May 13, 2015

Advice Letter 4581-E, Advice Letter 4581-E-A

Meredith Allen
Senior Director, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94177

Subject: AL 4581-E and AL 4581-E-A – Revisions to Electric Rate Schedules E-19 and E-20 in Compliance with Decision 14-12-080

Dear Ms. Allen:

On February 2, 2015 PG&E filed Advice Letter (AL) 4581-E to implement revisions to PG&E’s electric rate schedules E-19 and E-20 as required by CPUC Decision (D.) 14-12-080, to become effective June 1, 2015. These revisions concern an “Option R” electric rate for certain PG&E customers with photovoltaic (PV) solar energy systems that generate 15% or more of their annual electricity usage. On May 1, 2015 PG&E filed AL 4581-E-A to revise the rate schedules of AL 4581-E consistent with the March 1, 2015 change to electric rates. No protests were received by May 10, 2015 to the supplemental AL.

Energy Division staff has reviewed PG&E’s AL 4581-E and AL 4581-E-A and determined that they are in compliance with Decision 14-12-080, and will become effective June 1, 2015.

AL 4581-E and AL 4581-E-A propose to add Option R rate tables to schedules E-19 and E-20 showing both total and unbundled rates for Option R. The ALs also add sections that explain the terms and conditions of Option R, as well as proposing a calculation to determine if a solar PV system is providing 15% or more of a customer’s annual electricity usage.

The California Clean DG Coalition (CCDC) timely filed a protest to AL 4581-E on February 23, 2015. PG&E timely filed Reply Comments on March 2, 2015.

CCDC recommended that the CPUC suspend AL 4581-E pending issuance of a decision on PG&E’s Application for a Rehearing of D.14-12-080. In its protest, CCDC also sought clarification that a customer that otherwise qualified for Option R would not lose that eligibility if it also installed a combined heat and power (CHP) system.
Energy Division rejects CCDC’s request to suspend AL 4581-E for the following reasons:

1. D.14-12-080 was adopted by the Commission and is in effect until PG&E’s Application for Rehearing is addressed by the CPUC.\(^1\) Therefore, PG&E is required to implement D.14-12-080.

2. AL 4581-E is consistent with D.14-12-080, and this is not contested by CCDC’s protest.

With respect to CCDC’s request for clarification on whether or not customers that install CHP would remain eligible for Option R, Ordering Paragraph 1 of D.14-12-080 is clear that “[t]he Option R rate shall be available to qualifying customers, including voluntary E-19 customers, with solar PV systems that provide 15% or more of their annual electricity usage, with no cap on participation.” Therefore, customers with CHP or other forms of distributed generation (DG) are not precluded from Option R eligibility.

PG&E’s Reply Comments to CCDC’s protest correctly affirm that installing a complementary CHP system (or any other form of DG) would not affect eligibility for Option R so long as the customer’s PV system continued to meet 15% or more of the customer’s annual electricity usage.

For the foregoing reasons, CCDC’s protest is denied. AL 4581-E and AL 4581-E-A are determined to be in compliance with D.14-12-080. AL 4581-E and AL 4581-E-A are approved and will become effective June 1, 2015.

Sincerely,

Edward Randolph
Director, Energy Division

cc: Ann L. Trowbridge, Day Carter Murphy LLP

\(^1\) See Public Utilities Code Section 1735 (“An application for rehearing shall not excuse any corporation or person from complying with and obeying any order or decision…”).
February 2, 2015

Advice 4581-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: Revisions to Electric Rate Schedules E-19 and E-20 in Compliance with Decision 14-12-080

Purpose

Pacific Gas and Electric Company (PG&E) hereby modifies its Electric Rate Schedules E-19 and E-20 in compliance with Decision (D.) 14-12-080.

The filing would not increase any current rate or charge, cause the withdrawal of service or conflict with any rate schedule or rule, except as discussed below.

Background

On December 18, 2014, the California Public Utilities Commission (Commission or CPUC) approved D.14-12-080, Decision on a Rate Design Proposal to Adopt an Option R Tariff for Pacific Gas and Electric Company.

D.14-12-080 directs PG&E to offer to Schedule E-19 and E-20 customers a new rate option termed “Option R.” Option R will be available on a voluntary basis to qualifying E-19 and E-20 customers that have installed solar photovoltaic (PV or solar). To qualify for Option R, a customer’s annual solar output must be at least 15 percent of the customer’s annual energy usage. Per D.14-12-080, Option R is not available to customers with other non-solar types of distributed generation. Option R converts 100 percent of peak and part-peak generation demand charges, and 75 percent of peak and part-peak distribution demand charges, to peak and part-peak energy charges. Solar customers on Schedule E-19V, for voluntary Schedule E-19 service below 500 kW, are also eligible for Option R.

Ordering Paragraph (OP) 1 of the Decision orders that “Within 45 days of the issuance of this decision, Pacific Gas and Electric Company shall file a Tier 2 Advice Letter with revised tariff sheets for rate schedules E-19 and E-20 that include an Option R.” The Decision was issued on December 19, 2014, so this Advice Letter is timely filed. Also
per OP 1, the Option R rates will be effective June 1, 2015, unless PG&E’s pending Application For Rehearing of D.14-12-080 is granted before that date.

Proposed Revisions

This Advice Letter proposes the following changes to Electric Rate Schedule E-19, consistent with the Decision:
- Addition of rate tables showing total and unbundled Option R rates.
- Addition of Section 20, which explains Option R terms and conditions and proposes the calculation to determine that a PV system is providing 15 percent or more of annual electricity usage.

This Advice Letter proposes the following changes to Electric Rate Schedule E-20, consistent with the Decision:
- Addition of rate tables showing total and unbundled Option R rates.
- Addition of Section 18, which explains Option R terms and conditions and proposes the calculation to determine that a PV system is providing 15 percent or more of annual electricity usage.

Revenue Neutrality

OP 1 to D.14-12-080 provides as follows:

“The Option R rates shall shift all revenues collected for generation capacity costs from peak and part-peak demand charges to peak and part-peak energy charges in a manner that would be revenue neutral within the E-19 and E-20 customer classes. The Option R rates shall shift 75% of the revenues collected for distribution capacity costs from peak and part-peak demand charges to peak and part-peak energy charges. The tariff sheets shall become effective June 1, 2015, subject to Energy Division determining that they are in compliance with this order.”

