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

June 3, 2026

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: Advice No. 26-24, UM 2377 Compliance Filing

Portland General Electric Company (PGE) submits this electronic compliance filing pursuant to Oregon Revised Statutes 757.205 and 757.210 and Oregon Administrative Rules (OARs) 860-022-0025 and 860-022-0030. This Tariff is submitted in compliance with Order No. 26-154 (Final Order), issued on May 7, 2026, to be effective June 10, 2026.

This compliance filing creates new Schedule 96 and all associated direct access variations, updates 2025 base rates and 2026 power costs based upon updated marginal costs, the implementation of the peak growth modifier and the energy growth modifier, as well as provides updated tariff language in Schedules 89, 90, 96 and all associated direct access schedules and Rule I. PGE has added an interconnection queue related to generation for Schedule 96 under Rule I consistent with the Final Order. PGE will develop queue management practices and procedures and expects to address any implementation issues requiring tariff changes or additions in its next general rate case.

In addition to updates to base rate and power cost, this compliance filing updates Schedule 121 Distribution System Plan Alternative Recovery prices as agreed to via Stipulation which was adopted by the Commission in Order No. 26-074 in Docket UE 459. PGE has also updated Schedule 109 Energy Efficiency Funding Adjustment as directed in Order No. 26-154. Collectively, the price changes to be effective June 10, 2026 result in an average decrease of 1.3% for residential customers, a 2.2% average decrease for commercial customers, an average decrease of 1.5% for industrial customers, and an average rate increase of 29% for data center customers.

Fifth Revision of Sheet No. 1-2
Third Revision of Sheet No. 1-4
First Revision of Sheet No. 1-5
Third Revision of Sheet No. 7-1
Third Revision of Sheet No. 7-2
Third Revision of Sheet No. 15-1
Third Revision of Sheet No. 15-2
Third Revision of Sheet No. 15-3
Third Revision of Sheet No. 15-4
Third Revision of Sheet No. 15-5
Third Revision of Sheet No. 15-6
Fourth Revision of Sheet No. 32-1
Fourth Revision of Sheet No. 38-1
Third Revision of Sheet No. 47-1
Third Revision of Sheet No. 49-1
First Revision of Sheet No. 54-1
Third Revision of Sheet No. 75-1
Fifth Revision of Sheet No. 83-1
Fourth Revision of Sheet No. 85-1
Fourth Revision of Sheet No. 89-1
First Revision of Sheet No. 89-3
Fourth Revision of Sheet No. 90-1
First Revision of Sheet No. 90-3
Third Revision of Sheet No. 91-7
Third Revision of Sheet No. 92-1
Third Revision of Sheet No. 95-5
Original Sheet No. 96-1
Original Sheet No. 96-2
Original Sheet No. 96-3
Original Sheet No. 96-4
Fourth Revision of Sheet No. 100-1
Third Revision of Sheet No. 100-2
Third Revision of Sheet No. 105-2
Original Sheet No. 105-3
Second Revision of Sheet No. 109-1
Fourth Revision of Sheet No. 109-2
Fourth Revision of Sheet No. 109-3
Original Sheet No. 111-1
Original Sheet No. 111-2
Third Revision of Sheet No. 120-1
Second Revision of Sheet No. 120-2
First Revision of Sheet No. 121-1
First Revision of Sheet No. 121-2
First Revision of Sheet No. 121-3
Fourth Revision of Sheet No. 122-1
Fourth Revision of Sheet No. 122-2
Second Revision of Sheet No. 125-1
Fourth Revision of Sheet No. 125-3
Third Revision of Sheet No. 125-4
Second Revision of Sheet No. 125-5
First Revision of Sheet No. 126-1
First Revision of Sheet No. 126-3
Second Revision of Sheet No. 126-4
Third Revision of Sheet No. 126-5
Third Revision of Sheet No. 126-6
Fourth Revision of Sheet No. 128-1
Fourth Revision of Sheet No. 128-2
Fifth Revision of Sheet No. 128-4
Second Revision of Sheet No. 129-1
Fourth Revision of Sheet No. 129-5
Fourth Revision of Sheet No. 129-6
Fifth Revision of Sheet No. 129-8
Fourth Revision of Sheet No. 129-9
First Revision of Sheet No. 129-10
Original Sheet No. 129-11
Second Revision of Sheet No. 135-1
Second Revision of Sheet No. 135-2
Third Revision of Sheet No. 136-2
First Revision of Sheet No. 137-2
Second Revision of Sheet No. 138-1
Second Revision of Sheet No. 138-2
Third Revision of Sheet No. 139-1
Third Revision of Sheet No. 139-2
Third Revision of Sheet No. 139-3
Third Revision of Sheet No. 146-1
Third Revision of Sheet No. 146-2
Third Revision of Sheet No. 150-2
Ninth Revision of Sheet No. 151-2
Fourth Revision of Sheet No. 152-2
First Revision of Sheet No. 153-2
Fourth Revision of Sheet No. 485-1
Fourth Revision of Sheet No. 489-1
First Revision of Sheet No. 489-3
First Revision of Sheet No. 489-4
First Revision of Sheet No. 489-5
Fourth Revision of Sheet No. 490-1
First Revision of Sheet No. 490-3
First Revision of Sheet No. 490-4
Original Sheet No. 490-5
Second Revision of Sheet No. 491-1
Third Revision of Sheet No. 491-6
Seventh Revision of Sheet No. 491-8
Fourth Revision of Sheet No. 491-9
Third Revision of Sheet No. 491-10
Third Revision of Sheet No. 491-11
Fourth Revision of Sheet No. 491-12

Third Revision of Sheet No. 491-13
Third Revision of Sheet No. 491-14
Third Revision of Sheet No. 492-1
Second Revision of Sheet No. 495-1
Third Revision of Sheet No. 495-5
Sixth Revision of Sheet No. 495-7
Second Revision of Sheet No. 495-9
Third Revision of Sheet No. 495-10
Original Sheet No. 496-1
Original Sheet No. 496-2
Original Sheet No. 496-3
Original Sheet No. 496-4
Original Sheet No. 496-5
Third Revision of Sheet No. 515-1
Third Revision of Sheet No. 515-2
Third Revision of Sheet No. 515-3
Third Revision of Sheet No. 515-4
Third Revision of Sheet No. 515-5
Fourth Revision of Sheet No. 532-1
Third Revision of Sheet No. 538-1
Third Revision of Sheet No. 549-1
Third Revision of Sheet No. 575-1
Fourth Revision of Sheet No. 583-1
Fourth Revision of Sheet No. 585-1
Fourth Revision of Sheet No. 589-1
First Revision of Sheet No. 589-2
First Revision of Sheet No. 589-3
Fourth Revision of Sheet No. 590-1
First Revision of Sheet No. 590-2
First Revision of Sheet No. 590-3
Third Revision of Sheet No. 591-6
Seventh Revision of Sheet No. 591-7
Fourth Revision of Sheet No. 591-8
Third Revision of Sheet No. 591-9
Third Revision of Sheet No. 591-10
Fourth Revision of Sheet No. 591-11
Third Revision of Sheet No. 591-12
Third Revision of Sheet No. 591-13
Third Revision of Sheet No. 592-1
Sixth Revision of Sheet No. 595-5
Third Revision of Sheet No. 595-6
Second Revision of Sheet No. 595-8
Third Revision of Sheet No. 595-9
Original Sheet No. 596-1
Original Sheet No. 596-2
Original Sheet No. 596-3
Original Sheet No. 596-4
Fourth Revision of Sheet No. 689-2
First Revision of Sheet No. 689-4
Original Sheet No. 696-1
Original Sheet No. 696-2
Original Sheet No. 696-3
Original Sheet No. 696-4
Original Sheet No. 696-5
Original Sheet No. 696-6
Original Sheet No. 696-7
Original Sheet No. 696-8
Original Sheet No. 696-9
Second Revision of Sheet No. 750-1
Second Revision of Sheet No. 750-2
Original Sheet No. 750-3
First Revision of Sheet No. G-1
Second Revision of Sheet No. I-1
Second Revision of Sheet No. I-2
Second Revision of Sheet No. I-3
Second Revision of Sheet No. I-4
Second Revision of Sheet No. I-5
Second Revision of Sheet No. I-6
Second Revision of Sheet No. I-7
Second Revision of Sheet No. I-8
Second Revision of Sheet No. I-9
Second Revision of Sheet No. I-10
Second Revision of Sheet No. I-11
First Revision of Sheet No. I-12
First Revision of Sheet No. I-13
First Revision of Sheet No. I-14
First Revision of Sheet No. I-15
First Revision of Sheet No. I-16
First Revision of Sheet No. I-17
First Revision of Sheet No. I-18
First Revision of Sheet No. I-19
First Revision of Sheet No. I-20
Original Sheet No. I-21
Original Sheet No. I-22
Original Sheet No. I-23
Original Sheet No. I-24
Original Sheet No. I-25

Redline versions are provided as a courtesy.

Work papers supporting the calculation of prices changes are attached as follows:

A: Billing Comparisons for major rate schedules
B: Rate Spread/Rate Design and other work papers

To satisfy the requirements of Oregon Administrative Rules (OAR) 860-022-0025 and 860-022-0030, PGE provides the following responses:

PGE estimates that approximately 963,000 customers will be impacted by this overall reclassification across all customer classes from current prices. A typical Schedule 7 residential customer consuming 780 kWh monthly will see an approximate decrease of $1.92 or approximately 1.1% in their bill.

Please direct any questions regarding this filing to Casey Manley at casey.manley@pgn.com Please direct all formal correspondence and requests to pge.opuc.filings@pgn.com

Sincerely,

\s\ *Jaki Ferchland*

Jaki Ferchland
Senior Manager, Rates and Regulatory Affairs
Pricing, Tariffs, and Power Costs

Enclosures
cc: UM 2377 Service List

PGE Advice No. 26-24
Work Papers

Provided in electronic format through the
OPUC Huddle Portal

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES (Continued)

Schedule	Description	
	Standard Service Schedules (Continued)	
81	Nonresidential Emergency Default Service	
83	Large Nonresidential Standard Service (31 – 200 kW)	
85	Large Nonresidential Standard Service (201 – 4,000 kW)	
86	Nonresidential Demand Buy Back Rider	
88	Load Reduction Program	
89	Large Nonresidential Standard Service (>4,000 kW)	
90	Large Nonresidential Standard Service (>4,000 kW and Aggregate to >30 MWa)	
91	Street and Highway Lighting Standard Service (Cost of Service)	
92	Traffic Signals (No New Service) Standard Service (Cost of Service)	
95	Street and Highway Lighting New Technology (Cost of Service)	
96	Data Center Standard Service (Facilities ≥ 20,000 kW)	(N)
99	Special Contracts	
	Adjustment Schedules	
100	Summary of Applicable Adjustments	
102	Federal Columbia River Benefits supplied by Bonneville Power Administration	
103	Metro Supportive Housing Services Business Income Tax Recovery	
105	Regulatory Adjustments	
106	Multnomah County Business Income Tax Recovery	
108	Public Purpose Charge	
109	Energy Efficiency Funding Adjustment	
111	Targeted Energy Support Program Surcharge	(N)
115	Low Income Assistance	
118	Bill Adjustment Cost Recovery Mechanism	
120	Seaside Battery Storage Resource Alternative Recovery	
121	Distribution System Plan Alternative Recovery Mechanism	
122	Renewable Resources Automatic Adjustment Clause	
123	Decoupling Adjustment	
125	Annual Power Cost Update	

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES (Continued)

Schedule	Description	
	Schedules Summarizing Other Charges	
300	Charges as defined by the Rules and Regulations and Miscellaneous Charges	
328	Clean Fuels Credit Monetization Optional Service	
339	On-Bill Loan Repayment Service – Clean Energy Works of Oregon Program	
340	On-Bill Repayment Service Energy Efficiency and Sustainable Technologies (EEAST)	
341	Energy Efficiency Upgrade Voluntary On-Bill Repayment Service	
342	Voluntary On-Bill Repayment Service Customer Flexible Load Journeys	
343	Voluntary Customer Information Platform	
	Promotional Concessions	
402	Promotional Concessions Residential Products and Services	
	Large Nonresidential Cost of Service Opt-Out Schedules	
485	Large Nonresidential Cost of Service Opt-Out (201 – 4,000 kW)	
489	Large Nonresidential Cost of Service Opt-Out (>4,000 kW)	
490	Large Nonresidential Cost of Service Opt-Out (>4,000 kW and Aggregate to >30 MWa)	
491	Street and Highway Lighting Cost of Service Opt-Out	
492	Traffic Signals Cost of Service Opt-Out	
495	Street and Highway Lighting New Technology Cost of Service Opt-Out	
496	Data Center Cost of Service Opt-Out (Facilities ≥ 20,000 kW)	**(N)**
	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	
575	Partial Requirements Service Direct Access Service	
576R	Economic Replacement Power Rider Direct Access Service	
583	Large Nonresidential Direct Access Service (31 – 200 kW)	
585	Large Nonresidential Direct Access Service (201 – 4,000 kW)	
589	Large Nonresidential Direct Access Service (>4,000 kW)	

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES (Concluded)

Schedule	Description	
590	Large Nonresidential Direct Access Service (>4,000 kW and Aggregate to >30 MWa)	
591	Street and Highway Lighting Direct Access Service	
592	Traffic Signals Direct Access Service	
595	Street and Highway Lighting New Technology Direct Access Service	
596	Data Center Direct Access Service (Facilities ≥ 20,000 kW)	(N)
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)	(N)
	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	$13.00		
Multi-Family Home	$10.00		
Transmission and Related Services Charge	0.805	¢ per kWh	**(R)**
Distribution Charge	6.941	¢ per kWh	**(R)**
Energy Charge	3.543	¢ 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	$13.00		
Multi-Family Home	$10.00		
On-Peak Charge	30.263	¢ per kWh	(R)
Transmission and Related Services	2.310	¢ per kWh	(R)
Distribution	19.840	¢ per kWh	(R)
Energy	8.113	¢ per kWh	(I)
Mid-Peak Charge	11.143	¢ per kWh	(R)
Transmission and Related Services	0.790	¢ per kWh	(R)
Distribution	6.850	¢ per kWh	(R)
Energy	3.503	¢ per kWh	(I)
Off-Peak Charge	5.514	¢ per kWh	(R)
Transmission and Related Services	0.350	¢ per kWh	(R)
Distribution	3.010	¢ per kWh	(R)
Energy	2.154	¢ 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	0.344	¢ per kWh	**(R)**
Distribution Charge	7.331	¢ per kWh	**(R)**
Cost of Service Energy Charge	2.396	¢ per kWh	**(R)**

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	$11.78 [2]	(R)
	400	21,000	147	20.58 [2]	
	1,000	55,000	374	43.33 [2]	
HPS	70	6,300	30	9.05 [2]	
	100	9,500	43	9.55	
	150	16,000	62	11.54	
	200	22,000	79	13.77	
	250	29,000	102	15.73	
	310	37,000	124	18.06 [2]	
	400	50,000	163	22.00	
Flood, HPS	100	9,500	43	9.43 [2]	
	200	22,000	79	15.20 [2]	
	250	29,000	102	17.67	
	400	50,000	163	23.72	
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	8.85	
	100	9,500	43	10.75	
	150	16,500	62	13.12	
Special Acorn Type, HPS	100	9,500	43	15.38	
HADCO Victorian, HPS	150	16,500	62	17.31	
Early American Post-Top, HPS					
Black	100	9,500	43	11.05	(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	$13.66	(R)
	175	12,000	71	13.05	
Flood, Metal Halide	350	30,000	139	22.50	
	400	40,000	156	21.86	
Flood, HPS	750	105,000	285	39.36	
HADCO Independence, HPS	100	9,500	43	15.04	
HADCO Techtra, HPS	100	9,500	43	22.11	
	150	16,000	62	24.85	(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	$14.82	(R)
	>40-45	3,500	15	15.02	
	>45-50	5,488	16	12.54	
	>50-55	4,000	18	15.32	
	>55-60	4,213	20	15.52	
	>60-65	4,273	21	15.62	
	>65-70	4,332	23	15.47	
	>70-75	4,897	25	16.03	
	>91-100	8,100	32	16.77	
HADCO LED	70	5,120	24	19.49	
Roadway LED	>20-25	3,000	8	6.03	
	>25-30	3,470	9	6.13	
	>30-35	2,530	11	6.60	
	>35-40	4,245	13	6.53	
	>40-45	5,020	15	6.90	
	>45-50	3,162	16	6.99	
	>50-55	3,757	18	7.47	
	>55-60	4,845	20	7.40	
	>60-65	4,700	21	7.50	
	>65-70	5,050	23	8.45	
	>70-75	7,640	25	8.68	
	>75-80	8,935	26	8.78	
	>80-85	9,582	28	8.98	
	>85-90	10,230	30	9.18	
	>90-95	9,928	32	9.38	
	>95-100	11,719	33	9.48	
	>100-110	7,444	36	9.60	
	>110-120	12,340	39	10.09	
	>120-130	13,270	43	10.49	
	>130-140	14,200	46	11.18	
	>140-150	15,250	50	13.55	
	>150-160	16,300	53	13.85	
	>160-170	17,300	56	14.15	
	>170-180	18,300	60	14.21	
	>180-190	19,850	63	14.85	
	>190-200	21,400	67	14.43	
	>200-210	27,033	70	14.80	
	>210-220	28,535	74	15.98	
	>220-230	30,017	77	16.28	(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	$16.69	(R)
	>240-250	31,507	84	17.49	
Pendant LED (Non-Flare)	36	3,369	12	15.32	
	53	5,079	18	17.05	
	69	6,661	24	17.43	
	85	8,153	29	18.49	
Pendant LED (Flare)	>35-40	3,369	13	14.85	
	>40-45	3,797	15	15.89	
	>45-50	4,438	16	15.99	
	>50-55	5,079	18	18.94	
	>55-60	5,475	20	15.55	
	>60-65	6,068	21	19.24	
	>65-70	6,661	23	18.57	
	>70-75	7,034	25	16.06	
	>75-80	7,594	26	19.09	
	>80-85	8,153	28	19.29	
CREE XSP LED	>20-25	2,529	8	6.19	
	>30-35	4,025	11	6.49	
	>40-45	3,819	15	6.89	
	>45-50	4,373	16	7.05	
	>55-60	5,863	20	7.45	
	>65-70	9,175	23	8.31	
	>90-95	8,747	32	9.21	
	>130-140	18,700	46	12.11	
Post-Top, American Revolution LED	>30-35	3,395	11	8.10	
	>45-50	4,409	16	8.60	
Flood LED	>75-80	12,716	26	9.89	
	>80-85	10,530	28	10.09	
	>110-120	18,265	38	11.64	
	>120-130	16,932	43	12.14	
	>160-170	26,349	56	14.65	
	>180-190	23,797	63	15.35	
	>290-300	46,950	116	25.10	(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	$24.70	**(R)**
	>331-340	48,692	116	25.10	|
	>341-350	50,145	119	25.40	|
	>351-360	51,598	123	25.81	|
	>370-380	48,020	127	26.21	**(R)**

Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$6.54
	40 to 55	7.71
Wood, Painted for Underground	35 or less	6.48 [3]
Wood, Curved Laminated	30 or less	7.62 [3]
Aluminum, Regular	16	5.00
	25	9.29
	30	10.66
	35	12.34
Aluminum, Fluted Ornamental	14	8.80
Aluminum, Fluted Ornamental	16	9.14
Aluminum Davit	25	9.91
	30	11.16
	35	12.76
	40	16.38
Aluminum Double Davit	30	12.38
Aluminum, Smooth Techtra Ornamental	18	18.84

(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 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	$24.00		
Three Phase Service	$33.00		
Transmission and Related Services Charge	0.346	¢ per kWh	**(R)**
Distribution Charge			
First 5,000 kWh	6.922	¢ per kWh	**(I)**
Over 5,000 kWh	3.388	¢ per kWh	**(R)**
Energy Charge Options			
Standard Service	2.958	¢ per kWh	**(R)**
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	5.508	¢ per kWh	
Mid-Peak Period	2.958	¢ per kWh	**(R)**
Off-Peak Period	1.836	¢ per kWh	

* See Schedule 100 for applicable adjustments.

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	$50.00		
Three Phase Service	$60.00		
Transmission and Related Services Charge	0.399	¢ per kWh	**(R)**
Distribution Charge	8.960	¢ per kWh	**(I)**
Energy Charge**			
On-Peak Period	3.642	¢ per kWh	**(R)**
Mid-Peak Period	2.898	¢ per kWh	**(R)**
Off-Peak Period	2.526	¢ per kWh	**(R)**

* 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 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**	$39.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.685	¢ per kWh	(R)
Distribution Charge			
First 50 kWh per kW of Demand***	13.288	¢ per kWh	(I)
Over 50 kWh per kW of Demand	11.288	¢ per kWh	(I)
Energy Charge	3.732	¢ 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**	$60.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.290	¢ per kWh	(R)
Distribution Charge			
First 50 kWh per kW of Demand***	13.069	¢ per kWh	(I)
Over 50 kWh per kW of Demand	11.069	¢ per kWh	(I)
Energy Charge	3.373	¢ per kWh	(R)

* 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 54
LARGE NONRESIDENTIAL
RENEWABLE ENERGY CERTIFICATES RIDER

PURPOSE

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Customers taking service under any of the following PGE schedules: 38, 49, 83, 85, 89, 90, 91, 95, 96, 485, 489, 490, 491, 495, 496, 583, 585, 589, 590, 591, 595, 596, 689, and 696. Customers who are on one of these base schedules who also have schedule 15 area lighting may include those schedule 15 lights in this program. **(C)**

PRODUCT OFFERINGS

I. PGE Green Resource Mix

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

II. Specified Resource

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

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,630.00	$3,590.00	$4,770.00	**(R)**
Transmission and Related Services Charge				
per kW of monthly Peak Demand**	$2.19	$2.17	$2.13	**(R)**
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.43	$1.42	$1.41	**(I)**
Over 4,000 kW	$1.12	$1.11	$1.10	**(I)**
per kW of monthly Peak Demand**	$1.68	$1.66	$0.27	**(R)(I)**
Generation Contingency Reserves Charges				
Spinning Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.385 ¢	0.382 ¢	0.379 ¢	**(I)**
Energy Charge				
per kWh	See Energy Charge Below			

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

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	$50.00	
Three Phase Service	$60.00	
Transmission and Related Services Charge		
per kW of monthly Peak Demand**	$2.19	(R)
Distribution Charges***		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$6.12	(I)
Over 30 kW	$6.02	(I)
per kW of monthly Peak Demand**	$1.68	(I)
Energy Charge		(C)
Generation Demand Charge		(D)
per kW of monthly Peak Demand**	$9.75	(I)
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	1.023¢	(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.

(D)

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	$730.00	$610.00	(R)
Transmission and Related Services Charge			
per kW of monthly Peak Demand**	$2.19	$2.17	(R)
Distribution Charges***			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$4.06	$4.01	(I)
Over 200 kW	$3.96	$3.91	(I)
per kW of monthly Peak Demand**	$1.68	$1.66	(I)
Energy Charge			(C)
Generation Demand Charge			(D)
per kW of monthly Peak Demand**	$11.39	$11.26	(I)
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.281 ¢	0.278 ¢	(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.

(D)

SCHEDULE 89
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW.

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,630.00	$3,590.00	$4,770.00	(I)(R)
Transmission and Related Services Charge				
per kW of monthly Peak Demand**	$2.19	$2.17	$2.13	(R)
Distribution Charges***				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.43	$1.42	$1.41	(R)
Over 4,000 kW	$1.12	$1.11	$1.10	(R)
per kW of monthly Peak Demand**	$1.68	$1.66	$0.27	(I)
Energy Charge				(C)
See below for Daily Pricing Option description.				(D)
Generation Demand Charge	$15.46	$15.31	$5.81	(N)
per kW of monthly Peak Demand**				(N)
System Usage Charge				
per kWh	0.385 ¢	0.382 ¢	0.379 ¢	(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.

(D)

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 and Subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

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

CAPACITY EXCEEDANCE PENALTY **(N)**

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. **(N)**

SCHEDULE 90
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account.

MONTHLY RATE

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

	Delivery Voltage		
	Primary	Subtransmission	
Basic Charge	$11,300.00	$11,300.00	**(R)**
Transmission and Related Services Charge			
per kW of monthly Peak Demand**	$2.17	$2.13	**(R)**
Distribution Charges**			**(C)**
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$2.37	$2.17	**(I)**
Over 4,000 kW	$2.06	$2.06	**(I)**
per kW of monthly Peak Demand**	$1.66	$0.27	**(I)**
Energy Charge			**(C)**
Generation Demand Charge (30 MWa – 250			**(C)**
MWa) per kW of monthly Peak Demand	$18.22	$17.92	**(C)(I)**
Generation Demand Charge (greater than			**(C)**
250 MWa) per kW of monthly Peak Demand	$17.00	$16.70	**(C)(I)**
System Usage Charge			
Usage (30 MWa – 250 MWa) per kWh	0.218¢	0.218¢	**(R)**
Usage (greater than 250 MWa) per kWh	0.218¢	0.218¢	**(R)**

* See Schedule 100 for applicable adjustments. **(D)**

** 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. **(C)**

SCHEDULE 90 (Continued)

ELECTION WINDOWS

Balance-of-Year Election Window

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

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

November Election Window

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

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

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, 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 and Subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

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

CAPACITY EXCEEDANCE PENALTY **(N)**

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. **(N)**

SCHEDULE 91 (Continued)

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.311 ¢ per kWh	**(R)**
Distribution Charge	7.364 ¢ per kWh	**(R)**
Energy Charge		
Cost of Service Option	2.396 ¢ per kWh	**(R)**

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.319¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

Prices reported with no transaction volume or as “survey-based” will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0640.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

Enrollment for Service

To begin service under the Daily Price Option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

SCHEDULE 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	0.375	¢ per kWh	**(R)**
Distribution Charge	2.156	¢ per kWh	**(I)**
Energy Charge	2.626	¢ per kWh	**(R)**

* 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 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election (Continued)

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91/95 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires.

STREETLIGHT POLES SERVICE OPTIONS

See Schedule 91 for Streetlight poles service options.

MONTHLY RATE

In addition to the service rates for Option A and Option B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.311 ¢ per kWh	**(R)**
Distribution Charge	7.364 ¢ per kWh	**(R)**
Energy Charge		
Cost of Service Option	2.396 ¢ per kWh	**(R)**

NON-COST OF SERVICE OPTION

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.319¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

SCHEDULE 96
DATA CENTER
STANDARD SERVICE
(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 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.

SCHEDULE 96 (Continued)

MONTHLY RATE

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

	Primary	Subtransmission
Basic Charge	$12,000.00	$12,000.00
Transmission and Related Services Charge		
per kW of monthly Peak Demand**	$2.17	$2.13
Distribution Charges***		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$6.54	$6.54
Over 4,000 kW	$6.23	$6.23
per kW of monthly Peak Demand**	$1.66	$0.27
Generation Demand Charge	$19.04	$18.70
per kW of monthly Peak Demand**		
System Usage Charge		
per kWh	2.99 ¢	2.99 ¢

* 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.

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 0.319¢ 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.

SCHEDULE 96 (Continued)

NON-COST OF SERVICE OPTION (Continued)

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

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530

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.

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

SCHEDULE 96 (Concluded)

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 and Subtransmission voltage service respectively, unless different minimums are specified in the Customer Service Contract.

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.

CONTRACTS

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.

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	(N)
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	
75	x[2]	x	x[2]	x	x	x[2]		x	x	x[2]	x	x[2]	x	x[2]	x[2]	
76	x	x		x	x			x	x							
83	x	x	x	x	x	x		x	x	x	x	x	x	x	x	
85	x	x	x	x	x	x		x	x	x	x	x	x	x	x	
89	x	x	x	x	x	x		x	x	x	x	x	x	x	x	
90	x	x	x	x	x	x		x	x	x	x	x	x	x	x	
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	
95		x	x	x	x	x		x	x	x	x	x	x	x	x	
96			x			x	x			x	x	x		x	x	(N)
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]	
490	x	x	x	x	x	x		x	x		x		x		x	
491		x	x	x	x	x		x	x		x		x		x	
492		x	x	x	x	x		x	x		x		x		x	
495		x	x	x	x	x		x	x		x		x		x	
496			x			x	x				x				x	(N)
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]	
575	x[2]	x	x[2]	x	x	x		x	x		x		x		x[2]	
576	x	x		x	x			x	x							
583	x	x	x	x	x	x		x	x		x		x		x[5]	
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]	
590	x	x	x	x	x	x		x	x		x		x		x	
591		x	x	x	x	x		x	x		x		x		x[5]	
592		x	x	x	x	x		x	x		x		x		x[5]	
595		x	x	x	x	x		x	x		x		x		x[5]	
596			x			x	x				x				x	(N)
689	x	x	x	x	x	x		x	x		x		x		x	
696			x			x	x				x				x	(N)

1. Where applicable.
2. These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
3. Schedule 108 applies to the sum of all charges less taxes, Schedule 109 and 115 charges and one-time charges such as deposits.
4. Applicable to Nonresidential Customer who receive service at Daily pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 485, 489, 490, 491, 492 and 495).
5. Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 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	(M)
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	
75	x		x	x	x	x			x	x	x	x	x	x	x	x	
76												x		x			
83	x		x	x	x	x			x	x	x	x	x	x	x	x	
85	x		x	x	x	x			x	x	x	x	x	x	x	x	
89	x		x	x	x	x			x	x	x	x	x	x	x	x	
90	x		x	x	x	x			x	x	x	x	x	x	x	x	
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	
95	x		x	x	x	x			x	x	x	x	x	x	x	x	
96	x		x	x	x	x			x		x		x	x	x	x	(N)
485		x		x	x				x			x	x	x	x	x	
489		x		x	x				x			x	x	x	x	x	
490		x		x	x				x			x	x	x	x	x	
491		x		x	x				x			x	x	x	x	x	
492		x		x	x				x			x	x	x	x	x	
495		x		x	x				x			x	x	x	x	x	
496		x		x	x				x				x	x	x	x	(N)
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	
575	x		x	x	x	x			x	x	x	x	x	x	x	x	
576												x		x			
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	
590	x		x	x	x	x			x	x	x	x	x	x	x	x	
591	x		x	x	x	x			x	x	x	x	x	x	x	x	
592	x		x	x	x	x			x	x	x	x	x	x	x	x	
595	x		x	x	x	x			x	x	x	x	x	x	x	x	
596	x		x	x	x	x			x		x		x	x	x	x	(N)
689				x	x		x		x			x	x	x	x	x	(M)
696	x				x		x		x				x	x	x	x	(N)

1) Where applicable.
2) These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
3) Schedule 108 applies to the sum of all charges less taxes, Schedule 109 and 115 charges and one-time charges such as deposits.
4) Applicable to Nonresidential Customer who receive service at Daily pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 485, 489, 490, 491, 492 and 495).
5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 105 (Continued) **(T)**

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	
Subtransmission	0.012	0.008	0.020	¢ per kWh	
90/590 30-250 MWa					
Primary	0.010	0.008	0.018	¢ per kWh	
Subtransmission	0.010	0.008	0.018	¢ per kWh	
90/590 >250 MWa					
Primary	0.010	0.008	0.018	¢ per kWh	
Subtransmission	0.010	0.008	0.018	¢ per kWh	
91/591	0.005	0.008	0.013	¢ per kWh	
92/592	0.007	0.008	0.015	¢ per kWh	
95/595	0.005	0.008	0.013	¢ per kWh	
96/596	0.010	0.008	0.018	¢ per kWh	**(N)**
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	
Subtransmission	0.003	0.000	0.003	¢ per kWh	
490					
Primary	0.001	0.000	0.001	¢ per kWh	
Subtransmission	0.001	0.000	0.001	¢ per kWh	
491	(0.005)	0.000	(0.005)	¢ per kWh	
492	(0.004)	0.000	(0.004)	¢ per kWh	
495	(0.005)	0.000	(0.005)	¢ per kWh	
496					**(N)**
Primary	0.003	0.000	0.003	¢ per kWh	
Subtransmission	0.003	0.000	0.003	¢ per kWh	**(N)**

SCHEDULE 105 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
689					(M)
Secondary	0.003	0.000	0.003	¢ per kWh	
Primary	0.003	0.000	0.003	¢ per kWh	
Subtransmission	0.003	0.000	0.003	¢ per kWh	(M)
696					(N)
Primary	0.003	0.000	0.003	¢ per kWh	
Subtransmission	0.003	0.000	0.003	¢ per kWh	(N)

SCHEDULE 109
ENERGY TRUST OF OREGON FUNDING ADJUSTMENT

PURPOSE

To fund the acquisition of Energy Efficiency as administered by the Energy Trust of Oregon (ETO) for the benefit of the Company's Customers pursuant to ORS 757.054.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory. Nonresidential Customers who meet the eligibility qualifications under 2021 Legislative Session House Bill (HB) 3141 and whose load exceeded 1 aMW but less than 10 aMW during the prior calendar year are subject to an annual cap of $250,000 for combined Energy Trust of Oregon Funding Adjustment and Public Purpose Charges. Nonresidential Customers who meet the eligibility qualifications under HB 3141 and whose load exceeded 10 aMW are subject to an annual cap of $4,000,000 for combined Energy Trust of Oregon Funding Adjustment and Public Purpose Charges.

Sites receiving service under Schedule 96 are charged such that these sites pay the maximum allowable amount under HB 3141 per Commission Order 26-154, directing treatment of large loads under the POWER Act (HB 3546). **(N)** **(N)**

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be an SDC, the Large Nonresidential Customer must have a load that exceeds 1 aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy (ODOE) as an SDC. The Company will include the credits due, as reported by the ODOE, to the applicable portions of the SDC's monthly Schedule 109 Charge.

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue the incremental amounts between the amounts associated with the ETO budget and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

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	(R)
15/515	0.752 ¢ 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	
75/575		
Secondary	0.483 ¢ per kWh	
Primary	0.478 ¢ per kWh	
Subtransmission	0.410 ¢ per kWh	
83/583	0.700 ¢ per kWh	
85/485/585		
Secondary	0.620 ¢ per kWh	
Primary	0.768 ¢ per kWh	
89/489/589/689		
Secondary	0.483 ¢ per kWh	
Primary	0.478 ¢ per kWh	
Subtransmission	0.410 ¢ per kWh	
90/490/590		
Primary 30-250MWa	0.478 ¢ per kWh	
Primary >250MWa	0.000 ¢ per kWh	
Subtransmission	0.478 ¢ per kWh	
91/491/591	0.780 ¢ per kWh	
92/492/592	0.526 ¢ per kWh	
95/495/595	0.780 ¢ per kWh	(R)
96/496/596/696	0.766 ¢ per kWh	(N)

SCHEDULE 109 (Concluded)

ENERGY TRUST OF OREGON FUNDING ADJUSTMENT (Continued)

Over One Average Megawatt Pricing

Schedule	Adjustment Rate	
75/575 >1aMW		
Secondary	0.483	¢ per kWh
Primary	0.478	¢ per kWh
Subtransmission	0.410	¢ per kWh
83/583 >1aMW	0.426	¢ per kWh
85/485/585 >1aMW		
Secondary	0.296	¢ per kWh
Primary	0.272	¢ per kWh
89/489/589/689 >1aMW		
Secondary	0.483	¢ per kWh
Primary	0.478	¢ per kWh
Subtransmission	0.410	¢ per kWh
90/490/590 >1aMW		
Primary 30-250MWa	0.478	¢ per kWh
Primary >250MWa	0.000	¢ per kWh
Subtransmission	0.478	¢ per kWh
96/496/596/696	0.766	¢ per kWh

(R)
(C)
(R)
(N)

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 111
TARGETED ENERGY SUPPORT PROGRAM SURCHARGE

PURPOSE

Revenue from this surcharge will be used for non-cost-effective energy efficiency (EE), repairs and distributed resource solutions to reduce energy burden.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to all Large Nonresidential Customers receiving service under Schedule 96, 496, 596 or 696 with an Allocated System Capacity of 100 MW or greater per site or to those customers without a signed Large Load Customer Agreement who have met or exceeded 100 MW of peak demand at least two times in the preceding twelve months.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

Allocated System Capacity – The then-current held capacity on the Company's system that is available to reliably serve a Customer at a Site, based on the applicable Large Load Customer Agreement.

BALANCING ACCOUNT

Effective June 10, 2026, the Company will establish a balancing account to record the differences between the actual fully loaded qualifying expenses associated with administering non-cost-effective energy efficiency, non-cost-effective demand side management or other programs and the revenues collected under this schedule adjusted for allowance for uncollectibles, franchise fees, and other revenue sensitive costs. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

SCHEDULE 111 (Concluded)

TARGETED ENERGY SUPPORT PROGRAM SURCHARGE

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

Schedule	Adjustment Rate
96	1.000 ¢ per kWh
496	1.000 ¢ per kWh
596	1.000 ¢ per kWh
696	1.000 ¢ per kWh

SPECIAL CONDITIONS

1. Applicability will be reviewed on a periodic basis based on contracted capacity greater or equal to 100 MW, or for customers without a Large Load Customer Agreement, who have met or exceeded 100 MW of peak demand at least two times in the preceding twelve months.

