Portland General Electric
121 SW Salmon Street • Portland, OR 97204
portlandgeneral.com

August 4, 2026

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301
P.O. Box 1088
Salem, OR 97308-1088

Re: Advice No. 26-32, UE 473 – Portland General Electric Company's Request for a General Rate Revision

Dear Filing Center:

Portland General Electric Company (PGE) submits this electronic filing pursuant to Oregon Revised Statutes 757.205 and 757.210 and Oregon Administrative Rules (OAR) 860-022-0025 and 860-022-0030 for filing proposed tariff sheets associated with Tariff P.U.C. 19 implementing a general rate revision.

As previously discussed, PGE will submit 1 printed copy of proposed Tariff P.U.C. E-19 Tariff Sheets, Executive Summary, List of Acronyms, Direct Testimony, and Exhibits to the PUC as requested, via FedEx. Exhibits that are too voluminous to print were provided electronically. Confidential Testimony and Exhibits were provided electronically in coordination with Filing Center staff using Huddle. Confidential information is subject to General Protective Order No. 23-132 and Modified Protective Order No. 26-274. We appreciate Commission's and Staff's willingness to accept fewer printed copies than required by OAR 860-022-0019.

Work papers will be uploaded to Huddle.

The proposed tariff sheets are filed with a requested effective date of September 4, 2026, subject to suspension for investigation. PGE requests a prehearing conference be held as quickly as time allows to establish a schedule that provides a Commission Order by mid-June 2027, and revised prices effective July 1, 2027.

Please direct all formal correspondence, questions, and requests related to this filing to pge.opuc.filings@pgn.com.

Additionally, PGE requests that all data requests in this docket be submitted via Huddle and addressed to:

Greg Batzler
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 1WTC12
Portland, OR 97204

Confidential material in support of this filing has been provided to parties under the General Protective Order No. 23-132 noticed July 27, 2026, and Modified Protective Order No. 26-274 granted by ALJ Katherine Mapes on July 29, 2026.

The following are to receive notices and communications via the email service list:

Dan Polkow General Counsel 121 SW Salmon, 1WTC1301 Portland, OR 97204	Sujata Pagedar Senior Director of Regulatory and Governance 121 SW Salmon, 1WTC12 Portland, OR 97204	Greg Batzler Manager, Rates & Regulatory Affairs 121 SW Salmon 1WTC12 Portland, OR 97204

Sincerely,

/s/ Sujata Pagedar

Sujata Pagedar
Senior Director of Regulatory and Governance

Enclosures

Advice No. 26-32
Portland General Electric Company UE 473 General Rate Revision
Revised Tariff Sheets Issued August 4, 2026
Requested Effective Date of September 4, 2026

Fourth Revision of Sheet No. 1-1
Sixth Revision of Sheet No. 1-2
Second Revision of Sheet No. 1-3
Fourth Revision of Sheet No. 1-4
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Due to pagination, PGE hereby withdraws Sheets:

First Revision of Sheet No. 123-3
First Revision of Sheet No. 123-4
Original Sheet No. No. 123-5

PGE hereby withdraws the following Schedules in their entirety from the tariff:

Schedule 75, Partial Requirements Service (Sheets 75-1 through 75-8)

Schedule 76, Partial Requirements Economic Replacement Power Rider (Sheets 76-1 through 76-6)

Schedule 90, Large Nonresidential Standard Service (>4,000 kW and Aggregate to >30 MWa) (Sheets 90-1 through 90-4)

Schedule 95, Street and Highway Lighting New Technology (Cost of Service) (Sheets 95-1 through 95-14)

Schedule 490, Large Nonresidential Cost of Service Opt-Out (>4,000 kW and Aggregate to >30 MWa) (Sheets 490-1 through 490-5)

Schedule 495, Street and Highway Lighting New Technology Cost of Service Opt-Out (Sheets 495-1 through 495-15)

Schedule 575, Partial Requirements Service Direct Access Service (Sheets 575-1 through 575-7)

Schedule 576, Economic Replacement Power Rider Direct Access Service (Sheets 576-1 through 576-3)

Schedule 590, Large Nonresidential Direct Access Service (>4,000 kW and Aggregate to >30 MWa) (Sheets 590-1 through 590-3)

Schedule 595, Street and Highway Lighting New Technology Direct Access Service (Sheets 595-1 through 595-14)

PORTLAND GENERAL ELECTRIC COMPANY
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	Table of Contents, Rules and Regulations
	Residential Service
4	Multifamily Residential Demand Response Water Heater Pilot
5	Residential Direct Load Control Program
7	Residential Service
8	Residential Electric Vehicle Charging Pilot
13	Smart Grid Testbed Technology Validation and Testing
14	Residential Battery Energy Storage Pilot
	Standard Service Schedules
15	Outdoor Area Lighting Standard Service (Cost of Service)
17	Community Solar - Optional
18	Income-Qualified Bill Discount - Optional
25	Nonresidential Direct Load Control Pilot
26	Nonresidential Demand Response Program
32	Small Nonresidential Standard Service
38	Large Nonresidential Optional Time-of-Day Standard Service (Cost of Service)
47	Small Nonresidential Irrigation and Drainage Pumping Standard Service (Cost of Service)
49	Large Nonresidential Irrigation and Drainage Pumping Standard Service (Cost of Service)
50	Retail Electric Vehicle (EV) Charging
52	Nonresidential Electric Vehicle Charging Rebate Pilot
53	Nonresidential Heavy-Duty Electric Vehicle Charging
55	Large Nonresidential Green Energy Affinity Rider (GEAR)
56	Commercial Electric Vehicle Make-Ready Pilot

(D)

PORTLAND GENERAL ELECTRIC COMPANY
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89	Large Nonresidential Standard Service (>4,000 kW)	
91	Street and Highway Lighting Standard Service (Cost of Service)	(D)
92	Traffic Signals (No New Service) Standard Service (Cost of Service)	(D)
96	Data Center Standard Service (Facilities ≥ 20,000 kW)	
97	Customer Dedicated Resource Service	(N)
99	Special Contracts	
	Adjustment Schedules	
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103	Metro Supportive Housing Services Business Income Tax Recovery	
105	Regulatory Adjustments	
106	Multnomah County Business Income Tax Recovery	
108	Public Purpose Charge	
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111	Targeted Energy Support Program Surcharge	
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118	Bill Adjustment Cost Recovery Mechanism	
120	Seaside Battery Storage Resource Alternative Recovery	
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123	Decoupling Adjustment	
125	Annual Power Cost Update	

PORTLAND GENERAL ELECTRIC COMPANY
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137	Customer-Owned Solar Payment Option Cost Recovery Mechanism	
138	Energy Storage Cost Recovery Mechanism	
139	New Large Load Transition Cost Adjustment	
142	Underground Conversion Cost Recovery Adjustment	
143	Spent Fuel Adjustment	
145	Boardman Power Plant Decommissioning Adjustment	
146	Colstrip Power Plant Operating Life Adjustment	
149	Environmental Remediation Cost Recovery Adjustment, Automatic Adjustment Clause	
150	Transportation Electrification Cost Recovery Mechanism	
151	Wildfire Mitigation Cost Recovery	
152	Major Event Cost Recovery	
153	Community Benefits and Impacts Advisory Group Cost Recovery Mechanism	
	Small Power Production	
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200	Dispatchable Standby Generation	
203	Net Metering Service	
204	Community Solar Program Interconnection and Power Purchase Schedule	
215	Solar Payment Option Pilot Small Systems (10 kW or Less)	
216	Solar Payment Option Pilot Medium Systems (Greater Than 10 kW to 100 kW)	
217	Solar Payment Option Pilot Large Systems (Greater Than 100 kW to 500 kW)	

PORTLAND GENERAL ELECTRIC COMPANY
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RATE SCHEDULES (Continued)

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339	On-Bill Loan Repayment Service – Clean Energy Works of Oregon Program	
340	On-Bill Repayment Service Energy Efficiency and Sustainable Technologies (EEAST)	
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491	Street and Highway Lighting Cost of Service Opt-Out	(D)
492	Traffic Signals Cost of Service Opt-Out	
496	Data Center Cost of Service Opt-Out (Facilities ≥ 20,000 kW)	(D)
	Direct Access Schedules	
515	Outdoor Area Lighting Direct Access Service	
532	Small Nonresidential Direct Access Service	
538	Large Nonresidential Optional Time-of-Day Direct Access Service	
549	Large Nonresidential Irrigation and Drainage Pumping Direct Access Service	
583	Large Nonresidential Direct Access Service (31 – 200 kW)	(D)
585	Large Nonresidential Direct Access Service (201 – 4,000 kW)	
589	Large Nonresidential Direct Access Service (>4,000 kW)	

PORTLAND GENERAL ELECTRIC COMPANY
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RATE SCHEDULES (Concluded)

Schedule	Description	
591	Street and Highway Lighting Direct Access Service	(D)
592	Traffic Signals Direct Access Service	(D)
596	Data Center Direct Access Service (Facilities ≥ 20,000 kW)	
600	Electricity Service Supplier Charges	
689	New Large Load Cost of Service Opt-Out (>10MWa)	
696	New Large Load Data Center Cost of Service Opt-Out (≥ 20 MWa)	
	Non-Utility Services	
54	Large Nonresidential Renewable Energy Certificates Rider	
320	Meter Information Services	
715	Electrical Equipment Services	
750	Informational Only: Franchise Fee Rate Recovery	
800	Service Maps	

SCHEDULE 7
RESIDENTIAL SERVICE

PURPOSE

This schedule provides Standard and Optional Service choices for residential customers. Optional Services include Time-of-Day (TOD), Peak Time Rebate, and Green Future[SM] renewable portfolio options.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

ENERGY PRICE PLANS (DEFAULT PLAN OR TOD)

RESIDENTIAL SERVICE PRICE PLAN (DEFAULT PLAN)

This default plan is provided to Residential Customers who have not chosen the TOD portfolio option price plan.

Monthly Rate

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

Basic Charge			
Single-Family Home	$15.00		**(I)**
Multi-Family Home	$12.00		**(I)**
Transmission and Related Services Charge	0.912	¢ per kWh	**(I)**
Distribution Charge		¢ per kWh	**(C)**
Single-Family Home	7.761		**(N)**
Multi-Family Home	7.036		**(N)**
Energy Charge	4.198	¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

SCHEDULE 7 (Continued)

TIME-OF-DAY (TOD) PORTFOLIO OPTION

This optional price plan provides TOD pricing for transmission and related services, distribution and energy and can apply to a whole premise or to plug-in electric vehicle charging only*. Enrollment is necessary.

Monthly Rate

Basic Charge			
Single-Family Home	$15.00		(I)
Multi-Family Home	$12.00		(I)
On-Peak Charge	34.720	¢ per kWh	(I)
Transmission and Related Services	2.605	¢ per kWh	
Distribution	22.236	¢ per kWh	
Energy	9.879	¢ per kWh	
Mid-Peak Charge	12.708	¢ per kWh	
Transmission and Related Services	0.900	¢ per kWh	
Distribution	7.657	¢ per kWh	
Energy	4.151	¢ per kWh	
Off-Peak Charge	6.228	¢ per kWh	
Transmission and Related Services	0.396	¢ per kWh	
Distribution	3.362	¢ per kWh	
Energy	2.470	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

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.

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	0.413	¢ per kWh	**(I)**
Distribution Charge	3.543	¢ per kWh	**(R)**
Cost of Service Energy Charge	2.696	¢ per kWh	**(I)**

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Cobrahead					
Mercury Vapor	175	7,000	66	$10.37 [2]	(R)
	400	21,000	147	16.01 [2]	
	1,000	55,000	374	31.84 [2]	
HPS	70	6,300	30	7.76 [2]	
	100	9,500	43	8.57	
	150	16,000	62	9.85	
	200	22,000	79	11.02	
	250	29,000	102	12.50	
	310	37,000	124	15.62 [2]	
	400	50,000	163	16.55	
Flood, HPS	100	9,500	43	8.90 [2]	
	200	22,000	79	12.04 [2]	
	250	29,000	102	16.04	
	400	50,000	163	20.09	
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	8.76	
	100	9,500	43	10.16	
	150	16,500	62	11.90	
Special Acorn Type, HPS	100	9,500	43	13.10	
HADCO Victorian, HPS	150	16,500	62	16.16	
Early American Post-Top, HPS					
Black	100	9,500	43	10.48	(R)

(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	$12.51	**(R)**
	175	12,000	71	11.54	
Flood, Metal Halide	350	30,000	139	19.06	
	400	40,000	156	17.41	
Flood, HPS	750	105,000	285	28.21	
HADCO Independence, HPS	100	9,500	43	14.56	
HADCO Techtra, HPS	100	9,500	43	21.76	
	150	16,000	62	23.89	**(R)**

(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	$17.97	(I)
	>40-45	3,500	15	18.11	
	>45-50	5,488	16	14.54	
	>50-55	4,000	18	18.31	
	>55-60	4,213	20	18.44	
	>60-65	4,273	21	18.51	
	>65-70	4,332	23	17.73	
	>70-75	4,897	25	18.77	
	>91-100	8,100	32	19.24	
HADCO LED	70	5,120	24	31.48	
Roadway LED	>20-25	3,000	8	6.23	
	>25-30	3,470	9	7.01	
	>30-35	2,530	11	7.27	
	>35-40	4,245	13	6.86	
	>40-45	5,020	15	7.63	
	>45-50	3,162	16	7.69	
	>50-55	3,757	18	7.83	
	>55-60	4,845	20	7.96	
	>60-65	4,700	21	8.10	
	>65-70	5,050	23	8.63	
	>70-75	7,640	25	9.20	
	>75-80	8,935	26	9.27	
	>80-85	9,582	28	9.40	
	>85-90	10,230	30	9.54	
	>90-95	9,928	32	9.67	
	>95-100	11,719	33	9.74	(I)
	>100-110	7,444	36	9.36	(R)
	>110-120	12,340	39	10.30	(I)
	>120-130	13,270	43	10.40	(R)
	>130-140	14,200	46	10.64	
	>140-150	15,250	50	13.68	
	>150-160	16,300	53	13.88	
	>160-170	17,300	56	14.08	
	>170-180	18,300	60	13.44	
	>180-190	19,850	63	14.54	(R)
	>190-200	21,400	67	14.81	(I)
	>200-210	27,033	70	15.01	(R)
	>210-220	28,535	74	15.27	(R)
	>220-230	30,017	77	15.47	(R)

(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]	
Roadway LED (Cont)	>230-240	30,800	81	$15.74	**(R)**
	>240-250	31,507	84	15.94	**(R)**
Pendant LED (Non-Flare)	36	3,369	12	17.98	**(I)**
	53	5,079	18	18.38	
	69	6,661	24	18.78	
	85	8,153	29	19.92	**(I)**
Pendant LED (Flare)	>25-30	3,100	9	17.78	**(N)**
	>30-35	3,650	11	17.91	**(N)**
	>35-40	3,369	13	18.04	**(I)**
	>40-45	3,797	15	18.18	**(I)**
	>45-50	4,438	16	18.24	**(I)**
	>50-55	5,079	18	18.38	**(R)**
	>55-60	5,475	20	18.51	**(I)**
	>60-65	6,068	21	18.58	**(R)**
	>65-70	6,661	23	18.71	**(I)**
	>70-75	7,034	25	18.84	
	>75-80	7,594	26	19.72	
	>80-85	8,153	28	19.85	
CREE XSP LED	>20-25	2,529	8	8.93	
	>30-35	4,025	11	9.13	
	>40-45	3,819	15	9.40	
	>45-50	4,373	16	9.96	
	>55-60	5,863	20	10.23	
	>65-70	9,175	23	8.96	
	>90-95	8,747	32	9.56	**(I)**
	>130-140	18,700	46	11.54	**(R)**
Post-Top, American Revolution LED	>30-35	3,395	11	9.84	**(I)**
	>45-50	4,409	16	10.17	
Flood LED	>75-80	12,716	26	10.46	
	>80-85	10,530	28	11.57	
	>110-120	18,265	38	12.88	
	>120-130	16,932	43	13.24	
	>160-170	26,349	56	15.33	
	>180-190	23,797	63	15.88	**(I)**
	>290-300	46,950	116	25.30	**(R)**

(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]	
Flood LED					
	>321-330	46,802	112	$25.03	**(R)**
	>331-340	48,692	116	25.30	
	>341-350	50,145	119	25.50	
	>351-360	51,598	123	25.76	
	>370-380	48,020	127	26.03	**(R)**

Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$8.91	**(I)**
	40 to 55	10.24	**(I)**
Wood, Painted for Underground	35 or less	9.31 [3]	**(I)** **(D)**
Aluminum, Regular	16	9.86	**(I)**
	25	20.23	
	30	20.12	
	35	24.14	
Aluminum, Fluted Ornamental	14	12.45	
Aluminum, Fluted Ornamental	16	12.81	
Aluminum Davit	25	18.35	
	30	20.67	
	35	24.21	
	40	25.01	
Aluminum Double Davit	30	14.95	
Aluminum, Smooth Techtra Ornamental	18	25.79	**(I)**

(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)

MONTHLY RATE (Continued)

Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Fiberglass Fluted Ornamental; Black	14	$ 13.84	**(I)**
Fiberglass, Regular			
Black	20	8.51	**(I)**
Black or Bronze	30	13.02	**(N)**
Gray	30	14.55	**(C)(I)**
Black, Gray, or Bronze	35	14.00	**(I)**
Fiberglass, Anchor Base, Gray or Black	35	25.79	
Fiberglass, Anchor Base (Color may vary)	25	22.68	
	30	24.49	
Fiberglass, Direct Bury with Shroud	18	10.77	
Aluminum, Regular with Breakaway Base	35	24.15	
Aluminum, Double-Arm, Smooth Ornamental	25	27.62	
Aluminum, Smooth, Black, Pendant	23	26.48	
Aluminum, Regular with Breakaway Base	25	18.87	
	30	23.21	**(I)**

INSTALLATION CHARGE

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.

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.

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.

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

Summer Event Season – Typically includes the successive calendar months June through September, but may occur at other times as system or programmatic conditions warrant.

Winter Event Season – Typically includes the successive calendar months November through February, but may occur at other times as system or programmatic conditions warrant.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Nonresidential Customers served under Schedules 32, 38, 47, 49, 83, 85, and 89. 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 26 (Continued)

DEFINITIONS (Continued)

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.

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

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.

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 – Typically includes the successive calendar months June through September, but may occur beyond these months as system or programmatic conditions warrant.

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

Winter Event Season – Typically includes the successive calendar months November through February, but may occur beyond these months as system or programmatic conditions warrant.

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

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 2026	Feb 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026	Nov 2026	Dec 2026
$79.50	$63.70	$36.50	$68.60	$78.80	$71.50	$57.20	$78.80

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:

(D)

Primary Delivery Voltage	1.0490	**(R)**
Secondary Delivery Voltage	1.0620	**(R)**

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:

Baseline Load Profile

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)

GRID SUPPORT EVENTS (Continued)

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.

Grid Support events are in response to a grid emergency and may occur at any day or time, including Holidays.

EVENT NOTIFICATION

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 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.

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.

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.

2. Customers that choose to take service under Schedules 86, 485, 489, 532, 538, 549, 583, 585, 589, or 689 will be withdrawn from this program. **(C) (C) (D)**

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

SCHEDULE 26 (Concluded)

SPECIAL CONDITIONS (Continued)

4. 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. **(T)**

5. 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)**

6. 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. **(T)**

7. 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. **(T)**

8. Customers who participate in this schedule may be placed on a calendar monthly billing cycle. **(T)**

9. 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. **(T)**

10. 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. **(T)**

11. 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. **(T)**

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	$26.00		(I)
Three Phase Service	$35.00		(I)
Transmission and Related Services Charge	0.548	¢ per kWh	(I)
Distribution Charge			
First 5,000 kWh	7.963	¢ per kWh	(I)
Over 5,000 kWh	3.445	¢ per kWh	(I)
Energy Charge Options			
Standard Service	3.715	¢ per kWh	(I)
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	7.311	¢ per kWh	(I)
Mid-Peak Period	3.677	¢ per kWh	(I)
Off-Peak Period	1.836	¢ per kWh	

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

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 0.349¢ per kWh for wheeling **(I)**
- times a loss adjustment factor of 1.0620 **(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.

PLUG-IN ELECTRIC VEHICLE (EV) TOU OPTION

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 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.

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. or 3) for Customers taking service on the separately metered Plug-In Electric Vehicle Time of Day option 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.