The Option R rates presented in the attached tariff sheets present Option R rates consistent with OP 1. The Option R rates shown in the attached tariff sheets have not been adjusted in any way to account for revenue shortfalls. PG&E proposes that future adjustments for the treatment of revenue shortfalls attributable to Option R be incorporated into future Schedule E-19 and E-20 rates as described below.

The Option R rates presented in the attached tariff sheets are based on revenue neutrality with respect to the rates for Schedules E-19 and E-20 that are currently effective. Because further rate changes are expected before Option R rates are implemented on June 1, the attached rates are illustrative and may need to be updated to be consistent with the rates for Schedules E-19 and E-20 that will be effective as of the June 1, 2015 implementation date.
Revenue Shortfalls

To comply with the directive in OP 1 that Option R rates be revenue neutral within the class, and consistent with the language in D.14-12-080, that, “As a result of this decision, some revenues will likely be shifted among customers on the E-19 and E-20 tariffs,” PG&E proposes an ex post, or after-the-fact, methodology for calculating the revenue shortfall from offering Option R and ensuring that it remains within the E-19 and E-20 customers classes. This ex post methodology is consistent with similar practices approved by the CPUC where revenue shortfalls could not be accurately forecast, but were none-the-less required to be retained within the originating class.2,3

PG&E proposes to allocate all Option R revenue shortfalls back to the rate schedule and voltage of origin.

Tariff Revisions

In Attachment 1, PG&E presents the tariff revisions necessary to incorporate solar Option R into Schedules E-19 and E-20.

1 D.14-12-080, p. 3.
2 For Peak Day Pricing, see D.10-02-032 in PG&E’s 2009 Rate Design Window proceeding, pp. 16-26 (Section 5.5, Allocation of Under- and Over-Collected, and associated Section 5.5.1, Discussion). Alternate methods of allocating shortfalls only to the participants or to both non-participants and participants are discussed, with the latter being adopted. In addition, see Annual Electric True-Up (AET) Advice 3727-E, September 1, 2010, pp. 21-22, and supplemental AET Advice 3727-E-A, December 30, 2010, p.12, for a description of how these PDP revenue shortfall rate adjustments are implemented in AET rates.
3 For revenue neutral adjustments for agricultural rates, see PG&E’s 2011 GRC Phase 2 D.11-12-053, Section 3.6.1, Uncontested Proposals in the Agricultural Rate Design Settlement, p. 59, and sub-Section 3.6.1.3, TOU Revenue Neutrality, pp. 60-61, and associated D.11-12-053 Appendix F, Supplemental Settlement Agreement on Agricultural Rate Design Issues in PG&E’s Application 10-03-014, Term V.B.3, TOU Revenue Neutrality, and associated Exhibit B, Illustrative Revenue Neutrality Adjustments, to Appendix F. See also AET Advice 4278-E, August 30, 2013, p. 22, and supplemental AET Advice 4278-E-B, December 31, 2013, pp. 12-13, for a discussion of the agricultural after-the-fact revenue neutral adjustments to account for revenue shortfalls when non-TOU agricultural customers transition to mandatory TOU rates in March of each year.
Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than February 23, 2015, which is 21 days\textsuperscript{4} after the date of this filing, due to the fact that the 20\textsuperscript{th} day falls on a Sunday. Protests must be submitted to:

CPUC Energy Division  
ED Tariff Unit  
505 Van Ness Avenue, 4\textsuperscript{th} Floor  
San Francisco, California 94102  

Facsimile: (415) 703-2200  
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Meredith Allen  
Senior Director, Regulatory Relations  
Pacific Gas and Electric Company  
77 Beale Street, Mail Code B10C  
P.O. Box 770000  
San Francisco, California 94177  

Facsimile: (415) 973-7226  
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

\textsuperscript{4} The 20-day protest period concludes on a weekend. PG&E is hereby moving this date to the following business day.
Effective Date

As ordered by OP 1 of D.14-12-080, PG&E requests that this Tier 2 advice filing become effective on June 1, 2015, subject to Energy Division determining that PG&E is in compliance with this order. On January 20, 2015, PG&E filed an Application for Rehearing of D.14-12-080 in A.12-12-002. If PG&E’s Application for Rehearing is approved, PG&E will withdraw this advice letter.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for A.12-12-002. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission’s Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Meredith Allen
Senior Director, Regulatory Relations

Attachments

cc: Service List, A.12-12-002
Company name/CPUC Utility No. Pacific Gas and Electric Company (ID U39 E)

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<th>Utility type:</th>
<th>Contact Person: Kingsley Cheng</th>
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<td>☑ ELC</td>
<td>Phone #: (415) 973-5265</td>
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EXPLANATION OF UTILITY TYPE
ELC = Electric  GAS = Gas
PLC = Pipeline   HEAT = Heat  WATER = Water

Advice Letter (AL) #: 4581-E  Tier: 2
Subject of AL: Revisions to Electric Rate Schedules E-19 and E-20 in Compliance with Decision 14-12-080
Keywords (choose from CPUC listing): Compliance
AL filing type: ☑ Monthly  ☐ Quarterly  ☐ Annual  ☑ One-Time  ☐ Other _____________________________
If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.14-12-080
Summarize differences between the AL and the prior withdrawn or rejected AL: ____________________
Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: No
Confidential information will be made available to those who have executed a nondisclosure agreement: N/A
Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: __________________________________________________________________________________________________
Resolution Required? ☐ Yes  ☑ No
Requested effective date: June 1, 2015  No. of tariff sheets: 30
Estimated system annual revenue effect (%): N/A
Estimated system average rate effect (%): N/A
When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).
Tariff schedules affected: Electric Rate Schedules E-19 and E-20
Service affected and changes proposed: New Option for Electric Rate Schedules E-19 and E-20
Pending advice letters that revise the same tariff sheets: N/A

Protests, dispositions, and all other correspondence regarding this AL are due no later than 21 days¹ after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission  Pacific Gas and Electric Company
Energy Division  Attn: Meredith Allen
EDTariffUnit  Senior Director, Regulatory Relations
505 Van Ness Ave., 4th Flr.  77 Beale Street, Mail Code B10C
San Francisco, CA 94102  P.O. Box 770000
E-mail: EDTariffUnit@cpuc.ca.gov  San Francisco, CA 94177
E-mail: PGETariffs@pge.com

¹ The 20-day protest period concludes on a weekend. PG&E is hereby moving this date to the following business day.
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ATTACHMENT 1
Advice 4581-E
Cancelling Cal P.U.C. Sheet No.