2. Funding will be collected, administered, and disbursed by the Company based on a set of criteria to be informed by the PGE Community Benefits and Impacts Advisory Committee (CBIAG).

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 76, 485, 489, 490, 491, 492, 495, 496, 515, 532, 538, 549, 575, 576, 583, 585, 589, 596, 689 and 696. **(C)** **(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	0.230	(0.000)	0.230	¢ per kWh
15	0.163	(0.000)	0.163	¢ per kWh
32	0.202	(0.000)	0.202	¢ per kWh
38	0.197	(0.000)	0.197	¢ per kWh
47	0.241	(0.000)	0.241	¢ per kWh
49	0.236	(0.000)	0.236	¢ per kWh

SCHEDULE 120 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Part A	Part B	Adjustment Rate		
75					
Secondary	0.179	(0.000)	0.179	¢ per kWh	
Primary	0.177	(0.000)	0.177	¢ per kWh	
Subtransmission	0.176	(0.000)	0.176	¢ per kWh	
83	0.196	(0.000)	0.196	¢ per kWh	
85					
Secondary	0.194	(0.000)	0.194	¢ per kWh	
Primary	0.183	(0.000)	0.183	¢ per kWh	
89					
Secondary	0.179	(0.000)	0.179	¢ per kWh	
Primary	0.177	(0.000)	0.177	¢ per kWh	
Subtransmission	0.176	(0.000)	0.176	¢ per kWh	
90					
Primary 30-250 MWa	0.175	(0.000)	0.175	¢ per kWh	
Primary >250 MWa	0.171	(0.000)	0.171	¢ per kWh	
Subtransmission	0.175	(0.000)	0.175	¢ per kWh	
91	0.163	(0.000)	0.163	¢ per kWh	
92	0.176	(0.000)	0.176	¢ per kWh	
95	0.163	(0.000)	0.163	¢ per kWh	
96	0.176	(0.000)	0.176	¢ per kWh	**(N)**

SPECIAL CONDITIONS

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

2. The costs for projects included under this schedule will be updated annually as provided above and will continue to be recovered under Schedule 120 until such time as the costs 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 Schedule 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 except Schedules 76R, and 576R.

ADJUSTMENT RATE

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

Schedule	Adjustment Rate		
7	0.400	¢ per kWh	(R)
15/515	0.371	¢ per kWh	
32/532	0.355	¢ per kWh	(R)
38/538	0.458	¢ per kWh	(I)
47	0.600	¢ per kWh	
49/549	0.571	¢ per kWh	(I)
75/575			
Secondary	0.098	¢ per kWh	(R)
Primary	0.096	¢ per kWh	
Subtransmission	0.145	¢ per kWh	
83/583	0.250	¢ per kWh	(R)
85/585			
Secondary	0.161	¢ per kWh	(I)
Primary	0.145	¢ per kWh	(I)
89/589			
Secondary	0.098	¢ per kWh	(R)
Primary	0.096	¢ per kWh	
Subtransmission	0.145	¢ per kWh	(R)

SCHEDULE 121 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
90/590			
Primary 30-250 MWa	0.082	¢ per kWh	(I)
Primary >250 MWa	0.082	¢ per kWh	
Subtransmission	0.082	¢ per kWh	(I)
91/591	0.371	¢ per kWh	(R)
92/592	0.146	¢ per kWh	
95/595	0.371	¢ per kWh	(R)
96/596			(N)
Primary	0.124	¢ per kWh	
Subtransmission	0.124	¢ per kWh	(N)
485			
Secondary	0.069	¢ per kWh	(I)
Primary	0.060	¢ per kWh	(I)
489			
Secondary	0.059	¢ per kWh	(R)
Primary	0.029	¢ per kWh	
Subtransmission	0.020	¢ per kWh	(R)
490			
Primary	0.035	¢ per kWh	(I)
Subtransmission	0.035	¢ per kWh	(I)
491	0.326	¢ per kWh	(R)
492	0.096	¢ per kWh	
495	0.326	¢ per kWh	(R)
496			(N)
Primary	0.061	¢ per kWh	
Subtransmission	0.061	¢ per kWh	(N)
689			
Secondary	0.056	¢ per kWh	(I)
Primary	0.056	¢ per kWh	
Subtransmission	0.055	¢ per kWh	(I)

SCHEDULE 121 (Concluded)

ADJUSTMENT RATE (Continued) **(N)**

Schedule	Adjustment Rate	
696		
Primary	0.056	¢ per kWh
Subtransmission	0.055	¢ per kWh

(N)

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 76, 485, 489, 490, 491, 492, 495, 496, 576, 689 and 696. This schedule is not applicable to direct access customers after December 31, 2010. **(C)** **(C)**

ADJUSTMENT RATE

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

Schedule		Adjustment Rate	
7		0.214	¢ per kWh
15		0.152	¢ per kWh
32		0.188	¢ per kWh
38		0.184	¢ per kWh
47		0.224	¢ per kWh
49		0.220	¢ per kWh
75			
	Secondary	0.166	¢ per kWh
	Primary	0.165	¢ per kWh
	Subtransmission	0.163	¢ per kWh
83		0.183	¢ per kWh
85			
	Secondary	0.181	¢ per kWh
	Primary	0.171	¢ per kWh
89			**(M)**
	Secondary	0.166	¢ per kWh
	Primary	0.165	¢ per kWh
	Subtransmission	0.163	¢ per kWh **(M)**

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

	Schedule	Adjustment Rate		
90				
	Primary 30-250 Mwa	0.163	¢ per kWh	
	Primary >250 Mwa	0.133	¢ per kWh	
	Subtransmission	0.163	¢ per kWh	
91		0.162	¢ per kWh	
92		0.163	¢ per kWh	
95		0.162	¢ per kWh	
96		0.164	¢ per kWh	**(N)**

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 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an automatic adjustment clause as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all Cost-of-Service bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 90, 91, 92, 95, and 96. Customers served under the Daily Price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 90, 91 and 95 are exempt from Schedule 125. **(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)

FILING AND EFFECTIVE DATE (Continued)

On November 15th, or the next available business day if the 15th is on a weekend the Company will file the final estimate of NVPC and will calculate and file the final change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) the final planned maintenance outages and load forecast from the October 1st filing, 3) final update to Qualifying Facilities online dates, and 4) final price for the energy generation at the Priest Rapids and Wanapum hydro facilities, as provided in the power contract between PGE and Grant County.

RATE ADJUSTMENT
The rate adjustment will be based on the Annual NVPC adjusted for Revenue Sensitive Costs applied to forecast loads used to determine Net Variable Power Costs.

ADJUSTMENT RATES

Schedule		¢ per kWh	
7		5.619	**(R)**
7-TOD	On-Peak Period	12.868	
	Mid-Peak Period	5.555	
	Off-Peak Period	3.416	
15		3.893	
32		4.936	**(R)**
32-TOU	On-Peak Period	8.256	
	Mid-Peak Period	5.009	
	Off-Peak Period	2.754	
38	On-Peak Period	6.083	**(I)**
	Mid-Peak Period	4.843	**(I)**
	Off-Peak Period	4.223	**(I)**
47		5.940	**(R)**
49		5.822	**(R)**

SCHEDULE 125 (Continued)

ADJUSTMENT RATES (Continued)

Schedule		¢ per kWh	
75			
	Secondary[(1)]		
	On-Peak Period	5.672	(I)
	Mid-Peak Period	4.528	(I)
	Off-Peak Period	3.765	(R)
	Primary[(1)]		
	On-Peak Period	5.337	(I)
	Mid-Peak Period	4.593	
	Off-Peak Period	4.098	
	Subtransmission[(1)]		
	On-Peak Period	5.373	
	Mid-Peak Period	4.629	
	Off-Peak Period	4.134	(I)
83			
	On-Peak Period	6.024	(R)
	Mid-Peak Period	4.87	
	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	(R)
89			
	Secondary		
	On-Peak Period	5.672	(I)
	Mid-Peak Period	4.528	(I)
	Off-Peak Period	3.765	(R)
	Primary		
	On-Peak Period	5.337	(I)
	Mid-Peak Period	4.593	
	Off-Peak Period	4.098	
	Subtransmission		
	On-Peak Period	5.373	
	Mid-Peak Period	4.629	
	Off-Peak Period	4.134	(I)

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

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		¢ per kWh	
90			
	Primary 30-250 MWa		(R)
	On-Peak Period	4.579	
	Off-Peak Period	3.829	
	Primary >250 MWa		
	On-Peak Period	4.579	
	Off-Peak Period	3.829	
	Subtransmission 30-250 MWa		
	On-Peak Period	4.579	
	Off-Peak Period	3.829	
	Subtransmission >250 MWa		
	On-Peak Period	4.579	
	Off-Peak Period	3.829	(R)
91		4.082	(I)
92		4.317	(R)
95		4.082	(I)
96	Primary		(N)
	On-Peak Period	5.770	
	Mid-Peak Period	5.026	
	Off-Peak Period	4.531	(N)

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 76R and 576R, 485, 489, 490, 491, 492, 495, 496, 515, 532, 538, 549, 583, 585, 589, 591, 592, 595, 596, 689 and 696, or served under Schedules 83, 85, 89 or 90 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 590, 591, 592, 595, and 596 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment. **(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)

DEFINITIONS (Continued)

Annual Variance (AV) - The Annual Variance (AV) is the dollar amount calculated annually based on the following formula:

(Actual Unit NVPC – Adjusted Base Unit NVPC) * (Actual Loads – RCE Loads)

Base Unit NVPC - The Base Unit NVPC is the NVPC used to develop rate schedules for the applicable year divided by the associated calendar basis retail loads. Base NVPC are updated annually in accordance with Schedule 125.

Adjusted Base Unit NVPC - The Adjusted Base Unit NVPC is the NVPC used to calculate the Annual Variance. The Adjusted Base Unit NVPC is the Base Unit NVPC (determined in accordance with Schedule 125) adjusted for load and cost changes resulting from non-residential customers choosing service under Schedule 515 through 596 after the November update for the applicable year. **(C)**

Negative Annual Power Cost Deadband
Negative Annual Power Cost Deadband is ($15.0 million).

Positive Annual Power Cost Deadband
The Positive Annual Power Cost Deadband is $30.0 million.

Net Variable Power Costs (NVPC) - The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Exclude 80 percent of power costs prudently incurred during RCEs.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the relevant period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.

SCHEDULE 126 (Continued)

DEFINITIONS (Continued)

- Include Energy Charge revenues from Schedules 76R, 38, 83, 85, 89, 90, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485, 489, 490, 491, 492, 495, 689, and 696 as an offset to NVPC. **(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 1.0350 to account for franchise fees, uncollectibles, and OPUC fees.

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(2)	
32/532	0.214 ¢ per kWh(2)	
38/538	0.214 ¢ per kWh(2)	
47	0.214 ¢ per kWh	
49/549	0.214 ¢ per kWh(2)	
75/575		
Secondary	0.214 ¢ per kWh(1)	
Primary	0.214 ¢ per kWh(1)	
Subtransmission	0.214 ¢ per kWh(1)	
83/583	0.214 ¢ per kWh(2)	
85/585		
Secondary	0.214 ¢ per kWh(2)	
Primary	0.214 ¢ per kWh(2)	
89/589		
Secondary	0.214 ¢ per kWh(2)	
Primary	0.214 ¢ per kWh(2)	
Subtransmission	0.214 ¢ per kWh(2)	
90/590		
Primary	0.214 ¢ per kWh	
Subtransmission	0.214 ¢ per kWh	
91/591	0.214 ¢ per kWh(2)	
92/592	0.214 ¢ per kWh(2)	
95/595	0.214 ¢ per kWh(2)	
96/596	0.214 ¢ per kWh(2)	**(N)**

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 126 (Concluded)

POWER COST VARIANCE RATES (Continued)

Schedule	Adjustment Rate	
485		
Secondary	0.214	¢ per kWh(2)
Primary	0.214	¢ per kWh(2)
489		
Secondary	0.214	¢ per kWh(2)
Primary	0.214	¢ per kWh(2)
Subtransmission	0.214	¢ per kWh(2)
490		
Primary	0.214	¢ per kWh
Subtransmission	0.214	¢ per kWh
491	0.214	¢ per kWh
492	0.214	¢ per kWh
495	0.214	¢ per kWh
496	0.214	¢ per kWh (N)
689		
Secondary	0.214	¢ per kWh(2)
Primary	0.214	¢ per kWh(2)
Subtransmission	0.214	¢ per kWh(2)
696	0.214	¢ per kWh (N)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

TERM

Effective for service on and after January 17, 2007 and continuing until terminated by the Commission.

This schedule may only be terminated upon approval or order of the Commission. If this schedule is terminated for any reason, the Company will determine the remaining Adjustment Amount on a prorated basis consistent with the principles of this schedule. In such case, any balance in the PCV Account will be amortized to rates over a period to be determined by the Commission.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 85, 89, 90, 91, 95 or 96 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 590, 591, 592, 595 and 596. This Schedule is not applicable to Customers served on Schedules 485, 489, 490, 491, 492, 495 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 (3)
32		1.671	
38		1.457	
75	Secondary	0.852 (2)	
	Primary	0.843 (2)	
	Subtransmission	0.729 (2)	
83		(1.325)	9.34
85	Secondary	(1.523)	10.80
	Primary	(1.456)	10.68

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday

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 (3)	
89	Secondary	0.852		
	Primary	0.843		
	Subtransmission	0.729		
90 30-250 MWa	Primary	0.833		
90 >250 MWa	Primary	0.637		
91		0.362		
95		0.362		
96		0.843		**(N)**
515		0.344		
532		1.671		
538		1.457		
549		3.353		
575	Secondary	0.852 (2)		
	Primary	0.843 (2)		
	Subtransmission	0.729 (2)		
583		(1.325)	9.34	
585	Secondary	(1.523)	10.80	
	Primary	(1.456)	10.68	
589	Secondary	0.852		
	Primary	0.843		
	Subtransmission	0.729		
590 30-250 MWa	Primary	0.833		
590 >250 MWa	Primary	0.637		
591		0.362		
592		0.894		
595		0.362		
596		0.843		**(N)**

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

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 (Concluded)

Second Quarter – April 1st Balance of Year Adjustment Rate(1)

Schedule		9-Month Part A ¢ per kWh(2)	9-Month Part B $ per KW of Peak Demand(4)	
38		1.817		
75	Secondary	1.143(3)		
	Primary	1.130(3)		
	Subtransmission	1.063(3)		
83		(0.958)	9.34	
85	Secondary	(1.158)	10.80	
	Primary	(1.087)	10.68	
89	Secondary	1.143		
	Primary	1.130		
	Subtransmission	1.063		
90 30-250 MWa	Primary	1.205		
90 >250 MWa	Primary	0.970		
91		0.782		
95		0.782		
96		1.130		(N)
538		1.817		
575	Secondary	1.143(3)		
	Primary	1.130(3)		
	Subtransmission	1.063(3)		
583		(0.958)	9.34	
585	Secondary	(1.158)	10.80	
	Primary	(1.087)	10.68	
589	Secondary	1.143		
	Primary	1.130		
	Subtransmission	1.063		
590 30-250 MWa	Primary	1.205		
590 >250 MWa	Primary	0.970		
591		0.782		
592		1.314		
595		0.782		
596		1.130		(N)

(1) Applicable April 1, 2026 through December 31, 2026.
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.
(4) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

SCHEDULE 129
LONG-TERM TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected service under Schedules 485, 489, 490, 491, 492, 495, and 496. **(C)**

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Periods A - R: 0.000 ¢ per kWh

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 (Continued)

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

(N)

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2025	(5.510)	(4.231)	(0.528)	(0.523)	(0.704)	(0.558)	(0.702)	(0.523)
2026	(5.510)	(4.231)	(0.528)	(0.523)	(0.704)	(0.558)	(0.702)	(0.523)
2027	(5.510)	(4.231)	(0.528)	(0.523)	(0.704)	(0.558)	(0.702)	(0.523)
2028	(5.510)	(4.231)	(0.528)	(0.523)	(0.704)	(0.558)	(0.702)	(0.523)
2029	(5.510)	(4.231)	(0.528)	(0.523)	(0.704)	(0.558)	(0.702)	(0.523)
After 2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(N)

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

(N)

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	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ 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	0.000	0.000
2026	10.80	10.68	0.000	0.000	0.000	0.000	0.000	0.000
2027	10.80	10.68	0.000	0.000	0.000	0.000	0.000	0.000
2028	10.80	10.68	0.000	0.000	0.000	0.000	0.000	0.000
2029	10.80	10.68	0.000	0.000	0.000	0.000	0.000	0.000
After 2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(N)

SCHEDULE 129 (Continued)

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

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	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. 30-250 Mwa Vol. ¢ per kWh	Sch. 490 Pri. >250 Mwa Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2026	(1.773)	(0.903)	0.425	0.420	0.434	(0.052)	(0.027)	(0.567)	0.420
2027	(1.773)	(0.903)	0.425	0.420	0.434	(0.052)	(0.027)	(0.567)	0.420
2028	(1.773)	(0.903)	0.425	0.420	0.434	(0.052)	(0.027)	(0.567)	0.420
2029	(1.773)	(0.903)	0.425	0.420	0.434	(0.052)	(0.027)	(0.567)	0.420
2030	(1.773)	(0.903)	0.425	0.420	0.434	(0.052)	(0.027)	(0.567)	0.420
After 2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(N)
(N)

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	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. 30-250 Mwa Vol. $ per kW of Peak Demand	Sch. 490 Pri. >250 Mwa Vol. ¢ per kWh	Schs. 491/492/495 $ 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	0.000	0.000	0.000
2027	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2028	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2029	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2030	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000
After 2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(N)
(N)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three 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	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2024	(5.205)	(5.134)	(2.870)	(2.840)	(2.905)	(3.116)	(2.398)
2025	(4.724)	(4.696)	(2.351)	(2.327)	(2.336)	(2.615)	(1.978)
2026	(4.532)	(4.508)	(2.147)	(2.125)	(2.094)	(2.442)	(2.094)

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

Period	Sch. 485 Sec. Vol. $ per 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	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ per kW of Peak Demand
2024	9.32	9.22	0.000	0.000	0.000	0.000	0.000
2025	9.32	9.22	0.000	0.000	0.000	0.000	0.000
2026	9.32	9.22	0.000	0.000	0.000	0.000	0.000

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

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2025	(1.729)	(1.701)	0.652	0.643	0.638	(0.275)	0.107	0.643
2026	(2.842)	(2.775)	(0.436)	(0.432)	(0.363)	(1.299)	(1.012)	(0.432)
2027	(3.229)	(3.153)	(0.827)	(0.820)	(0.686)	(1.659)	(1.471)	(0.820)

(N) **(N)**

SCHEDULE 129 (Continued)

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

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

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	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ 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	0.000	0.000
2026	10.62	10.50	0.000	0.000	0.000	0.000	0.000	0.000
2027	10.62	10.50	0.000	0.000	0.000	0.000	0.000	0.000

(N)

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

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. 30-250 Mwa Vol. ¢ per kWh	Sch. 490 Pri. >250 Mwa Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2026	(6.041)	(6.054)	(3.282)	(3.247)	(3.201)	(3.536)	(3.787)	(3.840)	(3.247)
2027	(7.470)	(7.153)	(4.537)	(4.487)	(4.521)	(4.764)	(4.853)	(4.912)	(4.487)
2028	(7.563)	(7.262)	(4.629)	(4.579)	(4.593)	(4.878)	(4.982)	(5.041)	(4.579)

(N)

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

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	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. 30-250 Mwa Vol. $ per kW of Peak Demand	Sch. 490 Pri. >250 Mwa Vol. ¢ per kWh	Schs. 491/492/495 $ 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	0.000	0.000	0.000
2027	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2028	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(N)

SCHEDULE 129 (Continued) **(T)**

SPECIAL CONDITIONS

1. Annually, the total amount paid in Schedule 129 Long-Term Transition Cost Adjustments associated with Enrollment Periods A through K will be collected through applicable Large Nonresidential rate schedules (Schedules 75, 85, 89, 90, 485, 489, 490, 575, 585, 589 and 590), through either the System Usage or Distribution Charges. Commencing with Enrollment Period L, the Schedule 129 amounts paid or received will be collected from all rate schedules, through either System Usage Charges or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedules 485, 489, 490, 491, 492, 495, 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, 490, 491, 492, 495, 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
	Subtransmission	2.672
90		2.683
91		2.478
92		2.478
95		2.478
96		2.701

(N)

SCHEDULE 129 (Concluded)

TERM **(M)**

The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 485, 489, 490, 491, 492, 495 or 496. **(C)(M)**

SCHEDULE 135
DEMAND RESPONSE COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with demand response pilots not otherwise included in rates. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 496, 576R, 689, and 696. **(C)** **(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
75/575		
Secondary	0.068	¢ per kWh(1)
Primary	0.067	¢ per kWh(1)
Subtransmission	0.066	¢ per kWh(1)
83/583	0.072	¢ per kWh
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	
Subtransmission	0.066	¢ per kWh	
90/590			
Primary 30-250 MWa	0.065	¢ per kWh	
Primary >250 MWa	0.061	¢ per kWh	
Subtransmission	0.065	¢ per kWh	
91/591	0.061	¢ per kWh	
92/592	0.066	¢ per kWh	
95/595	0.061	¢ per kWh	
96/596	0.066	¢ per kWh	**(N)**

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with automated demand response and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the implementation and administration of demand response pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of demand response pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

SPECIAL CONDITION

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

SCHEDULE 136 (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
Subtransmission	0.019	¢ per kWh
90/490/590		
Primary 30-250 Mwa	0.016	¢ per kWh
Primary >250 Mwa	0.016	¢ per kWh
Subtransmission	0.016	¢ per kWh
91/491/591	0.031	¢ per kWh
92/492/592	0.021	¢ per kWh
95/495/595	0.031	¢ per kWh
96/496/596/696	0.018	¢ per kWh

(N)

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between incremental costs associated with the Oregon CSP and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the Oregon CSP.

SPECIAL 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 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
89/489/589			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.010	¢ per kWh	
90/490/590			
Primary	0.010	¢ per kWh	
Subtransmission	0.010	¢ per kWh	
91/491/591	0.018	¢ per kWh	
92/492/592	0.012	¢ per kWh	
95/495/595	0.018	¢ per kWh	
96/496/596/696	0.011	¢ per kWh	**(N)**
689			
Secondary	0.011	¢ per kWh	
Primary	0.011	¢ per kWh	
Subtransmission	0.010	¢ per kWh	

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 76R, 485, 489, 490, 491, 492, 495, 496, 576R, 689, and 696. **(C)** **(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
75/575			
	Secondary	0.002	¢ per kWh
	Primary	0.002	¢ per kWh
	Subtransmission	0.002	¢ per kWh
83/583		0.003	¢ per kWh
85/585			
	Secondary	0.002	¢ per kWh
	Primary	0.002	¢ per kWh

SCHEDULE 138 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
89/589		
Secondary	0.002	¢ per kWh
Primary	0.002	¢ per kWh
Subtransmission	0.002	¢ per kWh
90/590		
Primary 30-250 Mwa	0.002	¢ per kWh
Primary >250 Mwa	0.002	¢ per kWh
Subtransmission	0.002	¢ per kWh
91/591	0.002	¢ per kWh
92/592	0.002	¢ per kWh
95/595	0.002	¢ per kWh
96/596	0.002	¢ per kWh (N)

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with energy storage pilots and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the implementation and administration of the energy storage pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of energy storage pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

SPECIAL CONDITION

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

SCHEDULE 139
NEW LARGE LOAD TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected New Large Load Cost-of-Service Opt-Out service under Schedule 689 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. (C) (C) (C)

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Period 2 (2021), the Transition Cost Adjustment will be: (N)

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2021	0.702	0.689	0.680	0.689
2022	0.587	0.580	0.576	0.580
2023	0.655	0.648	0.645	0.648
2024	0.609	0.602	0.598	0.602
2025	0.635	0.628	0.623	0.628
2026*	0.761	0.753	0.747	0.753
After 2027	0.000	0.000	0.000	0.000

(N)

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

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2022	0.587	0.580	0.576	0.580
2023	0.655	0.648	0.645	0.648
2024	0.609	0.602	0.598	0.602
2025	0.635	0.628	0.623	0.628
2026	0.761	0.753	0.747	0.753
2027*	0.761	0.753	0.747	0.753
After 2028	0.000	0.000	0.000	0.000

(N)

*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: (N)

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2023	0.655	0.648	0.645	0.648
2024	0.609	0.602	0.598	0.602
2025	0.635	0.628	0.623	0.628
2026	0.761	0.753	0.747	0.753
2027	0.761	0.753	0.747	0.753
2028*	0.761	0.753	0.747	0.753
After 2029	0.000	0.000	0.000	0.000

(N)

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

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2024	0.609	0.602	0.598	0.602
2025	0.635	0.628	0.623	0.628
2026	0.761	0.753	0.747	0.753
2027	0.761	0.753	0.747	0.753
2028	0.761	0.753	0.747	0.753
2029*	0.761	0.753	0.747	0.753
After 2030	0.000	0.000	0.000	0.000

(N)

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

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2025	0.635	0.628	0.623	0.628
2026	0.761	0.753	0.747	0.753
2027	0.761	0.753	0.747	0.753
2028	0.761	0.753	0.747	0.753
2029	0.761	0.753	0.747	0.753
2030*	0.761	0.753	0.747	0.753
After 2031	0.000	0.000	0.000	0.000

(N)

*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: **(N)**

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2026	0.761	0.753	0.747	0.753
2027	0.761	0.753	0.747	0.753
2028	0.761	0.753	0.747	0.753
2029	0.761	0.753	0.747	0.753
2030	0.761	0.753	0.747	0.753
2031*	0.761	0.753	0.747	0.753
After 2032	0.000	0.000	0.000	0.000

(N)

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

SPECIAL CONDITIONS

1. Annually, the total amount collected in Schedule 139 New Large Load Transition Cost Adjustments will be incorporated into all rate schedules, through either System Usage Charges or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

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. **(C)**

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. **(C)**

SCHEDULE 146
COLSTRIP POWER PLANT
OPERATING LIFE ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the Company's share of the full revenue requirement for the Colstrip Power Plant Units 3 and 4 and associated common facilities. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 496, 576R, 689, and 696. **(C)** **(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
75/575	
Secondary	0.175 ¢ per kWh
Primary	0.173 ¢ per kWh
Subtransmission	0.171 ¢ 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
Subtransmission	0.171 ¢ per kWh
90/590 30-250 Mwa	
Primary	0.170 ¢ per kWh
Subtransmission	0.170 ¢ per kWh
90/590 90 >250 Mwa	
Primary	0.166 ¢ per kWh
Subtransmission	0.166 ¢ per kWh

SCHEDULE 146 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate	
91/591	0.159	¢ per kWh
92/592	0.171	¢ per kWh
95/595	0.159	¢ per kWh
96/596	0.171	¢ per kWh

(N)

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 150 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
90/490/590		
Primary 30-250 Mwa	0.018	¢ per kWh
Primary >250 Mwa	0.017	¢ per kWh
Subtransmission	0.018	¢ per kWh
91/491/591	0.021	¢ per kWh
92/492/592	0.021	¢ per kWh
95/495/595	0.021	¢ per kWh
96/496/596/696	0.020	¢ per kWh

(N)

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 (Concluded)

ADJUSTMENT RATES (Continued)

89/489/589/689		
Secondary	0.090	¢ per kWh
Primary	0.065	¢ per kWh
Subtransmission	0.059	¢ per kWh
90/490/590		
Primary	0.075	¢ per kWh
Subtransmission	0.075	¢ per kWh
91/491/591	0.477	¢ per kWh
92/492/592	0.159	¢ per kWh
95/495/595	0.477	¢ per kWh
96/496/596/696	0.070	¢ per kWh

(N)

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 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate	
89/489/589/689		
Secondary	0.058	¢ per kWh
Primary	0.038	¢ per kWh
Subtransmission	0.037	¢ per kWh
90/490/590		
Primary	0.042	¢ per kWh
Subtransmission	0.042	¢ per kWh
91/491/591	0.283	¢ per kWh
92/492/592	0.093	¢ per kWh
95/495/595	0.283	¢ per kWh
96/496/596/696	0.040	¢ per kWh

(N)

BALANCING ACCOUNT

The Company will maintain balancing accounts to track the difference between deferred amounts and the actual Schedule 152 revenues.

SCHEDULE 153 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate	
89/489/589		
Secondary	0.001	¢ per kWh
Primary	0.001	¢ per kWh
Subtransmission	0.001	¢ per kWh
90/490/590		
Primary	0.001	¢ per kWh
Subtransmission	0.001	¢ per kWh
91/491/591	0.001	¢ per kWh
92/492/592	0.001	¢ per kWh
95/495/595	0.001	¢ per kWh
96/496/596/696	0.001	¢ per kWh (N)
689		
Secondary	0.001	¢ per kWh
Primary	0.001	¢ per kWh
Subtransmission	0.001	¢ per kWh

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with the Community Benefits and Impact Advisory Group and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request. The deferral will be amortized over one year in this schedule unless otherwise directed by the Oregon Public Utility Commission.

SCHEDULE 485
LARGE NONRESIDENTIAL
COST OF SERVICE OPT-OUT
(201 - 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

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

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$730.00	$610.00	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$4.06	$4.01	(I)
Over 200 kW	$3.96	$3.91	(I)
per kW of monthly Peak Demand****	$1.68	$1.66	(I)
System Usage Charge			
per kWh	0.065 ¢	0.065 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.
**** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

SCHEDULE 489
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW more than once within the preceding 13 months and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,630.00	$3,590.00	$4,770.00	**(I)(R)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.43	$1.42	$1.41	**(R)**
Over 4,000 kW	$1.12	$1.11	$1.10	**(R)**
per kW of monthly Peak Demand****	$1.68	$1.66	$0.27	**(I)**
System Usage Charge				
per kWh	0.178 ¢	0.177 ¢	0.176 ¢	**(I)**

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.
**** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

SCHEDULE 489 (Continued)

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

TRANSMISSION MINIMUMS **(N)**

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

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. **(N)**

ON AND OFF PEAK HOURS

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

LOSSES

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

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

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.

(M)
(D)

SCHEDULE 489 (Continued)

ADJUSTMENTS (M)

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: (M) (D)

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.

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.

SCHEDULE 489 (Concluded)

SPECIAL CONDITIONS (Continued) **(T)**

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company. **(M)**

9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill. **(M)**

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 490
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window*** enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to this and Schedules 485, 489, 490, 491, 492, and 495. Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges per SP*:

	Delivery Voltage		
	Primary	Subtransmission	
Basic Charge	$11,300.00	$11,300.00	**(R)**
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$2.37	$2.37	**(I)**
Over 4,000 kW	$2.06	$2.06	**(I)**
per kW of monthly Peak Demand****	$1.66	$0.27	**(I)**
System Usage Charge			
per kWh	0.021 ¢	0.021¢	**(I)**

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.
**** Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

SCHEDULE 490 (Continued)

TRANSMISSION MINIMUMS (N)

If a customer subject to a Large Load Customer Agreement (LLCA) transitions from Schedule 90 to Schedule 490 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 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. (N)

ON AND OFF PEAK HOURS

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

LOSSES

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

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

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 490 (Continued) (T)

SPECIAL CONDITIONS (M)(T)

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule. (M)

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

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

SCHEDULE 490 (Concluded)

TERM

(M)

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

(M)

SCHEDULE 491
STREET AND HIGHWAY LIGHTING
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments with no fewer than 30,000 lights purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, 495, 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.

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)

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

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.184 ¢ per kWh	**(R)**

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's Service Points (SPs) under this schedule.

SCHEDULE 491 (Continued)

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	*	$3.99	$3.09	**(R)**
	400	50,000	163	*	*	11.71	
Cobrahead, Non-Power Door	70	6,300	30	$8.27	3.32	2.16	
	100	9,500	43	8.39	4.17	3.09	
	150	16,000	62	*	5.54	4.45	
	200	22,000	79	11.57	6.82	5.68	
	250	29,000	102	12.87	8.46	7.33	
	400	50,000	163	17.37	12.83	11.71	
Flood	250	29,000	102	14.81	8.65	7.33	
	400	50,000	163	19.09	13.00	11.71	
Early American Post-Top	100	9,500	43	9.89	4.33	3.09	
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	8.07	3.31	2.16	
	100	9,500	43	*	4.30	3.09	
	150	16,000	62	*	5.71	4.45	**(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 POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Fiberglass, Black, Bronze or Gray	20	$5.61	$0.19
Fiberglass, Black or Bronze	30	9.13	0.31
Fiberglass, Gray	30	9.13	0.31
Fiberglass, Smooth, Black or Bronze	18	6.01	0.20
Fiberglass, Regular	18	5.06	0.17
Black, Bronze, or Gray	35	8.85	0.30
Aluminum, Regular with Breakaway Base	25	16.33	0.55
	30	16.66	0.56
	35	18.02	0.60
Aluminum, Smooth, Black, Pendant	23	18.39	0.61
Wood, Standard	30 to 35	6.82	0.23
Wood, Standard	40 to 55	7.98	0.27

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	$14.22	$4.77	$3.09	**(R)**
HADCO Victorian, HPS	150	16,000	62	*	6.14	4.45	
	200	22,000	79	*	7.22	5.68	
	250	29,000	102	16.86	8.87	7.33	
HADCO Capitol Acorn, HPS	100	9,500	43	16.81	5.04	3.09	
	150	16,000	62	*	6.32	4.45	
	200	22,000	79	*	7.66	*	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	*	4.72	3.09	
	150	16,000	62	*	*	4.45	
HADCO Techtra, HPS	100	9,500	43	*	5.44	*	
HADCO Techtra, HPS	150	16,000	62	23.14	6.88	4.45	
	250	29,000	102	*	9.70	*	
HADCO Westbrooke, HPS	70	6,300	30	14.36	3.93	*	
	100	9,500	43	15.19	4.85	3.09	**(R)**

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	*	$6.40	*	(R)
	200	22,000	79	*	6.67	*	
	250	29,000	102	$19.01	9.07	*	
Special Types				*	*	*	
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	$4.60	
Ornamental Acorn	55	2,800	21	*	*	1.51	
Ornamental Acorn Twin	55	5,600	42	*	*	3.02	
Composite, Twin	140	6,815	54	*	*	3.88	
	175	9,815	66	*	*	4.74	(R)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Regular	25	$9.63	$0.32
	30	11.00	0.37
	35	12.68	0.42
Aluminum Davit	25	10.25	0.34
	30	11.50	0.38
	35	13.10	0.44
	40	16.80	0.56
Aluminum Double Davit	30	12.72	0.43
Aluminum, Fluted Ornamental	14	9.01	0.30

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

SCHEDULE 491 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Smooth Techtra Ornamental	18	$19.18	$0.64
Aluminum, Fluted Ornamental	16	9.34	0.31
Aluminum, Double-Arm, Smooth Ornamental	25	15.18	0.51
Aluminum, Fluted Westbrooke	18	18.06	0.60
Aluminum, Non-Fluted Ornamental, Pendant	18	17.95	0.60
Fiberglass, Fluted Ornamental Black	14	11.88	0.40
Fiberglass, Anchor Base, Gray or Black	35	11.97	0.40
Fiberglass, Anchor Base (Color may vary)	25	10.74	0.36
	30	13.05	0.44

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Metal Halide	150	10,000	60	*	*	$4.31	**(R)**
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.80	
	175	7,000	66	$10.03	$5.81	4.74	
	250	10,000	94	*	*	6.75	
	400	21,000	147	16.42	11.67	10.56	
	1,000	55,000	374	32.61	28.07	26.87	
Holophane Mongoose, HPS	150	16,000	62	*	6.12	*	
	250	29,000	102	*	9.13	*	**(R)**

* Not offered.