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$65.00		**(I)**
Three Phase Service	$75.00		**(I)**
Transmission and Related Services Charge	1.193	¢ per kWh	**(I)**
Distribution Charge	8.230	¢ per kWh	**(R)**
Energy Charge**			
On-Peak Period	5.858	¢ per kWh	**(I)**
Mid-Peak Period	3.858	¢ per kWh	**(I)**
Off-Peak Period	2.858	¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

** Energy On-peak hours are Monday - Saturday 4:00 p.m. to 10:00 p.m. Mid-peak hours are Monday - Saturday 6:00 a.m. to 4:00 p.m. Off-peak hours are Monday - Saturday 10:00 p.m. to 6:00 a.m. and all day Sunday.

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 allocated among the time periods and billed based either on the Customer's historic usage per period or the class average. Upon installation and configuration of an interval meter, the Company will bill the Customer according to actual metered usage.

SCHEDULE 38 (Continued)

DIRECT ACCESS DEFAULT SERVICE (Continued)

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.349¢ 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. **(I)**

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

Secondary Delivery Voltage	1.0620	**(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 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.

SPECIAL CONDITIONS

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.

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**	$42.00		**(I)**
Winter Months**	No Charge		
Transmission and Related Services Charge	1.033	¢ per kWh	**(I)**
Distribution Charge			
First 50 kWh per kW of Demand***	15.995	¢ per kWh	**(I)**
Over 50 kWh per kW of Demand	13.995	¢ per kWh	**(I)**
Energy Charge	4.361	¢ per kWh	**(I)**

* 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 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 exceeded 30 kW once.

MONTHLY RATE

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

Basic Charge			
Summer Months**	$70.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.508	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand***	13.317	¢ per kWh	(I)
Over 50 kWh per kW of Demand	11.317	¢ per kWh	(I)
Energy Charge	3.881	¢ per kWh	(I)

* 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 50 (Continued)

AVAILABLE

The service described in this schedule is available through a point-of-sale transaction 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.

APPLICABLE

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

RATE

Pricing is as follows:

	Off-Peak Fee (all hours)	On-Peak Charging Price	Idle Fee	
Direct Current Fast Charger	$0.30 per kWh	$0.58 per kWh	$0.40 per minute after 10 minutes	(T)
Level 2 Charger	$0.15 per kWh	$0.45 per kWh	$0.10 per minute after 10 minutes**	(I)
Income Qualified DCFC Charger*	$0.24 per kWh	$0.52 per kWh	$0.40 per minute after 10 minutes	
Income Qualified Level 2 Charger	$0.10 per kWh	$0.32 per kWh	$0.10 per minute after 10 minutes**	

* Income qualified customers must apply for the discount through PGE and may need to provide additional information, such as a username or email used to register with the charging provider, to link their charging provider account and verify that the customer is enrolled in the IQBD program. Customers must already be currently enrolled in the IQBD program.

** Idle fees will not be charged on Level 2 Chargers between the hours of 8 PM and 8 AM

Payment will be made via credit card or other applicable payment method at the PGE charging Station, via the charging station's mobile app, or via calling the charging station's customer service.

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. 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 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 0.349¢ 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-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. **(I)**

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:

Primary Delivery Voltage	1.0490	**(D)** **(R)**
Secondary Delivery Voltage	1.0620	**(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 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	$60.00	(I)
Three Phase Service	$70.00	(I)
Transmission and Related Services Charge		
per kW of monthly Peak Demand**	$2.16	(R)
Distribution Charges***		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$5.99	(R)
Over 30 kW	$5.89	(R)
per kW of monthly Peak Demand**	$2.22	(I)
Energy Charge		
Generation Demand Charge		
per kW of monthly Peak Demand**	$12.61	(I)
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	1.224¢	(I)

* See Schedule 100 for applicable adjustments.
** Peak Demand hours are Monday - Saturday 6:00 a.m. to 10:00 p.m.
*** 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.

SCHEDULE 83 (Continued)

MONTHLY RATE (Continued)

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 allocated among the time periods and billed based either on the Customer's historic usage per period or the class average. Upon installation and configuration of an interval meter, the Company will bill the Customer according to actual metered usage.

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 0.349¢ 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. **(I)**

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

Secondary Delivery Voltage	1.0620	**(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 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 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	$790.00	$640.00	(I)
Transmission and Related Services Charge			
per kW of monthly Peak Demand**	$3.04	$3.01	(R)
Distribution Charges***			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$4.50	$4.45	(I)
Over 200 kW	$4.40	$4.35	(I)
per kW of monthly Peak Demand**	$2.27	$2.24	(I)
Energy Charge			
Generation Demand Charge			
per kW of monthly Peak Demand**	$14.31	$14.15	(I)
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.271 ¢	0.268 ¢	(R)

* See Schedule 100 for applicable adjustments.
** Peak Demand hours are Monday - Saturday 6:00 a.m. to 10:00 p.m.
*** 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.

SCHEDULE 85 (Continued)

MONTHLY RATE (Continued)

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 allocated among the time periods and billed based either on the Customer's historic usage per period or the class average. Upon installation and configuration of an interval meter, the Company will bill the Customer according to actual metered usage.

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 0.349¢ 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. **(I)**

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

Primary Delivery Voltage	1.0490	**(R)**
Secondary Delivery Voltage	1.0620	**(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 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.

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 Primary	
Basic Charge	$4,820.00	(I)
Transmission and Related Services Charge		
per kW of monthly Peak Demand**	$4.57	(I)
Distribution Charges***		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.12	(I)
Over 4,000 kW	$0.81	(I)
per kW of monthly Peak Demand**	$1.54	(R)
Substation Credit per kW of monthly Peak Demand****	($1.52)	(N)
Energy Charge		
See below for Daily Pricing Option description.		
Generation Demand Charge	$21.43	(I)
per kW of monthly Peak Demand**		
System Usage Charge		
per kWh	0.201 ¢	(R)(C)

(C)

* See Schedule 100 for applicable adjustments.
** Peak Demand hours are Monday - Saturday 6:00 a.m. to 10:00 p.m.
*** 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.
****Applicable only to Customers who own and maintain the substation that distributes power to their service. (N)

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 0.349¢ 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. **(I)**

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

		(D)
Primary Delivery Voltage	1.0490	**(R)**
		(D)

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.

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, https://portlandgeneral.com

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. **(C)**

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 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.

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. Maintenance under Option A luminaires excludes maintenance related to vegetation management. **(C)** **(C)**

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 503-612-4685 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.

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.

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)**

(N)

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. 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 of this Schedule.

SCHEDULE 91 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Option B Luminaire Maintenance (Continued)

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.

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.

(D)

SCHEDULE 91 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

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.

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. **(N)** **(N)**

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.

SCHEDULE 91 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Upon Customer request, the Company may install and replace Option B poles at their discretion 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. All costs to repair or replace damaged streetlight poles are the sole responsibility of the customer, in addition to the applicable monthly Option B rate. **(C)** **(C)** **(C)**

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.

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	0.396 ¢ per kWh	**(I)**
Distribution Charge	0.917 ¢ per kWh	**(R)**
Energy Charge		
Cost of Service Option	2.696 ¢ per kWh	**(I)**

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91. This selection of this option applies to all luminaires served under Schedules 91. 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 0.349¢ 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. **(C)** **(C)** **(I)**

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 1.0620. **(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.

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	Option B		
Cobrahead Power Doors **	100	9,500	43	*	$0.92		(I)
	200	22,000	79	$7.38	0.98	(N)	
	400	50,000	163	*	1.00	(N)	
Cobrahead	70	6,300	30	5.76	0.88	(R)	(R)
	100	9,500	43	5.71	0.87	(I)	
	150	16,000	62	5.73	0.88		
	200	22,000	79	5.76	0.88		
	250	29,000	102	5.71	0.87		
	400	50,000	163	5.71	0.87		
Flood	250	29,000	102	9.25	1.10		
	400	50,000	163	9.25	1.10		
Early American Post-Top	100	9,500	43	7.62	0.99		
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	6.76	0.95	(I)	
	100	9,500	43	*	0.97		
	150	16,000	62	*	1.00		(R)

* Not offered.
** Service is only available to Customers with total power door luminaires in excess of 2,500.

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates (N)

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	Option B	
Roadway LED	>20-25	3,000	8	$5.70	$0.31	
	>25-30	3,470	9	6.41	0.31	
	>30-35	2,530	11	6.54	0.32	
	>35-40	4,245	13	6.00	0.31	
	>40-45	5,020	15	6.63	0.32	
	>45-50	3,162	16	6.63	0.32	
	>50-55	3,757	18	6.63	0.32	
	>55-60	4,845	20	6.63	0.32	
	>60-65	4,700	21	6.70	0.32	
	>65-70	5,050	23	7.10	0.32	
	>70-75	7,640	25	7.54	0.33	
	>75-80	8,935	26	7.54	0.33	
	>80-85	9,582	28	7.54	0.33	
	>85-90	10,230	30	7.54	0.33	
	>90-95	9,928	32	7.54	0.33	
	>95-100	11,719	33	7.54	0.33	(N)

SCHEDULE 91 (Continued)

(N)

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Roadway LED	>100-110	7,444	36	$6.97	$0.32
	>110-120	12,340	39	7.71	0.33
	>120-130	13,270	43	7.54	0.33
	>130-140	14,200	46	7.58	0.33
	>140-150	15,250	50	10.35	0.36
	>150-160	16,300	53	10.35	0.36
	>160-170	17,300	56	10.35	0.36
	>170-180	18,300	60	9.45	0.35
	>180-190	19,850	63	10.35	0.36
	>190-200	21,400	67	10.35	0.36
	>200-210	27,033	70	10.35	0.36
	>210-220	28,535	74	10.35	0.36
	>220-230	30,017	77	10.35	0.36
	>230-240	30,800	81	10.35	0.36
	>240-250	31,507	84	10.35	0.36

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	Option B
Acorn LED	>35-40	3,262	13	$17.11	$0.43
	>40-45	3,500	15	17.11	0.43
	>45-50	5,488	16	13.48	0.39
	>50-55	4,000	18	17.11	0.43
	>55-60	4,213	20	17.11	0.43
	>60-65	4,273	21	17.11	0.43
	>65-70	4,332	23	16.20	0.42
	>70-75	4,897	25	17.11	0.43
	>90-100	8,100	32	17.11	0.43
HADCO LED	70	5,120	24	29.88	0.57
Pendant LED (Non-Flared)	36	3,369	12	17.18	0.43
	53	5,079	18	17.18	0.43
	69	6,661	24	17.18	0.43
	85	8,153	29	17.99	0.44

(N)

SCHEDULE 91 (Continued)

Light-Emitting Diode (LED) Only – Option A and Option B Service Rates (Continued) **(N)**

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Pendant LED (Flared)	>25-30	3,100	9	$17.18	$0.43
	>30-35	3,650	11	17.18	0.43
	>35-40	3,369	13	17.18	0.43
	>40-45	3,797	15	17.18	0.43
	>45-50	4,438	16	17.18	0.43
	>50-55	5,079	18	17.18	0.43
	>55-60	5,475	20	17.18	0.43
	>60-65	6,068	21	17.18	0.43
	>65-70	6,661	23	17.18	0.43
	>70-75	7,034	25	17.18	0.43
	>75-80	7,594	26	17.99	0.44
	>80-85	8,153	28	17.99	0.44
Post-Top, American Revolution LED	>30-35	3,395	11	9.11	0.34
	>45-50	4,409	16	9.11	0.34
Flood LED	>75-80	12,716	26	8.73	0.34
	>80-85	10,530	28	9.71	0.35
	>110-120	18,265	38	10.35	0.36
	>120-130	16,932	43	10.38	0.36
	>160-170	26,349	56	11.60	0.37
	>180-190	23,797	63	11.69	0.37
	>290-300	46,950	116	17.58	0.44
	>320-330	46,802	112	17.58	0.44
	>330-340	48,692	116	17.58	0.44
	>340-350	50,145	119	17.58	0.44
	>350-360	51,598	123	17.58	0.44
	>370-380	48,020	127	17.58	0.44

(N)

SCHEDULE 91 (Continued)

Light-Emitting Diode (LED) Only – Option C Energy Use **(N)**

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
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)

(N)

SCHEDULE 91 (Continued)

RATES FOR STANDARD POLES

(M)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B		
Fiberglass, Black, Bronze, or Gray	20	$8.51	$0.27	(I)	(I)
Fiberglass, Black or Bronze	30	13.02	0.41		
Fiberglass, Gray	30	14.55	0.46		
Fiberglass, Smooth, Black or Bronze	18	9.38	0.29		
Fiberglass, Regular					
Black, Bronze, or Gray	18	7.99	0.25		
	35	14.00	0.44		
Aluminum, Regular with Breakaway Base	25	18.87	0.59		
	30	23.21	0.73		
	35	24.15	0.76		
Aluminum, Smooth, Black, Pendant	23	26.48	0.83		
Wood, Standard	30 to 35	8.91	0.28		
Wood, Standard	40 to 55	10.24	0.32	(I)	(I)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B		
Special Acorn-Types							
HPS	100	9,500	43	$10.24	$1.16	(R)	(R)
HADCO Victorian, HPS	150	16,000	62	*	1.27		
	200	22,000	79	*	1.19		
	250	29,000	102	10.25	1.16	(I)	
HADCO Capitol Acorn, HPS	100	9,500	43	14.67	1.44	(I)	
	150	16,000	62	*	1.37		
	200	22,000	79	*	1.46		
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	*	1.25		
	150	16,000	62	*	*		
HADCO Techtra, HPS	100	9,500	43	18.90	1.70	(I)	
	150	16,000	62	19.77	1.76	(I)	
						(D)	
HADCO Westbrooke, HPS	70	6,300	30	13.19	1.35	(I)	
	100	9,500	43	13.04	1.33	(I)	
	150	16,000	62	*	1.46		
	200	22,000	79	*	0.85		(R)
	250	29,000	102	20.69	1.82	(I)	(I)

(M)

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	750	105,000	285	$9.25	*	**(C)(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	$20.23	$0.63	**(I)**	**(I)**
	30	20.12	0.63		
	35	24.14	0.76		
Aluminum Davit	25	18.35	0.57		
	30	20.67	0.65		
	35	24.21	0.76		
	40	25.01	0.78		
Aluminum Double Davit	30	14.95	0.47	**(I)**	**(I)**

(M) **(M)**

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued) **(M)**

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B		
Aluminum, Fluted Ornamental	14	$12.45	$0.39	**(I)**	**(I)**
Aluminum, Smooth Techtra Ornamental	18	25.79	0.81	**(I)**	**(I)**
Aluminum, Fluted Ornamental	16	12.81	0.40	**(I)**	**(I)**
Aluminum, Double-Arm, Smooth Ornamental	25	27.62	0.87	**(I)**	**(I)**
Aluminum, Fluted Westbrooke	18	16.35	0.51	**(R)**	**(R)**
Aluminum, Non-Fluted Ornamental, Pendant	18	18.15	0.57	**(I)**	**(R)**
Fiberglass, Fluted Ornamental Black	14	13.84	0.43	**(I)**	**(I)**
Fiberglass, Anchor Base, Gray or Black	35	25.79	0.81	**(I)**	**(I)**
Fiberglass, Anchor Base (Color may vary)	25	22.68	0.71	**(I)**	**(I)**
	30	24.49	0.77	**(I)**	**(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		
						(D)	
Cobrahead, Mercury Vapor	100	4,000	39	*	*		
	175	7,000	66	$5.98	$0.87	**(I)**	**(R)**
						(D)	
	400	21,000	147	6.23	0.89	**(I)**	**(R)**
	1,000	55,000	374	6.96	*	**(I)**	
Holophane Mongoose, HPS	150	16,000	62	*	1.26		**(R)**
	250	29,000	102	*	1.36		**(R)**
Special Box Similar to GE "Space-Glo"							
						(D)	
Mercury Vapor	175	7,000	66	*	0.92		**(R)**

* Not offered. **(M)**

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued) **(M)**

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B		
Special Box, Anodized Aluminum Similar to GardCo Hub							
HPS	70	6,300	30	*	*		
	150	16,000	62	*	*		
	250	29,000	102	*	*		
	400	50,000	163	*	*	**(N)**	
Metal Halide	250	20,500	99	*	1.14		**(I)**
	400	40,000	156	*	1.14		**(I)**
Cobrahead, Metal Halide	175	12,000	71	*	*		
Flood, Metal Halide	400	40,000	156	7.03	*	**(I)**	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	*		
	165	12,000	60	*	*		
HADCO Techtra, QL	165	12,000	60	*	0.72		**(R)**
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	1.37		**(I)**
KIM Archetype, HPS	250	29,000	102	*	1.37		**(R)**
	400	50,000	163	*	1.60		**(R)**
Special Acorn-Type, HPS	70	6,300	30	9.93	1.12	**(R)**	**(R)**
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*		
Mercury Vapor	175	7,000	66	*	*		

* Not offered.

(M)

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued) **(M)**

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B		
Early American Post-Top, HPS							
Black	70	6,300	30	$5.76	$0.86	**(R)**	**(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	6.27	0.89	**(R)**	**(R)**
Flood, HPS							
	100	9,500	43	6.04	0.88	**(I)**	**(R)**
	200	22,000	79	6.78	0.93	**(R)**	**(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.

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Option A	Option B		
Aluminum Post	30	$9.86	*	**(I)**	
Aluminum, Painted Ornamental	35	*	$0.76		**(I)**
Aluminum, Regular	16	9.86	0.31	**(I)**	**(I)**
Concrete, Ornamental	35 or less	20.23	0.63	**(I)**	**(I)**
Fiberglass, Direct Bury with Shroud	18	10.77	0.34	**(I)**	**(I)**
Steel, Painted Regular **	25	20.23	0.63	**(I)**	**(I)**
Steel, Painted Regular **	30	20.12	0.63	**(I)**	**(I)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.63		**(I)**
Steel, Unpainted 8-foot Mast Arm **	35	*	0.76		**(I)**
Wood, Laminated without Mast Arm	20	9.97	0.31	**(I)**	**(I)**
Wood, Curved Laminated	30	*	0.27		**(I)**
Wood, Painted Underground	35	9.31	0.29	**(I)**	**(I)**

* Not offered.
** Maintenance does not include replacement of rusted steel poles. **(M)**

SCHEDULE 91 (Continued) (T)

SPECIALTY SERVICES OFFERED (M)

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.
- Permitting. (N)
- Transfer of Customer-owned streetlights attached to PGE-maintained Poles.(1) (N)

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 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. (M)

(1) See Schedule 300-3 for Luminaire Transfer Charge. (N)
(N)

SCHEDULE 91 (Continued)

(M)

SPECIAL CONDITIONS (Continued)

6. For Option C lights: The Company does not provide the circuit on new Option C 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 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.

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.

(M)

SCHEDULE 91 (Continued)

SPECIAL CONDITIONS (Continued) **(M)**

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.

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)**

SCHEDULE 91 (Concluded)

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.

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	0.586	¢ per kWh	**(I)**
Distribution Charge	2.024	¢ per kWh	**(R)**
Energy Charge	3.018	¢ per kWh	**(I)**

* 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 96 (Continued)

MONTHLY RATE

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

	Primary	
Basic Charge	$3,600.00	(R)
Transmission and Related Services Charge		
per kW of monthly Peak Demand**	$11.55	(I)
Distribution Charges***		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$0.77	(R)
Over 4,000 kW	$0.46	(R)
per kW of monthly Peak Demand**	$1.80	(I)
Substation Credit per kW of monthly Peak Demand****	($1.52)	(N)
Generation Demand Charge	$23.66	(I)
per kW of monthly Peak Demand**		
System Usage Charge		
per kWh	0.281 ¢	(R)

(C) (C)

* See Schedule 100 for applicable adjustments.
** Peak Demand hours are Monday - Saturday 6:00 a.m. to 10:00 p.m.
*** 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.
****Applicable only to Customers who own and maintain the substation that distributes power to their service. (N)

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.

SCHEDULE 96 (Continued)

NON-COST OF SERVICE OPTION **(T)**

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.349¢ 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. **(M) (I) (M)**

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

Primary Delivery Voltage	1.0490	**(D) (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 96 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.

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.

SCHEDULE 96 (Continued) **(T)**

ELECTION WINDOWS (Continued) **(T)**

November Election Window **(M)**

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, https://portlandgeneral.com **(M)**

MINIMUM CHARGE

The Basic, Distribution, Transmission, and Generation Charges specified in this schedule will be subject to minimums specified in Rule I and the Customer Service Contracts required under this Schedule. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage respectively, unless different minimums are specified in the Customer Service Contract. **(C)**

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.

CAPACITY EXCEEDANCE PENALTY

If the Customer's actual demand exceeds Allocated System Capacity, then the Customer will be assessed an exceedance penalty. The penalty amount will be calculated and charged per hour and per MW of exceedance over the threshold as four times the transmission rate and one and a half times the generation rate specified by demand per the rates in this schedule. Customers who exceed their Capacity Exceedance Threshold will be subject to curtailment, termination and other remedies specified in the Customer Service Contract.

