Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

July 9, 2021

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: UE 394 – Portland General Electric Company's Request for a General Rate Revision
PGE Advice No. 21-18

Dear Filing Center:

Portland General Electric Company (PGE) submits this electronic filing pursuant to Oregon Revised Statutes 757.205 and 757.210 and Oregon Administrative Rules (OAR) 860-022-0025 and 860-022-0030 for filing proposed tariff sheets associated with Tariff P.U.C. 18.

In addition, PGE hereby submits for filing revised tariff sheets implementing a general rate revision. A list of the revised tariff sheets is attached.

As previously discussed, PGE has submitted 12 printed copies of our Revised Tariff Sheets, Executive Summary, List of Acronyms, Direct Testimony, and Exhibits to the PUC office located at 201 High Street SE, Suite 100, Salem, OR 97301-3398 via FedEx. Exhibits that are too voluminous to print were provided electronically. Confidential Testimony and Exhibits were provided electronically in coordination with Filing Center staff using Huddle. Confidential information is subject to General Protective Order No. 21-206. We appreciate Commission's and Staff's willingness to accept fewer printed copies than required by OAR 860-022-0019.

Work papers will be emailed to puc.workpapers@puc.oregon.gov.

The tariff changes are filed with an effective date of August 9, 2021, subject to suspension for investigation. PGE requests a prehearing conference be held as quickly as time allows to establish a schedule that provides a Commission Order by mid-April 2022, and revised prices effective May 1, 2022.

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

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

Jaki Ferchland
Portland General Electric Company
Manager, Revenue Requirement
121 SW Salmon Street, 3WTC0306
Portland, OR 97204

Confidential material in support of this filing has been provided to parties under the General Protective Order No. 21-206 issued June 24, 2021.

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

Loretta Mabinton Associate General Counsel 121 SW Salmon, 1WTC1301 Portland, OR 97204	Jay Tinker Director, Rates & Regulatory Affairs 121 SW Salmon, 3WTC0306 Portland, OR 97204	Jaki Ferchland Manager, Revenue Requirement 121 SW Salmon 3WTC0306 Portland, OR 97204

Sincerely,

/s/ Jay Tinker

Jay Tinker
Director, Rates & Regulatory Affairs

JT/np
Enclosure

Advice No. 21-18
Portland General Electric General Rate Revision
Revised Tariff Sheets filed July 9, 2021
Requested Effective Date of August 9, 2021

Eighteenth Revision of Sheet No. 7-1
Eleventh Revision of Sheet No. 7-2
Twelfth Revision of Sheet No. 7-3
Seventh Revision of Sheet No. 7-4
Thirteenth Revision of Sheet No. 15-1
Fourteenth Revision of Sheet No. 15-2
Fifteenth Revision of Sheet No. 15-3
Seventeenth Revision of Sheet No. 15-4
Twelfth Revision of Sheet No. 15-5
Eighth Revision of Sheet No. 15-6
Second Revision of Sheet No. 15-7
Original Sheet No. 15-8
Fourth Revision of Sheet No. 26-6
Fifth Revision of Sheet No. 26-7
Fifteenth Revision of Sheet No. 32-1
Eleventh Revision of Sheet No. 32-4
Sixteenth Revision of Sheet No. 38-1
Twelfth Revision of Sheet No. 38-3
Fifteenth Revision of Sheet No. 47-1
Sixteenth Revision of Sheet No. 49-1
Eighteenth Revision of Sheet No. 75-1
Ninth Revision of Sheet No. 75-5
Fourth Revision of Sheet No. 75-6
Thirteenth Revision of Sheet No. 76R-1
Ninth Revision of Sheet No. 76R-3
Ninth Revision of Sheet No. 76R-4
Ninth Revision of Sheet No. 76R-5
Tenth Revision of Sheet No. 81-1
Seventeenth Revision of Sheet No. 83-1
Thirteenth Revision of Sheet No. 83-2
Fourteenth Revision of Sheet No. 85-1
Ninth Revision of Sheet No. 85-2
Eighteenth Revision of Sheet No. 89-1
Thirteenth Revision of Sheet No. 89-2
Tenth Revision of Sheet No. 90-1
Fifth Revision of Sheet No. 90-2
Seventeenth Revision of Sheet No. 91-7
Twelfth Revision of Sheet No. 91-9
Eleventh Revision of Sheet No. 91-10
Eleventh Revision of Sheet No. 91-11
Twelfth Revision of Sheet No. 91-12
Tenth Revision of Sheet No. 91-13
Ninth Revision of Sheet No. 91-14
Eleventh Revision of Sheet No. 91-15
Seventeenth Revision of Sheet No. 92-1
Eighteenth Revision of Sheet No. 95-5
Third Revision of Sheet No. 95-6
Sixth Revision of Sheet No. 95-7
Eighth Revision of Sheet No. 95-8
First Revision of Sheet No. 108-1
Nineteenth Revision of Sheet No. 122-1
Eighteenth Revision of Sheet No. 122-2
Tenth Revision of Sheet No. 123-2
Seventeenth Revision of Sheet No. 123-3
Seventeenth Revision of Sheet No. 123-4
Seventeenth Revision of Sheet No. 123-5
Fifth Revision of Sheet No. 123-6
Fifteenth Revision of Sheet No. 125-2
Twentieth Revision of Sheet No. 125-3
Twelfth Revision of Sheet No. 126-1
Twelfth Revision of Sheet No. 126-3
Twenty Sixth Revision of Sheet No. 128-1
Twenty Fifth Revision of Sheet No. 128-2
Eleventh Revision of Sheet No. 129-1
Twenty Second Revision of Sheet No. 129-2
Thirty Fourth Revision of Sheet No. 129-3
Fifteenth Revision of Sheet No. 129-5
Tenth Revision of Sheet No. 129-6
Twelfth Revision of Sheet No. 135-1
Twelfth Revision of Sheet No. 135-2
Sixth Revision of Sheet No. 137-1
Fourth Revision of Sheet No. 137-2
First Revision of Sheet No. 137-3
Original Sheet No. 138-1
Original Sheet No. 138-2
Second Revision of Sheet No. 139-1
First Revision of Sheet No. 139-2
Original Sheet No. 139-3
Third Revision of Sheet No. 146-1
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Original Sheet No. 146-3
Original Sheet No. 150-1
Original Sheet No. 150-2
Eighth Revision of Sheet No. 300-5
Seventh Revision of Sheet No. 300-6
Thirteenth Revision of Sheet No. 485-1
Tenth Revision of Sheet No. 485-2
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Eighteenth Revision of Sheet No. 489-1
Seventeenth Revision of Sheet No. 489-2
Fifteenth Revision of Sheet No. 489-3
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Eighth Revision of Sheet No. 490-2
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Tenth Revision of Sheet No. 491-6
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Fifteenth Revision of Sheet No. 491-8
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Ninth Revision of Sheet No. 491-10
Tenth Revision of Sheet No. 491-11
Eighth Revision of Sheet No. 491-12
Eighth Revision of Sheet No. 491-13
Seventh Revision of Sheet No. 491-14
Tenth Revision of Sheet No. 492-1
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Third Revision of Sheet No. 495-6
Sixth Revision of Sheet No. 495-7
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Second Revision of Sheet No. 495-12
Fourteenth Revision of Sheet No. 515-1
Fifteenth Revision of Sheet No. 515-2
Fifteenth Revision of Sheet No. 515-3
Twelfth Revision of Sheet No. 515-4
Fourth Revision of Sheet No. 515-5
First Revision of Sheet No. 515-6
Fourteenth Revision of Sheet No 532-1
Sixteenth Revision of Sheet No. 538-1
Fifteenth Revision of Sheet No. 549-1
Eighteenth Revision of Sheet No. 575-1
Thirteenth Revision of Sheet No. 576R-1
Sixteenth Revision of Sheet No. 583-1
Thirteenth Revision of Sheet No. 585-1
Eighteenth Revision of Sheet No. 589-1
Tenth Revision of Sheet No. 590-1
Twentieth Revision of Sheet No. 591-6
Twenty Fifth Revision of Sheet No. 591-7
Fifteenth Revision of Sheet No. 591-8
Fourteenth Revision of Sheet No. 591-9
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Twelfth Revision of Sheet No. 591-11
Eleventh Revision of Sheet No. 591-12
Twelfth Revision of Sheet No. 591-13
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Eighth Revision of Sheet No. 595-5
Eleventh Revision of Sheet No. 595-6
Fourth Revision of Sheet No. 595-7
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Third Revision of Sheet No. 595-9
Second Revision of Sheet No. 595-10
First Revision of Sheet No. 595-11
First Revision of Sheet No. 595-12
First Revision of Sheet No. 595-13
Original Sheet No. 595-14
Eleventh Revision of Sheet No. 600-2
Fourth Revision of Sheet No. 600-3
Fourth Revision of Sheet No. 689-2
Second Revision of Sheet No. 689-3
First Revision of Sheet No. 689-5
Sixth Revision of Sheet No. 750-1
Sixth Revision of Sheet No. 750-2
Sixth Revision of Sheet No. 750-3
Third Revision of Sheet No. B-5
Third Revision of Sheet No. B-6
Fourth Revision of Sheet No. B-7
Tenth Revision of Sheet No. B-8
Tenth Revision of Sheet No. B-9
First Revision of Sheet No. C-13
First Revision of Sheet No. C-14
Original Sheet No. C-15
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
First Revision of Sheet No. L-2

SCHEDULE 7
RESIDENTIAL SERVICE

PURPOSE

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

DEFINITIONS

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

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

RESIDENTIAL SERVICE PRICE PLAN (DEFAULT PLAN)

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

Monthly Rate

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

Basic Charge			(C)
Single-Family Home	$12.50		|
Multi-Family Home	$8.00		(C)
Transmission and Related Services Charge	0.601	¢ per kWh	(I)
Distribution Charge	5.651	¢ per kWh	(I)
Energy Charge**			
First 1,000 kWh	6.636	¢ per kWh	(I)
Over 1,000 kWh	6.996	¢ per kWh	(R)

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

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: DEFAULT PLAN (Continued)

Peak Time Rebate Event Participation

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

Monthly Rate

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

PTR Credit	100.00	¢ per kWh

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

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

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

Special Conditions Related to Peak Time Rebate Options **(M)**

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

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

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: DEFAULT PLAN (Continued)
Special Conditions Related to Peak Time Rebate Options (Continued (T) (M)

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

4. Customers enrolled in Schedule 5 Direct Load Control are not eligible to participate in PTR on this schedule.

5. Customers with interconnected energy storage are only eligible for this schedule if the energy storage system is controlled by the Company and not the Customer.

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

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

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

Monthly Rate

Basic Charge			(C)
Single-Family Home	$12.50		
Multi-Family Home	$8.00		(C)
On-Peak Charge	34.900	¢ per kWh	(I)
Transmission and Related Services	2.000	¢ per kWh	
Distribution	17.100	¢ per kWh	
Energy	15.800	¢ per kWh	
Mid-Peak Charge	11.900	¢ per kWh	
Transmission and Related Services	0.520	¢ per kWh	
Distribution	4.980	¢ per kWh	
Energy	6.400	¢ per kWh	
Off-Peak Charge	7.234	¢ per kWh	
Transmission and Related Services	0.250	¢ per kWh	
Distribution	2.796	¢ per kWh	
Energy	4.188	¢ per kWh	(I)
Over 1,000 kWh block adjustment**	0.360	¢ per kWh	(R)

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

SCHEDULE 7 (Continued)

ENERGY PRICE PLANS: TOU PORTFOLIO OPTION (Continued)

On- and Off-Peak Hours

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

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

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

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

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

Monthly Rate

Basic Charge			(C)
Single-Family Home	$12.50		|
Multi-Family Home	$8.00		(C)
Transmission and Related Services Charge TOU Portfolio			
On-Peak Period	0.986	¢ per kWh	(I)
Mid-Peak Period	0.986	¢ per kWh	(I)
Off-Peak Period	0.000	¢ per kWh	
Distribution Charge TOU Portfolio			
On-Peak Period	9.267	¢ per kWh	(I)
Mid-Peak Period	9.267	¢ per kWh	(I)
Off-Peak Period	0.000	¢ per kWh	
Energy Charge TOU Portfolio			
On-Peak Period	12.355	¢ per kWh	(I)
Mid-Peak Period	6.996	¢ per kWh	(R)
Off-Peak Period	4.119	¢ per kWh	(R)
First 1,000 kWh block adjustment**	(0.360)	¢ per kWh	(I)

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

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	0.312	¢ per kWh	**(I)**
Distribution Charge	7.187	¢ per kWh	**(I)**
Cost of Service Energy Charge	4.772	¢ per kWh	**(R)**

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate (1) Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$12.44(2)	(I)
	400	21,000	147	22.83(2)	(I)
	1,000	55,000	374	50.63(2)	(I)
HPS	70	6,300	30	8.31(2)	(I)
	100	9,500	43	9.61	(R)
	150	16,000	62	12.00	
	200	22,000	79	14.51	(I)
	250	29,000	102	16.95	(I)
	310	37,000	124	19.85(2)	(I)
	400	50,000	163	24.62	(R)
Flood, HPS	100	9,500	43	9.66(2)	(I)
	200	22,000	79	15.32(2)	(I)
	250	29,000	102	18.26	(I)
	400	50,000	163	25.74	(I)
Shoebox, HPS (bronze color, flat	70	6,300	30	8.57	(R)
lens or drop lens, multi-volt)	100	9,500	43	10.62	(R)
	150	16,500	62	13.34	(I)
Special Acorn Type, HPS	100	9,500	43	13.45	(I)
HADCO Victorian, HPS	150	16,500	62	15.78	(I)
	200	22,000	79	18.18	(I)
	250	29,000	102	20.92	(I)
Early American Post-Top, HPS					
Black	100	9,500	43	10.50	(I)

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

SCHEDULE 15 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire(1)		
Special Types						
Cobrahead, Metal Halide	150	10,000	60	$12.11	**(R)**	
	175	12,000	71	13.71	**(I)**	
Flood, Metal Halide	350	30,000	139	23.81	**(I)**	
	400	40,000	156	24.19	**(I)**	
Flood, HPS	750	105,000	285	43.16	**(I)**	
HADCO Independence, HPS	100	9,500	43	14.55	**(I)**	
					(D)	
Alternative Special Acorn, Techtra	165	12,000	60	26.06	**(N)**	
HADCO Capitol Acorn, HPS	100	9,500	43	17.17	**(I)**	
						(D)
	200	22,000	79	21.82	**(I)**	
	250	29,000	102	15.97	**(R)**	
HADCO Techtra, HPS	100	9,500	43	21.24	**(R)**	
	150	16,000	62	24.33	**(I)**	
						(D)
HADCO Westbrooke, HPS	70	6,300	30	14.92	**(I)**	
	100	9,500	43	16.67	**(I)**	
						(D)
	250	29,000	102	22.47	**(R)**	
Holophane Mongoose, HPS	150	16,000	62	17.89	**(I)**	

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[(1)]	
Acorn					
LED	>35-40	3,262	13	$8.43	(C)
	>40-45	3,500	15	6.99	
	>45-50	5,488	16	11.39	
	>50-55	4,000	18	7.37	
	>55-60	4,213	20	6.85	
	>60-65	4,273	21	9.48	
	>65-70	4,332	23	14.20	
	>70-75	4,897	25	7.60	
HADCO LED	70	5,120	24	16.44	(C)
Roadway LED	>25-30	3,470	9	13.81	(C)
	>30-35	2,530	11	4.01	
	>35-40	4,245	13	4.57	
	>40-45	5,020	15	7.68	
	>45-50	3,162	16	4.59	
	>50-55	3,757	18	5.08	
	>55-60	4,845	20	8.79	
	>60-65	4,700	21	9.89	
	>65-70	5,050	23	5.90	
	>70-75	7,640	25	14.46	
	>75-80	8,935	26	9.07	
	>80-85	9,582	28	7.67	
	>85-90	10,230	30	9.85	
	>90-95	9,928	32	8.30	
	>95-100	11,719	33	8.42	
	>100-110	7,444	36	7.86	
	>110-120	12,340	39	9.74	
	>120-130	13,270	43	10.23	
	>130-140	14,200	46	11.44	
	>140-150	15,250	50	11.15	
	>150-160	16,300	53	19.12	
	>160-170	17,300	56	11.88	
	>170-180	18,300	60	13.95	
	>180-190	19,850	63	12.75	
	>190-200	21,400	67	15.11	(C)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire(1)	
Pendant LED (Non-Flare)	36	3,369	12	12.46	**(C)**
	53	5,079	18	15.73	
	69	6,661	24	16.59	
	85	8,153	29	17.72	
Pendant LED (Flare)	>35-40	3,369	13	12.75	
	>40-45	3,797	15	8.79	
	>45-50	4,438	16	8.91	
	>50-55	5,079	18	16.19	
	>55-60	5,475	20	14.03	
	>60-65	6,068	21	14.16	
	>65-70	6,661	23	17.52	
	>70-75	7,034	25	14.68	
	>75-80	7,594	26	16.31	
	>80-85	8,153	28	18.32	**(C)**
CREE XSP LED	>20-25	2,529	8	$3.24	**(C)(M)**
	>30-35	4,025	11	14.17	
	>40-45	3,819	15	4.10	
	>45-50	4,373	16	4.46	
	>55-60	5,863	20	4.75	
	>65-70	9,175	23	16.66	
	>90-95	8,747	32	6.56	
	>130-140	18,700	46	19.53	**(C)(M)**

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Post-Top, American Revolution LED	>30-35	3,395	11	5.43	**(C)(M)**
	>45-50	4,409	16	6.36	
Flood LED	>80-85	10,530	28	14.70	
	>120-130	16,932	3	8.31	
	>180-190	23,797	63	19.04	
	>370-380	48,020	127	27.00	**(C)(M)**

Rates for Area Light Poles[2]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$5.32	**(I)(M)**
	40 to 55	$6.31	
Wood, Painted for Underground	35 or less	$5.32 [3]	**(I)**
Wood, Curved Laminated	30 or less	$6.32 [3]	**(R)**
Aluminum, Regular	16	$4.07	
	25	$7.59	
	30	$8.76	
	35	$10.19	
Aluminum, Fluted Ornamental	14	$7.31	
Aluminum, Fluted Ornamental	16	$7.59	**(R)**
			(D)

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

SCHEDULE 15 (Continued) **(T)**

MONTHLY RATE (Continued)

Rates for Area Light Poles[(1)]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Aluminum Davit	25	$8.12	(R)(M)
	30	$9.19	
	35	$10.55	
	40	$13.58	
Aluminum Double Davit	30	$10.23	
Aluminum, Smooth Techtra Ornamental	18	$16.08	
Aluminum, Fluted Westbrooke	18	$15.09	(R)
Aluminum, Non-fluted Ornamental, Pendant	22	$14.99	(C)
Fiberglass Fluted Ornamental; Black	14	$9.82	
Fiberglass, Regular			
Black	20	$4.41	
Gray or Bronze	30	$7.16	
Black, Gray, or Bronze	35	$7.05	
Fiberglass, Anchor Base, Gray or Black	35	$9.71	
Fiberglass, Direct Bury with Shroud	18	$5.97	(C)(M)

INSTALLATION CHARGE

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

ADJUSTMENTS

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

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

SCHEDULE 15 (Concluded)

SPECIAL CONDITIONS (M)

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

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

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

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

TERM

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

SCHEDULE 26 (Continued)

QUALIFIED LOAD REDUCTION (Continued)

If the Customer fails to deliver a minimum of 70% of the Committed Load Reduction on average during an event for which the Customer is enrolled during events in that month, the Customer is not eligible for the Energy Reduction Payment for that Event and the Reservation Payment for that month. If other Load Reduction Events are called in the same month, and the Customer complies, the corresponding Energy Reduction Payments are paid for each event that the Customer delivers a minimum of 70% of the Committed Load Reduction on average over each event for which the Customer is enrolled during events in that month.