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$8.60	*	*	**(R)**
Mercury Vapor	175	7,000	66	*	$5.89	$4.74	
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	70	6,300	30	*	*	2.16	
				*	*	*	
	150	16,000	62	*	*	4.45	
	250	29,000	102	*	*	7.33	
Metal Halide	250	20,500	99	*	8.06	7.11	
	400	40,000	156	*	12.16	*	
Cobrahead, Metal Halide	175	12,000	71	*	*	5.10	
Flood, Metal Halide	400	40,000	156	17.44	*	11.21	
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.39	4.45	
KIM Archetype, HPS	250	29,000	102	*	9.15	7.33	
	400	50,000	163	*	13.88	11.71	**(R)**

* Not offered

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$13.08	$3.63	*	(R)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	2.16	
Mercury Vapor	175	7,000	66	*	*	4.74	
Early American Post-Top, HPS							
Black	70	6,300	30	8.78	3.22	2.16	
Rectangle Type	200	22,000	79	*	*	5.68	
Incandescent	92	1,000	31	*	*	2.23	
	182	2,500	62	*	*	4.45	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	*	5.84	4.74	
Flood, HPS				*	*	*	
	100	9,500	43	8.27	4.17	*	
	200	22,000	79	13.00	6.84	5.68	
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	3.09	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	6.18	
Compact Fluorescent	28	N/A	12	*	*	0.86	(R)

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Aluminum Post	30	$5.15	*
Aluminum, Painted Ornamental	35	*	$0.44
Aluminum, Regular	16	5.20	0.17
Concrete, Ornamental	35 or less	9.52	0.32
Fiberglass, Direct Bury with Shroud	18	7.67	0.26
Steel, Painted Regular **	25	9.52	0.32
Steel, Painted Regular **	30	10.85	*
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36
Steel, Unpainted 8-foot Mast Arm **	35	*	0.44
Wood, Laminated without Mast Arm	20	*	0.19
Wood, Curved Laminated	30	*	0.26
Wood, Painted Underground	35	6.75	0.23

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

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	*	$2.30	**(R)**
	165	12,000	60	*	*	4.31	|
	165	12,000	60	*	$5.38	4.31	**(R)**

SCHEDULE 492
TRAFFIC SIGNALS
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 500 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, 495, 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	1.960 ¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's SPs under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

SCHEDULE 495
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments with no fewer than 30,000 lights purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, 495, 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

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services(1) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE's Outdoor Lighting Services at 503-612-4685 or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 495 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/491/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A and Option B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.184 ¢ per kWh	**(R)**

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's Service Points (SPs) under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

SCHEDULE 495 (Continued)

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

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

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Roadway LED	>20-25	3,000	8	$5.87	$0.96	(R)
	>25-30	3,470	9	5.95	1.04	
	>30-35	2,530	11	6.36	1.18	
	>35-40	4,245	13	6.23	1.32	
	>40-45	5,020	15	6.55	1.47	
	>45-50	3,162	16	6.61	1.54	
	>50-55	3,757	18	7.03	1.68	
	>55-60	4,845	20	6.91	1.83	
	>60-65	4,700	21	6.98	1.90	
	>65-70	5,050	23	7.86	2.05	
	>70-75	7,640	25	8.04	2.20	
	>75-80	8,935	26	8.11	2.27	
	>80-85	9,582	28	8.25	2.41	
	>85-90	10,230	30	8.40	2.56	
	>90-95	9,928	32	8.54	2.70	
	>95-100	11,719	33	8.61	2.77	
	>100-110	7,444	36	8.64	2.99	
	>110-120	12,340	39	9.04	3.20	
	>120-130	13,270	43	9.33	3.49	
	>130-140	14,200	46	9.93	3.71	
	>140-150	15,250	50	12.18	4.04	
	>150-160	16,300	53	12.40	4.26	
	>160-170	17,300	56	12.61	4.47	
	>170-180	18,300	60	12.56	4.75	
	>180-190	19,850	63	13.12	4.98	
	>190-200	21,400	67	12.57	5.24	
	>200-210	27,033	70	12.86	5.46	
	>210-220	28,535	74	13.93	5.77	
	>220-230	30,017	77	14.14	5.98	
	>230-240	30,800	81	14.43	6.27	
	>240-250	31,507	84	15.14	6.49	(R)

SCHEDULE 495 (Continued)

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

Type of Light	Watts*	Monthly kWh**
LED	>170 - 180	60
LED	>180 - 190	63
LED	>190 - 200	67
LED	>200 - 210	70
LED	>210 - 220	73
LED	>220 - 230	77
LED	>230 - 240	80
LED	>240 - 250	84
LED	>250 - 260	87
LED	>260 - 270	91
LED	>270 - 280	94
LED	>280 - 290	97
LED	>290 - 300	101

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

RATES FOR DECORATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Acorn LED	>35-40	3,262	13	$14.52	$1.46	**(R)**
	>40-45	3,500	15	14.67	1.61	
	>45-50	5,488	16	12.16	1.64	
	>50-55	4,000	18	14.88	1.82	
	>55-60	4,213	20	15.03	1.97	
	>60-65	4,273	21	15.10	2.04	
	>65-70	4,332	23	14.88	2.18	
	>70-75	4,897	25	15.39	2.33	
	>90-75	8,100	32	15.93	2.87	**(R)**

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING
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	
Acorn						
HADCO LED	70	5,120	24	$18.87	$2.32	(R)
Pendant LED (Non-Flared)	36	3,369	12	15.05	1.40	
	53	5,079	18	16.61	1.85	
	69	6,661	24	16.81	2.28	
	85	8,153	29	17.73	2.65	
Pendant LED (Flared)	>35-40	3,369	13	14.55	1.46	
	>40-45	3,797	15	15.54	1.63	
	>45-50	4,438	16	15.61	1.70	
	>50-55	5,079	18	18.50	1.89	
	>55-60	5,475	20	15.06	1.97	
	>60-65	6,068	21	18.72	2.11	
	>65-70	6,661	23	17.98	2.23	
	>70-75	7,034	25	15.42	2.33	
	>75-80	7,594	26	18.42	2.46	
	>80-85	8,153	28	18.56	2.60	
Post-Top, American Revolution LED	>30-35	3,395	11	7.86	1.21	
	>45-50	4,409	16	8.22	1.57	
Flood LED	>75-80	12,716	26	9.22	2.29	
	>80-85	10,530	28	9.36	2.43	
	>110-120	18,265	38	10.62	3.16	
	>120-130	16,932	43	10.98	3.52	
	>160-170	26,349	56	13.11	4.47	
	>180-190	23,797	63	13.62	4.98	
	>290-300	46,950	116	21.83	8.89	
	>320-330	46,802	112	21.55	8.61	
	>330-340	48,692	116	21.83	8.89	
	>340-350	50,145	119	22.05	9.11	
	>350-360	51,598	123	22.34	9.40	
	>370-380	48,020	127	22.62	9.68	(R)

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, 490, 491, 492, 495 and 496. Beginning with the September 2004 Enrollment Period C, Customers have a minimum five-year option and a fixed three-year option.

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	Subtransmission
Basic Charge	$12,000.00	$12,000.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$6.54	$6.54
Over 4,000 kW	$6.23	$6.23
per kW of monthly Peak Demand****	$1.66	$0.27
System Usage Charge		
per kWh	0.025 ¢	0.025 ¢

* 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.

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 $1.964 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.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

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:

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

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 either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

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

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers 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 7.151 ¢ 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	$9.85[2]	**(R)**
	400	21,000	147	16.29[2]	
	1,000	55,000	374	32.40[2]	
HPS	70	6,300	30	8.18[2]	
	100	9,500	43	8.29	
	150	16,000	62	9.73	
	200	22,000	79	11.46	
	250	29,000	102	12.75	
	310	37,000	124	14.44[2]	
	400	50,000	163	17.24	**(R)**

(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	$8.17[2]	(R)
	200	22,000	79	12.89[2]	
	250	29,000	102	14.69	
	400	50,000	163	18.96	
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	7.98	
	100	9,500	43	9.49	
	150	16,500	62	11.31	
Special Acorn Type, HPS	100	9,500	43	14.12	
HADCO Victorian, HPS	150	16,500	62	15.50	
Early American Post-Top, HPS, Black	100	9,500	43	9.79	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	11.91	
Cobrahead, Metal Halide	175	12,000	71	10.98	
Flood, Metal Halide	350	30,000	139	18.44	
Flood, Metal Halide	400	40,000	156	17.31	
Flood, HPS	750	105,000	285	31.04	
HADCO Independence, HPS	100	9,500	43	13.78	
HADCO Techtra, HPS	100	9,500	43	20.85	
	150	16,000	62	23.04	(R)

(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	$14.44	(R)
	>40-45	3,500	15	14.58	
	>45-50	5,488	16	12.07	
	>50-55	4,000	18	14.80	
	>55-60	4,213	20	14.94	
	>60-65	4,273	21	15.01	
	>65-70	4,332	23	14.79	
	>70-75	4,897	25	15.30	
	>91-100	8,100	32	15.84	
HADCO LED	70	5,120	24	18.79	
Roadway LED	>20-25	3,000	8	5.79	
	>25-30	3,470	9	5.86	
	>30-35	2,530	11	6.28	
	>35-40	4,245	13	6.15	
	>40-45	5,020	15	6.46	
	>45-50	3,162	16	6.52	
	>50-55	3,757	18	6.95	
	>55-60	4,845	20	6.82	
	>60-65	4,700	21	6.89	
	>65-70	5,050	23	7.77	
	>70-75	7,640	25	7.95	
	>75-80	8,935	26	8.02	
	>80-85	9,582	28	8.16	
	>85-90	10,230	30	8.31	
	>90-95	9,928	32	8.45	
	>95-100	11,719	33	8.52	
	>100-110	7,444	36	8.54	
	>110-120	12,340	39	8.95	
	>120-130	13,270	43	9.23	
	>130-140	14,200	46	9.84	
	>140-150	15,250	50	12.09	(R)

(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	$12.30	(R)
	>160-170	17,300	56	12.51	
	>170-180	18,300	60	12.46	
	>180-190	19,850	63	13.02	
	>190-200	21,400	67	12.47	
	>200-210	27,033	70	12.76	
	>210-220	28,535	74	13.82	
	>220-230	30,017	77	14.04	
	>230-240	30,800	81	14.32	
	>240-250	31,507	84	15.04	
Pendant LED (Non-Flare)	36	3,369	12	14.97	
	53	5,079	18	16.53	
	69	6,661	24	16.73	
	85	8,153	29	17.64	
Pendant LED (Flare)	>35-40	3,369	13	14.47	
	>40-45	3,797	15	15.45	
	>45-50	4,438	16	15.52	
	>50-55	5,079	18	18.42	
	>55-60	5,475	20	14.97	
	>60-65	6,068	21	18.63	
	>65-70	6,661	23	17.89	
	>70-75	7,034	25	15.33	
	>75-80	7,594	26	18.33	
	>80-85	8,153	28	18.47	
CREE XSP LED	>20-25	2,529	8	5.95	
	>30-35	4,025	11	6.17	
	>40-45	3,819	15	6.45	
	>45-50	4,373	16	6.58	
	>55-60	5,863	20	6.87	
	>65-70	9,175	23	7.63	
	>90-95	8,747	32	8.28	
	130-140	18,700	46	10.77	(R)

(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	$7.78	(R)
	>45-50	4,409	16	8.13	
Flood LED	>75-80	12,716	26	9.13	
	>80-85	10,530	28	9.27	
	111-120	18,265	38	10.53	
	121-130	16,932	43	10.88	
	161-170	26,349	56	13.01	
	181-190	23,797	63	13.52	
	291-300	46,950	116	21.72	
	321-330	46,802	112	21.43	
	331-340	48,692	116	21.72	
	341-350	50,145	119	21.93	
	351-360	51,598	123	22.22	
	370-380	48,020	127	22.50	(R)

Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$6.54
	40 to 55	7.71
Wood, Painted Underground	35 or less	6.48[3]
Wood, Curved laminated	30 or less	7.62[3]
Aluminum, Regular	16	5.00
	25	9.29
	30	10.66
	35	12.34
Aluminum, Fluted Ornamental	14	8.80
Aluminum, Fluted Ornamental	16	9.14
Aluminum Davit	25	9.91
	30	11.16
	35	12.76
	40	16.38
Aluminum Double Davit	30	12.38
Aluminum, Smooth Techtra Ornamental	18	18.84

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

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	$24.00	
Three Phase	$33.00	
Distribution Charge		
First 5,000 kWh	6.701 ¢ per kWh	(I)
Over 5,000 kWh	3.167 ¢ 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 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	$50.00		
Three Phase Service	$60.00		
Distribution Charge	8.742	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

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

REACTIVE DEMAND

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

ADJUSTMENTS

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

SCHEDULE 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**	$60.00	
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	12.215¢ per kWh	**(I)**
Over 50 kWh per kW of Demand	10.760 ¢ 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 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$3,630.00	$3,590.00	$4,770.00	(R)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.43	$1.42	$1.41	(I)
Over 4,000 kW	$1.12	$1.11	$1.10	(I)
per kW of monthly Peak Demand**	$1.68	$1.66	$0.27	(R)(I)
Generation Contingency Reserves Charges***				
Spinning Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.178¢	0.177 ¢	0.176 ¢	(I)

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.
*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

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	$50.00	
Three Phase Service	$60.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$6.12	(I)
Over 30 kW	$6.02	(I)
per kW of monthly Peak Demand***	$1.68	(I)
System Usage Charge		
per kWh	0.802 ¢	(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
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	$730.00	$610.00	**(R)**
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$4.06	$4.01	**(I)**
Over 200 kW	$3.96	$3.91	**(I)**
per kW of monthly Peak Demand***	$1.68	$1.66	**(I)**
System Usage Charge			
per kWh	0.065 ¢	0.065 ¢	**(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 589
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW, and who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,630.00	$3,590.00	$4,770.00	(I)(R)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.43	$1.42	$1.41	(R)
Over 4,000 kW	$1.12	$1.11	$1.10	(R)
per kW of monthly Peak Demand***	$1.68	$1.66	$0.27	(I)
System Usage Charge				
per kWh	0.178 ¢	0.177 ¢	0.176¢	(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 589 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (ESS) for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

TRANSMISSION MINIMUMS **(N)**

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

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. **(N)**

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 (M)

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 (M)

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

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

SCHEDULE 590
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

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

	Delivery Voltage		
	Primary	Subtransmission	
Basic Charge	$11,300.00	$11,300.00	**(R)**
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$2.37	$2.37	**(I)**
Over 4,000 kW	$2.06	$2.06	**(I)**
per kW of monthly Peak Demand***	$1.66	$0.27	**(I)**
System Usage Charge			
per kWh	0.021 ¢	0.021 ¢	**(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 590 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (ESS) for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

TRANSMISSION MINIMUMS **(N)**

If a customer subject to a Large Load Customer Agreement (LLCA) transitions from Schedule 90 to Schedule 590 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 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. **(N)**

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 590 (Concluded)

ADJUSTMENTS (M)

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 (M)

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

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

SCHEDULE 591 (Continued)

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

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.184 ¢ per kWh	**(R)**
Energy Charge	Provided by Electricity Service Supplier	

NOVEMBER ELECTION WINDOW

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

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, https://portlandgeneral.com

SCHEDULE 591 (Continued)

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	*	$3.99	$3.09	(R)
	400	50,000	163	*	*	11.71	
Cobrahead, Non-Power Door	70	6,300	30	$8.27	3.32	2.16	
	100	9,500	43	8.39	4.17	3.09	
	150	16,000	62	*	5.54	4.45	
	200	22,000	79	11.57	6.82	5.68	
	250	29,000	102	12.87	8.46	7.33	
	400	50,000	163	17.37	12.83	11.71	
Flood	250	29,000	102	14.81	8.65	7.33	
	400	50,000	163	19.09	13.00	11.71	
Early American Post-Top	100	9,500	43	9.89	4.33	3.09	
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	8.07	3.31	2.16	
	100	9,500	43		4.30	3.09	
	150	16,000	62	*	5.71	4.45	(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 POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Fiberglass, Black, Bronze or Gray	20	$5.61	$0.19
Fiberglass, Black or Bronze	30	9.13	0.31
Fiberglass, Gray	30	9.13	0.31
Fiberglass, Smooth, Black or Bronze	18	6.01	0.20
Fiberglass, Regular	18	5.06	0.17
Black, Bronze, or Gray	35	8.85	0.30
Aluminum, Regular with Breakaway Base	25	16.33	0.55
	30	16.66	0.56
	35	18.02	0.60
Aluminum, Smooth, Black, Pendant	23	18.39	0.61
Wood, Standard	30 to 35	6.82	0.23
Wood, Standard	40 to 55	7.98	0.27

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	$14.22	$4.77	$3.09	**(R)**
HADCO Victorian, HPS	150	16,000	62	*	6.14	4.45	
	200	22,000	79	*	7.22	5.68	
	250	29,000	102	16.86	8.87	7.33	
HADCO Capitol Acorn, HPS	100	9,500	43	16.81	5.04	3.09	
	150	16,000	62	*	6.32	4.45	
	200	22,000	79	*	7.66	*	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	*	4.72	3.09	
	150	16,000	62	*	*	4.45	
HADCO Techtra, HPS	100	9,500	43	*	5.44	*	
	150	16,000	62	23.14	6.88	4.45	
	250	29,000	102	*	9.70	*	
HADCO Westbrooke, HPS	70	6,300	30	14.36	3.93	*	
	100	9,500	43	15.19	4.85	3.09	**(R)**

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	*	$6.40	*	**(R)**
	200	22,000	79	*	6.67	*	
	250	29,000	102	$19.01	9.07	*	**(R)**
Special Types				*	*	*	
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	$4.60	**(R)**
Ornamental Acorn	55	2,800	21	*	*	1.51	
Ornamental Acorn Twin	55	5,600	42	*	*	3.02	
Composite, Twin	140	6,815	54	*	*	3.88	
	175	9,815	66	*	*	4.74	**(R)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Regular	25	$9.63	$0.32
	30	11.00	0.37
	35	12.68	0.42
Aluminum Davit	25	10.25	0.34
	30	11.50	0.38
	35	13.10	0.44
	40	16.80	0.56
Aluminum Double Davit	30	12.72	0.43
Aluminum, Fluted Ornamental	14	9.01	0.30

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

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Smooth Techtra Ornamental	18	$19.18	$0.64
Aluminum, Fluted Ornamental	16	9.34	0.31
Aluminum, Double-Arm, Smooth Ornamental	25	15.18	0.51
Aluminum, Fluted Westbrooke	18	18.06	0.60
Aluminum, Non-Fluted Ornamental, Pendant	18	17.95	0.60
Fiberglass, Fluted Ornamental Black	14	11.88	0.40
Fiberglass, Anchor Base, Gray or Black	35	11.97	0.40
Fiberglass, Anchor Base (Color may vary)	25	10.74	0.36
	30	13.05	0.44

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Metal Halide	150	10,000	60	*	*	$4.31	(R)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.80	
	175	7,000	66	$10.03	$5.81	4.74	
	250	10,000	94	*	*	6.75	
	400	21,000	147	16.42	11.67	10.56	
	1,000	55,000	374	32.61	28.07	26.87	
Holophane Mongoose, HPS	150	16,000	62	*	6.12	*	
	250	29,000	102	*	9.13	*	(R)

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$8.60	*	*	**(R)**
Mercury Vapor	175	7,000	66	*	$5.89	$4.74	
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	70	6,300	30	*	*	2.16	
				*	*	*	
	150	16,000	62	*	*	4.45	
	250	29,000	102	*	*	7.33	
Metal Halide	250	20,500	99	*	8.06	7.11	
	400	40,000	156	*	12.16	*	
Cobrahead, Metal Halide	175	12,000	71	*	*	5.10	
Flood, Metal Halide	400	40,000	156	17.44	*	11.21	
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.39	4.45	
KIM Archetype, HPS	250	29,000	102	*	9.15	7.33	
	400	50,000	163	*	13.88	11.71	**(R)**

* Not offered

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$13.08	$3.63	*	**(R)**
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	2.16	
Mercury Vapor	175	7,000	66	*	*	4.74	
Early American Post-Top, HPS							
Black	70	6,300	30	8.78	3.22	2.16	
Rectangle Type	200	22,000	79	*	*	5.68	
Incandescent	92	1,000	31	*	*	2.23	
	182	2,500	62	*	*	4.45	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	*	5.84	4.74	
Flood, HPS				*	*	*	
	100	9,500	43	8.27	4.17	*	
	200	22,000	79	13.00	6.84	5.68	
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	3.09	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	6.18	
Compact Fluorescent	28	N/A	12	*	*	0.86	**(R)**

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Aluminum Post	30	$5.15	*
Aluminum, Painted Ornamental	35	*	$0.44
Aluminum, Regular	16	5.20	0.17
Concrete, Ornamental	35 or less	9.52	0.32
Fiberglass, Direct Bury with Shroud	18	7.67	0.26
Steel, Painted Regular **	25	9.52	0.32
Steel, Painted Regular **	30	10.85	*
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36
Steel, Unpainted 8-foot Mast Arm **	35	*	0.44
Wood, Laminated without Mast Arm	20	*	0.19
Wood, Curved Laminated	30	*	0.26
Wood, Painted Underground	35	6.75	0.23

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

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	*	$2.30	(R)
	165	12,000	60	*	*	4.31	|
	165	12,000	60	*	5.38	4.31	(R)

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	1.960 ¢ 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 595 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election (Continued)

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91/95 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires.

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A and Option B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.184 ¢ per kWh	**(R)**
Energy Charge	Provided by Electricity Service Supplier	

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

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

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

SCHEDULE 595 (Continued)

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Roadway LED	>20-25	3,000	8	$5.87	$0.96	(R)
	>25-30	3,470	9	5.95	1.04	
	>30-35	2,530	11	6.36	1.18	
	>35-40	4,245	13	6.23	1.32	
	>40-45	5,020	15	6.55	1.47	
	>45-50	3,162	16	6.61	1.54	
	>50-55	3,757	18	7.03	1.68	
	>55-60	4,845	20	6.91	1.83	
	>60-65	4,700	21	6.98	1.90	
	>65-70	5,050	23	7.86	2.05	
	>70-75	7,640	25	8.04	2.20	
	>75-80	8,935	26	8.11	2.27	
	>80-85	9,582	28	8.25	2.41	
	>85-90	10,230	30	8.40	2.56	
	>90-95	9,928	32	8.54	2.70	
	>95-100	11,719	33	8.61	2.77	
	100-110	7,444	36	8.64	2.99	
	110-120	12,340	39	9.04	3.20	
	120-130	13,270	43	9.33	3.49	
	130-140	14,200	46	9.93	3.71	
	140-150	15,250	50	12.18	4.04	
	150-160	16,300	53	12.40	4.26	
	160-170	17,300	56	12.61	4.47	
	170-180	18,300	60	12.56	4.75	
	180-190	19,850	63	13.12	4.98	
	190-200	21,400	67	12.57	5.24	
	>200-210	27,033	70	12.86	5.46	
	>210-220	28,535	74	13.93	5.77	
	>220-230	30,017	77	14.14	5.98	
	>230-240	30,800	81	14.43	6.27	
	>240-250	31,507	84	15.14	6.49	(R)

SCHEDULE 595 (Continued)

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

Type of Light	Watts*	Monthly kWh**
LED	>170 - 180	60
LED	>180 - 190	63
LED	>190 - 200	67
LED	>200 - 210	70
LED	>210 - 220	73
LED	>220 - 230	77
LED	>230 - 240	80
LED	>240 - 250	84
LED	>250 - 260	87
LED	>260 - 270	91
LED	>270 - 280	94
LED	>280 - 290	97
LED	>290 - 300	101

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

RATES FOR DECORATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Acorn LED	>35-40	3,262	13	$14.52	$1.46	**(R)**
	>40-45	3,500	15	14.67	1.61	
	>45-50	5,488	16	12.16	1.64	
	>50-55	4,000	18	14.88	1.82	
	>55-60	4,213	20	15.03	1.97	
	>60-65	4,273	21	15.10	2.04	
	>65-70	4,332	23	14.88	2.18	
	>70-75	4,897	25	15.39	2.33	
	>90-100	8,100	32	15.93	2.87	**(R)**

SCHEDULE 595 (Continued)

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	$18.87	$2.32	(R)
Pendant LED (Non-Flared)	36	3,369	12	15.05	1.40	
	53	5,079	18	16.61	1.85	
	69	6,661	24	16.81	2.28	
	85	8,153	29	17.73	2.65	
Pendant LED (Flared)	>35-40	3,369	13	14.55	1.46	
	>40-45	3,797	15	15.54	1.63	
	>45-50	4,438	16	15.61	1.70	
	>50-55	5,079	18	18.50	1.89	
	>55-60	5,475	20	15.06	1.97	
	>60-65	6,068	21	18.72	2.11	
	>65-70	6,661	23	17.98	2.23	
	>70-75	7,034	25	15.42	2.33	
	>75-80	7,594	26	18.42	2.46	
	>80-85	8,153	28	18.56	2.60	
Post-Top, American Revolution LED	>30-35	3,395	11	7.86	1.21	
	>45-50	4,409	16	8.22	1.57	
Flood LED	>75-80	12,716	26	9.22	2.29	
	>80-85	10,530	28	9.36	2.43	
	>110-120	18,265	38	10.62	3.16	
	>120-130	16,932	43	10.98	3.52	
	>160-170	26,349	56	13.11	4.47	
	>180-190	23,797	63	13.62	4.98	
	>290-300	46,950	116	21.83	8.89	
	>320-330	46,802	112	21.55	8.61	
	>330-340	48,692	116	21.83	8.89	
	>340-350	50,145	119	22.05	9.11	
	>350-360	51,598	123	22.34	9.40	
	>370-380	48,020	127	22.62	9.68	(R)

SCHEDULE 596
DATA CENTER
DIRECT ACCESS SERVICE
(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 chosen to receive Electricity from an ESS. 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 596 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.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

SCHEDULE 596 (Continued)

MONTHLY RATE

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

	Delivery Voltage	
	Primary	Subtransmission
Basic Charge	$12,000.00	$12,000.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$6.54	$6.54
Over 4,000 kW	$6.23	$6.23
per kW of monthly Peak Demand***	$1.66	$0.27
System Usage Charge		
per kWh	0.025 ¢	0.025¢

* 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.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (ESS) for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

SCHEDULE 596 (Continued)

TRANSMISSION MINIMUMS

If a customer subject to a Large Load Customer Agreement (LLCA) transitions from Schedule 96 to Schedule 596 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 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.

REACTIVE DEMAND CHARGE

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

ADJUSTMENTS

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

NOVEMBER ELECTION WINDOW

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

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

SCHEDULE 596 (Concluded)

SPECIAL CONDITIONS (Continued)

2. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

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

SCHEDULE 689 (Continued)

APPLICABLE (Continued)

Load served under Schedule 689 will not be counted under the Long Term Direct Access cap that applies to Schedules 485, 489, 490, 491, 492, 495, 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			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,630.00	$3,590.00	$4,77000	**(I)(R)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.43	$1.42	$1.41	**(R)**
Over 4,000 kW	$1.12	$1.11	$1.10	**(R)**
per kW of monthly Peak Demand***	$1.68	$1.66	$0.27	**(I)**
System Usage Charge				
per kWh	0.178 ¢	0.177 ¢	0.176 ¢	**(R)**
Administrative Fee	$0.00	$0.00	$0.00	

* See Schedule 100 for applicable adjustments.

** The Customer's load, as reflected in the opt-out agreement executed between the Customer and PGE, may be higher than that reflected in a minimum load agreement for purposes of calculating the minimum monthly Facility Capacity and monthly Demand for the SP, for any Customer with dedicated substation capacity and/or redundant distribution facilities.

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

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 **(N)**

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. **(N)**

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly On-Peak Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

ON AND OFF PEAK HOURS

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

LOSSES

The following adjustment factors will be used where losses are to be included in the Energy Charges:

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

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
NEW LARGE LOAD DATA CENTER
COST-OF-SERVICE OPT-OUT
(≥ 20 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer with new load requirements that are expected to constitute "New Large Load" as that term is defined below, and that has contractually opted out such New Large Load from PGE's cost-of-service based pricing. Participation in this program means Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company.

New Large Load must be separately metered from an existing facility or measured separately with comparable accuracy in a mutually agreed upon form between the Customer and PGE, as specified within the opt-out agreement for this program. Any New Large Load being served under this Schedule 696 must meet a minimum load of 20 MWa over a consecutive 12-month period within the first 36 months of receiving service and engage directly in providing a service described under code 518210 of the 2022 North American Industry Classification System ("data center services") or be indirectly related as a landlord with tenants engaged in providing data center services.

New Large Load is defined in OAR 860-038-0710 as: any load associated with a new facility, an existing facility, or an expansion of an existing facility which (1) has never been contracted for or committed to receiving electric service in writing by a cost-of-service Customer with the Company and (2) is expected to result in a 10 MWa or more increase in the Customer's power requirements during the first three years after new operations begin.

Service under this rate schedule begins at the time that the new meter is energized, or at a mutually agreed upon date between the Customer and PGE. The Company and Customer will identify the SP(s) that qualifies for service under this rate schedule, which SP(s) will be referenced within the previously executed opt-out agreement between the Customer and the Company once the SP(s) is known. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule. Construction meters and energy supplied during construction will not apply to this rate schedule.

Service under this schedule is limited to 119 MWa (hereafter referred to as the "cap") and is available on a first-come, first-served basis to those who apply for service under this Schedule 696 and are deemed eligible; provided, however, that capacity must be available under the cap and such cap shall not be exceeded by those who are served under this Schedule 696.

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, 490, 491, 492, 495, 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.

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	Subtransmission
Basic Charge	$12,000.00	$12,000.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$6.54	$6.54
Over 4,000 kW	$6.23	$6.23
per kW of monthly Peak Demand***	$1.66	$0.27
System Usage Charge		
per kWh	0.025 ¢	0.025¢
Administrative Fee	$0.00	$0.00

* See Schedule 100 for applicable adjustments.

** The Customer's load, as reflected in the opt-out agreement executed between the Customer and PGE, may be higher than that reflected in a minimum load agreement for purposes of calculating the minimum monthly Facility Capacity and monthly Demand for the SP, for any Customer with dedicated substation capacity and/or redundant distribution facilities.

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

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 $1.964 per kW of monthly Demand.

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 and subtransmission voltage service respectively.

ON AND OFF PEAK HOURS

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

LOSSES

The following adjustment factors will be used where losses are to be included in the Energy Charges:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530

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 (Continued)

EXISTING LOAD SHORTAGE TRANSITION ADJUSTMENT

The Existing Load Shortage Transition Adjustment will be applied to the Existing Load Shortage of the Customer and to the Existing Load Shortage of the Customer's Affiliated Customers. An Affiliated Customer is a controlling interest which is held by another Customer, engaged in the same line of business as the holder of the controlling interest. Existing Load Shortage is the larger of zero or a Customer's average historic cost-of-service load plus Incremental Demand Side Management less the average cost-of-service eligible load during the previous 60 months. Average Historical Cost-of-Service Load is the average monthly Cost-of-Service Eligible Load during the preceding 60 months prior to signing of the service agreement between the Customer and the Company for service on this rate schedule. Incremental Demand Side Management is the effective net impact of energy efficiency measures after the Customer has entered a written and binding agreement with the Company through the service agreement between the Customer and the Company.

The Existing Load Shortage Transition Adjustment for the first 60 months is equal to 75 percent of fixed generation costs plus net variable power cost transition adjustments during the first 60 months after enrollment in this rate schedule. The Existing Load Shortage Transition Adjustment after 60 months of service on this rate schedule is equal to 100 percent of fixed generation costs plus net variable power cost transition adjustments.

The Customer may be exempted from the Existing Load Transition Adjustment if the Customer can demonstrate that the change in load in question is not due to load shifting activity described in OAR 860-038-0740. The Company will provide written notification to the Customer at least 30 days prior to charging the Existing Load Shortage Transition Adjustment. The Customer must demonstrate the change in load by providing a written request for exemption that includes explanation for the change in load and support from available documentation. The Company will approve or deny the request of the Customer within 90 days and will not charge the Existing Load Transition Adjustment within this time period.

ENROLLMENT

The prospective NLDA program participant with New Large Load and any current Large Nonresidential Customer with New Large Load, must notify the Company of its interest to enroll in this Schedule 696 and execute an opt out agreement at the earlier of one year prior to the expected energization date of the new meter or upon entering a written and binding service agreement for distribution service with the Company. The date of energization will be agreed upon between the Customer and the Company within a written and binding agreement for service under this Schedule, to be provided by the Company to the Customer. Upon energization, the Customer will begin service on PGE daily market energy option and will remain on daily market energy option unless and until PGE is notified that Customer has chosen an ESS and the ESS commences service.

SCHEDULE 696 (Continued)

ENROLLMENT (Continued)

Customer enrollment may be contingent upon additional agreements between the Company and the Customer, including but not limited to Minimum Load Agreements. The Company will not accept applications for service that exceed the current program cap or any remaining load available under the cap. Customer applications with expectations of load to grow beyond the program cap will require separate application and approval by the Commission.

A Customer will have ten (10) business days to sign the NLDA service agreement once tendered by PGE. If a Customer executes an opt out agreement for service under this schedule, and if a Customer is working with an ESS, the Company will notify the ESS when to send the enrollment Direct Access Service Request (DASR). Prerequisites and notification requirements are as contained in Rule K.

Applicants that do not meet the conditions above, or that are found in breach of the opt out agreement between the Customer and the Company are not eligible for enrollment/continued enrollment under this rate schedule. If the Customer or the Customer's selected ESS cannot demonstrate creditworthiness, the Customer will not be eligible for service under this rate schedule and will be enrolled in an applicable cost-of-service based rate.

Prior to receiving service, the existing or prospective Customer must agree to only purchase energy from a resource mix consistent with the specifications of OAR 860-038-0730(1), which does not include coal-fired generation. Prior to taking service under this program, the existing or prospective Customer must provide a signed affidavit to PGE representing that their energy supply will meet the requirements of OAR 860-038-0730 (1). Customers found in violation of the provision--that no coal will be delivered by wire after January 1, 2030--will be enrolled in the general cost-of-service opt out program in the next direct access opt out window and subject to transition adjustments as a new enrollment.

DE-ENROLLMENT

At the conclusion of 36 months of service, if Customer's actual load enrolled under this Schedule 696 does not meet the minimum load requirements for service under this rate schedule, the Company may de-enroll the Customer from this rate schedule. The Company will provide the Customer and the Commission with written notification of its decision prior to moving the Customer to the applicable cost-of-service rate schedule. The Customer may respond to the Company's notice in accordance with OAR 860-038-0750. A Customer that is de-enrolled will no longer be served by an ESS and will be served by the Company at an applicable cost-of-service rate. Once de-enrolled, the Customer is subject to all notice requirements and provisions of the applicable cost-of-service rate schedule under which the Customer is served. The Customer may elect to opt-out of cost-of-service in a subsequent direct access window, and in accordance with the Company's tariff requirements. Customers that opt out of cost of service in the September direct access window will be subject to Schedule 129 transition adjustment schedule charges.

SCHEDULE 696 (Continued)

DE-ENROLLMENT (Continued)

The Customer must provide written notification, within 60 days of PGE's notification of de-enrollment, to the Company and the Commission to demonstrate that its reduction in load to less than 10 MWa was the result of equipment failure, incremental demand side management, load curtailment or load control, or other causes outside the control of the Customer. The Customer must provide documentation to demonstrate this.

The Company will not transition a Customer to a new rate schedule before 90 days has passed since initial notification from the Company.

TERM

Service under this rate schedule will be for the minimum of 36 months to determine if the minimum load required for service under this rate schedule, 10 MWa for 12 consecutive months, is met. Upon completion of this term, if 10 MWa for 12 consecutive months is met, service will continue under this schedule. If the minimum load requirement is not met, the Customer will be de-enrolled and transitioned to the applicable cost-of-service rate and subject to all notice requirements and provisions of the applicable rate schedule under which the Customer is served.

QUEUE MANGEMENT PLAN

Pending an investigation of its NLDA tariff, PGE opened a non-binding queue to start the one-year notification period for any prospective NLDA program participant who wished to provide PGE with notice of its intent to participate in the New Load Direct Access program. In recognition of the program cap, the process for entry into the queue was posted on PGE's website, in advance of the opening of the queue, and prospective NLDA program participants were advised that queue positions would be established on a first-come, first-served basis, once the queue was opened. The purpose of the temporary queue process is to provide nondiscriminatory and transparent management of those interested in NLDA.

The opening of the queue and the start of the one-year notification period for all those who entered the queue on that date, was on April 15, 2019. Thus, any load energized prior to April 15, 2020 is deemed ineligible for NLDA.

PGE anticipates that once the program cap is reached or all prospective NLDA program participants who entered the queue on April 15, 2019 have been processed, whichever comes first, PGE will close its temporary queue. Thereafter, any prospective NLDA program participant will have their request for NLDA processed on a first-come, first-served basis, at any time any capacity is or may become available under the program cap, provided the Customer load fits within the available capacity under the cap. A new NLDA queue will be established if such should become necessary.

SCHEDULE 696 (Continued)

QUEUE MANGEMENT PLAN (Continued)

Once PGE tenders an opt out agreement under this schedule, the prospective NLDA program participant has ten (10) business days to sign and return the agreement to PGE, or the offer will be withdrawn.

Beyond the one-year notification period, a prospective NLDA program participant has up to one additional year to energize the new service (by April 15, 2021 for initial program participants) or two years if substation construction and/or substation upgrades are required to serve the Contracted Load (by April 15, 2022 for initial program participants), known as the "Timely Energization Date." Temporary power will not be considered "energization" for the purposes of determining a program participant's Timely Energization Date. Allowances will be made if delays in construction are outside of the NLDA program participant's control, such as materiel delays, or delays caused by PGE. The Customer must notify PGE at least 30 days prior to the Timely Energization Date to qualify for an allowance for additional time. Failure to meet the Timely Energization Date will result in automatic disenrollment from the NLDA program and termination of the New Large Load Cost of Service Opt-Out Agreement.