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Page 2 of 4
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<td>35079-E</td>
<td>ELECTRIC TABLE OF CONTENTS RATE SCHEDULES Sheet 4</td>
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1. APPLICABILITY: (Cont’d.)

**Definition of Maximum Demand:** Demand will be averaged over 15-minute intervals for customers whose maximum demand exceeds 499 kW. “Maximum demand” will be the highest of all the 15-minute averages for the billing month. If the customer’s use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer’s maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month. (See Section 6 for a definition of “Peak-Period.”) See Section 14 for the definition of maximum demand for customers voluntarily selecting E-19.

**Solar Pilot Program:** Customers who exceed 499 kW for at least three consecutive months during the most recent 12-month period and must otherwise take service on mandatory Schedule E-19 may elect service under Schedule A-6 under the terms outlined in the Solar Photovoltaic (solar or PV) Pilot Program section of Schedule A-6. (T)

**Option R for Solar:** The Option R rate is available to qualifying E-19 customers, including voluntary E-19 customers, with PV systems that provide 15% or more of their annual electricity usage. For additional Option R details and program specifics, see Sections 3 and 20. (N)

**Standby Demand:** For customers for whom Schedule S—Standby Service Special Conditions 1 through 6 apply, standby demand is the portion of a customer’s maximum demand in any month caused by nonoperation of the customer’s alternate source of power, and for which a demand charge is paid under the regular service schedule. If the customer imposes standby demand in any month, then the regular service maximum demand charge will be reduced by the applicable reservation capacity charge (see Schedule S Special Condition 1).

To qualify for the above reduction in the maximum demand charge, the customer must, within 30 days of the regular meter-read date, demonstrate to the satisfaction of PG&E the amount of standby demand in any month. This may be done by submitting to PG&E a completed Electric Standby Service Log Sheet (Form 79-726).

2. TERRITORY: This rate schedule applies everywhere PG&E provides electricity service.

3. RATES: Total bundled service charges are calculated using the total rates shown below. Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

(Continued)
**ELECTRIC SCHEDULE E-19**

**MEDIUM GENERAL DEMAND-METERED TOU SERVICE**

3. Rates: (Cont’d.)

### TOTAL RATES FOR OPTION R

(Continued)

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| Optional Meter Data Access Charge ($ per meter per day) | $0.98563 | $0.98563 | $0.98563 |

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</thead>
<tbody>
<tr>
<td>Peak Summer</td>
</tr>
<tr>
<td>Part-Peak Summer</td>
</tr>
<tr>
<td>Off-Peak Summer</td>
</tr>
<tr>
<td>Part-Peak Winter</td>
</tr>
<tr>
<td>Off-Peak Winter</td>
</tr>
</tbody>
</table>

| Power Factor Adjustment Rate ($/kWh/%) | $0.00005 | $0.00005 | $0.00005 |

Total bundled service charges shown on customers’ bills are unbundled according to the component rates shown below. PDP charges and credits are all generation and are not included below.
### ELECTRIC SCHEDULE E-19

**MEDIUM GENERAL DEMAND-METERED TOU SERVICE**

3. Rates: (Cont'd.)

#### UNBUNDLING OF TOTAL RATES FOR OPTION R
(for qualifying solar customers as set forth in Section 20)

Customer/Meter Charge Rates: Customer and meter charge rates provided in the Total Rates section above are assigned entirely to the unbundled distribution component.

<table>
<thead>
<tr>
<th>Demand Rates by Components ($ per kW)</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generation:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum Peak Demand Summer</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Part-Peak Demand Summer</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Demand Summer</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Part-Peak Demand Winter</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Demand Winter</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td><strong>Distribution</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum Peak Demand Summer</td>
<td>$1.37</td>
<td>$1.21</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Part-Peak Demand Summer</td>
<td>$0.37</td>
<td>$0.33</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Demand Summer</td>
<td>$9.29</td>
<td>$6.31</td>
<td>$2.10</td>
</tr>
<tr>
<td>Maximum Part-Peak Demand Winter</td>
<td>$0.06</td>
<td>$0.11</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Demand Winter</td>
<td>$9.29</td>
<td>$6.31</td>
<td>$2.10</td>
</tr>
<tr>
<td><strong>Transmission Maximum Demand</strong></td>
<td>$4.34</td>
<td>$4.34</td>
<td>$4.34</td>
</tr>
<tr>
<td><strong>Reliability Services Maximum Demand</strong></td>
<td>$0.04</td>
<td>$0.04</td>
<td>$0.04</td>
</tr>
</tbody>
</table>

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

** Distribution and New System Generation Charges are combined for presentation on customer bills.

(Continued)
### ELECTRIC SCHEDULE E-19

**MEDIUM GENERAL DEMAND-METERED TOU SERVICE**

3. Rates: (Cont’d.)

#### UNBUNDLING OF TOTAL RATES FOR OPTION R (Cont’d.)

(for qualifying solar customers as set forth in Section 20)

Customer/Meter Charge Rates: Customer and meter charge rates provided in the Total Rates section above are assigned entirely to the unbundled distribution component.