RESERVATION PAYMENTS

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

ENERGY PAYMENTS

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

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

Jan 2022	**Feb 2022**	**Jun 2022**	**Jul 2022**	**Aug 2022**	**Sep 2022**	**Nov 2022**	**Dec 2022**
$43.00	$38.00	$18.00	$42.50	$57.00	$49.00	$32.26	$40.41

(C)
(I)(R)

The Firm Energy Reduction Payment rates will be updated by December 1st for the next year beginning in January. Evaluation and settlement of the Firm Energy Reduction Payment will occur within 60 days of the Firm Load Reduction Event.

* PGE will not call events on Saturdays, Sundays, or Holidays. Holidays are New Year's Day (January 1), President's Day (third Monday of February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on Saturday, Friday is designated a holiday. If a holiday falls on Sunday, the following Monday is designated a holiday.

SCHEDULE 26 (Continued)

LINE LOSSES

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

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

LOAD REDUCTION MEASUREMENT

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

Baseline Load Profile

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

Typical Operational Days

Typical Operational Days exclude days that a Customer has participated in a Firm Load Reduction Event or pre-scheduled opt-out days as defined in the Special Conditions. Typical Operational Days for the baseline calculation are defined as the ten applicable days closest to the Load Reduction Event. Typical Operational Days may include or exclude Saturdays, Sundays and Western Electricity Coordinating Council (WECC) holidays.

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

LOAD REDUCTION EVENT

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

The Company initiates Load Reduction Events during the Events Season.

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$29.00		
Transmission and Related Services Charge	0.479	¢ per kWh	(I)
Distribution Charge			
First 5,000 kWh	5.408	¢ per kWh	(I)
Over 5,000 kWh	1.329	¢ per kWh	(R)
Energy Charge Options			
Standard Service	5.735	¢ per kWh	(R)
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.040	¢ per kWh	(R)
Mid-Peak Period	5.735	¢ per kWh	(R)
Off-Peak Period	3.349	¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

TIME OF USE PORTFOLIO OPTION

On- and Off-Peak Hours*

Summer Months (begins May 1st of each year)

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

Winter Months (begins November 1st of each year)

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

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

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

DAILY PRICE

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

The Daily Price will consist of:

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

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

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

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

Basic Charge	$30.00		
Transmission and Related Services Charge	0.425	¢ per kWh	(I)
Distribution Charge	7.142	¢ per kWh	(I)
Energy Charge*			
On-Peak Period	5.971	¢ per kWh	(R)
Off-Peak Period	4.471	¢ per kWh	(R)

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

MINIMUM CHARGE

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

REACTIVE DEMAND

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

SCHEDULE 38 (Continued)

DIRECT ACCESS DEFAULT SERVICE

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

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

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

Secondary Delivery Voltage 1.0640 **(R)**

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

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

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

ADJUSTMENTS

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

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

Basic Charge			
Summer Months**	$37.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.489	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand***	13.040	¢ per kWh	(I)
Over 50 kWh per kW of Demand	11.040	¢ per kWh	(I)
Energy Charge	6.384	¢ 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 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 exceeding 30 kW once.

MONTHLY RATE

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

Basic Charge			
Summer Months**	$45.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.493	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand***	9.917	¢ per kWh	(I)
Over 50 kWh per kW of Demand	7.917	¢ per kWh	(I)
Energy Charge	6.566	¢ 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 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$5,380.00	$3,630.00	$5,680.00	**(I)**
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$1.86	$1.84	$1.81	**(I)**
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	**(R)**
Over 4,000 kW	$1.04	$1.03	$1.03	**(R)**
per kW of monthly On-Peak Demand	$1.60	$1.58	$0.50	**(R)**
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	0.252 ¢	0.251 ¢	0.249 ¢	**(I)**
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

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

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

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

Scheduled Maintenance Energy

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

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

Unscheduled Energy

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

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Unscheduled Energy (Continued)

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

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

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

LOSSES

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

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

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

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

MINIMUM CHARGE

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

REACTIVE DEMAND CHARGE

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

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Transmission and Related Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.062	$0.062	$0.019	**(I)(R)**
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.072	$0.072	$0.071	**(R)(I)**
Transaction Fee per Energy Needs Forecast (ENF)	$50.00	$50.00	$50.00	
Energy Charge* per kWh of ERP	See below for ERP Pricing			

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

SCHEDULE 76R (Continued)

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

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

ERP Pricing

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

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

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

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

SCHEDULE 76R (Continued)

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

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

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

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

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

ACTUAL ENERGY USAGE

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

IMBALANCE ENERGY SETTLEMENT

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

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

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

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

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

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

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

The Imbalance Settlement Amount may be a credit or charge in any hour.

DAILY ERP DEMAND

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

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

UNSCHEDULED DEMAND

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

ADJUSTMENTS

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

SPECIAL CONDITIONS

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

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

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

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

APPLICABLE

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

MONTHLY RATE

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

ENERGY CHARGE DAILY RATE

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

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

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

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

REACTIVE DEMAND CHARGE

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

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

Basic Charge		
Single Phase Service	$35.00	
Three Phase Service	$45.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$1.86	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$5.12	**(I)**
Over 30 kW	$5.02	**(I)**
per kW of monthly On-Peak Demand	$1.60	**(R)**
Energy Charge (per kWh)		
On-Peak Period***	6.200 ¢	**(R)**
Off-Peak Period***	4.700 ¢	**(R)**
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.864 ¢	**(I)**

* See Schedule 100 for applicable adjustments.

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

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

SCHEDULE 83 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

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

NON COST OF SERVICE OPTION

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

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

Secondary Delivery Voltage 1.0640 **(R)**

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

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

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

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

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$810.00	$760.00	(I)
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$1.86	$1.84	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.48	$3.45	(I)
Over 200 kW	$2.28	$2.25	(I)
per kW of monthly On-Peak Demand	$1.60	$1.58	(R)
Energy Charge (per kWh)			
On-Peak Period***	6.001 ¢	5.941 ¢	(R)
Off-Peak Period***	4.501 ¢	4.441 ¢	(R)
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.308 ¢	0.306 ¢	(I)

* See Schedule 100 for applicable adjustments.

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

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

SCHEDULE 85 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

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

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

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

NON COST OF SERVICE OPTION

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

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

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

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

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

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$5,380.00	$3,630.00	$5,680.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$1.86	$1.84	$1.81	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	(R)
Over 4,000 kW	$1.04	$1.03	$1.03	(R)
per kW of monthly On-Peak Demand	$1.60	$1.58	$0.50	(R)
Energy Charge (per kWh)				
On-Peak Period***	5.914 ¢	5.856 ¢	5.797 ¢	(I)
Off-Peak Period***	4.414 ¢	4.356 ¢	4.297 ¢	(I)
See below for Daily Pricing Option description.				
System Usage Charge				
per kWh	0.252 ¢	0.251 ¢	0.249 ¢	(I)

* See Schedule 100 for applicable adjustments.

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

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

SCHEDULE 89 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

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

NON-COST OF SERVICE OPTION

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

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

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

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

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

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

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

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. (C)

MONTHLY RATE

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

Basic Charge	$20,900.00	(I)
Transmission and Related Services Charge per kW of monthly On-Peak Demand	$1.84	(I)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.70	(I)
Over 4,000 kW	$1.39	(I)
per kW of monthly on-peak Demand	$1.58	(R)
Energy Charge (per kWh)		
Usage (30MWa – 250MWa)		(C)
On-Peak Period***	5.652¢	(N)
Off-Peak Period***	4.152¢	(N)
Usage (greater than 250MWa)		
On-Peak Period***	5.539¢	(I)
Off-Peak Period***	4.039¢	(I)
See below for Daily Pricing Option description.		
System Usage Charge		
Usage (30MWa – 250MWa) per kWh	0.100¢	(C)
Usage (greater than 250MWa) per kWh	0.098¢	(C)

* See Schedule 100 for applicable adjustments.

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

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

SCHEDULE 90 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

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

NON-COST OF SERVICE OPTION

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

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

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

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

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

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 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	0.329 ¢ per kWh	**(I)**
Distribution Charge	7.170 ¢ per kWh	**(I)**
Energy Charge		
Cost of Service Option	4.839 ¢ 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 0.305¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. **(R)**

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. **(R)**

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

Enrollment for Service

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

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING

High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead Power Doors **	70	6,300	30	*	$0.81	(R)
	100	9,500	43	*	0.93	
	150	16,000	62	*	0.81	
	200	22,000	79	*	0.97	
	250	29,000	102	*	0.81	
	400	50,000	163	*	0.99	
Cobrahead	70	6,300	30	$4.71	1.10	
	100	9,500	43	4.41	1.05	
	150	16,000	62	4.47	1.06	
	200	22,000	79	5.11	1.13	
	250	29,000	102	4.72	1.07	
	400	50,000	163	4.91	1.10	
Flood	250	29,000	102	6.03	1.27	
	400	50,000	163	6.03	1.27	
Early American Post-Top	100	9,500	43	5.30	1.20	
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	4.97	1.15	(C)
	100	9,500	43	*	1.22	
	150	16,000	62	*	1.28	(R)(C)

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

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B		
Fiberglass, Black, Bronze, or Gray	20	$4.61	$0.17	(R)	(I)
Fiberglass, Black or Bronze	30	7.49	0.28	(I)	
Fiberglass, Gray	30	7.49	0.28	(R)	(I)
Fiberglass, Smooth, Black or Bronze	18	4.89	0.19	(I)	(I)
Fiberglass, Regular					
Black, Bronze, or Gray	18	$4.28	$0.16	(I)	(I)
	35	7.31	0.28	(R)	(I)
Aluminum, Regular with Breakaway Base	35	15.07	0.54	(N)	

SCHEDULE 91 (Continued)

RATES FOR STANDARD POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Wood, Standard	30 to 35	$5.58	$0.21	**(I)**
Wood, Standard	40 to 55	6.57	0.25	**(I)**

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Acorn-Types						
HPS	100	9,500	43	$8.46	$1.67	**(R)**
HADCO Victorian, HPS	150	16,000	62	8.46	1.67	**(R)**
	200	22,000	79	8.78	1.72	**(R)**
	250	29,000	102	8.69	1.70	**(R)**
HADCO Capitol Acorn, HPS	100	9,500	43	12.17	2.23	**(I)(R)**
	150	16,000	62	*	2.19	**(C)(R)**
	200	22,000	79	*	2.27	**(C)(I)**
	250	29,000	102	*	0.89	**(C)(R)**
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	9.56	1.81	**(I)(R)**
	150	16,000	62	*	1.53	**(C)(R)**
HADCO Techtra, HPS	100	9,500	43	16.25	2.84	**(R)**
	150	16,000	62	17.01	2.96	**(I)(R)**
	250	29,000	102	*	2.73	**(C)(R)**
HADCO Westbrooke, HPS	70	6,300	30	11.53	2.11	**(I)(R)**
	100	9,500	43	11.67	2.13	**(I)(R)**
	150	16,000	62	*	2.42	**(C)(R)**
	200	22,000	79	*	0.95	**(C)(R)**
	250	29,000	102	10.24	1.91	**(R)**

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Types						
Flood, Metal Halide	350	30,000	139	*	$1.45	(C)(R)
Flood, HPS	750	105,000	285	$8.48	1.78	(R)(R)
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	
Ornamental Acorn	55	2,800	21	*	*	
Ornamental Acorn Twin	55	5,600	42	*	*	
Composite, Twin	140	6,815	54	*	*	
	175	9,815	66	*	*	

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

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, Regular	25	$7.92	$0.30	(R)
	30	9.09	0.34	
	35	10.52	0.40	
Aluminum Davit	25	8.45	0.32	
	30	9.52	0.36	
	35	10.88	0.41	(I)
	40	13.97	0.53	(I)
Aluminum Double Davit	30	10.56	0.40	(R)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Fluted Ornamental	14	7.51	0.28	**(R)**
Aluminum, Smooth Techtra Ornamental	18	16.41	0.62	**(R)**
Aluminum, Fluted Ornamental	16	7.79	0.30	**(R)**
Aluminum, Double-Arm, Smooth Ornamental	18	12.65	0.48	**(R)(I)**
Aluminum, Fluted Westbrooke	18	15.42	0.58	**(R)**
Aluminum, Non-Fluted Ornamental, Pendant	22	15.32	0.58	**(C)(R)**
Fiberglass, Fluted Ornamental Black	14	10.51	0.40	**(R)(I)**
Fiberglass, Anchor Base, Gray or Black	35	9.98	0.38	**(R)**
Fiberglass, Anchor Base (Color may vary)	25	8.87	0.34	**(R)(I)**
	30	10.84	0.41	**(R)(I)**

SERVICE RATE FOR OBSOLETE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Cobrahead, Metal Halide	150	10,000	60	*	$1.16	**(C)(R)**
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	$4.39	1.06	**(R)**
	250	10,000	94	*	*	
	400	21,000	147	5.08	1.10	**(R)**
	1,000	55,000	374	5.03	1.22	**(R)**
Holophane Mongoose, HPS	150	16,000	62	*	1.98	**(C)(R)**
	250	29,000	102	*	1.99	**(C)(I)**
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	5.36	*	**(R)**
Mercury Vapor	175	7,000	66	5.36	1.16	**(R)**

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Box, Anodized Aluminum						
Similar to GardCo Hub						
HPS - Twin	70	6,300	60	*	*	
HPS	70	6,300	30	*	*	
	100	9,500	43	*	$1.49	**(R)**
	150	16,000	62	*	0.89	**(R)**
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	0.90	**(R)**
	400	40,000	156	*	0.90	**(R)**
Cobrahead, Metal Halide	175	12,000	71	*	1.17	**(R)**
Flood, Metal Halide	400	40,000	156	$5.34	1.20	**(R)**
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	0.89	**(R)**
100/150 Watt Ballast	100	9,500	43	*	0.89	**(R)**
100/150 Watt Ballast	150	16,000	62	*	0.89	**(R)**
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.33	**(R)**
	165	12,000	60	*	0.97	**(I)**
HADCO Techtra, QL	165	12,000	60	*	1.28	**(C)(I)**
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	0.89	**(R)**
KIM Archetype, HPS	250	29,000	102	*	2.01	**(R)**
	400	50,000	163	*	2.45	**(I)**
Special Acorn-Type, HPS	70	6,300	30	8.36	1.57	**(R)**
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Early American Post-Top, HPS						
Black	70	6,300	30	$5.14	$1.04	**(R)**
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	5.20	1.10	**(I)(R)**
Flood, HPS	70	6,300	30	4.45	1.09	**(R)**
	100	9,500	43	4.46	1.07	**(R)**
	200	22,000	79	5.92	1.16	**(R)**
Cobrahead, HPS						
Power Door	310	37,000	124	*	1.27	**(C)(R)**
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Fluorescent	28	N/A	12	*	*	

* Not offered.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	4.26	*	**(R)**
Aluminum, Painted Ornamental	35	*	*	**(C)**
Aluminum, Regular	16	4.26	0.16	**(R)**
Bronze Alloy GardCo	12	*	0.23	**(I)**
Concrete, Ornamental	35 or less	7.92	0.30	**(R)**
Fiberglass, Direct Bury with Shroud	18	6.30	0.24	**(R)**
Steel, Painted Regular **	25	7.92	0.30	**(R)**
Steel, Painted Regular **	30	9.09	0.34	**(R)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.41	**(I)**
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41	**(I)**
Wood, Laminated without Mast Arm	20	4.61	0.17	**(R)(I)**
Wood, Laminated Street Light Only	20	4.61	*	**(R)**
Wood, Curved Laminated	30	6.40	0.28	**(R)**
Wood, Painted Underground	35	5.58	0.21	**(I)**

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

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

. Trimming of trees adjacent to streetlight equipment and circuits.
. Arterial patrols to ensure correct operation of streetlights.
. Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

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

SCHEDULE 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	0.366	¢ per kWh	(I)
Distribution Charge	1.869	¢ per kWh	(R)
Energy Charge	5.098	¢ 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)

1. 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	0.329 ¢ per kWh	**(I)**
Distribution Charge	7.170 ¢ per kWh	**(I)**
Energy Charge		
Cost of Service Option	4.839 ¢ 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 0.305¢ per kWh for **(R)** wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

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

SCHEDULE 95 (Continued)

NON-COST OF SERVICE OPTION (Continued)

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

Losses will be included by multiplying the applicable daily Energy price by 1.0640. **(R)**

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

Enrollment for Service

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

Balance-of-year Election Window

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

During the Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. The move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to either the Cost of Service or Daily Price Option during the Balance-of-Year Election Window.

November Election Window

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

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

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

SCHEDULE 95 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate	Straight Time	Overtime
	$124.00 per hour	$155.00 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	$9.57	$0.41	(C)
	>25-30	3,470	9	4.49	0.41	
	>30-35	2,530	11	4.75	0.41	
	>35-40	4,245	13	4.50	0.41	
	>40-45	5,020	15	4.62	0.41	
	>45-50	3,162	16	4.72	0.41	
	>50-55	3,757	18	4.96	0.42	
	>55-60	4,845	20	4.63	0.41	
	>60-65	4,700	21	4.64	0.41	
	>65-70	5,050	23	5.16	0.43	
	>70-75	7,640	25	5.23	0.43	
	>75-80	8,935	26	5.24	0.43	
	>80-85	9,582	28	5.25	0.43	
	>85-90	10,230	30	5.21	0.43	
	>90-95	9,928	32	5.25	0.43	
	>95-100	11,719	33	5.25	0.43	
	>100-110	7,444	36	5.53	0.43	
	>110-120	12,340	39	5.26	0.43	
	>120-130	13,270	43	5.27	0.43	
	>130-140	14,200	46	6.09	0.45	
	>140-150	15,250	50	7.06	0.48	
	>150-160	16,300	53	6.99	0.48	
	>160-170	17,300	56	7.06	0.48	
	>170-180	18,300	60	6.88	0.47	
	>180-190	19,850	63	7.07	0.48	
	>190-200	21,400	67	7.18	0.48	(C)

SCHEDULE 95 (Continued)

RATES FOR DECORATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Acorn						
LED	>35-40	3,262	13	$11.70	$0.61	**(C)**
	>40-45	3,500	15	11.79	0.61	
	>45-50	5,488	16	9.71	0.55	
	>50-55	4,000	18	11.80	0.61	
	>55-60	4,213	20	11.70	0.61	
	>60-65	4,273	21	11.81	0.61	
	>65-70	4,332	23	11.67	0.61	
	>70-75	4,897	25	11.70	0.61	
HADCO LED	70	5,120	24	15.58	0.72	**(C)(D)**
Pendant LED (Non-Flared)	36	3,369	12	13.08	0.65	**(R)(I)(C)**
	53	5,079	18	13.81	0.67	
	69	6,661	24	13.92	0.67	
	85	8,153	29	14.45	0.69	**(R)(I)**
						(D)
Pendant LED (Flared)	>35-40	3,369	13	13.24	0.65	**(C)**
	>40-45	3,797	15	13.35	0.65	
	>45-50	4,438	16	13.35	0.65	
	>50-55	5,079	18	14.27	0.68	
	>55-60	5,475	20	14.40	0.68	
	>60-65	6,068	21	14.40	0.68	
	>65-70	6,661	23	14.99	0.70	
	>70-75	7,034	25	15.13	0.70	
	>75-80	7,594	26	15.32	0.71	
	>80-85	8,153	28	15.17	0.71	**(C)**
Post-Top, American Revolution						**(C)**
LED	>30-35	3,395	11	6.17	0.45	
	>45-50	4,409	16	6.49	0.46	
Flood LED	>80-85	10,530	28	6.19	0.45	
	>120-130	16,932	43	6.69	0.47	
	>180-190	23,797	63	7.69	0.50	
	>370-380	48,020	127	11.86	0.61	**(C)**

SCHEDULE 108
PUBLIC PURPOSE CHARGE

PURPOSE

To collect funds associated with activities mandated for the benefit of the general public pursuant to OAR 860-038-0480. Activities include Energy conservation, new market transformation, new renewable energy resources and new low-income weatherization.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except Nonresidential Customers qualifying as a Self-Directing Customer may be partially exempt.