PGE will calculate, in demand (kW), the New Large Load that is to be referenced in the New Large Load Cost of Service Opt-Out Agreement ("Contracted Load") and used for the purposes of determining remaining capacity available under the program cap, if any. This calculation will generally be based on the capacity of service currently being requested by the prospective NLDA program participant. PGE will design and construct facilities to serve the Contracted Load stated in the NLDA contract.

Provided any capacity is available under the program cap, such capacity will be offered serially, to the next prospective NLDA program participant in the queue, provided such prospective NLDA program participant's New Large Load can be served without exceeding the program cap. For example, if there is 25MWa available under the cap and the next prospective NLDA program participant in the queue with a 50MWa load seeks enrollment, that participant will be denied participation, as their New Large Load does not fit under the cap.

SPECIAL CONDITIONS

1. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar Customers not taking service under this schedule, including competitors to the Customer.

2. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

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 either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and arrangement and operation of such equipment will be subject to the approval of the Company.

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

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		4.780	¢ per kWh	Distribution Charge	**(R)**
15		0.825	¢ per kWh	Distribution Charge	**(R)**
32		0.437	¢ per kWh	Distribution Charge	**(R)**
38		0.500	¢ per kWh	Distribution Charge	
47		0.703	¢ per kWh	Distribution Charge	**(I)**
49		0.598	¢ per kWh	Distribution Charge	**(R)**
75					
	Secondary	0.222	¢ per kWh	System Usage Charge	
	Primary	0.220	¢ per kWh	System Usage Charge	
	Subtransmission	0.218	¢ per kWh	System Usage Charge	
83		0.338	¢ per kWh	System Usage Charge	
85					
	Secondary	0.272	¢ per kWh	System Usage Charge	
	Primary	0.269	¢ per kWh	System Usage Charge	
89					
	Secondary	0.222	¢ per kWh	System Usage Charge	
	Primary	0.220	¢ per kWh	System Usage Charge	
	Subtransmission	0.218	¢ per kWh	System Usage Charge	
90					
	Primary	0.207	¢ per kWh	System Usage Charge	
	Subtransmission	0.207	¢ per kWh	System Usage Charge	
91		0.874	¢ per kWh	Distribution Charge	
92		0.239	¢ per kWh	Distribution Charge	
95		0.874	¢ per kWh	Distribution Charge	**(R)**
96		2.830	¢ per kWh	System Usage Charge	**(N)**

DO NOT BILL

SCHEDULE 750 (Continued) **(T)**

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	0.056	¢ per kWh	System Usage Charge	**(I)**
Primary	0.056	¢ per kWh	System Usage Charge	**(I)**
489				
Secondary	0.015	¢ per kWh	System Usage Charge	
Primary	0.015	¢ per kWh	System Usage Charge	
Subtransmission	0.015	¢ per kWh	System Usage Charge	**(I)**
490				
Primary	0.009	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.009	¢ per kWh	System Usage Charge	**(R)**
491	0.692	¢ per kWh	Distribution Charge	**(R)**
492	0.043	¢ per kWh	Distribution Charge	**(I)**
495	0.692	¢ per kWh	Distribution Charge	**(R)**
496	0.100		System Usage Charge	**(N)**
515	0.640	¢ per kWh	Distribution Charge	**(R)**
532	0.216	¢ per kWh	Distribution Charge	**(I)**
538	0.282	¢ per kWh	Distribution Charge	**(I)**
549	0.344	¢ per kWh	Distribution Charge	**(I)**
575				
Secondary	0.015	¢ per kWh	System Usage Charge	
Primary	0.015	¢ per kWh	System Usage Charge	
Subtransmission	0.015	¢ per kWh	System Usage Charge	**(I)**
583	0.117	¢ per kWh	System Usage Charge	**(I)**
585				
Secondary	0.056	¢ per kWh	System Usage Charge	**(I)**
Primary	0.056	¢ per kWh	System Usage Charge	**(I)**
589				
Secondary	0.015	¢ per kWh	System Usage Charge	
Primary	0.015	¢ per kWh	System Usage Charge	
Subtransmission	0.015	¢ per kWh	System Usage Charge	**(I)**
590				
Primary	0.009	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.009	¢ per kWh	System Usage Charge	**(R)**
591	0.695	¢ per kWh	Distribution Charge	**(R)**
592	0.043	¢ per kWh	Distribution Charge	**(I)**
595	0.695	¢ per kWh	Distribution Charge	**(R)**
596	0.100		System Usage Charge	**(N)**

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					**(M)**
Secondary	0.015	¢ per kWh	System Usage Charge		‖
Primary	0.015	¢ per kWh	System Usage Charge		‖
Subtransmission	0.015	¢ per kWh	System Usage Charge	**(I)**	**(M)**
696	0.100	¢ per kWh	System Usage Charge	**(N)**	

DO NOT BILL

RULE G
DIRECT ACCESS SERVICE AND BILLING

1. Direct Access Service

All Customers, except Residential, may elect to receive Direct Access Service from an ESS under the terms of the parallel Direct Access schedule (500 series). Direct Access Service is also an option for eligible Nonresidential Customers served on Schedules 485, 489, 490, 496, 689 and 696. **(C)** **(C)**

A. **Enrollment**
Direct Access Service is only available upon acceptance of an Enrollment DASR by the Company. Prerequisites and notification requirements are as contained in each service schedule and Rule K.

B. **Emergency Default Service**
The Company will provide Emergency Default Service under Schedule 81 when an ESS or the Customer informs the Company that the ESS is no longer providing service or when the Company becomes aware that the Customer is no longer receiving service from the ESS and the Company has not received the 10 business day notice required for Standard Service under the appropriate schedule.

2. Special Requirements for Direct Access Billings

A. **Generally**

A Customer purchasing Electricity from an ESS may choose from two billing options: the ESS bills for all services (ESS Consolidated Bill) or the Company and the ESS each bill for their respective services (Company/ESS Split Bill).

1) **Company/ESS Split Bill**
When the Customer is receiving a Company/ESS Split Bill, the Company may disconnect Electricity Service for nonpayment of Direct Access Service under the guidelines set forth in Rule H.
2) **ESS Consolidated Bill**
When the Customer receives an ESS Consolidated Bill, failure of the Customer to pay the ESS for Direct Access Service does not relieve the ESS of the responsibility to pay the Company for Direct Access Services and any other Company charges.

B. **ESS Billing Responsibilities**

An ESS is responsible for the following:

1) Confirming receipt of Customer usage data within 12 hours of transmittal from the Company;
2) Responding to Customer inquiries regarding ESS charges; and
3) Under the ESS Consolidated Bill option, issuing a timely corrected bill to the Customer when the Company provides revised billing information.

RULE I
NEW CONNECTIONS, LINE EXTENSIONS, AND SYSTEM UPGRADES

1. Purpose

This rule establishes procedures and defines respective cost responsibilities for new Electricity Service connections or increases to existing Electricity Service and their respective system upgrades including but not limited to a Line Extension to a builder, developer, Customer or Applicant who requests a Line Extension on its own behalf, or a Customer or Applicant's agent.

A. Generally

Line Extensions will be at primary and/or secondary voltage levels. Modifications to transmission or subtransmission voltage facilities or substations are not considered Line Extensions for purposes of this rule and require special contract arrangements as described herein. When an agent requests a Line Extension on behalf of a Customer or Applicant, the agent must provide documentation acceptable to the Company evidencing its authority to request a Line Extension. (C) (C)

B. Definitions

1) **Allocated System Capacity**
The capacity on the Company's transmission system that is available to reliably serve an Applicant or Customer and that the Company allocates as a result of the system capacity allocation process, which is reflected in the Customer Service Contract.

2) **Applicant**
For purposes of this rule, an Applicant is a builder, developer, Customer, Applicant or other Customer or Applicant agent requesting a Line Extension to:
a) Serve new construction; or
b) Obtain additional capacity for, or a change in, service conditions relative to existing Distribution Facilities.

3) **Cost of Work**
The Company's actual direct and indirect costs to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs and assigned to the Applicant in the Customer Service Contract, including but not limited to administrative and engineering design costs. The cost of Exclusive Use Facilities for an Applicant will be allocated 100% to Applicant and Applicant shall be assigned proportional costs of any new, additional, or upgraded Distribution Facilities to serve Applicant that are not Exclusive Use Facilities. (C) (C)

RULE I (Continued)

Definitions (Continued)

4) **Customer Service Contracts** (M)
Are either (1) a Minimum Load Agreement (MLA) for Applicants in Capacity Category 2B or (2) a Large Load Customer Agreement (LLCA) for Applicants in Capacity Category 3, the terms and conditions for which are outlined in this Rule I. (C)

5) **Distribution Capacity**
The capacity that the Company makes available to the Customer or Applicant via upgrades to existing or construction of new Distribution Facilities. (M)

6) **Distribution Facilities**
Distribution Facilities are all structures and devices needed to distribute Electricity at any of the primary or secondary voltages listed in Rule C. Distribution Facilities will be installed in accordance with applicable laws, codes and Company standards and practices. It is the Applicant's responsibility to provide the Company with accurate information about their usage including but not limited to nameplate ratings of major installed electrical equipment and the intent to operate equipment above or below the nameplate rating. If damage results to Facilities owned by the Company through failure of the Applicant to fully disclose its load requirement to the Company, the repair and, or replacement costs of such Facilities will be paid by the Applicant.

7) **Enhanced Planning Area**
An area within the Company's service territory in which the transmission system requires more complex planning efforts to reliably serve expected capacity requirements. These designations are reviewed annually during system-wide analysis and with every study performed for customer requests. The Company will update designations based on a variety of factors such as changes in system conditions, regional growth, and/or individual capacity requests. (C)

8) **Estimated Cost of Work** (N)
The Company's estimated Cost of Work as determined in the final study report issued by the Company. (N)

9) **Exclusive Use Facilities** (T)
Facilities owned and operated by the Company required to provide Electric Service to the Customer between existing Company transmission or Distribution Facilities and the Applicant's or Customer's Service Point (SP) that are for the sole benefit and use of the Customer receiving Electricity Service are Exclusive Use Facilities. Customers with Exclusive Use Facilities are responsible for all costs associated with such facilities less any Line Extension Allowance for which the Customer qualifies. Neither upgrades to the Company's transmission nor distribution network(s) made for the benefit of all respective users are considered Exclusive Use Facilities and, as such, their costs are not allocated directly to any Customer(s).

RULE I (Continued)

Definitions (Continued)

(M)

10) **Exit Fee** (T)

The amount that a Customer must pay to the Company if the Customer Service Contract expires or is terminated by the Customer or by the Company in the event of a Customer default or breach or by either the Company or Customer in the event of change of law defined in the Customer Service Contract.

11) **Facilities Study**

A study performed by the Company that includes analysis of facilities impacts and Applicant or Customer cost allocation as applicable to Distribution Facilities upgrades or new construction required to accommodate a capacity request. (T)

12) **Feasibility Study** (T)

A high-level planning study performed by the Company to determine whether service can be provided at the location and under the timeline specified in the Applicant's request and whether new or upgrades to transmission or Distribution Facilities may be required. The results of a Feasibility Study may indicate the need for more detailed review in either a System Impact or Facilities Study. (M)

13) **Line Extension** (T)

A Line Extension is the installation of new, additional or upgraded Distribution Facilities from a point on the Company's existing distribution system that the Company provides for the Applicant's planned Electricity needs to the Applicant's Service Point (SP). Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service, upgrades to existing primary lines will not be considered part of the Line Extension. Any new primary or secondary Line Extensions, transformer additions or replacements necessary to serve the new load will be considered part of the Line Extension. However, for residential Electric Vehicle charging-related line extensions, transformer additions or replacements necessary to serve that charging load will not be considered part of the Line Extension.

14) **Line Extension Allowance** (T)

The Line Extension Allowance is the portion of the Line Extension Cost that the Company will provide without charge to the Applicant. Estimated annual kWh values used to calculate non-Residential Customer line extension allowances do not reflect onsite generation.

RULE I (Continued)

Definitions (Continued)

15) **Line Extension Cost** (T) (M)

The Company's total estimated cost to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs. Line Extension Costs are intended to recover the expenses of labor, material and equipment involved in the design, installation and inspection of the Line Extension under the Company's design standards and using standard construction methods inclusive of but not limited to primary and secondary voltage conductors, tree trimming or tree removal, Company indirect charges and the cost of any necessary rearrangement of existing Facilities. Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service and the transformer requires upgrading, the Line Extension Cost will be credited for the estimated original cost, less depreciation, less removal costs, of the existing transformer.

However, for residential Electric Vehicle charging line extensions, any transformer additions, or replacements necessary to serve the charging load will not be considered part of the Line Extension. Estimates of Line Extension Costs provided to Applicants are valid for six months from the date of issue. After six months the Company reserves the right to provide a revised estimate. The Line Extension Cost does not include payments to a third party for easements, additional costs associated with Underground Line Extension or other additional costs described in this rule. (M)

16) **Long Side Service Connection** (T)

A service connection, which runs parallel to the street, rather than perpendicular to the street.

17) **Primary Voltage Project** (T)

A Primary Voltage Project is a planned undertaking of construction, where the Company initially installs only primary voltage facilities. Primary Voltage Projects include large lot residential subdivisions, industrial parks and other similar complexes. It is expected that within the project each Customer will be served from one or more transformers dedicated to that Customer's use.

18) **Public Thoroughfare** (T)

A Public Thoroughfare is a municipal, county, state, federal, or other street, road, or highway, which is dedicated, maintained and open to public use in which the Company has the right to construct, operate, and maintain Facilities.

19) **Residential Subdivision** (T)

A Residential Subdivision is a parcel of land divided into four or more smaller lots for the purpose of development or sale, which has been platted and filed under Oregon law as a subdivision. It is expected that within the subdivision several homes will be or are served from the same transformer.

RULE I (Continued)

Definitions (Continued)

(M)

20) **System Impact Study** (T)
A study performed by the Company to identify system-specific upgrades or new construction required to accommodate a capacity request while maintaining system reliability, stability, and performance. The System Impact Study report also includes a rough order of magnitude (ROM) cost estimate and preliminary schedule to energization. The results of a System Impact Study may indicate the need for more detailed review in a Facilities Study.

C. **Company Requirements**

1) **Capacity Categories**
Total requested capacity by Site, as defined in Rule B and subject to the Like Ownership provision of Rule E, is categorized in this Rule as follows:

Category 1: Less than 1,000 kW
Category 2: 1,000 kW to 19,999 kW with (C)

A: no required substation transformer upgrade costs allocated to Applicant and for which total Line Extension Costs required to serve the load request are estimated to be less than $1 million, or (C)
B: required substation transformer upgrade costs allocated to Applicant or for which total Line Extension Costs required to serve the load request are estimated to be $1 million or greater. (C)

Category 3: 20,000 kW and greater (C)

(M)

For customers in Capacity Categories 2 and 3, the Company will aggregate capacity requests as one Site request where buildings with Like Ownership are located within 2,500 feet or are located at greater than 2,500 feet and are electrically connected, such as served from the same substation.

Transportation electrification customers who qualify for service under Schedule 38 are exempt from requirements applicable to Capacity Category 2B or 3 under this Rule I.

RULE I (Continued)

Company Requirements (Continued)

(M)

1) **Facilities Equipment Sizing and Use** (T)

It is the Applicant's or Customer's responsibility to provide the Company with accurate information about their usage including but not limited to nameplate ratings of major installed electrical equipment and the intent to operate equipment above or below the nameplate rating. If damage results to Facilities owned by the Company through failure of the Applicant or Customer to fully disclose its load requirement to the Company, the repair and/or replacement costs of such Facilities will be paid by the Applicant or Customer.

2) **Company to Determine Route** (T)

The Company will determine the route for all Line Extensions along Public Thoroughfares and may determine the route of a Line Extension made on private property. If the Applicant requests a route different than that determined by the Company, the Company may provide the Line Extension along the requested route if the Applicant pays the Company all additional costs resulting from the provision of that route and the requested route is not contrary to Company standards and practices.

3) **Company Ownership** (T)

The Company will own and maintain all Facilities to the SP.

4) **Company Installation** (T)

The Company will install all Facilities to the SP except that an Applicant for overhead Facilities may arrange to have the Facilities located on the property constructed by an electrical contractor acceptable to the Company, subject to the following conditions:

a) The Company will furnish the design and construction specifications for the connection and perform the necessary surveying; (M)

b) The Applicant will, prior to the beginning of construction, cause the contractor to furnish the Company a certificate naming the Company as an additional insured in an amount not less than $1 million under the contractor's general liability policy;

c) During and after completion of the work by the contractor, the Company will make inspections. If the construction meets the Company's design specifications, the Company will accept ownership, and the Applicant will provide to the Company the title to the construction using form documents provided by the Company, together with all rights-of-way and easements required by the Company, free and clear of any liens or encumbrances; and

d) Following receipt of the title and Company-approved form documents indicating successful transfer, the Company will energize the Line Extension to make Electricity Service available to the Applicant.

e) If the Company determines that the overhead Distribution Facilities are deficient in materials or workmanship within 24 months of the time the Company energized the Line Extension, the Applicant must pay the cost to correct the deficiency to the Company's satisfaction.

RULE I (Continued)

Company Installation (Continued)

5) **Unusual Distribution Facilities or Nonstandard Construction** (M) (T)
The Company is required to install only those Facilities deemed necessary to render service in accordance with the Tariff. The Company is not required to make Line Extensions which involve additional or unusual Facilities, nonstandard construction, or other unusual conditions. Any facilities installed at Applicant's request which are in addition to, or in substitution of, the standard Distribution Facilities which the Company would normally install but which are otherwise acceptable to the Company, the additional cost of such nonstandard Facilities will be paid by the Applicant and will not be subject to the Line Extension Allowance in Schedule 300. In the case of conversion from overhead service to underground service, Section 6 of this Rule applies. In the case of relocation or removal of services and facilities, Section 7 of Rule C applies. (M)

6) **System Capacity for Customers without Allocated System Capacity** (N)
The Company will plan for load of Customers without an active allocated system capacity under a Customer Service Contract based on historical usage no less than three years from energization, available capacity, and Company planning practices. Existing customers with expansion of 1,000kW or greater will be required to follow Company's Tariff process for existing customer expansions in this Rule I. (N)

2. Applicant Cost Responsibilities (M)

A. **Payment**

Applicants who have cost responsibilities under this section and Section 3 will make payment in full at the time the Company agrees to make the Line Extension or for Applicants in Capacity Categories 2B or 3, pursuant to the terms of their Customer Service Contract. (M)

A letter of credit or a deposit may be required by the Company if the Applicant does not meet the Company's credit requirements and is requesting capacity of 1,000 kW or greater. Applicant's payment requirements for jobs with Line Extension Costs estimated to be equal to or exceeding $250,000 but with requested capacity in Capacity Categories 1 and 2A are as follows:

1) The Applicant will provide a cash payment of 10% of the estimated Line Extension Cost prior to the Company initiating design work;
2) At the time the Company orders any special order and/or long lead-time electrical and/or pathway material, the Applicant will provide a cash payment to the Company for the full cost of the order; and

RULE I (Continued)

Payment (Continued)

3) At the commencement of construction, the Applicant will provide a payment equal to any remaining Line Extension Costs necessary to complete construction. Acceptable means of payment will be at the sole discretion of the Company. (M)

A Line Extension Allowance shall only be available for Customers or Applicants in Capacity Categories 1 or 2A. The Line Extension Allowance will be refunded at the time the Applicant's Electricity Service is established. If Applicant's Electricity Service is not established, payments made under Section (2)(A) are not refundable.

B. **Applicants for New Permanent Service – Capacity Categories 1 and 2A**

Applicants for new permanent services in Capacity Category 2A will be required to enter into a study agreement or study agreements and shall make any required payment prior to the Company initiating the study(ies) within the specified periods to retain queue position as described in Section 4 of this rule. Applicants will be assessed a non-refundable application fee based on the size of their request. Applicants with requests between 1MW and 3.99MW will pay a flat fee for all required studies for their request. Applicants with requests 4MW and greater will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference between actual costs as applicable at the conclusion of or upon Applicant's exit from the study process. (D) (C) (C)(M)

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 authorize the Company to proceed with design of the Line Extension or execute a subsequent study agreement, whichever is 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 providing formal authorization to the Company to proceed with design of the Line Extension or Applicant fails to execute a study agreement offered by the Company before the expiration of the study results. (N) (N)

RULE I (Continued)

(M)

Applicants for New Permanent Service – Capacity Categories 1 and 2A (Continued) (C)

The following provisions will apply to Applicants and Customers in Capacity Categories 1 or 2A.

1) **Individual Applicants**
Applicants for new permanent service will be responsible for the Line Extension Costs, less the applicable Line Extension Allowance listed in Schedule 300. In addition, any payments to a third party for easements, permits, additional costs associated with Underground Line Extensions, and all other additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

2) **Other than Individual Applicants**
The Company will install a main-line primary distribution system to provide service to a project (e.g., a subdivision, industrial park, or similar project) to serve Customers within the project provided the Applicant pays in advance for: 1) the total estimated cost of the installation of a continuous conduit system which includes, but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits; and 2) all other Applicant cost responsibilities based on the expected load within the project. The expected load in a large lot subdivision, industrial park, or similar project is comprised of only those loads projected to be connected within the first five years. Any Line Extension refund owed to the Customer or Applicant will be based on load connected within the first five years.

In residential subdivisions or phases of residential subdivisions where Line Extensions will not require subsequent additional extensions of primary voltage Distribution Facilities to serve the ultimate users within the subdivision, the refund will be based on the Line Extension Allowances for the subdivision calculated in accordance with Schedule 300. (M)

RULE I (Continued)

C. **Existing Customers – Capacity Categories 1 and 2A** (M)

Existing customers in Capacity Category 2A or expanding into Capacity Category 2A will be required to enter into a study agreement or study agreements and shall make any required payment prior to the Company initiating the study(ies) within the specified periods to retain queue position as described in Section 4 of this rule. Applicants will be assessed a non-refundable application fee based on the size of their request. Applicants with requests between 1MW and 3.99MW will pay a flat fee for all required studies for their request. Applicants with requests 4MW and greater will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference between actual costs as applicable at the conclusion of or upon Applicant's exit from the study process. (C) (C)

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 authorize the Company to proceed with design of the Line Extension or execute a subsequent study agreement, whichever offered by the Company. (N)

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 providing formal authorization to the Company to proceed with design of the Line Extension or Applicant fails to execute a study agreement offered by the Company before the expiration of the study results. (N)

The following provisions will apply to Applicants and Customers in Capacity Categories 1 or 2A. (M)

RULE I (Continued)

Existing Customers – Capacity Categories 1 and 2A (Continued) **(M)**

1) **Nonresidential**
Where an Applicant is an existing Nonresidential Customer requesting an additional SP, the conversion of a single-phase service to three-phase service, or additional capacity, the Applicant will make payment in full at the time the Company agrees to make the Line Extension. The Line Extension Allowance in these cases will be based on the incremental, annual kWh to be served by the Company or, in the case of a change in the applicable rate schedule, equal to four times the increase in annual revenues from Basic and Distribution Charges.

2) **Residential**
Where an Applicant is a Residential Customer requesting additional capacity at the same SP, the Line Extension Allowance is as listed in Schedule 300. Any excess amount will be the responsibility of the Applicant. In addition, any payments to a third party for easements, permits and additional costs associated with Underground Line Extensions and all additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

D. **New and Existing Customers - Capacity Categories 2B and 3**

1) Applicants for new permanent service or existing customer expansions between 1MW and 3.99MW are required to pay a nonrefundable study fee. Applicants shall make payment prior to the Company initiating the study process and within specified periods to retain queue position as described in Section 4 below. **(N)** **(N)**

2) Applicants for new permanent service or existing customer expansions 4MW and greater are required to pay a nonrefundable application fee and to enter into an agreement to pay study costs. Applicants will make payment for each applicable study prior to the Company initiating the study and within specified periods to retain queue position as described in Section 4 below. The Applicant will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference as applicable at the conclusion of each required study. **(C)** **(C)**

3) Applicants for new permanent service or existing customer expansions in Capacity Categories 2B or 3 shall be required to enter into a Customer Service Contract that will allocate the Cost of Work to the Applicant and contain other commercially reasonable terms and conditions, including but not limited the obligations and benefits outlined in this Rule I. **(T)**

4) The Company reserves the right to recover transmission costs from Customers in Capacity Categories 2B or 3 in a manner other than through a Customer Service Contract if the nature of the transmission investments required to serve the Customer are such that an alternative method of recovery is required to avoid an inequitable or unreasonable result. **(T)** **(M)**

RULE I (Continued)

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

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. (N) (N)

3. Special Conditions for Underground Line Extensions (M)

A. **Applicability**

Underground Line Extensions will be made:

1) When required by a governmental authority having jurisdiction;
2) When required by the Company for reasons of safety, resiliency or because the extension is from an existing underground system; or
3) When otherwise mutually agreed upon by the Company and the Applicant.

B. **Responsibility for Costs**

1) The Applicant will be responsible for the current and reasonable future costs associated with the installation of the Line Extension's continuous conduit system, which includes but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits. The Company will own and maintain the conduit system once Company conductors have been installed.
2) At its option, the Company may perform the Applicant's responsibilities listed in (B)(1) above at the Applicant's expense or permit the Applicant to perform these responsibilities at Applicant's expense. Where work is to be performed in an existing right-of-way and requires the Company to obtain a permit from a governmental body, the Company may specify additional requirements and place restrictions on the selection of contractors.
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. (M)

RULE I (Continued)

C. **Additional Services** (M)

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. (M)

RULE I (Continued)

General Conditions (Continued) **(M)**

2) Applicants will be placed in a queue. The Company reserves discretion to divide Applicants or Customers into separate queues and to perform studies in clusters by service interconnection, requested capacity, location within Enhanced Planning Areas, or other relevant factors. Applicants in Capacity Categories 2A or 2B in an area that has not been identified as an Enhanced Planning Area and all Applicants in Capacity Category 2A or 2B with requested capacity of less than 4 MW will be studied and positioned in the queue based upon the date of a complete Application. The Company will make a good faith effort to manage queue position on a first-come, first-served basis for such Applicants. All other Applicants in Capacity Categories 2A, 2B or 3 will be placed in a cluster study upon completion of an Application to be studied with other Applicants in the cluster study.
3) For Applicants in a cluster study, the determination of Allocated System Capacity will be assessed on a pro-rata framework based on the total requested capacity and available capacity up to the transmission system capacity limit derived based on reliability standards requirements for the transmission system. Additional system capacity may be allocated to Applicants committing to providing dispatchable flexible load pursuant to a Company-authorized flexible load program such as Schedule 200 or demand side management program.
4) Study durations may be significantly affected if coordination with other utilities is required.
5) Completion of a study by the Company does not guarantee capacity or service or that capacity will be allocated to the Applicant.
6) Failure of the Applicant to sign a required study agreement within 60 days of receipt from the Company and provide any required accompanying evidence, such as property ownership or good faith efforts to acquire property, shall automatically forfeit position within the queue. **(C)**
7) Generally, the Allocated System Capacity and in-service timeframe offered to the Applicant by the Company will be determined by available system capacity and the amount of capacity the Applicant requests and are subject to change by the Company until a Customer Service Contract is executed by the Applicant and the Company.

B. **Allocation Process**

1) **Pre-Feasibility Review**
The Applicant or Customer shall submit a capacity request to the Company. The request may be evaluated for pre-feasibility, which includes a high-level screening of the Company's general ability to serve the request at the specified location and within the requested timeframe. **(C)**
2) **Application Submission**
The Applicant or Customer shall submit a completed application to the Company to enter into the system capacity allocation process. The Applicant may be required to pay the application fee and sign the Study Agreement. **(C)** **(M)**

RULE I (Continued)

Allocation Process (Continued) (M)

3) **Load Flexibility**
Applicants in a study may gain access to additional Allocated System Capacity beyond their initial allocation by participating in eligible Company flexible load programs. In order to be considered for such allocation of additional transmission capacity, an Applicant must include proposed eligible flexible load in their Application prior to the initial study. Any proposed eligible flexible load will be required to meet the applicable requirements of a Company-approved flexible load program, including but not limited to Schedule 200 and demand side management programs. Requests to add flexible load after the initial study completion may require submission of a new Application or result in the need to restudy the Application.

4) **Feasibility Study**
The Company requires a minimum of 30 days to complete Applicant's Feasibility Study and will provide the Applicant with an estimated completion date in the study agreement.

5) **System Impact Study**
The Company requires a minimum of 60 days to complete Applicant's System Impact Study and will provide the Applicant with an estimated completion date in the study agreement.

6) **Facilities Study**
The Company requires a minimum of 90 days to complete Applicant's Facilities Study and will provide the Applicant with an estimated completion date in the study agreement. (M)

5. Interconnection Queue – Capacity Category 3 and seeking service under Schedule 96 (N)

Applicants in Capacity Category 3 who will qualify for Schedule 96 will be placed in an interconnection queue. Applicants placed in the interconnection queue will be removed from the queue only after they have a Service Plan. A Service Plan will identify a plan to secure resources that match an Applicant's load ramp and to comply with the applicable carbon emission targets set forth in HB 2021. A Service Plan may include a variety of energy and capacity resources, including the Applicant's own non-emitting resources through a special contract, direct access, load flexibility, customer funded load reductions in PGE's service territory, or other resources that are part of a Commission-approved resource plan or Service Plan. Applicants in a lower queue position with a Service Plan will be provided a reasonable opportunity to exit the queue ahead of a higher-queued project for whom a Service Plan is not available. PGE will submit Service Plans to the Commission for approval for each Applicant, or group of Applicants, that it proposes to remove from the queue unless the Applicant is being removed from the queue because it will be served through Direct Access. PGE will seek Commission approval within 60 days of filing a Service Plan. (N)

RULE I (Continued)

6. Customer Service Contracts – Capacity Categories 2B and 3 (T) (M)

Applicants in Capacity Categories 2B and 3 will be required to sign a Customer Service Contract as a condition of receiving Electricity Service from the Company. The Applicant's Customer Service Contract will be provided along with the last study report of the system capacity allocation process and must be signed by the Applicant within 60 days of issuance. Failure to return a signed Customer Service Contract to the Company within 60 days of issuance will result in forfeiture of the Applicant's queue position. This requirement may be temporarily waived by PGE for a reasonable period of time if the Customer Service Contract is subject to revision based on a pending proceeding before the Oregon Public Utility Commission.

Customer Service Contracts will be form contracts with terms and conditions required by this Rule as well as other commercially reasonable terms and conditions and may be revised by the Company consistent with applicable requirements in the Company's tariffs, the Public Utility Commission rules and orders.

A. **Billed Distribution Demand**

If providing service to the Applicant requires the construction of Distribution Facilities, the Customer Service Contract will contain an annual Billed Demand that the Customer must pay at the then-current tariff rates for distribution. Billed Demand will be based on the Company's initial revenue requirement resulting from the Cost of Work attributable to the Customer. The annual revenue requirement for Exclusive Use Facilities is allocated 100% to the attributable Customer but is otherwise proportionally assigned. Generally, under any LLCA or MLA, the Billed Demand shall be a flat amount that the Customer will be billed at the then-current tariff rate regardless of the Customer's actual demand. (C) (C)

Billed Demand for a LLCA or MLA will be directly calculated as a kW or MW equivalent based on the annual revenue requirement associated with the Cost of Work. Under the LLCA, the Billed Demand will continue during any renewal period if and only if Billed Demand exceeds Allocated System Capacity. If a Customer under a LLCA or MLA would be required to pay a Billed Demand amount of less than 25% of its Allocated System Capacity, then the Customer will be billed at the greater of Billed Demand or actual demand. (C) (C) (M)

Customer may elect to contribute up to one hundred percent (100%) of the Cost of Work via a Contribution in Aid of Construction (CIAC) payment. (N)

Billed Demand for Applicants with a Minimum Load Agreement will be based on the Company's initial revenue requirement associated with the Cost of Work attributable to the Customer. (N)

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued) (M)

(D)

B. **Contract Term**
The term of a Minimum Load Agreement will be 10 years. The term of the LLCA will be a minimum of 10 years for 20 MW of total allocated system capacity, increasing one year for each 10 MW increment in total allocated system capacity to a maximum of 30 years for a load of 220 MW or greater, measured from the in-service date. (C) (C)

C. **Contract Renewal**
Customer Service Contracts will renew automatically unless terminated according to the terms of the Customer Service Contract.

D. **Credit Requirements**
If Applicant does not meet the Company's credit requirements or does not provide a parental guarantee from a parent company meeting the Company's credit requirements, then Applicant will be required to provide a deposit in the form of a letter of credit, surety bond, or other financial instrument that meets the Company's credit support requirements. The Company's credit requirements are as follows: A senior long-term debt rating of A- (S&P) or A3 (Moody's).. (C) (C)

E. **Exit Fee**
In the event a Customer Service Contract expires or is terminated by the Customer or by the Company in the event of a Customer default or breach or by either the Company or Customer in the event of change of law defined in the Customer Service Contract, the Company will calculate the Exit Fee in a commercially reasonable manner and provide notice of the amount to Customer and Customer shall pay the Exit Fee to the Company within ten (10) calendar days of the date of such notice. (M)

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued) (M)

The Exit Fee for the LLCA shall be (i) the net book value of the Cost of Work calculated as of the date that is three (3) years after the date of termination or expiration of the LLCA, as determined by the Company in accordance with generally accepted accounting principles; plus (ii) any additional costs reasonably incurred or owing by the Company in connection with winding up the construction work, including any costs of decommissioning and removal of the Distribution Facilities, net of salvage value as determined by the Company in its reasonable discretion, and costs incurred in connection with the cancellation of third-party contracts; plus (iii) an amount equal to three years of distribution charges at the then current tariff rates for distribution and equal to either Billed Demand or actual demand (if there is no Billed Demand) as applicable to the Customer at the time of termination or expiration of the LLCA, plus the greater of the remaining Minimum Transmission and Minimum Generation Demand charges for the remainder of the contract term, or an amount equal to three years of Minimum Transmission and Minimum Generation Demand charges at the highest allocated system capacity. If a CIAC is paid by Customer, the net book value of the Cost of Work shall be reduced accordingly for the purpose of calculating the Exit Fee. (T) (C) (C)

The Exit Fee for the Minimum Load Agreement shall be (i) the net book value of the Cost of the Work calculated as of the date of termination or expiration of the Minimum Load Agreement, as determined by the Company in accordance with generally accepted accounting principles; plus (ii) any additional costs reasonably incurred or owing by the Company in connection with winding up the construction work, including any costs of decommissioning and removal of the Distribution Facilities, net of salvage value as determined by the Company in its reasonable discretion, and costs incurred in connection with the cancellation of third-party contracts. (M)

In the event that an Exit Fee is collected by the Company, the exiting Customer may be eligible for a partial refund if the facility is assumed within three years of service termination by a Customer with similar service characteristics, prorated based upon the amount of capacity assumed by the Customer and the date of connection. The Company will calculate any applicable refund by accounting for asset depreciation and minimum distribution, transmission, and generation revenue per the original Customer Service Contract. (N) (N)

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued) (M)

F. **Failure to Satisfy Flexible Load Requirements**
The Customer Service Contract will contain terms and conditions providing for remedies if a Customer fails to satisfy the requirements for its participation in any Company-approved flexible load program when such participation is a condition of service. Customers who are enrolled in a flexible load program with the Company as a condition of service are not eligible for financial benefits associated with such programs so long as participation in the Company approved flexible load program is a condition of service.

(D)

G. **Minimum Transmission Demand** (T)
LLCAs will require Customers receiving service under Schedules 90 and 96 to annually meet or pay a minimum of 90%, or for Customers receiving service under Schedule 89, 80% of Allocated System Capacity (the "Minimum Transmission Demand") at the then current tariff rate for transmission per the retail schedule under which the Customer is served. (C) (C)

H. **Minimum Generation Demand** (N))
LLCAs will require Customers receiving service under Schedules 90 and 96 to annually meet or pay a minimum of 90% of Allocated System Capacity (the "Minimum Generation Demand") at the then current tariff rate for fixed generation per the retail schedule under which the Customer is served.

