company Facilities, if conditions cannot be prescribed which, in the Company's judgment, will adequately protect its employees or agents against hazards.

5) **Remediation Costs**

Nothing contained in this Tariff will be construed as obligating the Company to pay any remediation costs relating to hazards.

6) **Hazards in Public Right-of-Way**

This Tariff does not apply to hazards in a public right-of-way, either for purpose of recovery of extraordinary costs associated with installation, maintenance or repair, or for indemnification against future costs, except where the Customer's or Applicant's Premises are the source of the hazards in the right-of-way.

5. Interconnection of Customer-Generator Facilities

The following will apply to all interconnected Customers unless they are covered by an Interconnection Agreement entered into pursuant to the Company's Open Access Transmission Tariff (OATT) on file with the Federal Energy Regulatory Commission (FERC).

A. **Conformance with Regulations**

In order to ensure system safety and reliability of interconnected operations, the facility will be constructed, interconnected, and operated in accordance with all applicable federal, state, local laws and regulations, including the Company's Interconnection Guidelines, as may be amended from time to time.

B. **Control and Protective Devices**

The Customer will furnish, install, operate, and maintain in good order and repair without cost to the Company such switching equipment, relays, locks and seals, breakers, automatic synchronizers, and other control and protective apparatus as shown by the Company to be reasonably necessary for the operation of the facility in parallel with the Company's system. In all cases, the protective relaying design and equipment proposed for the interconnection of generator(s) must be approved by the Company.

C. **Cost Responsibilities**

The Customer is responsible for all costs of interconnection including any costs incurred by the Company. Additionally, the Customer is responsible for any modification to the Customer's facility that may be required by the Company for purposes of safety and reliability. The Customer will also reimburse the Company for administrative costs the Company incurs in this process.

D. **Conformance with Codes**

A facility will meet all applicable safety and performance standards established in the Oregon State Building Code. The standards will be consistent with the applicable standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and Underwriters Laboratories or other similarly accredited laboratory.

E. **Isolating Equipment**

A readily accessible, lockable and visible-break isolation device will be provided by the Customer at the point of interconnection for the Company's use and will be accessible to the Company at all times. At the Company's option, the Company may operate the isolating equipment if, in the sole opinion of the Company, continued operation of the qualifying facility in connection with the Company's system may create or contribute to a system emergency. At the Company's option, Customers installing small photovoltaic generators may customize their isolating equipment.

6. Transformers

A. **Generally**

Transformers furnished by the Company will be sized to the Customer's kVA requirement as determined by the Company. Transformers furnished by the Customer must be approved by the Company prior to connection.

B. **Restrictions on Transformer Types**

The Company will not furnish transformers with unusual specifications or connections, transformers with voltages not provided by the Company, or transformers insulated with gases or fluids other than oil. Dry-type transformers will be furnished only if:

1) A dry-type transformer installed by the Company prior to October 1, 1975, fails while in service.
2) A Company-owned, dry-type transformer requires replacement because of overload, provided no increase in the ampacity of the Customer's service entrance equipment has been made.
3) Multiple transformations are required to provide 120/240-volt single-phase service to load centers located throughout a residential building over five stories where the tenants are directly metered.

7. Relocation or Removal of Facilities

A. **Generally**

Any relocation of Facilities for a requesting party, including builders, developers, Customers or Customers' agents, will be performed by the Company at the requesting party's expense. The Company may require payment in advance of a sum equal to the estimated original cost of installed Facilities to be removed, less estimated salvage and less depreciation, plus estimated removal cost, plus any operating expense associated with the removal or relocation. **(C)**

B. **Public Works Project**

Under the following circumstances, the cost for relocation or removal of Facilities within the public right-of-way will be borne by the Company unless an ordinance, legislation or private agreement specifies other cost responsibilities:

1) The rearrangement can be identified to be for a Public Works Project. Examples of Public Works Projects include but are not limited to public transit or a road widening financed by public funds;
2) Reasonable notice is provided to the Company;
3) The overall project can generally be scheduled during normal work hours (excluding load transfers which may need to be performed outside of normal work hours); and
4) The Public Works Project does not require the Company to make temporary relocations.

C. **Easement**

Costs for permanently relocating Facilities on a private easement will be borne by the requesting party regardless of status as Public Works Project or otherwise.

D. **Permit Job**

Where it can be identified that the requesting party has received a permit through a city or county for work within the public right-of-way that is required for the requesting party's construction project, the requesting party is responsible for all of the costs associated with the necessary rearrangement of Facilities.

E. **Relocation of Overhead or Underground Facilities at Company Expense**

If the necessary work can be performed by Company crews in a single trip to the requesting party's Premises during Scheduled Crew Hours (7:00 a.m. to 3:30 p.m., Monday through Friday, except Company recognized holidays) relocation or removal of overhead or underground service distribution Facilities on or adjacent to the Premises will be performed at Company expense, under the circumstances listed below. For underground relocations, the requesting party is responsible for any necessary trenching, boring, backfilling, conduit, paving, vaults and pads.

1) Such Facilities are idle, meaning not receiving Electricity Service for more than six months, except in the case of conversion from overhead to underground service; or
2) The location of such Facilities in the street area deprive the requesting party of reasonable ingress to or egress from the Premises, provided such Facilities are not on a property line or a property line extended. Generally, one driveway is considered reasonable ingress or egress; or
3) Such Facilities occupy space on the requesting party's Premises that will be used for an expansion of the requesting party's building or plant. In these cases, the Line Extension Allowance will apply for the expansion. Costs exceeding the Line Extension Allowance must be borne by the Customer; or
4) The purpose is to relocate a meter to a more accessible location approved by the Company; or
5) Relocation of a service drop is the only work requested.

If more than one trip is required to accommodate the Customer, the Customer will be billed all costs plus loadings incurred for the additional trips.

F. **Temporary Relocations**

Where the Company is required to temporarily move its Facilities either because the Company cannot move its Facilities to the new permanent placement or the Facilities will be returned to their former location at a later point in time, the costs of the temporary relocation will be borne by the requesting party regardless of its status as a Public Works Project or otherwise. A temporary relocation is defined as any relocation where the Company must move its facilities two or more times within a three-year period.

8. Service Restoration

A. **Generally**

During a major outage due to events such as a major storm, the Company will follow priorities for service restoration as provided below. These restoration procedures are followed in order to restore service to the greatest number of Customers as quickly, efficiently, and safely as possible with special consideration **(C)** given to Customers that are critically essential to public safety and welfare. **(C)**

The Company maintains a list of critical Customers that includes but is not limited **(C)** to hospitals, airports, 911 dispatch centers, fire and police stations, water and sewage treatment plants, emergency media, and emergency communications facilities. The Company will establish a prioritization framework for service restoration to critical Customers that leverages the service priority order in the next section. **(C)**

B. **Service Priority [Order]** **(C)**

The Service restoration work priorities listed below may be performed in parallel by different work crews from different parts of the Company to ensure all Customers are restored as quickly, efficiently, and safely as possible. **(C)**

The priorities for service restoration are generally as follows:

1) **Protect Public Safety**

The Company will clear energized, downed power lines and repair **(C)** equipment that poses a public safety hazard. The Company will ensure that critical [Customers'] facilities have power. **(C)**

2) **Check Generation Facilities** (N)

The Company will determine if repairs are needed to any of its generation facilities. If so, the generation facility will be taken off-line, and the Company will use undamaged generation facilities for power production. (N)

3) **Repair Transmission Lines to Substations**

The Company will make necessary repairs to the transmission system, connecting generation facilities to substations to ensure system stability. The Company will also make necessary repairs to transmission lines, substations, and distribution facilities prioritizing those that connect substations to critical Customers. The Company will continue to repair remaining transmission lines. (C)

4) **Repair Substations** (T)

The Company will repair substations making it possible to restore service to distribution lines. (C)

5) **Repair Feeder Distribution Lines** (C)

The Company will repair distribution lines serving critical Customers as well as lines that may be blocking streets or highways. The Company will repair remaining distribution lines after service is restored to critical Customers. (C)

6) **Repair Tap Lines** (C)

The Company will repair tap lines that serve smaller groupings, such as Residential Customers. (C)

7) **Repair Individual Service Connections** (C)

The Company generally will repair individual service connections last. If Customer-owned equipment has been damaged, such as the meter base, that equipment must be repaired to the satisfaction of the authority having jurisdiction, including obtaining any required permits and inspections, before the Company can restore service at that location. Such repairs are the responsibility of the Customer. (C)

(M)

C. **Other**

The Company will not give priority restoration to any Customer, non-utility generator or ESS, but will employ the above process over the Company's entire territory served. **(M)**

(M)

RULE C (Concluded) **(M)**

RULE D
APPLICATION FOR ELECTRICITY SERVICE

1. **Notification Requirement**

   An Applicant must provide the Company with five business days notice of intent to purchase Utility Provided Service.

2. **Required Residential Identification Standards**

   In order to establish Electricity Service, an Applicant must provide identification as outlined below as well as meet the credit requirements as established in Rule E.

   A. **Residential Applicants**

   1) A Residential Applicant must provide the following information for the person(s) responsible for payment of the account:

      a) Name(s);

      b) Name to be used to identify the account, if different than the actual name(s) provided under (1)(a);

      c) Date(s) of birth;

      d) One of the following: (C)

         i. Social Security Number(s) (SSN);

         ii. an Individual Taxpayer Identification Number (ITIN) issued by the Internal Revenue Service (IRS),

         iii. current, valid Driver's License Number(s)

         iv. other current, valid state or United States Federal identification containing the name and photograph of the person(s) responsible for payment on the account

         v. photo identification from country of origin,

         vi. a current photo identification from school or employer, or,

         vii. other information deemed sufficient by the Company to establish the Applicant's identification. (M)

      e) Service address; (C)(M) (T)

      f) Preferred mailing address; and

      g) Telephone number(s) where the Applicant may be reached. (T)

(D)

(M)

B. **Nonresidential Applicants**

Sole proprietors must provide the identification required under (2)(A) of this rule as well as meet the credit requirements as established in Rule E. All other Nonresidential Applicants must provide the following information for the person(s) responsible for payment of the account:

1) Company name and, if applicable, name used for Doing Business As (DBA);
2) Service address;
3) Preferred mailing address;
4) State of incorporation;
5) Name of an officer or other responsible employee;
6) A current, valid telephone number(s) where the officer or other employee named for (5) may be reached; and
7) A Federal Tax Identification Number.

3. Forms of Requests for Electricity Service

A. An Applicant may request Utility Provided Service from the Company by telephone, electronically or in person at one of the Company's offices. The Company has the discretion to require an Applicant to fill out and sign a written application form.

B. The Company may accept complete third party applications for residential Utility Provided Service. The Company may refuse to process such an application until it receives satisfactory evidence of the third party's authority to request such service.

C. When a Nonresidential Applicant selects Direct Access Service through an ESS, the ESS must submit a Direct Access Service Request (DASR) under the provisions of Rule K prior to initiation of Direct Access Service.

4. Effect of Application

An application does not bind the Company to provide service and does not bind the Applicant to remain a Customer for a period longer than the minimum term specified in the applicable rate schedule.

5. Customer Service Agreements

In most cases, the Company will not require a written Customer Service Agreement as a condition of providing Electricity Service. Certain rate schedules and Rule I of these General Rules and Regulations may require a written Customer Service Agreement.

6. Consequences of Accepting Electricity Service

Any person who occupies or is responsible for Premises where Electricity Service is supplied and/or delivered by the Company where the Company has no accepted current application for Electricity Service is liable for all charges for such Electricity Service, based on the applicable rate schedule. Such persons, however, do not have the rights and privileges accorded to Customers.

7. Refusal of Electricity Service

The Company may refuse an application for Electricity Service until it receives full payment of any past due amount or other obligation related to a Customer's/Applicant's prior account or as also set forth in OAR 860-021-0335.

RULE D (Concluded)

RULE E
ESTABLISHING CREDIT / TREATMENT OF DEPOSITS (T)

1. Residential Credit Standards

A. **Generally**

Before the Company accepts an application for Electricity Service, it may require the Applicant to establish credit standing. OAR 860-021-0200 (hereinafter referred to as "Commission Credit Rules") determines the criteria for establishing credit.

The establishment or reestablishment of credit under this rule does not relieve an Applicant or Customer from complying with all of the Company's rules and regulations on file with the Commission, making prompt payment of bills, and being subject to the discontinuance of Electricity Service for nonpayment.

B. **Establishing Credit**

A Residential Applicant may establish credit standing for new or continuing service by providing one of the following:

1) Submit an authorized letter from his/her previous electric utility, on the utility's letterhead, verifying all of the following: (T)
   a) The dates the Applicant received service;
   b) That the Applicant was the responsible person on a service account where 12 months of continuous, equivalent Electricity Service was received within the prior 24 months;
   c) That the Applicant's service was not disconnected for theft, diversion of service or for tampering with utility facilities; and (T)
   d) That the Applicant's service was not disconnected for nonpayment (T) during the final 12 months that service was received. (T)
2) If the Applicant has previously received Electricity Service from the Company, then the Company may verify the Applicant's creditworthiness based on the same standards listed above;

3) A letter from the Applicant's employer, income provider or authorized representative verifying the Applicant's ability to pay. A letter from an employer must state that the Applicant is currently employed and has been employed the entire 12 months prior to the application, and must contain a telephone number for an authorized representative of the employer. The Company must be able to verify the Applicant's employment; or **(D)**

C. **Residential Deposit Not Required** **(C)**

The Company does not require Residential Deposits starting May 9, 2022 consistent with Commission Order No. 22-129. **(C)**

D. **Treatment and Refund of Residential Deposits** **(D)(T)(M)**

The Company will furnish a receipt upon payment of deposit and will hold the deposit until credit is satisfactorily established or re-established. For the purposes of this section of the rule, credit is considered to be established or re-established if, at the end of 12 months after a deposit is paid in full:

1) The account is current;

2) The Customer has not been issued more than two 5 day disconnection notices during the previous 12 months; and

3) The Customer was not disconnected for nonpayment, meter tampering, or diversion of electricity service during the previous 12 months.

In the event the Customer moves to a new address within the Company's Service Territory and the Company is holding a deposit in accordance with this rule, the deposit, plus accrued interest, will be transferred to the new account.

(D) (M)

E. **Interest Accrual** **(D)(T)(M)**

Deposits will accrue interest at a rate prescribed by order of the Commission and set forth in Schedule 300. If a deposit is held beyond 12 months, accrued interest will be paid by a credit to the Customer's account on the next bill for service following the anniversary of the accrual date. Interest will be prorated on deposits held by the Company for less than a full 12 months.

F. **Delinquent Accounts** **(T)**

When residential service is voluntarily closed, the Company will refund a Customer deposit with interest accrued at the rate as listed in Schedule 300, except that such refund will first be applied to reduce or eliminate any unpaid balance(s) on any other Customer account(s).

The Company is under no obligation to draw on deposits to cure delinquency of an active Customer account. **(M)**

(D)

2. Nonresidential Credit Standards (D)(M)

A. **Generally**

Before an application for Electricity Service is accepted, the Company will require the Nonresidential Applicant or Customer to establish credit as defined below in this rule. The establishment or re-establishment of credit under this rule does not relieve an Applicant or Customer from complying with all of the Company's rules and regulations on file with the Commission, making prompt payment of bills, and being subject to the discontinuance of Electricity Service for nonpayment.

B. **Privacy**

The Company treats credit, financial information or documentation received from Customer as confidential, and requires written or electronic permission from Customer before disclosing to any third parties. The Company will not release such information without such permission unless required by law or the Company in good faith believes such action is necessary to (1) comply with the law or legal process, (2) protect and defend the Company's rights or property or (3) protect the personal safety or property of the Company's other customers or the public.