SCHEDULE 96 (Concluded)

CONTRACTS **(M)**

The following customers must enter into a contract with the Company for the provision of service: Customers commencing service after the effective date of HB 3546 (the Power Act) (June 16, 2025) or commencing service before June 16, 2025 if the provision of electricity service requires the Company to make significant investments or incur costs after June 16, 2025, that could result in increased costs or risks to other PGE retail customers. Customers required to enter into a contract for service under this Schedule may sign a contract with the Company consistent with the terms and conditions of this Schedule and Rule I or enter into a special contract with the Company for provision of electricity service, including as applicable, transmission, distribution, energy, capacity or ancillary electricity services. Any special contract signed by a customer and the Company under this Schedule shall be subject to Commission review and approval.

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 or the Customer Service Agreement. **(M)**

SCHEDULE 97
CUSTOMER DEDICATED RESOURCE SERVICE

PURPOSE

This Schedule establishes the tariffed framework under which the Company may procure, contract for, acquire, construct, own, or arrange a Customer Dedicated Resource (CDR) for a Large Load. A CDR and the associated Customer Dedicated Resource Agreement (CDSA) may be used to satisfy all or a portion of any generation-supply, clean-energy, resource-adequacy, or other Service Plan requirements established in the Large Load Customer Agreement, Rule I, Schedule 96, an applicable Commission order, or other governing authority. To the extent the CDR does not cover the Large Load's full Allocated System Capacity (ASC) or covers only a designated tranche, the remaining ASC is served from Company Portfolio Service under Schedule 96 or additional CDRs, each of which would be subject to a separate agreement under this Schedule.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Cost of Service Customer that will receive service on Schedule 96. A CDR may be combined with Company Portfolio Service or customer-sited resources as permitted under the Large Load Customer Agreement; this Schedule governs only CDR service.

DEFINITIONS

Allocated System Capacity (ASC) - as defined in Rule I and the Large Load Customer Agreement. References to ASC include the Large Load’s approved load-ramp schedule, as applicable.

CDR Actual Delivery Peak Demand - the metered kW of CDR output delivered to the Company's balancing authority area during the billing period.

CDR Contracted Capacity - the nameplate, contract, or ownership capacity of a CDR for which the Large Load is financially responsible under the CDSA. CDR Contracted Capacity may exceed the Large Load’s ASC; any credit under this Schedule remains subject to the applicable credit cap.

Commission - means the value of capacity, calculated as described in PGE’s IRP, at the time the resource contract is executed.

Company Portfolio Service - generation and related supply service provided from the Company’s system resource portfolio.

SCHEDULE 97 (Continued)

DEFINITIONS (Continued)

Customer Dedicated Resource (CDR) - a generating resource, energy storage resource, or resource tranche that is procured, contracted for, acquired, constructed, owned, or arranged by the Company and financially dedicated to a specific Large Load Customer under a CDSA. CDR dedication is a financial and contractual allocation and does not create a physical entitlement to specific electrons or restrict the Company's dispatch authority.

Customer Dedicated Service Agreement (CDSA) - the agreement between the Company and the Large Load Customer that implements CDR service under this Schedule and assigns the CDR's costs, risks, obligations, benefits, credits, environmental attributes, collateral, and termination exposure.

Forecast CDR Generation - the hourly generation forecast for a CDR used for billing and established under the CDSA using project-specific production forecasts, seasonal shapes, expected outages, expected curtailment, degradation, storage charging assumptions, transmission losses, and other reasonable inputs.

Large Load Customer - as defined in the Applicable section.

Large Load Customer Agreement (LLCA) - the agreement required under Rule I establishing the Large Load Customer's ASC, load ramp, service term, Improvements, construction and financial commitments, and other service requirements.

Service Plan - any generation-supply or related service plan required for a Large Load Customer under a Large Load Customer Agreement, Rule I, Schedule 96, or an applicable Commission order. This Schedule does not independently establish Service Plan requirements.

CUSTOMER DEDICATED RESOURCE ELIGIBILITY AND ENVIRONMENTAL ATTRIBUTES

CDR ELIGIBILITY AND CLEAN-ENERGY CONSISTENCY

A CDR must be consistent with any applicable generation-supply, clean-energy, emissions, or environmental-attribute requirements established in the Large Load Customer Agreement, Rule I, Schedule 96, an applicable Commission order, or other governing authority. A CDR and CDSA may be used to satisfy all or a portion of those requirements, but this Schedule does not independently establish the amount or attributes of generation supply the Large Load Customer must procure.

Unless the Commission approves an applicable reliability, cost-cap, temporary exemption, or other lawful compliance mechanism, a resource that directly emits greenhouse gases in electricity generation does not qualify as a CDR. Approval of an exemption or other compliance mechanism does not permit CDR-specific or Large Load compliance costs to be recovered from other customers unless the Commission expressly determines that the costs provide a shared benefit and approves the allocation.

SCHEDULE 97 (Continued)

Customer Dedicated Resource Eligibility and Environmental Attributes (Continued)

ELIGIBLE SUPPLY AND ATTRIBUTE ACCOUNTING

An emissions-free CDR may include renewable generation, hydroelectric generation, or another non-emitting resource producing no direct greenhouse gas emissions in electricity generation, subject to applicable law and Commission approval.

For each CDSA, Renewable Energy Certificate ownership may be negotiated between the Company and the Large Load Customer. The Company will retain all other transferable environmental attributes, rights, benefits, claims, and credits associated with the CDR unless the CDSA expressly provides otherwise. The Company may not claim compliance credit for Renewable Energy Certificates retained by the Large Load Customer, and the Large Load Customer may not represent service as emissions-free based on attributes assigned to the Company or retired for another purpose. Renewable Energy Certificates alone do not establish physical delivery, deliverability, or hourly supply.

RESOURCE ADEQUACY

USE OF CDRS

Resources procured under this Schedule may be used by the Company to satisfy resource adequacy requirements. Any such use, including applicable qualification, performance, deliverability, replacement, and cost-responsibility terms, must be stated in the LLCA or CDSA. This Schedule does not independently establish a resource adequacy requirement or satisfaction.

CDR SERVICE

ELIGIBLE CDRS

A CDR must have CDR Contracted Capacity of at least 15 MW unless the Company approves aggregation of smaller resources. The CDR may be sized above the Large Load's ASC, provided the Large Load Customer pays all associated costs and accepts that credits are capped under this Schedule.

Before CDSA execution, the resource must demonstrate reasonable development maturity, which may include site control, a completed feasibility or system-impact study, an executed interconnection-study agreement, material permits, a credible development schedule, financing capability, or an executed development agreement. The Company may require additional diligence based on technology, location, transmission, counterparty, tax, supply-chain, or construction risk.

SCHEDULE 97 (Continued)

CDR SERVICE (Continued)

A CDR is not required to have firm transmission at the time the CDSA is executed. If it lacks firm deliverability, the Large Load Customer bears all resulting transmission, congestion, market, replacement-supply, curtailment, and nonperformance costs unless the CDSA expressly allocates a specific risk differently. The Large Load also bears the risk that the CDR may not qualify for, retain, or deliver the resource adequacy value assumed in the Service Plan, including any resulting deficiency, replacement-capacity, deliverability, accreditation, compliance, or related costs.

TERM

The term of the CDSA must equal or exceed the Large Load Customer's LLCA term, measured from the CDR commercial operation date. Where a shorter CDSA term is commercially necessary, the CDSA must specify rollback mechanics, including either: (a) the Large Load Customer's election to roll back to Company Portfolio Service at the end of the CDR term; or (b) the Large Load Customer's intent to enter into a replacement CDSA providing materially equivalent generation and capacity accreditation. A shorter CDR term does not create an automatic right to Company Portfolio Service.

If the Large Load Customer elects to roll back to Company Portfolio Service under subsection (a), the rollback date must be no earlier than four (4) years after the execution date of the CDSA, unless otherwise approved by the Company and the Commission. The Large Load Customer remains responsible for all costs, obligations, and minimum billing requirements under the CDSA, LLCA, Schedule 96, and this Schedule until the effective rollback date.

If the Large Load Customer elects or identifies the replacement-CDSA pathway under subsection (b), the Large Load Customer bears all risks associated with securing, approving, and implementing the replacement CDSA. The Company shall not be liable if the Large Load Customer fails to obtain a replacement CDSA, if a proposed replacement resource is delayed or rejected, or if the replacement resource does not provide materially equivalent generation or capacity accreditation. In all such circumstances, the Large Load Customer remains subject to its LLCA and Schedule 96 obligations, including any applicable minimum billing, demand, and service obligations.

SCHEDULE 97 (Continued)

MONTHLY RATE

Service under this Schedule is in addition to, and does not replace, modify, reduce, or otherwise relieve the Large Load Customer of any obligation under Schedule 96 and its LLCA. The Large Load Customer remains responsible for all rates, charges, minimum billing obligations, demand obligations, and other requirements applicable under Schedule 96 and its LLCA, calculated on the Large Load Customer's full ASC at the applicable Delivery Voltage for each Service Point. In addition to all amounts due under Schedule 96, the Large Load Customer shall pay all Schedule 97 CDR-specific charges applicable to the CDR resource, less any applicable CDR credits provided under this Schedule.

CDR SPECIFIC CHARGES

In addition to Schedule 96 charges on the full ASC, the Large Load Customer pays the following CDR-specific charges attributable to each CDR:

CDR CAPACITY CARGE (FORECAST)

In the case of a resource purchase agreement where the Company is not the owner, the sum of the forecasted amounts of (a) any applicable capacity payment due under the resource purchase agreement, and (b) any other fixed costs specified in the agreement.

In the case where the Company is the owner the sum of (a) ownership carrying cost including depreciation, allowed return, taxes, insurance, fixed O&M, and other similar costs; and (b) interconnection and integration fixed costs.

The CDR Capacity Charge will be based on the annual forecast for the resource. PGE will assess actual performance during the year in the CDR Forecast True-Up.

CDR ENERGY CHARGE (FORECAST)

The forecast pass-through of CDR variable costs, including contract energy payments, variable operations and maintenance, fuel or charging costs when applicable, losses, imbalance, scheduling, dispatch, and replacement power costs caused by CDR outage, delay, underperformance, or developer default. The charge applies to all CDR output and resource operations financially assigned to the Large Load Customer, regardless of whether the energy directly serves the Large Load Customer, charges storage, is exported, is curtailed, or is used by the Company for system operations, subject to the credits and market settlement provisions below.

The CDR Energy Charge will be based on the annual forecast for the resource. PGE will assess actual performance during the year in the CDR Forecast True-Up.

SCHEDULE 97 (Continued)

CDR SPECIFIC CHARGES (Continued)

CDR TRANSMISSION ACCESS CHARGE

If applicable and not included elsewhere, the CDR Transmission Access Charge may include incremental transmission, ancillary service, operating reserve, scheduling, congestion, loss, uplift, EDAM or WEIM imbalance, registration, telemetry, integration, and other similar costs reasonably required to deliver, schedule, integrate, or operate the CDR, to the extent such costs are not otherwise recovered through Schedule 96, the CDR Capacity Charge, or another charge under this Schedule. These costs may include OATT network integration or point-to-point transmission service, third-party transmission service, RA Authority transmission registration, deliverability-related ancillary services, and other transmission or market-participation costs specifically attributable to the CDR. This charge is in addition to the Schedule 96 Transmission Charge, which covers Company system transmission for the Large Load's full ASC.

CDR ADMINISTRATIVE CHARGE

Flat monthly charge recovering PGE's incremental administrative, legal, regulatory-compliance, and reporting costs specifically attributable to the CDR arrangement beyond the contract-administration component of the CDR Capacity Charge. This may also include any CDR risk adder that is identified by the Company, if any.

CDR-SPECIFIC CREDITS

In addition to Schedule 96 charges on the full ASC and the CDR specific charges, the Large Load Customer will receive the CDR-specific credits:

CDR GENERATION DEMAND CREDIT (FORECAST)

To prevent double recovery of generation demand costs for capacity supplied by a CDR, the Company will apply a CDR Generation Demand Credit against the Schedule 96 Generation Demand Charge for each Billing Period:

[The Company is continuing to evaluate the CDR Generation Demand Credit methodology. The credit is intended to avoid double recovery of generation demand costs while preserving cost-causation principles. Details will be supported through testimony.]

For each CDR, CDR Generation Credit Demand may not exceed the lesser of: (a) CDR Contracted Capacity; or (b) 90% of the Large Load Customer's ASC. The aggregate CDR Generation Demand Credit for all CDRs may not exceed the Schedule 96 Generation Demand Rate multiplied by 90% of ASC and may not create a negative generation demand charge. The CDR Generation Demand Credit will be based on the annual forecast for the resource. PGE will assess actual performance during the year in the CDR Forecast True-Up.

SCHEDULE 97 (Continued)

CDR-SPECIFIC CREDITS (Continued)

CDR ENERGY CREDIT (FORECAST)

To prevent double recovery of energy costs for forecast energy supplied by a CDR, the Company will apply a CDR Energy Credit against the Schedule 125 charges recovered through Schedule 96 for each Billing Period:

[The Company is continuing to evaluate the CDR Energy Credit methodology. The credit is intended to avoid double recovery of energy costs while preserving cost-causation principles. Details will be supported through testimony.]

The CDR Energy Credit will be calculated using Forecast CDR Generation rather than actual CDR generation. The Company will establish the Forecast CDR Generation for each Billing Period using the methodology specified in the CDSA, which may include project-specific production forecasts, seasonal shapes, metered historical performance, expected outages, expected curtailment, and other reasonable forecasting inputs. The same Forecast CDR Generation used to calculate the CDR Energy Charge for the Billing Period shall be used to calculate the CDR Energy Credit, unless the CDSA expressly provides otherwise.

The CDR Energy Credit will be based on the annual forecast for the resource. PGE will assess actual performance during the year in the CDR Forecast True-Up.

CDR FORECAST TRUE-UP

1. Step One: Resource Cost True-Up
   The monthly CDR Energy based on Forecast CDR Generation. The Company will calculate a CDR Forecast True-Up to reconcile actual CDR generation to Forecast CDR Generation (the "Energy Cost True Up") and the Company will reconcile the actual CDR Capacity Charges with the forecasted CDR Capacity Charge (the "Capacity Cost True Up", and together with the Energy Cost True Up the "Resource Cost True-Up").

   Energy Cost True Up =
   Σh [(Actual CDR Generation (MWh) − Forecast CDR Generation (MWh)) × CDR Energy Price ($/MWh)]

   Capacity Cost True Up =
   Actual CDR Capacity Cost – Forecasted CDR Capacity Cost

2. Step Two: CDR Energy Credit True-Up
   [The Company is continuing to evaluate whether a CDR Energy Credit true-up is needed and, if so, the appropriate methodology. Any true-up would be designed to avoid double recovery while assigning CDR-specific forecasting, settlement, and performance risk to the Large Load Customer. Details will be supported through testimony.]

SCHEDULE 97 (Continued)

CDR FORECAST TRUE-UP (Continued)

3. Step Three: CDR Generation Demand Credit True-Up
   [The Company is continuing to evaluate whether a CDR Generation Demand Credit true-up is needed and, if so, the appropriate methodology. Any true-up would be designed to avoid double recovery while assigning CDR-specific accreditation, deliverability, replacement-capacity, and performance risk to the Large Load Customer. Details will be supported through testimony.]

4. Billing and Timing
   The Company will complete each annual true-up within 120 days after the later of the end of the applicable true-up period or receipt of final market and contract settlement data, unless the CDSA specifies a different timing or cadence. The Company may update forecasts prospectively during the year if material changes make the existing forecast unreasonable.

RESOURCE DELAY, DEFAULT, AND CUSTOMER EXIT

[The Company is continuing to evaluate the appropriate treatment of CDR delay, default, customer exit, load reduction, early termination, and related CDR impacts. Any approach would be designed to assign CDR-specific costs and risks to the Large Load Customer and avoid cost shifting to other customers. Details will be supported through testimony.]

COLLATERAL

The form, amount, timing, and ongoing adjustment of collateral shall be specified in the CDSA, subject to Company credit review.

ADJUSTMENTS

CDR-specific Schedule 97 charges are not subject to Schedule 100 adjustments. Schedule 96 charges preserved under this Schedule are subject to all applicable Schedule 100 adjustments.

CONTRACTS

Service requires a CDSA to be executed under this Schedule. The Company will file each executed CDSA with the Commission, and each CDSA will be subject to a 60-day Commission review period. Any CDSA that materially differs from the requirements of this Schedule, Schedule 96, Rule I, the applicable LLCA, or a prior Commission order must identify the material difference and will be subject to an additional 30-day Commission review period

SCHEDULE 97 (Concluded)

SPECIAL CONDITION

1. This Schedule supplements Schedule 96 and Rule I. It does not replace, reduce, suspend, or otherwise modify any Schedule 96 minimum billing, demand, interconnection, construction, deposit, collateral, exit-fee, or other obligation except to the limited extent an express credit or adjustment is stated in this Schedule or the Large Load Customer's CDSA and approved by the Commission.

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]	111[1]	115	118	120	121	122	123[1]	125[1]	126	
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	
38	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	
83	x	x	x	x	x	x		x	x	x	x	x	x	x	x	(D)
85	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	(D)
91		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	(D)
96			x			x	x			x	x	x		x	x	
485	x	x	x	x	x	x		x	x		x		x		x[5]	
489	x	x	x	x	x	x		x	x		x		x		x[5]	(D)
491		x	x	x	x	x		x	x		x		x		x	
492		x	x	x	x	x		x	x		x		x		x	(D)
496			x			x	x				x				x	
515	x	x	x	x	x	x		x	x		x		x		x[5]	
532	x	x	x	x	x	x		x	x		x		x		x[5]	
538	x	x	x	x	x	x		x	x		x		x		x[5]	
549	x	x	x	x	x	x		x	x		x		x		x[5]	
583	x	x	x	x	x	x		x	x		x		x		x[5]	(D)
585	x	x	x	x	x	x		x	x		x		x		x[5]	
589	x	x	x	x	x	x		x	x		x		x		x[5]	
591		x	x	x	x	x		x	x		x		x		x[5]	(D)
592		x	x	x	x	x		x	x		x		x		x[5]	(D)
596			x			x	x				x				x	
689	x	x	x	x	x	x		x	x		x		x		x	
696			x			x	x				x				x	

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, 491, and 492). (C)
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)

Schs.	128[4]	129[1]	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	
15			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	
38	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	
49			x	x	x	x			x	x	x	x	x	x	x	x	
83	x		x	x	x	x			x	x	x	x	x	x	x	x	(D)
85	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	
91	x		x	x	x	x			x	x	x	x	x	x	x	x	(D)
92			x	x	x	x			x	x	x	x	x	x	x	x	(D)
96	x		x	x	x	x			x		x		x	x	x	x	
485		x		x	x				x			x	x	x	x	x	
489		x		x	x				x			x	x	x	x	x	(D)
491		x		x	x				x			x	x	x	x	x	
492		x		x	x				x			x	x	x	x	x	(D)
496		x		x	x				x				x	x	x	x	
515	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	
538	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	(D)
583	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	
589	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	(D)
592	x		x	x	x	x			x	x	x	x	x	x	x	x	(D)
596	x		x	x	x	x			x		x		x	x	x	x	(D)
689				x	x		x		x			x	x	x	x	x	
696	x				x		x		x				x	x	x	x	

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, 491, and 492). (C)
5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

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	0.123	0.000	0.123	¢ per kWh	
15/515	0.006	0.000	0.006	¢ per kWh	
32/532	0.009	0.000	0.009	¢ per kWh	
38/538	0.003	0.008	0.011	¢ per kWh	
47	0.009	0.000	0.009	¢ per kWh	
49/549	0.008	0.008	0.016	¢ per kWh	(D)
83/583	0.011	0.008	0.019	¢ per kWh	
85/585					
Secondary	0.010	0.008	0.018	¢ per kWh	
Primary	0.010	0.008	0.018	¢ per kWh	

(D)

SCHEDULE 105 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
89/589					
Secondary	0.012	0.008	0.020	¢ per kWh	
Primary	0.012	0.008	0.020	¢ per kWh	**(D)**
91/591	0.005	0.008	0.013	¢ per kWh	
92/592	0.007	0.008	0.015	¢ per kWh	**(D)**
96/596	0.010	0.008	0.018	¢ per kWh	
485					
Secondary	0.000	0.000	0.000	¢ per kWh	
Primary	0.000	0.000	0.000	¢ per kWh	
489					
Secondary	0.003	0.000	0.003	¢ per kWh	
Primary	0.003	0.000	0.003	¢ per kWh	**(D)**
491	(0.005)	0.000	(0.005)	¢ per kWh	
492	(0.004)	0.000	(0.004)	¢ per kWh	**(D)**
496					
Primary	0.003	0.000	0.003	¢ per kWh	**(D)**

SCHEDULE 105 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
689					
Secondary	0.003	0.000	0.003	¢ per kWh	
Primary	0.003	0.000	0.003	¢ per kWh	**(D)**
696					
Primary	0.003	0.000	0.003	¢ per kWh	**(D)**

SCHEDULE 109 (Continued)

ENERGY TRUST OF OREGON FUNDING ADJUSTMENT

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Standard Pricing

Schedule	Adjustment Rate	
7	1.004 ¢ per kWh	
15/515	0.742 ¢ per kWh	
32/532	0.916 ¢ per kWh	
38/538	1.000 ¢ per kWh	
47	1.310 ¢ per kWh	
49/549	1.190 ¢ per kWh	(D)
83/583	0.700 ¢ per kWh	
85/485/585		
Secondary	0.622 ¢ per kWh	
Primary	0.752 ¢ per kWh	
89/489/589/689		
Secondary	0.487 ¢ per kWh	
Primary	0.482 ¢ per kWh	(D)
91/491/591	0.770 ¢ per kWh	
92/492/592	0.526 ¢ per kWh	
96/496/596/696	0.764 ¢ per kWh	(D)

SCHEDULE 109 (Concluded)

ENERGY TRUST OF OREGON FUNDING ADJUSTMENT (Continued)

Over One Average Megawatt Pricing

Schedule	Adjustment Rate	
83/583 >1aMW	0.422 ¢ per kWh	**(D)**
85/485/585 >1aMW		
Secondary	0.298 ¢ per kWh	
Primary	0.274 ¢ per kWh	
89/489/589/689 >1aMW		
Secondary	0.487 ¢ per kWh	
Primary	0.482 ¢ per kWh	**(D)**
96/496/596/696	0.764 ¢ per kWh	

SPECIAL CONDITION

1. Any adjustments relating to eligible Nonresidential Customers subject to annual caps as described in HB 3141 will be paid from the Schedule 109 Energy Trust of Oregon Funding Adjustment balancing account. Nonresidential Customers meeting the requirements for the combined annual cap under HB 3141 will notify the Company by March 31 of the following year to receive an adjustment.