<table>
<thead>
<tr>
<th>Energy Charges by Components ($ per kWh)</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generation:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak Summer</td>
<td>$0.29122</td>
<td>$0.29454</td>
<td>$0.29248</td>
</tr>
<tr>
<td>Part-Peak Summer</td>
<td>$0.12164</td>
<td>$0.11504</td>
<td>$0.11283</td>
</tr>
<tr>
<td>Off-Peak Summer</td>
<td>$0.05720</td>
<td>$0.05870</td>
<td>$0.05461</td>
</tr>
<tr>
<td>Part-Peak Winter</td>
<td>$0.08508</td>
<td>$0.08110</td>
<td>$0.06918</td>
</tr>
<tr>
<td>Off-Peak Winter</td>
<td>$0.06120</td>
<td>$0.06201</td>
<td>$0.05632</td>
</tr>
<tr>
<td><strong>Distribution</strong>:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak Summer</td>
<td>$0.04352</td>
<td>$0.04261</td>
<td>$0.00000</td>
</tr>
<tr>
<td>Part-Peak Summer</td>
<td>$0.01089</td>
<td>$0.01074</td>
<td>$0.00000</td>
</tr>
<tr>
<td>Off-Peak Summer</td>
<td>$0.00000</td>
<td>$0.00000</td>
<td>$0.00000</td>
</tr>
<tr>
<td>Part-Peak Winter</td>
<td>$0.00097</td>
<td>$0.00203</td>
<td>$0.00000</td>
</tr>
<tr>
<td>Off-Peak Winter</td>
<td>$0.00000</td>
<td>$0.00000</td>
<td>$0.00000</td>
</tr>
<tr>
<td><strong>Transmission Rate Adjustments</strong></td>
<td>$0.00395</td>
<td>$0.00395</td>
<td>$0.00395</td>
</tr>
<tr>
<td><strong>Public Purpose Programs</strong></td>
<td>$0.01175</td>
<td>$0.01084</td>
<td>$0.01080</td>
</tr>
<tr>
<td><strong>Nuclear Decommissioning</strong></td>
<td>$0.00097</td>
<td>$0.00097</td>
<td>$0.00097</td>
</tr>
<tr>
<td><strong>Competition Transition Charge</strong></td>
<td>$0.00095</td>
<td>$0.00095</td>
<td>$0.00095</td>
</tr>
<tr>
<td><strong>Energy Cost Recovery Amount</strong></td>
<td>($0.00504)</td>
<td>($0.00504)</td>
<td>($0.00504)</td>
</tr>
<tr>
<td><strong>DWR Bond</strong></td>
<td>$0.00526</td>
<td>$0.00526</td>
<td>$0.00526</td>
</tr>
<tr>
<td><strong>New System Generation Charge</strong></td>
<td>$0.00238</td>
<td>$0.00238</td>
<td>$0.00238</td>
</tr>
<tr>
<td><strong>California Climate Credit</strong></td>
<td>($0.00419)</td>
<td>($0.00421)</td>
<td>($0.00307)</td>
</tr>
</tbody>
</table>

---

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

** Distribution and New System Generation Charges are combined for presentation on customer bills.

*** Only customers that qualify as Small Businesses – California Climate Credit under Rule 1 are eligible for the California Climate Credit.
ELECTRIC SCHEDULE E-19

MEDIUM GENERAL DEMAND-METERED TOU SERVICE

Sheet 10

3. Rates: (Cont’d.)
   a. TYPES OF CHARGES: The customer’s monthly charge for service under Schedule E-19 is the sum of a customer charge, demand charges, and energy charges:

   – The **customer charge** is a flat monthly fee.

   – This schedule has three **demand charges**, a maximum-peak-period-demand charge, a maximum part-peak-period and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month’s peak hours, the maximum part-peak-period demand charge per kilowatt applies to the maximum demand during the month’s part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges. (Time periods are defined in Section 6.)

   – The **energy charge** is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour (kWh), and rates are differentiated according to time of day and time of year.

   – The meters required for this schedule may become obsolete as a result of electric industry restructuring or other action by the California Public Utilities Commission. Therefore, any and all risks of paying the required charges and not receiving commensurate benefit are entirely that of the customer.

   – The monthly charges may be increased or decreased based upon the power factor. (See Section 7.)

   – As shown on the rate chart, which set of customer, demand, and energy charges is paid depends on the level of the customers maximum demand and the voltage at which service is taken. Service voltages are defined in Section 5 below.
4. METERING REQUIREMENTS: PG&E will install a time-of-use meter that is appropriate for this schedule that measures and registers the amount of electricity a customer uses.

Customers with a maximum demand of 200 kW or greater for three consecutive months must have an interval data meter that can be read remotely by PG&E. A Meter Data Management Agent (MDMA) may also read the customer’s meter on behalf of the customer’s Energy Service Provider (ESP) if a customer is receiving Direct Access Service.

For bundled service customers with a maximum demand of 200 kW or greater for three consecutive months, PG&E will provide and install the interval data meter at no additional cost to the customer. After the interval meter is installed, the customer must take service on a time-of-use schedule. The installation of an interval data meter for customers taking service under the provisions of Direct Access is the responsibility of the customer’s Energy Service Provider, or their Agent, and must be installed in accordance with Electric Rule 22.

If the customer does not currently qualify for an interval data meter, the customer must pay PG&E for the cost of purchasing and installing an interval meter, together with applicable Income Tax Component of Contribution (ITCC) charges and the cost to operate and maintain the interval meter, and must sign an Interval Meter Installation Service Agreement (Form 79-984).

Customers who also request any meter data management services must also sign an Interval Meter Data Management Service Agreement (Form 79-985) and must have an appropriate interval data meter.

5. DEFINITION OF SERVICE VOLTAGE: The following defines the three voltage classes of Schedule E-19 rates. Standard Service Voltages are listed in Rule 2, Section B.1.

   a. Secondary: This is the voltage class if the service voltage is less than 2,400 volts or if the definitions of “primary” and “transmission” do not apply to the service.

   b. Primary: This is the voltage class if the customer is served from a “single customer substation” or without transformation from PG&E’s serving distribution system at one of the standard primary voltages specified in PG&E’s Electric Rule 2, Section B.1.

   c. Transmission: This is the voltage class if the customer is served without transformation from PG&E’s serving transmission system at one of the standard transmission voltages specified in PG&E’s Rule 2, Section B.1.
6. DEFINITION OF TIME PERIODS:

Times of the year and times of the day are defined as follows:

SUMMER
Period A (Service from May 1 through October 31):

Peak: 12:00 noon to 6:00 p.m. Monday through Friday (except holidays)
Partial-peak: 8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays)
Off-peak: 9:30 p.m. to 8:30 a.m. All day Monday through Friday, All day Saturday, Sunday, and holidays

WINTER
Period B (service from November 1 through April 30):

Partial-Peak: 8:30 a.m. to 9:30 p.m. Monday through Friday (except holidays)
Off-Peak: 9:30 p.m. to 8:30 a.m. All day Monday through Friday, All day Saturday, Sunday, and holidays

HOLIDAYS: “Holidays” for the purposes of this rate schedule are New Year’s Day, President’s Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

DAYLIGHT SAVING TIME ADJUSTMENT: The time periods shown 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.

CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents.

7. POWER FACTOR ADJUSTMENTS:

Bills will be adjusted based on the power factor for all customers except those selecting voluntary E-19 service. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent.

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor rate and the kilowatt-hour usage for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill will be increased by the product of the power factor rate and the kilowatt-hour usage for each percentage point below 85 percent.