C. **Establishing Credit**

1) A Nonresidential Applicant or Customer with 12 or more months of continuous and equivalent Electricity Service may establish credit for new or continuing service by:

a) Demonstrating that immediately prior to the date of application, the Nonresidential Applicant or Customer did not, during that 12 months:

1. Receive more than two 5-day disconnection notices;
2. Have service disconnected for non-payment,
3. Owe an account balance from a prior account that when closed was not paid according to its terms;

b) Demonstrating that in the previous 24 months prior to the date of application did not engage in meter tampering, theft or diversion of electricity service; and

(D)(M)

c) Demonstrating that in the 36 months prior to the date of application was not involved in an insolvency proceeding including but not limited to, bankruptcy, receivership, liquidation, bulk sale, or financial reorganization naming the Nonresidential Applicant, Customer, or any principals of the corporation, partnership, or Nonresidential entity as a debtor party to the filing. **(M)**

If the Nonresidential Customer or Applicant cannot demonstrate all of the above conditions, the Applicant or Customer must pay a deposit.

2) Where there is no account history, or fewer than 12 months of Company account history from which the Company can draw from in the establishment or re-establishment of credit, the Applicant or Customer may establish credit for new or continuing service by doing the following:
   a) Providing a form of security satisfactory to the Company; or
   b) Payment of a deposit.
3) Where a Nonresidential Applicant or Customer has multiple accounts for Electricity service, the establishment or re-establishment of credit will be based on all Nonresidential account history and all such accounts must meet the above requirements.

(M)

(D)

D. **Maintaining Creditworthiness** **(M)**

The Company may verify the Nonresidential Customer's creditworthiness at any time, which may include, but is not limited to, the Customer providing financial information or other documentation the Company deems necessary. If the Customer is unable to demonstrate creditworthiness, the Customer may be required to pay a deposit, or provide an acceptable form of other security as described in Section C(2). A lack of credit worthiness is demonstrated by, but is not limited to, public disclosure of significant financial losses; inability to make scheduled debt payments; disclosure of potential bankruptcy; foreclosure of assets by secured creditors or the sale of assets in order to fulfill secured credit obligations.

E. **Nonresidential Deposit Requirement**

A deposit equal to a maximum of two average month's billings for Company charges is required when the Nonresidential Applicant or Customer:

1) Does not satisfy the credit criteria as defined in Section (2)(C) of this rule;
2) Was previously exempted from paying a deposit based upon false information given at the time of application;
3) Was previously terminated for theft of service by the Company or was otherwise found to have tampered with Company facilities, or diverted utility service;
4) Owed an account balance that when closed was not paid according to its terms, or that service was involuntarily terminated.

In lieu of a deposit required under this Section E and at the Company's discretion, a Nonresidential Applicant or Customer may provide other security in a form which the Company finds reasonable and satisfactory in the establishment or re-establishment of credit. Terms and conditions of such security must be established and agreed to between the Company and the Applicant or Customer within the five days from the date the deposit is first required.

In the case of Nonresidential Applicants or Customers with seasonal usage, the maximum deposit amount will be based on the two highest months of usage.

(M)

F. **New or Additional Nonresidential Deposits** (M)

A Nonresidential Customer may be required to re-establish credit where conditions of Electricity Service or the basis upon which credit was originally established have materially changed. A Nonresidential Customer's re-establishment of credit may lead to the requirement of a new or additional deposit, or an expansion of other forms of security. For the purposes of this rule, conditions are considered to have materially changed if any of the following exist:

1) The Nonresidential Customer's Electricity usage is such that, the Company does not have a deposit that equals 1/6 of the estimated annual usage where a deposit has been paid, or the Customer must establish credit at a different service address;
2) The expected billings to the Nonresidential Customer have changed as a result of the Customer's enrollment in Portfolio or other Electricity Service options;
3) The Nonresidential Customer returns to Standard Service from Direct Access Service or Emergency Default Service; or
4) Conditions in Subsection E are found to apply.

G. **Timing of Payment of a Nonresidential Deposit**

If the Nonresidential Applicant has an account balance from a prior service account that was not paid according to its terms, the Applicant must pay the required deposit either in full, or enter into a payment agreement within five business days of the service request. Failure to pay the deposit or enter into a payment agreement within the five days may result in the disconnection of service without further notice.

Absent an account balance from a prior service, if the service is connected at the requested service address, the Nonresidential Applicant must either pay the deposit in full or pay the deposit as it is billed for the new service regardless of whether or not the first month's billing is for a full Billing Period. Failure to pay the deposit may result in the disconnection of service following five days written notice. (M)

If service is not connected at the service address; the Nonresidential Applicant must pay the deposit in full, or have entered into a payment arrangement before service is connected. (M)

Where a non-cash deposit payment is paid to the Company and that payment is subsequently returned by the financial institution for insufficient funds, the Nonresidential Applicant or Customer is subject to service disconnection and will not obtain or retain Customer status. The Company will attempt to notify the Nonresidential Applicant or Customer of the returned payment and will provide a 5-day notice, either verbally or in writing, prior to disconnection.

An existing Nonresidential Customer whose Electricity Service is disconnected for nonpayment of a deposit will be required to pay the full amount of the deposit, plus any applicable Reconnection Charge, Late Payment Charge, and any past due amount(s) before service is restored. Written notice of disconnection for nonpayment of deposit will be provided to Nonresidential Customers five days before service disconnection. The procedures in OAR 860-021-0505 will be used in issuing the notice of disconnection.

H. **Like Ownership**

If the Company, in its discretion, determines that principals of a corporation, partnership, or other commercial enterprise are substantially the same as another corporation, partnership, or commercial enterprise that either is receiving or has at one time received Electricity Service, they are deemed to be the same Nonresidential Applicant or Customer for the purpose of this Rule E. (M)

I. **Treatment and Refund of Nonresidential Deposits** (M)

The Company will furnish a receipt upon payment of deposit and will hold the deposit until credit is satisfactorily established or re-established. For the purposes of this section of the rule, credit is considered to be established or re-established and the deposit, with accrued interest, refunded to the Customer, if, at the end of 12 months after the deposit is paid in full:

1) The account is current; and
2) The Nonresidential Customer has not been issued more than two 5-day disconnect notices during the previous 12 months; and
3) The Nonresidential Customer was not disconnected for nonpayment, or was found to have engaged in theft, diversion of energy, or tampering with Company facilities, during the previous 12 months; and
4) The Company has determined that the condition which necessitated the deposit no longer impedes the Nonresidential Customer's ability to demonstrate creditworthiness and that no new condition or material change would require a deposit.

Prior to refunding the deposit, when a Nonresidential Customer has multiple accounts or one account that includes other products and services, the Company may review such accounts and contractual obligations to determine if unpaid past due balances are owed to the Company. The Company will not review any Residential electricity service accounts. The Company will first apply the refundable deposit and accrued interest to any such past due amounts. Any remaining balance, at the Customer's option, shall be refunded or credited to any account or contractual commitment for which products and/or services were provided.

In the event the Nonresidential Customer moves to a new address within the Company's Service Territory and the Company is holding a deposit in accordance with this rule, the deposit, plus accrued interest, will be transferred to the new account. (M)

J. **Interest Accrual for Nonresidential Deposits** (M)

Nonresidential Customer deposits will accrue interest at a rate prescribed by order of the Commission and set forth in Schedule 300. If a deposit is held beyond 12 months, accrued interest will be paid by a credit to the Nonresidential Customer's account on the next bill for service following the anniversary of the accrual date. Interest will be prorated on deposits held by the Company for less than a full 12 months.

K. **Delinquent Accounts**

When a Nonresidential service account is voluntarily closed, the Company will refund the Nonresidential Customer deposit with interest accrued at the rate listed in Schedule 300, except that such refund will first be applied to reduce or eliminate any unpaid balance(s) on the Nonresidential Customer's account(s) and under any contractual obligations it has with the Company.

The Company is under no obligation to draw on deposits to cure delinquency of an active Nonresidential Customer's account.

(M)

RULE E (Concluded) (M)

RULE F
BILLINGS

1. Basis for Billing

A. Generally

Unless specifically provided otherwise in a rate schedule or in a contract, the Company's rates are based upon the furnishing of continuous Electricity Service to the Customer's Premises at a single Service Point (SP), and at a single voltage and phase. If the Company agrees to additional SPs, each SP is separately metered and billed and treated as a separate Line Extension under the provisions of Rule I. **(C)** **(C)**

B. Individual Metering

Each separately operated business activity and each separate building is individually metered and billed except:

1) Where two or more buildings on one Premises are occupied and used by one Customer in the operation of a single and integrated business enterprise, the Company may furnish Electricity Service for the entire group of buildings through one service connection at one SP; and **(C)**
2) Where a site has service measured and billed from a single meter, a Customer will furnish Electricity to the tenants on its Premises, provided the cost to the tenant for such Electricity is included as a general cost in the rent and is not separately billed or paid.

C. Continuing Nature of Charges

Disconnect and reconnect transactions do not relieve a Customer from the obligation to pay Basic or Minimum Charges that accumulate during the periods where the Company makes Electricity Service available but such service is not used by the Customer.

D. Tax Adjustment

A separately stated tax adjustment is billed in any community or area where a governmental authority imposes a tax or assessment in excess of the limit established by the Commission in OAR 860-022-0040 and 0045.

E. **Resale** **(D)**

1) Electricity Service will not be supplied for resale, except on Premises and through installations where a Customer engaged in resale to tenants prior to November 5, 1973. In such cases, the Customer will bill the tenants at the Company's applicable rates or, if approved by the Company, at the Company's average rate per kWh (the Customer's total bill for Electricity including all charges, adjustments and taxes divided by the associated kWh). The Company will allow billing at the Customer's average rate when the Customer does not have adequate metering to bill tenants at applicable rates or the usage characteristics of the tenants do not lend themselves to standard billing.

2) Electricity service used for the exclusive purpose of transportation fuel is exempt from restriction of resale as directed by OPUC Order 12-013, which "*explicitly permits a customer to re-sell electricity as motor fuel consistent with ORS. 757.005(1)(b)(G)*". **(N)** **(N)**

2. Customer to be Billed; Responsibility for Payment

The Customer receiving Electricity Service is responsible for payment of all Company charges except when an ESS is providing consolidated billing as specified in Section (2) of Rule G. In such case, the ESS is responsible for payment of Direct Access Service and other Company charges.

Customers are responsible for checking their billings and verifying their accuracy.

When a change in occupancy occurs or the Customer otherwise chooses to close an account, the Customer must provide five business days' notice to the Company, before the change will go into effect. The Company may accept a change of occupancy notification from a third party. The Company may refuse to process a change of occupancy until it receives satisfactory evidence of the third party's authority to request such a change. The outgoing Customer (or serving ESS if it is providing a Consolidated Bill) is held responsible for all service supplied to the Premises until the account is closed.

3. Application for Site

In order for multiple accounts to be billed as a Site, the Customer must either obtain Site certification through the Oregon Department of Energy (ODOE) or request Company certification. **(M)**

To request Company certification, the Customer must provide a list of all account numbers and maps or other supporting documentation to demonstrate that these accounts comprise a Site. The Customer will be required to sign and return a letter of understanding before any billing changes are effective. **(M)** **(M)**

As a Site, the Customer's primary account will be assessed the maximum $500 Schedule 115 charge. When the Customer's usage is seasonal, the Company will review the usage from all accounts comprising the Site and assess the maximum or less than the maximum charge as applicable. For nonseasonal Customers, if the combined usage from all accounts comprising the Site is such that the total Schedule 115 charge based on kWh would be less than $500 a month, the Customer is responsible to provide sufficient documentation to the Company in order to be refunded any overpayment. For purposes of Schedule 108, the Customer must be certified as a Site with ODOE and have completed a certified project. Once the project is certified, the Customer must notify and provide documentation to the Company before Schedule 108 billing changes will be made.

4. Meter Readings

A. **Generally**

The Company will keep a record of at least three years of meter readings. Meter readings are the basis for determining all bills rendered for metered service.

B. **Assessed Demand**

At the Company's option, Demand may be determined by test or assessment. The assessed Demand of each motor is the nameplate horsepower of the motor multiplied by 0.825 rounded to the nearest whole kW.

C. **Estimated or Prorated Meter Readings**

The amount of Electricity, Demand or Reactive Demand used by the Customer is estimated by the Company from the best available sources and evidence in the following circumstances:

1) Where a meter is inaccessible due to conditions on the Customer's Premises; or
2) When it is determined that the amount of Electricity, Demand, or Reactive Demand used was different from that recorded or billed; or
3) In preparing opening and closing bills. It is the normal practice of the Company, however, to make reasonable efforts to prepare opening and closing bills from actual meter readings.

D. **Incorrect Metering or Billing**

1) When Utility Service has been unmetered, incorrectly metered or billed, regardless of cause, the Company in accordance to OAR 860-021-0135, may adjust its billings and issue a corrected bill to collect under billed amounts or must issue a refund or bill credit for previous amounts over billed. **(T)** **(C)** **(C)** **(N)**

2) Except as provided in Section (5) of this rule, when an adjustment is necessary:

a)The Company may rebill the Customer the correct amounts when an under billing is identified. The Company may not rebill for charges accruing more than two years before the date on which the Company identified the incorrect bill. The rebill may not include charges accruing more than 12-months from the date of the last incorrect bill.

b)The Company must refund the Customer when an over billing is identified. The Company may not refund amounts overpaid more than three years before the date on which the Company identified the incorrect bill. The refund period may not include overpayments made more than 12-months from the date of the last incorrect bill.

3) The Company will provide written notice to the Customer detailing the circumstances of the adjustment, time period, the adjusted amount of an under or over-billing and the Commission's dispute process. If an over-billing occurs, the Customer will have the option of a refund or a bill credit. For an under-billing, the Company will offer the Customer a time payment agreement or renegotiate the terms of an existing time payment agreement to include the under-billing. A time payment agreement will not apply if the under-billing is due to the conditions listed in Section (4) of this rule.

4) If the under-billing is the result of fraud, tampering, diversion, theft, misinformation, false identification or any other unlawful conduct on the part of the Customer or former Customer, the Company may bill for and collect the full amount owed to the Company without limitation. **(N)**

5) The Company may waive re-billing or issuance of a refund when costs of taking such action are uneconomical or when a meter is found to be less than 2% fast or slow. **(M)**

E. **Special Meter Reading** (M)

The Special Meter Reading Charge, as set forth under Schedule 300, is applied when a Customer has requested more than one Special Meter Reading during the preceding 12-month period to verify the accuracy of a previous meter reading. If the Special Meter Reading results in a billing correction, the Company will waive the Special Meter Reading Charge.

F. **Unmetered Loads**

Electricity Service to fixed loads with fixed periods of operation, such as streetlights, Schedule 92 traffic lights, television amplifiers and other similar installations, may be unmetered for the convenience and mutual benefit of the Customer and Company. Monthly usage is billed in accordance with the Customer's applicable rate schedule. Customers have the responsibility of notifying the Company of changes in connected load. Without such notice, the Company is not obligated to make retroactive adjustments to billings or continue to offer unmetered service to the fixed load.

G. **Special Demand**

All rate schedules are based upon loads for which standard Demand measurements reflect adequately the burden imposed on the Company's system. If a Customer has a load with large short-period fluctuations, the Company reserves the right to employ a Special Demand determination. (M)

H. **Reactive Demand**

All rate schedules assume that the Customer takes a minimum of Reactive Demand. Charges in the rate schedules for Reactive Demand are separate from and in addition to charges under the monthly rate for Demand and Electricity or under any minimum charge. Where the Customer installs equipment to supply part or all of its Reactive Demand requirement, such equipment must be switched in a manner acceptable to the Company. Separate charges for Reactive Demand will not be made when the Customer's Reactive Demand is 30 kVar or less. (M)

5. Presentation and Payment of Bills (M)

A. Generally

The rate schedules in this Tariff set forth the rates for one Billing Period. However, the Company may read meters and render bills for a period shorter or longer than one Billing Period, in which case the charges based on one month of service (e.g. monthly Basic Charges, charges for Facility Capacity and other Demand related charges) and the number of kWh in each of the rate blocks of the rate schedules will be prorated by multiplying by the number of days in the period and dividing by 30. The number of days in the Billing Period must be less than 27 or more than 34 for a bill to be prorated.

B. Prorating Initial and Closing Bills

Initial and closing bills are prorated, unless the time between initial and final use of service is less than 27 days.