TERM

This Schedule will terminate on January 1, 2036.

SCHEDULE 120
SEASIDE BATTERY STORAGE RESOURCE ALTERNATIVE RECOVERY

PURPOSE

This Schedule recovers the revenue requirement and provides customers with the Power Cost benefits associated with Seaside Battery Energy Storage System (BESS) resource.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 485, 489, 491, 492, 496, 515, 532, 538, 549, 583, 585, 589, 596, 689 and 696. **(C)**

PART A – REVENUE REQUIREMENT ADJUSTMENTS

Part A will include the fixed costs of the Seaside BESS resource associated 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 Seaside BESS resource.

PART B – POWER COST BENEFIT

Part B consists of the Net Variable Power Cost benefits from the Seaside BESS resource, until the benefits are included in the Annual Power Cost Update Schedule 125. Until the benefits are included in the Annual Power Cost Update Schedule 125, the net revenue requirements of the Seaside BESS resource will be included in the Schedule 120 rates. By no later than December 1 of 2025, the Company will file an update to this schedule to remove the power cost benefit for the following year and include the benefit in the AUT.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Part A	Part B	Adjustment Rate		
7	0.000	(0.000)	0.000	¢ per kWh	**(R)**
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	**(R)**

SCHEDULE 120 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Part A	Part B	Adjustment Rate		
83	0.000	(0.000)	0.000	¢ per kWh	(D) (R)
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	(R)
91	0.000	(0.000)	0.000	¢ per kWh	(D) (R)
92	0.000	(0.000)	0.000	¢ per kWh	(R)
96	0.000	(0.000)	0.000	¢ per kWh	(D) (R)

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using tl applicable schedule's forecasted energy on the basis of an equal percent of generati revenue applied on a cents per kWh basis to each applicable rate schedule.

2. The costs for projects included under this schedule will be updated annually as provid above and will continue to be recovered under Schedule 120 until such time as the cos are included in base rates or the project is no longer in service.

3. Once the Seaside resource is placed into base rates or is no longer in service, this Schedu will be withdrawn, and no other assets will be placed within this Schedule.

SCHEDULE 121
DISTRIBUTION SYSTEM PLAN ALTERNATIVE RECOVERY MECHANISM

PURPOSE

This Schedule recovers the revenue requirement associated with PGE's Distribution System Plan.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service. (C)

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)
15/515	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	(R)
83/583	0.000	¢ per kWh	(D)
85/585			(R)
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	
89/589			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	(R)
			(D)

SCHEDULE 121 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
91/591	0.000	¢ per kWh	(D) (R)
92/592	0.000	¢ per kWh	(R) (D)
96/596			
Primary	0.000	¢ per kWh	(R) (D)
485			
Secondary	0.000	¢ per kWh	(R)
Primary	0.000	¢ per kWh	
489			
Secondary	0.000	¢ per kWh	
Primary	0.000	¢ per kWh	(R)
491	0.000	¢ per kWh	(D) (R)
492	0.000	¢ per kWh	(D
496			
Primary	0.000	¢ per kWh	(R) (D)
689			
Secondary	0.000	¢ per kWh	(R)
Primary	0.000	¢ per kWh	(R) (D)

SCHEDULE 121 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
696			
Primary	0.000	¢ per kWh	**(R)** **(D)**

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 production, transmission, distribution and consumer revenue applied on a cents per kWh basis to each applicable rate schedule.

2. The costs for projects included under this schedule will be updated annually as provided above and will continue to be recovered under Schedule 121 until such time as the costs are included in base rates.

3. The Company will submit the annual update filing for Schedule 121 no later than the last business day of February each year.

4. Once the Distribution System Plan is included in base rates or is no longer in service, this Schedule will be withdrawn, and no other assets will be placed within this Schedule.

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 485, 489, 491, 492, 496, 689 and 696. This schedule is not applicable to direct access customers after December 31, 2010. **(C)**

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	**(R)**
49		0.000	¢ per kWh	
83		0.000	¢ per kWh	**(D)**
85				
	Secondary	0.000	¢ per kWh	**(R)**
	Primary	0.000	¢ per kWh	
89				
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	**(R)**
				(D)

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
91	0.000	¢ per kWh	(R)
92	0.000	¢ per kWh	(R)
96	0.000	¢ per kWh	(D)
			(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 123
DECOUPLING ADJUSTMENT

PURPOSE

This Schedule establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the impact on collections of fixed costs through volumetric customer prices caused by variations in applicable customer energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and small Nonresidential Customers served on Schedule 32 located within the Company's service territory. (C) (C)

NORMALIZED USAGE ADJUSTMENT (NUA) (N)(D)

The SNA NUA calculates the following on a monthly basis:

1) The difference between actual weather-normalized use per customer in each month from the forecasted weather-normalized use per customer as provided below:
    a) Forecast Residential (Schedule 7) use per customer: 759 kwh/customer
    b) Forecast Small Non-Residential (Schedule 32) use per customer: 1,267 kwh/customer
2) The differences in usage identified in 1) are multiplied by the applicable volumetric energy prices for Schedules 7 and 32 as approved by the Commission:
    a) Schedule 7 volumetric rate: 12.861 cents/kwh
    b) Schedule 32 volumetric rate: 12.226 cents/kwh

The amounts calculated above will accrue monthly into a balancing account and may be positive (forecast usage exceeding actual usage) or negative (actual usage exceeding forecast usage). Positive adjustments will result in an accrual for future collections while negative adjustments will result in an accrual for future refunds. The net accruals for Schedule 7 and 32 will be tracked separately.

NUA BALANCING ACCOUNTS

The Company will maintain a separate balancing account for Schedules 7 and 32. The accounts will accrue interest at the Commission-authorized Modified Blended Treasury Rate established for deferred accounts. (N)(D)

SCHEDULE 123 (Concluded) (T)

(D)(M)

DECOUPLING ADJUSTMENT

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate	
7	0.000 ¢ per kWh	(C)
32/532	0.000 ¢ per kWh	(C)

TIME AND MANNER OF FILING

Commencing in 2028 the Company will submit to the Commission the following information by August 1 of each year. (C)

1. The proposed price changes to this Schedule to be effective on October 1st based on the amounts in the NUA Balancing Accounts as of June 30th.

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 NUA weather-normalizing adjustments.

SPECIAL CONDITIONS

1. The volumetric energy prices for Schedules 7 and 32 will be updated annually to reflect Commission approved updates pursuant to the Bridge Framework.

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. Unless otherwise established by the Commission, the NUA will terminate on the effective date of Commission-approved rates pursuant to PGE's first multi-year rate plan, currently expected in the spring of 2030. Balances accrued up to that point will be subject to subsequent rate adjustment.

(C)(D)(M)

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, 83, 85, 89, 91, 92, and 96. Customers served under the Daily Price option contained in schedules 32, 38, 81, 83, 85, 89, and 91 are exempt from Schedule 125. **(C)** **(C)**

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:

- NVPC Modeling Changes
- 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 and solar 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.
- Dispatch of energy storage systems.
- 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.

SCHEDULE 125 (Continued)

ANNUAL UPDATES (Continued)

- 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.

REVENUE SENSITIVE COSTS

Changes in NVPC for purposes of rate determination under this schedule are adjusted for a revenue sensitive cost factor of 1.0348. **(I)**

FILING AND EFFECTIVE DATE

Should the Company propose modeling changes outside of a general rate case to be effective on January 1st of the following calendar year, the Company will file estimates of the proposed modeling changes and all associated minimum filing requirements no later than February 15 of the calendar year prior to the rate effective date. Any estimates for modeling changes proposed in a general rate case year shall be filed at the earlier of either the filing of GRC opening testimony or by April 1st prior to the rate 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 or the next available business day if the 6th is on a weekend 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, new market power and fuel contracts entered into since the previous updates, and updated projections of gas and electric prices, power, and fuel contracts.

SCHEDULE 125 (Continued)

ADJUSTMENT RATES (Continued)

Schedule		¢ per kWh	
83			**(D)**
	On-Peak Period	6.024	
	Mid-Peak Period	4.879	
	Off-Peak Period	4.116	
85			
	Secondary		
	On-Peak Period	5.808	
	Mid-Peak Period	4.664	
	Off-Peak Period	3.901	
	Primary		
	On-Peak Period	5.672	
	Mid-Peak Period	4.528	
	Off-Peak Period	3.765	
89			
	Secondary		
	On-Peak Period	5.672	
	Mid-Peak Period	4.528	
	Off-Peak Period	3.765	
	Primary		
	On-Peak Period	5.337	
	Mid-Peak Period	4.593	
	Off-Peak Period	4.098	**(D)**

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		¢ per kWh	
91		4.082	**(D)**
92		4.317	**(D)**
96	Primary		
	On-Peak Period	5.770	
	Mid-Peak Period	5.026	
	Off-Peak Period	4.531	

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 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 485, 489, 491, 492, 496, 515, 532, 538, 549, 583, 585, 589, 591, 592, 596, 689 and 696, or served under Schedules 83, 85, or 89 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 591, 592, and 596 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment. **(C)** **(C)** **(C)** **(C)**

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.

RELIABILITY CONTINGENCY EVENT POWER COST MECHANISM

Reliability Contingency Event (RCE) power costs are the amount of annual actual power costs prudently incurred during RCEs. Through an RCE Power Cost Mechanism, RCE Power Costs, adjusted by any amount of RCE forecast included within Schedule 125 for the associated calendar year, qualify for 80% cost recovery or refund. The remaining RCE costs not recovered through the RCE Power Cost Mechanism will flow through the Annual Power Cost Variance, subject to deadbands and 90% sharing.

The RCE power costs recoverable through the RCE Power Cost Mechanism will not be subject to the earnings test or deadbands for the Annual Power Cost Variance.

Pursuant to Commission Order No. 23-386, the RCE Power Cost Mechanism will be in effect for PGE's filings under this schedule submitted on or around July 1, 2025 for 2024 power costs and submitted on or around July 1, 2026 for 2025 power costs and shall not apply thereafter unless otherwise ordered by the Commission.

SCHEDULE 126 (Continued)

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record both the Annual Power Cost Variance amounts and the RCE Power Cost 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

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 1.0348 to account for franchise fees, uncollectibles, and OPUC fees. **(R)**

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 that is not the Exempted RCE Power Cost 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 that is not the Exempted RCE Power Cost 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.

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 calculated based on the following formula:

(Actual NVPC – 80% RCE costs) / (Actual Loads – 80% RCE Loads)

SCHEDULE 126 (Continued)

DEFINITIONS (Continued)

- Include Energy Charge revenues from Schedules 38, 83, 85, 89, 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, 491, 492, 689, and 696 as an offset to NVPC. **(C)** **(C)** **(C)**
- 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.

RCE Power Cost Mechanism – 80% of the RCE Power Cost that is exempt from the earnings test and deadbands.

RCE Load - Total retail load served by PGE during an RCE, adjusted to exclude loads of Customers to whom this adjustment schedule does not apply.

Reliability Contingency Event – An event qualifies as a Reliability Contingency Event (RCE) for cost recovery when at least 2 out of the 3 criteria are met:

1. The Day-ahead Mid-Columbia index prices exceed $150/MWh.
2. PGE is eligible to request or acquire resource adequacy (RA) assistance through a regional RA program in which it participates.
3. A neighboring Balancing Authority has publicly declared an event that indicates potential supply or actual supply constraints.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0348 to account for franchise fees, uncollectibles, and OPUC fees. **(R)**

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	0.214 ¢ per kWh	
15/515	0.214 ¢ per kWh(1)	**(T)**
32/532	0.214 ¢ per kWh(1)	**(T)**
38/538	0.214 ¢ per kWh(1)	**(T)**
47	0.214 ¢ per kWh	
49/549	0.214 ¢ per kWh(1)	**(T)**
83/583	0.214 ¢ per kWh(2)	**(D)**
85/585		
Secondary	0.214 ¢ per kWh(1)	**(T)**
Primary	0.214 ¢ per kWh(1)	**(T)**
89/589		
Secondary	0.214 ¢ per kWh(1)	**(T)**
Primary	0.214 ¢ per kWh(1)	**(T)**
91/591	0.214 ¢ per kWh(1)	**(T)(D)**
92/592	0.214 ¢ per kWh(1)	**(T)**
96/596	0.214 ¢ per kWh(1)	**(T)(D)**
		(D)

(1) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cos **(T)**
Variance accrued.

SCHEDULE 126 (Concluded)

POWER COST VARIANCE RATES (Continued)

Schedule	Adjustment Rate	
485		
Secondary	0.214 ¢ per kWh(1)	(T)
Primary	0.214 ¢ per kWh(1)	(T)
489		
Secondary	0.214 ¢ per kWh(1)	(T)
Primary	0.214 ¢ per kWh(1)	(T)
491	0.214 ¢ per kWh	(D)
492	0.214 ¢ per kWh	(D)
496	0.214 ¢ per kWh	
689		
Secondary	0.214 ¢ per kWh(1)	(T)
Primary	0.214 ¢ per kWh(1)	(T)
Subtransmission	0.214 ¢ per kWh(1)	(T)
696	0.214 ¢ per kWh	(D)(T)

(1) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

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, 83, 85, 89, 91, or 96 or Direct Access service on Schedules 515, 532, 538, 549, 583, 585, 589, 591, 592, and 596. This Schedule is not applicable to Customers served on Schedules 485, 489, 491, 492, and 496. **(C)** **(C)** **(C)**

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 2025, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2026:

Schedule		Annual Part A ¢ per kWh (1)	Annual Part B $ per KW of Peak Demand (2)	
32		1.671		**(T)**
38		1.457		
83		(1.325)	9.34	**(D)**
85	Secondary	(1.523)	10.80	
	Primary	(1.456)	10.68	

(1) Not applicable to Customers served on Cost of Service.
(2) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday **(D)** **(T)**

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual Part A ¢ per kWh (1)	Annual Part B $ per KW of Peak Demand (2)	
				(T)
89	Secondary	0.852		**(D)**
	Primary	0.843		
96		0.843		
515		0.344		
532		1.671		
538		1.457		
549		3.353		
583		(1.325)	9.34	**(D)**
585	Secondary	(1.523)	10.80	
	Primary	(1.456)	10.68	
589	Secondary	0.852		
	Primary	0.843		
591		0.362		**(D)**
592		0.894		
596		0.843		**(D)**

(1) Not applicable to Customers served on Cost of Service. **(D)**
(2) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. **(T)**

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 windows will be $60,000. **(T)**

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.

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, https://portlandgeneral.com on the day the rate is filed with the Commission.

SCHEDULE 128 (Concluded)

April 1st Balance of Year Adjustment Rate[1] **(C)**

Schedule		9-Month Part A ¢ per kWh[2]	9-Month Part B $ per KW of Peak Demand[3]	
38		1.817		**(T)**
83		(0.958)	9.34	**(D)**
85	Secondary	(1.158)	10.80	
	Primary	(1.087)	10.68	
89	Secondary	1.143		
	Primary	1.130		**(D)**
91		0.782		
96		1.130		**(D)**
538		1.817		
583		(0.958)	9.34	**(D)**
585	Secondary	(1.158)	10.80	
	Primary	(1.087)	10.68	
589	Secondary	1.143		
	Primary	1.130		
591		0.782		**(D)**
592		1.314		**(D)**
596		1.130		

(1) Applicable April 1, 2026 through December 31, 2026.
(2) Not applicable to Customers served on Cost of Service. **(D)**
(3) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. **(T)**

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, 491, 492, and 496. **(C)**

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Periods A - S: 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.