PUBLIC PURPOSE CHARGE

The Public Purpose Charge will be 3% of total revenue billed to the Customer "for electricity services, distribution, ancillary services, metering and billing, transition charges and other types of costs that were included in electric rates on July 23, 1999" as specified in OAR 860-038-0480(2).

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be a Self-Directing Customer (SDC), the Large Nonresidential Customer must have a load that exceeds one aMW and receive certification from the Oregon Department of Energy (ODOE) as an SDC. Beginning November 30, 2004, the Company will include the credits due, as reported by the ODOE, to the applicable portions of the SDCs monthly Public Purpose Charge.

SPECIAL CONDITIONS

1. Electricity Service Suppliers (ESS) – Each ESS that provides Direct Access Service in the Company's service territory will collect a Public Purpose Charge from its Direct Access Customers. The ESS will remit monthly to the Company the Public Purpose Charges it collects from Customers and provide calculations of the Public Purpose **(C)** Charge for each Service Point enrolled in Direct Access. The ESS will supply the Company with this information, so the Company can correctly allocate the applicable portions of the Direct Access SDC's monthly Public Purpose Charge and ensure Disbursement of Funds collected are allocated as required. **(C)**

SCHEDULE 122
RENEWABLE RESOURCES AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource and energy storage projects associated with renewable energy resources (including associated transmission) not otherwise included in rates. Additional new renewable and energy storage projects associated with renewable energy resources may be incorporated into this schedule as they are placed in service. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210 and Section 13 of the Oregon Renewable Energy Act (OREA).

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76, 485, 489, 490, 491, 492, 495, 576 and 689. This schedule is not applicable to direct access customers after December 31, 2010.

ADJUSTMENT RATE

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

Schedule		Adjustment Rate		
7		0.000	¢ per kWh	(R)
15		0.000	¢ per kWh	
32		0.000	¢ per kWh	
38		0.000	¢ per kWh	
47		0.000	¢ per kWh	
49		0.000	¢ per kWh	
75				
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	
	Subtransmission	0.000	¢ per kWh	
83		0.000	¢ per kWh	
85				
	Secondary	0.000	¢ per kWh	
	Primary	0.000	¢ per kWh	(R)

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

Schedule		Adjustment Rate		
89				
	Secondary	0.000	¢ per kWh	(R)
	Primary	0.000	¢ per kWh	
	Subtransmission	0.000	¢ per kWh	
90		0.000	¢ per kWh	
91		0.000	¢ per kWh	
92		0.000	¢ per kWh	
95		0.000	¢ per kWh	(R)

ANNUAL REVENUE REQUIREMENTS

The Annual Revenue Requirements of a qualifying project will include the fixed costs of the renewable resource or energy storage project associated with renewable energy resources and associated transmission (including return on and return of the capital costs), operation and maintenance costs, income taxes, property taxes, and other fees and costs that are applicable to the renewable resource or energy storage project associated with renewable energy resources or associated transmission. Until the dispatch benefits are included in the Annual Power Cost Update Schedule 125, the net revenue requirements of each project (fixed costs less market value of the energy produced by the renewable resource or energy storage project associated with renewable energy resources plus any power costs such as fuel, integration and wheeling costs) will be deferred and included in the Schedule 122 rates. By no later than April 1 of each year following the resource's on-line date, the Company will file an update to the revenue requirements of resources included in this schedule to recognize projected changes for the following calendar year. Should the final determination of a Schedule 122 filing for a new resource not allow for inclusion of its net variable power costs (NVPC) in the AUT, these will be included in the Schedule 122 revenue requirement used to set initial prices. In this circumstance, the resource's NVPC impacts will subsequently be removed from Schedule 122 prices and included in the AUT at the next available opportunity.

DEFERRAL MECHANISM

For each calendar year that the Company anticipates that a new renewable resource or energy storage project associated with renewable energy resources will commence operation, the Company may file a deferral request the earlier of the resource online date or April 1. The deferral amount will be for the fixed revenue requirements of the resource less net dispatch benefits. For purposes of determining dispatch benefits, the forward curves used to set rates for the year under the Annual Power Cost Update will be used. The deferral will be amortized over the next calendar year in Schedule 122 unless otherwise approved by the Oregon Public Utility Commission (OPUC). The balancing account will accrue interest at the Commission-authorized rate for deferred accounts, and the amortization of the deferred amount will not be subject to the provisions of ORS 757.259(5).

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

The SNA will calculate monthly as the Fixed Charge Revenue less actual revenues and will accrue to the SNA Balancing Account. The monthly amount accrued may be positive (an under-collection) or negative (an over-collection). The SNA is divided into sub-accounts so that net accruals for each rate schedule will track separately.

The SNA is applicable to the following rate schedules:

Schedule	Fixed Charge Energy Rate (¢ per kWh)	Monthly Fixed Charge	Monthly Secondary Fixed Charge	
7	9.265	$72.10	$49.75	(I)
32/532	8.087	$112.23		(I) (C)
38/538	10.044	$699.35		
47	14.876	$89.68		
49/549	11.855	$431.93		(C)
83/583	2.951	$581.37		(R)

*Applicable beginning in 2019. The Fixed Charge Energy Rate for Schedule 83 includes fixed generation charges only. (C)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA)

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532; 83 (starting in 2019), and 38, 47, 49, 538, 549 and 583 (starting in 2022) or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. Also included are differences in actual energy savings from a test year forecast associated with the conversion to LED streetlighting in Schedule 95 reported by the Company. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates. (C)

(M)

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA) (Continued)

The Lost Revenue Recovery Adjustment may be positive or negative. A negative Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are less than those estimated in setting base rates. A positive Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are greater than those estimated for the test year in setting base rates. The LRRA for each year subsequent to the test year will incorporate incremental kWh savings reported by the Energy Trust of Oregon for that year. (M)

For the purposes of this Schedule, the Lost Revenue Recovery Adjustment is the product of: (1) the reduction in kWh sales resulting from ETO-reported EEMs plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, and (2) the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule-weighted average of transmission, distribution, and fixed generation charges; including those contained in Schedule 122 and other applicable schedules. System usage or distribution charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. Franchise fee recovery is not included in the Lost Revenue Rate. The applicable Lost Revenue Rate is 5.074 cents per kWh. (R)

SNA and LRRA BALANCING ACCOUNTS

The Company will maintain a separate balancing account for the SNA applicable rate schedules and for the Nonresidential LRRA applicable rate schedules. Each balancing account will record over- and under-collections resulting from differences as determined, respectively, by the SNA and LRRA mechanisms. The accounts will accrue interest at the Commission-authorized Modified Blended Treasury Rate established for deferred accounts.

DECOUPLING ADJUSTMENT

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

Schedule	Adjustment Rate	
7	0.216 ¢ per kWh	(I)
15	0.010 ¢ per kWh	
32	0.255 ¢ per kWh	(I)
38	0.010 ¢ per kWh	
47	0.010 ¢ per kWh	
49	0.010 ¢ per kWh	

(M)

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued)

Schedule	Adjustment Rate		
75			(M)
Secondary	0.010		
Primary	0.010		
Subtransmission	0.010		
83	0.204		(M)(I)
85			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
89			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
Subtransmission	0.010	¢ per kWh	
90	0.010	¢ per kWh	
91	0.010	¢ per kWh	
92	0.010	¢ per kWh	
95	0.010	¢ per kWh	
485			
Secondary	0.002	¢ per kWh	
Primary	0.002	¢ per kWh	
489			
Secondary	0.002	¢ per kWh	
Primary	0.002	¢ per kWh	
Subtransmission	0.002	¢ per kWh	
490	0.002	¢ per kWh	
491	0.002	¢ per kWh	
492	0.002	¢ per kWh	
495	0.002	¢ per kWh	
515	0.010	¢ per kWh	
532	0.255	¢ per kWh	(I)
538	0.010	¢ per kWh	
549	0.010	¢ per kWh	

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued)

Schedule	Adjustment Rate		
575			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
Subtransmission	0.010	¢ per kWh	
583	0.204	¢ per kWh	(I)
585			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
589			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
Subtransmission	0.010	¢ per kWh	
590	0.010	¢ per kWh	
591	0.010	¢ per kWh	
592	0.010	¢ per kWh	
595	0.010	¢ per kWh	
689			
Secondary	0.002	¢ per kWh	
Primary	0.002	¢ per kWh	
Subtransmission	0.002	¢ per kWh	

TIME AND MANNER OF FILING

Commencing in 2014, the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the subsequent year based on a) the amounts in the SNA Balancing Accounts and b) the amount in the LRRA Balancing Account.

2. Revisions to this Schedule which reflect the new proposed prices and supporting work papers detailing the calculation of the new proposed prices and the SNA weather-normalizing adjustments.

SCHEDULE 123 (Concluded)

SPECIAL CONDITIONS

1. The Fixed Charge Energy Rate, Monthly Fixed Charge per Customer and the Lost Revenue Rate will be updated concurrently with a change in the applicable base revenues used to determine the rates.

2. Weather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that used for determining the forecasted loads used to establish base rates.

3. No revision to any SNA or LRRA Adjustment Rate will result in an estimated average annual rate increase greater than 2% to the applicable SNA or LRRA rate schedule, based on the net rates in effect on the effective date of the Schedule 123 rate revisions. If the amount of the proposed rate revision exceeds the 2% limit, only a 2% rate increase will be proposed and any remaining amount in the SNA balancing Account will be carried over to the following year(s). Rate revisions resulting in a rate decrease are not subject to the 2% limit. **(C)** **(C)**

4. The LRRA prices for Customers served under the provisions of Schedules 485, 489, 490, 491, 492, 495 and 689 will be calculated to apply to distribution services only.

5. The SNA and LRRA mechanisms will terminate on December 31, 2025 if not extended by the Commission. **(C)**

SCHEDULE 125 (Continued)

CHANGES IN NET VARIABLE POWER COSTS

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0331. **(I)**

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 6, 2020, for one-time only and due to extraordinary wildfire events in the state of Oregon, the Company will file updated estimates with final planned maintenance outages for the following hydro facilities: Faraday, Oak Grove, Harriet Lake, Timothy Lake, and Stone Creek.

On November 15th, 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) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES

Schedule		¢ per kWh	
7		0.000	(R)
15		0.000	
32		0.000	
38		0.000	
47		0.000	
49		0.000	
75			
	Secondary	0.000 [1]	
	Primary	0.000 [1]	
	Subtransmission	0.000 [1]	
83		0.000	
85			
	Secondary	0.000	
	Primary	0.000	
89			
	Secondary	0.000	
	Primary	0.000	
	Subtransmission	0.000	
90		0.000	
91		0.000	
92		0.000	
95		0.000	(R)

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

SPECIAL CONDITIONS

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

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an “automatic adjustment clause” as defined in ORS 757.210.

APPLICABLE

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

ANNUAL POWER COST VARIANCE

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

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record Annual Variance amounts. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. This account will accrue interest at the Commission-authorized rate for deferred accounts. At the end of each year the Adjustment Amount for the calendar year will be adjusted by 50% of the annual interest calculated at the Commission-authorized rate. This amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0331 to account for franchise fees, uncollectibles, and OPUC fees. **(I)**

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount to the extent that such recovery will not cause the Company’s Actual Return on Equity (ROE) for the year to exceed its Authorized ROE minus 100 basis points. The Company will refund the Adjustment Amount to the extent that such refunding will not cause the Company’s Actual Return on Equity (ROE) for the year to fall below its Authorized ROE plus 100 basis points.

Schedule 126 (Continued)

DEFINITIONS (Continued)

Net Variable Power Costs (NVPC)

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

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the deferral period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- Include Energy Charge revenues from Schedules 76R, 38, 83, 85, 89, 90, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485, 489, 490, 491, 492, 495 and 689 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.
- Actual NVPC will be increased to include the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.
- Include reciprocating engine lubrication oil expenses.
- Include actual State and Federal Production Tax Credits.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0331 to account for franchise fees, uncollectables, and OPUC fees. **(I)**

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

SHORT-TERM TRANSITION ADJUSTMENT

The Short-Term Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service in 2021, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2022: (C)
(C)

Schedule		Annual ¢ per kWh [1]	
32		2.154	(R)
38		1.682	
75	Secondary	1.793 [2]	
	Primary	1.773 [2]	
	Subtransmission	1.808 [2]	
83		2.092	
85	Secondary	1.905	
	Primary	1.867	(R)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual ¢ per kWh (1)	
89	Secondary	1.793	(R)
	Primary	1.773	
	Subtransmission	1.808	
90		1.446	
91		1.630	
95		1.630	
515		1.561	
532		2.154	
538		1.682	
549		2.772	
575	Secondary	1.793 (2)	
	Primary	1.773 (2)	
	Subtransmission	1.808 (2)	
583		2.092	
585	Secondary	1.905	
	Primary	1.867	
589	Secondary	1.793	
	Primary	1.773	
	Subtransmission	1.808	
590		1.446	
591		1.630	
592		1.618	
595		1.630	(R)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT REVISIONS

The Annual Short-Term Transition Adjustment rate will be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. Indicative, non-binding estimates for the Annual Short-Term Transition Adjustment and Cost-of-Service Energy Prices will be posted by the Company by September 1 and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

SCHEDULE 129
LONG-TERM TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Periods A - O: 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.

For Enrollment Period P (2017), 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	
2018	3.339	3.294	3.007	2.953	2.892	2.732	2.805	
2019	3.072	3.031	2.760	2.711	2.653	2.513	2.546	
2020	3.072	3.031	2.760	2.711	2.653	2.513	2.546	
2021	3.072	3.031	2.760	2.711	2.653	2.513	2.546	
2022	2.245	2.240	2.029	2.014	1.973	1.826	1.903	(R)
After 2022	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

For Enrollment Period Q (2018), 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	
2019	2.972	2.958	2.625	2.576	2.493	2.540	2.511	
2020	2.972	2.958	2.625	2.576	2.493	2.540	2.511	
2021	2.972	2.958	2.625	2.576	2.493	2.540	2.511	
2022	2.145	2.167	1.894	1.879	1.813	1.853	1.838	**(R)**
2023	2.145	2.167	1.894	1.879	1.813	1.853	1.838	**(R)**
After 2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

For Enrollment Period R (2019), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2020	2.376	2.359	2.042	2.004	1.918	1.960	1.968	
2021	2.376	2.359	2.042	2.004	1.918	1.960	1.968	
2022	1.549	1.568	1.311	1.307	1.238	1.273	1.295	**(R)**
2023	1.549	1.568	1.311	1.307	1.238	1.273	1.295	|
2024	1.549	1.568	1.311	1.307	1.238	1.273	1.295	**(R)**
After 2024	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

For Enrollment Period S (2020), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2021	3.167	3.137	2.801	2.749	2.770	2.704	2.666	
2022	2.340	2.346	2.070	2.052	2.090	2.017	1.993	(R)
2023	2.340	2.346	2.070	2.052	2.090	2.017	1.993	
2024	2.340	2.346	2.070	2.052	2.090	2.017	1.993	
2025	2.340	2.346	2.070	2.052	2.090	2.017	1.993	(R)
After 2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

For Enrollment Period T (2021), 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	
2022	2.123	2.091	1.752	1.720	1.683	1.687	1.742	
2023	2.123	2.091	1.752	1.720	1.683	1.687	1.742	
2024	2.123	2.091	1.752	1.720	1.683	1.687	1.742	
2025	2.123	2.091	1.752	1.720	1.683	1.687	1.742	
2026	2.123	2.091	1.752	1.720	1.683	1.687	1.742	
After 2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(N)

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out

For Enrollment Period S (2020), the Transition Cost Adjustment will be:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh
2021	3.170	3.085	2.770	2.718	2.624	2.476	2.612
2022	3.170	3.085	2.770	2.718	2.624	2.476	2.612
2023	3.170	3.085	2.770	2.718	2.624	2.476	2.612

For Enrollment Period T (2021), the Transition Cost Adjustment will be: **(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
2022	2.022	1.951	1.632	1.602	1.664	1.380	1.664
2023	2.022	1.951	1.632	1.602	1.664	1.380	1.664
2024	2.022	1.951	1.632	1.602	1.664	1.380	1.664

(N)

SCHEDULE 129 (Concluded)

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, and 495 customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges or Distribution Charges of all rate schedules. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage or Distribution Charges resulting from changes in fixed generation revenues shall not result in an overall rate increase or decrease of more than 2 percent except as noted below. For those Enrollment Periods in which the first-year Schedule 129 Transition Adjustments are expected to be positive charges to participants, the projected first-year revenues from Schedule 129 will be netted against the changes in fixed generation costs for purposes of calculating the proposed overall rate increase or decrease. Should the rate increase or decrease exceed 2 percent, the amounts exceeding 2 percent will be deferred for future recovery through a balancing account. This balancing account will be considered an "Automatic Adjustment Clause" as defined in ORS 757.210. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased participating load will be determined.

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

Schedule		¢ per kWh	
85	Secondary	2.813	(R)
	Primary	2.784	
89	Secondary	2.666	
	Primary	2.637	
	Subtransmission	2.609	
90		2.631	
91		2.510	
92		2.510	
95		2.510	(R)

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.

SCHEDULE 135
DEMAND RESPONSE COST RECOVERY MECHANISM

PURPOSE

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

ADJUSTMENT RATE

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

Schedule	Adjustment Rate		
7	0.125	¢ per kWh	(I)
15/515	0.095	¢ per kWh	
32/532	0.114	¢ per kWh	
38/538	0.105	¢ per kWh	
47	0.138	¢ per kWh	
49/549	0.138	¢ per kWh	
75/575			
Secondary	0.102	¢ per kWh(1)	
Primary	0.101	¢ per kWh(1)	
Subtransmission	0.101	¢ per kWh(1)	
83/583	0.113	¢ per kWh	
85/585			
Secondary	0.110	¢ per kWh	
Primary	0.108	¢ per kWh	(I)

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

SCHEDULE 135 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
89/589			
Secondary	0.102	¢ per kWh	(I)
Primary	0.101	¢ per kWh	
Subtransmission	0.101	¢ per kWh	
90/590	0.096	¢ per kWh	
91/591	0.095	¢ per kWh	
92/592	0.099	¢ per kWh	
95/595	0.095	¢ per kWh	(I)

BALANCING ACCOUNT

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

DEFERRAL MECHANISM

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

SPECIAL CONDITION

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

SCHEDULE 137
CUSTOMER-OWNED SOLAR PAYMENT OPTION
COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the costs associated with the Solar Payment Option pilot not otherwise included in rates. This adjustment schedule is implemented as an "automatic adjustment clause" as provided for under ORS 757.210, and defined in Renewable Portfolio Standards.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R and 576R. **(C)**

ADJUSTMENT RATES

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

Schedule	Adjustment Rate		
7	0.016	¢ per kWh	**(R)**
15	0.027	¢ per kWh	
32	0.015	¢ per kWh	
38	0.016	¢ per kWh	
47	0.024	¢ per kWh	
49	0.018	¢ per kWh	
75			
Secondary	0.008	¢ per kWh(1)	
Primary	0.008	¢ per kWh(1)	
Subtransmission	0.010	¢ per kWh(1)	
83	0.012	¢ per kWh	
85			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	**(R)**

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

SCHEDULE 137 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate		
89			
Secondary	0.008	¢ per kWh	(R)
Primary	0.008	¢ per kWh	
Subtransmission	0.010	¢ per kWh	
90	0.008	¢ per kWh	
91	0.027	¢ per kWh	
92	0.011	¢ per kWh	
95	0.027	¢ per kWh	(R)
485		¢ per kWh	(N)
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
489		¢ per kWh	
Secondary	0.008	¢ per kWh	
Primary	0.008	¢ per kWh	
Subtransmission	0.009	¢ per kWh	
490	0.008	¢ per kWh	
491	0.027	¢ per kWh	
492	0.011	¢ per kWh	
495	0.027	¢ per kWh	(N)
515	0.027	¢ per kWh	(R)
532	0.015	¢ per kWh	
538	0.016	¢ per kWh	
549	0.018	¢ per kWh	
575			
Secondary	0.008	¢ per kWh	
Primary	0.008	¢ per kWh	
Subtransmission	0.010	¢ per kWh	(R)

(M)

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

SCHEDULE 137 (Concluded)

ADJUSTMENT RATES (Continued)

583	0.012	¢ per kWh	(R)
585			
Secondary	0.010	¢ per kWh	
Primary	0.010	¢ per kWh	
589			
Secondary	0.008	¢ per kWh	
Primary	0.008	¢ per kWh	
Subtransmission	0.010	¢ per kWh	
590	0.008	¢ per kWh	
591	0.027	¢ per kWh	
592	0.011	¢ per kWh	
595	0.027	¢ per kWh	(R)
689		¢ per kWh	(N)
Secondary	0.008	¢ per kWh	
Primary	0.008	¢ per kWh	
Subtransmission	0.009	¢ per kWh	(N)

BALANCING ACCOUNT

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

DEFERRAL MECHANISM

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

SPECIAL CONDITION

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule. (C) (C)

SCHEDULE 138
ENERGY STORAGE COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with 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, and 576R.