I. **Transmission and Generation CIAC**
Customers may contribute up to 100% CIAC for transmission and generation where feasible to aid expediting the customer's interconnection. Transmission CIAC may be subject to FERC approval. (N)

J. **System Capacity Allocation Deposit** (T)
LLCAs will require Applicants provide a one-time deposit for Allocated System Capacity equal to two years' worth of Minimum Transmission Demand. Customers who meet their flexible load requirement and with no arrearage will be entitled to a refund of the System Capacity Allocation Deposit. Eligible refunds, along with simple interest accrued, will be paid at 50% following Year 2 and 50% following Year 3 of the Customer Service Contract. (C) (C) (M)

RULE I (Continued) (T)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued) (M)

K. **Subject to Revision** (T)
For any Customer Service Contract signed after April 16, 2025 and before June 10, 2026, all contract terms are subject to change pending and based upon Commission final orders in Commission Docket Nos. UE 430 and UM 2377. (C) (C)

L. **Effect of Direct Access** (M)
Customers under an LLCA who opt into a Direct Access schedule under the Tariff will be subject to transition adjustments under the schedule and will no longer be subject to the Minimum Generation Demand at the time the Customer begins service under the Direct Access schedule. Customers under an LLCA on Direct Access will be required to pay a Transmission Demand charge equal to the difference between actual usage and the Minimum Transmission Demand set in the LLCA if the Customer's actual usage is lesser than the Minimum Transmission Demand. (N) (N)

M. **System Capacity Allocation Adjustments** (C)(M)
Under the terms of any LLCA, the Company will hold Allocated System Capacity for the duration of the contract term, including renewals. The Company may reduce capacity if Customer fails to meet the requirements of the flexible load plan as outlined in the LLCA.

Customer requests for reductions of Allocated System Capacity and their accompanying cost responsibilities will be contingent upon the Company's ability to reallocate such capacity to another customer. Capacity reallocation will be allowed if either of the following conditions are met: (C) (D) (C)

(1) The assuming customer is at the same physical location and has the same electrical point of connection to the transmission grid as the customer requesting the capacity reallocation; or
(2) The assuming customer(s) is(are) at a different physical location, and the Company determines that reallocation is feasible through a study that checks electrical proximity and effects on the transmission system. Feasibility is met if the Company determines that the new physical location and electrical connection are not adversely impactful to power flow and network topology. The study will be provided to Staff of the Public Utility Commission of Oregon. (M)

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued)

Under the terms of an MLA, the Company will hold Allocated System Capacity for the initial five (5) years of the MLA term. After the initial five (5) years of the MLA term, the Company will plan system capacity for the Customer in accordance with Section 1.C.6 of this Rule I. (N)

N. **LLCA Renewal Policy**
The LLCA will automatically renew for a ten-year period at the conclusion of the initial term and for each term thereafter unless a Customer requests longer renewal terms. The renewed agreement will maintain the same terms and conditions as the initial term.

O. **Customer Election**
A Customer in Category 1 or 2A may elect to enter into an MLA or LLCA at PGE's discretion. A Customer in Category 2B may elect to enter into an LLCA at PGE's discretion. (N)

7. Refunds (T)(M)

A. Where an Applicant has paid all or a portion of the costs of a Line Extension and additional Customers are subsequently connected to it, the Company will, at its initiative or on request from the Applicant for the original Line Extension, compute on a prorated basis the Line Extension Cost responsibility for up to three additional new Applicants connected to the original Line Extension and make collections and refunds for up to three additional Applicants, provided the following three conditions are satisfied:
    1) The original Line Extension has been in service for less than five years when the additional connections are made;
    2) The original Line Extension has been in service less than six years when the application for refund is made; and
    3) The payment made by the original Applicant was $100 or more.
B. Where additional Applicants are connected within five years of completion of the original Line Extension, and the allowances for the subsequent Line Extensions exceed additional Applicants' costs, the difference may be refunded to the original Applicant under the following conditions:
    1) Application for such refunds may be made as additional Applicants are connected, but no more frequently than on an annual basis; and
    2) The total amount refunded will not exceed the Line Extension Cost paid by the original Applicant. (M)

RULE I (Continued)

8. Special Conditions for Portland River District Undergrounding Project **(T)(M)**

For an area within the City of Portland, depicted as the shaded region on the map included as Appendix A[(1)], the applicable Applicant cost responsibilities of Underground Line Extensions, as specified in Section (3)B(1), will be incurred as a Service Connection Charge. This charge will be equal to $39,040.00[(2)] for a standard 200' X 200' block within the district. For any development area other than the standard size, the charge will be prorated based on the comparative size of that area.

(1) Between Broadway and Glisan Street and behind Union Station, the River District boundary is defined by the railroad right-of-way. Their respective streets or the Willamette River defines all other sections of the River District boundary.

(2) This amount will be applicable through the year 2009. Beyond 2009, the charge will be escalated annually by the Company's then authorized cost of capital.

9. Conversion from Overhead to Underground Service **(T)**

A. **General**

The Company will replace overhead with underground Facilities whenever such conversion is practicable and economically feasible. Customers connected by overhead Distribution Facilities owned by the Company that desire underground service will comply with applicable provisions of this rule.

B. **Payment for Service Changes**

The party requesting conversion from overhead to underground will pay the Company, prior to conversion, the estimated original cost, less depreciation, less salvage value, plus removal expense of any existing overhead Facilities no longer used or useful by reason of said underground system, and the costs of any necessary rearrangements, modifications, and additions to existing Facilities to accommodate the conversion of Facilities from overhead to underground.

C. **Special Conditions**

The conversion of overhead to underground Facilities affecting more than one Customer will be conditioned on the following:

1) The governing body of the city or county in which the Company's Facilities are located will have adopted an ordinance creating an underground district in the area in which both the existing and new Facilities are and will be located, providing:

(M)

RULE I (Continued)

Conversions from Overhead to Underground Service (Continued) **(M)**

a) All existing overhead communication equipment and Distribution Facilities in such district are removed;
b) Each Customer served from such electric overhead Facilities will, in accordance with the Company's rules for underground service, make all necessary electrical facility changes on said Customer's Premises in order to receive service from the Company's underground Facilities as soon as available; and
c) The Company is authorized to discontinue its overhead service on completion of the underground Facilities.

2) All Customers served from overhead Facilities will agree in writing to perform the wiring changes required on their Premises so that service may be furnished in accordance with the Company's rules regarding underground service. Such Customers must also authorize the Company to discontinue overhead service upon completion of the underground Facilities.
3) The local government requires the Company to convert overhead Facilities to underground at the Company's expense, the provisions of OAR 860-022-0046 will apply.
4) That portion of the overhead system that is placed underground will not impair the utilization of the remaining overhead system.

D. **Cost of Area Conversions**

Area conversions may involve an assessment of costs and responsibilities among Customers. Such assessment and collection thereof will be the responsibility of a governmental unit or an association of those affected.

E. **Cost of Additional Circuit Capacity**

Where the Company installs an underground circuit with capacity in excess of the existing overhead, any additional cost to provide such excess circuit capacity will be at the Company's expense. Applicant cost responsibilities will be as defined in Section (6)(B) plus all reasonable costs for conduit or vault space installed to establish pathways for future circuit capacity. **(M)**

RULE I (Continued)

10. Nonpermanent Line Extension (T)(M)

A. General

A Line Extension is nonpermanent when the Company believes service for its intended purpose by the Applicant will continue for less than five years. If the Company believes a requested Line Extension is nonpermanent, the Company will require a cash advance of the entire Line Extension Cost, plus payments to third parties for easements and those costs outlined under Section 3, plus the estimated cost of removing the Line Extension, less any salvage value. If service is used for the intended purpose by the Line Extension Applicant for a period of five years, that portion of the amount advanced by the Applicant which was in excess of the amount that would have been charged for a permanent Line Extension will be refunded to the Applicant with interest.

B. Nonresidential Nonpermanent Service – Capacity Categories 1 and 2A

Nonresidential Line Extension Applicants with Line Extension Costs of $50,000 or greater, with loads in excess of 1 MWa, will sign a contract agreeing to accept Electricity Service at a specified minimum load. If service is terminated within an initial term of five years or if service is reduced to shut-down mode, a Service Termination Charge equal to the Line Extension Allowance (LEA) less 1/5th for each year service was taken at the specified minimum will be assessed as follows:

$$\left[\frac{(5 - \text{Years Served})}{5} * \text{LEA}\right]$$ (M)

C. Nonresidential Nonpermanent Transmission Upgrades (N)

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. (N)

11. Excess Capacity (T)(M)

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. (M)

RULE I (Concluded)

Excess Capacity (Continued) **(M)**

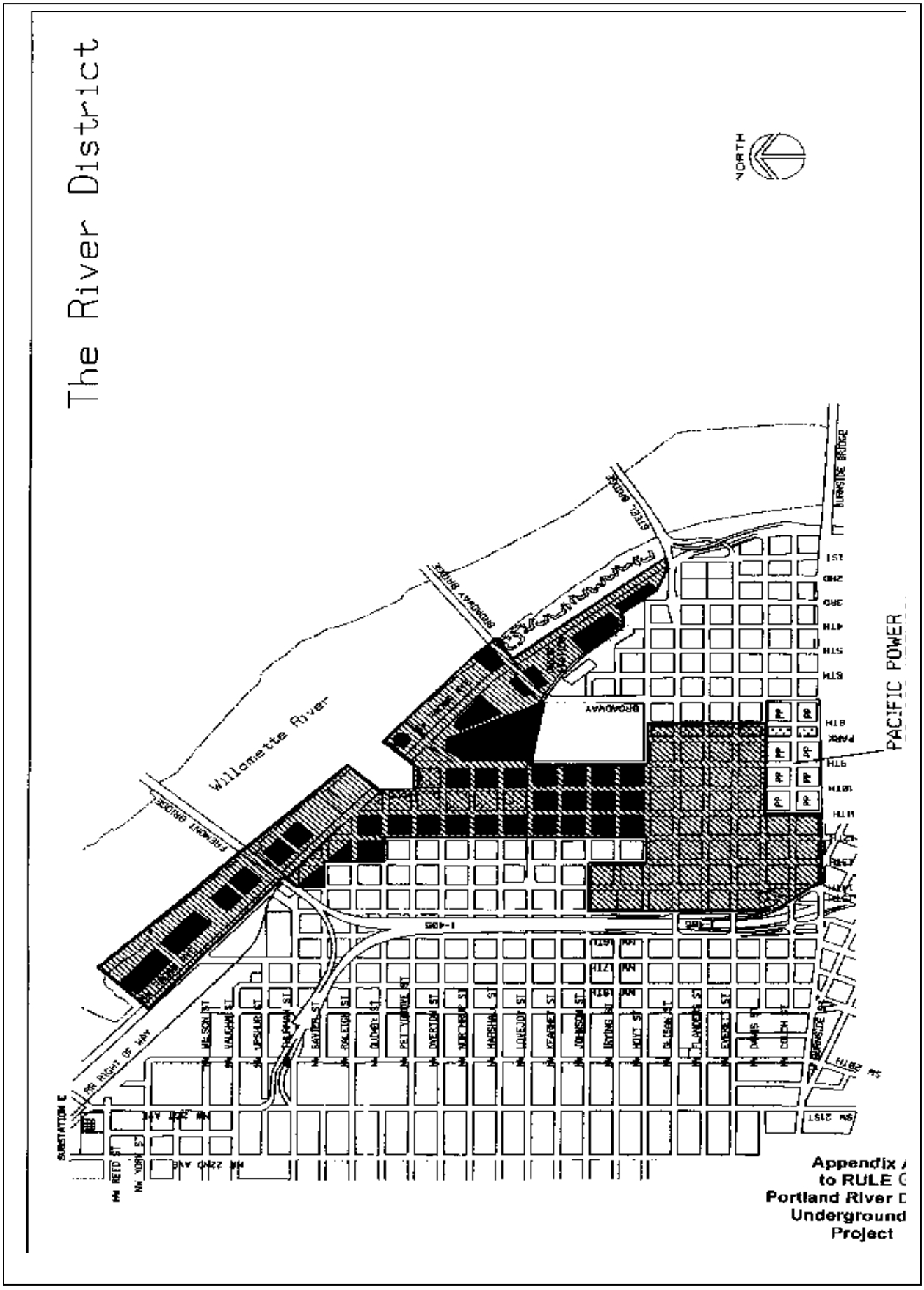
D. When a Customer applying for a service upgrade or a new service Applicant requires Excess Capacity, such installation will be ineligible for a Line Extension Allowance associated with the unused or underutilized portion of the Line Extension. The unused or underutilized portion of the Line Extension will be determined by comparing the cost of the Line Extension with and without the Facilities necessary to serve the Excess Capacity. The Customer or Applicant will also be responsible for a maintenance charge equal to the present value of future maintenance of the excess Facilities at the time the new service or service upgrade is installed. If within five years of installation the excess capacity situation is determined to no longer exist the Company will refund the portion of the Line Extension charges that resulted from the designation of Excess Capacity, including the maintenance charge. It is the responsibility of the Customer to inform the Company as to the change in their capacity requirement within the five-year period. **(T)**

12. Rules Previously in Effect **(T)**

Amounts advanced under the conditions established by a rule or contract previously in effect will be refunded in accordance with the provisions of that rule or contract. **(M)**

RULE I

APPENDIX A



PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES (Continued)

Schedule	Description
	Standard Service Schedules (Continued)
81	Nonresidential Emergency Default Service
83	Large Nonresidential Standard Service (31 – 200 kW)
85	Large Nonresidential Standard Service (201 – 4,000 kW)
86	Nonresidential Demand Buy Back Rider
88	Load Reduction Program
89	Large Nonresidential Standard Service (>4,000 kW)
90	Large Nonresidential Standard Service (>4,000 kW and Aggregate to >30 MWa)
91	Street and Highway Lighting Standard Service (Cost of Service)
92	Traffic Signals (No New Service) Standard Service (Cost of Service)
95	Street and Highway Lighting New Technology (Cost of Service)
96	Data Center Standard Service (Facilities ≥ 20,000 kW)
99	Special Contracts
	Adjustment Schedules
100	Summary of Applicable Adjustments
102	Federal Columbia River Benefits supplied by Bonneville Power Administration
103	Metro Supportive Housing Services Business Income Tax Recovery
105	Regulatory Adjustments
106	Multnomah County Business Income Tax Recovery
108	Public Purpose Charge
109	Energy Efficiency Funding Adjustment
111	Targeted Energy Support Program Surcharge
115	Low Income Assistance
118	Bill Adjustment Cost Recovery Mechanism
120	Seaside Battery Storage Resource Alternative Recovery
121	Distribution System Plan Alternative Recovery Mechanism
122	Renewable Resources Automatic Adjustment Clause
123	Decoupling Adjustment
125	Annual Power Cost Update

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES (Continued)

Schedule	Description
	Schedules Summarizing Other Charges
300	Charges as defined by the Rules and Regulations and Miscellaneous Charges
328	Clean Fuels Credit Monetization Optional Service
339	On-Bill Loan Repayment Service – Clean Energy Works of Oregon Program
340	On-Bill Repayment Service Energy Efficiency and Sustainable Technologies (EEAST)
341	Energy Efficiency Upgrade Voluntary On-Bill Repayment Service
342	Voluntary On-Bill Repayment Service Customer Flexible Load Journeys
343	Voluntary Customer Information Platform
	Promotional Concessions
402	Promotional Concessions Residential Products and Services
	Large Nonresidential Cost of Service Opt-Out Schedules
485	Large Nonresidential Cost of Service Opt-Out (201 – 4,000 kW)
489	Large Nonresidential Cost of Service Opt-Out (>4,000 kW)
490	Large Nonresidential Cost of Service Opt-Out (>4,000 kW and Aggregate to >30 MWa)
491	Street and Highway Lighting Cost of Service Opt-Out
492	Traffic Signals Cost of Service Opt-Out
495	Street and Highway Lighting New Technology Cost of Service Opt-Out
496	Data Center Cost of Service Opt-Out (Facilities ≥ 20,000 kW)
	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
575	Partial Requirements Service Direct Access Service
576R	Economic Replacement Power Rider Direct Access Service
583	Large Nonresidential Direct Access Service (31 – 200 kW)
585	Large Nonresidential Direct Access Service (201 – 4,000 kW)
589	Large Nonresidential Direct Access Service (>4,000 kW)

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES (Concluded)

Schedule	Description
590	Large Nonresidential Direct Access Service (>4,000 kW and Aggregate to >30 MWa)
591	Street and Highway Lighting Direct Access Service
592	Traffic Signals Direct Access Service
595	Street and Highway Lighting New Technology Direct Access Service
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	$13.00	
Multi-Family Home	$10.00	
Transmission and Related Services Charge	0.8056~~2~~	¢ per kWh
Distribution Charge	~~7.009~~6.941	¢ per kWh
Energy Charge	3.543~~0~~	¢ per kWh

* 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	$13.00	
Multi-Family Home	$10.00	
On-Peak Charge	30.263	¢ per kWh
Transmission and Related Services	2.310	¢ per kWh
Distribution	19.840	¢ per kWh
Energy	8.113	¢ per kWh
Mid-Peak Charge	11.143	¢ per kWh
Transmission and Related Services	0.790	¢ per kWh
Distribution	6.850	¢ per kWh
Energy	3.503	¢ per kWh
Off-Peak Charge	5.514	¢ per kWh
Transmission and Related Services	0.350	¢ per kWh
Distribution	3.010	¢ per kWh
Energy	2.154	¢ per kWh

* 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	0.344	¢ per kWh
Distribution Charge	7.331	¢ per kWh
Cost of Service Energy Charge	2.396	¢ per kWh

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	$11.78 [2]
	400	21,000	147	20.58 [2]
	1,000	55,000	374	43.33 [2]
HPS	70	6,300	30	9.05 [2]
	100	9,500	43	9.55
	150	16,000	62	11.54
	200	22,000	79	13.77
	250	29,000	102	15.73
	310	37,000	124	18.06 [2]
	400	50,000	163	22.00
Flood, HPS	100	9,500	43	9.43 [2]
	200	22,000	79	15.20 [2]
	250	29,000	102	17.67
	400	50,000	163	23.72
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	8.85
	100	9,500	43	10.75
	150	16,500	62	13.12
Special Acorn Type, HPS	100	9,500	43	15.38
HADCO Victorian, HPS	150	16,500	62	17.31
Early American Post-Top, HPS				
Black	100	9,500	43	11.05

(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	$13.66
	175	12,000	71	13.05
Flood, Metal Halide	350	30,000	139	22.50
	400	40,000	156	21.86
Flood, HPS	750	105,000	285	39.36
HADCO Independence, HPS	100	9,500	43	15.04
HADCO Techtra, HPS	100	9,500	43	22.11
	150	16,000	62	24.85

(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	$14.82
	>40-45	3,500	15	15.02
	>45-50	5,488	16	12.54
	>50-55	4,000	18	15.32
	>55-60	4,213	20	15.52
	>60-65	4,273	21	15.62
	>65-70	4,332	23	15.47
	>70-75	4,897	25	16.03
	>91-100	8,100	32	16.77
HADCO LED	70	5,120	24	19.49
Roadway LED	>20-25	3,000	8	6.03
	>25-30	3,470	9	6.13
	>30-35	2,530	11	6.60
	>35-40	4,245	13	6.53
	>40-45	5,020	15	6.90
	>45-50	3,162	16	6.99
	>50-55	3,757	18	7.47
	>55-60	4,845	20	7.40
	>60-65	4,700	21	7.50
	>65-70	5,050	23	8.45
	>70-75	7,640	25	8.68
	>75-80	8,935	26	8.78
	>80-85	9,582	28	8.98
	>85-90	10,230	30	9.18
	>90-95	9,928	32	9.38
	>95-100	11,719	33	9.48
	>100-110	7,444	36	9.60
	>110-120	12,340	39	10.09
	>120-130	13,270	43	10.49
	>130-140	14,200	46	11.18
	>140-150	15,250	50	13.55
	>150-160	16,300	53	13.85
	>160-170	17,300	56	14.15
	>170-180	18,300	60	14.21
	>180-190	19,850	63	14.85
	>190-200	21,400	67	14.43
	>200-210	27,033	70	14.80
	>210-220	28,535	74	15.98
	>220-230	30,017	77	16.28

(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	$16.69
	>240-250	31,507	84	17.49
Pendant LED (Non-Flare)	36	3,369	12	15.32
	53	5,079	18	17.05
	69	6,661	24	17.43
	85	8,153	29	18.49
Pendant LED (Flare)	>35-40	3,369	13	14.85
	>40-45	3,797	15	15.89
	>45-50	4,438	16	15.99
	>50-55	5,079	18	18.94
	>55-60	5,475	20	15.55
	>60-65	6,068	21	19.24
	>65-70	6,661	23	18.57
	>70-75	7,034	25	16.06
	>75-80	7,594	26	19.09
	>80-85	8,153	28	19.29
CREE XSP LED	>20-25	2,529	8	6.19
	>30-35	4,025	11	6.49
	>40-45	3,819	15	6.89
	>45-50	4,373	16	7.05
	>55-60	5,863	20	7.45
	>65-70	9,175	23	8.31
	>90-95	8,747	32	9.21
	>130-140	18,700	46	12.11
Post-Top, American Revolution LED	>30-35	3,395	11	8.10
	>45-50	4,409	16	8.60
Flood LED	>75-80	12,716	26	9.89
	>80-85	10,530	28	10.09
	>110-120	18,265	38	11.64
	>120-130	16,932	43	12.14
	>160-170	26,349	56	14.65
	>180-190	23,797	63	15.35
	>290-300	46,950	116	25.10

(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	$24.70
	>331-340	48,692	116	25.10
	>341-350	50,145	119	25.40
	>351-360	51,598	123	25.81
	>370-380	48,020	127	26.21

Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$6.54
	40 to 55	7.71
Wood, Painted for Underground	35 or less	6.48 [3]
Wood, Curved Laminated	30 or less	7.62 [3]
Aluminum, Regular	16	5.00
	25	9.29
	30	10.66
	35	12.34
Aluminum, Fluted Ornamental	14	8.80
Aluminum, Fluted Ornamental	16	9.14
Aluminum Davit	25	9.91
	30	11.16
	35	12.76
	40	16.38
Aluminum Double Davit	30	12.38
Aluminum, Smooth Techtra Ornamental	18	18.84

(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 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	$24.00	
Three Phase Service	$33.00	
Transmission and Related Services Charge	0.346	¢ per kWh
Distribution Charge		
First 5,000 kWh	6.922	¢ per kWh
Over 5,000 kWh	3.388	¢ per kWh
Energy Charge Options		
Standard Service	2.958	¢ per kWh
or		
Time-of-Use (TOU) Portfolio (enrollment is necessary)		
On-Peak Period	5.508	¢ per kWh
Mid-Peak Period	2.958	¢ per kWh
Off-Peak Period	1.836	¢ per kWh

* See Schedule 100 for applicable adjustments.

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	$50.00	
Three Phase Service	$60.00	
Transmission and Related Services Charge	0.399	¢ per kWh
Distribution Charge	8.960	¢ per kWh
Energy Charge**		
On-Peak Period	3.642	¢ per kWh
Mid-Peak Period	2.898	¢ per kWh
Off-Peak Period	2.526	¢ per kWh

* 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 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**	$39.00	
Winter Months**	No Charge	
Transmission and Related Services Charge	0.685	¢ per kWh
Distribution Charge		
First 50 kWh per kW of Demand***	1.3288	¢ per kWh
Over 50 kWh per kW of Demand	1.1288	¢ per kWh
Energy Charge	3.732	¢ per kWh

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

MINIMUM CHARGE

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

SCHEDULE 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**	$60.00	
Winter Months**	No Charge	
Transmission and Related Services Charge	0.290	¢ per kWh
Distribution Charge		
First 50 kWh per kW of Demand***	12.4833.069	¢ per kWh
Over 50 kWh per kW of Demand	10.4831.069	¢ per kWh
Energy Charge	3.373	¢ per kWh

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

MINIMUM CHARGE

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

SCHEDULE 54
LARGE NONRESIDENTIAL
RENEWABLE ENERGY CERTIFICATES RIDER

PURPOSE

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Customers taking service under any of the following PGE schedules: 38, 49, 83, 85, 89, 90, 91, 95, 96, 485, 489, 490, 491, 495, 496, 583, 585, 589, 590, 591, 595, 596, 689, and 6968~~89~~. Customers who are on one of these base schedules who also have schedule 15 area lighting may include those schedule 15 lights in this program.

PRODUCT OFFERINGS

I. PGE Green Resource Mix

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

II. Specified Resource

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

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$3,630890.00	$3,590840.00	$5,4604,770.00
Transmission and Related Services Charge			
per kW of monthly Peak Demand**	$3.372.19	$3.332.17	$3.272.13
Distribution Charges			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.4314	$1.4213	$1.4112
Over 4,000 kW	$1.120.83	$1.110.82	$1.100.81
per kW of monthly Peak Demand**	$1.682.00	$1.6698	$0.2713
Generation Contingency Reserves Charges			
Spinning Reserves			
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves			
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234
System Usage Charge			
per kWh	0.311 385 ¢	0.308382 ¢	0.305 379 ¢
Energy Charge			
per kWh	See Energy Charge Below		

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

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	$50.00
Three Phase Service	$60.00
Transmission and Related Services Charge	
per kW of monthly Peak Demand**	$2.19
Distribution Charges***	
The sum of the following:	
per kW of Facility Capacity	
First 30 kW	$6.12
Over 30 kW	$6.02
per kW of monthly Peak Demand**	$1.68
Energy Charge****	
~~On-Peak Period per kWh~~	~~0.297 ¢~~
~~Mid-Peak Period per kWh~~	~~0.242 ¢~~
~~Off-Peak Period per kWh~~	~~0.205¢~~
Generation Demand Charge	
per kW of monthly Peak Demand**	$9.75034
See below for Daily Pricing Option description.	
System Usage Charge	
per kWh	1.~~156~~ 023¢

* 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.

~~**** 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.~~

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	$730.00800.00	$610.0080.00
Transmission and Related Services Charge		
per kW of monthly Peak Demand**	$2.1972	$2.1769
Distribution Charges***		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$4.063.37	$4.013.33
Over 200 kW	$3.9627	$3.9123
per kW of monthly Peak Demand**	$1.683	$1.661
Energy Charge****		
~~On-Peak Period per kWh~~	~~0.288 ¢~~	~~0.285 ¢~~
~~Mid-Peak Period per kWh~~	~~0.233 ¢~~	~~0.230 ¢~~
~~Off-Peak Period per kWh~~	~~0.196 ¢~~	~~0.193 ¢~~
Generation Demand Charge		
per kW of monthly Peak Demand**	$11.3900.80	$11.2600.68
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.282 281 ¢	0.279 278 ¢

* 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.
~~**** 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.~~

SCHEDULE 89
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW.

MONTHLY RATE

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

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$3,630450.00	$3,590410.00	$4,7705,020.00
Transmission and Related Services Charge			
per kW of monthly Peak Demand**	$2.1972	$2.1769	$2.1364
Distribution Charges***			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.4370	$1.4268	$1.4166
Over 4,000 kW	$1.1239	$1.1137	$1.1035
per kW of monthly Peak Demand**	$1.683	$1.6661	$0.2713
~~Energy Charge****~~			
~~On-Peak Period per kWh~~	~~3.250 ¢~~	~~3.220 ¢~~	~~3.189 ¢~~
~~Mid-Peak Period per kWh~~	~~2.794¢~~	~~2.764 ¢~~	~~2.733 ¢~~
~~Off-Peak Period per kWh~~	~~2.490 ¢~~	~~2.460 ¢~~	~~2.429 ¢~~
See below for Daily Pricing Option description.			
Generation Demand Charge per kW of monthly Peak Demand**	$15.460	$15.310	$5.810
System Usage Charge			
per kWh	0.311385 ¢	0.308382 ¢	0.305 379¢

* 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.
~~**** 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.~~

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 and Subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

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

CAPACITY EXCEEDANCE PENALTY

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.

SCHEDULE 90
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account.

MONTHLY RATE

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

	Delivery Voltage	
	Primary	Subtransmission
Basic Charge	$11,300.00~~700.00~~	$11,~~7~~300.00
Transmission and Related Services Charge per kW of monthly Peak Demand**	$2.17~~69~~	$2.13~~64~~
Distribution Charges**~~*~~		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$~~1.91~~2.37	$~~1.91~~2.17
Over 4,000 kW	$2.06~~1.60~~	$~~1.60~~2.06
per kW of monthly Peak Demand**	$1.6~~6~~1	$0.~~13~~27
Energy Charge**		
~~Usage~~Generation Demand Charge (30 MWa – 250 MWa)		
~~Peak Period per kWh~~per kW of monthly Peak Demand	~~3.004¢~~$18.22	~~2.793¢~~$17.92
~~Off-Peak Period per kWh~~	~~2.254¢~~	~~2.043¢~~
~~Usage~~ Generation Demand Charge (greater than 250 MWa)	~~2.825¢~~$17.00	~~2.793¢~~$16.70
~~Peak Period per kWh~~per kW of monthly Peak Demand		
~~Off-Peak Period per kWh~~	~~2.075¢~~	~~2.043¢~~
System Usage Charge		
Usage (30 MWa – 250 MWa) per kWh	0.2~~20~~218¢	0.2~~20~~218¢
Usage (greater than 250 MWa) per kWh	0.2~~20~~218¢	0.2~~20~~218¢

* See Schedule 100 for applicable adjustments.

~~** On-Peak hours are Monday - Saturday 6:00 a.m. to 10:00 p.m. Off-Peak hours are Monday - Saturday 10:00 p.m. to 6:00 a.m. and all day Sunday.~~

**~~*~~ 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 90 (Continued)

ELECTION WINDOWS

Balance-of-Year Election Window

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

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

November Election Window

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

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

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, 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 and Subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

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

CAPACITY EXCEEDANCE PENALTY

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.

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	0.311 ¢ per kWh
Distribution Charge	7.364 ¢ per kWh
Energy Charge	
Cost of Service Option	2.396 ¢ per kWh

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.319¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

Prices reported with no transaction volume or as “survey-based” will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0640.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

Enrollment for Service

To begin service under the Daily Price Option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

SCHEDULE 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	0.375~~522~~	¢ per kWh
Distribution Charge	~~2.061~~2.156	¢ per kWh
Energy Charge	2.626~~95~~	¢ per kWh

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Balance-of-Year Election Window

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

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

SCHEDULE 95 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election (Continued)

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91/95 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires.

STREETLIGHT POLES SERVICE OPTIONS

See Schedule 91 for Streetlight poles service options.

MONTHLY RATE

In addition to the service rates for Option A and Option B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.311 ¢ per kWh
Distribution Charge	7.364 ¢ per kWh
Energy Charge	
Cost of Service Option	2.396 ¢ per kWh

NON-COST OF SERVICE OPTION

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.319¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

SCHEDULE 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
75	x[2]	x	x[2]	x	x	x[2]		x	x	x[2]	x	x[2]	x	x[2]	x[2]
76	x	x		x	x			x	x						
83	x	x	x	x	x	x		x	x	x	x	x	x	x	x
85	x	x	x	x	x	x		x	x	x	x	x	x	x	x
89	x	x	x	x	x	x		x	x	x	x	x	x	x	x
90	x	x	x	x	x	x		x	x	x	x	x	x	x	x
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
95		x	x	x	x	x		x	x	x	x	x	x	x	x
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]
490	x	x	x	x	x	x		x	x		x		x		x
491		x	x	x	x	x		x	x		x		x		x
492		x	x	x	x	x		x	x		x		x		x
495		x	x	x	x	x		x	x		x		x		x
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]
575	x[2]	x	x[2]	x	x	x		x	x		x		x		x[2]
576	x	x		x	x			x	x						
583	x	x	x	x	x	x		x	x		x		x		x[5]
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]
590	x	x	x	x	x	x		x	x		x		x		x
591		x	x	x	x	x		x	x		x		x		x[5]
592		x	x	x	x	x		x	x		x		x		x[5]
595		x	x	x	x	x		x	x		x		x		x[5]
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, 490, 491, 492 and 495).
5. Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 100 (Concluded)

SUMMARY OF APPLICABLE ADJUSTMENTS (Continued)

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
75	x		x	x	x	x			x	x	x	x	x	x	x	x
76												x		x		
83	x		x	x	x	x			x	x	x	x	x	x	x	x
85	x		x	x	x	x			x	x	x	x	x	x	x	x
89	x		x	x	x	x			x	x	x	x	x	x	x	x
90	x		x	x	x	x			x	x	x	x	x	x	x	x
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
95	x		x	x	x	x			x	x	x	x	x	x	x	x
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
490		x		x	x				x			x	x	x	x	x
491		x		x	x				x			x	x	x	x	x
492		x		x	x				x			x	x	x	x	x
495		x		x	x				x			x	x	x	x	x
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
575	x		x	x	x	x			x	x	x	x	x	x	x	x
576												x		x		
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
590	x		x	x	x	x			x	x	x	x	x	x	x	x
591	x		x	x	x	x			x	x	x	x	x	x	x	x
592	x		x	x	x	x			x	x	x	x	x	x	x	x
595	x		x	x	x	x			x	x	x	x	x	x	x	x
596	x		x	x	x	x			x		x		x	x	x	x
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, 490, 491, 492 and 495).
5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 105 (Continued~~cluded~~)

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
Subtransmission	0.012	0.008	0.020	¢ per kWh
90/590 30-250 MWa				
Primary	0.010	0.008	0.018	¢ per kWh
Subtransmission	0.010	0.008	0.018	¢ per kWh
90/590 >250 MWa				
Primary	0.010	0.008	0.018	¢ per kWh
Subtransmission	0.010	0.008	0.018	¢ per kWh
91/591	0.005	0.008	0.013	¢ per kWh
92/592	0.007	0.008	0.015	¢ per kWh
95/595	0.005	0.008	0.013	¢ per kWh
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
Subtransmission	0.003	0.000	0.003	¢ per kWh
490				
Primary	0.001	0.000	0.001	¢ per kWh
Subtransmission	0.001	0.000	0.001	¢ per kWh
491	(0.005)	0.000	(0.005)	¢ per kWh
492	(0.004)	0.000	(0.004)	¢ per kWh
495	(0.005)	0.000	(0.005)	¢ per kWh
496				
Primary	0.003	0.000	0.003	¢ per kWh
Subtransmission	0.003	0.000	0.003	¢ per kWh

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
Subtransmission	0.003	0.000	0.003	¢ per kWh
696				
Primary	0.003	0.000	0.003	¢ per kWh
Subtransmission	0.003	0.000	0.003	¢ per kWh

SCHEDULE 109
ENERGY TRUST OF OREGON FUNDING ADJUSTMENT

PURPOSE

To fund the acquisition of Energy Efficiency as administered by the Energy Trust of Oregon (ETO) for the benefit of the Company's Customers pursuant to ORS 757.054.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory. Nonresidential Customers who meet the eligibility qualifications under 2021 Legislative Session House Bill (HB) 3141 and whose load exceeded 1 aMW but less than 10 aMW during the prior calendar year are subject to an annual cap of $250,000 for combined Energy Trust of Oregon Funding Adjustment and Public Purpose Charges. Nonresidential Customers who meet the eligibility qualifications under HB 3141 and whose load exceeded 10 aMW are subject to an annual cap of $4,000,000 for combined Energy Trust of Oregon Funding Adjustment and Public Purpose Charges.

Customers receiving service under Schedule 96 are charged such that they pay the amount that is the maximum amount allowable under Section 3 of HB 3141 (ORS 757.054) as specified above and pursuant to Commission Order No. 26-154.

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be an SDC, the Large Nonresidential Customer must have a load that exceeds 1 aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy (ODOE) as an SDC. The Company will include the credits due, as reported by the ODOE, to the applicable portions of the SDC's monthly Schedule 109 Charge.

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue the incremental amounts between the amounts associated with the ETO budget and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

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	1.0680024	¢ per kWh
15/515	0.82274852	¢ per kWh
32/532	0.99691666	¢ per kWh
38/538	1.03600220	¢ per kWh
47	1.39234010	¢ per kWh
49/549	1.25219220	¢ per kWh
75/575		
Secondary	0.477830.512	¢ per kWh
Primary	0.47280.506	¢ per kWh
Subtransmission	0.402100.496	¢ per kWh
83/583	0.7667060	¢ per kWh
85/485/585		
Secondary	0.66661820	¢ per kWh
Primary	0.784768	¢ per kWh
89/489/589/689		
Secondary	0.51247783	¢ per kWh
Primary	0.47250668	¢ per kWh
Subtransmission	0.40296610	¢ per kWh
90/490/590		
Primary 30-250MWa	0.47285500	¢ per kWh
Primary >250MWa	0.000	¢ per kWh
Subtransmission	0.47285500	¢ per kWh
91/491/591	0.82676680	¢ per kWh
92/492/592	0.56255246	¢ per kWh
95/495/595	0.82676680	¢ per kWh
96/496/596/696	0.76666	¢ per kWh

SCHEDULE 109 (Concluded)

ENERGY TRUST OF OREGON FUNDING ADJUSTMENT (Continued)

Over One Average Megawatt Pricing

Schedule	Adjustment Rate	
75/575 >1aMW		
Secondary	0.477830.512	¢ per kWh
Primary	0.47280.506	¢ per kWh
Subtransmission	0.402100.496	¢ per kWh
83/583 >1aMW	0.4824326	¢ per kWh
85/485/585 >1aMW		
Secondary	0.328296	¢ per kWh
Primary	0.276272	¢ per kWh
89/489/589/689 >1aMW		
Secondary	0.477830.512	¢ per kWh
Primary	0.47280.506	¢ per kWh
Subtransmission	0.402100.496	¢ per kWh
90/490/590 >1aMW		
Primary 30-250MWa	0.472500	¢ per kWh
Primary >250MWa	0.000	¢ per kWh
Subtransmission	0.472500	¢ per kWh
96/496/596/696	0.766	¢ 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 76, 485, 489, 490, 491, 492, 495, 496, 515, 532, 538, 549, 575, 576, 583, 585, 589, 596, and 689 and 696.