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

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	Schs. 491/492 ¢ per kWh
2022	0.851	0.845	0.590	0.602	0.669
2023	0.851	0.845	0.590	0.602	0.669
2024	0.995	0.970	0.702	0.712	0.729
2025	1.138	1.095	0.832	0.841	0.787
2026	1.138	1.095	0.832	0.841	0.787
After 2026	0.000	0.000	0.000	0.000	0.000

(D) (D) (C) (D)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

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	Schs. 491/492 ¢ per kWh
2023	(1.985)	(1.799)	(0.766)	(0.758)	(0.769)
2024	(1.845)	(1.677)	(0.629)	(0.651)	(0.706)
2025	(1.702)	(1.552)	(0.499)	(0.522)	(0.648)
2026	(1.702)	(1.552)	(0.499)	(0.522)	(0.648)
2027	(1.702)	(1.552)	(0.499)	(0.522)	(0.648)
After 2027	0.000	0.000	0.000	0.000	0.000

(D) (C) (D)

For Enrollment Period U (2022), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492 $ per kW of Peak Demand
2023	5.17	5.15	0.000	0.000	0.000
2024	5.17	5.15	0.000	0.000	0.000
2025	5.17	5.15	0.000	0.000	0.000
2026	5.17	5.15	0.000	0.000	0.000
2027	5.17	5.15	0.000	0.000	0.000
After 2027	0.000	0.000	0.000	0.000	0.000

(D) (C) (D)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out (Continued)

For Enrollment Period V (2023), 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	Schs. 491/492 ¢ per kWh
2024	(4.669)	(4.269)	(2.431)	(2.405)	(2.101)
2025	(4.526)	(4.144)	(2.301)	(2.276)	(2.043)
2026	(4.526)	(4.144)	(2.301)	(2.276)	(2.043)
2027	(4.526)	(4.144)	(2.301)	(2.276)	(2.043)
2028	(4.526)	(4.144)	(2.301)	(2.276)	(2.043)
After 2028	0.000	0.000	0.000	0.000	0.000

(D) (C) (D)

For Enrollment Period V (2023), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492 $ per kW of Peak Demand
2024	10.12	10.01	0.000	0.000	0.000
2025	10.12	10.01	0.000	0.000	0.000
2026	10.12	10.01	0.000	0.000	0.000
2027	10.12	10.01	0.000	0.000	0.000
2028	10.12	10.01	0.000	0.000	0.000
After 2028	0.000	0.000	0.000	0.000	0.000

(D) (C) (D)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out (Continued)

For Enrollment Period W (2024), the current Transition Cost Adjustments are:

(D) (C)

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	Schs. 491/492 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2025	(5.510)	(4.231)	(0.528)	(0.523)	(0.702)	(0.523)
2026	(5.510)	(4.231)	(0.528)	(0.523)	(0.702)	(0.523)
2027	(5.510)	(4.231)	(0.528)	(0.523)	(0.702)	(0.523)
2028	(5.510)	(4.231)	(0.528)	(0.523)	(0.702)	(0.523)
2029	(5.510)	(4.231)	(0.528)	(0.523)	(0.702)	(0.523)
After 2029	0.000	0.000	0.000	0.000	0.000	0.000

(D)

For Enrollment Period W (2024), the Generation Demand Charge are:

(D) (C)

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492 $ per kW of Peak Demand	Sch. 496 Pri. Vol. $ per kW of Peak Demand
2025	10.80	10.68	0.000	0.000	0.000	0.000
2026	10.80	10.68	0.000	0.000	0.000	0.000
2027	10.80	10.68	0.000	0.000	0.000	0.000
2028	10.80	10.68	0.000	0.000	0.000	0.000
2029	10.80	10.68	0.000	0.000	0.000	0.000
After 2029	0.000	0.000	0.000	0.000	0.000	0.000

(D)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out (Continued)

For Enrollment Period X (2025), 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	Schs. 491/492 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2026	(1.773)	(0.903)	0.425	0.420	(0.567)	0.420
2027	(1.773)	(0.903)	0.425	0.420	(0.567)	0.420
2028	(1.773)	(0.903)	0.425	0.420	(0.567)	0.420
2029	(1.773)	(0.903)	0.425	0.420	(0.567)	0.420
2030	(1.773)	(0.903)	0.425	0.420	(0.567)	0.420
After 2030	0.000	0.000	0.000	0.000	0.000	0.000

(D) (C) (D)

For Enrollment Period X (2025), the Generation Demand Charge are:

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492 $ per kW of Peak Demand	Sch. 496 Pri. Vol. $ per kW of Peak Demand
2026	$10.80	$10.68	0.000	0.000	0.000	0.000
2027	$10.80	$10.68	0.000	0.000	0.000	0.000
2028	$10.80	$10.68	0.000	0.000	0.000	0.000
2029	$10.80	$10.68	0.000	0.000	0.000	0.000
2030	$10.80	$10.68	0.000	0.000	0.000	0.000
After 2030	0.000	0.000	0.000	0.000	0.000	0.000

(D) (C) (D)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)

Three Year Opt-Out

This option was not available during Enrollment Periods A and B

For Enrollment Periods C - U, No Longer Available (C) (D)

For Enrollment Period V (2023), the current Transition Cost Adjustments are: (M) (D) (C)

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	Schs. 491/492 ¢ per kWh
2024	(5.205)	(5.134)	(2.870)	(2.840)	(2.398)
2025	(4.724)	(4.696)	(2.351)	(2.327)	(1.978)
2026	(4.532)	(4.508)	(2.147)	(2.125)	(2.094)

(D)

For Enrollment Period V (2023), the Generation Demand Charge are: (D) (C)

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492 $ per kW of Peak Demand
2024	9.32	9.22	0.000	0.000	0.000
2025	9.32	9.22	0.000	0.000	0.000
2026	9.32	9.22	0.000	0.000	0.000

(D)

For Enrollment Period W (2024), the current Transition Cost Adjustments are: (D) (C)

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	Schs. 491/492 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2025	(1.729)	(1.701)	0.652	0.643	0.107	0.643
2026	(2.842)	(2.775)	(0.436)	(0.432)	(1.012)	(0.432)
2027	(3.229)	(3.153)	(0.827)	(0.820)	(1.471)	(0.820)

(D) (M)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out (Continued)

For Enrollment Period W (2024), the Generation Demand Charge are: (M) (D) (C) (D)

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492 $ per kW of Peak Demand	Sch. 496 Pri. Vol. $ per kW of Peak Demand
2025	10.62	10.50	0.000	0.000	0.000	0.000
2026	10.62	10.50	0.000	0.000	0.000	0.000
2027	10.62	10.50	0.000	0.000	0.000	0.000

For Enrollment Period X (2025), the current Transition Cost Adjustments are: (D) (C) (D)

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	Schs. 491/492 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2026	(6.041)	(6.054)	(3.282)	(3.247)	(3.840)	(3.247)
2027	(7.470)	(7.153)	(4.537)	(4.487)	(4.912)	(4.487)
2028	(7.563)	(7.262)	(4.629)	(4.579)	(5.041)	(4.579)

For Enrollment Period X (2025), the Generation Demand Charge are: (D) (C) (D) (M)

Period	Sch. 485 Sec. Vol. $ per kW of Peak Demand	Sch. 485 Pri. Vol. $ per kW of Peak Demand	Sch. 489 Sec. Vol. $ per kW of Peak Demand	Sch. 489 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/ $ per kW of Peak Demand	Sch. 496 Pri. Vol. $ per kW of Peak Demand
2026	$10.80	$10.68	0.000	0.000	0.000	0.000
2027	$10.80	$10.68	0.000	0.000	0.000	0.000
2028	$10.80	$10.68	0.000	0.000	0.000	0.000

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 85, 89, 485, 489, 585, and 589), 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. **(C)**

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedules 485, 489, 491, 492, and 496 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. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased participating load will be determined. **(C)**

3. In determining changes in fixed generation revenues from movement to or from Schedules 485, 489, 491, 492, and 496, the following factors will be used: **(C)**

Schedule		¢ per kWh	
85	Secondary	2.896	
	Primary	2.866	
89	Secondary	2.731	
	Primary	2.701	**(D)**
91		2.478	
92		2.478	
96		2.701	**(D)(M)**

SCHEDULE 129 (Continued)

TERM (M)

The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 485, 489, 491, 492, or 496. (C) (M)

SCHEDULE 129 (Concluded)

[Sheet intentional left blank] **(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 485, 489, 491, 492, 496, 689, and 696. **(C)**

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate		
7	0.086	¢ per kWh	
15/515	0.061	¢ per kWh	
32/532	0.076	¢ per kWh	
38/538	0.074	¢ per kWh	
47	0.091	¢ per kWh	
49/549	0.089	¢ per kWh	
83/583	0.072	¢ per kWh	**(D)**
85/585			
Secondary	0.075	¢ per kWh	
Primary	0.068	¢ per kWh	

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 135 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
89/589			
Secondary	0.068	¢ per kWh	
Primary	0.067	¢ per kWh	
91/591	0.061	¢ per kWh	**(D)**
92/592	0.066	¢ per kWh	
96/596	0.066	¢ per kWh	**(D)**

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremen costs associated with automated demand response and the revenues collected under tl schedule. This balancing account will accrue interest at the Commission-authorized rate 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. **(C)**

ADUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.040	¢ per kWh
15/515	0.031	¢ per kWh
32/532	0.038	¢ per kWh
38/538	0.039	¢ per kWh
47	0.053	¢ per kWh
49/549	0.047	¢ per kWh

(D)

SCHEDULE 136 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
83/583	0.028	¢ per kWh	
85/485/585			
Secondary	0.024	¢ per kWh	
Primary	0.022	¢ per kWh	
89/489/589/689			
Secondary	0.019	¢ per kWh	
Primary	0.019	¢ per kWh	
91/491/591	0.031	¢ per kWh	**(D)**
92/492/592	0.021	¢ per kWh	
96/496/596/696	0.018	¢ per kWh	**(D)**

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between incremental cc associated with the Oregon CSP and the revenues collected under this schedule. This balanc 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 CONDITIONS

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.

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. (C)

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate		
7	0.024	¢ per kWh	
15/515	0.018	¢ per kWh	
32/532	0.021	¢ per kWh	
38/538	0.023	¢ per kWh	
47	0.033	¢ per kWh	
49/549	0.029	¢ per kWh	
83/583	0.017	¢ per kWh	(D)
85/485/585			
Secondary	0.014	¢ per kWh	
Primary	0.012	¢ per kWh	(D)

SCHEDULE 137 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
89/489/589			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
91/491/591	0.018	¢ per kWh	**(D)**
92/492/592	0.012	¢ per kWh	
96/496/596/696	0.011	¢ per kWh	**(D)**
689			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	**(D)**

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.

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 485, 489, 491, 492, 496, 689, and 696. **(C)**

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.003	¢ per kWh
15/515	0.002	¢ per kWh
32/532	0.003	¢ per kWh
38/538	0.002	¢ per kWh
47	0.003	¢ per kWh
49/549	0.003	¢ per kWh
83/583	0.003	¢ per kWh
85/585		
Secondary	0.002	¢ per kWh
Primary	0.002	¢ per kWh

(D)

SCHEDULE 138 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
89/589		
Secondary	0.002 ¢ per kWh	
Primary	0.002 ¢ per kWh	(D)
91/591	0.002 ¢ per kWh	
92/592	0.002 ¢ per kWh	
96/596	0.002 ¢ per kWh	(D)

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. The 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 and 696. This transition adjustment will be paid when the Customer begins service under Schedule 689 and 696. 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 and 696. 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 2 (2021), the Transition Cost Adjustment will be: (D)

Period	Sch. 689 Primary Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2021	0.689	0.689
2022	0.580	0.580
2023	0.648	0.648
2024	0.602	0.602
2025	0.628	0.628
2026*	0.753	0.753
After 2027	0.000	0.000

(D)

For Period 3 (2022), the Transition Cost Adjustment will be: (D)

Period	Sch. 689 Primary Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2022	0.580	0.580
2023	0.648	0.648
2024	0.602	0.602
2025	0.628	0.628
2026	0.753	0.753
2027*	0.753	0.753
After 2028	0.000	0.000

(D)

*Applicable pricing only to completion of five-year period and zero thereafter.

SCHEDULE 139 (Continued)

TRANSITION COST ADJUSTMENT (Continued)

For Period 4 (2023), the Transition Cost Adjustment will be: **(D)**

Period	Sch. 689 Primary Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2023	0.648	0.648
2024	0.602	0.602
2025	0.628	0.628
2026	0.753	0.753
2027	0.753	0.753
2028*	0.753	0.753
After 2029	0.000	0.000

(D)

For Period 5 (2024), the Transition Cost Adjustment will be: **(D)**

Period	Sch. 689 Primary Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2024	0.602	0.602
2025	0.628	0.628
2026	0.753	0.753
2027	0.753	0.753
2028	0.753	0.753
2029*	0.753	0.753
After 2030	0.000	0.000

(D)

For Period 6 (2025), the Transition Cost Adjustment will be: **(D)**

Period	Sch. 689 Primary Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2025	0.628	0.628
2026	0.753	0.753
2027	0.753	0.753
2028	0.753	0.753
2029	0.753	0.753
2030*	0.753	0.753
After 2031	0.000	0.000

(D)

*Applicable pricing only to completion of five-year period and zero thereafter.

SCHEDULE 139 (Concluded)

TRANSITION COST ADJUSTMENT (Continued)

For Period 7 (2026), the Transition Cost Adjustment will be: (D)

Period	Sch. 689 Primary Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2026	0.753	0.753
2027	0.753	0.753
2028	0.753	0.753
2029	0.753	0.753
2030	0.753	0.753
2031*	0.753	0.753
After 2032	0.000	0.000

(D)

*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.

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedules 689 and 696 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. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased participating load will be determined.

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 689 and 696 but will not exceed 60 months.

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 485, 489, 491, 492, 689 and 696. **(C)**

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
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
83/583	0.000	¢ per kWh **(D)**
85/585		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
89/589		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh **(D)**

SCHEDULE 145 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
91/591	0.000 ¢ per kWh	**(D)**
92/592	0.000 ¢ per kWh	
96/596	0.000 ¢ per kWh	**(D)** **(N)**

DETERMINATION OF ADJUSTMENT AMOUNT

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.

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Boardman Power Plant decommissioning revenue requirement.

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.

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.

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 485, 489, 491, 492, 496, 689, and 696. **(C)**

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	0.224	¢ per kWh
15/515	0.159	¢ per kWh
32/532	0.197	¢ per kWh
38/538	0.192	¢ per kWh
47	0.235	¢ per kWh
49/549	0.230	¢ per kWh
83/583	0.195	¢ per kWh
85/585		
Secondary	0.190	¢ per kWh
Primary	0.176	¢ per kWh
89/589		
Secondary	0.175	¢ per kWh
Primary	0.173	¢ per kWh

(D)

(D)

SCHEDULE 146 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate	
91/591	0.159 ¢ per kWh	
92/592	0.171 ¢ per kWh	
96/596	0.171 ¢ per kWh	(D)

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.

DETERMINATION OF ADJUSTMENT AMOUNTS

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).

BALANCING ACCOUNT

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.

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	
83/583	0.000 ¢ per kWh	**(D)**
85/485/585		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
89/489/589/689		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
91/491/591	0.000 ¢ per kWh	**(D)**
92/492/592	0.000 ¢ per kWh	**(D)**
96/496/596/696	0.000 ¢ per kWh	**(N)**

SPECIAL CONDITIONS

1. By March 15 of each year, PGE will submit a prudence review filing that includes a report all activity associated with Harborton Restoration Project development costs, ERC, ER and other related third-party proceeds recorded in the PHERA Annual Account. Staff a other Parties will complete the prudence review, and Staff will submit its report a recommendation to the Commission within 120 days of submittal. Only cash expenditur will be included in the PHERA Annual Account for recovery under the PHERA mechanis PGE shall defer, separately track, and capitalize as a regulatory asset, continge environmental liability accruals. This regulatory asset shall not be included in rate base a PGE shall not earn a return on the balance.

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. **(C)**

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate		
7	0.030	¢ per kWh	
15/515	0.023	¢ per kWh	
32/532	0.027	¢ per kWh	
38/538	0.033	¢ per kWh	
47	0.026	¢ per kWh	
49/549	0.021	¢ per kWh	
83/583	0.032	¢ per kWh	**(D)**
85/485/585			
Secondary	0.026	¢ per kWh	
Primary	0.024	¢ per kWh	
89/489/589/689			
Secondary	0.024	¢ per kWh	
Primary	0.021	¢ per kWh	**(D)**

SCHEDULE 150 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
91/491/591	0.021	¢ per kWh	**(D)**
92/492/592	0.021	¢ per kWh	
96/496/596/696	0.020	¢ per kWh	**(D)**

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.

SPECIAL CONDITIONS

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.

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.

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	0.567	¢ per kWh
15/515	0.477	¢ per kWh
32/532	0.565	¢ per kWh
38/538	0.617	¢ per kWh
47	0.896	¢ per kWh
49/549	0.750	¢ per kWh
83/583	0.317	¢ per kWh (D)
85/485/585		
Secondary	0.182	¢ per kWh
Primary	0.132	¢ per kWh

SCHEDULE 151 (Concluded)

ADJUSTMENT RATES (Continued)

89/489/589/689			
Secondary	0.090	¢ per kWh	
Primary	0.065	¢ per kWh	**(D)**
91/491/591	0.477	¢ per kWh	
92/492/592	0.159	¢ per kWh	
96/496/596/696	0.070	¢ per kWh	**(D)**

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 January 2024 Winter Storm.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service. **(C)**

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.335	¢ per kWh
15/515	0.283	¢ per kWh
32/532	0.334	¢ per kWh
38/538	0.364	¢ per kWh
47	0.526	¢ per kWh
49/549	0.444	¢ per kWh
83/583	0.185	¢ per kWh
85/485/585		
Secondary	0.105	¢ per kWh
Primary	0.079	¢ per kWh

(D)

SCHEDULE 152 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
89/489/589/689			
Secondary	0.058	¢ per kWh	
Primary	0.038	¢ per kWh	(D)
91/491/591	0.283	¢ per kWh	
92/492/592	0.093	¢ per kWh	(D)
96/496/596/696	0.040	¢ per kWh	

BALANCING ACCOUNT

The Company will maintain balancing accounts to track the difference between deferred amounts and the 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. **(T)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service. **(C)**

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate		
7	0.001	¢ per kWh	
15/515	0.001	¢ per kWh	
32/532	0.001	¢ per kWh	
38/538	0.001	¢ per kWh	
47	0.002	¢ per kWh	
49/549	0.002	¢ per kWh	
83/583	0.001	¢ per kWh	**(D)**
85/485/585			
Secondary	0.001	¢ per kWh	
Primary	0.001	¢ per kWh	

(D)

SCHEDULE 153 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
89/489/589			
Secondary	0.001	¢ per kWh	
Primary	0.001	¢ per kWh	
91/491/591	0.001	¢ per kWh	**(D)**
92/492/592	0.001	¢ per kWh	
96/496/596/696	0.001	¢ per kWh	**(D)**
689			
Secondary	0.001	¢ per kWh	
Primary	0.001	¢ per kWh	**(D)**

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 199
DISPATCHABLE ENERGY STORAGE RESOURCE

PURPOSE

To provide the Company with additional flexibility by contracting with Large Nonresidential Customers for the right to operate their Energy Storage Resource(s) for the purpose of providing Grid Services and assisting during periods of regional power supply and deliverability concerns.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Cost-of-Service Customers with a minimum demand of 250 kW and 750 kWh or the greater of permanently installed behind the meter Energy Storage Resource(s) in place as defined in the Energy Storage Resource Agreement.

This retail tariff is limited to Energy Storage Resources that are connected behind the customer's meter. Energy Storage Resources that are in front of the customer's meter or are standalone with no connection to the customer greater than 10 MW will default to the FERC interconnection process under the Company's OATT.

DEFINITIONS

Aid in Construction Allowance - The amount of funding PGE may contribute to an individual project to enable the Energy Storage Resource to be integrated with PGE for dispatch to support Grid Services.

Ancillary Services - As defined in the Open Access Transmission Tariff (OATT) posted on OASIS.

Energy Storage Resource (ESR) - An electrochemical or other 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.

Collocated - Two or more Energy Storage Resources that share a point of common coupling with the Company's system, or that are located on the same or contiguous sites under common ownership of control. Separate metering, separate service connections, or separate legal entities under common ownership or control do not render otherwise Collocated resources separate.

Demand Response - The dispatch of a qualified enrolled Energy Storage Resource for the purpose of changing usage from normal consumption in response to a direct or indirect signal designed to reduce energy use.

SCHEDULE 199 (Continued)

DEFINITIONS (Continued)

Energy Storage Resource 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 Energy Storage Resource, operational requirements, the terms of the Customer's usage of the Energy Storage Resource, applicable compensation, charging and discharging the Energy Storage Resource and, if applicable, any amount of the Aid in Construction Allowance provided by the Company.

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).

Grid Services – For the purposes of this Schedule includes the dispatch of Energy Storage Resources for Ancillary Services or Demand Response.

Reserve Status - Indicates a resource is available for dispatch by PGE.

CUSTOMER RESPONSIBILITIES

The Customer will grant the Company access to its Energy Storage Resource(s) such that the Company can operate the Energy Storage Resource(s) at the site or remotely operate the Energy Storage Resource(s) in coordination with the Company's distribution system in accordance with the enrollment option the Customer elects.

The Customer may operate the Energy Storage Resource(s) at the site as specified in the Energy Storage Resource Agreement (Agreement).

All participating Energy Storage Resources under this schedule must install metering, provide telemetry, and provide communications sufficient to permit Company monitoring, dispatch, and control of the resource. Applicable standards are determined by the services the resource is enrolled to provide:

(a) Resources enrolled to provide Ancillary Services must install revenue-quality metering, provide telemetry at intervals of two to ten seconds, and provide communications sufficient to permit direct Company control.
(b) Resources enrolled to provide Demand Response or scheduled congestion management, and not enrolled to provide Ancillary Services, must install interval metering, provide telemetry at intervals not exceeding [X] minutes, and provide communications sufficient to permit Company monitoring and dispatch.

For purposes of determining applicable standards, Collocated Energy Storage Resources are counted as a single Energy Storage Resource. Equipment specifications, communication protocols, and commissioning test requirements are specified in the Agreement.

Additional requirements for market modeling and providing daily schedules may be required in the Agreement.

SCHEDULE 199 (Continued)

COMPANY RESPONSIBILITIES

The Company will conduct an analysis of the Customer's Energy Storage Resource and develop a cost estimate for the installation of the equipment necessary for participation under this schedule to be paid for by the participating Customer. The Company may pay for and will own all communications and metering equipment, depending on the purpose by which the customer is enrolling in this program as outlined in the Special Conditions.

AID IN CONSTRUCTION ALLOWANCE

The Company's Aid in Construction Allowance is based on the cost of Company owned equipment, system protection, safety, communications, related administrative costs, and the Energy Storage Resource switchgear, wiring, and conduit modifications necessary to permit Customer's Energy Storage Resource to run in coordination with the Company's system. Customers who are enrolling in this tariff to enable faster interconnection are not eligible for Aid in Construction Allowance.

The Company will perform regular testing of the Customer's Energy Storage Resource(s), control system and the Company's dispatch control and interconnection facilities. The Company will provide power quality monitoring and data reporting of the Customer's facility and Energy Storage Resource(s). Specific testing protocols, performance requirements, availability standards, and reporting obligations shall be defined in the Agreement.