ADJUSTMENT RATE

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

Schedule	Adjustment Rate
7	0.004 ¢ per kWh
15/515	0.003 ¢ per kWh
32/532	0.004 ¢ per kWh
38/538	0.004 ¢ per kWh
47	0.007 ¢ per kWh
49/549	0.006 ¢ per kWh
75/575	
Secondary	0.003 ¢ per kWh
Primary	0.003 ¢ per kWh
Subtransmission	0.003 ¢ per kWh
83/583	0.004 ¢ per kWh
85/585	
Secondary	0.004 ¢ per kWh
Primary	0.004 ¢ per kWh

SCHEDULE 138 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
89/589		
Secondary	0.003	¢ per kWh
Primary	0.003	¢ per kWh
Subtransmission	0.003	¢ per kWh
90/590	0.003	¢ per kWh
91/591	0.003	¢ per kWh
92/592	0.003	¢ per kWh
95/595	0.003	¢ 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 the energy storage pilots. The rate on this schedule recovers only the incremental costs for implementation and administration of energy storage pilots. The deferral will be amortized over one year in this schedule unless otherwise approved by the Oregon Public Utility Commission.

SPECIAL CONDITION

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

SCHEDULE 139
NEW LARGE LOAD TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected New Large Load Cost-of-Service Opt-Out service under Schedule 689. This transition adjustment will be paid when the Customer begins service under Schedule 689. This transition adjustment represents 20 percent of the Company's fixed generation costs and is subject to change annually during the Customer's five-years enrolled in Schedule 689. At the end of the Customer's five-year payment term of these transition adjustments, the Customer will no longer be subject to the charges in this rate schedule. The Customer will not be subject to the charges in this rate schedule with at least three years of notification to the Company of a return to cost-of-service pricing.

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Period 1 (2020), the Transition Cost Adjustment will be:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	
2020	0.679	0.667	0.658	
2021	0.702	0.689	0.680	
2022	0.533	0.527	0.522	(R)
2023	0.533	0.527	0.522	
2024	0.533	0.527	0.522	
2025*	0.533	0.527	0.522	(R)
After 2026	0.000	0.000	0.000	

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

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh	
2021	0.702	0.689	0.680	
2022	0.533	0.527	0.522	(R)
2023	0.533	0.527	0.522	
2024	0.533	0.527	0.522	
2025	0.533	0.527	0.522	
2026*	0.533	0.527	0.522	(R)
After 2027	0.000	0.000	0.000	

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

SCHEDULE 139 (Continued) **(T)**

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

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

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh
2022	0.533	0.527	0.522
2023	0.533	0.527	0.522
2024	0.533	0.527	0.522
2025	0.533	0.527	0.522
2026	0.533	0.527	0.522
2027*	0.533	0.527	0.522
After 2028	0.000	0.000	0.000

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

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 Customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges or Distribution Charges of all rate schedules. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage or Distribution Charges resulting from changes in fixed generation revenues shall not result in an overall rate increase or decrease of more than 2 percent except as noted below. For those Enrollment Periods in which the first-year Schedule 139 Transition Adjustments are expected to be positive charges to participants, the projected first-year revenues from Schedule 139 will be netted against the changes in fixed generation costs for purposes of calculating the proposed overall rate increase or decrease. Should the rate increase or decrease exceed 2 percent, the amounts exceeding 2 percent will be deferred for future recovery through a balancing account. This balancing account will be considered an "Automatic Adjustment Clause" as defined in ORS 757.210. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased participating load will be determined.

(M)

SCHEDULE 139 (Concluded)

TERM (M)

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

SCHEDULE 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. **(C)** **(C)**

APPLICABLE

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

ADJUSTMENT RATES

Schedule 146 Adjustment Rates will be set based on an equal percent of Energy Charge revenues applicable at the time of any filing that revises rates pursuant to this schedule.

Schedule	Adjustment Rate		
7	0.334	¢ per kWh	**(I)**
15/515	0.238	¢ per kWh	
32/532	0.286	¢ per kWh	
38/538	0.265	¢ per kWh	
47	0.319	¢ per kWh	
49/549	0.328	¢ per kWh	
75/575			
Secondary	0.265	¢ per kWh	
Primary	0.262	¢ per kWh	
Subtransmission	0.264	¢ per kWh	
83/583	0.284	¢ per kWh	
85/585			
Secondary	0.274	¢ per kWh	
Primary	0.269	¢ per kWh	
89/589			
Secondary	0.265	¢ per kWh	
Primary	0.262	¢ per kWh	
Subtransmission	0.264	¢ per kWh	**(I)**

SCHEDULE 146 (Continued) (T)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate		
90/590	0.245	¢ per kWh	(I)
91/591	0.242	¢ per kWh	
92/592	0.256	¢ per kWh	
95/595	0.242	¢ per kWh	(I)

PART A- DECOMMISSIONING AMOUNTS (N)(M)

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. (N)

(M)
(D)

SCHEDULE 146 (Concluded)

DETERMINATION OF ADJUSTMENT AMOUNTS (M)

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 decommissioning revenue requirement and depreciation revenue requirement (Parts A and B). Any additional updates (Part C) to this schedule can only be made pursuant to 1) the removal of Colstrip from regulated service, or 2) rate change requests effectuated through a separate docketed proceeding as allowable through Oregon Revised Statutes and Oregon Administrative Rules (e.g., through a general rate case). (C) (C)(M)

BALANCING ACCOUNT (N)

The Company will maintain a balancing account to track the difference between the Schedule 146 Part A only amounts and the actual Schedule 146 revenues for Part A. This difference will accrue interest at the Commission-authorized rate for deferred accounts. No other amounts included within Schedule 146 will be subject to balancing account treatment.

TIME AND MANNER OF FILING

Commencing in 2022, the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the following year based on the updated revenue requirements described above.

2. Work papers supporting the Schedule 146 prices, the updated depreciation and decommissioning revenue requirements, the projected applicable billing determinants, and the projected balancing account activity.

With respect to a Schedule 146 rate change for the inclusion or update of costs outside of revised decommissioning or operating life adjustments and in compliance with the Commission's findings in separate cost recovery proceeding(s), the Company will file updated Schedule 146 rates by no less than 30 days prior to the rate effective date.

(N)

SCHEDULE 150
TRANSPORTATION ELECTRIFICATION COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with transportation electrification 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, and 576R.

ADJUSTMENT RATE

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

Schedule	Adjustment Rate	
7	0.016	¢ per kWh
15/515	0.027	¢ per kWh
32/532	0.015	¢ per kWh
38/538	0.017	¢ per kWh
47	0.024	¢ per kWh
49/549	0.018	¢ per kWh
75/575		
Secondary	0.010	¢ per kWh
Primary	0.008	¢ per kWh
Subtransmission	0.010	¢ per kWh
83/583	0.012	¢ per kWh
85/585		
Secondary	0.010	¢ per kWh
Primary	0.010	¢ per kWh
89/589		
Secondary	0.010	¢ per kWh
Primary	0.008	¢ per kWh
Subtransmission	0.010	¢ per kWh

SCHEDULE 150 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule		Adjustment Rate	
90/590		0.008	¢ per kWh
91/591		0.027	¢ per kWh
92/592		0.011	¢ per kWh
95/595		0.027	¢ per kWh
485			
	Secondary	0.010	¢ per kWh
	Primary	0.010	¢ per kWh
489			
	Secondary	0.009	¢ per kWh
	Primary	0.010	¢ per kWh
	Subtransmission	0.009	¢ per kWh
689			
	Secondary	0.009	¢ per kWh
	Primary	0.008	¢ per kWh
	Subtransmission	0.009	¢ per kWh

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 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 300 (Continued)

LINE EXTENSIONS (Rule I)

Line Extension Allowance (Section 1)[1]

Residential Service All Electric[2]	$2,660.00 / dwelling unit	(I)
Residential Service Primary Other[3]	$1,867.00 / dwelling unit	
Schedule 32	$0.2638 / estimated annual kWh	
Schedules 38 and 83	$0.1082 / estimated annual kWh	
Schedules 85 and 89 Secondary Voltage Service	$0.0791 / estimated annual kWh	
Schedules 85 and 89 Primary Voltage Service	$0.0474 / estimated annual kWh	
Schedules 15, 91 and 95 Outdoor Lighting	$0.1992 / estimated annual kWh	(I)
Schedule 92 Traffic Signals	$0.0521 / estimated annual kWh	(R)
Schedules 47 and 49	$0.0995 / estimated annual kWh	(I)

Trenching or Boring (Section 2)

Trenching and backfilling associated with Service Installation except where General Rules and Regulations require actual cost.

In Residential Subdivisions:	
Short-side service connection up to 30 feet	$ 100.00
Otherwise:	
First 75 feet or less	$ 219.00
Greater than 75 feet	$ 3.80 / foot
Mainline trenching, boring and backfilling	Estimated Actual Cost

Lighting Underground Service Areas[4]

Installation of conduit on a wood pole for lighting purposes	$ 75.00 per pole

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

(2) Residential All Electric Service is a dwelling where the primary heating is provided by an active electric HVAC-system. Common qualifying system include but are not limited to stand-alone ducted heat pumps, ducted heat pumps with auxiliary electric resistant heat strips, ductless mini-splits, and packaged terminal air conditioners. Electric resistant heat strips, baseboards, and electric resistant in-wall heaters are allowed as back-up heat source. Dwellings heated solely by electric resistance heating systems without a primary qualifying electric heating system are excluded from the Residential All Electric Service Line extension allowance.

(3) Residential Service Primary Other is a dwelling where the primary heating source is provided by an alternative HVAC-system that uses heating fuels such as natural gas, propane, oil, and biodiesel. Common qualifying HVAC-systems include but are not limited to stand-alone combustion furnaces, combustion furnaces with air conditioners, combustion furnaces with heat pumps, as well as gas boilers. Dwellings heated primarily by electric resistance heating and passive means also fall into this category.

(4) Applies only to 1-inch conduit without brackets.

SCHEDULE 300 (Concluded)

LINE EXTENSIONS (Rule I) Continued

Additional Services (Section 3)
(applies solely to Residential Subdivisions in Underground Service Areas)

Service Guarantee	$ 100.00
Wasted Trip Charge	$ 100.00
Service Locate Charge	$ 30.00
Long-Side Service Connection	$ 120.00

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$1077.00	(I)
Permanent Customer obtained		
Overhead Service	$607.00	
Underground Service	$632.00	
Existing service	$819.00	(I)

Enhanced Temporary Service

Fixed fee for initial 6-month period	$865.00	(C)
Fixed fee per 6-month renewal	$354.00	(C)

Temporary Area Lights — Estimated Actual Cost(1)

PGE TRAINING

Educational and Energy Efficiency (EE) training available to:

PGE Business Customer	No Charge(2)
Non-PGE Business Customer	Estimated Actual Cost(3)

(1) Based on install, removal and energy for pole and luminaire. Energy will be calculated based on burning hours used for Option C Schedule 91, 95
(2) Charges may be assessed for training courses registered through the states of Oregon and Washington for electrical licensees.
(3) Based on the cost associated with instructor, facility, food, and materials per attendee.

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$810.00	$760.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.48	$3.45	(I)
Over 200 kW	$2.28	$2.25	(I)
per kW of monthly On-Peak Demand	$1.60	$1.58	(R)
System Usage Charge			
per kWh	0.180 ¢	0.180 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 485 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

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

Direct Access Service

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

Company Supplied Energy

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

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

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

SCHEDULE 485 (Continued)

FACILITY CAPACITY

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

CHANGE IN APPLICABILITY

If a Customer’s usage changes such that their facility capacity falls below 201 kW, the customer will be moved to an otherwise applicable rate schedule.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum monthly On-Peak Demand (in kW) will be 100 kW for primary voltage service.

ON AND OFF PEAK HOURS

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

LOSSES

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

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

REACTIVE DEMAND CHARGE

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

ADJUSTMENTS

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

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

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$5,380.00	$3,630.00	$5,680.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	(R)
Over 4,000 kW	$1.04	$1.03	$1.03	
per kW of monthly On-Peak Demand	$1.60	$1.58	$0.50	(R)
System Usage Charge				
per kWh	0.126 ¢	0.127 ¢	0.126 ¢	(I)

* See Schedule 100 for applicable adjustments.

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

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

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

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

Direct Access Service

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

Company Supplied Energy

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

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

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

SCHEDULE 489 (Continued)

MINIMUM CHARGE

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

ON AND OFF PEAK HOURS

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

LOSSES

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

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

REACTIVE DEMAND CHARGE

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

ADJUSTMENTS

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

SPECIAL CONDITIONS

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

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

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

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

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. **(C)**

MONTHLY RATE

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

Basic Charge	$20,900.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.70	**(I)**
Over 4,000 kW	$1.39	**(I)**
per kW of monthly On-Peak Demand	$1.58	**(R)**
System Usage Charge		
per kWh	(0.023) ¢	**(I)**

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 490 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

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

Direct Access Service

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

Company Supplied Energy

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

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

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

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

SCHEDULE 490 (Continued)

ON AND OFF PEAK HOURS

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

LOSSES

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

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

REACTIVE DEMAND CHARGE

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

ADJUSTMENTS

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

SPECIAL CONDITIONS

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

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

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

SCHEDULE 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 7.051 ¢ per kWh **(I)**

MARKET BASED PRICING OPTION

Energy Supply

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

SCHEDULE 491 (Continued)

MARKET BASED PRICING OPTION (Continued)

Direct Access Service

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

Company Supplied Energy

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

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

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company’s Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

ON AND OFF PEAK HOURS

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

LOSSES

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

Secondary Delivery Voltage 1.0640 **(R)**

SCHEDULE 491 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$124.00 per hour	$155.00 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 **							
	70	6,300	30	*	$2.93	$2.12	**(R)(I)**
	100	9,500	43	*	3.96	3.03	**(R)(I)**
	150	16,000	62	*	5.18	4.37	**(I)**
	200	22,000	79	*	6.54	5.57	**(I)**
	250	29,000	102	*	8.00	7.19	**(I)**
	400	50,000	163	*	12.48	11.49	**(I)**
Cobrahead, Non-Power Door	70	6.300	30	$6.83	3.22	2.12	**(I)(R)**
	100	9,500	43	7.44	4.08	3.03	**(R)(I)**
	150	16,000	62	8.84	5.43	4.37	**(R)(I)**
	200	22,000	79	10.68	6.70	5.57	**(R)(I)**
	250	29,000	102	11.91	8.26	7.19	**(R)(I)**
	400	50,000	163	16.40	12.59	11.49	**(I)**
Flood	250	29,000	102	13.22	8.46	7.19	**(I)**
	400	50,000	163	17.52	12.76	11.49	**(I)**
Early American Post-Top	100	9,500	43	8.33	4.23	3.03	**(I)(R)**
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	7.09	3.27	2.12	**(R)(I)**
	100	9,500	43	*	4.25	3.03	**(C)(R)(I)**
	150	16,000	62	*	5.65	4.37	**(C)(R)(I)**

* 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	$4.61	$0.17	**(R)(I)**
Fiberglass, Black or Bronze	30	7.49	0.28	**(I)**
Fiberglass, Gray	30	7.49	0.28	**(R)(I)**
Fiberglass, Smooth, Black or Bronze	18	4.89	0.19	**(R)(I)**
Fiberglass, Regular				
Black, Bronze, or Gray	18	$4.28	$0.16	**(I)**
	35	7.31	0.28	**(R)(I)**
Aluminum, Regular with Breakaway Base	35	18.74	0.71	**(I)**
Wood, Standard	30 to 35	$5.58	$0.21	**(I)**
Wood, Standard	40 to 55	6.57	0.25	**(I)**

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	$11.49	$4.70	$3.03	**(I)**
HADCO Victorian, HPS	150	16,000	62	12.83	6.04	4.37	**(I)**
	200	22,000	79	14.35	7.29	5.57	**(I)**
	250	29,000	102	15.88	8.89	7.19	**(I)**
HADCO Capitol Acorn, HPS	100	9,500	43	15.20	5.26	3.03	**(I)**
	150	16,000	62	*	6.56	4.37	**(C)(I)**
	200	22,000	79	*	7.84	5.57	**(C)(I)**
	250	29,000	102	*	8.08	7.19	**(C)(R)(I)**
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	12.59	4.84	3.03	**(I)**
	150	16,000	62	*	5.90	4.37	**(C)(I)**
HADCO Techtra, HPS	100	9,500	43	19.28	5.87	3.03	**(R)(I)**
	150	16,000	62	21.38	7.33	4.37	**(I)**
	250	29,000	102	*	9.92	7.19	**(C)(I)**
HADCO Westbrooke, HPS	70	6,300	30	13.65	4.23	*	**(I)**
	100	9,500	43	14.70	5.16	3.03	**(I)**

* 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	*	$6.79	$4.37	**(C)(I)**
	200	22,000	79	*	6.52	5.57	**(C)(R)(I)**
	250	29,000	102	$17.39	9.10	7.19	**(R)(I)**
Special Types							
Flood, Metal Halide	350	30,000	139	*	11.25	9.80	**(C)(I)**
Flood, HPS	750	105,000	285	28.58	21.88	20.10	**(I)**
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	4.51	**(I)**
Ornamental Acorn	55	2,800	21	*	*	1.48	**(I)**
Ornamental Acorn Twin	55	5,600	42	*	*	2.95	**(I)**
Composite, Twin	140	6,815	54	*	*	3.81	**(I)**
	175	9,815	66	*	*	4.65	**(I)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B		
Aluminum, Regular	25	$7.92	$0.30	**(R)**	
	30	9.09	0.34	**(R)**	
	35	10.52	0.40	**(R)**	
Aluminum Davit	25	8.45	0.32	**(R)**	
	30	9.52	0.36	**(R)**	
	35	10.88	0.41	**(R)**	**(I)**
	40	13.97	0.53	**(R)**	**(I)**
Aluminum Double Davit	30	10.56	0.40	**(R)**	**(I)** **(M)**

* 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, Fluted Ornamental	14	7.51	0.28	**(M)(R)**
Aluminum, Smooth Techtra Ornamental	18	16.41	0.62	**(R)**
Aluminum, Fluted Ornamental	16	7.79	0.30	**(R)**
Aluminum, Double-Arm, Smooth Ornamental	18	12.65	0.48	**(R)(I)**
Aluminum, Fluted Westbrooke	18	15.42	0.58	**(R)**
Aluminum, Non-Fluted Ornamental, Pendant	22	15.32	0.58	**(C)**
Fiberglass, Fluted Ornamental Black	14	10.51	0.40	**(R)(I)**
Fiberglass, Anchor Base, Gray or Black	35	9.98	0.38	**(R)**
Fiberglass, Anchor Base (Color may vary)	25	8.87	0.34	**(R)(I)**
	30	10.84	0.41	**(I)**

SERVICE RATE FOR OBSOLETE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Metal Halide	150	10,000	60	*	$5.39	$4.23	**(C)(R)(I)**
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.75	**(I)**
	175	7,000	66	9.07	5.71	4.65	**(I)**
	250	10,000	94	*	*	6.63	**(I)**
	400	21,000	147	15.44	11.46	10.36	**(I)**
	1,000	55,000	374	31.40	27.59	26.37	**(I)**
Holophane Mongoose,	150	16,000	62	*	6.35	4.37	**(C)(I)**
HPS	250	29,000	102	*	9.18	*	**(C)(I)**

* Not offered.