Power factor adjustments will be assigned to distribution for billing purposes.
8. CHARGES FOR TRANSFORMER AND LINE LOSSES:
The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of Rule 2.

9. STANDARD SERVICE FACILITIES:
If PG&E must install any new or additional facilities to provide the customer with service under this schedule, the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a line extension agreement. See Rules 2, 15, and 16 for details. This section does not apply to customers voluntarily taking service under Schedule E-19.

Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in the line extension agreement.

10. SPECIAL FACILITIES:
PG&E will normally install only those standard facilities it deems necessary to provide service under this schedule. If the customer requests any additional facilities, those facilities will be treated as “special facilities” in accordance with Section I of Rule 2.

11. ARRANGEMENTS FOR VISUAL-Displays DISPLAY METERING:
If the customer wishes to have visual-display metering equipment in addition to the regular metering equipment, and the customer would like PG&E to install that equipment, the customer must submit a written request to PG&E. PG&E will provide and install the equipment within 180 days of receiving the request. The visual-display metering equipment will be installed near the present metering equipment. The customer will be responsible for providing the required space and associated wiring. PG&E will continue to use the regular metering equipment for billing purposes.
12. COMMON-AREA ACCOUNTS: Common-area accounts that are separately metered by PG&E and which took electric service from PG&E on or prior to January 16, 2003, have a one-time opportunity to return to a residential rate schedule from April 1, 2004 to May 31, 2004, by notifying PG&E in writing.

In the event that the CPUC substantially amends any or all of PG&E’s commercial or residential rate schedules, the Executive Council of Homeowners (ECHO) can direct PG&E to begin an optional second right-of-return period lasting 105 days. However, if this occurs prior to the April 1, 2004 to May 31, 2004, time period, the ECHO directed right of return period will be the only window for returning to a residential schedule.

Newly constructed common-areas that are separately metered by PG&E and which first took electric service from PG&E after January 16, 2003, have a one-time opportunity to transfer to a residential rate schedule during a two-month window that begins 14 months after taking service on a commercial rate schedule. This must be done by notifying PG&E in writing. These common-area accounts have an additional opportunity to return to a residential schedule in the event that ECHO directs PG&E to begin a second right-of-return period.

Only those common-area accounts taking service on Schedule E-8 prior to moving to this tariff may return to Schedule E-8.

Common-area accounts are those accounts that provide electric service to Common Use Areas as defined in Rule 1.
13. VOLUNTARY SERVICE PROVISIONS: Customers voluntarily taking service on Schedule E-19 (see Applicability Section) shall be governed by all the terms and conditions shown in Sections 1 through 12, unless different terms and conditions are shown below.

   a. DEFINITION OF MAXIMUM DEMAND: Demand will be averaged over 15-minute intervals except, in special cases. "Maximum demand" will be the highest of all 15-minute averages for the billing month.

      SPECIAL CASES: (1) If the customer’s use of energy is intermittent or subject to severe fluctuations, a 5-minute interval may be used; and (2) If the customer uses welders, the demand charge will be subject to the minimum demand charges for those welders’ ratings, as explained in Section J of Rule 2.

   b. REDUCED CUSTOMER CHARGE: The reduced customer charge will be assessed only if the customer is taking service under this schedule on a voluntary basis or if the customer’s maximum billing demand has not exceeded 499 kW for 12 or more consecutive months.

   c. SERVICE CONTRACTS: This rate schedule will remain in effect for at least twelve consecutive months before another schedule change is made, unless the customer’s maximum demand has exceeded 499 kW for three consecutive months.

14. BILLING: A customer’s bill is calculated based on the option applicable to the customer.
14. BILLING: Bundled Service Customers receive supply and delivery services solely from PG&E. (L)
The customer’s bill is based on the Total Rates and Conditions set forth in this schedule.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, New System Generation Charges1, the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, New System Generation Charges1, the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

DA / CCA CRS

Energy Cost Recovery Amount Charge (per kWh) ($0.00504) (R)
DWR Bond Charge (per kWh) $0.00526 (I)
CTC Charge (per kWh) $0.00050 (R)
Power Charge Indifference Adjustment (per kWh)
Pre-2009 Vintage ($0.00046)
2009 Vintage $0.00383
2010 Vintage $0.00892
2011 Vintage $0.00916
2012 Vintage $0.00907
2013 Vintage $0.00875
2014 Vintage $0.00866
2015 Vintage $0.00866

15. CARE DISCOUNT FOR NONPROFIT GROUP- LIVING AND SPECIAL EMPLOYEE HOUSING FACILITIES:

Facilities which meet the eligibility criteria in Rule 19.2 or 19.3 are eligible for a California Alternate Rates for Energy discount under Schedule E-CARE. CARE customers are exempt from paying the DWR Bond Charge rate component. For CARE customers, no portion of the rates shall be used to pay the DWR bond charge. Generation is calculated residually based on the total rate less the sum of the following: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Public Purpose Programs, Nuclear Decommissioning, New System Generation Charges1, Competition Transition Charges (CTC), and Energy Cost Recovery Amount.

_________________
1 Per Decision 11-12-031, New System Generation Charges are effective 1/1/2012. (L)
ELECTRIC SCHEDULE E-19
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

16. ELECTRIC EMERGENCY PLAN
    ROTATING BLOCK OUTAGES

As set forth in CPUC Decision 01-04-006, all transmission level customers except essential use customers, Optional Binding Mandatory Curtailment (OBMC) plan participants, net suppliers to the electrical grid, or others exempt by the Commission, are to be included in rotating outages in the event of an emergency. A transmission level customer who refuses or fails to drop load shall be added to the next rotating outage group so that the customer does not escape curtailment. If the transmission level customer fails to cooperate and drop load at PG&E’s request, automatic equipment controlled by PG&E will be installed at the customer’s expense per Electric Rule 2. A transmission level customer who refuses to drop load before installation of the equipment shall be subject to a penalty of $6/kWh for all load requested to be curtailed that is not curtailed. The $6/kWh penalty shall not apply if the customer’s generation suffers a verified, forced outage and during times of scheduled maintenance. The scheduled maintenance must be approved by both the ISO and PG&E, but approval may not be unreasonably withheld.
17. **STANDBY APPLICABILITY:**

**SOLAR GENERATION FACILITIES EXEMPTION:** Customers who utilize solar generating facilities which are less than or equal to one megawatt to serve load and who do not sell power or make more than incidental export of power into PG&E’s power grid and who have not elected service under Schedule NEM, will be exempt from paying the otherwise applicable standby reservation charges.