Failure of the Energy Storage Resource(s) to successfully complete required testing, maintain required operational availability, or perform as required when dispatched by the Company may result in remedies specified in the Agreement, including suspension of program participation, performance penalties, reduction of compensation, repayment or clawback of any Aid in Construction Allowance previously provided by the Company, or other remedies deemed necessary to protect customers and ensure resource reliability.

The Company's design will be such that during outage situations, the Customer's Energy Storage Resource(s) will automatically start and provide backup power to the Customer, unless otherwise agreed by the Company and Customer.

Upon termination of the Agreement, the Company may remove its equipment.

SCHEDULE 199 (Continued)

PROGRAM ENROLLMENT OPTIONS

Customers meeting the applicability requirements of this section may enroll in one of the following options. Enrollment options and any applicable compensation are determined by the purpose for which the Customer enrolls, as described in the Special Conditions. Customers may request to update their enrollment no more than once annually in alignment with PGE's Annual Update Tariff process so that planning may be adjusted.

Option 1: Transmission Congestion Management

This option is required at a minimum for all customers participating in this schedule to access additional service capacity. Customers participating in this option must provide PGE with a rolling seven-day schedule of net load on an hourly or sub-hourly basis. PGE will provide notice and scheduling protocols for PGE's use of the resource specified in the Energy Storage Resource Agreement. Customers may utilize their resource as desired so long as contractual and reliability obligations are met. Should the resource be unavailable as specified in this option, the customer load will be curtailed.

Customers enrolling in Option 1 are responsible for the costs associated with charging the Energy Storage Resource if applicable and must adhere to any charging schedule as determined by PGE. Customers participating in this option will not receive any compensation for use of their resource as it has allowed the Customer to access additional service capacity. Should a customer request to update their enrollment, the customer must show how transmission constraints related to their load have been resolved.

Option 2: Transmission Congestion Management and Resource Adequacy

Customers wishing to enroll in this option agree to give PGE full control of their Energy Storage Resource to support Customer's resource adequacy requirements. Customers participating in this option must provide PGE with a rolling seven-day schedule of net load on an hourly or sub-hourly basis. PGE will provide notice to the customer of the potential for dispatch on a rolling 7-day basis, however no notice is required for dispatch. Customers may not dispatch their resource under this option. Customers participating in this option will not receive any compensation for use of their resource as it has allowed the Customer to satisfy their resource adequacy obligations and exit the Company's large load interconnection queue at an earlier date than would have otherwise been possible. Should a customer request to update their enrollment, the customer must show how transmission constraints related to their load have been resolved and how they are meeting their resource adequacy obligations through other sources.

Option 3: Market Participating Flexibility Resource

Energy Storage Resources that want to participate in the CAISO market are required to have a Contract between the Customer and PGE to perform EDAM scheduling coordinator functions and adhere to the requirements of the Company's Open Access Transmission Tariff (OATT), Attachment P and Attachment P-1.

SCHEDULE 199 (Concluded)

PROGRAM ENROLLMENT OPTIONS (Continued)

Customers whose enrollment does not provide access to additional service capacity, expedited interconnection, or satisfaction of a resource adequacy obligation will receive a credit equal to $137.40 per nominated KW-year for participating in both Demand Response and Ancillary Services, reflecting value rendered to the grid beyond any benefit received through enrollment. Compensation rates are subject to review through the Company's Annual Update Tariff process.

SPECIAL CONDITIONS

1. The Customer's charges for Electricity Service under any of the Company's Standard 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. Operation of Energy Storage Resources must satisfy Company interconnection requirements.

3. The Customer will ensure that the Energy Storage Resource(s), communications equipment, switchgear and metering equipment are accessible to the Company at all times.

4. Prior to receiving service pursuant to this schedule, the Customer and the Company must enter into a written Agreement, signed by the Customer.

5. The Customer must obtain all required permits prior to service initiation to allow all planned operations as specified in the Agreement.

6. 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 removal fees as specified in the Agreement.

7. The customer is responsible for maintaining the nominated capacity of the Energy Storage Resource, the details of which are described in the Agreement.

8. PGE may request that the Customer allow PGE to use the Energy Storage Resource(s) in Reserve Status. The decision to allow PGE to use the Energy Storage Resource(s) for any given period of time in Reserve Status is up to the Customer, as specified in the Agreement.

9. The Company will have the right to refuse to approve projects for any reason; including, but not limited to projects deemed high-risk, not cost effective, of poor equipment quality, or the technology is non-House Bill 2021 compliant. Reasons for denial will be provided in writing to the Customer upon request.

10. The Company shall not provide Aid in Construction Allowance compensation to customers who are required as part of their customer service agreement with PGE to add an Energy Storage Resource and participate under the terms and conditions of this schedule.

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)

3.5% per annum.

BILLING RATES (Rules C, E, F, H, J, M and Sch 201)

Trouble call, cause in Customer-owned equipment

Scheduled Crew Hours (1)	No charge	
Other than Scheduled Crew Hours (1)	$320.00	
Returned Payment Charge	$25.00	
Special Meter Reading Charge (non-network)	$40.00	**(I)**
Meter Test Charge	$180.00	**(I)**
Late Payment Charge (monthly)	2.4% of delinquent balance	
Field Visit Charge (2)	$70.00	**(I)**
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, formatted and analyzed)	Mutually agreed price	
Switching Fee	$20.00	
Unauthorized Connection of Service / Tamper Fee	$149.00	**(I)**
Monthly Service Charge Sch 201	$151.00	
Qualifying Facility 10 MW or Less (3)		

(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.
(3) See Schedule 201 Monthly Service Charge. (Applicable only to new Standard Power Purchase Agreements after January 1, 2024).

SCHEDULE 300 (Continued)

CREDIT RELATED DISCONNECTION AND RECONNECTION RATES (Rule H)

Disconnects	
Monday through Friday	No charge
Reconnection	
Standard Reconnection	
At Meter Base	$ 9.00
Other than Meter Base	$145.00
After Hours Reconnection(1)	
At Meter Base	$ 26.00
Other than Meter Base	$370.00

CUSTOMER REQUESTED DISCONNECTION AND RECONNECTION RATES (Rule H)(2)(3)

Disconnects	
Standard	
At Meter Base	No charge
Other than Meter Base	No charge
Reconnects	
Standard	
Safety related	No charge
Non-safety related	
At Meter Base	$ 9.00
Other than Meter Base	$145.00

(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, including standby time, overtime and golden time. **(C)**

(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)

Installation of Standard Meter Option (1 or 2 outputs)	$ 670.00	**(I)**
Installation of Complex Meter Option (1 – 4 outputs)	$1,620.00	**(I)**

NON-NETWORK RESIDENTIAL METER RATES (Rule M)

Installation of non-network meter (one time charge)	$180.00	**(I)**
Non-network Meter Read	$30.00 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

LUMINAIRE TRANSFERS (Schedules 91, 491 and 591) **(N)**

Luminaire Transfer Charge	$585.00	**(N)**

TRANSFORMERS (Rule I Section 3)

Submersible Transformers

For applications that require submersible transformers, which include but are not limited to network service areas and densely populated urban areas, 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)

LINE EXTENSIONS (Rule I)

Line Extension Allowance (Section 1)[1][2] **(C)**

Residential Service All Electric[3]	$3,520.00 / dwelling unit	**(T)**
Residential Service Primary Other[4]	$2,730.00 / dwelling unit	**(T)**
Schedule 32	$0.3240 / estimated annual kWh	
Schedules 38 and 83	$0.1389 / estimated annual kWh	
Schedules 85 and 89 Secondary Voltage Service	$0.0812 / estimated annual kWh	
Schedules 85 and 89 Primary Voltage Service	$0.0367 / estimated annual kWh	
Schedules 15 and 91 Outdoor Lighting	$0.1745 / estimated annual kWh	**(C)**
Schedule 92 Traffic Signals	$0.0452 / estimated annual kWh	
Schedules 47 and 49	$0.1314 / estimated annual kWh	

Trenching or Boring (Section 2)

Trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits	Estimated Actual Cost
Mainline trenching, boring and backfilling	

Lighting Underground Service Areas

Installation of conduit on a wood pole for lighting purposes	Estimated Actual Cost

(1) Estimated annual kWh values used to calculate non-Residential Customer line extension allowances do not reflect onsite generation.

(2) Applicants required to underground residential single-family line extensions because of wildfire risk receive a $1,820.00 credit in addition to their Line Extension Allowance. **(N)** **(N)**

(3) 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. **(T)**

(4) 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. **(T)**

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	$ 203.00	

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$2,255.00	**(I)**
Permanent Customer obtained		
Overhead Service	$1,377.00	**(I)**
Underground Service	$1,377.00	**(I)**
Existing service	$1,728.00	**(I)**

Enhanced Temporary Service

Fixed fee for initial 6-month period	$1,424.00	**(I)**
Fixed fee per 6-month renewal	$334.00	**(R)**

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 and removal labor for pole(s) and luminaire(s), including any construction costs (i.e., permitting, flagging, etc) and any facilities to energize luminaire(s). See Schedule 15 regarding the monthly energy and maintenance cost.
(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 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, 491, 492, and 496. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option. **(C)**

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	$790.00	$640.00	**(I)**
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$4.50	$4.45	**(I)**
Over 200 kW	$4.40	$4.35	**(I)**
per kW of monthly Peak Demand****	$2.27	$2.24	**(I)**
System Usage Charge			
per kWh	(0.069) ¢	(0.709) ¢	**(R)**

* 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.
**** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

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 $2.43 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	1.0490	**(R)**
Secondary Delivery Voltage	1.0620	**(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 (Concluded)

SPECIAL CONDITIONS (Continued)

8. If the Customer is served at primary 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. **(C)**

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 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.

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.

* 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, 491, 492, and 496. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option. **(C)**

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per SP*:

	Delivery Voltage Primary	
		(D)
Basic Charge	$4,820.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.12	**(I)**
Over 4,000 kW	$0.81	**(I)**
per kW of monthly Peak Demand****	$1.54	**(R)**
Substation Credit per kW of monthly Peak Demand*****	($1.52)	**(N)**
System Usage Charge		
per kWh	0.086 ¢	**(R)(D)**

* 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.

**** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

***** Applicable only to Customers who own and maintain the substation that distributes power to their service. **(N)**

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 $2.434 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 service respectively. **(C)**

TRANSMISSION MINIMUMS

If a customer subject to a Large Load Customer Agreement (LLCA) transitions from Schedule 89 to Schedule 489 and does not meet the minimum transmission demand stipulated in the LLCA, that customer shall pay PGE the difference between their actual demand and contracted demand multiplied by the currently effective Schedule 96 transmission demand rate.

CAPACITY EXCEEDANCE PENALTY

Under the terms of any Large Load Customer Agreement or any Minimum Load Agreement for Allocated System Capacity of 12 MW or greater, if the Customer's actual demand exceeds Allocated System Capacity by 10% or 5,000 kW, whichever is less ("Capacity Exceedance Threshold"), then the Customer will be assessed an exceedance penalty. The penalty amount will be calculated and charged per hour and per MW of exceedance over the threshold as four times the transmission rate specified by demand per this schedule. Customers who exceed their Capacity Exceedance Threshold will be subject to curtailment, termination and other remedies specified in the Customer Service Contract.

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	1.0490	**(D)** **(R)** **(D)**

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.

SCHEDULE 489 (Concluded)

SPECIAL CONDITIONS (Continued)

8. If the Customer is served at primary 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. **(C)**

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 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.

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.

* A list of Enrollment Periods can be found in Schedule 129.

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, 491, 492, and 496. **(C)**

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. Maintenance under Option A luminaires excludes maintenance related to vegetation management. **(C)** **(C)**

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 503-612-4685 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.

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)** **(N)**

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. 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 this Schedule.

SCHEDULE 491 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Option B Luminaire Maintenance (Continued)

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.

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.

(D)

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.

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. **(N)** **(N)**

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.

SCHEDULE 491 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Upon Customer request, the Company may install and replace Option B poles at their discretion 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. (M) (M)

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. All costs to repair or replace damaged streetlight poles are the sole responsibility of the customer, in addition to the applicable monthly Option B rate. (C) (C) (C)

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	0.689 ¢ per kWh	(R)

SCHEDULE 491 (Continued)

MARKET BASED PRICING OPTION

Energy Supply (M)

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. (M)

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 $2.434 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.

SCHEDULE 491 (Continued)

LOSSES **(M)**

The following adjustment factors will be used where losses are to be included in the energy charges:

Secondary Delivery Voltage	1.0620	**(R)(M)**

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$170.00 per hour	$214.00 per hour

(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 **	100	9,500	43	*	$1.22	$0.30	**(R)**
	400	50,000	163	*	2.12	1.12	**(I)(R)**
Cobrahead, Non-Power Door	70	6,300	30	$5.97	1.09	0.21	**(R)**
	100	9,500	43	6.01	1.17	0.30	**(R)**
	150	16,000	62	6.16	1.31	0.43	**(R)**
	200	22,000	79	6.30	1.42	0.54	**(R)**
	250	29,000	102	6.41	1.57	0.70	**(R)**
	400	50,000	163	6.83	1.99	1.12	**(R)**
Flood	250	29,000	102	9.95	1.80	0.70	**(R)**
	400	50,000	163	10.37	2.22	1.12	**(R)**
Early American Post-Top	100	9,500	43	7.92	1.29	0.30	**(R)**
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	6.97	1.16	0.21	**(I)(R)**
	100	9,500	43	7.60	1.27	0.30	**(I)(R)**
	150	16,000	62	8.21	1.43	0.43	**(I)(R)**

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 491 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option A and Option B Service Rates **(N)**

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Roadway LED	>20-25	3,000	8	$5.76	$0.37
	>25-30	3,470	9	6.47	0.37
	>30-35	2,530	11	6.62	0.40
	>35-40	4,245	13	6.09	0.40
	>40-45	5,020	15	6.73	0.42
	>45-50	3,162	16	6.74	0.43
	>50-55	3,757	18	6.75	0.44
	>55-60	4,845	20	6.77	0.46
	>60-65	4,700	21	6.84	0.46
	>65-70	5,050	23	7.26	0.48
	>70-75	7,640	25	7.71	0.50
	>75-80	8,935	26	7.72	0.51
	>80-85	9,582	28	7.73	0.52
	>85-90	10,230	30	7.75	0.54
	>90-95	9,928	32	7.76	0.55
	>95-100	11,719	33	7.77	0.56
	>100-110	7,444	36	7.22	0.57
	>110-120	12,340	39	7.98	0.60
	>120-130	13,270	43	7.84	0.63
	>130-140	14,200	46	7.90	0.65
	>140-150	15,250	50	10.69	0.70
	>150-160	16,300	53	10.72	0.73
	>160-170	17,300	56	10.74	0.75
	>170-180	18,300	60	9.86	0.76
	>180-190	19,850	63	10.78	0.79
	>190-200	21,400	67	10.81	0.82
	>200-210	27,033	70	10.83	0.84
	>210-220	28,535	74	10.86	0.87
	>220-230	30,017	77	10.88	0.89
	>230-240	30,800	81	10.91	0.92
	>240-250	31,507	84	10.93	0.94

(N)

SCHEDULE 491 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option C Energy Use (Continued) **(N)**

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

* 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)

(N)

SCHEDULE 491 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option C Energy Use (Continued) **(N)**

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)

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	Option B
Acorn LED	>35-40	3,262	13	$17.20	$0.52
	>40-45	3,500	15	17.21	0.53
	>45-50	5,488	16	13.59	0.50
	>50-55	4,000	18	17.23	0.55
	>55-60	4,213	20	17.25	0.57
	>60-65	4,273	21	17.25	0.57
	>65-70	4,332	23	16.36	0.58
	>70-75	4,897	25	17.28	0.60
	>90-100	8,100	32	17.33	0.65

(N)

SCHEDULE 491 (Continued)

RATES FOR DECORATIVE LIGHTING (Continued) **(N)**
Light-Emitting Diode (LED) Only – Option A and Option B Service Rates (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
HADCO LED	70	5,120	24	$30.05	$0.74
Pendant LED (Non-Flared)	36	3,369	12	17.26	0.51
	53	5,079	18	17.30	0.55
	69	6,661	24	17.35	0.60
	85	8,153	29	18.19	0.64
Pendant LED (Flared)	>25-30	3,100	9	17.24	0.49
	>30-35	3,650	11	17.26	0.51
	>35-40	3,369	13	17.27	0.52
	>40-45	3,797	15	17.28	0.53
	>45-50	4,438	16	17.29	0.54
	>50-55	5,079	18	17.30	0.55
	>55-60	5,475	20	17.32	0.57
	>60-65	6,068	21	17.32	0.57
	>65-70	6,661	23	17.34	0.59
	>70-75	7,034	25	17.35	0.60
	>75-80	7,594	26	18.17	0.62
	>80-85	8,153	28	18.18	0.63
Post-Top, American Revolution LED	>30-35	3,395	11	9.19	0.42
	>45-50	4,409	16	9.22	0.45
Flood LED	>75-80	12,716	26	8.91	0.52
	>80-85	10,530	28	9.90	0.54
	>110-120	18,265	38	10.61	0.62
	>120-130	16,932	43	10.68	0.66
	>160-170	26,349	56	11.99	0.76
	>180-190	23,797	63	12.12	0.80
	>290-300	46,950	116	18.38	1.24
	>320-330	46,802	112	18.35	1.21
	>330-340	48,692	116	18.38	1.24
	>340-350	50,145	119	18.40	1.26
	>350-360	51,598	123	18.43	1.29
	>370-380	48,020	127	18.46	1.32

(N)

SCHEDULE 491 (Continued)

RATES FOR STANDARD POLES (M)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black, Bronze or Gray	20	$8.51	$0.27	(I)
Fiberglass, Black or Bronze	30	13.02	0.41	(I)
Fiberglass, Gray	30	14.55	0.46	(I)
Fiberglass, Smooth, Black or Bronze	18	9.38	0.29	(I)
Fiberglass, Regular	18	7.99	0.25	(I)
Black, Bronze, or Gray	35	14.00	0.44	(I)
Aluminum, Regular with Breakaway Base	25	18.87	0.59	(I)
	30	23.21	0.73	(I)
	35	24.15	0.76	(I)
Aluminum, Smooth, Black, Pendant	23	26.48	0.83	(I)
Wood, Standard	30 to 35	8.91	0.28	(I)
Wood, Standard	40 to 55	10.24	0.32	(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	$10.54	$1.46	$0.30	(R)
HADCO Victorian, HPS	150	16,000	62	*	1.70	0.43	(R)
	200	22,000	79	*	1.73	0.54	(R)
	250	29,000	102	10.95	1.86	0.70	(R)
HADCO Capitol Acorn, HPS	100	9,500	43	14.97	1.74	0.30	(R)
	150	16,000	62	*	1.80	0.43	(R)
	200	22,000	79	*	2.00	*	(R)
Special Architectural Types							(R)
HADCO Independence, HPS	100	9,500	43	*	1.55	0.30	(R)
	150	16,000	62	*	*	0.43	(R)
HADCO Techtra, HPS	100	9,500	43	19.20	2.00	*	(I)(R)
HADCO Techtra, HPS	150	16,000	62	20.20	2.19	0.43	(R)
							(D)
HADCO Westbrooke, HPS	70	6,300	30	13.40	1.56	*	(I)(R)
	100	9,500	43	13.34	1.63	0.30	(R)

(M)

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM LIGHTING (Continued) **(M)**

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	*	$1.89	*	**(R)**
	200	22,000	79	*	1.39	*	**(R)**
	250	29,000	102	$21.39	2.52	*	**(I)(R)**
Special Types							
				11.21	*	*	**(R)**
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	$0.44	**(R)**
Ornamental Acorn	55	2,800	21	*	*	0.14	**(R)**
Ornamental Acorn Twin	55	5,600	42	*	*	0.29	**(R)**
Composite, Twin	140	6,815	54	*	*	0.37	**(R)**
	175	9,815	66	*	*	0.45	**(R)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$20.23	$0.63	**(I)**
	30	20.12	0.63	**(I)**
	35	24.14	0.76	**(I)**
Aluminum Davit	25	18.35	0.57	**(I)**
	30	20.67	0.65	**(I)**
	35	24.21	0.76	**(I)**
	40	25.01	0.78	**(I)**
Aluminum Double Davit	30	14.95	0.47	**(I)**
Aluminum, Fluted Ornamental	14	12.45	0.39	**(I)**

* Not offered.
** Rates are based on current kWh energy charges. **(M)**

SCHEDULE 491 (Continued)