C. Prorating for Tariff Changes

Changes in Tariff charges or provisions which become effective with service rendered as of a particular date rather than upon the date of meter readings or billings are prorated based on the number of days during the Billing Period that service was provided under the former and revised rate schedules unless the Company is billing on a daily basis using daily readings. (M)

D. Payment of Bills

All bills are due and payable 15 days from the date of presentation, unless otherwise specified on the bill. The date of presentation is the date on which the Company mails or transmits the bill.

Customers who meet eligibility requirements may request a due date different than the date designated for that customer's regular billing cycle. At no time will the actual due date be earlier in a calendar month than the date requested by the customer, but it may vary up to 7 days. A Customer may change their bill due date up to two times within a 12 month period.

Non-cash payments remitted by Customers in payment of bills are accepted conditionally. A Returned Payment Charge, set forth under Schedule 300, is assessed when the Customer's financial institution refuses to pay as charged.

(M)

If a Customer's non-cash payment is returned by the Customer's financial institution within the last 12 months, future payments must be made in cash, money order, verified credit card payment or cashier's check.

PGE does not allow PGE employees to collect payments at the door. **(N)**

E. **Processing of Payments**

The Company will allocate payments from Customers in the following order:

1) Past due deposits or installments;
2) Required deposits currently due;
3) Past due regulated charges for Electricity Services;
4) Current regulated charges for Electricity Services;
5) Past due charges for optional services by oldest date first; and
6) Current charges for optional services.

F. **Budget Pay Plans**

Budget Pay Plans are available to Residential and Small Nonresidential Customers **(C)** who have satisfactory credit and have no past due balance on their account. No additional charges will be made for rendering bills under a Budget Pay Plan. The **(C)** Company may adjust a Customer's budget pay amount if changes in the Customer's usage patterns or other factors cause the budget pay amount to no longer accurately reflect the Customer's actual billings.

The Company may discontinue a Customer's Budget Pay Plan if the Customer fails to pay the monthly budget pay amount in full by the due date. Customers may discontinue participation in the Budget Pay Plan upon notification to the Company. If a Budget Pay Plan is discontinued, the Customer must pay any unpaid balance determined by subtracting the total amount paid under the Budget Pay Plan from the total amount the bills would have been, based on the actual kWh used. If a budget pay plan is voluntarily or involuntarily discontinued, the Company is not obligated to offer another Budget Pay Plan to that Customer for a period of 12 months from the time the plan was discontinued.

Budget Pay Plans (Continued)

Other monthly charges, such as financing contract and area light charges, will be added to the Customer's monthly bill but are not included when computing the monthly budget pay amount. The Company offers:

1) **Equal Pay Plan**

The monthly payment amount is based upon 1/11 of the anticipated annual bill, adjusted as necessary for Tariff changes. After the annual equal pay anniversary date, the Customer will be charged or credited the difference between the actual usage and the forecasted usage in addition to the updated equal pay amount. Annually, Customer accounts are reviewed to determine the equal pay amount for the subsequent 12 months. Outside of the annual review, at the Customer's request, a present account balance can be settled. Adjustments in the equal pay amount may be made by the Company at times other than annually if the Customer's actual bill would differ significantly from their previously calculated anticipated annual bill. **(C)** **(C)**

G. **Time Payment Agreements**

Residential Customers who are notified of pending disconnection may choose between two Time Payment Agreement options: a levelized payment plan and an arrearage plan as described in OAR 860-021-0415.

H. **Credit Balance**

Except where a Customer is on a Time Payment Agreement, an amount paid in excess of what is owed the Company for services rendered and other applicable charges will be carried as a credit balance on its account and applied to bills for future service unless the Customer requests a cash refund. When a customer on a Time Payment Agreement pays more than the billed amount, the excess payment will be applied to the principal due.

I. **Forced Shutdown of Customer's Operations**

If a Nonresidential Customer's productive operations are completely shut down for a continuous period of more than 15 days solely by reason of fire, flood, wind, action of the elements, acts of God, or other accident or casualty beyond the Customer's control, and the Customer so notifies the Company in writing immediately upon the Customer's knowledge of such event, any minimum charge provision of the applicable rate schedule will be waived during the time of such shutdown. During such time, bills will be computed on the basis of actual Demand and Electricity use and prorated to the number of days involved. The Customer will give notice to the Company prior to resumption of any productive operations.

J. **Late Payment Charge**

A Late Payment Charge may be assessed to any account that is not paid in full each month. For Residential Customers, the Late Payment Charge will be computed as specified in Schedule 300 and applied to the delinquent balance no earlier than at the time of preparing the subsequent month's bill. A Nonresidential Customer may be assessed a late payment charge against any account that is not paid in full each month. A Late Payment Charge will not be applied to a Residential account with a Time Payment Agreement or a Budget Pay Plan that is current. A Late Payment Charge will not be applied to Residential Customers who qualify as an eligible Low-Income Residential Customer as that term is defined in OAR 860-021-0008. **(C)** **(C)**

K. **Bill History Information Service Charge**

Advance payment of the Bill History Information Service Charge, as specified in Schedule 300, is required for each year of requested prior bill information beyond the most recent 12 months. No charge is assessed when the billing information is required to resolve billing disputes filed with the Commission. The Company will provide unformatted and unanalyzed interval usage data, if available, to a Customer who requests such data for the Customer Interval Data Charge specified in Schedule 300. In the case where a Customer requests formatted and analyzed interval data, the charge will be based on a mutually agreeable charge.

RULE F (Concluded)

RULE G
DIRECT ACCESS SERVICE AND BILLING

1. Direct Access Service

All Customers, except Residential, may elect to receive Direct Access Service from an ESS under the terms of the parallel Direct Access schedule (500 series). Direct Access Service is also an option for eligible Nonresidential Customers served on Schedules 485, 489 and 689. **(C)**

A. **Enrollment**

Direct Access Service is only available upon acceptance of an Enrollment DASR by the Company. Prerequisites and notification requirements are as contained in each service schedule and Rule K.

B. **Emergency Default Service**

The Company will provide Emergency Default Service under Schedule 81 when an ESS or the Customer informs the Company that the ESS is no longer providing service or when the Company becomes aware that the Customer is no longer receiving service from the ESS and the Company has not received the 10 business day notice required for Standard Service under the appropriate schedule.

2. Special Requirements for Direct Access Billings

A. **Generally**

A Customer purchasing Electricity from an ESS may choose from two billing options: the ESS bills for all services (ESS Consolidated Bill) or the Company and the ESS each bill for their respective services (Company/ESS Split Bill).

1) **Company/ESS Split Bill**

When the Customer is receiving a Company/ESS Split Bill, the Company may disconnect Electricity Service for nonpayment of Direct Access Service under the guidelines set forth in Rule H.

2) **ESS Consolidated Bill**

When the Customer receives an ESS Consolidated Bill, failure of the Customer to pay the ESS for Direct Access Service does not relieve the ESS of the responsibility to pay the Company for Direct Access Services and any other Company charges.

B. **ESS Billing Responsibilities**

An ESS is responsible for the following:

1) Confirming receipt of Customer usage data within 12 hours of transmittal from the Company;
2) Responding to Customer inquiries regarding ESS charges; and
3) Under the ESS Consolidated Bill option, issuing a timely corrected bill to the Customer when the Company provides revised billing information.

C. **Company Billing Responsibilities**

The Company will provide usage data to the ESS within two business days of the Customer's meter reading. When the ESS provides an ESS Consolidated Bill, the Company will provide bill-ready data within two business days of the Customer's meter reading. The Company is not responsible for computing or determining the accuracy of ESS charges.

D. **Information Included in Billing**

ESS billing for Customers will include the following information:

1) The beginning and ending dates of the Billing Period;
2) The number of units of service supplied;
3) The telephone number, identified as a Company number, to call for outage reporting and other local electrical utility matters;
4) The Service Point Identification (SPIDs) of the Customer; **(C)**
5) The price and amount due for each service or product the Customer is purchasing;
6) Price, power source and environmental impact information in accordance with Oregon Administrative Rule 860-038-0300; and
7) The amount of the Public Purpose Charge, if any.
8) When the Customer receives an ESS Consolidated Bill, the bill will include the following additional information:
   a) Any tax adjustments;
   b) The amount of any transition charge or credit; and
   c) Mandated legal and safety notices in the format provided by the Company.

3. Customer Responsibility

Customers are responsible for checking their billings and verifying their accuracy. Questions regarding ESS charges must be directed to the ESS and questions regarding Company charges must be directed to the Company.

Rule G (Concluded)

RULE H
DISCONNECTION AND RECONNECTION

1. Grounds for Disconnection of Electricity Service

Electricity Service may be disconnected:

A. When service is being received after having obtained Customer status through the provision of false identification or verification of identity;

B. Where Customer facilities provided are unsafe or do not comply with state and municipal codes governing service or the rules and regulations of the Company (OAR 860-021-0335);

C. Where the Customer does not cooperate in providing access to the meter (OAR 860-021-0120);

D. When a Customer requests the Company to disconnect or close an Electricity Service account (OAR 860-021-0310);

E. When a joint account is closed and any remaining Customer(s) fails to reapply for Electricity Service within 20 days, so long as the Company has provided a notice of pending disconnection;

F. Where dangerous or emergency conditions exist at the Premises [OAR 860-021- **(T)**
0315; OAR 860-024-0012(1)]; **(C)**

G. For failure to pay Oregon Tariff charges due for Electricity Service rendered **(T)**
[OAR 860-021-0405; OAR 860-021-0505]; **(T)**

H. For meter tampering, diverting Electricity Service or other Theft of Service;

I. For failure to abide by the terms of a time payment agreement [OAR 860-021-0410(6); OAR 860-021-0415(5)];

J. Where a Customer fails to disclose reasonable load information (860-021-0305); **(N)**
or

K. When the Commission approves the disconnection of Electricity Service. **(T)**

2. Procedures for Disconnection and Reconnection of Electricity Service

The Company will discontinue and reconnect Electricity Service in accordance with the rules of the Commission. These rules, copies of which may be obtained from the Company, are contained in OAR 860-021-0057 and OAR 860-021-0305 through 860-021-0505.

A Field Visit Charge specified in Schedule 300 may be charged whenever the Company personnel visits a service address intending to reconnect or disconnect service, but due to customer action is unable to complete the reconnection or disconnection at the time of the visit. The first Field Visit Charge within a rolling 12-month period will be waived for Residential Customers who qualify as an eligible Low-Income Residential Customer as that term is defined in OAR 860-021-0008. **(C)** **(C)**

A Customer who has avoided disconnection, established credit, or gained reconnection of Electricity Service by making a non-cash payment that is subsequently returned by the Customer's financial institution is subject to disconnection of such service. Prior to disconnection the Company must make a good-faith attempt to notify the Customer of the returned payment and that service will be disconnected without further notice if payment is not received within one business day. When remitting for dishonored funds, the Customer will make the payment in either cash, money order, cashier's check or verified credit card payment.

3. Credit Related Disconnection and Reconnection Charges

No charge is incurred for credit-related disconnection of Residential service. The Company may impose a charge for reconnection of Electricity Service to an Applicant to whom Electricity Service has been disconnected involuntarily. Applicants may call the Company's call center to fulfill the requirements for and request service reconnection. Regular Business Hours for the Company's call center are Monday through Friday, 7:00 a.m. to 7:00 p.m., excluding state-recognized holidays. Applicants who fulfill all the requirements for service reconnection, including making all necessary payments, incur one of the following reconnection charges as set forth in Schedule 300:

(M)

A. **Standard Reconnection** **(M)**

The Standard Reconnection charge is incurred when a scheduled After Hours Reconnection is not requested and a qualified request for service reconnection is received. Standard reconnection requests will result in reconnection of service no later than the end of the next day following the business day on which the request for service is received or treated as received according to this rule. For the purposes of this rule, a business day is 8:00 a.m. to 5:00 p.m., Monday through Thursday, or 8:00 a.m. to 3:00 p.m. on Friday. Calls received after 5:00 p.m., Monday through Thursday* or after 3:00 p.m. on Fridays* are treated as if received at 8:00 a.m. the next business day. **(M)**

The reconnection charge for the first two remote reconnections or first non-remote reconnection in a calendar year will be waived for Residential Customers who qualify as an eligible Low-Income Residential Customer as that term is defined in OAR 860-021-0008. **(C)**

B. **After Hours Reconnection**

An After Hours Reconnection charge is incurred when a Customer requests that service be reconnected at after 5:00 p.m. Monday through Thursday**, after 3:00 p.m. on Friday**, or when service restoration is requested outside the parameters of when the Standard Reconnection charge would apply.

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* Excluding State recognized holidays. **(M)**

** Excluding State- and utility-recognized holidays.

4. Customer Requested Disconnection and Reconnection (M)

Charges for service disconnection and reconnection are as listed in Schedule 300. At the Customer's request, the Company will disconnect and reconnect Electricity Service to ensure safe working conditions. The disconnection and reconnection will be done without charge if the work can be completed on the initial trip or on a second trip scheduled during Scheduled Crew Hours. If, at the Customer's request, the disconnection and reconnection are performed during other than Scheduled Crew Hours or for reasons other than to ensure safe working conditions, Schedule 300 charges for disconnection and reconnection apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In all other cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.

5. Generally

A. In cases where the disconnection is performed at the meter base, the charge for Reconnects at Meter Base will be imposed in order to reconnect service.

B. Should it become necessary to disconnect the Electricity Service at other than the meter base, the Schedule 300 charge for Reconnects at Other Than Meter Base will be imposed in order to reconnect service. Should this require a second trip to the premises to perform the disconnection, the charge for reconnects at Other Than Meter Base is in addition to the normal charge under Reconnects at Meter Base.

C. Should other than authorized Company personnel unlawfully reconnect the Electricity Service, an additional charge set forth in Schedule 300 is imposed.

(M)

(M)

D. No charge is imposed for a reconnection performed during Scheduled Crew Hours in order to provide Electricity Service to a new Applicant. If such a reconnection is performed outside of Scheduled Crew Hours, a charge set forth under Disconnection and Reconnection Rates of Schedule 300 is imposed.

E. In the case where a building owner or manager requests reconnection of Electricity Service for cleaning, showing the unit, or any other purpose other than to provide Electricity Service to an occupant, a charge for reconnection as specified in Schedule 300 will be imposed.

F. In cases where the Company has been requested to reconnect Electricity Service after it has been disconnected at the meter and the visit has not resulted in a reconnection of service due to Customer action or inaction, a Field Visit Charge is assessed as specified in Schedule 300. The first Field Visit Charge (C) within a rolling 12-month period will be waived for Residential Customers who qualify as an eligible Low-Income Residential Customer as that term is defined in OAR 860-021-0008. (C)

6. **<u>Nonwaiver of Right to Disconnect Service</u>**

The Company has the option, but is not obligated, to seek disconnection of Electricity Service if grounds exist. Delay or failure on the Company's part to exercise the option does not constitute a waiver of its right to do so at a later time.

7. **<u>Severe Weather Disconnection Moratorium</u>**

The Company will not disconnect service for nonpayment to a Residential or Small Nonresidential Customer when the weather conditions specified in OAR 860-021-0407(1),(2) or (3) are forecasted in the Company's service territory. This provision applies to the service territory specified in Rule A of this Tariff. The Company will observe forecasted temperatures daily and by 8:00 am each morning from the National Weather Service office in Portland, Oregon. The Company will resume disconnections for nonpayment during the next available business day as operational conditions allow. Upon request from Customers who have been disconnected for nonpayment within 72 hours prior to weather conditions specified in OAR 860-021-0407(1), (2) or (3), the Company will attempt to reconnect service. Reconnection fees authorized in OAR 860-021-0330 may apply.

(M)

8. Wildfire Displacement Disconnection Moratorium (M)

The Company will make a best effort to not disconnect service for nonpayment to a Residential or Nonresidential Customer when the Customer is under a level 2 or 3 evacuation notice or the day after a level 2 or 3 evacuation notice has been lifted, as specified in OAR 860-021-0406(1) and (2). This provision applies to the service territory specified in Rule A of this Tariff. Upon request from Customers who have been disconnected for nonpayment within 72 hours prior to a level 2 or 3 evacuation notice, the Company will attempt to reconnect service. Reconnection fees authorized in OAR 860-021-0330 may apply.