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	0.230	(0.000)	0.230	¢ per kWh
15	0.163	(0.000)	0.163	¢ per kWh
32	0.202	(0.000)	0.202	¢ per kWh
38	0.197	(0.000)	0.197	¢ per kWh
47	0.241	(0.000)	0.241	¢ per kWh
49	0.236	(0.000)	0.236	¢ per kWh

SCHEDULE 120 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Part A	Part B	Adjustment Rate	
75				
Secondary	0.179	(0.000)	0.179	¢ per kWh
Primary	0.177	(0.000)	0.177	¢ per kWh
Subtransmission	0.176	(0.000)	0.176	¢ per kWh
83	0.196	(0.000)	0.196	¢ per kWh
85				
Secondary	0.194	(0.000)	0.194	¢ per kWh
Primary	0.183	(0.000)	0.183	¢ per kWh
89				
Secondary	0.179	(0.000)	0.179	¢ per kWh
Primary	0.177	(0.000)	0.177	¢ per kWh
Subtransmission	0.176	(0.000)	0.176	¢ per kWh
90				
Primary 30-250 MWa	0.175	(0.000)	0.175	¢ per kWh
Primary >250 MWa	0.171	(0.000)	0.171	¢ per kWh
Subtransmission	0.175	(0.000)	0.175	¢ per kWh
91	0.163	(0.000)	0.163	¢ per kWh
92	0.176	(0.000)	0.176	¢ per kWh
95	0.163	(0.000)	0.163	¢ per kWh
96	0.176	(0.000)	0.176	¢ per kWh

SPECIAL CONDITIONS

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

2. The costs for projects included under this schedule will be updated annually as provided above and will continue to be recovered under Schedule 120 until such time as the costs 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 Schedule 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 except Schedules 76R, and 576R.

ADJUSTMENT RATE

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

Schedule	Adjustment Rate	
7	0.~~410~~400	¢ per kWh
15/515	0.~~391~~371	¢ per kWh
32/532	0.~~380~~355	¢ per kWh
38/538	0.~~464~~458	¢ per kWh
47	0.~~601~~600	¢ per kWh
49/549	0.~~579~~571	¢ per kWh
75/575		
Secondary	0.~~097~~098	¢ per kWh
Primary	0.~~096~~096	¢ per kWh
Subtransmission	0.~~148~~145	¢ per kWh
83/583	0.~~260~~250	¢ per kWh
85/585		
Secondary	0.~~155~~161	¢ per kWh
Primary	0.~~141~~145	¢ per kWh
89/589		
Secondary	0.~~097~~098	¢ per kWh
Primary	0.~~096~~096	¢ per kWh
Subtransmission	0.~~148~~145	¢ per kWh

SCHEDULE 121 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
90/590		
Primary 30-250 MWa	0.~~081~~082	¢ per kWh
Primary >250 MWa	0.~~081~~082	¢ per kWh
Subtransmission	0.~~081~~082	¢ per kWh
91/591	0.~~391~~371	¢ per kWh
92/592	0.~~149~~146	¢ per kWh
95/595	0.~~391~~371	¢ per kWh
96/596		
Primary	~~x.xxx~~0.124	¢ per kWh
Subtransmission	~~x.xxx~~0.124	¢ per kWh
485		
Secondary	0.~~063~~069	¢ per kWh
Primary	0.~~054~~060	¢ per kWh
489		
Secondary	0.~~064~~059	¢ per kWh
Primary	0.~~028~~029	¢ per kWh
Subtransmission	0.~~018~~020	¢ per kWh
490		
Primary	0.~~032~~035	¢ per kWh
Subtransmission	0.~~032~~035	¢ per kWh
491	0.~~341~~326	¢ per kWh
492	0.~~094~~096	¢ per kWh
495	0.~~341~~326	¢ per kWh
496		
Primary	~~x.xxx~~0.061	¢ per kWh
Subtransmission	0.061	¢ per kWh
689		
Secondary	0.~~026~~056	¢ per kWh
Primary	0.~~026~~056	¢ per kWh
Subtransmission	0.~~026~~055	¢ per kWh

SCHEDULE 121 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
696		
Primary	0.056	¢ per kWh
Subtransmission	0.055	¢ per kWh

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 76, 485, 489, 490, 491, 492, 495, 496, 576, and 689 and 696. This schedule is not applicable to direct access customers after December 31, 2010.

ADJUSTMENT RATE

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

Schedule		Adjustment Rate	
7		0.214	¢ per kWh
15		0.152	¢ per kWh
32		0.188	¢ per kWh
38		0.184	¢ per kWh
47		0.224	¢ per kWh
49		0.220	¢ per kWh
75			
	Secondary	0.166	¢ per kWh
	Primary	0.165	¢ per kWh
	Subtransmission	0.163	¢ per kWh
83		0.183	¢ per kWh
85			
	Secondary	0.181	¢ per kWh
	Primary	0.171	¢ per kWh
89			
	Secondary	0.166	¢ per kWh
	Primary	0.165	¢ per kWh
	Subtransmission	0.163	¢ per kWh

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

Schedule		Adjustment Rate	
~~89~~			
	~~Secondary~~	~~0.166~~	~~¢ per kWh~~
	~~Primary~~	~~0.165~~	~~¢ per kWh~~
	~~Subtransmission~~	~~0.163~~	~~¢ per kWh~~
90			
	Primary 30-250 Mwa	0.163	¢ per kWh
	Primary >250 Mwa	0.133	¢ per kWh
	Subtransmission	0.163	¢ per kWh
91		0.162	¢ per kWh
92		0.163	¢ per kWh
95		0.162	¢ per kWh
96		0.164	¢ per kWh

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 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an automatic adjustment clause as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all Cost-of-Service bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 90, 91, 92, 95, and 965. Customers served under the Daily Price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 90, 91 and 95 are exempt from Schedule 125.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- 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)

FILING AND EFFECTIVE DATE (Continued)

On November 15th, or the next available business day if the 15th is on a weekend the Company will file the final estimate of NVPC and will calculate and file the final change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) the final planned maintenance outages and load forecast from the October 1st filing, 3) final update to Qualifying Facilities online dates, and 4) final price for the energy generation at the Priest Rapids and Wanapum hydro facilities, as provided in the power contract between PGE and Grant County.

RATE ADJUSTMENT
The rate adjustment will be based on the Annual NVPC adjusted for Revenue Sensitive Costs applied to forecast loads used to determine Net Variable Power Costs.

ADJUSTMENT RATES

Schedule		¢ per kWh
7		5.~~685~~619
7-TOD	On-Peak Period	1~~23~~.~~019~~868
	Mid-Peak Period	5.~~620~~555
	Off-Peak Period	3.~~456~~416
15		~~4.049~~3.893
32		~~5.006~~4.936
32-TOU	On-Peak Period	8.256
	Mid-Peak Period	5.009
	Off-Peak Period	2.754
38	On-Peak Period	6.~~064~~083
	Mid-Peak Period	4.~~824~~843
	Off-Peak Period	4.~~204~~223
47		~~6.016~~5.940
49		~~5.892~~5.822

SCHEDULE 125 (Continued)

ADJUSTMENT RATES (Continued)

Schedule		¢ per kWh
75		
	Secondary[1]	
	On-Peak Period	5.6725.241
	Mid-Peak Period	4.5284.489
	Off-Peak Period	3.7653.988
	Primary[1]	
	On-Peak Period	5.3375.184
	Mid-Peak Period	4.5934.440
	Off-Peak Period	4.0983.945
	Subtransmission[1]	
	On-Peak Period	5.3735.130
	Mid-Peak Period	4.6294.386
	Off-Peak Period	4.1343.891
83		
	On-Peak Period	6.093024
	Mid-Peak Period	4.94844879
	Off-Peak Period	4.185116
85		
	Secondary	
	On-Peak Period	5.881808
	Mid-Peak Period	4.737664
	Off-Peak Period	3.974901
	Primary	
	On-Peak Period	5.876672
	Mid-Peak Period	4.732528
	Off-Peak Period	3.969765
89		
	Secondary	
	On-Peak Period	5.241672
	Mid-Peak Period	4.489528
	Off-Peak Period	3.988765
	Primary	
	On-Peak Period	5.184337
	Mid-Peak Period	4.440593
	Off-Peak Period	3.9454.098
	Subtransmission	
	On-Peak Period	5.130373
	Mid-Peak Period	4.386629
	Off-Peak Period	3.8914.134

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

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		¢ per kWh
90		
	Primary 30-250 MWa	
	On-Peak Period	4.688579
	Off-Peak Period	3.938829
	Primary >250 MWa	
	On-Peak Period	4.688579
	Off-Peak Period	3.938829
	Subtransmission 30-250 MWa	
	On-Peak Period	4.688579
	Off-Peak Period	3.938829
	Subtransmission >250 MWa	
	On-Peak Period	4.688579
	Off-Peak Period	3.938829
91		4.050082
92		4.371317
95		4.050082
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 76R and 576R, 485, 489, 490, 491, 492, 495, 496, 515, 532, 538, 549, 583, 585, 589, 591, 592, 595, 596, ~~and~~ 689 and 696, or served under Schedules 83, 85, 89 or 90 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 590, 591, 592, ~~and~~ 595, and 596 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE

Subject to the Earnings Test, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.

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)

DEFINITIONS (Continued)

Annual Variance (AV) - The Annual Variance (AV) is the dollar amount calculated annually based on the following formula:

(Actual Unit NVPC – Adjusted Base Unit NVPC) * (Actual Loads – RCE Loads)

Base Unit NVPC - The Base Unit NVPC is the NVPC used to develop rate schedules for the applicable year divided by the associated calendar basis retail loads. Base NVPC are updated annually in accordance with Schedule 125.

Adjusted Base Unit NVPC - The Adjusted Base Unit NVPC is the NVPC used to calculate the Annual Variance. The Adjusted Base Unit NVPC is the Base Unit NVPC (determined in accordance with Schedule 125) adjusted for load and cost changes resulting from non-residential customers choosing service under Schedule 515 through 5965 after the November update for the applicable year.

Negative Annual Power Cost Deadband
Negative Annual Power Cost Deadband is ($15.0 million).

Positive Annual Power Cost Deadband
The Positive Annual Power Cost Deadband is $30.0 million.

Net Variable Power Costs (NVPC) - The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Exclude 80 percent of power costs prudently incurred during RCEs.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the relevant period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.

SCHEDULE 126 (Continued)

DEFINITIONS (Continued)

- Include Energy Charge revenues from Schedules 76R, 38, 83, 85, 89, 90, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485, 489, 490, 491, 492, 495, and 689, and 696 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.
- Actual NVPC will be increased to include the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.
- Include reciprocating engine lubrication oil expenses.
- Include actual State and Federal Production Tax Credits.

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 1.0350 to account for franchise fees, uncollectibles, and OPUC fees.

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(2)
32/532	0.214 ¢ per kWh(2)
38/538	0.214 ¢ per kWh(2)
47	0.214 ¢ per kWh
49/549	0.214 ¢ per kWh(2)
75/575	
Secondary	0.214 ¢ per kWh(1)
Primary	0.214 ¢ per kWh(1)
Subtransmission	0.214 ¢ per kWh(1)
83/583	0.214 ¢ per kWh(2)
85/585	
Secondary	0.214 ¢ per kWh(2)
Primary	0.214 ¢ per kWh(2)
89/589	
Secondary	0.214 ¢ per kWh(2)
Primary	0.214 ¢ per kWh(2)
Subtransmission	0.214 ¢ per kWh(2)
90/590	
Primary	0.214 ¢ per kWh
Subtransmission	0.214 ¢ per kWh
91/591	0.214 ¢ per kWh(2)
92/592	0.214 ¢ per kWh(2)
95/595	0.214 ¢ per kWh(2)
96/596	0.214 ¢ per kWh(2)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 126 (Concluded)

POWER COST VARIANCE RATES (Continued)

Schedule	Adjustment Rate
485	
Secondary	0.214 ¢ per kWh(2)
Primary	0.214 ¢ per kWh(2)
489	
Secondary	0.214 ¢ per kWh(2)
Primary	0.214 ¢ per kWh(2)
Subtransmission	0.214 ¢ per kWh(2)
490	
Primary	0.214 ¢ per kWh
Subtransmission	0.214 ¢ per kWh
491	0.214 ¢ per kWh
492	0.214 ¢ per kWh
495	0.214 ¢ per kWh
496	0.214 ¢ per kWh
689	
Secondary	0.214 ¢ per kWh(2)
Primary	0.214 ¢ per kWh(2)
Subtransmission	0.214 ¢ per kWh(2)
696	0.214 ¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

TERM

Effective for service on and after January 17, 2007 and continuing until terminated by the Commission.

This schedule may only be terminated upon approval or order of the Commission. If this schedule is terminated for any reason, the Company will determine the remaining Adjustment Amount on a prorated basis consistent with the principles of this schedule. In such case, any balance in the PCV Account will be amortized to rates over a period to be determined by the Commission.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 85, 89, 90, 91, 95 or 965 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 590, 591, 592, 595 and 5965. This Schedule is not applicable to Customers served on Schedules 485, 489, 490, 491, 492, 495 and 4965.

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 (3)
32		1.671	
38		1.457	
75	Secondary	0.852 (2)	
	Primary	0.843 (2)	
	Subtransmission	0.729 (2)	
83		(1.325)	9.34
85	Secondary	(1.523)	10.80
	Primary	(1.456)	10.68

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday

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 (3)
89	Secondary	0.852	
	Primary	0.843	
	Subtransmission	0.729	
90 30-250 MWa	Primary	0.833	
90 >250 MWa	Primary	0.637	
91		0.362	
95		0.362	
96		0.843	
515		0.344	
532		1.671	
538		1.457	
549		3.353	
575	Secondary	0.852 (2)	
	Primary	0.843 (2)	
	Subtransmission	0.729 (2)	
583		(1.325)	9.34
585	Secondary	(1.523)	10.80
	Primary	(1.456)	10.68
589	Secondary	0.852	
	Primary	0.843	
	Subtransmission	0.729	
590 30-250 MWa	Primary	0.833	
590 >250 MWa	Primary	0.637	
591		0.362	
592		0.894	
595		0.362	
596		0.843	

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

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 (Concluded)

Second Quarter – April 1st Balance of Year Adjustment Rate(1)

Schedule		9-Month Part A ¢ per kWh(2)	9-Month Part B $ per KW of Peak Demand(4)
38		1.817	
75	Secondary	1.143(3)	
	Primary	1.130(3)	
	Subtransmission	1.063(3)	
83		(0.958)	9.34
85	Secondary	(1.158)	10.80
	Primary	(1.087)	10.68
89	Secondary	1.143	
	Primary	1.130	
	Subtransmission	1.063	
90 30-250 MWa	Primary	1.205	
90 >250 MWa	Primary	0.970	
91		0.782	
95		0.782	
96		1.130	
538		1.817	
575	Secondary	1.143(3)	
	Primary	1.130(3)	
	Subtransmission	1.063(3)	
583		(0.958)	9.34
585	Secondary	(1.158)	10.80
	Primary	(1.087)	10.68
589	Secondary	1.143	
	Primary	1.130	
	Subtransmission	1.063	
590 30-250 MWa	Primary	1.205	
590 >250 MWa	Primary	0.970	
591		0.782	
592		1.314	
595		0.782	
596		1.130	

(1) Applicable April 1, 2026 through December 31, 2026.
(2) Not applicable to Customers served on Cost of Service.
(3) Applicable only to the Baseline and Scheduled Maintenance Energy.
(4) Peak Demand hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.

SCHEDULE 129
LONG-TERM TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected service under Schedules 485, 489, 490, 491, 492, 495, and 4956.

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Periods A - R: 0.000 ¢ per kWh

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 (Continued)

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

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2025	(5.510)	(4.231)	(0.528)	(0.523)	(0.704)	(0.558)	(0.702)	(0.523)
2026	(5.510)	(4.231)	(0.528)	(0.523)	(0.704)	(0.558)	(0.702)	(0.523)
2027	(5.510)	(4.231)	(0.528)	(0.523)	(0.704)	(0.558)	(0.702)	(0.523)
2028	(5.510)	(4.231)	(0.528)	(0.523)	(0.704)	(0.558)	(0.702)	(0.523)
2029	(5.510)	(4.231)	(0.528)	(0.523)	(0.704)	(0.558)	(0.702)	(0.523)
After 2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

For Enrollment Period W (2024), 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	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ 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	0.000	0.000
2026	10.80	10.68	0.000	0.000	0.000	0.000	0.000	0.000
2027	10.80	10.68	0.000	0.000	0.000	0.000	0.000	0.000
2028	10.80	10.68	0.000	0.000	0.000	0.000	0.000	0.000
2029	10.80	10.68	0.000	0.000	0.000	0.000	0.000	0.000
After 2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

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	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. 30-250 Mwa Vol. ¢ per kWh	Sch. 490 Pri. >250 Mwa Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2026	(1.773)	(0.903)	0.425	0.420	0.434	(0.052)	(0.027)	(0.567)	0.420
2027	(1.773)	(0.903)	0.425	0.420	0.434	(0.052)	(0.027)	(0.567)	0.420
2028	(1.773)	(0.903)	0.425	0.420	0.434	(0.052)	(0.027)	(0.567)	0.420
2029	(1.773)	(0.903)	0.425	0.420	0.434	(0.052)	(0.027)	(0.567)	0.420
2030	(1.773)	(0.903)	0.425	0.420	0.434	(0.052)	(0.027)	(0.567)	0.420
After 2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

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	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. 30-250 Mwa Vol. $ per kW of Peak Demand	Sch. 490 Pri. >250 Mwa Vol. ¢ per kWh	Schs. 491/492/495 $ 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	0.000	0.000	0.000
2027	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2028	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2029	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2030	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000
After 2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three 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	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2024	(5.205)	(5.134)	(2.870)	(2.840)	(2.905)	(3.116)	(2.398)
2025	(4.724)	(4.696)	(2.351)	(2.327)	(2.336)	(2.615)	(1.978)
2026	(4.532)	(4.508)	(2.147)	(2.125)	(2.094)	(2.442)	(2.094)

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

Period	Sch. 485 Sec. Vol. $ per 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	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ per kW of Peak Demand
2024	9.32	9.22	0.000	0.000	0.000	0.000	0.000
2025	9.32	9.22	0.000	0.000	0.000	0.000	0.000
2026	9.32	9.22	0.000	0.000	0.000	0.000	0.000

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

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2025	(1.729)	(1.701)	0.652	0.643	0.638	(0.275)	0.107	0.643
2026	(2.842)	(2.775)	(0.436)	(0.432)	(0.363)	(1.299)	(1.012)	(0.432)
2027	(3.229)	(3.153)	(0.827)	(0.820)	(0.686)	(1.659)	(1.471)	(0.820)

SCHEDULE 129 (Continued)

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

For Enrollment Period W (2024), 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	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. Vol. $ per kW of Peak Demand	Schs. 491/492/495 $ 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	0.000	0.000
2026	10.62	10.50	0.000	0.000	0.000	0.000	0.000	0.000
2027	10.62	10.50	0.000	0.000	0.000	0.000	0.000	0.000

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	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. 30-250 Mwa Vol. ¢ per kWh	Sch. 490 Pri. >250 Mwa Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	Sch. 496 Pri. Vol. ¢ per kWh
2026	(6.041)	(6.054)	(3.282)	(3.247)	(3.201)	(3.536)	(3.787)	(3.840)	(3.247)
2027	(7.470)	(7.153)	(4.537)	(4.487)	(4.521)	(4.764)	(4.853)	(4.912)	(4.487)
2028	(7.563)	(7.262)	(4.629)	(4.579)	(4.593)	(4.878)	(4.982)	(5.041)	(4.579)

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	Sch. 489 Sub. Vol. $ per kW of Peak Demand	Sch. 490 Pri. 30-250 Mwa Vol. $ per kW of Peak Demand	Sch. 490 Pri. >250 Mwa Vol. ¢ per kWh	Schs. 491/492/495 $ 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	0.000	0.000	0.000
2027	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2028	$10.80	$10.68	0.000	0.000	0.000	0.000	0.000	0.000	0.000

SCHEDULE 129 (Continuedcluded)

SPECIAL CONDITIONS

1. Annually, the total amount paid in Schedule 129 Long-Term Transition Cost Adjustments associated with Enrollment Periods A through K will be collected through applicable Large Nonresidential rate schedules (Schedules 75, 85, 89, 90, 485, 489, 490, 575, 585, 589 and 590), through either the System Usage or Distribution Charges. Commencing with Enrollment Period L, the Schedule 129 amounts paid or received will be collected from all rate schedules, through either System Usage Charges or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedules 485, 489, 490, 491, 492, 495, and 4956 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.

3. In determining changes in fixed generation revenues from movement to or from Schedules 485, 489, 490, 491, 492, 495, and 4965, the following factors will be used:

Schedule		¢ per kWh
85	Secondary	2.896
	Primary	2.866
89	Secondary	2.731
	Primary	2.701
	Subtransmission	2.672
90		2.683
91		2.478
92		2.478
95		2.478
96		2.701

~~**TERM**~~

~~The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 485, 489, 490, 491, 492 or 495.~~

Angelica Espinosa, Senior Vice President **on and after June 10, 2026**

SCHEDULE 129 (Concluded)

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 485, 489, 490, 491, 492, 495 or 4965.

SCHEDULE 135
DEMAND RESPONSE COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with demand response pilots not otherwise included in rates. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 496, 576R, 689, and 6899896.

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
75/575		
Secondary	0.068	¢ per kWh(1)
Primary	0.067	¢ per kWh(1)
Subtransmission	0.066	¢ per kWh(1)
83/583	0.072	¢ per kWh
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
Subtransmission	0.066	¢ per kWh
90/590		
Primary 30-250 MWa	0.065	¢ per kWh
Primary >250 MWa	0.061	¢ per kWh
Subtransmission	0.065	¢ per kWh
91/591	0.061	¢ per kWh
92/592	0.066	¢ per kWh
95/595	0.061	¢ per kWh
96/596	0.066	¢ per kWh

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with automated demand response and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the implementation and administration of demand response pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of demand response pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

SPECIAL CONDITION

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

SCHEDULE 136 (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
Subtransmission	0.019	¢ per kWh
90/490/590		
Primary 30-250 Mwa	0.016	¢ per kWh
Primary >250 Mwa	0.016	¢ per kWh
Subtransmission	0.016	¢ per kWh
91/491/591	0.031	¢ per kWh
92/492/592	0.021	¢ per kWh
95/495/595	0.031	¢ per kWh
96/496/596/696	0.018	¢ per kWh

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between incremental costs associated with the Oregon CSP and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the Oregon CSP.

SPECIAL 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 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate	
89/489/589		
Secondary	0.011	¢ per kWh
Primary	0.011	¢ per kWh
Subtransmission	0.010	¢ per kWh
90/490/590		
Primary	0.010	¢ per kWh
Subtransmission	0.010	¢ per kWh
91/491/591	0.018	¢ per kWh
92/492/592	0.012	¢ per kWh
95/495/595	0.018	¢ per kWh
96/496/596/696	0.011	¢ per kWh
689		
Secondary	0.011	¢ per kWh
Primary	0.011	¢ per kWh
Subtransmission	0.010	¢ per kWh

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 76R, 485, 489, 490, 491, 492, 495, 496, and 576R, and 689, and 696.

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
75/575			
	Secondary	0.002	¢ per kWh
	Primary	0.002	¢ per kWh
	Subtransmission	0.002	¢ per kWh
83/583		0.003	¢ per kWh
85/585			
	Secondary	0.002	¢ per kWh
	Primary	0.002	¢ per kWh

SCHEDULE 138 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate
89/589	
Secondary	0.002 ¢ per kWh
Primary	0.002 ¢ per kWh
Subtransmission	0.002 ¢ per kWh
90/590	
Primary 30-250 Mwa	0.002 ¢ per kWh
Primary >250 Mwa	0.002 ¢ per kWh
Subtransmission	0.002 ¢ per kWh
91/591	0.002 ¢ per kWh
92/592	0.002 ¢ per kWh
95/595	0.002 ¢ per kWh
96/596	0.002 ¢ per kWh

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with energy storage pilots and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request to defer the incremental costs associated with the implementation and administration of the energy storage pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of energy storage pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

SPECIAL CONDITION

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

SCHEDULE 139
NEW LARGE LOAD TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected New Large Load Cost-of-Service Opt-Out service under Schedule 689 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:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2021	0.702	0.689	0.680	0.689
2022	0.587	0.580	0.576	0.580
2023	0.655	0.648	0.645	0.648
2024	0.609	0.602	0.598	0.602
2025	0.635	0.628	0.623	0.628
2026*	0.761	0.753	0.747	0.753
After 2027	0.000	0.000	0.000	0.000

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

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2022	0.587	0.580	0.576	0.580
2023	0.655	0.648	0.645	0.648
2024	0.609	0.602	0.598	0.602
2025	0.635	0.628	0.623	0.628
2026	0.761	0.753	0.747	0.753
2027*	0.761	0.753	0.747	0.753
After 2028	0.000	0.000	0.000	0.000

*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:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2023	0.655	0.648	0.645	0.648
2024	0.609	0.602	0.598	0.602
2025	0.635	0.628	0.623	0.628
2026	0.761	0.753	0.747	0.753
2027	0.761	0.753	0.747	0.753
2028*	0.761	0.753	0.747	0.753
After 2029	0.000	0.000	0.000	0.000

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

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2024	0.609	0.602	0.598	0.602
2025	0.635	0.628	0.623	0.628
2026	0.761	0.753	0.747	0.753
2027	0.761	0.753	0.747	0.753
2028	0.761	0.753	0.747	0.753
2029*	0.761	0.753	0.747	0.753
After 2030	0.000	0.000	0.000	0.000

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

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2025	0.635	0.628	0.623	0.628
2026	0.761	0.753	0.747	0.753
2027	0.761	0.753	0.747	0.753
2028	0.761	0.753	0.747	0.753
2029	0.761	0.753	0.747	0.753
2030*	0.761	0.753	0.747	0.753
After 2031	0.000	0.000	0.000	0.000

*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:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	Sch. 696 Primary Voltage ¢ per kWh
2026	0.761	0.753	0.747	0.753
2027	0.761	0.753	0.747	0.753
2028	0.761	0.753	0.747	0.753
2029	0.761	0.753	0.747	0.753
2030	0.761	0.753	0.747	0.753
2031*	0.761	0.753	0.747	0.753
After 2032	0.000	0.000	0.000	0.000

*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 146
COLSTRIP POWER PLANT
OPERATING LIFE ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the Company's share of the full revenue requirement for the Colstrip Power Plant Units 3 and 4 and associated common facilities. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 496, 576R, and 689, and 696.

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
75/575	
Secondary	0.175 ¢ per kWh
Primary	0.173 ¢ per kWh
Subtransmission	0.171 ¢ 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
Subtransmission	0.171 ¢ per kWh
90/590 30-250 Mwa	
Primary	0.170 ¢ per kWh
Subtransmission	0.170 ¢ per kWh
90/590 90 >250 Mwa	
Primary	0.166 ¢ per kWh
Subtransmission	0.166 ¢ per kWh

SCHEDULE 146 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate
91/591	0.159 ¢ per kWh
92/592	0.171 ¢ per kWh
95/595	0.159 ¢ per kWh
96/596	0.171 ¢ per kWh

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 150 (Continued)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
90/490/590		
Primary 30-250 Mwa	0.018	¢ per kWh
Primary >250 Mwa	0.017	¢ per kWh
Subtransmission	0.018	¢ per kWh
91/491/591	0.021	¢ per kWh
92/492/592	0.021	¢ per kWh
95/495/595	0.021	¢ per kWh
96/496/596/696	0.020	¢ per kWh

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 (Concluded)

ADJUSTMENT RATES (Continued)

89/489/589/689		
Secondary	0.090	¢ per kWh
Primary	0.065	¢ per kWh
Subtransmission	0.059	¢ per kWh
90/490/590		
Primary	0.075	¢ per kWh
Subtransmission	0.075	¢ per kWh
91/491/591	0.477	¢ per kWh
92/492/592	0.159	¢ per kWh
95/495/595	0.477	¢ per kWh
96/496/596/696	0.070	¢ per kWh

ANNUAL REVENUE REQUIREMENTS

The Annual Revenue Requirements will include all reasonable operating costs plus investment and associated capital-related costs to develop, implement and/or operate a wildfire mitigation plan under ORS 757.963.

BALANCING ACCOUNT

The Company will maintain a balancing account to track the difference between the actual incremental Schedule 151 revenue requirement and Schedule 151 revenues. The balancing account will accrue interest at the Commission-authorized rate.

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of non-generation revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule. The fixed revenue for all lighting schedules is removed from the non-generation revenue and is not used as the basis for the allocation.

2. The costs for projects included under this schedule will be updated annually and will continue to be recovered under Schedule 151 until such time as the costs are included in base rates.

SCHEDULE 152 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate	
89/489/589/689		
Secondary	0.058	¢ per kWh
Primary	0.038	¢ per kWh
Subtransmission	0.037	¢ per kWh
90/490/590		
Primary	0.042	¢ per kWh
Subtransmission	0.042	¢ per kWh
91/491/591	0.283	¢ per kWh
92/492/592	0.093	¢ per kWh
95/495/595	0.283	¢ per kWh
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 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate	
89/489/589		
Secondary	0.001	¢ per kWh
Primary	0.001	¢ per kWh
Subtransmission	0.001	¢ per kWh
90/490/590		
Primary	0.001	¢ per kWh
Subtransmission	0.001	¢ per kWh
91/491/591	0.001	¢ per kWh
92/492/592	0.001	¢ per kWh
95/495/595	0.001	¢ per kWh
96/496/596/696	0.001	¢ per kWh
689		
Secondary	0.001	¢ per kWh
Primary	0.001	¢ per kWh
Subtransmission	0.001	¢ per kWh

BALANCING ACCOUNT

The Company will maintain a balancing account to accrue differences between the incremental costs associated with the Community Benefits and Impact Advisory Group and the revenues collected under this schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

DEFERRAL MECHANISM

Each year the Company may file a deferral request. The deferral will be amortized over one year in this schedule unless otherwise directed by the Oregon Public Utility Commission.

SCHEDULE 485
LARGE NONRESIDENTIAL
COST OF SERVICE OPT-OUT
(201 - 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

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

	Delivery Voltage	
	Secondary	Primary
Basic Charge	$730.00800.00	$610.00680.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$4.063.37	$4.013.33
Over 200 kW	$3.963.27	$3.9123
per kW of monthly Peak Demand****	$1.683	$1.6661
System Usage Charge		
per kWh	0.060 065 ¢	0.060 065 ¢

* 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 489
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW more than once within the preceding 13 months and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

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

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$3,630~~450~~.00	$3,590~~410~~.00	$4,770~~5,020~~.00
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.43~~70~~	$1.42~~68~~	$1.41~~66~~
Over 4,000 kW	$1.12~~39~~	$1.11~~37~~	$1.10~~35~~
per kW of monthly Peak Demand****	$1.68~~3~~	$1.66~~1~~	$0.~~13~~27
System Usage Charge			
per kWh	0.~~100~~ 178~~84~~ ¢	0.~~099~~ 177 ¢	0.~~098~~ 176 ¢

* 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 489 (Continued)

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

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

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:

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

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:~~

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

SCHEDULE 489 (Continued)

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:
~~SPECIAL CONDITIONS (Continued)~~

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.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

~~8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.~~

~~9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.~~

SCHEDULE 489 (Concluded)

SPECIAL CONDITIONS (Continued)

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

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

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers 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 490
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window*** enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to this and Schedules 485, 489, 490, 491, 492, and 495. Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges per SP*:

	Delivery Voltage	
	Primary	Subtransmission
Basic Charge	$11,370~~0~~0.00	$11,~~7~~300.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$2.37~~1.91~~	$2.37~~1.91~~
Over 4,000 kW	$2.06~~1.60~~	$2.06~~1.60~~
per kW of monthly Peak Demand****	$1.66~~1~~	$0.27~~13~~
System Usage Charge		
per kWh	0.~~006~~021 ¢	0.~~006~~021¢

* 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 490 (Continued)

TRANSMISSION MINIMUMS

If a customer subject to a Large Load Customer Agreement (LLCA) transitions from Schedule 90 to Schedule 490 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 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:

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

REACTIVE DEMAND CHARGE

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

ADJUSTMENTS

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

~~SPECIAL CONDITIONS~~

~~Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:~~

~~1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.~~

~~2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.~~

SCHEDULE 490 (ContinuedConcluded)

SPECIAL CONDITIONS (Continued)

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

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

SCHEDULE 490 (Concluded)

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than three years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 491
STREET AND HIGHWAY LIGHTING
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments with no fewer than 30,000 lights purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, 495, and 4965.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

Includes preventative group lamp replacement and glassware cleaning subject to the Company's operating schedule.

Emergency Lamp Replacement and Luminaire Repair

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following actual knowledge of an inoperable luminaire. "Actual knowledge" for these purposes requires notification to PGE's Customer Service or PGE's Outdoor Lighting Services (1) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE's Outdoor Lighting Services at 503-612-4685or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 491 (Continued)

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

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.184 ¢ per kWh	( )

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's Service Points (SPs) under this schedule.

SCHEDULE 491 (Continued)

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	*	$3.99	$3.09
	400	50,000	163	*	*	11.71
Cobrahead, Non-Power Door	70	6,300	30	$8.27	3.32	2.16
	100	9,500	43	8.39	4.17	3.09
	150	16,000	62	*	5.54	4.45
	200	22,000	79	11.57	6.82	5.68
	250	29,000	102	12.87	8.46	7.33
	400	50,000	163	17.37	12.83	11.71
Flood	250	29,000	102	14.81	8.65	7.33
	400	50,000	163	19.09	13.00	11.71
Early American Post-Top Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	100	9,500	43	9.89	4.33	3.09
	70	6,300	30	8.07	3.31	2.16
	100	9,500	43	*	4.30	3.09
	150	16,000	62	*	5.71	4.45

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

SCHEDULE 491 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Fiberglass, Black, Bronze or Gray	20	$5.61	$0.19
Fiberglass, Black or Bronze	30	9.13	0.31
Fiberglass, Gray	30	9.13	0.31
Fiberglass, Smooth, Black or Bronze	18	6.01	0.20
Fiberglass, Regular	18	5.06	0.17
Black, Bronze, or Gray	35	8.85	0.30
Aluminum, Regular with Breakaway Base	25	16.33	0.55
	30	16.66	0.56
	35	18.02	0.60
Aluminum, Smooth, Black, Pendant	23	18.39	0.61
Wood, Standard	30 to 35	6.82	0.23
Wood, Standard	40 to 55	7.98	0.27

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C
Special Acorn-Types						
HPS	100	9,500	43	$14.22	$4.77	$3.09
HADCO Victorian, HPS	150	16,000	62	*	6.14	4.45
	200	22,000	79	*	7.22	5.68
	250	29,000	102	16.86	8.87	7.33
HADCO Capitol Acorn, HPS	100	9,500	43	16.81	5.04	3.09
	150	16,000	62	*	6.32	4.45
	200	22,000	79	*	7.66	*
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	*	4.72	3.09
	150	16,000	62	*	*	4.45
HADCO Techtra, HPS	100	9,500	43	*	5.44	*
HADCO Techtra, HPS	150	16,000	62	23.14	6.88	4.45
	250	29,000	102	*	9.70	*
HADCO Westbrooke, HPS	70	6,300	30	14.36	3.93	*
	100	9,500	43	15.19	4.85	3.09

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
HADCO Westbrooke, HPS	150	16,000	62	*	$6.40	*
	200	22,000	79	*	6.67	*
	250	29,000	102	$19.01	9.07	*
Special Types				*	*	*
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	$4.60
Ornamental Acorn	55	2,800	21	*	*	1.51
Ornamental Acorn Twin	55	5,600	42	*	*	3.02
Composite, Twin	140	6,815	54	*	*	3.88
	175	9,815	66	*	*	4.74

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Regular	25	$9.63	$0.32
	30	11.00	0.37
	35	12.68	0.42
Aluminum Davit	25	10.25	0.34
	30	11.50	0.38
	35	13.10	0.44
	40	16.80	0.56
Aluminum Double Davit	30	12.72	0.43
Aluminum, Fluted Ornamental	14	9.01	0.30

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

SCHEDULE 491 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Smooth Techtra Ornamental	18	$19.18	$0.64
Aluminum, Fluted Ornamental	16	9.34	0.31
Aluminum, Double-Arm, Smooth Ornamental	25	15.18	0.51
Aluminum, Fluted Westbrooke	18	18.06	0.60
Aluminum, Non-Fluted Ornamental, Pendant	18	17.95	0.60
Fiberglass, Fluted Ornamental Black	14	11.88	0.40
Fiberglass, Anchor Base, Gray or Black	35	11.97	0.40
Fiberglass, Anchor Base (Color may vary)	25	10.74	0.36
	30	13.05	0.44

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Cobrahead, Metal Halide	150	10,000	60	*	*	$4.31
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.80
	175	7,000	66	$10.03	$5.81	4.74
	250	10,000	94	*	*	6.75
	400	21,000	147	16.42	11.67	10.56
	1,000	55,000	374	32.61	28.07	26.87
Holophane Mongoose, HPS	150	16,000	62	*	6.12	*
	250	29,000	102	*	9.13	*

* Not offered.