**DISTRIBUTED ENERGY RESOURCES EXEMPTION:** Any customer under a time-of-use (TOU) rate schedule using electric generation technology that meets the criteria as defined in Electric Rule 1 for Distributed Energy Resources is exempt from the otherwise applicable standby reservation charges. Customers qualifying for this exemption shall be subject to the following requirements. Customers qualifying for an exemption from standby charges under Public Utilities (PU) Code Sections 353.1 and 353.3, as described above, must take service on a TOU schedule in order to receive this exemption until a real-time pricing program, as described in PU Code 353.3, is made available. Once available, customers qualifying for the standby charge exemption must participate in the real-time program referred to above. Qualification for and receipt of this distributed energy resources exemption does not exempt the customer from metering charges applicable to TOU and real-time pricing, or exempt the customer from reasonable interconnection charges, non-bypassable charges as required in Preliminary Statement BB - Competition Transition Charge Responsibility for All Customers and CTC Procurement, or obligations determined by the Commission to result from participation in the purchase of power through the California Department of Water Resources, as provided in PU Code Section 353.7.

18. **DWR BOND CHARGE:**

The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts.
19. PEAK DAY PRICING DETAILS:

a. Default Provision: The default of eligible customers to PDP will occur once per year with the start of their billing cycle on or after November 1. Eligible customers will have at least 45-days notice prior to their planned default date when they may opt-out of PDP rates to take service on TOU rates. During the 45-day period, customers will continue to take service on their non-PDP rate. Customers may elect any applicable PDP rate. However, if the customers taking service on this schedule have not made that choice or elected to opt-out to a TOU rate at least five (5) days before their proposed default date, their service will be defaulted to the PDP version of this rate schedule on their default date. Existing customers on a PDP rate eligible demand response program will have the option to enroll.

b. Capacity Reservation Level: Customers may elect a capacity reservation level (CRL) and pay for a fixed level of capacity, specified in kW. While the CRL is applicable year round, customers electing a CRL will be billed on a take-or-pay basis up to the specified CRL under the non-PDP rate of this schedule during the summer period (May 1 through October 31). This means that customers will be billed for summer peak generation demand charges up to the level of their CRL, even in summer months when the actual demand might be less than their CRL. Customers will receive PDP credits on summer usage above the CRL on summer-period non-PDP event days. All usage during a PDP event protected under the CRL will be billed at the non-PDP rate. All usage above the CRL (as measured in 15-minute intervals), and not protected during a PDP event, will be billed at the PDP rate.

If a customer fails to elect an initial CRL, the customer’s initial CRL will be set at 50% of its most recent six (6) summer months’ average peak-period maximum demand and may go back to previous year to make a full summer season (if available). If the customer has not established any historic summer billing demand, the CRL will be set at zero (0).

A customer may only elect to change their CRL once every 12 months.

c. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12 months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

If a customer terminates its participation on the PDP rate prior to the initial 12 month period expiring, the customer will receive bill stabilization up to the date when the customer terminates its participation. Bill stabilization benefits will be computed on a cumulative basis, based on the earlier of 1) when a customer terminates its participation on the PDP rate or 2) at the end of the initial 12-month period. Any applicable credits will be applied to the customer’s account on a subsequent regular bill. Bill stabilization is only available one time per customer. If a customer un-enrolls or terminates its participation on a PDP rate, bill stabilization will not be offered again.
ELECTRIC SCHEDULE E-19
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

19. PEAK DAY PRICING DETAILS:
   (cont.)

d. Notification Equipment: Customers, at their expense, must have access to the
   Internet and an e-mail address or a phone number to receive notification of a PDP
   event. In addition, all customers can have, at their expense, an alphanumeric pager
   or cellular telephone that is capable of receiving a text message sent via the
   Internet, and/or a facsimile machine to receive notification messages.

   If a PDP event occurs, customers will be notified using one or more of the above-
   mentioned systems. Receipt of such notice is the responsibility of the participating
   customer. PG&E will make reasonable efforts to notify customers, however it is the
   customer's responsibility to maintain accurate notification contact information,
   receive such notice and to check the PG&E website to see if an event is activated.
   PG&E does not guarantee the reliability of the phone, text messaging, e-mail
   system or Internet site by which the customer receives notification.

   PG&E may conduct notification test events once a month to ensure a customer's
   contact information is up-to-date. These are not actual PDP events and no load
   reduction is required.

e. Demand Response Operations Website: Customers with demands of 200 kW or
   greater for three consecutive months can use PG&E's demand response operations
   website located at https://inter-act.pge.com for load curtailment event notifications
   and communications.

   The customer's actual energy usage is available at PG&E's demand response
   operations website or on "My Account". This data may not match billing quality
   data, and the customer understands and agrees that the data posted to PG&E's
   demand response operations website or on "My Account" may be different from the
   actual bill.

f. Program Operations: A maximum of fifteen (15) PDP events and a minimum of
   nine (9) PDP events may be called in any calendar year. PG&E will notify
   customers by 2:00 p.m. on a day-ahead basis when a PDP event will occur the next
   day. The PDP program will operate year-round and PDP events may be called for
   any day of the week. PDP events will be called from 2:00 p.m. to 6:00 p.m.

g. Event Cancellation: PG&E may initiate the cancellation of a PDP event before 4:00
   p.m. the day-ahead of a noticed PDP event. If PG&E cancels an event, it will count
   the cancelled event toward the PDP limits.

h. Event Trigger: PG&E will trigger a PDP event when the day-ahead temperature
   forecast trigger is reached. The trigger will be the average of the day-ahead
   maximum temperature forecasts for San Jose, Concord, Red Bluff, Sacramento and
   Fresno.

(Continued)
ELECTRIC SCHEDULE E-19
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

19. PEAK DAY PRICING DETAILS:

h. Beginning May 1 of each summer season, the PDP events on non-holiday weekdays will be triggered at 98 degrees Fahrenheit (°F), and will be triggered at 105° F on holidays and weekends. If needed, PG&E will adjust the non-holiday weekday trigger up or down over the course of the summer to achieve the range of 9 to 15 PDP events in any calendar year. Such adjustments would be made no more than twice per month and would be posted to the demand response operations website or on PG&E’s PDP website.