9. Other Remedies

The Company reserves the right to pursue all other legal remedies available to it if grounds for disconnection of Electricity Service exist, whether or not it exercises its right to disconnect service.

(M)

RULE I
LINE EXTENSIONS

1. Purpose

This rule establishes procedures and defines respective cost responsibilities to provide a Line Extension to a builder, developer, Customer or Applicant who requests a Line Extension on its own behalf, or a Customer or Applicant's agent.

A. **Generally**

Line Extensions will be at primary and/or secondary voltage levels. Modifications to transmission or subtransmission voltage facilities or substations are not considered Line Extensions for purposes of this rule and require special contract arrangements.

When an agent requests a Line Extension on behalf of a Customer or Applicant, the agent must provide documentation acceptable to the Company evidencing its authority to request a Line Extension.

B. **Definitions**

1) **Applicant**

For purposes of this rule, an Applicant is a builder, developer, Customer, Applicant or other Customer or Applicant agent requesting a Line Extension to:

a) Serve new construction; or

b) Obtain additional capacity for, or a change in, service conditions relative to existing Distribution Facilities.

2) **Distribution Facilities**

Distribution Facilities are all structures and devices needed to distribute Electricity at any of the primary or secondary voltages listed in Rule C. Distribution Facilities will be installed in accordance with applicable laws, codes and Company standards and practices. It is the Applicant's responsibility to provide the Company with accurate information about their usage including but not limited to nameplate ratings of major installed electrical equipment and the intent to operate equipment above or below the nameplate rating. If damage results to Facilities owned by the Company through failure of the Applicant to fully disclose its load requirement to the Company, the repair and, or replacement costs of such Facilities will be paid by the Applicant.

3) **Line Extension**

A Line Extension is the installation of new, additional or upgraded Distribution Facilities from a point on the Company's existing distribution system that the Company has determined has adequate capacity for the Applicant's planned Electricity needs to the Applicant's Service Point (SP). Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service, upgrades to existing primary lines will not be considered part of the Line Extension. Any new primary or secondary Line Extensions, transformer **(C)**
additions or replacements necessary to serve the new load will be considered part of the Line Extension. However, for residential Electric **(C)**
Vehicle charging-related line extensions, transformer additions or replacements necessary to serve that charging load will not be considered part of the Line Extension. **(C)**

4) **Line Extension Allowance**

The Line Extension Allowance is the portion of the Line Extension Cost that the Company will provide without charge to the Applicant. Estimated annual kWh values used to calculate non-Residential Customer line extension allowances do not reflect onsite generation.

5) **Line Extension Cost**

A Line Extension Cost is the Company's total estimated cost to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs. Line Extension Costs are intended to recover the expenses of labor, material and equipment involved in the design, installation and inspection of the Line Extension. Line Extension Costs include, but are not limited to, labor costs, the cost of transformers, primary and secondary voltage conductors, tree trimming or tree removal, Company indirect charges and the cost of any necessary rearrangement of existing Facilities. Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service and the transformer requires upgrading, the Line Extension Cost will be credited for the estimated original cost, less depreciation, less removal costs, of the existing transformer. However, for residential **(C)**
Electric Vehicle charging line extensions, any transformer additions, or replacements necessary to serve the charging load will not be considered part of the Line Extension. **(C)** Estimates of Line Extension Costs provided to Applicants are valid for six months from the date of issue. After six months the Company reserves the right to provide a revised estimate. The Line Extension Cost does not include payments to a third party for easements, additional costs associated with Underground Line Extension or other additional costs described in this rule.

6) **Long Side Service Connection**

A service connection, which runs parallel to the street, rather than perpendicular to the street.

7) **Primary Voltage Project**

A Primary Voltage Project is a planned undertaking of construction, where the Company initially installs only primary voltage facilities. Primary Voltage Projects include large lot residential subdivisions, industrial parks and other similar complexes. It is expected that within the project each Customer will be served from one or more transformers dedicated to that Customer's use.

8) **Public Thoroughfare**

A Public Thoroughfare is a municipal, county, state, federal, or other street, road, or highway, which is dedicated, maintained and open to public use in which the Company has the right to construct, operate, and maintain Facilities.

9) **Residential Subdivision**

A Residential Subdivision is a parcel of land divided into four or more smaller lots for the purpose of development or sale, which has been platted and filed under Oregon law as a subdivision. It is expected that within the subdivision several homes will be or are served from the same transformer.

C. **Company Requirements**

1) **Company to Determine Route**

The Company will determine the route for all Line Extensions along Public Thoroughfares and may determine the route of a Line Extension made on private property. If the Applicant requests a route different than that determined by the Company, the Company may provide the Line Extension along the requested route if the Applicant pays the Company all additional costs resulting from the provision of that route and the requested route is not contrary to Company standards and practices.

2) **Company Ownership**

The Company will own and maintain all Facilities to the SP.

3) **Company Installation**

The Company will install all Facilities to the SP except that an Applicant for overhead Facilities may arrange to have the Facilities located on the property constructed by an electrical contractor acceptable to the Company, subject to the following conditions:

a) The Company will furnish the design and construction specifications for the connection and perform the necessary surveying;

b) The Applicant will, prior to the beginning of construction, cause the contractor to furnish the Company a certificate naming the Company as an additional insured in an amount not less than $1 million under the contractor's general liability policy;

c) During and after completion of the work by the contractor, the Company will make inspections. If the construction meets the Company's design specifications, the Company will accept ownership, and the Applicant will provide to the Company the title to the construction, together with all rights-of-way and easements required by the Company, free and clear of any liens or encumbrances; and

d) Following receipt of the title, the Company will energize the Line Extension to make Electricity Service available to the Applicant.

e) If, within 24 months of the time the Company energized the Line Extension, it determines that the overhead Distribution Facilities are deficient in materials or workmanship, the Applicant must pay the cost to correct the deficiency to the Company’s satisfaction.

4) **Unusual Distribution Facilities or Nonstandard Construction**

The Company is required to install only those Facilities deemed necessary to render service in accordance with the Tariff. The Company is not required to make Line Extensions which involve additional or unusual Facilities, nonstandard construction, or other unusual conditions. If, at the Applicant's request, the Company installs Facilities which are in addition to, or in substitution of, the standard Facilities which the Company would normally install but which are otherwise acceptable to the Company, the additional cost of such nonstandard Facilities will be paid by the Applicant and will not be subject to the Line Extension Allowance in Schedule 300. In the case of conversion from overhead service to underground service, Section 6 of this Rule applies. In the case of relocation or removal of services and facilities, Section 7 of Rule C applies.

2. Applicant Cost Responsibilities

A. **Payment**

Applicants who have cost responsibilities under this section and Section 3 will make payment in full at the time the Company agrees to make the Line Extension.

Applicant's payment requirements for jobs with Line Extension Costs estimated to be equal to or exceeding $250,000 may be as follows: (M) (T)

a) The Applicant will provide a cash payment of 10% of the estimated Line Extension Cost prior to the Company initiating design work;

b) At the time the Company orders any special order and/or long lead-time electrical and/or pathway material, the Applicant will provide a cash payment to the Company for the full cost of the order; and

c) At the commencement of construction, the Applicant will provide a payment equal to any remaining Line Extension Costs necessary to complete construction. Acceptable means of payment will be at the sole discretion of the Company. (T)

(M)

The Line Extension Allowance will be refunded at the time the Applicant's Electricity Service is established. If Applicant's Electricity Service is not established, payments made under Section (2)(A) are not refundable. **(M)** **(C)**

B. **Applicants for New Permanent Service**

1) **Individual Applicants**

Applicants for new permanent service will be responsible for the Line Extension Costs, less the applicable Line Extension Allowance listed in Schedule 300. In addition, any payments to a third party for easements, permits, additional costs associated with Underground Line Extensions, and all other additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance. **(M)**

2) **Other than Individual Applicants**

The Company will install a main-line primary distribution system to provide service to a project (e.g., a subdivision, industrial park, or similar project) to serve Customers within the project provided the Applicant pays in advance for: 1) the total estimated cost of the installation of a continuous conduit system which includes, but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits; and 2) all other Applicant cost responsibilities based on the expected load within the project. The expected load in a large lot subdivision, industrial park, or similar project is comprised of only those loads projected to be connected within the first five years. Any Line Extension refund owed to the Customer or Applicant will be based on load connected within the first five years.

In residential subdivisions or phases of residential subdivisions where Line Extensions will not require subsequent additional extensions of primary voltage Distribution Facilities to serve the ultimate users within the subdivision, the refund will be based on the Line Extension Allowances for the subdivision calculated in accordance with Schedule 300. **(M)**

C. **Existing Customers**

1) **Nonresidential**

Where an Applicant is an existing Nonresidential Customer requesting an additional SP, the conversion of a single-phase service to three-phase service, or additional capacity, the Applicant will make payment in full at the time the Company agrees to make the Line Extension. The Line Extension Allowance in these cases will be based on the incremental, annual kWh to be served by the Company or, in the case of a change in the applicable rate schedule, equal to four times the increase in annual revenues from Basic and Distribution Charges. **(M)**

2) **Residential**

Where an Applicant is a Residential Customer requesting additional capacity at the same SP, the Line Extension Allowance is as listed in Schedule 300. Any excess amount will be the responsibility of the Applicant. In addition, any payments to a third party for easements, permits and additional costs associated with Underground Line Extensions and all additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

3. Special Conditions for Underground Line Extensions (M)

A. **Applicability**

Underground Line Extensions will be made:

1) When required by a governmental authority having jurisdiction;

2) When required by the Company for reasons of safety or because the extension is from an existing underground system; or

3) When otherwise mutually agreed upon by the Company and the Applicant.

B. **Responsibility for Costs**

1) The Applicant will be responsible for the current and reasonable future costs associated with the installation of the Line Extension's continuous conduit system, which includes but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits. The Company will own and maintain the conduit system once Company conductors have been installed.

2) At its option, the Company may perform the Applicant's responsibilities listed in (B)(1) above at the Applicant's expense or permit the Applicant to perform these responsibilities at Applicant's expense. Where work is to be performed in an existing right-of-way and requires the Company to obtain a permit from a governmental body, the Company may specify additional requirements and place restrictions on the selection of contractors. (M)

3) Where the Company provides trenching and backfilling for installation of applicable residential underground service laterals, the charges specified in Schedule 300 will apply. Estimated actual costs will apply where the Company provides trenching, and backfilling beyond the service lateral installation process. The Applicant will be responsible for all additional costs of excavating rock, furnishing and installing raceway, excavating to a depth in excess of Company standards, manual digging, and the repair of paved roads, walks, and driveways when such work must be performed.

4) Where no other restrictions apply and the Applicant is only considering submersible transformers for aesthetic reasons, the Applicant may request the installation of submersible transformers instead of standard pad-mounted transformers. In this event, the cost set forth under the Transformers Section of Schedule 300 will be paid by the Applicant. (M)

(M)

C. **Additional Services**

1) **Service Locates**

The Company will locate underground water, sewer and water runoff services along the Applicant's proposed trench route on the Applicant's property if requested by the Applicant. The cost set forth in Schedule 300 will be paid by the Applicant.

2) **Service Guarantee/Wasted Trip Charge**

The Company will begin the installation of residential single family underground service laterals within seven working days following the date an Applicant requests such service, except during periods of major storms or other such conditions beyond the Company's control. If the Company does not meet this standard, the Company will pay the Applicant the Service Guarantee Charge in Schedule 300. If, however, Company resources are dispatched to install the residential single family service lateral within the seven-day period and the Applicant's site or other facilities are not ready for service, the Applicant will be assessed the Wasted Trip Charge in Schedule 300.

3) **Long-Side Service Connection Charge**

Where the Applicant requests that the Company provide trenching and conduit for a long-side service connection the charge in Schedule 300 will apply.

4) **Joint Trench Installation Charge**

Upon mutual agreement between the Company and the Applicant, the Company may install telephone and cable services during the installation of the underground service lateral. The parties involved will mutually agree to the price for such service.

4. Refunds

A. Where an Applicant has paid all or a portion of the costs of a Line Extension and additional Customers are subsequently connected to it, the Company will, at its initiative or on request from the Applicant for the original Line Extension, compute on a prorated basis the Line Extension Cost responsibility for up to three additional new Applicants connected to the original Line Extension and make collections and refunds for up to three additional Applicants, provided the following three conditions are satisfied:

1) The original Line Extension has been in service for less than five years when the additional connections are made;

2) The original Line Extension has been in service less than six years when the application for refund is made; and

3) The payment made by the original Applicant was $100 or more.

B. Where additional Applicants are connected within five years of completion of the original Line Extension, and the allowances for the subsequent Line Extensions exceed additional Applicants' costs, the difference may be refunded to the original Applicant under the following conditions:

1) Application for such refunds may be made as additional Applicants are connected, but no more frequently than on an annual basis; and

2) The total amount refunded will not exceed the Line Extension Cost paid by the original Applicant.

5. Special Conditions for Portland River District Undergrounding Project

For an area within the City of Portland, depicted as the shaded region on the map included as Appendix A(1), the applicable Applicant cost responsibilities of Underground Line Extensions, as specified in Section (3)B(1), will be incurred as a Service Connection Charge. This charge will be equal to $39,040.00(2) for a standard 200' X 200' block within the district. For any development area other than the standard size, the charge will be prorated based on the comparative size of that area. **(C)**

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(1) Between Broadway and Glisan Street and behind Union Station, the River District boundary is defined by the railroad right-of-way. Their respective streets or the Willamette River defines all other sections of the River District boundary.

(2) This amount will be applicable through the year 2009. Beyond 2009, the charge will be escalated annually by the Company's then authorized cost of capital. **(C)**

6. Conversion from Overhead to Underground Service

A. **General**

The Company will replace overhead with underground Facilities whenever such conversion is practicable and economically feasible. Customers connected by overhead Distribution Facilities owned by the Company that desire underground service will comply with applicable provisions of this rule.

B. **Payment for Service Changes**

The party requesting conversion from overhead to underground will pay the Company, prior to conversion, the estimated original cost, less depreciation, less salvage value, plus removal expense of any existing overhead Facilities no longer used or useful by reason of said underground system, and the costs of any necessary rearrangements, modifications, and additions to existing Facilities to accommodate the conversion of Facilities from overhead to underground.

C. **Special Conditions**

The conversion of overhead to underground Facilities affecting more than one Customer will be conditioned on the following:

1) The governing body of the city or county in which the Company's Facilities are located will have adopted an ordinance creating an underground district in the area in which both the existing and new Facilities are and will be located, providing:

a) All existing overhead communication equipment and Distribution Facilities in such district are removed;

b) Each Customer served from such electric overhead Facilities will, in accordance with the Company's rules for underground service, make all necessary electrical facility changes on said Customer’s Premises in order to receive service from the Company’s underground Facilities as soon as available; and

c) The Company is authorized to discontinue its overhead service on completion of the underground Facilities.

2) All Customers served from overhead Facilities will agree in writing to perform the wiring changes required on their Premises so that service may be furnished in accordance with the Company's rules regarding underground service. Such Customers must also authorize the Company to discontinue overhead service upon completion of the underground Facilities.

3) When the local government requires the Company to convert overhead Facilities to underground at the Company's expense, the provisions of OAR 860-022-0046 will apply.

4) That portion of the overhead system that is placed underground will not impair the utilization of the remaining overhead system.

D. **Cost of Area Conversions**

Area conversions may involve an allocation or assessment of costs and responsibilities among Customers. Such assessment and collection thereof will be the responsibility of a governmental unit or an association of those affected.

E. **Cost of Additional Circuit Capacity**

Where the Company installs an underground circuit with capacity in excess of the existing overhead, any additional cost to provide such excess circuit capacity will be at the Company’s expense. Applicant cost responsibilities will be as defined in Section (6)(B) plus all reasonable costs for conduit or vault space installed to establish pathways for future circuit capacity.