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$7.48	*	*	**(R)**
Mercury Vapor	175	7,000	66	10.01	$5.81	$4.65	**(I)**
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	4.23	**(I)**
	70	6,300	30	*	*	2.12	**(I)**
	100	9,500	43	*	4.52	3.03	**(R)(I)**
	150	16,000	62	*	5.26	4.37	**(R)(I)**
	250	29,000	102	*	*	7.19	**(I)**
	400	50,000	163	*	*	11.49	**(I)**
Metal Halide	250	20,500	99	*	7.88	6.98	**(I)**
	400	40,000	156	*	11.90	*	**(I)**
Cobrahead, Metal Halide	175	12,000	71	*	6.18	5.01	**(I)**
Flood, Metal Halide	400	40,000	156	16.34	12.20	11.00	**(I)**
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.92	*	**(R)**
100/150 Watt Ballast	100	9,500	43	*	3.92	*	**(R)**
100/150 Watt Ballast	150	16,000	62	*	5.26	4.37	**(R)(I)**
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.26	4.37	**(R)(I)**
KIM Archetype, HPS	250	29,000	102	*	9.20	7.19	**(I)**
	400	50,000	163	*	13.94	11.49	**(I)**

* Not offered

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$10.48	$3.69	*	**(I)(R)**
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	$2.12	**(I)**
Mercury Vapor	175	7,000	66	*	*	4.65	**(I)**
Early American Post-Top, HPS							
Black	70	6,300	30	7.26	3.16	2.12	**(I)(R)**
Rectangle Type	200	22,000	79	*	*	5.57	**(I)**
Incandescent	92	1,000	31	*	*	2.19	**(I)**
	182	2,500	62	*	*	4.37	**(I)**
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	9.85	5.75	4.65	**(I)**
Flood, HPS	70	6,300	30	6.57	3.21	*	**(R)**
	100	9,500	43	7.49	4.10	3.03	**(I)(R)**
	200	22,000	79	11.49	6.73	5.57	**(I)**
Cobrahead, HPS							
Power Door	310	37,000	124	*	10.01	8.74	**(C)(I)**
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	3.03	**(I)**
Twin ornamental, HPS	Twin 100	9,500	86	*	*	6.06	**(I)**
Compact Fluorescent	28	N/A	12	*	*	0.85	**(I)**

* 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	4.26	*	**(R)**
Aluminum, Painted Ornamental	35	*	*	**(C)**
Aluminum, Regular	16	4.26	0.16	**(R)**
Bronze Alloy GardCo	12	*	0.23	**(I)**
Concrete, Ornamental	35 or less	7.92	0.30	**(R)**
Fiberglass, Direct Bury with Shroud	18	6.30	0.24	**(R)**
Steel, Painted Regular **	25	7.92	0.30	**(R)**
Steel, Painted Regular **	30	9.09	0.34	**(R)**
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.41	**(I)**
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41	**(I)**
Wood, Laminated without Mast Arm	20	4.61	0.17	**(R)(I)**
Wood, Laminated Street Light Only	20	4.61	*	**(R)**
Wood, Curved Laminated	30	6.40	0.28	**(R)(I)**
Wood, Painted Underground	35	5.58	0.21	**(I)**

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

SERVICE RATES FOR ALTERNATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$2.59	$2.26	**(R)(I)**
	165	12,000	60	*	2.03	1.06	**(R)**
	165	12,000	60	*	5.51	4.23	**(C)(I)**

SCHEDULE 492
TRAFFIC SIGNALS
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

CHARACTER OF SERVICE

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

MONTHLY RATE

The charge per Service Point (SP)* is:

Distribution Charge	1.743 ¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

MARKET BASED PRICING OPTION

Energy Supply

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

Direct Access Service

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

SCHEDULE 492 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

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

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

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

ON AND OFF PEAK HOURS

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

LOSSES

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

Secondary Delivery Voltage 1.0640 **(R)**

ADJUSTMENTS

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

SCHEDULE 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 7.051 ¢ per kWh **(I)**

MARKET BASED PRICING OPTION

Energy Supply

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

Direct Access Service

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

Company Supplied Energy

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

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

SCHEDULE 495 (Continued)

MARKET BASED PRICING OPTION (Continued)

Wheeling Charge

The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

ON AND OFF PEAK HOURS

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

LOSSES

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

Secondary Delivery Voltage 1.0640 **(R)**

SCHEDULE 495 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates (1)	Straight Time	Overtime
	$124.00 per hour	$155.00 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	$10.13	$0.97	(C)
	>25-30	3,470	9	5.12	1.04	
	>30-35	2,530	11	5.53	1.19	
	>35-40	4,245	13	5.42	1.33	
	>40-45	5,020	15	5.68	1.47	
	>45-50	3,162	16	5.85	1.54	
	>50-55	3,757	18	6.23	1.69	
	>55-60	4,845	20	6.04	1.82	
	>60-65	4,700	21	6.12	1.89	
	>65-70	5,050	23	4.49	2.04	
	>70-75	7,640	25	6.99	2.19	
	>75-80	8,935	26	7.07	2.26	
	>80-85	9,582	28	7.22	2.40	
	>85-90	10,230	30	7.33	2.55	
	>90-95	9,928	32	7.51	2.69	
	>95-100	11,719	33	7.58	2.76	
	>100-110	7,444	36	8.07	2.97	
	>110-120	12,340	39	8.01	3.18	
	>120-130	13,270	43	8.30	3.46	
	>130-140	14,200	46	9.33	3.69	
	>140-150	15,250	50	10.59	4.01	
	>150-160	16,300	53	10.73	4.22	
	>160-170	17,300	56	11.01	4.43	
	>170-180	18,300	60	11.11	4.70	
	>180-190	19,850	63	11.51	4.92	
	>190-200	21,400	67	11.90	5.20	(C)

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Acorn						
LED	>35-40	3,262	13	$12.62	$1.53	(C)
	>40-45	3,500	15	12.85	1.67	
	>45-50	5,488	16	10.84	1.68	
	>50-55	4,000	18	13.07	1.88	
	>55-60	4,213	20	13.11	2.02	
	>60-65	4,273	21	13.29	2.09	
	>65-70	4,332	23	13.29	2.23	
	>70-75	4,897	25	13.46	2.37	
HADCO LED	70	5,120	24	17.27	2.41	(C)
Pendant LED (Non-Flared)	36	3,369	12	13.93	1.50	(R)(I)
	53	5,079	18	15.08	1.94	
	69	6,661	24	15.61	2.36	
	85	8,153	29	16.49	2.73	(R)(I) (D)
Pendant LED (Flared)	>35-40	3,369	13	14.16	1.57	(C)
	>40-45	3,797	15	14.41	1.71	
	>45-50	4,438	16	14.48	1.78	
	>50-55	5,079	18	15.54	1.95	
	>55-60	5,475	20	15.81	2.09	
	>60-65	6,068	21	15.88	2.16	
	>65-70	6,661	23	16.61	2.32	
	>70-75	7,034	25	16.89	2.46	
	>75-80	7,594	26	17.15	2.54	
	>80-85	8,153	28	17.14	2.68	(C)
Post-Top, American Revolution LED	>30-35	3,395	11	6.95	1.23	(C)
	>45-50	4,409	16	7.62	1.59	
Flood LED	>80-85	10,530	28	8.16	2.42	
	>120-130	16,932	43	9.72	3.50	
	>180-190	23,797	63	12.13	4.94	
	>370-380	48,020	127	20.81	9.56	(C)

(M)

SCHEDULE 495 (Continued)

SPECIALTY SERVICES OFFERED (M)

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

. Trimming of trees adjacent to streetlight equipment and circuits.
. Arterial patrols to ensure correct operation of streetlights.
. Painting or staining of wood and steel streetlight poles. (M)

ESS CHARGES

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

ADJUSTMENTS

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

SPECIAL CONDITIONS

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

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

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

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer’s request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

(M)

SCHEDULE 495 (Continued)

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

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

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage. **(M)**

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A “Qualified Worker” means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a “qualified person” or “qualified employee” with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

10. Indemnification:

    a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

SCHEDULE 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. **(N)**

Distribution Charge 7.068 ¢ per kWh **(N)**

SERVICE RATES FOR AREA LIGHTING

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$9.00[2]	**(I)**
	400	21,000	147	15.18[2]	**(I)**
	1,000	55,000	374	31.17[2]	**(I)**
HPS	70	6,300	30	6.75[2]	**(I)**
	100	9,500	43	7.37	**(R)**
	150	16,000	62	8.77	**(R)**
	200	22,000	79	10.40	**(I)**
	250	29,000	102	11.64	**(I)**
	310	37,000	124	13.39[2]	**(I)**
	400	50,000	163	16.14	**(I)**
					(M)

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

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Flood , HPS	100	9,500	43	7.42[2]	**(I) (M)**
	200	22,000	79	11.21[2]	**(I)**
	250	29,000	102	12.95	**(I)**
	400	50,000	163	17.26	**(I)**
Shoebox, HPS (bronze color, flat lens,	70	6,300	30	7.01	**(R)**
or drop lens, multi-volt)	100	9,500	43	8.38	**(R)**
	150	16,500	62	10.11	**(I) (M)**
Special Acorn Type, HPS	100	9,500	43	$ 11.21	**(I)**
HADCO Victorian, HPS	150	16,500	62	12.55	**(I)**
	200	22,000	79	14.07	**(I)**
	250	29,000	102	15.61	**(I)**
Early American Post-Top, HPS, Black	100	9,500	43	8.26	**(I)**
Special Types					
Cobrahead, Metal Halide	150	10,000	60	8.99	**(R)**
Cobrahead, Metal Halide	175	12,000	71	10.02	**(I)**
Flood, Metal Halide	350	30,000	139	16.57	**(I)**
Flood, Metal Halide	400	40,000	156	16.08	**(I)**
Flood, HPS	750	105,000	285	28.33	**(I)**
HADCO Independence, HPS	100	9,500	43	12.31	**(I)**
Alternative Special Acorn - Techtra	165	12,000	60	22.94	**(C)**
HADCO Capitol Acorn, HPS	100	9,500	43	14.93	**(I)**
	200	22,000	79	17.71	**(I) (D)**
	250	29,000	102	10.66	**(R)**
HADCO Techtra, HPS	100	9,500	43	19.00	**(R)**
	150	16,000	62	21.10	**(I)**
					(D)
HADCO Westbrooke, HPS	70	6,300	30	13.36	**(I)**
	100	9,500	43	14.43	**(I)**
					(D)
	250	29,000	102	17.16	**(R)**
Holophane Mongoose, HPS	150	16,000	62	14.66	**(I)**

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire	
Acorn					
LED	>35-40	3,262	13	$7.75	(C)
	>40-45	3,500	15	6.21	
	>45-50	5,488	16	10.56	
	>50-55	4,000	18	6.43	
	>55-60	4,213	20	5.81	
	>60-65	4,273	21	8.38	
	>65-70	4,332	23	13.01	
	>70-75	4,897	25	6.30	
HADCO LED	70	5,120	24	15.19	(C)
Roadway LED	>25-30	3,470	9	13.35	(C)
	>30-35	2,530	11	3.44	
	>35-40	4,245	13	3.89	
	>40-45	5,020	15	6.90	
	>45-50	3,162	16	3.76	
	>50-55	3,757	18	4.14	
	>55-60	4,845	20	7.75	
	>60-65	4,700	21	8.79	
	>65-70	5,050	23	4.71	
	>70-75	7,640	25	13.16	
	>75-80	8,935	26	7.72	
	>80-85	9,582	28	6.21	
	>85-90	10,230	30	8.29	
	>90-95	9,928	32	6.63	
	>95-100	11,719	33	6.70	
	>100-110	7,444	36	5.98	
	>110-120	12,340	39	7.71	
	>120-130	13,270	43	7.99	
	>130-140	14,200	46	9.05	
	>140-150	15,250	50	8.54	
	>150-160	16,300	53	16.37	
	>160-170	17,300	56	8.97	
	>170-180	18,300	60	10.83	
	>180-190	19,850	63	9.47	
	>190-200	21,400	67	11.63	(C)

SCHEDULE 515 (Continued)

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

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Pendant LED (Non-Flare)	36	3,369	12	11.84	**(C)(M)**
	53	5,079	18	14.79	
	69	6,661	24	15.34	
	85	8,153	29	16.21	
Pendant LED (Flare)	>35-40	3,369	13	12.07	
	>40-45	3,797	15	8.01	
	>45-50	4,438	16	8.08	
	>50-55	5,079	18	15.25	
	>55-60	5,475	20	12.99	
	>60-65	6,068	21	13.06	
	>65-70	6,661	23	16.33	
	>70-75	7,034	25	13.38	
	>75-80	7,594	26	14.96	
	>80-85	8,153	28	16.86	**(C)(M)**
CREE XSP LED	>20-25	2,529	8	2.83	**(C)**
	>30-35	4,025	1411	13.60	
	>40-45	3,819	1615	3.32	
	>45-50	4,373	16	3.63	
	>55-60	5,863	1920	3.71	
	>65-70	9,175	3123	15.47	
	>90-95	8,747	32	4.89	
	130-140	18,700	46	17.14	
Post-Top, American Revolution LED	>30-35	3,395	11	4.86	
	>45-50	4,409	16	5.53	
Flood LED	>80-85	10,530	29	13.24	
	120-130	16,932	44	6.07	
	180-190	23,797	63	15.76	
	370-380	48,020	127	20.40	**(C)**

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

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

Rates for Area Light Poles(2)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$ 5.32	**(I) (M)**
	40 to 55	6.31	**(I)**
Wood, Painted Underground	35 or less	5.32 (3)	**(I)**
Wood, Curved laminated	30 or less	6.32 (3)	**(R)**
Aluminum, Regular	16	4.07	**(R)**
	25	7.59	**(R)**
	30	8.76	**(R)**
	35	10.19	**(R)**
Aluminum, Fluted Ornamental	14	7.31	**(R)**
Aluminum, Fluted Ornamental	16	7.59	**(R)**
			(D)
			(M)
Aluminum Davit	25	$ 8.12	**(R)**
	30	9.19	**(R)**
	35	10.55	**(R)**
	40	13.58	**(R)**
Aluminum Double Davit	30	10.23	**(R)**
Aluminum, Smooth Techtra Ornamental	18	16.08	**(R)**
Aluminum, Fluted Ornamental	18	15.09	**(C)**
Aluminum, Non-Fluted Ornamental, Pendant	22	14.99	**(C)**
Fiberglass Fluted Ornamental; Black	14	9.82	**(R)**
Fiberglass, Regular			
Black	20	4.41	**(R)**
Gray or Bronze	30	7.16	**(R)**
Black, Gray, or Bronze	35	7.05	**(R)**
Fiberglass, Anchor Base, Gray or Black	35	9.82	**(R)**
			(D)
Fiberglass, Direct Bury with Shroud	18	5.97	**(R)**

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

SCHEDULE 515 (Concluded)

INSTALLATION CHARGE (M)

See Schedule 300 regarding the installation of conduit on wood poles (M)

ESS CHARGES

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

ADJUSTMENTS

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

SPECIAL CONDITIONS

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

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

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

TERM

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

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

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

MONTHLY RATE

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

Basic Charge		
Single Phase	$20.00	
Three Phase	$29.00	
Distribution Charge		
First 5,000 kWh	5.265 ¢ per kWh	**(I)**
Over 5,000 kWh	1.186 ¢ 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	$30.00		
Distribution Charge	7.010	¢ 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**	$45.00	
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	9.754 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	7.754 ¢ 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	$5,380.00	$3,630.00	$5,680.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	(R)
Over 4,000 kW	$1.04	$1.03	$1.03	|
per kW of monthly On-Peak Demand**	$1.60	$1.58	$0.50	(R)
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	0.252¢	0.250¢	0.248¢	(I)

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

SCHEDULE 576R
ECONOMIC REPLACEMENT POWER RIDER
DIRECT ACCESS SERVICE

PURPOSE

To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 575.

CHARACTER OF SERVICE

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

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 575:*

	Secondary	Primary	Subtransmission	
Daily Economic Replacement Power (ERP) Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.072	$0.072	$0.071	**(R)(I)**
Transaction Fee per Energy Needs Forecast (ENF) submission or revision	$50.00	$50.00	$50.00	

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

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

MONTHLY RATE

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

Basic Charge		
Single Phase Service	$35.00	
Three Phase Service	$45.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$5.12	(I)
Over 30 kW	$5.02	(I)
per kW of monthly On-Peak Demand	$1.60	(R)
System Usage Charge		
per kWh	0.722 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

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

MONTHLY RATE

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

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$810.00	$760.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.48	$3.45	(I)
Over 200 kW	$2.28	$2.25	(I)
per kW of monthly On-Peak Demand	$1.60	$1.58	(R)
System Usage Charge			
per kWh	0.180 ¢	0.180 ¢	(I)

* See Schedule 100 for applicable adjustments.

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

SCHEDULE 589
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

CHARACTER OF SERVICE

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

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$5,380.00	$3,630.00	$5,680.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	(R)
Over 4,000 kW	$1.04	$1.03	$1.03	
per kW of monthly on-peak Demand	$1.60	$1.58	$0.50	(R)
System Usage Charge				
per kWh	0.126 ¢	0.127 ¢	0.126 ¢	(I)

* See Schedule 100 for applicable adjustments.

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

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

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. **(C)**

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	$20,900.00	**(I)**
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.70	**(I)**
Over 4,000 kW	$1.39	**(I)**
per kW of monthly on-peak Demand	$1.58	**(R)**
System Usage Charge		
per kWh	(0.023) ¢	**(I)**

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.