PDP events may also be initiated as warranted on a day-ahead basis by 1) extreme system conditions such as special alerts issued by the California Independent System Operator, 2) under conditions of high forecasted California spot market power prices, 3) to meet annual PDP event limits for a calendar year, or 4) for testing/evaluation purposes.

i. Program Terms: A customer may opt-out anytime during their initial 12 months on a PDP rate. After the initial 12 months, customer’s participation will be in accordance with Electric Rule 12.

Customers may opt-out of a PDP rate at anytime to enroll in another demand response program beginning May 1, 2011.

j. Interaction with Other PG&E Demand Response Programs: Customers on a PDP rate may participate in a day-of dispatchable demand response program as established in D.09-08-027.

20. Option R The Option R rate is available to qualifying E-19 customers, including voluntary E-19 customers, with PV systems that provide 15% or more of their annual electricity usage.

For a customer installing a new PV system, this eligibility requirement will be calculated as follows:

\[
\text{Annual PV system output}^1 / \text{Annual electricity usage}^2 \geq 15%
\]

For a customer with an existing PV system, this eligibility requirement will be calculated as follows:

\[
\text{Annual PV system output}^3 / (\text{Annual PV system output}^3 + \text{Annual electricity usage}^2) \geq 15%
\]

\(^1\) For a customer installing a new system, annual PV system output (kWh) will be estimated as CEC rating of the panels (kW) \* 8,760 hours/year \* 18% capacity factor.
\(^2\) Annual electricity usage (kWh) will be measured at the PG&E meter over the last 12 months.
\(^3\) For a customer with an existing system, the customer may choose to supply PG&E with reliable metered data measuring annual PV system output, if such data are available. Alternatively, annual PV system output will be estimated using the formula in footnote 1.
ENERC SCHEDULE E-20  
SERVICE TO CUSTOMERS WITH MAXIMUM  
DEMANDS of 1000 KILOWATTS or MORE

1. APPLICABILITY:  
Definition of Maximum Demand: Demand will be averaged over 15-minute intervals.  
"Maximum demand" will be the highest of all the 15-minute averages for the billing month.  
If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used.  
If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals.  
The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month.  
(See Section 6 for a definition of "Peak-Period.")  

Standby Demand:  For customers for whom Schedule S—Standby Service Special Conditions 1 through 6 apply, standby demand is the portion of a customer's maximum demand in any month caused by nonoperation of the customer's alternate source of power, and for which a demand charge is paid under the regular service schedule.  

If the customer imposes standby demand in any month, then the regular service maximum demand charge will be reduced by the applicable reservation capacity charge (see Schedule S Special Condition 1).  

To qualify for the above reduction in the maximum demand charge, the customer must, within 30 days of the regular meter read date, demonstrate to the satisfaction of PG&E the amount of standby demand in any month.  
This may be done by submitting to PG&E a completed Electric Standby Service Long Sheet (Form 79-726).  

Solar or Fuel Cell Generation Demand Adjustment:  A customer who installs a solar electric generation facility on or after January 1, 2007, or fuel cell electric generation facility may be eligible to receive a Generation Demand Adjustment.  
A customer will qualify for a Generation Demand Adjustment if both of the following conditions are met:  
(1) either the customer's solar electric generating facility was installed after January 1, 2007, or the customer's fuel cell electric generation facility was installed (and approved for interconnection by PG&E); and (2) the electric generation facility reduces the customer's maximum demand to the point that the customer would no longer be eligible for service under this schedule.  
The Generation Demand Adjustment will be the fixed reduction in demand as determined by PG&E from the customer's interconnection agreement, and will be added to the customer's maximum demand for the sole purpose of determining the customer's eligibility for Schedule E-20.  

The Generation Demand Adjustment does not specifically guarantee the customer's continued eligibility for service under this schedule nor will it be applied to the customer's maximum demand for purposes of calculating the monthly maximum demand charge.  

The Generation Demand Adjustment for solar generating facilities will terminate on December 31, 2016.  

Option R for Solar:  The Option R rate is available to qualifying E-20 customers, with solar photovoltaic (PV) systems that provide 15% or more of their annual electricity usage.  
For additional Option R details and program specifics, see Sections 3 and 18.  

2. TERRITORY:  Schedule E-20 applies everywhere PG&E provides electric service.  

(Continued)
### ELECTRIC SCHEDULE E-20

**SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE**

3. **RATES: (Cont’d.)**

#### TOTAL RATES FOR OPTION R

*(for qualifying solar customers as set forth in Section 18)*

<table>
<thead>
<tr>
<th>Total Customer/Meter Charge Rates</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Charge Mandatory E-20</td>
<td>$32.85421</td>
<td>$49.28131</td>
<td>$65.70842</td>
</tr>
<tr>
<td>($ per meter per day)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Optional Meter Data Access Charge</td>
<td>$0.98563</td>
<td>$0.98563</td>
<td>$0.98563</td>
</tr>
<tr>
<td>($ per meter per day)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Total Demand Rates ($ per kW)

<table>
<thead>
<tr>
<th></th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Peak Demand Summer</td>
<td>$1.29</td>
<td>$1.30</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Part-Peak Demand Summer</td>
<td>$0.33</td>
<td>$0.35</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Demand Summer</td>
<td>$13.25</td>
<td>$10.60</td>
<td>$4.64</td>
</tr>
<tr>
<td>Maximum Part-Peak Demand Winter</td>
<td>$0.07</td>
<td>$0.07</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Demand Winter</td>
<td>$13.25</td>
<td>$10.60</td>
<td>$4.64</td>
</tr>
</tbody>
</table>

#### Total Energy Rates ($ per kWh)

<table>
<thead>
<tr>
<th></th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Summer</td>
<td>$0.32390</td>
<td>$0.32407</td>
<td>$0.27818</td>
</tr>
<tr>
<td>Part-Peak Summer</td>
<td>$0.14213</td>
<td>$0.13632</td>
<td>$0.11925</td>
</tr>
<tr>
<td>Off-Peak Summer</td>
<td>$0.07611</td>
<td>$0.07755</td>
<td>$0.06900</td>
</tr>
<tr>
<td>Part-Peak Winter</td>
<td>$0.10039</td>
<td>$0.10025</td>
<td>$0.08654</td>
</tr>
<tr>
<td>Off-Peak Winter</td>
<td>$0.07731</td>
<td>$0.08171</td>
<td>$0.07320</td>
</tr>
</tbody>
</table>

#### Power Factor Adjustment Rate ($/kWh/%)

<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Factor Adjustment Rate</td>
<td>$0.00005</td>
<td>$0.00005</td>
<td>$0.00005</td>
</tr>
<tr>
<td>($/kWh/%)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total bundled service charges shown on customers’ bills are unbundled according to the component rates shown below. PDP charges and credits are all generation and are not included below.
### ELECTRIC SCHEDULE E-20

**Sheet 6**

**SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE**

3. Rates: (Cont’d.) (N)

#### UNBUNDLING OF TOTAL RATES FOR OPTION R

(for qualifying solar customers as set forth in Section 18)

Customer/Meter Charge Rates: Customer and meter charge rates provided in the Total Rates section above are assigned entirely to the unbundled distribution component.