RATES FOR CUSTOM POLES (Continued) (M)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Smooth Techtra Ornamental	18	$25.79	$0.81	(I)
Aluminum, Fluted Ornamental	16	12.81	0.40	(I)
Aluminum, Double-Arm, Smooth Ornamental	25	27.62	0.87	(I)
Aluminum, Fluted Westbrooke	18	16.35	0.51	(R)
Aluminum, Non-Fluted Ornamental, Pendant	18	18.15	0.57	(I)(R)
Fiberglass, Fluted Ornamental Black	14	13.84	0.43	(I)
Fiberglass, Anchor Base, Gray or Black	35	25.79	0.81	(I)
Fiberglass, Anchor Base (Color may vary)	25	22.68	0.71	(I)
	30	24.49	0.77	(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	
							(D)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	0.27	(R)
	175	7,000	66	$6.43	$1.32	0.45	(R)
							(D)
	400	21,000	147	7.24	1.90	1.01	(R)
	1,000	55,000	374	9.54	*	2.58	(R)
Holophane Mongoose,	150	16,000	62	*	1.69	*	(R)
HPS	250	29,000	102	*	2.06	*	(R)

* Not offered. (M)

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued) (M)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							(D)
Mercury Vapor	175	7,000	66	*	$1.37	*	(R)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	70	6,300	30	*	*	0.21	(R)
	150	16,000	62	*	*	0.43	(R)
	250	29,000	102	*	*	0.70	(R)
Metal Halide	250	20,500	99	*	1.82	0.68	(R)
	400	40,000	156	*	2.21	*	(R)
Cobrahead, Metal Halide	175	12,000	71	*	*	0.49	(R)
Flood, Metal Halide	400	40,000	156	8.10	*	1.07	(R)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	1.80	0.43	(R)
KIM Archetype, HPS	250	29,000	102	*	2.07	0.70	(R)
	400	50,000	163	*	2.72	1.12	(R)

* Not offered (M)

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued) (M)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$10.14	$1.33	*	(R)
Special GardCo Bronze Alloy HPS	70	5,000	30	*	*	0.21	(R)
Mercury Vapor	175	7,000	66	*	*	0.45	(R)
Early American Post-Top, HPS Black	70	6,300	30	5.97	1.07	0.21	(R)
Rectangle Type	200	22,000	79	*	*	0.54	(R)
Incandescent	92	1,000	31	*	*	0.21	(R)
	182	2,500	62	*	*	0.43	(R)
Town and Country Post-Top Mercury Vapor	175	7,000	66	6.72	1.34	0.45	(R)
Flood, HPS	100	9,500	43	6.34	1.18	0.30	(R)
	200	22,000	79	7.32	1.47	0.54	(R)
Special Types Customer-Owned & Maintained Ornamental, HPS	100	9,500	43	*	*	0.30	(R)
Twin ornamental, HPS	Twin 100	9,500	86	*	*	0.59	(R)
Compact Fluorescent	28	N/A	12	*	*	0.08	(R)

* Not offered. (M)

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

(M)

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B	
Aluminum Post	30	$9.86	*	(I)
Aluminum, Painted Ornamental	35	*	$0.76	(I)
Aluminum, Regular	16	9.86	0.31	(I)
Concrete, Ornamental	35 or less	20.23	0.63	(I)
Fiberglass, Direct Bury with Shroud	18	10.77	0.34	(I)
Steel, Painted Regular **	25	20.23	0.63	(I)
Steel, Painted Regular **	30	20.12	0.63	(I)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.63	(I)
Steel, Unpainted 8-foot Mast Arm **	35	*	0.76	(I)
Wood, Laminated without Mast Arm	20	9.97	0.31	(I)
Wood, Curved Laminated	30	*	0.27	(I)
Wood, Painted Underground	35	9.31	0.29	(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	Option B	Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	*	$0.22	(R)
	165	12,000	60	*	*	0.41	(R)
	165	12,000	60	*	1.13	0.41	(R)

(M)

SCHEDULE 491 (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)
- Permitting. (N)
- Transfer of Customer-owned streetlights attached to PGE-maintained Poles.(1) (N) (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. (M)

(1) See Schedule 300-3 for Luminaire Transfer Charge. (N)

SCHEDULE 491 (Continued) **(T)**

SPECIAL CONDITIONS (Continued) **(M)**

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 491 (Continued)

SPECIAL CONDITIONS (Continued) **(M)**

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. **(M)**

SCHEDULE 491 (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.

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. (M)

SCHEDULE 491 (Continued)

(M)

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.

(M)

SCHEDULE 491 (Concluded)

SPECIAL CONDITIONS (Continued) (M)

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. (C)

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 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, 491, 492, and 496 **(C)**

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	1.827¢ per kWh	**(R)**

* 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 $2.434 per kW of monthly Demand.

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	1.0620	**(R)**

ADJUSTMENTS

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

SCHEDULE 496
DATA CENTER
COST-OF-SERVICE OPT-OUT
(FACILITIES ≥ 20,000 kW)

PURPOSE

This tariff describes the terms and conditions for facilities whose end use is a Data Center. Customers subject to this Schedule may be tenants of companies who build, develop and may own the Data Center or customers who are landlords with tenant companies who are data centers. Tenants of data center campuses or sites individually metered that receive service from the Company are subject to this schedule even if the site demand does not exceed 20,000 kW at the time of energization, but where the aggregated site meets or exceeds 20,000 kW or has contracted with PGE for at least 20,000 kW.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has met or exceeded 20,000 kW or has a contract for demand of 20,000 kW or greater within their site point of delivery as defined in Rule I who is engaged directly in providing a service described under code 518210 of the 2022 North American Industry Classification System (“data center services”) or who is indirectly related as a landlord with tenants engaged in providing data center services and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll the entire site served under Schedule 96 prior to opt-out. Customers wishing to opt into Schedule 496 must have taken service on Schedule 96 for a minimum of one year prior to receiving service on this schedule unless the customer existed prior to the existence of Schedule 96. 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, 491, 492, and 496. Beginning with the September 2004 Enrollment Period C, Customers have a minimum five-year option and a fixed three-year option. **(C)**

SCHEDULE 496 (Continued)

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per SP*:

	Delivery Voltage Primary	
Basic Charge	$3,600.00	(R)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$0.77	(R)
Over 4,000 kW	$0.46	(R)
per kW of monthly Peak Demand****	$1.80	(I)
Substation Credit per kW of monthly Peak Demand*****	($1.52)	(N)
System Usage Charge		
per kWh	0.821 ¢	(I) (D)

(D)

* 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.
**** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.
***** Applicable only to Customers who own and maintain the substation that distributes power to their service. (N)

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.

SCHEDULE 496 (Continued)

MARKET BASED PRICING OPTION (Continued)

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 $2.434 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 respectively. **(C)**

TRANSMISSION MINIMUMS

If a customer subject to a Large Load Customer Agreement (LLCA) transitions from Schedule 96 to Schedule 496 and does not meet the minimum transmission demand stipulated in the LLCA, that customer shall pay PGE the difference between their actual demand and contracted demand multiplied by the currently effective Schedule 96 transmission demand rate.

CAPACITY EXCEEDANCE PENALTY

If the Customer's actual demand exceeds Allocated System Capacity, then the Customer will be assessed an exceedance penalty. The penalty amount will be calculated and charged per hour and per MW of exceedance over the threshold as four times the transmission specified by demand per the rates in this schedule. Customers who exceed their Capacity Exceedance Threshold will be subject to curtailment, termination and other remedies specified in the Customer Service Contract.

SCHEDULE 496 (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:

Primary Delivery Voltage	1.0490	**(D)** **(R)** **(D)**

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.

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.

SCHEDULE 496 (Concluded)

SPECIAL CONDITIONS (Continued)

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 primary 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. **(C)**

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 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.

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.

* A list of Enrollment Periods can be found in Schedule 129.

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 3.370 ¢ per kWh **(R)**

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$8.20 [2]	**(I)**
	400	21,000	147	11.18 [2]	**(I)**
	1,000	55,000	374	19.56 [2]	**(I)**
HPS	70	6,300	30	6.77 [2]	**(I)**
	100	9,500	43	7.16	**(I)**
	150	16,000	62	7.82	**(I)**
	200	22,000	79	8.42	**(I)**
	250	29,000	102	9.15	**(I)**
	310	37,000	124	11.55 [2]	**(I)**
	400	50,000	163	11.20	**(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	$7.49 [2]	(I)
	200	22,000	79	9.44 [2]	(I)
	250	29,000	102	12.69	(I)
	400	50,000	163	14.74	(I)
Shoebox, HPS (bronze color, flat lens,	70	6,300	30	7.77	(I)
or drop lens, multi-volt)	100	9,500	43	8.75	(I)
	150	16,500	62	9.87	(I)
Special Acorn Type, HPS	100	9,500	43	11.69	(I)
HADCO Victorian, HPS	150	16,500	62	14.13	(I)
Early American Post-Top, HPS, Black	100	9,500	43	9.07	(I)
Special Types					
Cobrahead, Metal Halide	150	10,000	60	10.54	(I)
Cobrahead, Metal Halide	175	12,000	71	9.21	(I)
Flood, Metal Halide	350	30,000	139	14.49	(I)
Flood, Metal Halide	400	40,000	156	12.29	(I)
Flood, HPS	750	105,000	285	18.85	(I)
HADCO Independence, HPS	100	9,500	43	13.15	(I)
HADCO Techtra, HPS	100	9,500	43	20.35	(I)
	150	16,000	62	21.86	(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	$17.55	(I)
	>40-45	3,500	15	17.62	(I)
	>45-50	5,488	16	14.02	(I)
	>50-55	4,000	18	17.72	(I)
	>55-60	4,213	20	17.78	(I)
	>60-65	4,273	21	17.82	(I)
	>65-70	4,332	23	16.98	(I)
	>70-75	4,897	25	17.95	(I)
	>91-100	8,100	32	18.19	(I)
HADCO LED	70	5,120	24	30.69	(I)
Roadway LED	>20-25	3,000	8	5.97	(I)
	>25-30	3,470	9	6.71	(I)
	>30-35	2,530	11	6.91	(I)
	>35-40	4,245	13	6.44	(I)
	>40-45	5,020	15	7.14	(I)
	>45-50	3,162	16	7.17	(I)
	>50-55	3,757	18	7.24	(I)
	>55-60	4,845	20	7.30	(I)
	>60-65	4,700	21	7.41	(I)
	>65-70	5,050	23	7.88	(I)
	>70-75	7,640	25	8.38	(I)
	>75-80	8,935	26	8.42	(I)
	>80-85	9,582	28	8.48	(I)
	>85-90	10,230	30	8.55	(I)
	>90-95	9,928	32	8.62	(I)
	>95-100	11,719	33	8.65	(I)
	>100-110	7,444	36	8.18	(I)
	>110-120	12,340	39	9.02	(I)
	>120-130	13,270	43	8.99	(I)
	>130-140	14,200	46	9.13	(I)
	>140-150	15,250	50	12.04	(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	
Roadway LED (Cont)	>150-160	16,300	53	$12.14	**(I)**
	>160-170	17,300	56	12.24	**(I)**
	>170-180	18,300	60	11.47	**(I)**
	>180-190	19,850	63	12.47	**(I)**
	>190-200	21,400	67	12.61	**(I)**
	>200-210	27,033	70	12.71	**(I)**
	>210-220	28,535	74	12.84	**(I)**
	>220-230	30,017	77	12.94	**(I)**
	>230-240	30,800	81	13.08	**(I)**
	>240-250	31,507	84	13.18	**(I)**
Pendant LED (Non-Flare)	36	3,369	12	17.58	**(I)**
	53	5,079	18	17.79	**(I)**
	69	6,661	24	17.99	**(I)**
	85	8,153	29	18.97	**(I)**
Pendant LED (Flare)	>20-25	3,100	9	17.48	**(N)**
	>30-35	3,650	11	17.55	**(N)**
	>35-40	3,369	13	17.62	**(I)**
	>40-45	3,797	15	17.69	**(I)**
	>45-50	4,438	16	17.72	**(I)**
	>50-55	5,079	18	17.79	**(I)**
	>55-60	5,475	20	17.85	**(I)**
	>60-65	6,068	21	17.89	**(I)**
	>65-70	6,661	23	17.96	**(I)**
	>70-75	7,034	25	18.02	**(I)**
	>75-80	7,594	26	18.87	**(I)**
	>80-85	8,153	28	18.93	**(I)**
CREE XSP LED	>20-25	2,529	8	8.67	**(I)**
	>30-35	4,025	11	8.77	**(I)**
	>40-45	3,819	15	8.91	**(I)**
	>45-50	4,373	16	9.44	**(I)**
	>55-60	5,863	20	9.57	**(I)**
	>65-70	9,175	23	8.21	**(I)**
	>90-95	8,747	32	8.51	**(I)**
	>130-140	18,700	46	10.03	**(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	
Post-Top, American Revolution LED	>30-35	3,395	11	$9.48	(I)
	>45-50	4,409	16	9.65	(I)
Flood LED	>75-80	12,716	26	9.61	(I)
	>80-85	10,530	28	10.65	(I)
	111-120	18,265	38	11.63	(I)
	>121-130	16,932	43	11.83	(I)
	>161-170	26,349	56	13.49	(I)
	>181-190	23,797	63	13.81	(I)
	>291-300	46,950	116	21.49	(I)
	>321-330	46,802	112	21.35	(I)
	>331-340	48,692	116	21.49	(I)
	>341-350	50,145	119	21.59	(I)
	>351-360	51,598	123	21.73	(I)
	>370-380	48,020	127	21.86	(I)

Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$8.91	(I)
	40 to 55	10.24	(I)
Wood, Painted Underground	35 or less	9.31 [3]	(I) (D)
Aluminum, Regular	16	9.86	(I)
	25	20.23	(I)
	30	20.12	(I)
	35	24.14	(I)
Aluminum, Fluted Ornamental	14	12.45	(I)
Aluminum, Fluted Ornamental	16	12.81	(I)
Aluminum Davit	25	18.35	(I)
	30	20.67	(I)
	35	24.21	(I)
	40	25.01	(I)
Aluminum Double Davit	30	14.95	(I)
Aluminum, Smooth Techtra Ornamental	18	25.79	(I)

(2) No pole charge for luminaires placed on existing Company-owned distribution poles.
(3) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Light Poles(2)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Fiberglass Fluted Ornamental; Black	14	$13.84	**(I)**
Fiberglass, Regular			
Black	20	8.51	**(I)**
Black or Bronze	30	13.02	**(N)**
Gray	30	14.55	**(C)**
Black, Gray, or Bronze	35	14.00	**(I)**
Fiberglass, Anchor Base, Gray or Black	35	25.79	**(I)**
Fiberglass, Anchor Base (Color may vary)	25	22.68	**(I)**
	30	24.49	**(I)**
Fiberglass, Direct Bury with Shroud	18	10.77	**(I)**
Aluminum, Regular with Breakaway Base	35	24.15	**(I)**
Aluminum, Double-Arm, Smooth Ornamental	25	27.62	**(I)**
Aluminum, Smooth, Black, Pendant	23	26.48	**(I)**
Aluminum, Regular with Breakaway Base	25	18.87	**(I)**
	30	23.21	**(I)**

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood 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.

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

SCHEDULE 515 (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 to add the luminaire type to this rate schedule. **(M)**

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.

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	$26.00	(I)
Three Phase	$35.00	(I)
Distribution Charge		
First 5,000 kWh	7.736 ¢ per kWh	(I)
Over 5,000 kWh	3.218 ¢ 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 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			
Single Phase Service	$65.00		(I)
Three Phase Service	$75.00		(I)
Distribution Charge	7.967	¢ per kWh	(R)

* 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 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**	$70.00	**(I)**
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	13.065¢ per kWh	**(I)**
Over 50 kWh per kW of Demand	11.065¢ 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 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	$60.00	(I)
Three Phase Service	$70.00	(I)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$5.99	(R)
Over 30 kW	$5.89	(R)
per kW of monthly Peak Demand***	$2.22	(I)
System Usage Charge		
per kWh	0.995 ¢	(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.

*** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

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 primary 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. **(C)**

TERM

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

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	$790.00	$640.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$4.50	$4.45	(I)
Over 200 kW	$4.40	$4.35	(I)
per kW of monthly Peak Demand***	$2.27	$2.24	(I)
System Usage Charge			
per kWh	(0.069¢)	(0.709) ¢	(R)

* 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.
*** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

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 primary 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. **(C)**

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 Primary	
Basic Charge	$4,820	(I) (D)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.12	(I)
Over 4,000 kW	$0.81	(I)
per kW of monthly Peak Demand***	$1.54	(R)
System Usage Charge		
per kWh	0.086 ¢	(R) (D)

* 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.
*** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

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 service respectively. **(C)**

TRANSMISSION MINIMUMS

If a customer subject to a Large Load Customer Agreement (LLCA) transitions from Schedule 89 to Schedule 589 and does not meet the minimum transmission demand stipulated in the LLCA, that customer shall pay PGE the difference between their actual demand and contracted demand multiplied by the currently effective Schedule 96 transmission demand rate.

CAPACITY EXCEEDANCE PENALTY

Under the terms of any Large Load Customer Agreement or any Minimum Load Agreement for Allocated System Capacity of 12 MW or greater, if the Customer's actual demand exceeds Allocated System Capacity by 10% or 5,000 kW, whichever is less ("Capacity Exceedance Threshold"), then the Customer will be assessed an exceedance penalty. The penalty amount will be calculated and charged per hour and per MW of exceedance over the threshold as four times the transmission rate specified by demand per this schedule. Customers who exceed their Capacity Exceedance Threshold will be subject to curtailment, termination and other remedies specified in the Customer Service Contract.

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.

SCHEDULE 589 (Concluded)

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, https://portlandgeneral.com

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 primary 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. **(C)**

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.

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. Maintenance under Option A luminaires excludes maintenance related to vegetation management. **(C)** **(C)**

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 503-612-4685or 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.

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.

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)** **(N)**

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. 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 of this Schedule.

SCHEDULE 591 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Option B Luminaire Maintenance (Continued)

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.

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.

(D)

SCHEDULE 591 (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.

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. **(N)** **(N)**

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.