7. Nonpermanent Line Extension

A. **General**

A Line Extension is nonpermanent when the Company believes service for its intended purpose by the Applicant will continue for less than five years. If the Company believes a requested Line Extension is nonpermanent, the Company will require a cash advance of the entire Line Extension Cost, plus payments to third parties for easements and those costs outlined under Section 3, plus the estimated cost of removing the Line Extension, less any salvage value. If service is used for the intended purpose by the Line Extension Applicant for a period of five years, that portion of the amount advanced by the Applicant which was in excess of the amount that would have been charged for a permanent Line Extension will be refunded to the Applicant with interest.

B. **Greater than 1 MWa Nonresidential Nonpermanent Service**

Nonresidential Line Extension Applicants with Line Extension Costs of $50,000 or greater, with loads in excess of 1 MWa, will sign a contract agreeing to accept Electricity Service at a specified minimum load. If service is terminated within an initial term of five years or if service is reduced to shut-down mode, a Service Termination Charge equal to the Line Extension Allowance (LEA) less 1/5th for each year service was taken at the specified minimum will be assessed as follows:

$$\left[\frac{5 - \text{Years Served}}{5} * \text{LEA}\right]$$

8. Excess Capacity

Excess Capacity will be determined to exist where:

A. The characteristics of the Customer's load require the Company to install Facilities larger than the kVA demand of the load for voltage regulation or other reasons;

B. The Customer requests additional capacity due to planned expansion needs that have not yet occurred; or

C. The Customer requests Facilities that are in excess of what the Company determines is required based on the Company’s analysis of the Customer’s planned load.

When a Customer applying for a service upgrade or a new service Applicant requires Excess Capacity, such installation will be ineligible for a Line Extension Allowance associated with the unused or underutilized portion of the Line Extension. The unused or underutilized portion of the Line Extension will be determined by comparing the cost of the Line Extension with and without the Facilities necessary to serve the Excess Capacity. The Customer or Applicant will also be responsible for a maintenance charge equal to the present value of future maintenance of the excess Facilities at the time the new service or service upgrade is installed. If within five years of installation the excess capacity situation is determined to no longer exist the Company will refund the portion of the Line Extension charges that resulted from the designation of Excess Capacity, including the maintenance charge. It is the responsibility of the Customer to inform the Company as to the change in their capacity requirement within the five-year period.

9. Rules Previously in Effect

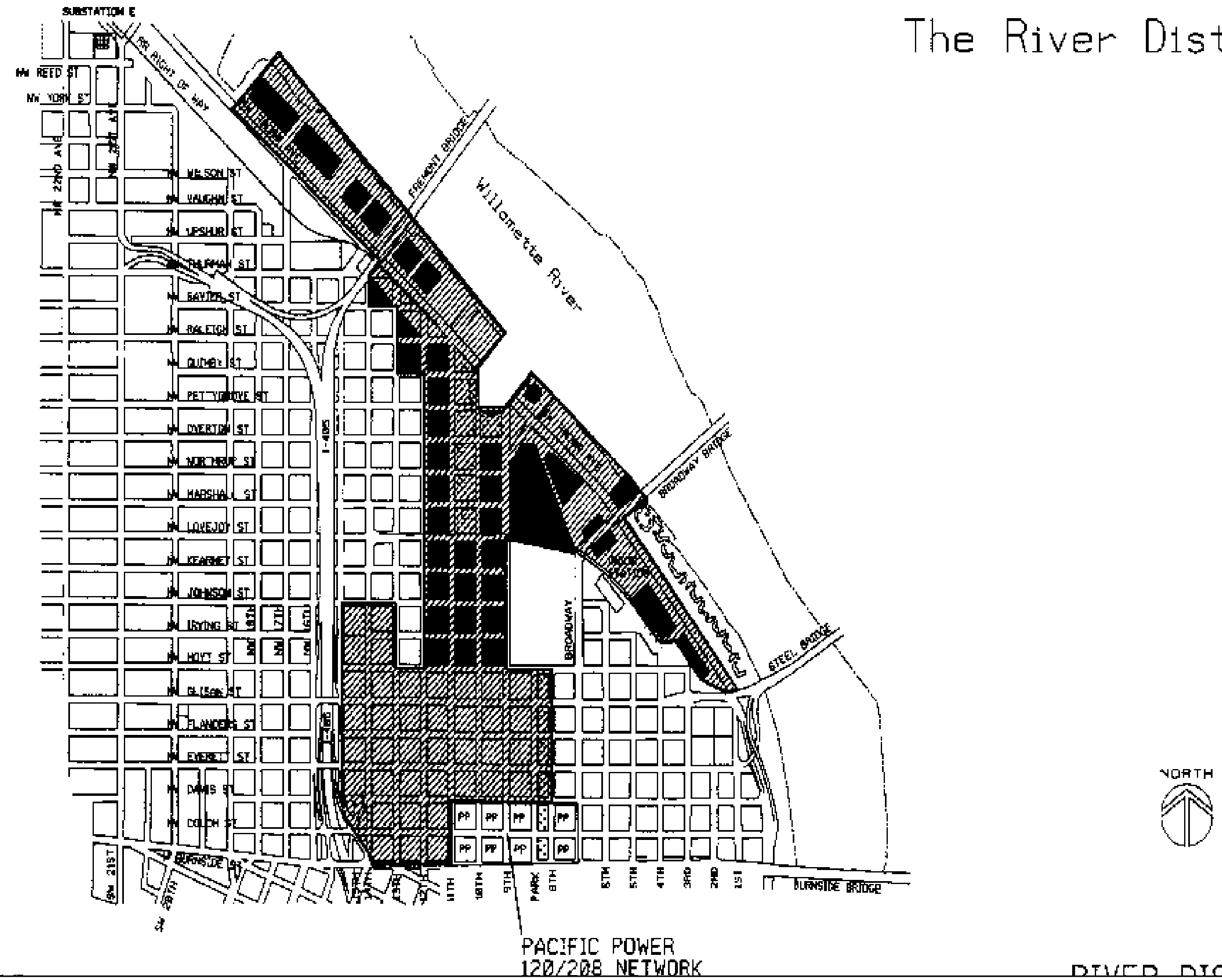
Amounts advanced under the conditions established by a rule or contract previously in effect will be refunded in accordance with the provisions of that rule or contract.

RULE I

APPENDIX A

RULE I (Concluded)

The River District



RIVER DISTRICT

RULE J
STANDARD SERVICE AND PORTFOLIO OPTIONS

1. Standard Service

A. **Eligibility**

A Nonresidential Customer may select Standard Service.

B. **Enrollment**

Standard Service will automatically be provided to a Large Nonresidential Customer who has received Emergency Default Service for five business days and/or does not select Direct Access Service.

A Small Nonresidential Customer that is receiving Direct Access Service may move to Standard Service upon 10 days' notice to the Company. A Large Nonresidential Customer may choose Direct Access Service during an election window and in accordance with the terms and conditions specified in Rule K. A Customer moving to or from Direct Access will be charged a Switching Fee as specified in Schedule 300.

C. **Term**

A Large Nonresidential Customer must remain on Standard Service until he/she has met the notice and term requirements of the Standard Service option selected.

2. Portfolio Options

A. **Eligibility**

A Residential or Small Nonresidential Customer is eligible for service under one or more Portfolio Options in addition to the Standard Cost of Service as contained in the applicable rate schedule.

B. **Enrollment**

Residential and Small Nonresidential Customers may select a Portfolio Option via telephone, in person, over the Internet or by other Company-approved means. The Portfolio Enrollment Charge as specified in Schedule 300 will be incurred for any requested portfolio enrollment change other than the initial enrollment and the first requested change per year.

RULE J (Concluded)

RULE K
REQUIREMENTS RELATING TO ESSs

1. Purpose

A. Generally

Prior to providing Electricity Service to Customers, an Electricity Service Supplier (ESS) must be certified by the Commission, if applicable, and meet the Company's requirements for providing service. The Company may provide information to the Commission certification process, if applicable, regarding the ESS's scheduling capabilities, electronic data transmission capabilities, insurance coverage and credit. **(T)**

B. Requirements for Providing Service

To provide Electricity to a Customer an ESS must:

1) Be certified by the Commission, if applicable;
2) Complete the Company's business application form and submit an Application Processing Fee or Renewal Fee as listed in Schedule 600;
3) Establish creditworthiness as set forth in the ESS Credit Requirements provision of this rule;
4) Demonstrate the capability to meet the information exchange requirements of the Company.
5) Name the Company as an additional insured in the amount of at least $10 million on the ESS's general liability policy;
6) Execute an ESS Service Agreement with the Company confirming the terms and conditions of the service(s) elected and agree to abide by the terms and conditions of the Company's Tariff and the Oregon Administrative Rules;
7) If a Scheduling ESS, execute a transmission service agreement under the Company's Open Access Transmission Tariff; and
8) If a Non-Scheduling ESS, provide the name of the Scheduling ESS.

2. ESS Credit Requirements

A. Credit Review/Applicability

An ESS's participation in Direct Access Service is contingent upon meeting and maintaining the credit requirements set forth in this Tariff and the applicable ESS Service Agreement. The Company will determine whether the ESS meets the Company's initial creditworthiness requirements as set forth below, and advise the Commission whether the ESS has been credit approved or not. The Company will enter into an ESS Service Agreement after ESS's credit has been established, collateral has been obtained and ESS certification by the Commission is complete. The Company will continue to monitor the ESS creditworthiness to determine continuing compliance under the minimum credit requirements.

B. Credit Exposure

An ESS must establish and maintain creditworthiness relative to the Company's credit exposure to the ESS. Credit exposure will include, but not be limited to, the expected liabilities of the ESS.

C. Establishment of Credit

An ESS must establish its creditworthiness as described below.

1) **Creditworthiness Requirements**

Each ESS, or guarantor, must meet the Company's creditworthiness requirements by satisfying all of the criteria below. An ESS who cannot meet the requirements below will provide a collateral deposit as described in item (4) below.

a) **Credit Evaluation**

An ESS seeking to enter into a new ESS Service Agreement with the Company must complete a credit application to provide the financial information necessary to conduct a credit evaluation and establish the ESS's initial credit profile. The Company may require an ESS to complete a new or revised credit application if the ESS's ESS Service Agreement has been terminated, was not renewed, or in any other manner was caused to lapse; if the ESS no longer meets the minimum credit criteria; or periodically based on the Company's standard commercial practice.

The credit evaluation will be conducted by the Company. This evaluation will be completed within 10 Business Days from the Company's receipt of a completed credit application and all relevant financial statements. All information required to evaluate credit will remain strictly confidential between the ESS and the Company, except as otherwise required by law. The Company will notify the Commission of its credit decision upon completion of the Company's credit review. All credit evaluations and associated collateral deposit calculations performed by the Company will be done in a non-discriminatory and consistent manner.

b) **Required Credit Information**

Each ESS and guarantor (if applicable) will be required to provide the following information: (1) completed credit application; (2) three years of annual, audited financial statements; and (3) the latest interim financial statements along with the same interim financial statements from the prior year.

c) **Rating Agency**

An ESS and guarantor (if applicable) must demonstrate a current and maintained long-term, senior unsecured debt rating of Baa3 or higher from Moody's Investor Service (Moody's) or BBB- or higher from Standard and Poors (S&P).

d) **Tangible Net Worth**

An ESS and guarantor (if applicable) must maintain a minimum Tangible Net Worth of $750 million dollars and demonstrate a minimum Tangible Net Worth of $750 million dollars for the prior two-year period. Tangible Net Worth is defined as net worth minus intangibles such as goodwill and rights to patents or royalties.

e) **Credit History**

An ESS and guarantor (if applicable) must not be currently in default under any of its agreements with the Company or under any of its other agreements, and must be current on all of its financial obligations. An ESS and guarantor (if applicable) must pay all past due amounts owed to the Company before credit is established.

2) **Unsecured Credit**

For an ESS and guarantor (if applicable) whose creditworthiness is established by satisfying the above requirements, an unsecured credit limit may be established by the Company. **(C)** **(D)**

The Company may increase or decrease the unsecured credit limit on a case by case basis using accepted commercial credit standards and based on the following criteria: (1) adequate financial statements: (2) credit payment history; and (3) business fundamentals, which includes review of (a) market position; (b) litigation and contingencies; (c) organization; and (d) strategic and financial support. The Company will monitor the established creditworthiness utilizing these factors on an on-going basis. **(C)**

3) **Collateral Requirements**

The ESS will be required to post or increase collateral under any of the following conditions:

a) The ESS does not meet the minimum creditworthiness standards established above;

b) The ESS fails to provide the Company sufficient relevant credit and financial information on an ongoing basis as required in this Tariff and the ESS Service Agreement;

c) The ESS experiences a material adverse change. A material adverse change is defined as the occurrence of any of the following events: (1) the ESS's long-term senior, unsecured debt rating is downgraded by either S&P or Moody’s below BBB- and Baa3, respectively, or (2) a change in condition (financial or otherwise), net worth, assets, or properties which can reasonably be anticipated to impair the ESS’s ability to fulfill its payment and credit obligations; or

d) The Company’s total credit exposure to the ESS exceeds the ESS’s unsecured credit limit and/or any existing Collateral Deposit.

4) **Collateral Deposits**

If collateral is required, the ESS will submit and maintain a collateral deposit as described below.

a) **Amount of Collateral Deposit**

The amount of the collateral deposit required to establish credit will be the sum of the following amounts as applicable:

(i) For ESSs billing customers for services provided by the Company, three times the estimated maximum monthly customer charges owed by the ESS to the Company, where such estimate is based on the usage and Tariff prices expected to prevail over the next 12 months;

(ii) All other charges from the Company to an ESS as estimated over a 90 day period; and

(iii) All invoiced and non-invoiced receivables due from the ESS; or

(iv) Not less than $500,000.

b) **Form of Collateral Deposit**

Collateral deposits will be in the form of (1) cash deposits, (2) Letters of Credit, defined as irrevocable and renewable issued by a major financial institution acceptable to the Company, or (3) guarantees, with guarantors who have a long-term senior, unsecured debt rating of Baa3 or higher from Moody's or BBB- or higher from S&P, unless the Company determines that a material change in the guarantor's creditworthiness has occurred, or, in other cases, through the credit evaluation process described above.

c) **Collateral Deposit Payment Timetable**

ESSs are obligated to post collateral deposits with the Company prior to entering into an ESS Service Agreement. Collateral deposit increases and/or adjustments must be received within two calendar days of a request from the Company. Collateral deposits must be established, maintained or extended within five days of expiration of a collateral deposit.

d) **Interest on Cash Deposit**

The Company will pay interest on cash collateral deposits. Interest will be calculated according to the interest rate prescribed in Schedule 300.

5) **On-going Maintenance of Credit**

a) The Company may review the ESS's creditworthiness, credit limits and the Company's credit exposure on a daily basis. The Company may request an increase in the collateral deposit by providing notice to the ESS that an increase is required as the ESS enrolls additional Customers, the ESS no longer satisfies the minimum criteria commensurate with its unsecured credit line as described above, the Company draws on the collateral deposit or a portion of the collateral deposit pursuant to this Section or the ESS Service Agreement, and/or the Company's credit exposure to the ESS increases.

b) To assure continued validity of established unsecured credit, the ESS will promptly notify the Company if the ESS (i) experiences any material adverse change; (ii) has its long-term, senior unsecured debt rating downgraded by Moody's and/or S&P; (iii) experiences a change in control as a result of merger or consolidation; (iv) sells or transfers a material portion of its assets; or (v) proposes to change its designation from Non-Scheduling to Scheduling or vice versa.

c) The ESS will provide to the Company an updated credit application reflecting current financial and business information pursuant to the terms of this Section; upon the occurrence of any event listed in Section (2)(C)(3)(c); if the ESS has been suspended pursuant to the terms of the ESS Service Agreement; to support a request for an increased credit line; or as the Company may reasonably require on a quarterly basis.

d) The ESS will review and maintain its collateral and establish, extend or increase collateral when required pursuant to this Section.

e) All collateral amounts will be adjusted up or down to the nearest integral multiple of $25,000, but never less than the required initial collateral deposit at the time the ESS enters into and signs an ESS Service Agreement. The Company will notify the ESS of any needed adjustments.