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	$8.60	*	*
Mercury Vapor	175	7,000	66	*	$5.89	$4.74
Special box, Anodized Aluminum						
Similar to GardCo Hub						
HPS	70	6,300	30	*	*	2.16
				*	*	*
	150	16,000	62	*	*	4.45
	250	29,000	102	*	*	7.33
Metal Halide	250	20,500	99	*	8.06	7.11
	400	40,000	156	*	12.16	*
Cobrahead, Metal Halide	175	12,000	71	*	*	5.10
Flood, Metal Halide	400	40,000	156	17.44	*	11.21
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	5.39	4.45
KIM Archetype, HPS	250	29,000	102	*	9.15	7.33
	400	50,000	163	*	13.88	11.71

* Not offered

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Special Acorn-Type, HPS	70	6,300	30	$13.08	$3.63	*
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	2.16
Mercury Vapor	175	7,000	66	*	*	4.74
Early American Post-Top, HPS						
Black	70	6,300	30	8.78	3.22	2.16
Rectangle Type	200	22,000	79	*	*	5.68
Incandescent	92	1,000	31	*	*	2.23
	182	2,500	62	*	*	4.45
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	*	5.84	4.74
Flood, HPS				*	*	*
	100	9,500	43	8.27	4.17	*
	200	22,000	79	13.00	6.84	5.68
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	3.09
Twin ornamental, HPS	Twin 100	9,500	86	*	*	6.18
Compact Fluorescent	28	N/A	12	*	*	0.86

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B
Aluminum Post	30	$5.15	*
Aluminum, Painted Ornamental	35	*	$0.44
Aluminum, Regular	16	5.20	0.17
Concrete, Ornamental	35 or less	9.52	0.32
Fiberglass, Direct Bury with Shroud	18	7.67	0.26
Steel, Painted Regular **	25	9.52	0.32
Steel, Painted Regular **	30	10.85	*
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36
Steel, Unpainted 8-foot Mast Arm **	35	*	0.44
Wood, Laminated without Mast Arm	20	*	0.19
Wood, Curved Laminated	30	*	0.26
Wood, Painted Underground	35	6.75	0.23

* 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	*	*	$2.30
	165	12,000	60	*	*	4.31
	165	12,000	60	*	$5.38	$4.31

SCHEDULE 492
TRAFFIC SIGNALS
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 500 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, 495, and 4965

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	1.859960 ¢ per kWh	( )

* 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 495
STREET AND HIGHWAY LIGHTING
NEW TECHNOLOGY
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments with no fewer than 30,000 lights purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, 495, and 4965.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control to be mutually agreeable to the Customer and Company for an average of 4,100 hours annually.

LUMINAIRE SERVICE OPTIONS - The Company offers the following Luminaire Service Options at the applicable rates specified herein.

The Customer will elect the Luminaire Service Option at the time of initial luminaire installation.

Option A - Luminaire

Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

Maintenance Service under Option A

The Company will only perform emergency maintenance on the luminaires listed in this schedule. The Company does not perform preventative maintenance on the luminaires listed in this schedule.

The Company will repair or replace inoperable luminaires as soon as reasonably possible, subject to the Company's operating schedule, following notification to PGE's Customer Service or PGE's Outdoor Lighting Services(1) department by the Customer, a member of the public, or a PGE employee performing luminaire replacement work. PGE has no obligation for repair or replacement of inoperable luminaires other than as described in this section of the tariff.

(1) Contact PGE's Outdoor Lighting Services at 503-612-4685 or www.portlandgeneral.com to report an inoperable streetlight.

SCHEDULE 495 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/491/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A and Option B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.184 ¢ per kWh

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's Service Points (SPs) under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

SCHEDULE 495 (Continued)

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

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

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Roadway LED	>20-25	3,000	8	$5.87	$0.96
	>25-30	3,470	9	5.95	1.04
	>30-35	2,530	11	6.36	1.18
	>35-40	4,245	13	6.23	1.32
	>40-45	5,020	15	6.55	1.47
	>45-50	3,162	16	6.61	1.54
	>50-55	3,757	18	7.03	1.68
	>55-60	4,845	20	6.91	1.83
	>60-65	4,700	21	6.98	1.90
	>65-70	5,050	23	7.86	2.05
	>70-75	7,640	25	8.04	2.20
	>75-80	8,935	26	8.11	2.27
	>80-85	9,582	28	8.25	2.41
	>85-90	10,230	30	8.40	2.56
	>90-95	9,928	32	8.54	2.70
	>95-100	11,719	33	8.61	2.77
	>100-110	7,444	36	8.64	2.99
	>110-120	12,340	39	9.04	3.20
	>120-130	13,270	43	9.33	3.49
	>130-140	14,200	46	9.93	3.71
	>140-150	15,250	50	12.18	4.04
	>150-160	16,300	53	12.40	4.26
	>160-170	17,300	56	12.61	4.47
	>170-180	18,300	60	12.56	4.75
	>180-190	19,850	63	13.12	4.98
	>190-200	21,400	67	12.57	5.24
	>200-210	27,033	70	12.86	5.46
	>210-220	28,535	74	13.93	5.77
	>220-230	30,017	77	14.14	5.98
	>230-240	30,800	81	14.43	6.27
	>240-250	31,507	84	15.14	6.49

SCHEDULE 495 (Continued)

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

Type of Light	Watts*	Monthly kWh**
LED	>170 - 180	60
LED	>180 - 190	63
LED	>190 - 200	67
LED	>200 - 210	70
LED	>210 - 220	73
LED	>220 - 230	77
LED	>230 - 240	80
LED	>240 - 250	84
LED	>250 - 260	87
LED	>260 - 270	91
LED	>270 - 280	94
LED	>280 - 290	97
LED	>290 - 300	101

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

RATES FOR DECORATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Acorn LED	>35-40	3,262	13	$14.52	$1.46
	>40-45	3,500	15	14.67	1.61
	>45-50	5,488	16	12.16	1.64
	>50-55	4,000	18	14.88	1.82
	>55-60	4,213	20	15.03	1.97
	>60-65	4,273	21	15.10	2.04
	>65-70	4,332	23	14.88	2.18
	>70-75	4,897	25	15.39	2.33
	>90-75	8,100	32	15.93	2.87

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING
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
Acorn					
HADCO LED	70	5,120	24	$18.87	$2.32
Pendant LED (Non-Flared)	36	3,369	12	15.05	1.40
	53	5,079	18	16.61	1.85
	69	6,661	24	16.81	2.28
	85	8,153	29	17.73	2.65
Pendant LED (Flared)	>35-40	3,369	13	14.55	1.46
	>40-45	3,797	15	15.54	1.63
	>45-50	4,438	16	15.61	1.70
	>50-55	5,079	18	18.50	1.89
	>55-60	5,475	20	15.06	1.97
	>60-65	6,068	21	18.72	2.11
	>65-70	6,661	23	17.98	2.23
	>70-75	7,034	25	15.42	2.33
	>75-80	7,594	26	18.42	2.46
	>80-85	8,153	28	18.56	2.60
Post-Top, American Revolution LED	>30-35	3,395	11	7.86	1.21
	>45-50	4,409	16	8.22	1.57
Flood LED	>75-80	12,716	26	9.22	2.29
	>80-85	10,530	28	9.36	2.43
	>110-120	18,265	38	10.62	3.16
	>120-130	16,932	43	10.98	3.52
	>160-170	26,349	56	13.11	4.47
	>180-190	23,797	63	13.62	4.98
	>290-300	46,950	116	21.83	8.89
	>320-330	46,802	112	21.55	8.61
	>330-340	48,692	116	21.83	8.89
	>340-350	50,145	119	22.05	9.11
	>350-360	51,598	123	22.34	9.40
	>370-380	48,020	127	22.62	9.68

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 — 7.151 ¢ per kWh

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire
Cobrahead				
Mercury Vapor	175	7,000	66	$9.85(2)
	400	21,000	147	16.29(2)
	1,000	55,000	374	32.40(2)
HPS	70	6,300	30	8.18(2)
	100	9,500	43	8.29
	150	16,000	62	9.73
	200	22,000	79	11.46
	250	29,000	102	12.75
	310	37,000	124	14.44(2)
	400	50,000	163	17.24

(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	$8.17[2]
	200	22,000	79	12.89[2]
	250	29,000	102	14.69
	400	50,000	163	18.96
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	7.98
	100	9,500	43	9.49
	150	16,500	62	11.31
Special Acorn Type, HPS	100	9,500	43	14.12
HADCO Victorian, HPS	150	16,500	62	15.50
Early American Post-Top, HPS, Black	100	9,500	43	9.79
Special Types				
Cobrahead, Metal Halide	150	10,000	60	11.91
Cobrahead, Metal Halide	175	12,000	71	10.98
Flood, Metal Halide	350	30,000	139	18.44
Flood, Metal Halide	400	40,000	156	17.31
Flood, HPS	750	105,000	285	31.04
HADCO Independence, HPS	100	9,500	43	13.78
HADCO Techtra, HPS	100	9,500	43	20.85
	150	16,000	62	23.04

(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	$14.44
	>40-45	3,500	15	14.58
	>45-50	5,488	16	12.07
	>50-55	4,000	18	14.80
	>55-60	4,213	20	14.94
	>60-65	4,273	21	15.01
	>65-70	4,332	23	14.79
	>70-75	4,897	25	15.30
	>91-100	8,100	32	15.84
HADCO LED	70	5,120	24	18.79
Roadway LED	>20-25	3,000	8	5.79
	>25-30	3,470	9	5.86
	>30-35	2,530	11	6.28
	>35-40	4,245	13	6.15
	>40-45	5,020	15	6.46
	>45-50	3,162	16	6.52
	>50-55	3,757	18	6.95
	>55-60	4,845	20	6.82
	>60-65	4,700	21	6.89
	>65-70	5,050	23	7.77
	>70-75	7,640	25	7.95
	>75-80	8,935	26	8.02
	>80-85	9,582	28	8.16
	>85-90	10,230	30	8.31
	>90-95	9,928	32	8.45
	>95-100	11,719	33	8.52
	>100-110	7,444	36	8.54
	>110-120	12,340	39	8.95
	>120-130	13,270	43	9.23
	>130-140	14,200	46	9.84
	>140-150	15,250	50	12.09

(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	$12.30
	>160-170	17,300	56	12.51
	>170-180	18,300	60	12.46
	>180-190	19,850	63	13.02
	>190-200	21,400	67	12.47
	>200-210	27,033	70	12.76
	>210-220	28,535	74	13.82
	>220-230	30,017	77	14.04
	>230-240	30,800	81	14.32 ~~13.59~~
	>240-250	31,507	84	15.04
Pendant LED (Non-Flare)	36	3,369	12	14.97
	53	5,079	18	16.53
	69	6,661	24	16.73
	85	8,153	29	17.64
Pendant LED (Flare)	>35-40	3,369	13	14.47
	>40-45	3,797	15	15.45
	>45-50	4,438	16	15.52
	>50-55	5,079	18	18.42
	>55-60	5,475	20	14.97
	>60-65	6,068	21	18.63
	>65-70	6,661	23	17.89
	>70-75	7,034	25	15.33
	>75-80	7,594	26	18.33
	>80-85	8,153	28	18.47
CREE XSP LED	>20-25	2,529	8	5.95
	>30-35	4,025	11	6.17
	>40-45	3,819	15	6.45
	>45-50	4,373	16	6.58
	>55-60	5,863	20	6.87
	>65-70	9,175	23	7.63
	>90-95	8,747	32	8.28
	130-140	18,700	46	10.77

(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	$7.78
	>45-50	4,409	16	8.13
Flood LED	>75-80	12,716	26	9.13
	>80-85	10,530	28	9.27
	111-120	18,265	38	10.53
	121-130	16,932	43	10.88
	161-170	26,349	56	13.01
	181-190	23,797	63	13.52
	291-300	46,950	116	21.72
	321-330	46,802	112	21.43
	331-340	48,692	116	21.72
	341-350	50,145	119	21.93
	351-360	51,598	123	22.22
	370-380	48,020	127	22.50

Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$6.54
	40 to 55	7.71
Wood, Painted Underground	35 or less	6.48[3]
Wood, Curved laminated	30 or less	7.62[3]
Aluminum, Regular	16	5.00
	25	9.29
	30	10.66
	35	12.34
Aluminum, Fluted Ornamental	14	8.80
Aluminum, Fluted Ornamental	16	9.14
Aluminum Davit	25	9.91
	30	11.16
	35	12.76
	40	16.38
Aluminum Double Davit	30	12.38
Aluminum, Smooth Techtra Ornamental	18	18.84

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

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	$24.00
Three Phase	$33.00
Distribution Charge	
First 5,000 kWh	6.701 ¢ per kWh
Over 5,000 kWh	3.167 ¢ per kWh

* 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	$50.00	
Three Phase Service	$60.00	
Distribution Charge	8.742	¢ per kWh

* 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**	$60.00
Winter Months**	No Charge
Distribution Charge	
First 50 kWh per kW of Demand	12.815¢ per kWh
Over 50 kWh per kW of Demand	10.760 ¢ per kWh

* 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 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

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

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge			
Three Phase Service	$3,630.00	$3,590.00	$4,770.00
Distribution Charge			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.43	$1.42	$1.41
Over 4,000 kW	$1.12	$1.11	$1.10
per kW of monthly Peak Demand**	$1.68	$1.66	$0.27
Generation Contingency Reserves Charges***			
Spinning Reserves			
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves			
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
System Usage Charge			
per kWh	0.178¢	0.177 ¢	0.176 ¢

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday.
*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

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	$50.00
Three Phase Service	$60.00
Distribution Charges**	
The sum of the following:	
per kW of Facility Capacity	
First 30 kW	$6.12
Over 30 kW	$6.02
per kW of monthly Peak Demand***	$1.68
System Usage Charge	
per kWh	0.802 ¢

* 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
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	$730.00	$610.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 200 kW	$4.06	$4.01
Over 200 kW	$3.96	$3.91
per kW of monthly Peak Demand***	$1.68	$1.66
System Usage Charge		
per kWh	0.065 ¢	0.065 ¢

* 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 590
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW and Aggregate to >30 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 30 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

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

	Delivery Voltage	
	Primary	Subtransmission
Basic Charge	$11,300.00	$11,300.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$2.37	$2.37
Over 4,000 kW	$2.06	$2.06
per kW of monthly Peak Demand***	$1.66	$0.27
System Usage Charge		
per kWh	0.021 ¢	0.021 ¢

* 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 590 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (ESS) for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

TRANSMISSION MINIMUMS

If a customer subject to a Large Load Customer Agreement (LLCA) transitions from Schedule 90 to Schedule 590 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 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.

~~**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~~

SCHEDULE 590 (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 either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

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

SCHEDULE 591 (Continued)

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

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.184 ¢ per kWh
Energy Charge	Provided by Electricity Service Supplier

NOVEMBER ELECTION WINDOW

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

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, https://portlandgeneral.com

SCHEDULE 591 (Continued)

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	*	$3.99	$3.09
	400	50,000	163	*	*	11.71
Cobrahead, Non-Power Door	70	6,300	30	$8.27	3.32	2.16
	100	9,500	43	8.39	4.17	3.09
	150	16,000	62	**	5.54	4.45
	200	22,000	79	11.57	6.82	5.68
	250	29,000	102	12.87	8.46	7.33
	400	50,000	163	17.37	12.83	11.71
Flood	250	29,000	102	14.81	8.65	7.33
	400	50,000	163	19.09	13.00	11.71
Early American Post-Top	100	9,500	43	9.89	4.33	3.09
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	8.07	3.31	2.16
	100	9,500	43	*	4.30	3.09
	150	16,000	62	*	5.71	4.45

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

SCHEDULE 591 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Fiberglass, Black, Bronze or Gray	20	$5.61	$0.19
Fiberglass, Black or Bronze	30	9.13	0.31
Fiberglass, Gray	30	9.13	0.31
Fiberglass, Smooth, Black or Bronze	18	6.01	0.20
Fiberglass, Regular	18	5.06	0.17
Black, Bronze, or Gray	35	8.85	0.30
Aluminum, Regular with Breakaway Base	25	16.33	0.55
	30	16.66	0.56
	35	18.02	0.60
Aluminum, Smooth, Black, Pendant	23	18.39	0.61
Wood, Standard	30 to 35	6.82	0.23
Wood, Standard	40 to 55	7.98	0.27

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C
Special Acorn-Types						
HPS	100	9,500	43	$14.22	$4.77	$3.09
HADCO Victorian, HPS	150	16,000	62	*	6.14	4.45
	200	22,000	79	*	7.22	5.68
	250	29,000	102	16.86	8.87	7.33
HADCO Capitol Acorn, HPS	100	9,500	43	16.81	5.04	3.09
	150	16,000	62	*	6.32	4.45
	200	22,000	79	*	7.66	*
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	*	4.72	3.09
	150	16,000	62	*	*	4.45
HADCO Techtra, HPS	100	9,500	43	*	5.44	*
	150	16,000	62	23.14	6.88	4.45
	250	29,000	102	*	9.70	*
HADCO Westbrooke, HPS	70	6,300	30	14.36	3.93	*
	100	9,500	43	15.19	4.85	3.09

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
HADCO Westbrooke, HPS	150	16,000	62	*	$6.40	*
	200	22,000	79	*	6.67	*
	250	29,000	102	$19.01	9.07	*
Special Types				*	*	*
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	$4.60
Ornamental Acorn	55	2,800	21	*	*	1.51
Ornamental Acorn Twin	55	5,600	42	*	*	3.02
Composite, Twin	140	6,815	54	*	*	3.88
	175	9,815	66	*	*	4.74

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Regular	25	$9.63	$0.32
	30	11.00	0.37
	35	12.68	0.42
Aluminum Davit	25	10.25	0.34
	30	11.50	0.38
	35	13.10	0.44
	40	16.80	0.56
Aluminum Double Davit	30	12.72	0.43
Aluminum, Fluted Ornamental	14	9.01	0.30

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

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Smooth Techtra Ornamental	18	$19.18	$0.64
Aluminum, Fluted Ornamental	16	9.34	0.31
Aluminum, Double-Arm, Smooth Ornamental	25	15.18	0.51
Aluminum, Fluted Westbrooke	18	18.06	0.60
Aluminum, Non-Fluted Ornamental, Pendant	18	17.95	0.60
Fiberglass, Fluted Ornamental Black	14	11.88	0.40
Fiberglass, Anchor Base, Gray or Black	35	11.97	0.40
Fiberglass, Anchor Base (Color may vary)	25	10.74	0.36
	30	13.05	0.44

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Cobrahead, Metal Halide	150	10,000	60	*	*	$4.31
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.80
	175	7,000	66	$10.03	$5.81	4.74
	250	10,000	94	*	*	6.75
	400	21,000	147	16.42	11.67	10.56
	1,000	55,000	374	32.61	28.07	26.87
Holophane Mongoose, HPS	150	16,000	62	*	6.12	*
	250	29,000	102	*	9.13	*

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	$8.60	*	*
Mercury Vapor	175	7,000	66	*	$5.89	$4.74
Special box, Anodized Aluminum						
Similar to GardCo Hub						
HPS	70	6,300	30	*	*	2.16
				*	*	*
	150	16,000	62	*	*	4.45
	250	29,000	102	*	*	7.33
Metal Halide	250	20,500	99	*	8.06	7.11
	400	40,000	156	*	12.16	*
Cobrahead, Metal Halide	175	12,000	71	*	*	5.10
Flood, Metal Halide	400	40,000	156	17.44	*	11.21
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	5.39	4.45
KIM Archetype, HPS	250	29,000	102	*	9.15	7.33
	400	50,000	163	*	13.88	11.71

* Not offered

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Special Acorn-Type, HPS	70	6,300	30	$13.08	$3.63	*
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	2.16
Mercury Vapor	175	7,000	66	*	*	4.74
Early American Post-Top, HPS						
Black	70	6,300	30	8.78	3.22	2.16
Rectangle Type	200	22,000	79	*	*	5.68
Incandescent	92	1,000	31	*	*	2.23
	182	2,500	62	*	*	4.45
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	*	5.84	4.74
Flood, HPS				*	*	*
	100	9,500	43	8.27	4.17	*
	200	22,000	79	13.00	6.84	5.68
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	3.09
Twin ornamental, HPS	Twin 100	9,500	86	*	*	6.18
Compact Fluorescent	28	N/A	12	*	*	0.86

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B
Aluminum Post	30	$5.15	*
Aluminum, Painted Ornamental	35	*	$0.44
Aluminum, Regular	16	5.20	0.17
Concrete, Ornamental	35 or less	9.52	0.32
Fiberglass, Direct Bury with Shroud	18	7.67	0.26
Steel, Painted Regular **	25	9.52	0.32
Steel, Painted Regular **	30	10.85	*
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36
Steel, Unpainted 8-foot Mast Arm **	35	*	0.44
Wood, Laminated without Mast Arm	20	*	0.19
Wood, Curved Laminated	30	*	0.26
Wood, Painted Underground	35	6.75	0.23

* 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	*	*	$2.30
	165	12,000	60	*	*	4.31
	165	12,000	60	*	5.38	4.31

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	1.960 ¢ per kWh	( )

* 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 595 (Continued)

LUMINAIRE SERVICE OPTIONS (Continued)
Special Provisions for Schedule 91/95/491/495/591/595 Option B to Schedule 95/495/595 Option C Luminaire Conversion and Future Maintenance Election (Continued)

2. Upon such conversion, the Customer will assume and bear the cost of all on-going maintenance responsibilities for the luminaires and associated circuits in accordance with this schedule's provisions for Option C luminaires from the date each luminaire is converted to Option C. After the three or five year period, any remaining Option B luminaires will be converted to Option C. The Company may not provide new Option B lighting under Schedule 91/95 following the election to convert any Option B luminaires to Schedule 91 or Schedule 95 Option C luminaires.

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A and Option B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	7.184 ¢ per kWh
Energy Charge	Provided by Electricity Service Supplier

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

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

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

SCHEDULE 595 (Continued)

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Roadway LED	>20-25	3,000	8	$5.87	$0.96
	>25-30	3,470	9	5.95	1.04
	>30-35	2,530	11	6.36	1.18
	>35-40	4,245	13	6.23	1.32
	>40-45	5,020	15	6.55	1.47
	>45-50	3,162	16	6.61	1.54
	>50-55	3,757	18	7.03	1.68
	>55-60	4,845	20	6.91	1.83
	>60-65	4,700	21	6.98	1.90
	>65-70	5,050	23	7.86	2.05
	>70-75	7,640	25	8.04	2.20
	>75-80	8,935	26	8.11	2.27
	>80-85	9,582	28	8.25	2.41
	>85-90	10,230	30	8.40	2.56
	>90-95	9,928	32	8.54	2.70
	>95-100	11,719	33	8.61	2.77
	100-110	7,444	36	8.64	2.99
	110-120	12,340	39	9.04	3.20
	120-130	13,270	43	9.33	3.49
	130-140	14,200	46	9.93	3.71
	140-150	15,250	50	12.18	4.04
	150-160	16,300	53	12.40	4.26
	160-170	17,300	56	12.61	4.47
	170-180	18,300	60	12.56	4.75
	180-190	19,850	63	13.12	4.98
	190-200	21,400	67	12.57	5.24
	>200-210	27,033	70	12.86	5.46
	>210-220	28,535	74	13.93	5.77
	>220-230	30,017	77	14.14	5.98
	>230-240	30,800	81	14.43	6.27
	>240-250	31,507	84	15.14	6.49

SCHEDULE 595 (Continued)

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

Type of Light	Watts*	Monthly kWh**
LED	>170 - 180	60
LED	>180 - 190	63
LED	>190 - 200	67
LED	>200 - 210	70
LED	>210 - 220	73
LED	>220 - 230	77
LED	>230 - 240	80
LED	>240 - 250	84
LED	>250 - 260	87
LED	>260 - 270	91
LED	>270 - 280	94
LED	>280 - 290	97
LED	>290 - 300	101

* Wattage based on total consumption of fixture (lamp, driver, photo control, etc). Customer may be required to provide verification of total energy consumption upon Company request.
** Monthly kWh figure based on 4,100 burning hours per year and midpoint of listed watt range, rounded to the nearest kWh.
Monthly kWh = (midpoint of wattage range / 1,000) x (4,100 hours / 12 months)

RATES FOR DECORATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Acorn LED	>35-40	3,262	13	$14.52	$1.46
	>40-45	3,500	15	14.67	1.61
	>45-50	5,488	16	12.16	1.64
	>50-55	4,000	18	14.88	1.82
	>55-60	4,213	20	15.03	1.97
	>60-65	4,273	21	15.10	2.04
	>65-70	4,332	23	14.88	2.18
	>70-75	4,897	25	15.39	2.33
	>90-100	8,100	32	15.93	2.87

SCHEDULE 595 (Continued)

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	$18.87	$2.32
Pendant LED (Non-Flared)	36	3,369	12	15.05	1.40
	53	5,079	18	16.61	1.85
	69	6,661	24	16.81	2.28
	85	8,153	29	17.73	2.65
Pendant LED (Flared)	>35-40	3,369	13	14.55	1.46
	>40-45	3,797	15	15.54	1.63
	>45-50	4,438	16	15.61	1.70
	>50-55	5,079	18	18.50	1.89
	>55-60	5,475	20	15.06	1.97
	>60-65	6,068	21	18.72	2.11
	>65-70	6,661	23	17.98	2.23
	>70-75	7,034	25	15.42	2.33
	>75-80	7,594	26	18.42	2.46
	>80-85	8,153	28	18.56	2.60
Post-Top, American Revolution LED	>30-35	3,395	11	7.86	1.21
	>45-50	4,409	16	8.22	1.57
Flood LED	>75-80	12,716	26	9.22	2.29
	>80-85	10,530	28	9.36	2.43
	>110-120	18,265	38	10.62	3.16
	>120-130	16,932	43	10.98	3.52
	>160-170	26,349	56	13.11	4.47
	>180-190	23,797	63	13.62	4.98
	>290-300	46,950	116	21.83	8.89
	>320-330	46,802	112	21.55	8.61
	>330-340	48,692	116	21.83	8.89
	>340-350	50,145	119	22.05	9.11
	>350-360	51,598	123	22.34	9.40
	>370-380	48,020	127	22.62	9.68

SCHEDULE 689 (Continued)

APPLICABLE (Continued)

Load served under Schedule 689 will not be counted under the Long Term Direct Access cap that applies to Schedules 485, 489, 490, 491, 492, 495, and 4965. The expected load of the Customer, defined as the "Contracted Load" in the opt out agreement between the Customer and the Company, will be the amount of load that is initially counted toward the New Load Direct Access cap for the first 60 months, unless a Customer is earlier de-enrolled under the terms of this Schedule 689 or the terms of the opt-out agreement.

The Contracted Load for each Customer will be counted toward the cap limit for up to the first 60 months of service. Following 60 months of service on Schedule 689, the Customer's actual load factor (LF) will be applied to the contracted demand (MW) to calculate a Customer's MWa to be captured and counted toward the New Large Load Program cap thereafter, and the total amount of load under the cap will be adjusted at such time of inquiry, in accordance with actual loads.

MONTHLY RATE

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

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$3,630450.00	$3,59041 0.00	$4,7705,020.00
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.4370	$1.4268	$1.4166
Over 4,000 kW	$1.1239	$1.1137	$1.1035
per kW of monthly Peak Demand***	$1.683	$1.661	$0.2713
System Usage Charge			
per kWh	0.100 178¢	0.0999177 ¢	0.0998 176¢
Administrative Fee	$0.00	$0.00	$0.00

* See Schedule 100 for applicable adjustments.

** The Customer's load, as reflected in the opt-out agreement executed between the Customer and PGE, may be higher than that reflected in a minimum load agreement for purposes of calculating the minimum monthly Facility Capacity and monthly Demand for the SP, for any Customer with dedicated substation capacity and/or redundant distribution facilities.

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

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

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 and subtransmission voltage service respectively.

ON AND OFF PEAK HOURS

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

LOSSES

The following adjustment factors will be used where losses are to be included in the Energy Charges:

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

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 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		4.~~806~~780	¢ per kWh	Distribution Charge
15		0.~~834~~825	¢ per kWh	Distribution Charge
32		0.~~449~~437	¢ per kWh	Distribution Charge
38		0.500	¢ per kWh	Distribution Charge
47		0.~~678~~703	¢ per kWh	Distribution Charge
49		0.~~599~~598	¢ per kWh	Distribution Charge
75				
	Secondary	0.~~226~~222	¢ per kWh	System Usage Charge
	Primary	0.~~224~~220	¢ per kWh	System Usage Charge
	Subtransmission	0.218~~21~~	¢ per kWh	System Usage Charge
83		0.~~346~~338	¢ per kWh	System Usage Charge
85				
	Secondary	0.~~273~~272	¢ per kWh	System Usage Charge
	Primary	0.~~270~~269	¢ per kWh	System Usage Charge
89				
	Secondary	0.~~226~~222	¢ per kWh	System Usage Charge
	Primary	0.~~224~~220	¢ per kWh	System Usage Charge
	Subtransmission	0.~~221~~218	¢ per kWh	System Usage Charge
90				
	Primary	0.~~209~~207	¢ per kWh	System Usage Charge
	Subtransmission	0.~~209~~207	¢ per kWh	System Usage Charge
91		0.~~888~~874	¢ per kWh	Distribution Charge
92		0.~~242~~239	¢ per kWh	Distribution Charge
95		0.~~888~~874	¢ per kWh	Distribution Charge
96		2.830	¢ per kWh	System Usage Charge

DO NOT BILL

SCHEDULE 750 (ContinuedcludedContinued)

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	0.051056	¢ per kWh	System Usage Charge
Primary	0.051056	¢ per kWh	System Usage Charge
489			
Secondary	0.015	¢ per kWh	System Usage Charge
Primary	0.015	¢ per kWh	System Usage Charge
Subtransmission	0.014015	¢ per kWh	System Usage Charge
490			
Primary	0.012009	¢ per kWh	System Usage Charge
Subtransmission	0.012009	¢ per kWh	System Usage Charge
491	0.703692	¢ per kWh	Distribution Charge
492	0.040043	¢ per kWh	Distribution Charge
495	0.703692	¢ per kWh	Distribution Charge
496	0.100		System Usage Charge
515	0.642640	¢ per kWh	Distribution Charge
532	0.214216	¢ per kWh	Distribution Charge
538	0.272282	¢ per kWh	Distribution Charge
549	0.328344	¢ per kWh	Distribution Charge
575			
Secondary	0.015	¢ per kWh	System Usage Charge
Primary	0.015	¢ per kWh	System Usage Charge
Subtransmission	0.014015	¢ per kWh	System Usage Charge
583	0.115117	¢ per kWh	System Usage Charge
585			
Secondary	0.051056	¢ per kWh	System Usage Charge
Primary	0.051056	¢ per kWh	System Usage Charge
589			
Secondary	0.015	¢ per kWh	System Usage Charge
Primary	0.015	¢ per kWh	System Usage Charge
Subtransmission	0.014015	¢ per kWh	System Usage Charge
590			
Primary	0.012009	¢ per kWh	System Usage Charge
Subtransmission	0.012009	¢ per kWh	System Usage Charge
591	0.703695	¢ per kWh	Distribution Charge
592	0.040043	¢ per kWh	Distribution Charge
595	0.703695	¢ per kWh	Distribution Charge
596	0.100		System Usage Charge
689			
Secondary	0.015	¢ per kWh	System Usage Charge
Primary	0.015	¢ per kWh	System Usage Charge
Subtransmission	0.014015	¢ per kWh	System Usage Charge

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			
Secondary	0.015	¢ per kWh	System Usage Charge
Primary	0.015	¢ per kWh	System Usage Charge
Subtransmission	0.015	¢ per kWh	System Usage Charge
696	0.100	¢ per kWh	System Usage Charge

DO NOT BILL

RULE G
DIRECT ACCESS SERVICE AND BILLING

1. Direct Access Service

All Customers, except Residential, may elect to receive Direct Access Service from an ESS under the terms of the parallel Direct Access schedule (500 series). Direct Access Service is also an option for eligible Nonresidential Customers served on Schedules 485, 489, 490, 496, 689 and 6968~~9~~.

A. Enrollment

Direct Access Service is only available upon acceptance of an Enrollment DASR by the Company. Prerequisites and notification requirements are as contained in each service schedule and Rule K.

B. Emergency Default Service

The Company will provide Emergency Default Service under Schedule 81 when an ESS or the Customer informs the Company that the ESS is no longer providing service or when the Company becomes aware that the Customer is no longer receiving service from the ESS and the Company has not received the 10 business day notice required for Standard Service under the appropriate schedule.

2. Special Requirements for Direct Access Billings

A. Generally

A Customer purchasing Electricity from an ESS may choose from two billing options: the ESS bills for all services (ESS Consolidated Bill) or the Company and the ESS each bill for their respective services (Company/ESS Split Bill).

1) **Company/ESS Split Bill**
When the Customer is receiving a Company/ESS Split Bill, the Company may disconnect Electricity Service for nonpayment of Direct Access Service under the guidelines set forth in Rule H.
2) **ESS Consolidated Bill**
When the Customer receives an ESS Consolidated Bill, failure of the Customer to pay the ESS for Direct Access Service does not relieve the ESS of the responsibility to pay the Company for Direct Access Services and any other Company charges.

B. ESS Billing Responsibilities

An ESS is responsible for the following:

1) Confirming receipt of Customer usage data within 12 hours of transmittal from the Company;
2) Responding to Customer inquiries regarding ESS charges; and
3) Under the ESS Consolidated Bill option, issuing a timely corrected bill to the Customer when the Company provides revised billing information.

RULE I
NEW CONNECTIONS, LINE EXTENSIONS, AND SYSTEM UPGRADES

1. Purpose

This rule establishes procedures and defines respective cost responsibilities for new Electricity Service connections or increases to existing Electricity Service and their respective system upgrades including but not limited to a Line Extension to a builder, developer, Customer or Applicant who requests a Line Extension on its own behalf, or a Customer or Applicant's agent.

A. Generally

Line Extensions will be at primary and/or secondary voltage levels. Modifications to transmission or subtransmission voltage facilities or substations are not considered Line Extensions for purposes of this rule and require special contract arrangements as described herein. When an agent requests a Line Extension on behalf of a Customer or Applicant, the agent must provide documentation acceptable to the Company evidencing its authority to request a Line Extension.

B. Definitions

1) **Allocated System Capacity**
The capacity on the Company's transmission system that is available to reliably serve an Applicant or Customer and that the Company allocates as a result of the system capacity allocation process, which is reflected in the Customer Service Contract.

2) **Applicant**
For purposes of this rule, an Applicant is a builder, developer, Customer, Applicant or other Customer or Applicant agent requesting a Line Extension to:
a) Serve new construction; or
b) Obtain additional capacity for, or a change in, service conditions relative to existing Distribution Facilities.

3) **Cost of Work**
The Company's actual direct and indirect costs to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs and assigned to the Applicant in the Customer Service Contract, including but not limited to administrative and engineering design costs. The cost of Exclusive Use Facilities for an Applicant will be allocated 100% to Applicant and Applicant shall be assigned proportional costs of any new, additional, or upgraded Distribution Facilities to serve Applicant that are not Exclusive Use Facilities.

RULE I (Continued)

Definitions (Continued)

4) **Customer Service Contracts**
aAre either (1) a Minimum Load Agreement (MLA) for Applicants in Capacity Category 2B or (2) a Large Load Customer Agreement (LLCA) for Applicants in Capacity Category 3, the terms and conditions for which are outlined in this Rule I.

5) **Distribution Capacity**
The capacity that the Company makes available to the Customer or Applicant via upgrades to existing or construction of new Distribution Facilities.

6) **Distribution Facilities**
Distribution Facilities are all structures and devices needed to distribute Electricity at any of the primary or secondary voltages listed in Rule C. Distribution Facilities will be installed in accordance with applicable laws, codes and Company standards and practices. It is the Applicant's responsibility to provide the Company with accurate information about their usage including but not limited to nameplate ratings of major installed electrical equipment and the intent to operate equipment above or below the nameplate rating. If damage results to Facilities owned by the Company through failure of the Applicant to fully disclose its load requirement to the Company, the repair and, or replacement costs of such Facilities will be paid by the Applicant.

7) **Enhanced Planning Area**
An area within the Company's service territory in which the transmission system requires more complex planning efforts in order to reliably serve expected capacity requirements. These designations are reviewed annually during system-wide analysis and with every study performed for customer requests. The Company will update designations based on a variety of factors such as changes in system conditions, regional growth, and/or individual capacity requests.