SCHEDULE 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)

Option B – Pole maintenance (Continued) **(M)**

Upon Customer request, the Company may install and replace Option B poles at their discretion 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. **(M)**

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. All costs to repair or replace damaged streetlight poles are the sole responsibility of the customer, in addition to the applicable monthly Option B rate. **(C)** **(C)** **(C)**

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	0.689¢ per kWh	**(R)**
Energy Charge	Provided by Electricity Service Supplier	

SCHEDULE 591 (Continued)

NOVEMBER ELECTION WINDOW **(M)**

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, https://portlandgeneral.com **(M)**

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$170.00 per hour	$214.00 per hour

(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 **	100	9,500	43	*	$1.22	$0.30	**(R)**
	400	50,000	163	*	2.12	1.12	**(I)(R)**
Cobrahead, Non-Power Door	70	6,300	30	$5.97	1.09	0.21	**(R)**
	100	9,500	43	6.01	1.17	0.30	**(R)**
	150	16,000	62	6.16	1.31	0.43	**(R)**
	200	22,000	79	6.30	1.42	0.54	**(R)**
	250	29,000	102	6.41	1.57	0.70	**(R)**
	400	50,000	163	6.83	1.99	1.12	**(R)**
Flood	250	29,000	102	9.95	1.80	0.70	**(R)**
	400	50,000	163	10.37	2.22	1.12	**(R)**
Early American Post-Top	100	9,500	43	7.92	1.29	0.30	**(R)**
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	6.97	1.16	0.21	**(I)(R)**
	100	9,500	43	7.60	1.27	0.30	**(I)(R)**
	150	16,000	62	8.21	1.43	0.43	**(I)(R)**

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 591 (Continued)

RATES FOR STANDARD LIGHTING (Continued) **(N)**
Light-Emitting Diode (LED) Only – Option A and Option B Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Roadway LED	>20-25	3,000	8	$5.76	$0.37
	>25-30	3,470	9	6.47	0.37
	>30-35	2,530	11	6.62	0.40
	>35-40	4,245	13	6.09	0.40
	>40-45	5,020	15	6.73	0.42
	>45-50	3,162	16	6.74	0.43
	>50-55	3,757	18	6.75	0.44
	>55-60	4,845	20	6.77	0.46
	>60-65	4,700	21	6.84	0.46
	>65-70	5,050	23	7.26	0.48
	>70-75	7,640	25	7.71	0.50
	>75-80	8,935	26	7.72	0.51
	>80-85	9,582	28	7.73	0.52
	>85-90	10,230	30	7.75	0.54
	>90-95	9,928	32	7.76	0.55
	>95-100	11,719	33	7.77	0.56
	>100-110	7,444	36	7.22	0.57
	>110-120	12,340	39	7.98	0.60
	>120-130	13,270	43	7.84	0.63
	>130-140	14,200	46	7.90	0.65
	>140-150	15,250	50	10.69	0.70
	>150-160	16,300	53	10.72	0.73
	>160-170	17,300	56	10.74	0.75
	>170-180	18,300	60	9.86	0.76
	>180-190	19,850	63	10.78	0.79
	>190-200	21,400	67	10.81	0.82
	>200-210	27,033	70	10.83	0.84
	>210-220	28,535	74	10.86	0.87
	>220-230	30,017	77	10.88	0.89
	>230-240	30,800	81	10.91	0.92
	>240-250	31,507	84	10.93	0.94

(N)

SCHEDULE 591 (Continued)

RATES FOR STANDARD LIGHTING (Continued) **(N)**
Light-Emitting Diode (LED) Only – Option C Energy Use (Continued)

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

* 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)

(N)

SCHEDULE 591 (Continued)

RATES FOR STANDARD LIGHTING (Continued) (N)
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)

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	Option B
Acorn LED	>35-40	3,262	13	$17.20	$0.52
	>40-45	3,500	15	17.21	0.53
	>45-50	5,488	16	13.59	0.50
	>50-55	4,000	18	17.23	0.55
	>55-60	4,213	20	17.25	0.57
	>60-65	4,273	21	17.25	0.57
	>65-70	4,332	23	16.36	0.58
	>70-75	4,897	25	17.28	0.60
	>90-100	8,100	32	17.33	0.65

(N)

SCHEDULE 591 (Continued)

RATES FOR DECORATIVE LIGHTING (Continued)
Light-Emitting Diode (LED) Only – Option A and Option B Service Rates (Continued) **(N)**

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
HADCO LED	70	5,120	24	$30.05	$0.74
Pendant LED (Non-Flared)	36	3,369	12	17.26	0.51
	53	5,079	18	17.30	0.55
	69	6,661	24	17.35	0.60
	85	8,153	29	18.19	0.64
Pendant LED (Flared)	>25-30	3,100	9	17.24	0.49
	>30-35	3,650	11	17.26	0.51
	>35-40	3,369	13	17.27	0.52
	>40-45	3,797	15	17.28	0.53
	>45-50	4,438	16	17.29	0.54
	>50-55	5,079	18	17.30	0.55
	>55-60	5,475	20	17.32	0.57
	>60-65	6,068	21	17.32	0.57
	>65-70	6,661	23	17.34	0.59
	>70-75	7,034	25	17.35	0.60
	>75-80	7,594	26	18.17	0.62
	>80-85	8,153	28	18.18	0.63
Post-Top, American Revolution LED	>30-35	3,395	11	9.19	0.42
	>45-50	4,409	16	9.22	0.45
Flood LED	>75-80	12,716	26	8.91	0.52
	>80-85	10,530	28	9.90	0.54
	>110-120	18,265	38	10.61	0.62
	>120-130	16,932	43	10.68	0.66
	>160-170	26,349	56	11.99	0.76
	>180-190	23,797	63	12.12	0.80
	>290-300	46,950	116	18.38	1.24
	>320-330	46,802	112	18.35	1.21
	>330-340	48,692	116	18.38	1.24
	>340-350	50,145	119	18.40	1.26
	>350-360	51,598	123	18.43	1.29
	>370-380	48,020	127	18.46	1.32

(N)

SCHEDULE 591 (Continued)

RATES FOR STANDARD POLES

(M)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black, Bronze or Gray	20	$8.51	$0.27	(I)
Fiberglass, Black or Bronze	30	13.02	0.41	(I)
Fiberglass, Gray	30	14.55	0.46	(I)
Fiberglass, Smooth, Black or Bronze	18	9.38	0.29	(I)
Fiberglass, Regular	18	7.99	0.25	(I)
Black, Bronze, or Gray	35	14.00	0.44	(I)
Aluminum, Regular with Breakaway Base	25	18.87	0.59	(I)
	30	23.21	0.73	(I)
	35	24.15	0.76	(I)
Aluminum, Smooth, Black, Pendant	23	26.48	0.83	(I)
Wood, Standard	30 to 35	8.91	0.28	(I)
Wood, Standard	40 to 55	10.24	0.32	(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	$10.54	$1.46	$0.30	(R)
HADCO Victorian, HPS	150	16,000	62	*	1.70	0.43	(R)
	200	22,000	79	*	1.73	0.54	(R)
	250	29,000	102	10.95	1.86	0.70	(R)
HADCO Capitol Acorn, HPS	100	9,500	43	14.97	1.74	0.30	(R)
	150	16,000	62	*	1.80	0.43	(R)
	200	22,000	79	*	2.00	*	(R)
Special Architectural Types							(R)
HADCO Independence, HPS	100	9,500	43	*	1.55	0.30	(R)
	150	16,000	62	*	*	0.43	(R)
HADCO Techtra, HPS	100	9,500	43	19.20	2.00	*	(I)(R)
	150	16,000	62	20.20	2.19	0.43	(R)
	250	29,000	102	*	*	*	(C)
HADCO Westbrooke, HPS	70	6,300	30	13.40	1.56	*	(I)(R)
	100	9,500	43	13.34	1.63	0.30	(R)

* Not offered.

(M)

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING (Continued) **(M)**

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	*	$1.89	*	**(R)**
	200	22,000	79	*	1.39	*	**(R)**
	250	29,000	102	$21.39	2.52	*	**(I)(R)**
Special Types							
				11.21	*	*	**(R)**
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	$0.44	**(R)**
Ornamental Acorn	55	2,800	21	*	*	0.14	**(R)**
Ornamental Acorn Twin	55	5,600	42	*	*	0.29	**(R)**
Composite, Twin	140	6,815	54	*	*	0.37	**(R)**
	175	9,815	66	*	*	0.45	**(R)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$20.23	$0.63	**(I)**
	30	20.12	0.63	**(I)**
	35	24.14	0.76	**(I)**
Aluminum Davit	25	18.35	0.57	**(I)**
	30	20.67	0.65	**(I)**
	35	24.21	0.76	**(I)**
	40	25.01	0.78	**(I)**
Aluminum Double Davit	30	14.95	0.47	**(I)**
Aluminum, Fluted Ornamental	14	12.45	0.39	**(I)**

* Not offered.
** Rates are based on current kWh energy charges. **(M)**

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued) **(M)**

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Smooth Techtra Ornamental	18	$25.79	$0.81	**(I)**
Aluminum, Fluted Ornamental	16	12.81	0.40	**(I)**
Aluminum, Double-Arm, Smooth Ornamental	25	27.62	0.87	**(I)**
Aluminum, Fluted Westbrooke	18	16.35	0.51	**(R)**
Aluminum, Non-Fluted Ornamental, Pendant	18	18.15	0.57	**(I)(R)**
Fiberglass, Fluted Ornamental Black	14	13.84	0.43	**(I)**
Fiberglass, Anchor Base, Gray or Black	35	25.79	0.81	**(I)**
Fiberglass, Anchor Base (Color may vary)	25	22.68	0.71	**(I)**
	30	24.49	0.77	**(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	
							(D)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	0.27	**(R)**
	175	7,000	66	$6.43	$1.32	0.45	**(R)**
							(D)
	400	21,000	147	7.24	1.90	1.01	**(R)**
	1,000	55,000	374	9.54	*	2.58	**(R)**
Holophane Mongoose,	150	16,000	62	*	1.69	*	**(R)**
HPS	250	29,000	102	*	2.06	*	**(R)**

* Not offered. **(M)**

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued) (M)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							(D)
Mercury Vapor	175	7,000	66	*	$1.37	*	(R)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	70	6,300	30	*	*	0.21	(R)
	150	16,000	62	*	*	0.43	(R)
	250	29,000	102	*	*	0.70	(R)
Metal Halide	250	20,500	99	*	1.82	0.68	(R)
	400	40,000	156	*	2.21	*	(R)
Cobrahead, Metal Halide	175	12,000	71	*	*	0.49	(R)
Flood, Metal Halide	400	40,000	156	8.10	*	1.07	(R)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	1.80	0.43	(R)
KIM Archetype, HPS	250	29,000	102	*	2.07	0.70	(R)
	400	50,000	163	*	2.72	1.12	(R)

* Not offered

(M)

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued) (M)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$10.14	$1.33	*	(R)
Special GardCo Bronze Alloy HPS	70	5,000	30	*	*	0.21	(R)
Mercury Vapor	175	7,000	66	*	*	0.45	(R)
Early American Post-Top, HPS Black	70	6,300	30	5.97	1.07	0.21	(R)
Rectangle Type	200	22,000	79	*	*	0.54	(R)
Incandescent	92	1,000	31	*	*	0.21	(R)
	182	2,500	62	*	*	0.43	(R)
Town and Country Post-Top Mercury Vapor	175	7,000	66	6.72	1.34	0.45	(R)
Flood, HPS							
	100	9,500	43	6.34	1.18	0.30	(R)
	200	22,000	79	7.32	1.47	0.54	(R)
Special Types Customer-Owned & Maintained Ornamental, HPS	100	9,500	43	*	*	0.30	(R)
Twin ornamental, HPS	Twin 100	9,500	86	*	*	0.59	(R)
Compact Fluorescent	28	N/A	12	*	*	0.08	(R)

* Not offered. (M)

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

(M)

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$9.86	*	(I)
Aluminum, Painted Ornamental	35	*	$0.76	(I)
Aluminum, Regular	16	9.86	0.31	(I)
Concrete, Ornamental	35 or less	20.23	0.63	(I)
Fiberglass, Direct Bury with Shroud	18	10.77	0.34	(I)
Steel, Painted Regular **	25	20.23	0.63	(I)
Steel, Painted Regular **	30	20.12	0.63	(I)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.63	(I)
Steel, Unpainted 8-foot Mast Arm **	35	*	0.76	(I)
Wood, Laminated without Mast Arm	20	9.97	0.31	(I)
Wood, Curved Laminated	30	*	0.27	(I)
Wood, Painted Underground	35	9.31	0.29	(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	*	*	$0.22	(R)
	165	12,000	60	*	*	0.41	(R)
	165	12,000	60	*	1.13	0.41	(R)

(M)

SCHEDULE 591 (Continued) **(T)**

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)**
- Permitting. **(N)**
- Transfer of Customer-owned streetlights attached to PGE-maintained Poles.(1) **(N)**

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 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. **(M)**

(1) See Schedule 300-3 for Luminaire Transfer Charge. **(N)**

SCHEDULE 591 (Continued)

SPECIAL CONDITIONS (Continued) **(M)**

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 591 (Continued)

SPECIAL CONDITIONS (Continued)

(M)

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.

(M)

SCHEDULE 591 (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.

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. **(M)**

SCHEDULE 591 (Concluded)

SPECIAL CONDITIONS (Continued) **(M)**

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.

TERM

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	1.827 ¢ per kWh	**(R)**

* 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 596 (Continued)

MONTHLY RATE

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

	Delivery Voltage Primary	
		(D)
Basic Charge	$3,600.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$0.77	**(R)**
Over 4,000 kW	$0.46	**(R)**
per kW of monthly Peak Demand***	$1.80	**(I)**
Substation Credit per kW of monthly Peak Demand****	($1.52)	**(N)**
System Usage Charge		
per kWh	0.821 ¢	**(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.
*** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.
**** Applicable only to Customers who own and maintain the substation that distributes power to their service. **(N)**

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 service respectively. **(C)**

SCHEDULE 596 (Concluded)

SPECIAL CONDITIONS (Continued)

2. If the Customer is served at primary 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. **(C)**

TERM

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

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

The ESS will schedule sufficient Energy to provide for the following losses on the Company's distribution system:

	Delivery Voltage		
	Secondary	Primary	**(D)**
Losses:	1.90%	0.6%	**(R)(D)**

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, 491, 492, and 496. 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. **(C)**

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 Primary	
Basic Charge	$4,820.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.12	**(I)**
Over 4,000 kW	$0.81	**(I)**
per kW of monthly Peak Demand***	$1.54	**(R)**
Substation Credit per kW of monthly Peak Demand****	($1.52)	**(N)**
System Usage Charge		
per kWh	0.086 ¢	**(R)**
Administrative Fee	$0.00	

(D) **(D)**

* 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.

*** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

**** Applicable only to Customers who own and maintain the substation that distributes power to their service. **(N)** **(N)**

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 $2.434 per kW of monthly Demand. **(I)**

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 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 below, for three years beginning from the date of notice to return to cost-of-service.

Energy Supply Return Charge
$0.00 per kWh

SCHEDULE 689 (Continued)

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.

CAPACITY EXCEEDANCE PENALTY

Under the terms of any Large Load Customer Agreement or any Minimum Load Agreement for Allocated System Capacity of 12 MW or greater, if the Customer's actual demand exceeds Allocated System Capacity by 10% or 5,000 kW, whichever is less ("Capacity Exceedance Threshold"), then the Customer will be assessed an exceedance penalty. The penalty amount will be calculated and charged per hour and per MW of exceedance over the threshold as four times the transmission rate specified by demand per this schedule. Customers who exceed their Capacity Exceedance Threshold will be subject to curtailment, termination and other remedies specified in the Customer Service Contract.

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 service respectively. **(C)**

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: **(D)**

Primary Delivery Voltage	1.0490	**(R)**

(D)

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 689 (Concluded)

SPECIAL CONDITIONS (Continued)

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 primary 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. **(C)**

5. Customers selecting service under this schedule will be limited to a Company/ESS Split Bill.

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 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 future proposed changes or requirements, the Commission stated that it intends to disfavor grandfathering.

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.

SCHEDULE 696 (Continued)

APPLICABLE (Continued)

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.

Load served under Schedule 696 will not be counted under the Long Term Direct Access cap that applies to Schedules 485, 489, 491, 492, and 496. 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 696 or the terms of the opt-out agreement. **(C)**

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 696, 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 Primary	
Basic Charge	$3,600.00	**(R)** **(D)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$0.77	**(R)**
Over 4,000 kW	$0.46	**(R)**
per kW of monthly Peak Demand***	$1.80	**(I)**
Substation Credit per kW of monthly Peak Demand****	($1.52)	**(N)**
System Usage Charge		
per kWh	0.667¢	**(I)**
Administrative Fee	$0.00	**(D)**

* 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.

*** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

**** Applicable only to Customers who own and maintain the substation that distributes power to their service. **(N)**

SCHEDULE 696 (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 $2.434 per kW of monthly Demand. **(I)**

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 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 below, for three years beginning from the date of notice to return to cost-of-service.

Energy Supply Return Charge
$0.00 per kWh

SCHEDULE 696 (Continued)

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.

CAPACITY EXCEEDANCE PENALTY

If the Customer's actual demand exceeds Allocated System Capacity, then the Customer will be assessed an exceedance penalty. The penalty amount will be calculated and charged per hour and per MW of exceedance over the threshold as four times the transmission specified by demand per the rates in this schedule. Customers who exceed their Capacity Exceedance Threshold will be subject to curtailment, termination and other remedies specified in the Customer Service Contract.

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 service respectively. **(C)**

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: **(D)**

Primary Delivery Voltage	1.0490	**(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 696 (Concluded)

SPECIAL CONDITIONS (Continued)

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 primary 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. **(C)**

5. Customers selecting service under this schedule will be limited to a Company/ESS Split Bill.

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 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 future proposed changes or requirements, the Commission stated that it intends to disfavor grandfathering.

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.

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	0.496	¢ per kWh	Distribution Charge	**(R)**
15	1.134	¢ per kWh	Distribution Charge	**(I)**
32	0.469	¢ per kWh	Distribution Charge	**(I)**
38	0.490	¢ per kWh	Distribution Charge	**(R)**
47	0.723	¢ per kWh	Distribution Charge	**(I)**
49	0.565	¢ per kWh	Distribution Charge	**(R)**
				(D)
83	0.345	¢ per kWh	System Usage Charge	**(I)**
85				
Secondary	0.293	¢ per kWh	System Usage Charge	**(I)**
Primary	0.289	¢ per kWh	System Usage Charge	**(I)**
89				
				(D)
Primary	0.221	¢ per kWh	System Usage Charge	**(I)**
				(D)
91	1.193	¢ per kWh	Distribution Charge	**(I)**
92	0.244	¢ per kWh	Distribution Charge	**(I)**
				(D)
96	0.304	¢ per kWh	System Usage Charge	**(R)**

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:	
485				
Secondary	0.065	¢ per kWh	System Usage Charge	**(I)**
Primary	0.064	¢ per kWh	System Usage Charge	**(I)**
489				
				(D)
Primary	0.013	¢ per kWh	System Usage Charge	**(R)**
				(D)
491	1.030	¢ per kWh	Distribution Charge	**(I)**
492	0.047	¢ per kWh	Distribution Charge	**(I)**
				(D)
496	0.011	¢ per kWh	System Usage Charge	**(R)**
515	0.962	¢ per kWh	Distribution Charge	**(I)**
532	0.242	¢ per kWh	Distribution Charge	**(I)**
538	0.227	¢ per kWh	Distribution Charge	**(R)**
549	0.313	¢ per kWh	Distribution Charge	**(R)**
				(D)
583	0.117	¢ per kWh	System Usage Charge	
585				
Secondary	0.065	¢ per kWh	System Usage Charge	**(I)**
Primary	0.064	¢ per kWh	System Usage Charge	**(I)**
589				
				(D)
Primary	0.012	¢ per kWh	System Usage Charge	**(R)**
				(D)
591	1.030	¢ per kWh	Distribution Charge	**(I)**
592	0.047	¢ per kWh	Distribution Charge	**(I)**
				(D)
596	0.011	¢ per kWh	System Usage Charge	**(R)**

DO NOT BILL

SCHEDULE 750 (Concluded)

FRANCHISE FEE RATE RECOVERY (Continued)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate		Included in:	
689				**(D)**
Primary	0.012	¢ per kWh	System Usage Charge	**(R)**
				(D)
696	0.011	¢ per kWh	System Usage Charge	**(R)**

DO NOT BILL

RULE I (Continued)

New and Existing Customers - Capacity Categories 2B and 3 (Continued)

5) All study results will expire 60 days from issuance. Applicant may request an extension of the validity of the study results for no longer than 365 days from issuance. Company may grant an extension of the validity of the study results so long as no other customer has applied for capacity on infrastructure the Company deems necessary to serve Applicant's load request. In the case where another customer applies for capacity on infrastructure the Company deems necessary to serve Applicant's load request, the Company will notify an Applicant with an extension that such application has been received and will issue Applicant a revised timeline to execute a Customer Service Contract or execute a subsequent study agreement, whichever offered by the Company. Applicant will forfeit their place in the capacity queue as described in Section 4 of this rule if the validity of their study results expires without Applicant executing a Customer Service Contract or study agreement, whichever is offered by the Company, before the expiration of the study results.

3. Special Conditions for Underground Line Extensions

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, resiliency, wildfire risk or because the extension is from an existing underground system; or (C)
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.
3) Where the Company provides trenching, and backfilling, estimated actual costs will apply as specified in Schedule 300. 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.

RULE I (Continued)

Special Conditions for Underground Line Extensions (Continued) **(T)**

4) Only underground line facilities would be permitted within designated wildfire risk areas unless PGE approves an alternative fire-safe facility design. The Applicant will be responsible for costs listed in (B)(1) above. Applicants forced to underground residential single-family line extensions because of wildfire risk receive a credit in Schedule 300 in addition to their Line Extension Allowance. **(N)** **(N)**

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.

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) **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. System Capacity Allocation Process – Capacity Categories 2A, 2B, and 3

Applicants in Capacity Categories 2A, 2B, and 3 will be required to enter a system capacity allocation process for system planning, energization schedule, and determination of Allocated System Capacity.

Existing customers that have already been allocated system capacity over 30 MW prior to December 19, 2023, and have entered into a service agreement with the Company but have not been energized by December 20, 2024, must agree to amend the terms of their service agreement with the Company to specify their Allocated system Capacity and associated Capacity Exceedance Threshold. These customers are otherwise exempt from this allocation process until or unless they request additional system capacity.

A. **General Conditions**

1) The Company will determine which study or studies will be required. Applicants may be required to sign a comprehensive study agreement for all required studies or individual agreements for each required study at the Company's discretion.

RULE I (Continued)

10. 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.

(D)
(T)

B. Nonresidential Nonpermanent Transmission Upgrades

Upgrades to transmission facilities will be deemed nonpermanent when the Company must temporarily upgrade transmission facilities to serve a single customer more rapidly before the permanent upgrade to such portion of the system is complete. If the Company believes that the upgrade is nonpermanent, the company will require upfront payment of the entire estimated cost of the nonpermanent upgrade from the Customer requesting the upgrade. Costs would be trued up to actuals following the conclusion of work.

11. 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.