SCHEDULE 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	7.051 ¢ per kWh	**(I)**
Energy Charge	Provided by Electricity Service Supplier	

NOVEMBER ELECTION WINDOW

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

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

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$124.00 per hour	$155.00 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 **							
	70	6,300	30	*	$2.93	$2.12	**(R)(I)**
	100	9,500	43	*	3.96	3.03	**(R)(I)**
	150	16,000	62	*	5.18	4.37	**(I)**
	200	22,000	79	*	6.54	5.57	**(I)**
	250	29,000	102	*	8.00	7.19	**(I)**
	400	50,000	163	*	12.48	11.49	**(I)**
Cobrahead, Non-Power Door	70	6.300	30	$6.83	3.22	2.12	**(I)(R)**
	100	9,500	43	7.44	4.08	3.03	**(R)(I)**
	150	16,000	62	8.84	5.43	4.37	**(R)(I)**
	200	22,000	79	10.68	6.70	5.57	**(R)(I)**
	250	29,000	102	11.91	8.26	7.19	**(R)(I)**
	400	50,000	163	16.40	12.59	11.49	**(I)(R)**
Flood	250	29,000	102	13.22	8.46	7.19	**(I)**
	400	50,000	163	17.52	12.76	11.49	**(I)**
Early American Post-Top	100	9,500	43	8.33	4.23	3.03	**(I)(R)**
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	7.09	3.27	2.12	**(R)(I)**
	100	9,500	43	*	4.25	3.03	**(C)(R)(I)**
	150	16,000	62	*	5.65	4.37	**(C)(I)**

* 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	$4.61	$0.17	**(R)(I)**
Fiberglass, Black or Bronze	30	7.49	0.28	**(I)**
Fiberglass, Gray	30	7.49	0.28	**(R)(I)**
Fiberglass, Smooth, Black or Bronze	18	4.89	0.19	**(R)(I)**
Fiberglass, Regular				
Black, Bronze, or Gray	18	$4.28	$0.16	**(I)**
	35	7.31	0.28	**(R)(I)**
Aluminum, Regular with Breakaway Base	35	18.74	0.71	**(I)**
Wood, Standard	30 to 35	$5.58	$0.21	**(I)**
Wood, Standard	40 to 55	6.57	0.25	**(I)**

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	$11.49	$4.70	$3.03	**(I)**
HADCO Victorian, HPS	150	16,000	62	12.83	6.04	4.37	**(I)**
	200	22,000	79	14.35	7.29	5.57	**(I)**
	250	29,000	102	15.88	8.89	7.19	**(I)**
HADCO Capitol Acorn, HPS	100	9,500	43	15.20	5.26	3.03	**(I)**
	150	16,000	62	*	6.56	4.37	**(C)(I)**
	200	22,000	79	*	7.84	5.57	**(C)(I)**
	250	29,000	102	*	8.08	7.19	**(C)(R)(I)**
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	12.59	4.84	3.03	**(I)**
	150	16,000	62	*	5.90	4.37	**(C)(R)(I)**
HADCO Techtra, HPS	100	9,500	43	19.28	5.87	3.03	**(R)(I)**
	150	16,000	62	21.38	7.33	4.37	**(I)**
	250	29,000	102	*	9.92	7.19	**(C)(I)**
HADCO Westbrooke, HPS	70	6,300	30	13.65	4.23	*	**(I)**
	100	9,500	43	14.70	5.16	3.03	**(I)**

* 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	*	$6.79	$4.37	**(C)(I)**
	200	22,000	79	*	6.52	5.57	**(C)(R)(I)**
	250	29,000	102	$17.39	9.10	7.19	**(R)(I)**
Special Types							
Flood, Metal Halide	350	30,000	139	*	11.25	9.80	**(C)(I)**
Flood, HPS	750	105,000	285	28.58	21.88	20.10	**(I)**
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	4.51	**(I)**
Ornamental Acorn	55	2,800	21	*	*	1.48	**(I)**
Ornamental Acorn Twin	55	5,600	42	*	*	2.95	**(I)**
Composite, Twin	140	6,815	54	*	*	3.81	**(I)**
	175	9,815	66	*	*	4.65	**(I)**

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$7.92	$0.30	**(R)**
	30	9.09	0.34	**(R)**
	35	10.52	0.40	**(R)**
Aluminum Davit	25	8.45	0.32	**(R)**
	30	9.52	0.36	**(R)**
	35	10.88	0.41	**(R)(I)**
	40	13.97	0.53	**(R)(I)**
Aluminum Double Davit	30	10.56	0.40	**(R)**
Aluminum, Fluted Ornamental	14	7.51	0.28	**(R)**

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

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Smooth Techtra Ornamental	18	16.41	0.62	(R)
Aluminum, Fluted Ornamental	16	7.79	0.30	(R)
Aluminum, Double-Arm, Smooth Ornamental	18	12.65	0.48	(R)(I)
Aluminum, Fluted Westbrooke	18	15.42	0.58	(R)
Aluminum, Non-Fluted Ornamental, Pendant	22	15.32	0.58	(C)
Fiberglass, Fluted Ornamental Black	14	10.51	0.40	(R)(I)
Fiberglass, Anchor Base, Gray or Black	35	9.98	0.38	(R)
Fiberglass, Anchor Base (Color may vary)	25	8.87	0.34	(R)(I)
	30	10.84	0.41	(I)

SERVICE RATE FOR OBSOLETE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Metal Halide	150	10,000	60	*	$5.39	$4.23	(C)(R)(I)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.75	(I)
	175	7,000	66	9.07	5.71	4.65	(I)
	250	10,000	94	*	*	6.63	(I)
	400	21,000	147	15.44	11.46	10.36	(I)
	1,000	55,000	374	31.40	27.59	26.37	(I)
Holophane Mongoose, HPS	150	16,000	62	*	6.35	4.37	(C)(I)
	250	29,000	102	*	9.18	*	(C)(I)

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$7.48	*	*	(R)
Mercury Vapor	175	7,000	66	10.01	$5.81	$4.65	(I)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	4.23	(I)
	70	6,300	30	*	*	2.12	(I)
	100	9,500	43	*	4.52	3.03	(R)(I)
	150	16,000	62	*	5.26	4.37	(R)(I)
	250	29,000	102	*	*	7.19	(I)
	400	50,000	163	*	*	11.49	(I)
Metal Halide	250	20,500	99	*	7.88	6.98	(I)
	400	40,000	156	*	11.90	*	(I)
Cobrahead, Metal Halide	175	12,000	71	*	6.18	5.01	(I)
Flood, Metal Halide	400	40,000	156	16.34	12.20	11.00	(I)
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.92	*	(R)
100/150 Watt Ballast	100	9,500	43	*	3.92	*	(R)
100/150 Watt Ballast	150	16,000	62	*	5.26	4.37	(R)(I)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.26	4.37	(R)(I)
KIM Archetype, HPS	250	29,000	102	*	9.20	7.19	(I)
	400	50,000	163	*	13.94	11.49	(I)

* Not offered

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$10.48	$3.69	*	(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	$2.12	(I)
Mercury Vapor	175	7,000	66	*	*	4.65	(I)
Early American Post-Top, HPS							
Black	70	6,300	30	7.26	3.16	2.12	(I)(R)
Rectangle Type	200	22,000	79	*	*	5.57	(I)
Incandescent	92	1,000	31	*	*	2.19	(I)
	182	2,500	62	*	*	4.37	(I)
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	9.85	5.75	4.65	(I)
Flood, HPS	70	6,300	30	6.57	3.21	*	(R)
	100	9,500	43	7.49	4.10	3.03	(I)(R)
	200	22,000	79	11.49	6.73	5.57	(I)
Cobrahead, HPS							
Power Door	310	37,000	124	*	10.01	8.74	(C)(I)(R)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	3.03	(I)
Twin ornamental, HPS	Twin 100	9,500	86	*	*	6.06	(I)
Compact Fluorescent	28	N/A	12	*	*	0.85	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	4.26	*	(R)
Aluminum, Painted Ornamental	35	*	*	(C)
Aluminum, Regular	16	4.26	0.16	(R)
Bronze Alloy GardCo	12	*	0.23	(I)
Concrete, Ornamental	35 or less	7.92	0.30	(R)
Fiberglass, Direct Bury with Shroud	18	6.30	0.24	(R)
Steel, Painted Regular **	25	7.92	0.30	(R)
Steel, Painted Regular **	30	9.09	0.34	(R)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.41	(I)
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41	(I)
Wood, Laminated without Mast Arm	20	4.61	0.17	(I)
Wood, Laminated Street Light Only	20	4.61	*	(I)
Wood, Curved Laminated	30	6.40	0.28	(R)(I)
Wood, Painted Underground	35	5.58	0.21	(I)

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

SERVICE RATES FOR ALTERNATIVE LIGHTING

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

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$2.59	$2.26	(R)(I)
	165	12,000	60	*	2.03	1.06	(R)
	165	12,000	60	*	5.51	4.23	(C)(I)

SCHEDULE 595 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A and Option B – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

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

Distribution Charge	7.051 ¢ per kWh	**(I)**
Energy Charge	Provided by Electricity Service Supplier	

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime [(1)]
	$124.00 per hour	$155.00 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.

(M)

SCHEDULE 595 (Continued)

RATES FOR STANDARD LIGHTING (Continued) **(M)**
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	$10.13	$0.97	**(C)**
	>25-30	3,470	9	5.12	1.04	
	>30-35	2,530	11	5.53	1.19	
	>35-40	4,245	13	5.42	1.33	
	>40-45	5,020	15	5.68	1.47	
	>45-50	3,162	16	5.85	1.54	
	>50-55	3,757	18	6.23	1.69	
	>55-60	4,845	20	6.04	1.82	
	>60-65	4,700	21	6.12	1.89	
	>65-70	5,050	23	6.78	2.04	
	>70-75	7,640	25	6.99	2.19	
	>75-80	8,935	26	7.07	2.26	
	>80-85	9,582	28	7.22	2.40	
	>85-90	10,230	30	7.33	2.55	
	>90-95	9,928	32	7.51	2.69	
	>95-100	11,719	33	7.58	2.76	
	100-110	7,444	36	8.07	2.97	
	110-120	12,340	39	8.01	3.18	
	120-130	13,270	43	8.30	3.46	
	130-140	14,200	46	9.33	3.69	
	140-150	15,250	50	10.59	4.01	
	150-160	16,300	53	10.73	4.22	
	160-170	17,300	56	11.01	4.43	
	170-180	18,300	60	11.11	4.70	
	180-190	19,850	63	11.51	4.92	
	190-200	21,400	67	11.90	5.20	**(C)**

(M)

SCHEDULE 595 (Continued)

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

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

Type of Light	Watts*	Monthly kWh**
LED	5 - 10	3
LED	>10 - 15	4
LED	>15 - 20	6
LED	>20 - 25	8
LED	>25 - 30	9
LED	>30 - 35	11
LED	>35 - 40	13
LED	>40 - 45	15
LED	>45 - 50	16
LED	>50 - 55	18
LED	>55 - 60	20
LED	>60 - 65	21
LED	>65 - 70	23
LED	>70 - 75	25
LED	>75 - 80	26
LED	>80 - 85	28
LED	>85 - 90	30
LED	>90 - 95	32
LED	>95 - 100	33
LED	>100 - 110	36
LED	>110 - 120	39
LED	>120 - 130	43
LED	>130 - 140	46
LED	>140 - 150	50
LED	>150 - 160	53
LED	>160 - 170	56

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

SCHEDULE 595 (Continued)

(M)

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

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

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

(M)

SCHEDULE 595 (Continued)

RATES FOR DECORATIVE LIGHTING

(M)

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	$12.62	$1.53	(C)
	>40-45	3,500	15	12.85	1.67	
	>45-50	5,488	16	10.84	1.68	
	>50-55	4,000	18	13.07	1.88	
	>55-60	4,213	20	13.11	2.02	
	>60-65	4,273	21	13.29	2.09	
	>65-70	4,332	23	13.29	2.23	
	>70-75	4,897	25	13.46	2.37	
HADCO LED	70	5,120	24	17.27	2.41	(C)
Pendant LED (Non-Flared)	36	3,369	12	13.93	1.50	(R)(I)
	53	5,079	18	15.08	1.94	
	69	6,661	24	15.61	2.36	
	85	8,153	29	16.49	2.73	(R)(I)
						(D)
Pendant LED (Flared)	>35-40	3,369	13	14.16	1.57	(C)
	>40-45	3,797	15	14.41	1.71	
	>45-50	4,438	16	14.48	1.78	
	>50-55	5,079	18	15.54	1.95	
	>55-60	5,475	20	15.81	2.09	
	>60-65	6,068	21	15.88	2.16	
	>65-70	6,661	23	16.61	2.32	
	>70-75	7,034	25	16.89	2.46	
	>75-80	7,594	26	17.15	2.54	
	>80-85	8,153	28	17.14	2.68	(C)
Post-Top, American Revolution						
LED	>30-35	3,395	11	6.95	1.23	(C)
	>45-50	4,409	16	7.62	1.59	
				8.16	2.42	
Flood LED	>80-85	10,530	28	9.72	3.50	
	>120-130	16,932	43	12.13	4.94	
	>180-190	23,797	63	20.81	9.56	
	>370-380	48,020	127	$12.62	$1.53	(C)

(M)

SCHEDULE 595 (Continued)

SPECIALTY SERVICES OFFERED **(M)**

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

. Trimming of trees adjacent to streetlight equipment and circuits.
. Arterial patrols to ensure correct operation of streetlights.
. Painting or staining of wood and steel streetlight poles.

ESS CHARGES

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

ADJUSTMENTS

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

NOVEMBER ELECTION WINDOW

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

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

SPECIAL CONDITIONS

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

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

(M)

SCHEDULE 595 (Continued)

SPECIAL CONDITIONS (Continued) (M)

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

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

5. If circuits or poles not already covered under Special Condition 2 or 3 are removed or relocated at the Customer’s request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

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

7. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

8. For Option A and Option B lights: The Company shall not be liable when either (i) the luminaires become inoperable or (ii) repair or replacement of inoperable luminaires is delayed or prevented; provided that, such inoperability of the luminaires or delay or prevention of repair or replacement is due to any cause beyond the Company's control, or that otherwise could not reasonably be foreseen or guarded against including but not limited to such causes as: strikes, lockouts, labor troubles, riots, insurrection, war, acts of God, extreme weather conditions, access to equipment, or the like.

9. For Option C lights: The Customer must ensure that (i) all maintenance and other work associated with this schedule is in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC and (ii) that all such work is performed by a Qualified Worker. A “Qualified Worker” means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a “qualified person” or “qualified employee” with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker is a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work. (M)

SCHEDULE 595 (Continued)

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

10. Indemnification:

a. For Option A lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, or agents that arise under this Schedule.

b. For Option B lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.d. below. The Company shall hold Customer harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Company, its officers, employees, agents, or contractors that arise under this Schedule.

c. For Option C lights: To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, the Customer shall hold the Company harmless and indemnify it for any and all third-party claims, actions, liability, costs, and expense by reason of injury to or death of persons or damage to property arising or resulting from any negligent acts or omissions or willful misconduct of the Customer, its officers, employees, or agents that arise under this Schedule, including but not limited to the street lighting requested by Customer, its officers, employees, or agents under this Schedule or the associated lighting levels or Customer's failure to comply with any of its obligations under Special Condition 10.c. below. This paragraph applies only to Option C lights that are attached to poles owned by PGE and does not apply to Option C lights attached to poles owned by Customer. **(M)**

SCHEDULE 595 (Continued) **(T)**

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

d. For Option B and Option C lights: Customer has the obligation to ensure that any contractor performing any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting carry commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies. Customer will, at least seven (7) business days prior to the performance by a contractor of any street or outdoor area light maintenance work or any construction associated with street or outdoor area lighting, cause the contractor to furnish the Company with a certificate naming the Company as an additional insured under the contractor's commercial liability policy or policies. This paragraph shall not apply to Option C lights that are attached to poles owned by Customer.

e. Customer will provide (i) commercial liability insurance in an aggregate amount of $5 million and $2 million per occurrence and list PGE as an additional insured on the policy or policies or (ii) proof of adequate self-insurance for the amounts identified. All Insurance certificates or proof of self-insurance required under this Schedule shall be sent to Portland General Electric Company, Utility Asset Management, 2213 SW 153rd, Beaverton, OR 97006. All insurance required by this Schedule, to the extent it is provided by an insurance carrier, must be provided by an insurance carrier rated "A-" VIII or better by the A.M. Best Key Rating Guide. All policies of insurance required to be carried under this Schedule shall not be cancelled, reduced in coverage or renewal refused without at least thirty (30) days' prior written notice to the Company. The insurance coverage required by this Schedule must (i) be primary over, and pay without contribution from, any other insurance or self-insurance used by the Company, and (ii) waive all rights of subrogation against the Company. Customer shall bear all costs of deductibles and shall remain solely and fully liable for the full amount of any liability to the Company that is not compensated by Customer's or contractor's insurance.

f. The indemnifying party under this Schedule shall be liable only for third-party claims, actions, liability, costs, and expense pursuant to the terms of this Schedule and shall not be liable to the indemnified party for any of the indemnified party's special, punitive, exemplary, consequential, incidental or indirect losses or damages. For avoidance of doubt, the indemnifying party shall pay all reasonable attorneys' fees, experts' fees, and other legal expenses incurred in responding to or defending the third-party claim or action.

11. The Customer is responsible for the cost of temporary disconnection and reconnection of Electricity Service. The Customer must provide written notice to request a temporary disconnection. During the period of temporary disconnection, the Customer remains responsible for all fixed charges in this schedule except for the cost of providing energy. After one year, the disconnection may no longer considered temporary and the facilities removed with the Customer responsible for the cost listed in Special Condition No. 3 of this schedule. **(M)**

SCHEDULE 595 (Concluded)

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

12. For Option C lights: Customer is responsible to notify the Company within 30 days of conversions to Option C lights in this Schedule. The Company will limit all billing adjustments to 30 days back. The Company will use the nearest billing cycle date for all adjustments.

TERM

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

(M)

SCHEDULE 600 (Continued)

ESS SUPPORT SERVICES

The following charges are applicable to Scheduling and Non-Scheduling ESSs:

(1)	Application Processing Fee	$400.00 with Application
(2)	Registration Renewal Fee	$200.00
(3)	Electronic Data Interchange Testing	$100.00 per man-hour for all hours in excess of 16 hours annually
(4)	Change of Effective Date Request (Rule K)	$ 35.00
(5)	Switching Fee (Rule K) (Applicable for each Enrollment or Drop DASR, not applicable for Rescind or Change DASRs)	$ 20.00
(6)	Customer Change of Location (Rule K)	$5,000.00 (R)

ESS BILLING SERVICES

(1)	ESS Consolidated Bill Billing Credit	$ 0.63 per bill
(2)	Late Pay Charge	2.0 % of delinquent balances for products and services purchased under this Tariff.

CUSTOMER INFORMATION

ESS Web Portal Historical Usage Download for Interval Data Charge	$ 20.00 per Service Point Identification (SPID)

BILLING AND PAYMENT

Charges incurred for Schedule 600 services are the responsibility of the ESS for which service was provided and are due and payable as described in the Company's General Rules and Regulations.

SCHEDULE 600 (Concluded)

SPECIAL CONDITION

The ESS must purchase firm Transmission Service under the Company's OATT for not less than one-month duration and will be charged at the OATT monthly rate for firm transmission.

PGE SYSTEM LOSSES

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Losses:	4.20%	3.09%	1.96%	**(C)**

SCHEDULE 689 (Continued)

APPLICABLE (Continued)

Load served under Schedule 689 will not be counted under the Long Term Direct Access cap that applies to Schedules 485, 489, 490, 491, 492 and 495. The expected load of the Customer, defined as the "Contracted Load" in the opt out agreement between the Customer and the Company, will be the amount of load that is initially counted toward the New Load Direct Access cap for the first 60 months, unless a Customer is earlier de-enrolled under the terms of this Schedule 689 or the terms of the opt-out agreement.

The Contracted Load for each Customer will be counted toward the cap limit for up to the first 60 months of service. Following 60 months of service on Schedule 689, the Customer's actual load factor (LF) will be applied to the contracted demand (MW) to calculate a Customer's MWa to be captured and counted toward the New Large Load Program cap thereafter, and the total amount of load under the cap will be adjusted at such time of inquiry, in accordance with actual loads.

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$5,380.00	$3,630.00	$5,680.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.35	$1.34	$1.34	(R)
Over 4,000 kW	$1.04	$1.03	$1.03	
per kW of monthly On-Peak Demand	$1.60	$1.58	$0.50	(R)
System Usage Charge				
per kWh	0.126 ¢	0.127 ¢	0.126 ¢	(I)
Administrative Fee	$0.00	$0.00	$0.00	

* See Schedule 100 for applicable adjustments.

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

SCHEDULE 689 (Continued)

ENERGY SUPPLY

The Customer may elect to purchase Energy from an Electric Service Supplier (ESS) certified by the PUC to do business in PGE's service territory,(Direct Access Service) or from the Company (Company Supplied Energy). Election of energy supply from an ESS or from the Company applies toward the cap of this program.