8) **Estimated Cost of Work**
The Company's estimated Cost of Work as determined in the final study report issued by the Company.

8)9) **Exclusive Use Facilities**
Facilities owned and operated by the Company required to provide Electric Service to the Customer between existing Company transmission or Distribution Facilities and the Applicant's or Customer's Service Point (SP) that are for the sole benefit and use of the Customer receiving Electricity Service are Exclusive Use Facilities. Customers with Exclusive Use Facilities are responsible for all costs associated with such facilities less any Line Extension Allowance for which the Customer qualifies. Neither upgrades to the Company's transmission nor distribution network(s) made for the benefit of all respective users are considered Exclusive Use Facilities and, as such, their costs are not allocated directly to any Customer(s).

RULE I (Continued)

Definitions (Continued)

9)10) **Exit Fee**
The amount that a Customer must pay to the Company if the Customer Service Contract expires or is terminated by the Customer or by the Company in the event of a Customer default or breach or by either the Company or Customer in the event of change of law defined in the Customer Service Contract.

10) **11)Facilities Study**
A study performed by the Company that includes analysis of facilities impacts and Applicant or Customer cost allocation as applicable to Distribution Facilities upgrades or new construction required to accommodate a capacity request.

11) **12)Feasibility Study**
A high-level planning study performed by the Company to determine whether service can be provided at the location and under the timeline specified in the Applicant's request and whether new or upgrades to transmission or Distribution Facilities may be required. The results of a Feasibility Study may indicate the need for more detailed review in either a System Impact or Facilities Study.

12) **13)Line Extension**
A Line Extension is the installation of new, additional or upgraded Distribution Facilities from a point on the Company's existing distribution system that the Company provides for the Applicant's planned Electricity needs to the Applicant's Service Point (SP). Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service, upgrades to existing primary lines will not be considered part of the Line Extension. Any new primary or secondary Line Extensions, transformer additions or replacements necessary to serve the new load will be considered part of the Line Extension. However, for residential Electric Vehicle charging-related line extensions, transformer additions or replacements necessary to serve that charging load will not be considered part of the Line Extension.

13) **14)Line Extension Allowance**
The Line Extension Allowance is the portion of the Line Extension Cost that the Company will provide without charge to the Applicant. Estimated annual kWh values used to calculate non-Residential Customer line extension allowances do not reflect onsite generation.

RULE I (Continued)

Definitions (Continued)

14) **15)Line Extension Cost**
The Company's total estimated cost to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs. Line Extension Costs are intended to recover the expenses of labor, material and equipment involved in the design, installation and inspection of the Line Extension under the Company's design standards and using standard construction methods inclusive of but not limited to primary and secondary voltage conductors, tree trimming or tree removal, Company indirect charges and the cost of any necessary rearrangement of existing Facilities. Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service and the transformer requires upgrading, the Line Extension Cost will be credited for the estimated original cost, less depreciation, less removal costs, of the existing transformer.
However, for residential Electric Vehicle charging line extensions, any transformer additions, or replacements necessary to serve the charging load will not be considered part of the Line Extension. Estimates of Line Extension Costs provided to Applicants are valid for six months from the date of issue. After six months the Company reserves the right to provide a revised estimate. The Line Extension Cost does not include payments to a third party for easements, additional costs associated with Underground Line Extension or other additional costs described in this rule.

15) **16)Long Side Service Connection**
A service connection, which runs parallel to the street, rather than perpendicular to the street.

16) **17)Primary Voltage Project**
A Primary Voltage Project is a planned undertaking of construction, where the Company initially installs only primary voltage facilities. Primary Voltage Projects include large lot residential subdivisions, industrial parks and other similar complexes. It is expected that within the project each Customer will be served from one or more transformers dedicated to that Customer's use.

17) **18)Public Thoroughfare**
A Public Thoroughfare is a municipal, county, state, federal, or other street, road, or highway, which is dedicated, maintained and open to public use in which the Company has the right to construct, operate, and maintain Facilities.

18) **19)Residential Subdivision**
A Residential Subdivision is a parcel of land divided into four or more smaller lots for the purpose of development or sale, which has been platted and filed under Oregon law as a subdivision. It is expected that within the subdivision several homes will be or are served from the same transformer.

RULE I (Continued)

Definitions (Continued)

19) 20)**System Impact Study**
A study performed by the Company to identify system-specific upgrades or new construction required to accommodate a capacity request while maintaining system reliability, stability, and performance. The System Impact Study report also includes a rough order of magnitude (ROM) cost estimate and preliminary schedule to energization. The results of a System Impact Study may indicate the need for more detailed review in a Facilities Study.

C. **Company Requirements**

1) **Capacity Categories**
Total requested capacity by Site, as defined in Rule B and subject to the Like Ownership provision of Rule E, is categorized in this Rule as follows:

Category 1: Less than 1,000 kW
Category 2: 1,000 kW to 230,000 19,999 kW with

A: no required substation transformer upgrades costs allocated to Applicant and for which total Line Extension Costs required to serve the load request are estimated to be less than $1 million, or
B: required substation transformer upgrades costs allocated to Applicant or for which total Line Extension Costs required to serve the load request are estimated to be $1 million or greater.

Category 3: Greater than 30,000 kW20,000 kW and greater

For customers in Capacity Categories 2 and 3, the Company will aggregate capacity requests as one Site request where buildings with Like Ownership are located within 2,500 feet or are located at greater than 2,500 feet and are electrically connected, such as served from the same substation.

Transportation electrification customers who qualify for service under Schedule 38 are exempt from requirements applicable to Capacity Category 2B or 3 under this Rule I.

RULE I (Continued)

Company Requirements (Continued)

2) 1) **Facilities Equipment Sizing and Use**

It is the Applicant's or Customer's responsibility to provide the Company with accurate information about their usage including but not limited to nameplate ratings of major installed electrical equipment and the intent to operate equipment above or below the nameplate rating. If damage results to Facilities owned by the Company through failure of the Applicant or Customer to fully disclose its load requirement to the Company, the repair and/or replacement costs of such Facilities will be paid by the Applicant or Customer.

3)2) **Company to Determine Route**

The Company will determine the route for all Line Extensions along Public Thoroughfares and may determine the route of a Line Extension made on private property. If the Applicant requests a route different than that determined by the Company, the Company may provide the Line Extension along the requested route if the Applicant pays the Company all additional costs resulting from the provision of that route and the requested route is not contrary to Company standards and practices.

4)3) **Company Ownership**

The Company will own and maintain all Facilities to the SP.

5)4) **Company Installation**

The Company will install all Facilities to the SP except that an Applicant for overhead Facilities may arrange to have the Facilities located on the property constructed by an electrical contractor acceptable to the Company, subject to the following conditions:

a) The Company will furnish the design and construction specifications for the connection and perform the necessary surveying;

b) The Applicant will, prior to the beginning of construction, cause the contractor to furnish the Company a certificate naming the Company as an additional insured in an amount not less than $1 million under the contractor's general liability policy;

c) During and after completion of the work by the contractor, the Company will make inspections. If the construction meets the Company's design specifications, the Company will accept ownership, and the Applicant will provide to the Company the title to the construction using form documents provided by the Company, together with all rights-of-way and easements required by the Company, free and clear of any liens or encumbrances; and

d) Following receipt of the title and Company-approved form documents indicating successful transfer, the Company will energize the Line Extension to make Electricity Service available to the Applicant.

e) If the Company determines that the overhead Distribution Facilities are deficient in materials or workmanship within 24 months of the time the Company energized the Line Extension, the Applicant must pay the cost to correct the deficiency to the Company's satisfaction.

RULE I (Continued)

Company Installation (Continued)

6)5) **Unusual Distribution Facilities or Nonstandard Construction**

The Company is required to install only those Facilities deemed necessary to render service in accordance with the Tariff. The Company is not required to make Line Extensions which involve additional or unusual Facilities, nonstandard construction, or other unusual conditions. Any facilities installed at Applicant's request which are in addition to, or in substitution of, the standard Distribution Facilities which the Company would normally install but which are otherwise acceptable to the Company, the additional cost of such nonstandard Facilities will be paid by the Applicant and will not be subject to the Line Extension Allowance in Schedule 300. In the case of conversion from overhead service to underground service, Section 6 of this Rule applies. In the case of relocation or removal of services and facilities, Section 7 of Rule C applies.

6) **System Capacity for Customers without Allocated System Capacity**

The Company will plan for load of Customers without an active allocated system capacity under a Customer Service Contract based on historical usage no less than three years from energization, available capacity, and Company planning practices. Existing customers with expansion of 1,000kW or greater will be required to follow Company's Tariff process for existing customer expansions in this Rule I.

2. Applicant Cost Responsibilities

A. Payment

Applicants who have cost responsibilities under this section and Section 3 will make payment in full at the time the Company agrees to make the Line Extension or for Applicants in Capacity Categories 2B or 3, pursuant to the terms of their Customer Service Contract.

A letter of credit or a deposit may be required by the Company if the Applicant does not meet the Company's credit requirements and is requesting capacity of 1,000 kW or greater. Applicant's payment requirements for jobs with Line Extension Costs estimated to be equal to or exceeding $250,000 but with requested capacity in Capacity Categories 1 and 2A are as follows:

1) The Applicant will provide a cash payment of 10% of the estimated Line Extension Cost prior to the Company initiating design work;
2) At the time the Company orders any special order and/or long lead-time electrical and/or pathway material, the Applicant will provide a cash payment to the Company for the full cost of the order; and

RULE I (Continued)

Payment (Continued)

3) At the commencement of construction, the Applicant will provide a payment equal to any remaining Line Extension Costs necessary to complete construction. Acceptable means of payment will be at the sole discretion of the Company.

A Line Extension Allowance shall only be available for Customers or Applicants in Capacity Categories 1 or 2A. The Line Extension Allowance will be refunded at the time the Applicant's Electricity Service is established. If Applicant's Electricity Service is not established, payments made under Section (2)(A) are not refundable.

B. **Applicants for New Permanent Service – Capacity Categories 1 and 2A**

Applicants for new permanent service in Capacity Categories Category 2A will be required to pay a nonrefundable application fee that cannot be applied to Line Extension Costs and to enter into an agreement to pay study costs and will make payment for each applicable study prior to the Company initiating the study and within specified periods to retain queue position as described in Section 4 of this rule

Applicants for new permanent services in Capacity Category 2A will be required to enter into a study agreement or study agreements and shall make any required payment prior to the Company initiating the study(ies) within the specified periods to retain queue position as described in Section 4 of this rule. Applicants will be assessed a non-refundable application fee based on the size of their request. Applicants with requests between 1MW and 3.99MW will pay a flat fee for all required studies for their request. Applicants with requests 4MW and greater will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference between actual costs as applicable at the conclusion of or upon Applicant's exit from the study process.

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 authorize the Company to proceed with design of the Line Extension or execute a subsequent study agreement, whichever is 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 providing formal authorization to the Company to proceed with design of the Line Extension or Applicant fails to execute a study agreement offered by the Company before the expiration of the study results.

RULE I (Continued)

Payment Applicants for New Permanent Service – Capacity Categories 1 and 2A (Continued)

The following provisions will apply to Applicants and Customers in Capacity Categories 1 or 2A.

1) **Individual Applicants**
Applicants for new permanent service will be responsible for the Line Extension Costs, less the applicable Line Extension Allowance listed in Schedule 300. In addition, any payments to a third party for easements, permits, additional costs associated with Underground Line Extensions, and all other additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

2) **Other than Individual Applicants**
The Company will install a main-line primary distribution system to provide service to a project (e.g., a subdivision, industrial park, or similar project) to serve Customers within the project provided the Applicant pays in advance for: 1) the total estimated cost of the installation of a continuous conduit system which includes, but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits; and 2) all other Applicant cost responsibilities based on the expected load within the project. The expected load in a large lot subdivision, industrial park, or similar project is comprised of only those loads projected to be connected within the first five years. Any Line Extension refund owed to the Customer or Applicant will be based on load connected within the first five years.

In residential subdivisions or phases of residential subdivisions where Line Extensions will not require subsequent additional extensions of primary voltage Distribution Facilities to serve the ultimate users within the subdivision, the refund will be based on the Line Extension Allowances for the subdivision calculated in accordance with Schedule 300.

RULE I (Continued)

C. **Existing Customers – Capacity Categories 1 and 2A**

Existing customers in Capacity Category 2A or expanding into Capacity Category 2A will be required to enter into a study agreement or study agreements and shall make any required payment prior to the Company initiating the study(ies) within the specified periods to retain queue position as described in Section 4 of this rule. Applicants will be assessed a non-refundable application fee based on the size of their request. Applicants with requests between 1MW and 3.99MW will pay a flat fee for all required studies for their request. Applicants with requests 4MW and greater will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference between actual costs as applicable at the conclusion of or upon Applicant's exit from the study process.

~~Existing customer expansions in Capacity Category 2A will be required to enter into an agreement to pay study costs and will make payment for each applicable study prior to the Company initiating the study and within specified periods to retain queue position as described in Section 4 of this rule. The Applicant will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference as applicable at the conclusion of or upon Applicant's exit from the study process.~~

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 authorize the Company to proceed with design of the Line Extension 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 providing formal authorization to the Company to proceed with design of the Line Extension or Applicant fails to execute a study agreement offered by the Company before the expiration of the study results.

The following provisions will apply to Applicants and Customers in Capacity Categories 1 or 2A.

RULE I (Continued)

Existing Customers – Capacity Categories 1 and 2A (Continued)

1) **Nonresidential**
Where an Applicant is an existing Nonresidential Customer requesting an additional SP, the conversion of a single-phase service to three-phase service, or additional capacity, the Applicant will make payment in full at the time the Company agrees to make the Line Extension. The Line Extension Allowance in these cases will be based on the incremental, annual kWh to be served by the Company or, in the case of a change in the applicable rate schedule, equal to four times the increase in annual revenues from Basic and Distribution Charges.

2) **Residential**
Where an Applicant is a Residential Customer requesting additional capacity at the same SP, the Line Extension Allowance is as listed in Schedule 300. Any excess amount will be the responsibility of the Applicant. In addition, any payments to a third party for easements, permits and additional costs associated with Underground Line Extensions and all additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

D. **New and Existing Customers - Capacity Categories 2B and 3**

1) Applicants for new permanent service or existing customer expansions between 1MW and 3.99MW are required to pay a nonrefundable study fee. Applicants shall make payment prior to the Company initiating the study process and within specified periods to retain queue position as described in Section 4 below.

~~1)~~ 2)Applicants for new permanent service or existing customer expansions 4MW and greater ~~in Capacity Categories 2B or 3~~ are required to pay a nonrefundable application fee and to enter into an agreement to pay study costs. Applicants will make payment for each applicable study prior to the Company initiating the study and within specified periods to retain queue position as described in Section 4 below. The Applicant will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference as applicable at the conclusion of each required study.

~~2)~~ 3)Applicants for new permanent service or existing customer expansions in Capacity Categories 2B or 3 shall be required to enter into a Customer Service Contract that will allocate the Cost of Work to the Applicant and contain other commercially reasonable terms and conditions, including but not limited the obligations and benefits outlined in this Rule I.

~~3)~~4)The Company reserves the right to recover transmission costs from Customers in Capacity Categories 2B or 3 in a manner other than through a Customer Service Contract if the nature of the transmission investments required to serve the Customer are such that an alternative method of recovery is required to avoid an inequitable or unreasonable result.

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 or because the extension is from an existing underground system; or
3) When otherwise mutually agreed upon by the Company and the Applicant.

B. Responsibility for Costs

1) The Applicant will be responsible for the current and reasonable future costs associated with the installation of the Line Extension's continuous conduit system, which includes but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits. The Company will own and maintain the conduit system once Company conductors have been installed.
2) At its option, the Company may perform the Applicant's responsibilities listed in (B)(1) above at the Applicant's expense or permit the Applicant to perform these responsibilities at Applicant's expense. Where work is to be performed in an existing right-of-way and requires the Company to obtain a permit from a governmental body, the Company may specify additional requirements and place restrictions on the selection of contractors.
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)

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)

General Conditions (Continued)

2) Applicants will be placed in a queue. The Company reserves discretion to divide Applicants or Customers into separate queues and to perform studies in clusters by service interconnection, requested capacity, location within Enhanced Planning Areas, or other relevant factors. Applicants in Capacity Categories 2A or 2B in an area that has not been identified as an Enhanced Planning Area and all Applicants in Capacity Category 2A or 2B with requested capacity of less than 4 MW will be studied and positioned in the queue based upon the date of a complete Application. The Company will make a good faith effort to manage queue position on a first-come, first-served basis for such Applicants. All other Applicants in Capacity Categories 2A, 2B or 3 will be placed in a cluster study upon completion of an Application to be studied with other Applicants in the cluster study.
3) For Applicants in a cluster study, the determination of Allocated System Capacity will be assessed on a pro-rata framework based on the total requested capacity and available capacity up to the transmission system capacity limit derived based on reliability standards requirements for the transmission system. Additional system capacity may be allocated to Applicants committing to providing dispatchable flexible load pursuant to a Company-authorized flexible load program such as Schedule 200 or demand side management program.
4) Study durations may be significantly affected if coordination with other utilities is required.
5) Completion of a study by the Company does not guarantee capacity or service or that capacity will be allocated to the Applicant.
6) Failure of the Applicant to sign a required study agreement within ~~30~~ 60 days of receipt from the Company and provide any required accompanying evidence, such as property ownership or good faith efforts to acquire property, shall automatically forfeit position within the queue.
7) Generally, the Allocated System Capacity and in-service timeframe offered to the Applicant by the Company will be determined by available system capacity and the amount of capacity the Applicant requests and are subject to change by the Company until a Customer Service Contract is executed by the Applicant and the Company.

B. **Allocation Process**

1) **Pre-Feasibility Review**
The Applicant or Customer shall submit a capacity request to the Company. The request ~~will~~ may be evaluated for pre-feasibility, which includes a high-level screening of the Company's general ability to serve the request at the specified location and within the requested timeframe.
2) **Application Submission**
The Applicant or Customer shall submit a completed application to the Company to enter into the system capacity allocation process. The Applicant ~~will~~ may be required to pay the application fee and sign the Study Agreement.

RULE I (Continued)

Allocation Process (Continued)

3) **Load Flexibility**
Applicants in a study may gain access to additional Allocated System Capacity beyond their initial allocation by participating in eligible Company flexible load programs. In order to be considered for such allocation of additional transmission capacity, an Applicant must include proposed eligible flexible load in their Application prior to the initial study. Any proposed eligible flexible load will be required to meet the applicable requirements of a Company-approved flexible load program, including but not limited to Schedule 200 and demand side management programs. Requests to add flexible load after the initial study completion may require submission of a new Application or result in the need to restudy the Application.

4) **Feasibility Study**
The Company requires a minimum of 30 days to complete Applicant's Feasibility Study and will provide the Applicant with an estimated completion date in the study agreement.

5) **System Impact Study**
The Company requires a minimum of 60 days to complete Applicant's System Impact Study and will provide the Applicant with an estimated completion date in the study agreement.

6) **Facilities Study**
The Company requires a minimum of 90 days to complete Applicant's Facilities Study and will provide the Applicant with an estimated completion date in the study agreement.

5. Interconnection Queue – Capacity Category 3 and seeking service under Schedule 96

Applicants in Capacity Category 3 who will qualify for Schedule 96 will be placed in an interconnection queue. Applicants placed in the interconnection queue will be removed from the queue only after they have a Service Plan. A Service Plan will identify a plan to secure resources that match an Applicant's load ramp and to comply with the applicable carbon emission targets set forth in HB 2021. A Service Plan may include a variety of energy and capacity resources, including the Applicant's own non-emitting resources through a special contract, direct access, load flexibility, customer funded load reductions in PGE's service territory, or other resources that are part of a Commission-approved resource plan or Service Plan. Applicants in a lower queue position with a Service Plan will be provided a reasonable opportunity to exit the queue ahead of higher-queued project for whom a Service Plan is not available. PGE will submit Service Plans to the Commission for approval for each Applicant, or group of Applicants, that it proposes to remove from the queue unless the Applicant is being removed from the queue because it will be served through Direct Access. PGE will seek Commission approval within 60 days of filing a Service Plan.

RULE I (Continued)

~~5~~6. Customer Service Contracts – Capacity Categories 2B and 3

Applicants in Capacity Categories 2B and 3 will be required to sign a Customer Service Contract as a condition of receiving Electricity Service from the Company. The Applicant's Customer Service Contract will be provided along with the last study report of the system capacity allocation process and must be signed by the Applicant within 60 days of issuance. Failure to return a signed Customer Service Contract to the Company within 60 days of issuance will result in forfeiture of the Applicant's queue position. This requirement may be temporarily waived by PGE for a reasonable period of time if the Customer Service Contract is subject to revision based on a pending proceeding before the Oregon Public Utility Commission.

Customer Service Contracts will be form contracts with terms and conditions required by this Rule as well as other commercially reasonable terms and conditions and may be revised by the Company consistent with applicable requirements in the Company's tariffs, the Public Utility Commission rules and orders.

A. **Billed Distribution Demand**

If providing service to the Applicant requires the construction of Distribution Facilities, the Customer Service Contract will contain an annual Billed Demand that the Customer must pay at the then-current tariff rates for distribution. Billed Demand will be based on the Company's ~~levelized annual~~ initial revenue requirement ~~associated with~~resulting from the Cost of Work attributable to the Customer. The annual revenue requirement for Exclusive Use Facilities is allocated 100% to the attributable Customer but is otherwise proportionally assigned. Generally, under any LLCA or MLA, the Billed Demand shall be a flat amount that the Customer will be billed at the then-current tariff rate regardless of the Customer's actual demand.

Billed Demand for a LLCA or MLA will be directly calculated as a kW or MW equivalent based on the annual revenue requirement associated with the Cost of Work. Under the LLCA, the Billed Demand will continue during any renewal period if and only if Billed Demand exceeds Allocated System Capacity. If a Customer under a LLCA or MLA would be required to pay a Billed Demand amount of less than 25% of its Allocated System Capacity, then the Customer will be billed at the greater of Billed Demand or actual demand.

Customer may elect to contribute up to one hundred percent (100%) of the Cost of Work via a Contribution in Aid of Construction (CIAC) payment.

Billed Demand for Applicants with a Minimum Load Agreement will be based on the Company's initial revenue requirement associated with the Cost of Work attributable to the Customer.

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued)

~~Billed Demand for Minimum Load Agreements will be set in the fifth year to no less than 75% of Distribution Capacity and set to recover no less than 17% of the Cost of Work totaled over the five-year load ramp period, provided that for each year during the ramp period the Billed Demand many not exceed the Distribution Capacity. Customers under a Minimum Load Agreement will be billed at the greater of Billed Demand or actual demand.~~

B. **Contract Term**
The term of a Minimum Load Agreement will be 10 years. The term of the LLCA will be a minimum of 10~~8~~ years for 20 MW of total allocated system capacity, increasing one year for each 10 MW increment in total allocated system capacity to a maximum of 30 years for a load of 220 MW or greater, ~~at the Customer's election,~~ measured from the in-service date.

C. **Contract Renewal**
Customer Service Contracts will renew automatically unless terminated according to the terms of the Customer Service Contract.

D. **Credit Requirements**
If Applicant does not meet the Company's credit requirements or does not provide a parental guarantee from a parent company meeting the Company's credit requirements, then Applicant will be required to provide a deposit in the form of a letter of credit, surety bond, or other financial instrument that meets the Company's credit support requirements. The Company's credit requirements are as follows: A senior long-term debt rating of A- (S&P) or A3 (Moody's). ~~will be identified in the Customer Service Contract~~.

E. **Exit Fee**
In the event a Customer Service Contract expires or is terminated by the Customer or by the Company in the event of a Customer default or breach or by either the Company or Customer in the event of change of law defined in the Customer Service Contract, the Company will calculate the Exit Fee in a commercially reasonable manner and provide notice of the amount to Customer and Customer shall pay the Exit Fee to the Company within ten (10) calendar days of the date of such notice.

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued)

The Exit Fee for the LLCA shall be (i) the net book value of the Cost of ~~the~~ Work calculated as of the date that is three (3) years after the date of termination or expiration of the LLCA, as determined by the Company in accordance with generally accepted accounting principles; plus (ii) any additional costs reasonably incurred or owing by the Company in connection with winding up the construction work, including any costs of decommissioning and removal of the Distribution Facilities, net of salvage value as determined by the Company in its reasonable discretion, and costs incurred in connection with the cancellation of third-party contracts; plus (iii) an amount equal to three years of distribution charges at the then current tariff rates for distribution and equal to either Billed Demand or actual demand (if there is no Billed Demand) as applicable to the Customer at the time of termination or expiration of the LLCA, plus the greater of the remaining Minimum Transmission and Minimum Generation Demand charges for the remainder of the contract term, or an amount equal to three years of Minimum Transmission and Minimum Generation Demand charges at the highest allocated system capacity. If a CIAC is paid by Customer, the net book value of the Cost of Work shall be reduced accordingly for the purpose of calculating the Exit Fee.

The Exit Fee for the Minimum Load Agreement shall be (i) the net book value of the Cost of the Work calculated as of the date of termination or expiration of the Minimum Load Agreement, as determined by the Company in accordance with generally accepted accounting principles; plus (ii) any additional costs reasonably incurred or owing by the Company in connection with winding up the construction work, including any costs of decommissioning and removal of the Distribution Facilities, net of salvage value as determined by the Company in its reasonable discretion, and costs incurred in connection with the cancellation of third-party contracts.

In the event that an Exit Fee is collected by the Company, the exiting Customer may be eligible for a partial refund if the facility is assumed within three years of service termination by a Customer with similar service characteristics, prorated based upon the amount of capacity assumed by the Customer and the date of connection. The Company will calculate any applicable refund by accounting for asset depreciation and minimum distribution, transmission, and generation revenue per the original Customer Service Contract.

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued)

F. **Failure to Satisfy Flexible Load Requirements**
The Customer Service Contract will contain terms and conditions providing for remedies if a Customer fails to satisfy the requirements for its participation in any Company-approved flexible load program when such participation is a condition of service. Customers who are enrolled in a flexible load program with the Company as a condition of service are not eligible for financial benefits associated with such programs so long as participation in the Company approved flexible load program is a condition of service.

~~G. **Capacity Exceedance Penalty**~~
~~Under the terms of any LLCA 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 the retail schedule under which the Customer is served. Customers who exceed their Capacity Exceedance Threshold will be subject to curtailment, termination and other remedies specified in the Customer Service Contract.~~

~~H.~~G. **Minimum Transmission Demand**
LLCAs will require Customers receiving service under Schedules 90 and 96 to annually meet or pay a minimum of ~~98~~0%, or for Customers receiving service under Schedule 89, 80% of Allocated System Capacity (the "Minimum Transmission Demand") at the then current tariff rate for transmission per the retail schedule under which the Customer is served.

H. **Minimum Generation Demand**
LLCAs will require Customers receiving service under Schedules 90 and 96 to annually meet or pay a minimum of 90% of Allocated System Capacity (the "Minimum Generation Demand") at the then current tariff rate for fixed generation per the retail schedule under which the Customer is served.

I. **Transmission and Generation CIAC**
Customers may contribute up to 100% CIAC for transmission and generation where feasible to aid expediting the customer's interconnection. Transmission CIAC may be subject to FERC approval.

~~I.~~J. **System Capacity Allocation Deposit**
LLCAs will require Applicants provide a one-time deposit for Allocated System Capacity equal to two years' worth of Minimum Transmission Demand. Customers who meet their flexible load requirement and with no arrearage will be entitled to a refund of the System Capacity Allocation Deposit. Eligible refunds, along with simple interest accrued, will be paid at 50% following Year 2 and 50% following Year 3 of the Customer Service Contract.

RULE I (Continued~~cluded~~)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued)

~~J.~~K. **Subject to Revision**

For any Customer Service Contract signed after April 16, 2025 and before June 10, 2026, all contract terms are subject to change pending and based upon Commission final orders in Commission Docket Nos. UE 430 and UM 2377.

L. **Effect of Direct Access**

Customers under an LLCA who opt into a Direct Access schedule under the Tariff will be subject to transition adjustments under the schedule and will no longer be subject to the Minimum Generation Demand at the time the Customer begins service under the Direct Access schedule. Customers under an LLCA on Direct Access will be required to pay a Transmission Demand charge equal to the difference between actual usage and the Minimum Transmission Demand set in the LLCA if the Customer's actual usage is lesser than the Minimum Transmission Demand.

~~K.~~M. **System Capacity Allocation ~~Period~~Adjustments**

Under the terms of any LLCA, the Company will hold Allocated System Capacity for the duration of the contract term, including renewals. The Company may reduce capacity if Customer fails to meet the requirements of the flexible load plan as outlined in the LLCA. ~~determined on a rolling three-year basis until the termination or expiration of the LLCA. At the end of each allocation period, the allocation will auto-renew at the Allocated System Capacity unless, (1) the Company has reduced the Allocated System Capacity due to failure to meet the Minimum Transmission Demand at least three (3) times in the immediately preceding allocation period, (2) the customer has requested a reduction of their Allocated System Capacity and the Company has accepted the reallotment of system capacity to another customer, or (3) the Customer fails to meet the requirements of the Flexible Load Plan, as defined in the LLCA.~~

~~If Customer's Demand fails to meet the Minimum Transmission Demand as outlined in the LLCA at least three (3) times in the immediately preceding allocation period, then the Company may reduce the Allocated System Capacity to Customer's highest Demand measured during such allocation period pursuant to the terms of the LLCA. The terms and conditions applicable to potential reductions in Allocated System Capacity based upon the Customer's failure to satisfy the requirements of any Company flexible load program or upon the Customer's timely request to reduce the Allocated System Capacity will be set forth in the LLCA. The Customer will not be required to pay a new System Capacity Allocation Deposit at commencement of each allocation period, but transmission charges will be based upon the Minimum Transmission Demand established for the three-year period.~~

Customer requests for reductions of Allocated System Capacity and their accompanying cost responsibilities ~~will only be considered at the expiration of each three-year allocation period and~~ will be contingent upon the Company's ability to reallocate such capacity to another customer. Capacity reallocation will be allowed if either of the following conditions are met:

(1) The assuming customer is at the same physical location and has the same electrical point of connection to the transmission grid as the customer requesting the capacity reallocation; or

(2) The assuming customer(s) is(are) at a different physical location, and the

Company determines that reallocation is feasible through a study that checks electrical proximity and effects on the transmission system. Feasibility is met if the Company determines that the new physical location and electrical connection are not adversely impactful to power flow and network topology. The study will be provided to Staff of the Public Utility Commission of Oregon.

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued)

Under the terms of an MLA, the Company will hold Allocated System Capacity for the initial five (5) years of the MLA term. After the initial five (5) years of the MLA term, the Company will plan system capacity for the Customer in accordance with Section 1.C.6 of this Rule I.

N. **LLCA Renewal Policy**
The LLCA will automatically renew for a ten-year period at the conclusion of the initial term and for each term thereafter unless a Customer requests longer renewal terms. The renewed agreement will maintain the same terms and conditions as the initial term.

O. **Customer Election**
A Customer in Category 1 or 2A may elect to enter into an MLA or LLCA at PGE's discretion. A Customer in Category 2B may elect to enter into an LLCA at PGE's discretion.

~~6~~7. Refunds

A. Where an Applicant has paid all or a portion of the costs of a Line Extension and additional Customers are subsequently connected to it, the Company will, at its initiative or on request from the Applicant for the original Line Extension, compute on a prorated basis the Line Extension Cost responsibility for up to three additional new Applicants connected to the original Line Extension and make collections and refunds for up to three additional Applicants, provided the following three conditions are satisfied:
    1) The original Line Extension has been in service for less than five years when the additional connections are made;
    2) The original Line Extension has been in service less than six years when the application for refund is made; and
    3) The payment made by the original Applicant was $100 or more.
B. Where additional Applicants are connected within five years of completion of the original Line Extension, and the allowances for the subsequent Line Extensions exceed additional Applicants' costs, the difference may be refunded to the original Applicant under the following conditions:
    1) Application for such refunds may be made as additional Applicants are connected, but no more frequently than on an annual basis; and
    2) The total amount refunded will not exceed the Line Extension Cost paid by the original Applicant.

RULE I (Continued)

~~7~~8. Special Conditions for Portland River District Undergrounding Project

For an area within the City of Portland, depicted as the shaded region on the map included as Appendix A[(1)], the applicable Applicant cost responsibilities of Underground Line Extensions, as specified in Section (3)B(1), will be incurred as a Service Connection Charge. This charge will be equal to $39,040.00[(2)] for a standard 200' X 200' block within the district. For any development area other than the standard size, the charge will be prorated based on the comparative size of that area.

(1) Between Broadway and Glisan Street and behind Union Station, the River District boundary is defined by the railroad right-of-way. Their respective streets or the Willamette River defines all other sections of the River District boundary.

(2) This amount will be applicable through the year 2009. Beyond 2009, the charge will be escalated annually by the Company's then authorized cost of capital.

~~8~~9. Conversion from Overhead to Underground Service

A. General

The Company will replace overhead with underground Facilities whenever such conversion is practicable and economically feasible. Customers connected by overhead Distribution Facilities owned by the Company that desire underground service will comply with applicable provisions of this rule.

B. Payment for Service Changes

The party requesting conversion from overhead to underground will pay the Company, prior to conversion, the estimated original cost, less depreciation, less salvage value, plus removal expense of any existing overhead Facilities no longer used or useful by reason of said underground system, and the costs of any necessary rearrangements, modifications, and additions to existing Facilities to accommodate the conversion of Facilities from overhead to underground.

C. Special Conditions

The conversion of overhead to underground Facilities affecting more than one Customer will be conditioned on the following:

1) The governing body of the city or county in which the Company's Facilities are located will have adopted an ordinance creating an underground district in the area in which both the existing and new Facilities are and will be located, providing:

RULE I (Continued)

Conversions from Overhead to Underground Service (Continued)

a) All existing overhead communication equipment and Distribution Facilities in such district are removed;
b) Each Customer served from such electric overhead Facilities will, in accordance with the Company's rules for underground service, make all necessary electrical facility changes on said Customer's Premises in order to receive service from the Company's underground Facilities as soon as available; and
c) The Company is authorized to discontinue its overhead service on completion of the underground Facilities.

2) All Customers served from overhead Facilities will agree in writing to perform the wiring changes required on their Premises so that service may be furnished in accordance with the Company's rules regarding underground service. Such Customers must also authorize the Company to discontinue overhead service upon completion of the underground Facilities.
3) The local government requires the Company to convert overhead Facilities to underground at the Company's expense, the provisions of OAR 860-022-0046 will apply.
4) That portion of the overhead system that is placed underground will not impair the utilization of the remaining overhead system.

D. **Cost of Area Conversions**

Area conversions may involve an assessment of costs and responsibilities among Customers. Such assessment and collection thereof will be the responsibility of a governmental unit or an association of those affected.

E. **Cost of Additional Circuit Capacity**

Where the Company installs an underground circuit with capacity in excess of the existing overhead, any additional cost to provide such excess circuit capacity will be at the Company's expense. Applicant cost responsibilities will be as defined in Section (6)(B) plus all reasonable costs for conduit or vault space installed to establish pathways for future circuit capacity.

RULE I (Continued)

~~9~~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.

B. Nonresidential Nonpermanent Service – Capacity Categories 1 and 2A

Nonresidential Line Extension Applicants with Line Extension Costs of $50,000 or greater, with loads in excess of 1 MWa, will sign a contract agreeing to accept Electricity Service at a specified minimum load. If service is terminated within an initial term of five years or if service is reduced to shut-down mode, a Service Termination Charge equal to the Line Extension Allowance (LEA) less 1/5th for each year service was taken at the specified minimum will be assessed as follows:

$$\frac{[(5 - \text{Years Served}) * \text{LEA}]}{5}$$

C. 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.

1~~0~~1. 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.

RULE I (Concluded)

Excess Capacity (Continued)

~~A.~~ D. When a Customer applying for a service upgrade or a new service Applicant requires Excess Capacity, such installation will be ineligible for a Line Extension Allowance associated with the unused or underutilized portion of the Line Extension. The unused or underutilized portion of the Line Extension will be determined by comparing the cost of the Line Extension with and without the Facilities necessary to serve the Excess Capacity. The Customer or Applicant will also be responsible for a maintenance charge equal to the present value of future maintenance of the excess Facilities at the time the new service or service upgrade is installed. If within five years of installation the excess capacity situation is determined to no longer exist the Company will refund the portion of the Line Extension charges that resulted from the designation of Excess Capacity, including the maintenance charge. It is the responsibility of the Customer to inform the Company as to the change in their capacity requirement within the five-year period.

12~~1~~. Rules Previously in Effect

Amounts advanced under the conditions established by a rule or contract previously in effect will be refunded in accordance with the provisions of that rule or contract.

RULE I

APPENDIX A