6) **Re-establishment of Credit**

An ESS whose ESS Service Agreement has been suspended due to inadequate credit may re-establish its creditworthiness in the manner prescribed in item C above.

D. **Additional Documents**

The ESS will execute and deliver all documents and instruments (including, without limitation, security agreements and Company financing statements) reasonably required from time to time to implement the provisions set forth above and to perfect any security interest granted to the Company.

3. Electronic Data Transfer Interchange (EDI)

All electronic communications between the Company and the ESS must conform to industry standard electronic data interchange protocols. The ESS must demonstrate its ability to successfully exchange test data for all transactions before the first Direct Access Service Request (DASR) is processed. The ESS will also provide a point of contact to resolve daily electronic data interchange problems. If the ESS is certified, but does not have active enrollments within a six-month period, the Company will request that the ESS retest the interchange.

The ESS must notify the Company of plans to modify its electronic data interchange systems such as the installation of new software or upgrades to software as well as any plans to change system subcontractors when such plans may affect data transfers between the Company and the ESS. The Company may require retesting of data transfers under such circumstances. Where retesting is required, the ESS will be subject to the set-up and verification charge contained in Schedule 600.

When the Company makes any changes to its interchange systems or changes subcontractors, it will promptly notify all ESSs. If the changes require retesting of systems, the Company will not charge ESSs for this testing.

4. Electricity Service Supplier Decertification

A. **Notice to ESS**

The Company may recommend to the Commission decertification of an ESS that the Commission has certified at times other than the annual renewal date. The Company will notify the ESS that it is initiating such action, if applicable.

B. **Criteria for Recommending Decertification**

The Company may recommend decertification, if applicable, of an ESS to the Commission when the ESS fails to comply with the terms and conditions under this Tariff, or fails to perform obligations under the transmission service agreement or ESS Service Agreement. The following are examples of when the Company may recommend decertification of an ESS:

1) Failure to submit an Electricity Schedule that meets the requirements of Section 11;
2) Failure to deliver Electricity according to its Electricity Schedule;
3) Submission of a DASR not authorized by a Customer;
4) Failure to conform with industry electronic data interchange protocols;
5) Failure to comply with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) operating procedures;
6) Failure to pay for services rendered by the Company;
7) The ESS makes a general assignment or arrangement for the benefit of creditors;
8) The ESS becomes bankrupt, a debtor in a bankruptcy proceeding, insolvent, however evidenced, or is unable to pay its debts as they fall due;
9) The ESS files a petition or otherwise commences a proceeding under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it;
10) The ESS has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets;
11) Evidence that indicates the ESS has violated any state or federal customer protection laws or rules, including antitrust laws, during the past three years;
12) The ESS has materially failed to meet its obligations under terms of the ESS Service Agreement so as to constitute an event of default;

13) The ESS engages in unauthorized use of Electricity or a Customer of the ESS engages in unauthorized use of Electricity and the ESS knew about it;
14) Failure to provide a complete, accurate and truthful credit application;
15) Failure to maintain credit requirements; and
16) At the general discretion of the Company.

C. **Notice to Customers**

The Company, upon consultation with the Commission, may transfer the ESS's Customers to the applicable Utility Provided Service prior to ceasing to provide service to the ESS. The Company will notify the ESS's Customers of the transfer in writing as soon as possible. The ESS will be charged a Switching Fee for each Customer transferred as listed in Schedule 600.

D. **Decertification**

Upon decertification, the ESS may no longer serve Customers, and all amounts billed or owed by the ESS are immediately due. The Company will move all Customers served by the ESS to Emergency Default Service and the ESS will be charged the Switching Fee listed in Schedule 600 for each Service Point (SP) **(C)** that moves to Emergency Default Service.

5. Pre-enrollment Information Provided to ESS

With the Customer's authorization, the Company may provide account-specific information, including one year of monthly usage history but excluding credit information, to an ESS. The ESS will be charged the ESS Web Portal Data Access Fee as listed in Schedule 600 for such requests.

6. Customer Enrollment

A. **ESS/Company Relationship**

The ESS may not state or in any way imply that it has been given preferential status by the Company.

B. **ESS Liability**

The ESS will defend, indemnify and hold the Company harmless against all claims of loss made by any Customer arising from claims of inappropriate switching from the Company or another ESS in violation of the solicitation or verification provisions of the Commission, regardless of whether the person or entity doing the marketing or solicitation was an independent contractor of the ESS.

C. **Enrollment DASR**

The ESS must submit to the Company an Enrollment DASR which, at a minimum, includes the Customer's name, Company account number, service address, mailing address, type of service being purchased, name of the ESS, name of Scheduling ESS if different, proposed effective date, Customer's billing preference, and Service Point Identification (SPID) for each Customer that elects **(C)** service from the ESS.

1) Unless the Company deems otherwise, the Company will activate only one (1) Enrollment DASR per SPID per meter reading cycle. When **(C)** multiple Enrollment DASRs for the same SPID are received during the **(C)** same meter reading cycle, the Company will activate the first Enrollment DASR received. The Enrollment DASR must be submitted at least 13 business days prior to the effective date. The Company will notify the ESS of Enrollment DASR acceptance or rejection within three business days of its receipt. For Enrollment DASRs submitted during an enrollment window, the three business day notice period does not begin until the end of the enrollment period. The Company will notify the ESS as to the date the Customer will begin Direct Access Service once interval metering is verified.

2) The Company will charge the ESS the Switching Fee listed in Schedule 600 for each Enrollment DASR received whether accepted or rejected.

3) Upon acceptance of an Enrollment DASR the Company will provide notice within three business days to the Customer's current ESS, if any, of the pending change to a new ESS.

D. **Refusal of Enrollment DASR**

The Company may refuse to accept an Enrollment DASR when:

1) The Company has not received full payment from the Customer for past-due amounts or other obligations owed by it related to regulated charges from the Customer's prior Electricity Service account(s) unless such charges are part of a pending Customer dispute;
2) The Company has not received full payment or the Customer has not made an arrangement to pay the balance owed by the Customer on an existing Budget Payment Option or other agreements;
3) The Enrollment DASR is not accurate and/or complete;
4) The ESS has not complied with provisions of the ESS Service Agreement;
5) The Customer has not completed any term obligation under Standard Service; or
6) The ESS is not certified by the Commission.

E. **Change DASR**

A Change DASR must be submitted when the ESS is requesting a modification. The Change DASR requires up to 13 business days to process. The Change DASR may only be submitted after receipt of the assigned effective date of the information subject to modification and must be submitted at least 13 business days prior to the requested effective date of the Change DASR. There is no charge for submitting a Change DASR. However, when a Change DASR is submitted to change the assigned enrollment effective date to a date that is not a regular meter read date, a Change of Effective Date charge as listed in Schedule 600 will be imposed.

F. **Other DASRs**

The Other DASR forms are as follows:

1) **Rescind DASR**

A Rescind DASR is a request to withdraw an Enrollment DASR and it must be submitted prior to the issuance of an Direct Access effective date. No charge is assessed for a Rescind DASR. A Rescind DASR requires three business days to process. If the Company does not have three business days to process before the effective date is issued, a Cancel DASR is required.

2) **Cancel DASR**

A Cancel DASR is a request for cancellation of Direct Access Service that has been submitted after the Direct Access Service effective date has been issued. No charge is assessed for a Cancel DASR. A Cancel DASR requires three business days to process. Failure to provide adequate notice may require the Customer to take Direct Access Service and/or move to Emergency Default Service until processing is complete.

3) **Drop DASR**

A Drop DASR is a request to stop Direct Access Service and return to Standard Service or to close the service account. A Drop DASR must be submitted at least 13 business days before the requested effective date. Failure to provide adequate notice may require the Customer to continue Direct Access Service and/or move to Emergency Default Service until the Drop DASR process can be completed. The Customer or ESS, whichever initiates the Drop DSAR, is charged the Switching Fee as listed in Schedule 300 or Schedule 600.

The Company may submit a Rescind, Cancel, or Drop DASR on behalf of the Customer to nullify an Enrollment DASR submitted for a Customer without their consent. The Customer will not be charged the Schedule 300 Switching Fee and the Customer's service will not be switched regardless of the required processing timeframes described above.

G. **Customer Information**

The Customer consents to the release by the Company to its ESS monthly usage data when it agrees to take Direct Access Service. Upon acceptance of an Enrollment DASR, the Company may provide to the ESS account-specific information, including one year of monthly usage history, excluding credit information.

H. **Return of Customer Deposits**

Following acceptance of an Enrollment DASR, the Company will return any Customer deposit, net of any amounts owing when the ESS is providing Consolidated Billing. When the Company is continuing to bill the Customer or the Customer has requested split billings between the ESS and the Company, the Company will retain the portion of the deposit appropriate for two months of regulated Electricity Service billings from the Company and credit the excess deposit, if any, to the Customer's account.

I. **Customer Change of Location**

When a Customer moves 100% of its operation from an existing service location enrolled under Direct Access to a [single] new service location and elects to continue Direct Access Service at such new service location ("Change of Location"), the Customer's ESS must submit a Drop DASR for the existing/old service location and an Enrollment DASR for the new service location. Customer requests for a Change of Location will not be considered should the change occur more than 12 months after the old location has been vacated, regardless of whether the service at such old location is nominal or idle or has been discontinued. **(C)**

The following additional criteria will be applicable to a Customer's Change of Location: **(T)(M)** **(T)**

1) The Customer and the ESS must provide written notice to the Company of the intended Change of Location. After processing the written request, the Company will notify the ESS when to send the Drop DASR for the existing/old location and the Enrollment DASR for the new location; **(C)** **(C)** **(C)(M)**

2) For a customer with multiple locations, the projected monthly consumption patterns of the new location will be similar to the prior location;

3) The account for the existing/old location must be: (1) closed, (2) placed on the PGE Daily Price Option prior to the new location receiving service under the terms and conditions of the applicable direct access schedule, (3) idle (i.e. no usage), or (4) placed on Cost of Service with demonstrated nominal use consistent with a vacated location. The Schedule 128 Annual Short-Term Transition Adjustment will apply to the old location if the account is placed on the PGE Daily Price Option under the second option. With respect to the third and fourth options, the Customer carries the burden to demonstrate that the old location is idle or the usage at such location is nominal and consistent with the location being vacated;

4) For Schedules 485, 489, and 490, the new location must be expected to have a Facility Capacity of at least 250 kW;

5) Consistent with the terms and conditions of Customer's Long-Term Cost of Service Opt-Out Agreement, the enrollment period vintage of the existing/old location and the associated Schedule 129 Long-Term Transition Adjustments will be transferred to the Customer's new service location, as applicable;

6) The new service location may be temporarily served under the provisions of the PGE Market Based Pricing Option until such time that the transfer of service location may be effectively executed;

7) The ESS will pay all applicable Schedule 600 charges.

7. <u>ESS Service to Single Service Point</u> **(C)**

Only one ESS may serve any single Service Point (SP). If the Customer is receiving products and services from more than one ESS, the ESS that submitted the accepted Enrollment DASR is responsible for the coordination of services including, but not limited to billing, payment, delivery and scheduling. **(C)**

8. **Discontinuance of ESS Service** (M)

Upon determination by an ESS that it will discontinue service to a Customer because of nonpayment of charges or other reasons provided for in the ESS/Customer Agreement, the ESS will provide the Company with ten business days' notice of such discontinuance. The Company will subsequently move the Customer to Standard Service in the absence of an accepted Enrollment DASR. The Switching Fee listed in Schedule 600 will be charged to the ESS in conjunction with moving the Customer to Standard Service.

9. **Company Billings to the ESS**

The ESS is responsible for payment of all charges assessed to it by the Company. All bills issued under this Tariff are due and payable through electronic payment within 15 days of presentation. Billings unpaid by the due date are subject to a late payment charge as described in Schedule 600. When the ESS disputes charges assessed to it by the Company, the ESS is still responsible to make payment of such charges within 15 days of presentation.

10. **Processing of Payments**

Unless otherwise specified, the Company will allocate payments from ESSs in the following order:

(1) Past due deposits or installments;

(2) Required deposits currently due;

(3) Past due regulated charges for Electricity Services;

(4) Current regulated charges for Electricity Services;

(5) Past due charges for optional services by oldest date first; and

(6) Current charges for optional services.

11. **ESS Scheduling Responsibilities**

At least one day prior to the Day of Flow, in accordance with the ESS Service Agreement and transmission service agreement, each Scheduling ESS will provide the Company with an Electricity Schedule of the expected aggregated hourly load requirements of the Customers for which it has scheduling responsibility subject to the following terms and conditions: (M)

A. **Scheduling Period: Day of Flow** (M)

Each daily scheduling period will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable, "PPT").

B. **Changes in Load**

The Company may require a Scheduling ESS to change its Electricity Schedule if the Company determines the Electricity Schedule does not adequately represent the expected ESS Customer load. If a Customer or Customers are served under an interruptible arrangement by the ESS, the ESS will notify the Company of any interruption coincident with its notification to those Customers and will adjust its Electricity Schedule accordingly.

C. **Failure to Schedule**

An ESS that fails to submit an Electricity Schedule is subject to applicable charges and immediate termination of the ESS Service Agreement. The Customers served by the ESS will be moved to Emergency Default Service.

D. **Confirmation**

The Company reserves the right to confirm with appropriate transmission service providers each Electricity Schedule provided by ESSs and to reject any Electricity Schedule that cannot be confirmed.

E. **Conformance with Regional Requirements**

The ESS will conform to FERC, NERC and WECC scheduling, operating and reporting requirements.

F. **ESS Control Information**

An ESS that chooses to self-provide ancillary services will provide the Company a real-time load and power factor signal via electronic means.

12. Company Scheduling Responsibilities

A. **Change in Load**

The Company will notify an ESS as soon as practical of a planned outage when such outage affects its Customer(s) with a load greater than one megawatt. (M)

B. **Major Outage Procedures** **(M)**

The Company will attempt to maintain system balance during a major outage using all appropriate methods available according to utility practices. The Company may require an ESS to reduce its Electricity Schedule in the event of a major loss of load due to a major outage consistent with the Company's resources. In such case, the Company will notify the ESS when it can resume normal scheduling. The Company will waive related imbalance penalty adjustment provisions during such event. The Company is responsible for responding to inquiries related to major outages. Customers who contact their ESS regarding major outages should be referred to the Company.

13. Settlement

The Company will reconcile total Electricity delivered by the ESS with the total Electricity consumed by the Customers for which the ESS has scheduling responsibility in accordance with Schedule 600 of this Tariff. Customer Electricity consumption will be measured accordingly:

A. **Interval-Metered Electricity**

Where the Customer has an interval-meter installed, Electricity consumed is equal to the metered quantity plus losses as specified in Schedule 600.

B. **Profiled Electricity**

Where interval-meter data is missing, hourly consumption will be estimated using load profiles and adjusted based on available metered data plus losses as specified in Schedule 600. For unmetered loads, consumption will be based on a test or estimated from equipment ratings, adjusted for losses, and allocated to each hour based on hours of usage and whether the equipment is operational during that hour.

14. Operational Order to Deliver Electricity

A. **General**

An “Operational Order to Deliver Electricity” may be issued by the Company upon one hour’s notice for purposes of maintaining the integrity of its electrical distribution system.

(M)

B. **Action by the ESS** (M)

Upon receiving an Operational Order to Deliver Electricity, the ESS will endeavor to deliver its full capability for all its Customers served by adjusting its Electricity Schedule.

C. **Compensation**

The Company will waive all energy imbalance service charges and penalty provisions for an ESS that demonstrates substantial compliance with an Operational Order to Deliver Electricity. Compensation for excess Electricity delivered in accordance with the Company's Operational Order to Deliver Electricity will be at a rate equal to the higher of:

1) The ESS's direct cost of such Electricity; or
2) The highest incremental cost of Electricity purchased by the Company during each hour of the Operational Order to Deliver Electricity.