Direct Access Service

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

Company Supplied Energy

The Company Daily Market Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.
Upon not less than five business days' notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

Additional charges to meet the state of Oregon's Renewable Portfolio Standard may apply following future Commission determination.

Wheeling Charge
The Wheeling Charge will be $1.850 per kW of monthly Demand. **(I)**

SCHEDULE 689 (Continued)

ON AND OFF PEAK HOURS

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

LOSSES

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

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

REACTIVE DEMAND CHARGE

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

ADJUSTMENTS

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

EXISTING LOAD SHORTAGE TRANSITION ADJUSTMENT

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

SCHEDULE 750
INFORMATIONAL ONLY: FRANCHISE FEE RATE RECOVERY

PURPOSE

To inform customers regarding the level of franchise fee rate recovery contained in each schedule's system usage or distribution charges.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory.

FRANCHISE FEE RATE RECOVERY

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

Schedule	Franchise Fee Rate	Included in:	
7	0.326 ¢ per kWh	Distribution Charge	**(I)**
15	0.589 ¢ per kWh	Distribution Charge	**(I)**
32	0.296 ¢ per kWh	Distribution Charge	**(I)**
38	0.303 ¢ per kWh	Distribution Charge	**(R)**
47	0.486 ¢ per kWh	Distribution Charge	**(R)**
49	0.362 ¢ per kWh	Distribution Charge	**(R)**
75			
Secondary	0.148 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.146 ¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.145 ¢ per kWh	System Usage Charge	**(R)**

DO NOT BILL

SCHEDULE 750 (Continued)

FRANCHISE FEE RATE RECOVERY (Continued)

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

Schedule	Franchise Fee Rate		Included in:	
83	0.222	¢ per kWh	System Usage Charge	**(R)**
85				
Secondary	0.177	¢ per kWh	System Usage Charge	**(R)**
Primary	0.175	¢ per kWh	System Usage Charge	**(R)**
89				
Secondary	0.148	¢ per kWh	System Usage Charge	**(R)**
Primary	0.146	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.145	¢ per kWh	System Usage Charge	**(R)**
90	0.131	¢ per kWh	System Usage Charge	**(R)**
91	0.561	¢ per kWh	Distribution Charge	**(I)**
92	0.166	¢ per kWh	Distribution Charge	**(R)**
95	0.561	¢ per kWh	Distribution Charge	**(I)**
485				
Secondary	0.049	¢ per kWh	System Usage Charge	**(R)**
Primary	0.048	¢ per kWh	System Usage Charge	**(R)**
489				
Secondary	0.022	¢ per kWh	System Usage Charge	**(R)**
Primary	0.022	¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.022	¢ per kWh	System Usage Charge	**(R)**
490	0.010	¢ per kWh	System Usage Charge	**(R)**
491	0.442	¢ per kWh	Distribution Charge	**(I)**
492	0.040	¢ per kWh	Distribution Charge	**(R)**
495	0.442	¢ per kWh	Distribution Charge	**(I)**

SCHEDULE 750 (Concluded)

FRANCHISE FEE RATE RECOVERY (Concluded)

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

Schedule	Franchise Fee Rate	Included in:	
515	0.471 ¢ per kWh	Distribution Charge	(I)
532	0.153 ¢ per kWh	Distribution Charge	(I)
538	0.171 ¢ per kWh	Distribution Charge	(R)
549	0.199 ¢ per kWh	Distribution Charge	(I)
575			
Secondary	0.022 ¢ per kWh	System Usage Charge	(R)
Primary	0.022 ¢ per kWh	System Usage Charge	(R)
Subtransmission	0.022 ¢ per kWh	System Usage Charge	(R)
583	0.079 ¢ per kWh	System Usage Charge	(I)
585			
Secondary	0.049 ¢ per kWh	System Usage Charge	(R)
Primary	0.048 ¢ per kWh	System Usage Charge	(R)
589			
Secondary	0.022 ¢ per kWh	System Usage Charge	(R)
Primary	0.022 ¢ per kWh	System Usage Charge	(R)
Subtransmission	0.022 ¢ per kWh	System Usage Charge	(R)
590	0.010 ¢ per kWh	System Usage Charge	(R)
591	0.442 ¢ per kWh	Distribution Charge	(I)
592	0.040 ¢ per kWh	Distribution Charge	(R)
595	0.442 ¢ per kWh	Distribution Charge	(I)
689			
Secondary	0.022 ¢ per kWh	System Usage Charge	(R)
Primary	0.022 ¢ per kWh	System Usage Charge	(R)
Subtransmission	0.022 ¢ per kWh	System Usage Charge	(R)

29. Large Nonresidential Customer

A Nonresidential Customer whose monthly Demand has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service whose Demand has exceeded 30 kW.

30. Losses (N)

The difference between the amount of electricity generated and the amount sold to Customers within a given period of time. Losses largely reflect the electricity lost as a result transformation and transmission, but also include Company use and potentially electricity theft.

31. Multi-Family Dwelling

A residential building that contains three or more dwelling units. (N)

32. Network Meter (T)

Metered service that is the basis of PGE's Smart Grid (Advanced Metering Infrastructure) Technology Program with functionality to collect, receive and transmit meter-related data remotely.

33. Nonresidential Customer (T)

A Customer that does not meet the definition of a Residential Customer.

34. Non-Network Meter (Residential only) (T)

Metered service not part of PGE's Smart Grid (Advanced Metering Infrastructure) Technology Program with functionality to collect and receive meter-related data for manual collection.

35. Operational Order to Deliver Electricity (T)

An order issued by the Company to scheduling ESSs to deliver additional Electricity for purposes of maintaining the integrity of the Company's facilities.

36. Portfolio (T)

A set of product and pricing options provided to Residential Customers and Small Nonresidential Customers.

37. Premises (T)

Real and personal property owned and/or used by a Customer at a single location, which contains a Service Point.

38. Reactive Demand **(T)**

The maximum rate of delivery of kilovolt-amperes reactive (kVars) measured over a nominal 30-minute interval. Reactive Demand must be supplied to most types of magnetic equipment, such as motors. It is supplied by generators or by electrostatic equipment, such as capacitors, motors or transformers. It is recognized as a necessary Ancillary Service.

39. Reactive Demand Charge **(T)**

A charge for Reactive Demand assessed to Customers with loads that are supplied Reactive Demand on the Company's system.

40. Residential Customer **(T)**

A Customer that has applied for and been accepted to receive service at a dwelling primarily used for residential purposes, including, but not limited to, single family dwellings, separately metered apartment units, mobile homes, and houseboats, but excluding dwellings employed for Transient Occupancy, such as hotels, motels, camps, lodges, and clubs.

For purposes of this rule, a dwelling must contain permanent facilities for sleeping, bathing, and cooking.

Boarding houses with no more than four separate sleeping quarters for use by people who are not members of the Residential Customer’s family and “adult foster homes” (defined in ORS 443.705 as a home or facility in which residential care is provided for five or fewer adults who are not related to the Residential Customer by blood or marriage) are residential dwellings.

When there is nonresidential use of Electricity at a dwelling used primarily for residential purposes, the Company will classify the Customer as residential if the Company determines that Electricity consumed in a typical month for residential use exceeds that consumed for nonresidential use, and if the nonresidential use is carried out primarily by the occupants of the dwelling.

Individual dwelling units in newly constructed multi-family residential buildings will be individually metered and billed as Residential Customers.

Service through one meter to two dwelling units will be classified as one Residential Customer where an existing dwelling unit is or has been divided into two dwelling units, provided the ampacity of the service equipment is not increased. In the case where service is supplied through one meter to two or more new dwelling units, or to three or more existing dwelling units, service will be classified as nonresidential service.

With the exception of the separately metered Residential Electric Vehicle Time of Use (EV TOU) Option under Schedule 7, service through additional meters to other than dwellings on residential premises will be classified as nonresidential.

41. **Scheduled Crew Hours** **(T)**

Those times that Company service crew personnel are working at their regular rate of pay. Scheduled Crew Hours may vary by location and type of work.

42. **Service Point (SP)** **(T)**

Unless otherwise designated by agreement, the first point of connection of the Company's service drop, service lateral or bus to the Customer's service entrance conductors or equipment determined without regard to the location of the meter or metering equipment.

43. **Service Point Identification (SPID)** **(T)**

A code that identifies each unique Service Point and associated Company meter location (if applicable).

44. **Single-Family Dwelling** **(N)**

A residential building that contains less than three dwelling units. **(N)**

45. **Site** **(T)**

A. Buildings and related structures that are interconnected by facilities owned by a single retail electricity Customer and that are served through a single electric meter; or

B. A single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, such that

1) Each building or structure included in the site is no more than 1,000 feet from at least one other building or structure in the site;

(M)

2) Buildings and structures in the Site, and land containing and connecting buildings and structures in the Site, are owned by a single retail electricity Customer who is billed for electricity use at the buildings and structures; and (M)

3) Land will be considered to be contiguous even if there is an intervening public or railroad right of way, provided that rights of way land, on which municipal infrastructure facilities exist (such as streetlighting, sewerage transmission, and roadway controls), will not be considered contiguous.

46. Small Nonresidential Customer (T)

A Nonresidential Customer who does not meet the definition of a Large Nonresidential Customer, which means the Nonresidential Customer has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service had not exceeded 30 kW.

47. Standard Service (T)

A service option provided by the Company to a Nonresidential Customer who elects to purchase Electricity from the Company rather than from an ESS.

48. Summer Months (T)

Summer Months are the six regular Billing Periods from May through October.

49. Tariff (T)

This Tariff, including all schedules, rules and regulations as they may be modified or amended from time to time.

50. Theft of Service (T)

Theft of Service occurs when an Applicant or Customer initiates or maintains Electricity Service through fraudulent means, including but not limited to providing false identification or false information to establish an account or credit, paying for Electricity Service with a stolen financial account, tampering with Company equipment including but not limited to the meter, or diverting service.

51. Renewable Energy Certificates (T)

Renewable Energy Certificates (RECs) consist of the non-power attributes resulting from the generation of Energy by a qualified renewable resource. Such attributes may be fuel, emissions, or other environmental characteristics deemed of value by a REC purchaser.

Non-power attributes include, but are not limited to, any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and any other pollutant that is now or may in the future be regulated under the pollution control laws of the United States; and further include any avoided emissions of carbon dioxide (CO2) and any other greenhouse gas (GHG) that contributes to the actual or potential threat of altering the Earth's climate. These non-power attributes are expressed in MWh.

Non-power attributes do not include any energy, reliability, scheduling, shaping or other power attributes.

52. **Transient Occupancy** **(T)**

Tenancy at a Premise for a duration of less than 30 days.

53. **Utility Provided Service** **(T)**

The provision of Electricity Service to a Customer by the Company.

54. **Winter Months**

Winter Months are the six regular Billing Periods from November through April. **(T)**

RULE B (Concluded)

F. **Temporary Relocations**

Where the Company is required to temporarily move its Facilities either because the Company cannot move its Facilities to the new permanent placement or the Facilities will be returned to their former location at a later point in time, the costs of the temporary relocation will be borne by the requesting party regardless of its status as a Public Works Project or otherwise. A temporary relocation is defined as any relocation where the Company must move its facilities two or more times within a three-year period.

8. Service Restoration

A. **Generally**

During a major outage due to events such as a major storm, the Company will follow priorities for service restoration as provided below. These restoration procedures are followed in order to restore service to the greatest number of Customers as quickly, efficiently, and safely as possible with special consideration given to (C)
Customers that are critically essential to public safety and welfare. (C)

The Company maintains a list of critical Customers that includes but is not limited to hospitals, airports, 911 dispatch centers, fire and police stations, water and sewage treatment plants, emergency media, and emergency communications facilities. The Company will establish a prioritization framework for service restoration to critical Customers that leverages the service priority order in the next section. (C)

(C)

B. **Service Priority [Order]** (C)

The Service restoration work priorities listed below may be performed in parallel by different work crews from different parts of the Company to ensure all Customers are restored as quickly, efficiently, and safely as possible. (C)

The priorities for service restoration are generally as follows:

1) **Protect Public Safety**

The Company will clear energized, downed power lines and repair equipment that poses a public safety hazard. The Company will ensure that critical [Customers'] facilities have power. (C)

(C)

2) **Check Generation Facilities** (N)

The Company will determine if repairs are needed to any of its generation facilities. If so, the generation facility will be taken off-line, and the Company will use undamaged generation facilities for power production. (N)

3) **Repair Transmission Lines to Substations**

The Company will make necessary repairs to the transmission system, connecting generation facilities to substations to ensure system stability. The Company will also make necessary repairs to transmission lines, substations, and distribution facilities prioritizing those that connect substations to critical Customers. The Company will continue to repair remaining transmission lines. (C)

4) **Repair Substations** (T)

The Company will repair substations making it possible to restore service to distribution lines. (C)

5) **Repair Feeder Distribution Lines** (C)

The Company will repair distribution lines serving critical Customers as well as lines that may be blocking streets or highways. The Company will repair remaining distribution lines after service is restored to critical Customers. (C) (C)

6) **Repair Tap Lines** (C)

The Company will repair tap lines that serve smaller groupings, such as Residential Customers. (C)

7) **Repair Individual Service Connections** (C)

The Company generally will repair individual service connections last. If Customer-owned equipment has been damaged, such as the meter base, that equipment must be repaired to the satisfaction of the authority having jurisdiction, including obtaining any required permits and inspections, before the Company can restore service at that location. Such repairs are the responsibility of the Customer. (C) (C) (C)

(M)

C. **Other**

The Company will not give priority restoration to any Customer, non-utility generator or ESS, but will employ the above process over the Company's entire territory served. **(M)** **(M)**

RULE C (Concluded) **(M)**

4) **Unusual Distribution Facilities or Nonstandard Construction**

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

2. Applicant Cost Responsibilities

A. **Payment**

Applicants who have cost responsibilities under this section and Section 3 will make payment in full at the time the Company agrees to make the Line Extension.

Applicant's payment requirements for jobs with Line Extension Costs estimated to be equal to or exceeding $250,000 may be as follows: **(M)** **(T)**

a) The Applicant will provide a cash payment of 10% of the estimated Line Extension Cost prior to the Company initiating design work;

b) At the time the Company orders any special order and/or long lead-time electrical and/or pathway material, the Applicant will provide a cash payment to the Company for the full cost of the order; and

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

(M)

The Line Extension Allowance will be refunded at the time the Applicant's Electricity Service is established. If Applicant's Electricity Service is not established, payments made under Section (2)(A) are not refundable. **(M)** **(C)**

B. **Applicants for New Permanent Service**

1) **Individual Applicants**

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

2) **Other than Individual Applicants**

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

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

C. **Existing Customers**

1) **Nonresidential**

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

2) **Residential**

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

3. Special Conditions for Underground Line Extensions (M)

A. **Applicability**

Underground Line Extensions will be made:

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

B. **Responsibility for Costs**

1) The Applicant will be responsible for the current and reasonable future costs associated with the installation of the Line Extension's continuous conduit system, which includes but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits. The Company will own and maintain the conduit system once Company conductors have been installed.
2) At its option, the Company may perform the Applicant's responsibilities listed in (B)(1) above at the Applicant's expense or permit the Applicant to perform these responsibilities at Applicant's expense. Where work is to be performed in an existing right-of-way and requires the Company to obtain a permit from a governmental body, the Company may specify additional requirements and place restrictions on the selection of contractors. (M)
3) Where the Company provides trenching and backfilling for installation of applicable residential underground service laterals, the charges specified in Schedule 300 will apply. Estimated actual costs will apply where the Company provides trenching, and backfilling beyond the service lateral installation process. The Applicant will be responsible for all additional costs of excavating rock, furnishing and installing raceway, excavating to a depth in excess of Company standards, manual digging, and the repair of paved roads, walks, and driveways when such work must be performed.

4) Where no other restrictions apply and the Applicant is only considering submersible transformers for aesthetic reasons, the Applicant may request the installation of submersible transformers instead of standard pad-mounted transformers. In this event, the cost set forth under the Transformers Section of Schedule 300 will be paid by the Applicant. **(M)**

C. **Additional Services**

1) **Service Locates**

The Company will locate underground water, sewer and water runoff services along the Applicant's proposed trench route on the Applicant's property if requested by the Applicant. The cost set forth in Schedule 300 will be paid by the Applicant.

2) **Service Guarantee/Wasted Trip Charge**

The Company will begin the installation of residential single family underground service laterals within seven working days following the date an Applicant requests such service, except during periods of major storms or other such conditions beyond the Company's control. If the Company does not meet this standard, the Company will pay the Applicant the Service Guarantee Charge in Schedule 300. If, however, Company resources are dispatched to install the residential single family service lateral within the seven-day period and the Applicant's site or other facilities are not ready for service, the Applicant will be assessed the Wasted Trip Charge in Schedule 300.

3) **Long-Side Service Connection Charge**

Where the Applicant requests that the Company provide trenching and conduit for a long-side service connection the charge in Schedule 300 will apply.

4) **Joint Trench Installation Charge**

Upon mutual agreement between the Company and the Applicant, the Company may install telephone and cable services during the installation of the underground service lateral. The parties involved will mutually agree to the price for such service.

d) The fixed charges for Enhanced Temporary Service specified in Schedule 300 include Electricity usage for up to 6 months. After 6 months Customers may extend Enhanced Temporary Service at additional 6-month time periods at the fixed renewal charge specified in Schedule 300. After 24 months, a permanent connection is required. **(C)** **(C)**

C. In order to qualify for Enhanced Temporary Service, the Applicant must agree to the following:

1) Service will be used only for lights, tools, and equipment necessary for the construction of residential dwellings;

2) Service will not be used for the operation of permanently installed appliances or equipment or to heat or dry structures under construction;

3) For multi-family construction, the number of unmetered service pedestals can vary depending on the necessary service outlets per units/buildings under construction; and

4) Unless the trenching or boring work is provided by the Company under the terms of Schedule 300, the Applicant will provide a continuous underground conduit, suitable for Electricity Service, from the permanent meter base to the location of the Enhanced Temporary Service pedestal for the Company to use in later providing the permanent service.

In the event that Enhanced Temporary Service is used for purposes other than those specified, the Company will estimate the amount of Electricity used and bill according to the applicable rate schedule. The Company may restrict future availability of Enhanced Temporary Service in such cases.

2. <u>Emergency Service</u>

A. **<u>Definition</u>**

"Emergency Service" means Electricity Service supplied or made available to load devices which are operated only in emergency situations or in testing to respond to such situations. Electricity Service for freeze protection or similar applications likely to occur annually and/or only in the coldest time of the year is not an Emergency Service.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Executive Summary
Acronyms

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

July 9, 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.	**EXECUTIVE SUMMARY OF PORTLAND GENERAL ELECTRIC COMPANY**

I. INTRODUCTION

Portland General Electric Company ("PGE" or the "Company") is a public utility pursuant to ORS 757.005. The Public Utility Commission of Oregon ("OPUC" or "Commission") has jurisdiction over the price and terms of service provided by PGE to its customers. PGE is filing this request to revise its tariff schedules pursuant to ORS 757.210 and ORS 757.220. PGE submits this executive summary pursuant to the requirements of OAR 860-022-0019.

PGE's last general rate case was filed in February of 2018. That case was largely driven by investments in technology and infrastructure improvement (including cyber and physical security) centered on meeting customers' expectations and industry challenges. This case builds upon that and on investments designed to modernize the grid to a smarter, more flexible and integrated grid and to decarbonize our electricity portfolio to provide clean, reliable, and resilient service to customers. PGE remains proud to be the company on which customers and communities can depend for electric service provided in a safe, sustainable, and reliable manner, with excellent customer service, at reasonable prices. In addition to PGE's ongoing work to replace aging infrastructure to maintain its system and respond to growth in customer counts and load, PGE is building additional facilities to strengthen its system and support future technology. Key drivers of this rate case reflect PGE's customers expectations, including investments the Company has made in the new Integrated Operations Center ("IOC") – and the smart grid platforms it will house, the repowered Faraday powerhouse, its wildfire mitigation program, and hundreds of individual projects, large and small, to modernize and upgrade the transmission and distribution ("T&D") system for enhanced reliability and resilience. PGE continues to invest the capital and labor required to create new connections and meet customer demand. PGE's total

T&D capital additions for January 1, 2019 through April 30, 2022, are $1,566.3 million, with the IOC representing the single most significant portion of those investments at $215.2 million.

A. This case reflects infrastructure improvements in several areas including:

1) Extensive investments in other T&D system improvements over the last three years relate to replacing aging infrastructure, improving safety, maintaining compliance with North America Electric Reliability Corporation ("NERC") requirements, and supporting load growth.

   These initiatives:

   a. have allowed PGE to be responsive to the major events of the past year including COVID-19 pandemic, micro-bursts blowing down 500kV transmission towers, Labor Day Wildfire storms, and the February ice storm; and

   b. will allow PGE to implement a proactive approach to T&D system operations and maintenance by increasing reliability, resiliency, and flexibility that is needed to enable customers' clean energy future with a more resilient, secure, and integrated grid.

2) The new IOC, the single largest investment on behalf of customers in this case, supports safe grid operations, modernization, and decarbonization. The IOC will allow PGE to efficiently control and monitor all elements of the integrated grid in a single facility, even under extreme conditions.

3) Implementation of multiple projects as part of its grid modernization and decarbonization effort, including an Advanced Distribution Management System ("ADMS"), expansion of Dispatchable Standby Generation resources, enhanced

Enterprise Data Analytics, and expansion of the Reliability Performance Monitoring Center to include T&D assets.

4) The repowering of the Faraday Powerhouse on the Clackamas River Hydroelectric Project with a new, modern facility with more efficient turbines providing an excellent complement to the cutting-edge storage, distributed energy resources and grid management technologies also presented in this case.

B. This case also includes targeted operation and maintenance expenses ("O&M") related to PGE's expanded Wildfire Mitigation ("WM") Program. Because of the increasing threat of wildfires and impact on people, property, electric service, and the environment, PGE created a new WM Program in November 2020. PGE expects to spend $6.6 million in O&M on WM in 2022, a $4.6 million increase from 2020 levels. The Company also expects to place $6.0 million of capital for WM into service by April 30, 2022.

C. PGE's ongoing investment in customer service is demonstrated in its forecast of Customer Service O&M of $90.0 million for the 2022 test year, compared to $77.1 million in PGE's 2020 actual costs, which represents PGE's most recent actual results. The increase is primarily driven by returning labor to pre-pandemic levels. This case also discusses the Flexible Load Plan proposal, creation of the Transportation Electrification ("TE") program, and the costs as well as the customer benefits associated with that work. Finally, this case includes a PGE proposal to offer fee-free debit and credit card payments to small non-residential customers.

D. Additional increased costs, and upward pressure on prices, and price impact mitigation measures, in this case include[1]:

1) Higher property taxes due to increasing net plant assets plus additional construction work in progress balances that will be assessed property tax expense.
2) To mitigate the price increase while still allowing PGE to make essential system improvements, PGE has managed its costs carefully to keep the increase in O&M to a level well below the average rate of inflation. In addition, the Company modified its request as follows:) this case does not include any officer incentive compensation and PGE removed 50% of all other forecasted incentive compensation costs; 2) the Company is not requesting an increase in the return on equity ("ROE"); and 3) the Company has maintained the uncollectibles rate approved in PGE's last general rate case, UE 335. The Company's proposal is to maintain PGE's ROE of 9.5%, despite support from its ROE witness that would justify a higher ROE rate, and a capital structure of 50% debt and 50% equity. The testimony of Maria Pope and Brett Sims, PGE 100, describes the cost management efforts of PGE, and discusses some specific examples.
3) Finally, in this case, PGE honors its commitment to exclude all costs related to the Company's August 2020 trading losses.

[1] PGE's Net Variable Power Costs filing in Docket 391 has an initial forecast of $511.8 million and though not discussed in this case is identified as a cost driver in multiple testimonies.

II. SUMMARY OF THIS CASE

As described below, twelve pieces of testimony discuss the basis for the Company's request in this case. The witnesses are all, with the exception of the witness on the appropriate return on equity, PGE officers and employees. The testimony discusses the cost drivers in each area and the projected 2022 costs incorporated into this case.

This case is based on a normalized future test period of calendar year 2022, with rate base balances as of April 30, 2022, just prior to a May 1, 2022 rate effective date. In order to comply with IRS normalization requirements, base depreciation expense on plant-in-service is calculated through April 30, 2022. PGE seeks a schedule in this docket that will allow for a Commission order by mid-April 2022 and revised tariff schedules effective on May 1, 2022. The dollar amounts of the changes are discussed above.

PGE requests a continuation of its currently authorized ROE of 9.50% with a forecasted capital structure of 50% equity and 50% debt. The projected test year results show that without a price increase, PGE will earn an ROE of approximately 7.07%. That is significantly below PGE's currently authorized ROE, and below the level needed to maintain PGE's credit ratings and attract capital.

As set forth in the testimony in this docket, PGE is making significant infrastructure investments to meet customers' needs for safe, reliable, and secure service. Prices need to be set to allow PGE the opportunity to earn a return on invested capital that is commensurate with similar companies, allowing it to maintain its credit ratings and attract capital on terms that will ultimately be beneficial to customers.

Accounting Orders and Tariff changes. PGE also requests that as part of this rate case the Commission approve the following, discussed further in PGE Exhibit 1200:

Renewal and modification of PGE's Schedule 123 decoupling mechanism.

Changes to one supplemental schedule to implement non-bypassability of costs associated with the state's solar payment option program, allocating costs to all PGE customers.

Two new supplemental schedules to recover costs related to energy storage and transportation electrification.

Modifications to PGE's Schedule 146 to recover costs of its Colstrip generation plant including accelerated depreciation.

Level III Events. PGE also requests that as part of this rate case the Commission approve the modified recovery mechanism for Level III events that includes a balancing account and cost sharing between PGE customers and shareholders, discussed further in PGE Exhibit 800.

Net Variable Power Costs. Each year under Schedule 125, PGE's prices are adjusted to reflect projected net variable power costs for the coming year, and transition charges or credits for those customers opting for an alternate electricity supplier are calculated. Schedule 125 requires PGE to file estimates of the adjustments on or before April 1. PGE filed an update on April 1, and that docket (UE 391) is proceeding on a separate basis.

Compliance with OAR 860-022-0019. Attached as Exhibit 1 is the information required by OAR 860-022-0019. That exhibit shows the impact of the proposed price change on each customer class. The impact on residential customers of the requested price change is an increase of 6.4%, and the increase for an average residential customer using 780 kWh per month is $7.44.

III. TESTIMONY

PGE's testimony and exhibits demonstrate that the Commission should approve this Application. The prices and tariffs proposed result in prices that are just and reasonable. PGE is introducing twelve pieces of testimony sponsored by the following witnesses:

EXHIBIT NO.	TITLE	WITNESSES
100	Policy	Maria Pope and Brett Sims
200	Revenue Requirements	Alex Tooman and Greg Batzler
300	Compensation	Anne Mersereau and Tamara Neitzke
400	Corporate Support	Jim Ajello and Greg Batzler
500	Customer Service	John McFarland and Larry Bekkedahl
600	Flexible Load Plan	Jason Salmi Klotz
700	Production	Brad Jenkins and Stefan Cristea
800	Transmission and Distribution	Brad Jenkins and Larry Bekkedahl
900	Cost of Capital	Jardon Jaramillo, Bente Villadsen, and Jaki Ferchland
1000	Load Forecast	Amber Riter
1100	Marginal Cost of Service	Robert Macfarlane and Christopher Pleasant
1200	Pricing	Robert Macfarlane and Teresa Tang

IV. SUMMARY OF TESTIMONY

Exhibit 100. Maria Pope, President and Chief Executive Officer and Brett Sims, Vice President, Strategy, Regulation and Energy Supply present the opening testimony. They provide the business context for this filing and describe the customer value and benefits from investments PGE has made to enable a clean energy future with a smarter, more resilient, better integrated and more flexible power grid. Ms. Pope and Mr. Sims further discuss what PGE is doing to keep electricity prices as low as possible as PGE makes these investments, serving customers efficiently and equitably. They then summarize the proposed average all-in price increase in 2022 of 3.9%, 2.9% of which is supported by this filing. Ms. Pope and Mr. Sims also introduce the other testimonies in this docket.

Exhibit 200. Senior Regulatory Consultant Alex Tooman and Regulatory Consultant Greg Batzler, summarize the overall $2,105.0 million test year revenue requirement, comparing the request with that most recently approved in PGE's last general rate case UE 335 (2019 test

year). In Exhibit 200, PGE identifies a specific Colstrip revenue requirement and proposes that all identifiable Colstrip-related costs be included in a separate tariff schedule. The revenue requirement of $2,105.0 million includes $55.9 million of Colstrip related capital and expense costs. Messrs. Tooman's and Batzler's testimony also discusses PGE's net rate base, plus associated depreciation and amortization expense, and unbundled results.

Exhibit 300. Anne Mersereau, Vice President of Human Resources, Diversity and Inclusion, and Tamara Neitzke, Director of Total Rewards, present total compensation costs for the 2022 test year and describe how PGE's compensation philosophy is designed to address compensation challenges.

Exhibit 400. Jim Ajello, Chief Financial Officer and Treasurer, and Greg Batzler, Regulatory Consultant, explain PGE's request for administrative and general (A&G) costs in 2022.

Exhibit 500. Larry Bekkedahl, Senior Vice President of Grid Architecture, Integration, and System Operations, and John McFarland, Vice President and Chief Customer Officer, explain PGE's forecast of Customer Service O&M costs and address the Transportation Electrification program. They also discuss customer payment options and the proposal to offer fee free debit and credit card payments to small non-residential customers.

Exhibit 600. Jason Salmi Klotz, a Principal Product Development Specialist discusses PGE's Flexible Load Plan and explains PGE's proposal for submitting a portfolio level, multi-year plan and cost recovery options to address that plan, later this year.

Exhibit 700. Bradley Jenkins, Vice President, Utility Operations, and Stefan Cristea, Senior Regulatory Analyst explain the O&M expenses associated with PGE's long-term power supply resources. They also discuss the recent plant performance of PGE's generation fleet.

Exhibit 800. Larry Bekkedahl, Senior Vice President of Grid Architecture, Integration, and System Operations, and Bradley Jenkins, Vice President of Utility Operations, discuss T&D capital expenditures from 2019 through April 2022 and incremental O&M costs for the 2022 test year. In particular, their testimony includes a detailed discussion of the IOC, ADMS, Wildfire Mitigation, and Vegetation Management. They also present a modified recovery mechanism for Level III events that includes a balancing account and cost sharing between PGE customers and shareholders.

Exhibit 900. Jardon Jaramillo, Senior Director of Treasury, Investor Relations, and Risk Management, and Jaki Ferchland, Manager of Revenue Requirement in Regulatory Affairs, recommend the Company's cost of capital and capital structure for the 2022 test year; and Dr. Bente Villadsen, economist and principal at The Brattle Group, estimates PGE's required ROE and describes the supporting analyses.

These witnesses also address PGE's current and proposed test-year capital structure. In this case PGE proposes the same capital structure for ratemaking as was approved in immediately previous rate cases, 50% equity and 50% debt.

Exhibit 1000. Amber Riter, Economist and Lead Load Forecasting Analyst, provides PGE's 2022 test year load and customer forecast.

Exhibit 1100. Robert Macfarlane, Manager, Pricing and Tariffs, and Christopher Pleasant, Senior Regulatory Analyst, describe the methodologies and results of PGE's generation, transmission, distribution, customer service, and street lighting marginal cost of service studies.

Exhibit 1200. Robert Macfarlane, Manager, Pricing and Tariffs, and Teresa Tang Regulatory Consultant, describe how the proposed tariff changes recover PGE's 2022 revenue requirement to achieve fair, just, and reasonable prices for customers, and price changes to

various supplemental schedules. They also discuss PGE's proposal to implement non-bypassability of costs associated with the state's solar payment option program, allocating costs to all customers.

V. COMMUNICATIONS

PGE requests that communications regarding this filing be addressed to:

Jay Tinker
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VI. REQUEST FOR APPROVALS

PGE requests that the Commission issue an order:

(1) Approving the requested price changes, effective May 1, 2022;

(2) Approving the proposed tariffs;

(3) Approving a modified recovery mechanism for Level III events that includes a balancing account and cost sharing between PGE customers and shareholders;

(4) Renewing and revising PGE's decoupling mechanism, and

(5) Approving the non-bypassability of costs associated with the state's solar payment option program.

Dated this 9th day of July, 2021.

Respectfully submitted,

Loretta Mabinton

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Exhibit 1

Case Summary
($Millions)

Total Revenue Requirement	$2,105.0
Change in Revenues Requested	
Total Change in Revenues Requested	$59.0
Total Change net of RPA	$59.0
Percent Change in Base Revenues Requested	2.9%
Percent Change net of RPA	2.9%
Test Period	2022
Requested Rate of Return on Capital (Rate Base)	6.94%
Requested Rate of Return on Common Equity	9.50%
Proposed Rate Base	$5,737.5
Results of Operation	
A. Before Price Change	
Utility Operating Income	$328.2
Rate Base	$5,736.3
Rate of Return on Capital	5.72%
Rate of Return on Common Equity	7.07%
B. After Price Change	
Utility Operating Income	$398.0
Rate Base	$5,737.5
Rate of Return on Capital	6.94%
Rate of Return on Common Equity	9.50%
Base Rate Effect of Proposed Price Change	
A. Residential Customers	6.9%
B. Small Non-residential Customers	4.5%
C. Large Non-residential Customers	-1.8%
D. Lighting & Signal Customers	12.1%
Total Impact Including AUT and Supplementals	
A. Residential Customers	6.4%
B. Small Non-residential Customers	7.8%
C. Large Non-residential Customers	1.0%
D. Lighting & Signal Customers	14.3%
Note: Percent Changes are on a cycle basis for Cost of Service Customers. Base rate impacts do not include AUT.	

401k	Portland General Electric 401(k) Plan
12CP	Twelve Coincident Peak
A&G	Administrative and General
ACI	Annual Cash Incentive
ADIT	Accumulated Deferred Income Taxes
ADMS	Advanced Distribution Management System
AFDC/AFUDC	Allowance for Funds Used during Construction
AMI	Advanced Metering Infrastructure
APS	Arizona Public Services
ASC	Accounting Standards Codification
AUT	Annual Update Tariff
AWO	Accounting Work Order
AWRR	Advanced Wildfire Risk Reduction
BCEI	Blue Chip Economic Indicators
BCEM	Business Continuity and Emergency Management
BI	Business Intelligence Reporting Tool
BPA	Bonneville Power Administration
Brattle	The Brattle Group
CAISO	California Independent System Operation
CAPM	Capital Asset Pricing Model
CCCT	Combined Cycle Combustion Turbine
CE	Cost Element
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CIO	Customer Impact Offset
CIS	Customer Information System
CMC	Customer Marginal Costs
CM/GC	Construction Manager/General Contractor
ConEd	Consolidated Edison
COS	Cost of Service
CWIP	Construction Work in Progress
D&O	Directors and Officers
DA	Distribution Automation
DER	Distributed Energy Resources
DR	Demand Response
DSG	Dispatchable Standby Generation
DSM	Demand Side Management
DSO	Distribution System Operation
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EE	Energy Efficiency
EEI	Edison Electric Institute
ELI	Emerging Leaders Internship
EPRI	Electric Power Research Institute
EPS	Earnings per Share
ESS	Electricity Service Supplier
ETO	Energy Trust of Oregon

EV	Electric Vehicle
EVM	Enhanced Vegetation Management
F&A	Finance and Accounting
FAN	Field Area Network
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FITNES	Facility Inspections & Treatment to the National Electric Safety Code
FLISR	Fault Loaction, Isolation and Service Restoration
FLP	Flexible Load Plan
FMBs	First Mortgage Bonds
FOMC	Federal Open Market Committee
FP&L	Florida Power & Light
FTE	Full Time Equivalent
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GIS	Geospatial Information System
GMP	Guaranteed Maximum Price
GRC	General Rate Case
GSU	Generator Step-Up Transformer
HR	Human Resources
HRA	Health Reimbursement Account
HSA	Health Savings Account
IBEW	International Brotherhood of Electrical Workers
IEEE	Institute of Electrical and Electronics Engineers
IOC	Integrated Operations Center
IMT	Incident Management Team
IPC	Idaho Power Company
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISFSI	Independent Spent Fuel Storage Installation
ISOC	Integrated Security Operations Center
IT	Information Technology
kW	Kilowatt
kWh	Kilowatt hours
kV	Kilovolt
LADWP	Los Angeles Department of Water & Power
LEA	Line Extension Allowance
LED	Light-emitting diode
LRRA	Lost Revenue Recovery Adjustment
LTSA	Long-term Service Agreement
M&A	Merger and Acquisition
MAPE	Mean Average Percentage Error
MBA	Master of Business Intelligence
MCBIT	Multnomah Country Business Income Tax
MDCP	Managers Deferred Compensation Plan
Mid-C	Mid-Columbia

MMA	Major Maintenance Accruals
MONET	Multi-area Optimization Network Energy Transaction model
MRP	Market Risk Premium
MSI	Market Strategies International
MW	Megawatts
MWa	Megawatt average
MWh	Megawatt hours
NAICS	North America Industry Classification System
NCP	Non-coincident peak
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
NIMS	National Incident Management System
NIST	National Institute of Standards and Technology
NVPC	Net Variable Power Cost
NWPP	Northwest Power Pool
NYPSC	New York Public Service Commission
O&M	Operations and Maintenance
OATT	Open Access Transmission Tariff
OCAT	Oregon Corporate Activites Tax
OCS	Outage Communications Specialist
OEA	Office of Economic Analysis
OLS	Ordinary Least Squares
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PG&E	Pacific Gas &Electric
PGE	Portland General Electric Company
PIC	Performance Incentive Compensation
PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PPC	Public Purpose Charges
PRB	Pelton Round Butte plants
PTCs	Production Tax Credits
PURPA	Public Utility Regulatory Policies Act
PwC	PricewaterhouseCoopers
PW1	Port Westward 1
PW2	Port Westward 2
QF	Qualifying Facility
R&D	Research and Development
RA	Resource Adequacy
ROE	Return on Equity
ROW	Right of Way
RRA	Regulatory Research Associates
RRMP	Recreation Resources Management Plan
S&P	Standard & Poor’s
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

SAM	Strategic Asset Management
SB	Senate Bill
SCADA	Supervisory Control and Data Acquisition
SCC	System Control Center
SCCT	Simple Cycle Combustion Turbine
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SEC	Securities Exchange Commission
SERP	Supplemental Executive Retirement Plan
SFAS	Statement of Financial Accounting Standards
SG	Smart Grid
SIP	Strategic Investment Program
SME	Subject Matter Expert
SNA	Sales Normalization Adjustment
SPO	Solar Payment Option
STD	Short-term Disability
T&D	Transmission and Distribution
TA	Talent Acquisition
TE	Transportation Electrification
TLEA	Transportation Line Extension Allowance
TOU	Time-of-Use
TRC	Transmission Rate Case
UG	Underground
VIE	Variable Interest Entities
VM	Vegetation Management
W&S	Wages and Salaries
WACC	Weighted Average Cost of Capital
WECC	Western Energy Coordinating Council
WM	Wildfire Mitigation
WTC	World Trade Center
ZEV	Zero-Emission Vehicle