15. Preemption

In addition to an Operational Order to Deliver Electricity, the Company may take automatic or manual actions that, in its opinion, are necessary or prudent to protect the performance, integrity, reliability or stability of its electrical system or any electrical system with which it is interconnected. During such period, delivery of Electricity to Customers may be curtailed or interrupted by the Company even though the ESS continues to supply Electricity to the Company. The payment for such Electricity will be made at a rate equal to the higher of:

A. The ESS's direct cost of such Electricity; or

B. The highest incremental cost of Electricity purchased by the Company during each hour of the preemption.

16. Dispute Resolution

A Dispute Resolution process is contained in the ESS Service Agreement. (M)

RULE K (Concluded)

RULE L
SPECIAL TYPES OF ELECTRICITY SERVICE

1. Service of Limited Duration (Temporary Service)

A. Definition

"Service of Limited Duration" or "Temporary Service" means Electricity Service to a Customer who, in the Company's opinion, will not continue to receive service for the minimum of five years.

B. Availability

Service of Limited Duration includes installations requiring only an overhead service drop, a service lateral to existing underground Facilities, or service to Premises where Facilities are in place, whether or not a meter setting is required. Charges will be in accordance with Schedule 300. Where Facilities other than those specified above are needed to provide service, the provisions of Rule I, Line Extensions, will apply.

1) The Company provides Standard Temporary Service as well as an optional Enhanced Temporary Service subject to the following conditions.

   a) Standard Temporary Service will be provided to Applicant-supplied service entrance equipment in accordance with applicable codes and regulations. Electricity Service will be metered and billed according to the applicable rate schedule until the account is closed or converted to permanent service.

   b) Nonresidential Customers may receive Standard Temporary Service from an ESS and are required to pay for the installation and removal of interval metering and meter communications (telephone or other method) necessary to deliver such service.

   c) Enhanced Temporary Service is provided on an optional basis for the construction of residential single-family and multi-family dwellings in underground service areas. Under Enhanced Temporary Service, the Company will provide and install an unmetered service pedestal for use until the permanent service is installed.

d) The fixed charges for Enhanced Temporary Service specified in Schedule 300 include Electricity usage for up to 6 months. After 6 months Customers may extend Enhanced Temporary Service at additional 6-month time periods at the fixed renewal charge specified in Schedule 300. After 24 months, a permanent connection is required. **(C)** **(C)**

C. In order to qualify for Enhanced Temporary Service, the Applicant must agree to the following:

1) Service will be used only for lights, tools, and equipment necessary for the construction of residential dwellings;

2) Service will not be used for the operation of permanently installed appliances or equipment or to heat or dry structures under construction;

3) For multi-family construction, the number of unmetered service pedestals can vary depending on the necessary service outlets per units/buildings under construction; and

4) Unless the trenching or boring work is provided by the Company under the terms of Schedule 300, the Applicant will provide a continuous underground conduit, suitable for Electricity Service, from the permanent meter base to the location of the Enhanced Temporary Service pedestal for the Company to use in later providing the permanent service.

In the event that Enhanced Temporary Service is used for purposes other than those specified, the Company will estimate the amount of Electricity used and bill according to the applicable rate schedule. The Company may restrict future availability of Enhanced Temporary Service in such cases.

2. <u>Emergency Service</u>

A. **<u>Definition</u>**

"Emergency Service" means Electricity Service supplied or made available to load devices which are operated only in emergency situations or in testing to respond to such situations. Electricity Service for freeze protection or similar applications likely to occur annually and/or only in the coldest time of the year is not an Emergency Service.

B. **Availability**

Emergency Service will be provided only to permanent Customers. Where the Company must furnish, install and maintain additional or specific facilities or capacity to provide Emergency Service, the Customer must pay the entire cost of the Line Extension and is ineligible for the Line Extension Allowance as described in Rule I. The Customer is also responsible for a maintenance charge equal to the present value of future maintenance of the facilities at the time the service is installed. Where the Customer modifies its usage and consistently uses the service at its transformer rating within a five year period, the portion of the Line Extension charges that resulted from the designation of Emergency Service including the maintenance charge will be refunded to the Customer.

3. Intermittent Use Service

A. **Definition**

"Intermittent Use Service" means continually available Electricity Service which a Customer uses intermittently for a short duration and at a high Demand level such that standard Energy or Demand measurement does not adequately reflect the burden imposed on the Company's equipment and facilities. Examples of Intermittent Use Service include service to test facilities, elevator or hoist motors, welding equipment, x-ray equipment and whole house instant or tankless hot water heaters with a Demand of 18 kW or greater.

B. **Availability**

Intermittent Use Service will be furnished only to permanent Customers. Where the Company must furnish, install, and maintain additional or specific facilities or capacity to provide Intermittent Use Service, the Customer must pay the entire cost of the portion of the Line Extension associated with such service and is ineligible for a Line Extension Allowance for that portion of the service. The Customer is also responsible for a maintenance charge equal to the present value of future maintenance of the facilities at the time the service is installed. Where the Customer modifies its usage and consistently uses the service at its transformer rating within a five year period, the portion of the Line Extension charges that resulted from the designation of Intermittent Use Service including the maintenance charge will be refunded to the Customer.

4. Alternate Service

A. **Definition**

"Alternate Service" means Electricity Service to a Customer from a second independent primary voltage circuit for which the Company provides a second path for supply of service in the event of the failure of the first electrically independent circuit. Alternate Service facilities include, but are not limited to, the substation and distribution line capacity reserved for the Customer's exclusive use, plus any additional metering or switching equipment required which is beyond the Company's normal responsibility.

B. **Availability**

The Company will provide Alternate Service at the request of a Customer who demonstrates a requirement for a higher than normal degree of service continuity. The Company will maintain Alternate Service to the best of its ability consistent with the need to operate and maintain its overall distribution system and will notify the Customer if the Alternate Service is to be discontinued for any extended period of time. Alternate Service will be provided only under a contract between the Company and a Customer.

C. **Contract Provisions**

Alternate Service contracts will provide generally as follows:

1) The Customer will specify its Alternate Service kVA Demand requirement and the period of time for which Alternate Service is required;
2) The design and arrangement of both the preferred and alternate circuits will be at the option of the Company. The Customer will install and maintain an automatic transfer switch. The characteristics, arrangement, and operation of such switch and the associated circuits will be subject to the Company's approval.
3) The Customer will pay the Company either a monthly charge or a lump sum payment to cover the Company's cost to provide the Alternate Service. The rate of the monthly charge, per kVA of alternate capacity required, will be the levelized future revenue requirements imposed on the Company by its investment in Alternate Service facilities and all future maintenance of those facilities. The lump sum amount will be the present worth of the items used to determine the monthly charge.

4) The kVA Demand on the Alternate Service will be measured by separate kW and kVAr Demand meters. Should the Customer impose a kVA Demand on the Alternate Service facilities that is in excess of the amount contracted for, the Customer will pay the Company an additional monthly charge per kVA of excess Demand for that month and the succeeding 11 months. The amount will be determined by multiplying the excess Demand by the monthly rate per kVA as determined in (4)(C)(3) above. In addition to this monthly charge, the Customer must either promptly modify plant operation to prevent future excess kVA Demand or execute a supplemental agreement with the Company for the additional amount of Alternate Service required. The facilities cost for Alternate Service will be based on the costs of the Company in effect at that time and will be calculated and billed as determined in (4)(C)(3). The Customer will be billed the actual cost of any damage to the Company's facilities caused by the Customer's Alternate Service Demand in excess of the contracted amount.

5) The Customer may terminate the agreement for Alternate Service upon 30 days' written notice to the Company. If the Customer is making monthly payments for the Alternate Service, it will, upon termination, pay to the Company the amount that the Company's present-day investment in such facilities exceeds the value to the Company at that time. A Customer who has made a lump sum prepayment to the Company will, upon termination, receive from the Company an amount equal to the current value to the Company for those facilities dedicated to the Alternate Service. Such amount will not exceed the amount of the initial prepayment.

D. **Existing Alternate Service Customers**

Unless otherwise specifically provided, a Customer receiving Alternate Service on or before August 1, 1975 will continue to receive Alternate Service without charge subject to the conditions listed below.

1) Should the nature of the Premises change, Alternate Service without charge will be discontinued after 30 days' written notice by the Company.

2) Should an additional investment be required of the Company to continue to furnish Alternate Service, the Customer will be so notified and given the option of limiting the kVA Demand of Alternate Service required to that which is available from the Company at no charge or executing an agreement with the Company for Alternate Service in accordance with this rule.

3) Should a Customer receiving Alternate Service without charge modify its facilities such that an increase in Alternate Service requirement occurs, the Customer must execute an agreement with the Company for Alternate Service in accordance with this rule.

5. Distribution Facilities Service

A. **Definitions**

"Distribution Facilities Service" means the installation, operation, maintenance and ownership by the Company of Distribution Facilities that are dedicated solely to service on a Customer's site for the Customer's exclusive use, and located on the Customer's side of the Service Point (SP). "Distribution Facilities" includes **(C)** primary and secondary cable, distribution transformers, and associated equipment terminating at Customer-owned service entrance or meter base for each building or structure.

B. **Availability**

The Company will provide Distribution Facilities Service on an optional basis to Customers with a minimum installed transformer capacity of 500 kVA as mutually agreed to by contract between the Company and Customer. Upon request of a Customer and agreement by the Company, Distribution Facilities Service will be provided to an existing Customer-owned distribution facilities installation subject to all conditions of this rule and subject to Company determination that the existing system meets Company Distribution Facilities requirements.

If the Customer's existing system does not meet the Company's current standards but is otherwise acceptable to the Company, with respect to safety and reliability, the Company may choose to offer Distribution Facilities Service to the Customer provided that a mutually agreeable plan to upgrade the system, as necessary, is developed and included in the Distribution Facilities Service Charge.

C. **Contract Provisions**

Distribution Facilities Service contracts will provide generally as follows:

1) **Distribution Facilities requirements**

The Distribution Facilities, on the Customer's side of the SP, will meet Company distribution system requirements in a manner consistent with Company practices, Company overhead and underground construction standards, applicable standards of the National Electric Safety Code (NESC), American National Standards Institute (ANSI) and the Oregon Electric Service Requirements. **(C)**

2) **Facilities design and installation**

The design and arrangement of the Distribution Facilities will be as agreed to by the Customer and the Company. The Company will generally meter Electricity Service at the SP. **(C)**

3) **Memorandum of Agreement**

A Memorandum of Agreement will be filed with the appropriate county in order to provide notice of the existence of the Distribution Facilities Service contract.

4) **Access**

The Customer will provide the Company access to the Distribution Facilities on the Customer's premises without restrictions or structural impediments for purposes of maintenance and repair of the Distribution Facilities.

5) **Distribution Facilities Service Charge**

The Customer must pay the Company a monthly charge to cover the Company's cost to provide the Distribution Facilities Service. The rate of the monthly charge will be the levelized revenue requirements imposed on the Company by its investment in Distribution Facilities and all future maintenance of those facilities. This charge is in addition to any charges for the furnishing or delivery of Electricity to the SP. No Line Extension **(C)**
Allowance as described in Rule I will be applied to Distribution Facilities.

6) **Load Requirements**

The Customer will promptly notify the Company of any changes in electrical load. The Customer will reimburse the Company for all costs of modification, replacement or repair of any transformers or other Distribution Facilities necessitated by increased electrical load.

7) **Maintenance and Repair**

The Company and Customer will be responsible for components of maintenance and repair as set out in the contract. All modifications or enhancements to the Distribution Facilities will be performed by the Company unless otherwise agreed to, in writing, by the Company.

8) **Termination**

The Customer may terminate the contract for Distribution Facilities Service upon purchase of the Distribution Facilities at a purchase price specified, and on terms set out, in the contract or as otherwise mutually agreed upon. Transfer of Distribution Facilities to Customer ownership may occur only after the Distribution Facilities have been approved by local authorities as meeting all applicable codes and requirements for such non-utility owned distribution facilities. Any costs to modify the facilities are the obligation of the Customer.

RULE L (Concluded)

RULE M
METERING

1. Generally

A. Company Responsibility

The Company will own/lease, install, test, read, remove, replace and maintain meters for each Customer receiving metered Electricity Service. The meters and any meter transformers installed remain the Company's property and may be removed by the Company upon discontinuance of service.

B. Customer Responsibility

The Customer will, at Customer's expense, furnish, install and maintain the meter socket and all raceways and enclosures necessary to accept the Company's meters and metering transformers. The Company will provide metering transformers when required for installation by the Customer. The Customer will exercise proper care to protect Company property installed on the Premises, will not break the Company's seal or seals, and will pay for all loss or damage to such property caused by the Customer's negligence or misuse.

The Customer must grant the Company free and unrestricted access to the Premises at all reasonable times for purposes of inspecting, testing, reading, repairing, removing or replacing any or all metering equipment of the Company.

C. Meter Accuracy and Testing

The Company will, at a Customer's or Electricity Service Supplier's (ESS) request, **(T)**
test the accuracy of the registration of a meter once per 12-month period. If a Customer or ESS requests such a meter test more than once in a 12-month period, the Company will impose a Meter Test Charge as listed in Schedule 300. The Company will refund to the Customer or ESS the Meter Test Charge if the meter is found to be more than 2% fast or 2% slow.

2. Metering Requirements **(D)**

A. **Standard**

The Company will install at the Customer's Service Point (SP) a meter capable of registering kWh usage. Meters capable of registering Demand, Reactive Demand, and time of use or interval usage will be installed when required due to the Customer's Electricity usage or rate schedule.

B. **Interval Metering**

The Company will meter Electricity usage in intervals of 30-minutes or less for Customers that purchase Electricity Service from an ESS, with the exception of unmetered loads. Where an interval meter does not exist at the time the Company receives a Direct Access Service Request (DASR), the Company has 30 days from the date the DASR is accepted to install such meter. Once installed, the Customer may begin purchasing Electricity from the ESS. A Customer who would not normally receive interval metering may, at its request, have an interval meter installed at the charge established in Schedule 300.

C. **Pulse Output Metering**

The Company will provide a connection to its metering facilities to supply kWh data pulses to Customer-owned load control equipment. The Company will also supply a Demand interval timing pulse, provided the Customer's load-control equipment is of the ideal curve or forecasting type. A Customer may have a pulse output metering installed for the charge established in Schedule 300.

D. **Nonstandard Metering Requested by ESS**

The Company installs metering that corresponds to the Customer's Electricity usage and rate schedule requirements. If an ESS requests that the Company offer a specific meter capability, function or metering service not currently supported, the Company must approve or deny the request within 10 days. If the request is approved, the Company will file with the Commission to offer such meter or metering service within 30 days. If the request is denied, the ESS may appeal the decision to the Commission.

E. **Residential Non-Network Meter**

1) Upon request of a Residential Customer, the Company will install at the Residential Customer's SP, a non-network meter. A non-network meter does not have the capability to record, store or transmit customer interval load data. The Company will charge the customer the cost of a Special Meter Reading as specified in Schedule 300. If the Customer is not the owner of the premises, the Customer must provide authorization from the owner to the Company. The Company will charge the Customer the Company's costs of owning, installing, maintaining and reading the non-network meter. Prior to the Company's installation of the meter at the Customer's premises, the Customer must pay the cost of installation in full. The non-network meter installation charge and recurrent charges are set forth in Schedule 300. **(C)**
2) A Customer may request a non-network meter for that Customer's premises only.
3) If in the Company's opinion access to the meter is restricted, the Company will seek the Customer's cooperation through mutual agreement in obtaining unrestricted access. If agreement cannot be reached and access remains restricted, disconnection of service could result after reasonable notice is provide.

4) Customers with non-network meters are not eligible for time-of-use rates and may be excluded from participating in future Company offered programs, for which a network meter is required. (M)

3. Meter Location

A. **Generally**

Meters are to be installed on the outside of buildings at a location which is easily and conveniently accessible by Company personnel and by the Company's distribution lines; however, with the Company's prior approval, meters for nonresidential buildings may be located indoors if accessible to Company personnel during Scheduled Crew Hours.

B. **Locating Meter on Company's Pole, Pad, or Vault**

If no satisfactory location for the meter is available on or in the Customer's building, the meter and related equipment may, at the Company's option, be installed on the Company's pole or in a Company vault or enclosure. In such event, the Customer will pay the charge specified under Meter Installation Rates of Schedule 300.

C. **Unrestricted Access to Network Metering Equipment**

When in the Company's opinion the meter's communication signal/mechanism is impeded because of customer action or inaction, the Company may require the Customer, at the Customer's expense, to relocate the meter socket to a location satisfactory to the Company.

D. **Metered on the Non-Service Side of Transformation**

If the Company installs or maintains the metering equipment on the primary voltage side of the meter and the Customer is receiving service at secondary voltage, billing will be based on meter registration less 1-1/2%. If the meter is located after the occurrence of transformation, and the Customer is receiving service at primary voltage, the billing will be based on meter reading plus 1-1/2%. These billing adjustments compensate for transformer losses or gains.

E. **Customer Options for Relocating Residential Meter**

A Residential Customer and owner of the premises may request that installed metering equipment be relocated to a different location on the Customer's property if acceptable to the Company. The Customer will incur the cost of relocating the meter as described in Schedule 300.

RULE M (Concluded)

RULE N
CURTAILMENT PLAN

1. Purpose and Overview of the Curtailment Plan

This plan identifies the process by which the Company would initiate and implement load curtailment during a protracted regional Electricity shortage to ensure uniform treatment of all regional Customers. This plan would be activated only when declared necessary by State authorities.

The goal of this plan is to accomplish Curtailment while treating Customers fairly and equitably, minimizing adverse impacts from Curtailment, complying with existing State laws and regulations, and providing for smooth, efficient and effective Curtailment administration.

2. Definitions

The following definitions apply to terms used in this plan:

A. **Base Billing Period**

One of the Billing Periods that comprises the Base Year. Base Billing Period data are weather-normalized before being used to calculate the amount of Curtailment achieved.

B. **Base Year**

Normally, the 12-month period which immediately precedes imposition of State-initiated load curtailment.

C. **Critical Load Customer**

A Customer that supplies essential services relating to public health, public safety, welfare, or Electricity production.

D. **Curtailment**

Reduction in Electricity usage irrespective of the means by which that reduction is achieved.

E. **Curtailment Target**

The maximum amounts of Electricity that the Customer may use and still remain in compliance with State Action. The Curtailment Target is figured individually for each Customer by Base Billing Period.

F. **Excess Power Consumption**

The lower of the following two values for loads subject to penalty:

1) The difference between the Customer's actual (or metered) consumption level during a Billing Period and the Curtailment Target; or

2) The difference between the Customer's weather-normalized Electricity usage during a Billing Period and the Curtailment Target.

G. **General Use Customer**

Any Nonresidential Customer who purchased less than five average megawatts (43,800 MWh) during the Base Year.

H. **Major Use Customer**

A Customer who purchased more than five average annual megawatts (43,800 MWh) during the Base Year.

I. **Plan**

The Curtailment Plan.

J. **Region**

The states of Washington, Oregon, and Idaho, and those portions of Montana that are west of the Continental Divide and/or within the Balancing Authority area **(T)** of Northwestern Energy.

K. **Regional Plan**

The Regional Electric Energy Curtailment Plan as adopted by the Commission.

L. **State**

The Public Utility Commission of Oregon.

M. **State-Initiated**

Actions taken by the State to implement individual load curtailment plans within its jurisdiction.

N. **Threshold Consumption Level**

The maximum amount of Electricity that a Customer can use during mandatory load curtailment without being subject to penalties under this Plan.

O. **Utility Coordinator**

The Director of the Northwest Power Pool.

P. **Utility Curtailment Reports**

Report(s) summarizing Curtailment data, such reports are to be submitted monthly to the Commission and the Utility Coordinator.

Q. **Weather-Normalization**

The procedure used to reflect the impact of weather on load levels. Sometimes referred to as weather-adjustment.

3. Curtailment Stages

State curtailment directives apply to all retail loads served within the State of Oregon. Under the Plan, Curtailment is requested or ordered as a percentage of historical, weather-normalized (Base Billing Period) Electricity consumption. The curtailment stages are associated with increasing Electricity deficits. The five stages of Curtailment are:

Stage	Nature	Curtailment Requirement	Curtailment Type
Stage 1	Voluntary	No Specified %	Uniform Among All Regional Customers
Stage 2	Voluntary	5% or Greater	Uniform Among All Regional Customers
Stage 3	Mandatory	5 to 15%	Uniform Among All Regional Customers
Stage 4	Mandatory	15% 15% or Greater 15% or Greater	Residential Customers General Use Customers Major Use Customers
Stage 5	Mandatory	% Associated with Stage 4 Plus Additional Curtailment	Continued Customer Curtailment Plus Utility Action, Including Plant Closures and Possible Blackouts

4. Initiation of Load Curtailment

Curtailment will be initiated when directed by State authorities. However, nothing precludes the Company from requesting voluntary load reduction at any time.

5. Administration of State-Initiated Curtailment

A. **Stage-By-Stage Utility Administrative Obligations**

Upon notice from the State to initiate load curtailment, the Company will immediately begin complying with the directives of this Plan. All requirements for lower-level stages continue to apply to higher-level stages. Throughout a period of Curtailment, the Company will provide Electricity Service Suppliers (ESSs), Customers and the general public with as much useful information as can reasonably be supplied. The requirements specified below represent the minimum actions to be taken.

1) **Stage 1**

The Company will begin, or continue if it has already begun, providing Curtailment information to ESSs, Customers and the general public. The Company will also assist the State, as appropriate, in briefing the media about the shortage.

2) **Stage 2**

In Stage 2, the Company will:

a) Notify ESSs, Customers and the general public of the percentage level of voluntary curtailment stemming from State Action;

b) Provide Curtailment tips to ESSs, Customers and the general public;

c) Answer Customer questions about Curtailment;

d) Provide Curtailment reports to the State and the Utility Coordinator; and

e) Provide more detailed information to the media than provided in Stage 1.

3) **Stage 3**

In Stage 3, the Company will:

a) Notify ESSs, Customers and the general public of the percentage level of State-ordered mandatory Curtailment;

b) Calculate weather-normalized Base Billing Period data and Curtailment Targets for all Customers who will be audited in the current billing period;

c) Provide Curtailment Targets to ESSs and all Customers who request such data for their own accounts;

d) Provide audited Customers with information about how to apply for exemption and adjustment of Base Year data;

e) Process requests for exemption and Base Year data adjustments from those Customers selected for audit who would otherwise be subject to penalties; and

f) Implement the penalties aspect of the Plan.

4) **Stage 4**

In Stage 4, the Company will notify ESSs, Customers and the general public of any applicable changes in State-initiated mandatory curtailment.

5) **Stage 5**

In Stage 5, the Company will collaborate with the State to develop and implement the most effective methods to secure the required Electricity Curtailment while minimizing, to the extent possible, any economic and human hardships of the last stage of load curtailment.

B. **<u>Suggested Curtailment Actions</u>**

Information will be disseminated to Customers regarding actions that they can take to reduce their Electricity consumption. The Company will work with the State to develop this material. The recommendations will be based on the actions described in Appendix C of the Regional Plan.

6. Base Year Data and Curtailment Targets

A. Identification of the Base Year

The Base Year for a shortage will be established by the State. Base Year and Base Billing Period data shall be weather-normalized.

B. Estimating Base Billing Period Data for Customers for Whom No Base Billing Period Data Exists

Base Billing Period data must be obtained or developed for any Customer who is audited under this Plan. Although the Company has the option of excluding residential and General Use Customers without actual Base Billing Period data from the random sample of audited Customers, Base Billing Period data will be estimated for any audited Customer for whom actual data does not exist or is found to be inaccurate.

C. Communicating Curtailment Target Information to Customers

During mandatory Curtailment, retrospective, current billing period, and forthcoming billing period Curtailment Target information will be provided to any Customer who requests such information. Retrospective Curtailment Target information will be provided to any audited Customer who will be issued a warning or penalty. At its option, the Company may provide Curtailment Target information to other Customers or Customer classes as well.

7. Auditing Customers for Compliance With State Orders for Mandatory Load Curtailment During Curtailment Stages 3-5

A. Each billing period, at least 1% of residential users, 5% of General Use Customers, and 100% of Major Use Customers (including those Major Use Customers with estimated Base Billing Period data) plus any Customers penalized in the previous billing period will be audited. The number of Customers exempted or excluded from audit will not affect the sample size.

B. New compliance samples shall be drawn each month. Customers penalized under this Plan shall continue to be audited until their Energy use falls below the Threshold Consumption Level. Once their Energy use falls below that level, they will be audited again only if selected by random sample.

C. Unless the Company is auditing 100% of its residential users and General Use Customers, all such Customers selected for audit shall be chosen on a random sample basis, except that the following Customers are to be excluded: (a) Customers granted an exemption under this Plan; and (b) Customers with an estimated power bill in the current billing period. At its option the Company may also choose to exclude Customers with estimated Base Billing Period data, if the State does not require their inclusion in the pool of Customers subject to audit.

8. Penalties for Noncompliance

A. **Nature of Penalties**

The following penalties will be assessed under this Plan to Excess Power Consumption as defined below:

Violation	Penalty
First Bimonthly Violation	10¢ per kWh of Excess Use
Second Bimonthly Violation	20¢ per kWh of Excess Use
Third Bimonthly Violation	40¢ per kWh of Excess Use
Fourth Bimonthly Violation	1 Day Disconnection Plus 40¢ per kWh of Excess Use
Fifth Bimonthly Violation	2 Days Disconnection Plus 40¢ per kWh of Excess Use
Sixth and all Subsequent Violations	Penalties are Determined by the State; Civil Penalties or Other Corrective Actions would be possibilities.

The penalty for violators who are billed every two months will escalate on every power bill in which they are subject to penalty. Customers billed on a monthly basis will be assessed the same penalty on two successive occasions before incurring the next higher level penalty. During any continuous period of curtailment, assessed penalties remain on the record for the purposes of administration of subsequent penalties, even if there has been an intervening period of compliance.

Standard disconnect criteria and procedures will be used whenever disconnecting Customers in accordance with this Plan. Health, safety, and welfare considerations will be taken into account, and Customers will be billed for normal disconnect and reconnect charges.

B. **Calculation of Financial Penalties**

Financial penalties will be calculated by multiplying the Customer's Excess Electricity Consumption each billing period by the appropriate penalty level identified above.

1) **Threshold Consumption Level**

The Threshold Consumption Level assigned to each Customer class is identified as:

a) Residential Customers,
10% Above Curtailment Target.

b) General Use Customers,
10% Above Curtailment Target.

c) Major Use Customers,
2% Above Curtailment Target.

These values may be changed by the State so as to effect better compliance with the curtailment order.

2) **Excess Power Consumption Calculation**

Penalties will not be assessed if a Customer’s load (either actual load or weather-normalized load) is equal to, or less than, the Threshold Consumption Level. Excess Power Consumption is the lower of the following two values for each sampled load subject to penalty: (a) (Actual Load) minus (Curtailment Target) or (b) (Weather-Normalized Load) minus (Curtailment Target).

3) **Assessment of Penalties**

Penalties Vs Warnings. Customers will be assessed penalties only if they have Excess Electricity Consumption and if they are to be penalized based on the penalty assessment procedures described below. Any sampled Customer who is not penalized and whose use exceeds the Curtailment Target will receive a warning.

C. **Penalty Assessment Procedures**

Sample at the mandated minimum percentages for each section as specified in this Plan [1%-5%-100%] (or as otherwise specified by the State) and assess penalties on all Customers with Excess Power Consumption.

At its option, the Company may sample at higher percentages of Customers than the minimum required by Section 7 above and may choose among the following penalty assessment options:

1) **Option (1)**

Assess penalties on all sampled Customers with Excess Power Consumption (this methodology must be used for Major Use Customers even if the utility chooses Option (2), below, for its other Customer sectors); or

2) **Option (2)**

Develop a ratio of the minimum percentage sample size to the actual percentage sampled for the Residential and/or General Use Customer sectors. Multiply the resulting percentages by the total number of violators in each respective Customer sector to determine the minimum number of penalties that must be assessed in each sector. Calculate the percentage violation for each individual Customer that has been sampled (Excess Power Consumption divided by Curtailment Target) and apply penalties to the worst offenders in the overall sample based on their percentage Excess Power Consumption. Also penalize all Customers who were penalized in the previous billing period and who still have Excess Power Consumption.

D. **Billing Customers for Penalties**

The penalty on the power bill may be described as State-mandated and shall include any State-provided material describing the penalty aspect of the Plan as a bill stuffer in the bills of penalized Customers. If the Customer is receiving an ESS Consolidated Bill, the ESS will bill the Customer for any penalties incurred by that Customer. The bills shall include any Commission-provided material describing the penalty aspect of the Plan, such as a bill stuffer. When the Company is billing the Customer, the bills shall note that failure to pay penalties will result in service disconnection in accordance with standard disconnect criteria and procedures.

E. **Treatment of Penalties Pending Adjustment / Exemption Determinations**

A Customer that has applied for adjustment of Base Billing Period data and/or exemption from mandatory Curtailment may request a stay of enforcement of the penalty aspect of the Plan pending a final decision regarding its request. Any Customer who has been granted such a stay will be subject to retroactive penalties as applicable if the request is ultimately denied.

F. **Use of Funds Collected Under the Penalty Provisions of the Plan**

Funds collected under the State-ordered penalty provisions of this Plan shall be set aside in a separate account. The ultimate disposition of these funds will be determined by the Commission.

9. Exemptions and Adjustments

A. **Customer Application for Exemption/Adjustment**

Customers will be informed of how to apply for exemption from Plan requirements or adjustments of Base Billing Period data. At its option, the Company may elect to process exemptions and adjustments only for audited Customers. Customers seeking an exemption or adjustment shall apply first to the Company and then, if dissatisfied with that outcome, to the Commission.

At its option, the Company may provide for a credit against future curtailment for a Customer who has already accomplished a reduction in Demand for the utility's service by installing an alternative Energy device or by weatherization or other installed conservation measures equivalent to the proposed level of curtailment. Where the level of curtailment exceeds the Demand reduction produced by the conservation measures or installed alternative Energy device of the Customer, the Company may provide for credit against the level of curtailment ordered to the extent of the Demand reduction produced by the conservation measure or alternate Energy device.

B. **Granting Customer Requests for Exemption From Mandatory Curtailment**

No automatic Customer exemptions will be granted under mandatory State-initiated load curtailment. Exempted Customers should be informed that exemption may not protect them from Stage 5 blackouts.

1) **Critical Load Customers**

Critical Load Customers may be exempted once the Customers have demonstrated to the Company that they have eliminated all nonessential Energy use and are using any reliable, cost-effective backup Energy resources.

2) **Other Customers**

Exemptions for Customers not qualifying as Critical Load Customers under the Plan will be evaluated based on whether Curtailment would result in unreasonable exposure to health or safety hazards, seriously impair the welfare of the affected Customer, cause extreme economic hardship relative to the amount of Energy saved, or produce counterproductive results.

C. **Utility Record Keeping Relative to Customer Exemptions**

Records regarding exemption determinations will be made available to the Commission upon request.

10. Measurement of the Amount of Curtailment Achieved and Determination of Compliance

At all times during State-initiated regional load curtailment, the Commission and the Utility Coordinator will be provided with consumption and savings data on a monthly basis in the form specified in Appendix D of the Regional Plan. To the extent that circumstances at the time of actual load curtailment dictate the need for additional data or more frequent data submittal, a best effort to comply with the Commission request will be made.

11. Special Arrangements

A. **Use of Customer-Owned Generation Facilities**

Consistent with the need for safety and system protection, Customers having their own generation facilities or access to electricity from non-utility power sources may choose to use Energy from those other sources to supplement their curtailed power purchases from their electric utility under any protracted regional shortage situation.

B. **Curtailment Scheduling**

During periods of mandatory Curtailment, a Customer is obligated to provide the requisite amount of curtailment within each billing period. Within that period, and subject to equipment limitations and the Company's rules on load fluctuations, Customers are free to schedule their curtailment so as to minimize the economic cost, hardship or inconvenience they experience as a result of the mandatory curtailment requirement.

C. **Related Curtailment Information**

The Regional Electric Energy Curtailment Plan is included, by reference. That plan contains additional information on curtailment administration.

RULE N (Concluded)