<table>
<thead>
<tr>
<th>Demand Rates by Components ($ per kW)</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generation:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum Peak Demand Summer</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Part-Peak Demand Summer</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Demand Summer</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Part-Peak Demand Winter</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Demand Winter</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
</tr>
<tr>
<td><strong>Distribution</strong>:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum Peak Demand Summer</td>
<td>$1.29</td>
<td>$1.30</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Part-Peak Demand Summer</td>
<td>$0.33</td>
<td>$0.35</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Demand Summer</td>
<td>$8.82</td>
<td>$6.17</td>
<td>$0.21</td>
</tr>
<tr>
<td>Maximum Part-Peak Demand Winter</td>
<td>$0.07</td>
<td>$0.07</td>
<td>$0.00</td>
</tr>
<tr>
<td>Maximum Demand Winter</td>
<td>$8.82</td>
<td>$6.17</td>
<td>$0.21</td>
</tr>
<tr>
<td><strong>Transmission Maximum Demand</strong></td>
<td>$4.39</td>
<td>$4.39</td>
<td>$4.39</td>
</tr>
<tr>
<td><strong>Reliability Services Maximum Demand</strong></td>
<td>$0.04</td>
<td>$0.04</td>
<td>$0.04</td>
</tr>
</tbody>
</table>

#### Energy Rates by Component ($ per kWh)

<table>
<thead>
<tr>
<th>Generation:</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Summer</td>
<td>$0.26625</td>
<td>$0.26627</td>
<td>$0.26175</td>
</tr>
<tr>
<td>Part-Peak Summer</td>
<td>$0.11352</td>
<td>$0.10844</td>
<td>$0.10282</td>
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<tr>
<td>Off-Peak Summer</td>
<td>$0.05704</td>
<td>$0.05947</td>
<td>$0.05257</td>
</tr>
<tr>
<td>Part-Peak Winter</td>
<td>$0.08029</td>
<td>$0.08106</td>
<td>$0.07011</td>
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<tr>
<td>Off-Peak Winter</td>
<td>$0.05824</td>
<td>$0.06363</td>
<td>$0.05677</td>
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<table>
<thead>
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<th>Distribution**:</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Summer</td>
<td>$0.03858</td>
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<tr>
<td>Part-Peak Summer</td>
<td>$0.00954</td>
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</tr>
<tr>
<td>Off-Peak Summer</td>
<td>$0.00000</td>
<td>$0.00000</td>
<td>$0.00000</td>
</tr>
<tr>
<td>Part-Peak Winter</td>
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<tr>
<td>Off-Peak Winter</td>
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<td>$0.00000</td>
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</table>

<table>
<thead>
<tr>
<th>Transmission Rate Adjustments**</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>(all usage)</td>
<td>$0.00404</td>
<td>$0.00404</td>
<td>$0.00404</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Public Purpose Programs</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>(all usage)</td>
<td>$0.01145</td>
<td>$0.01048</td>
<td>$0.00888</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Nuclear Decommissioning</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>(all usage)</td>
<td>$0.00997</td>
<td>$0.00997</td>
<td>$0.00997</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Competition Transition Charge</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>(all usage)</td>
<td>$0.00047</td>
<td>$0.00045</td>
<td>$0.00040</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Energy Cost Recovery Amount</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>(all usage)</td>
<td>($0.00504)</td>
<td>($0.00504)</td>
<td>($0.00504)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>DWR Bond</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>(all usage)</td>
<td>$0.00526</td>
<td>$0.00526</td>
<td>$0.00526</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>New System Generation Charge</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>(all usage)**</td>
<td>$0.00192</td>
<td>$0.00192</td>
<td>$0.00192</td>
</tr>
</tbody>
</table>

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

** Distribution and New System Generation Charges are combined for presentation on customer bills.

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Advice Letter No: 4581-E  
Issued by  
Decision No.: 14-12-080  
Date Filed:  
Effective: February 2, 2015  
Resolution No.:  

Steven Malnight  
Senior Vice President  
Regulatory Affairs
3. **RATES:**

   a. **TYPES OF CHARGES:** The customer’s monthly charge for service under Schedule E-20 is the sum of a customer charge, demand charges, and energy charges:

   The **customer charge** is a flat monthly fee.

   - Schedule E-20 has three **demand charges**, a maximum-peak-period-demand charge, a maximum-part-peak-period demand charge, and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month’s peak hours, the maximum-part-peak-period demand charge per kilowatt applies to the maximum demand during the month’s part-peak hours, and the maximum-demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges. (Time periods are defined in Section 6.)

   - The **energy charge** is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour (kWh), and rates are differentiated according to time of day and time of year.

   - The monthly charges may be increased or decreased based upon the power factor. (See Section 7.)

   - As shown on the rate chart, which set of customer, demand, and energy charges is paid depends on the voltage at which service is taken. Service voltages are defined in Section 5 below.

---

**(Continued)**
4. METERING REQUIREMENTS:

An interval data meter that measures and registers the amount of electricity a customer uses and can be read remotely by PG&E is required for all customers on this schedule. A Meter Data Management Agent (MDMA) may also read the customer’s meter on behalf of the customer’s Energy Service Provider (ESP) if a customer is receiving Direct Access Service.

For bundled service customers with a maximum demand of 200 kW or greater for three consecutive months, PG&E will provide and install the interval data meter at no cost to the customer. The installation of an interval data meter for customers taking service under the provisions of Direct Access is the responsibility of the customer’s Energy Service Provider, or their Agent, and must be installed in accordance with Electric Rule 22.

Customers who also request any meter data management services, must also sign an Interval Meter Data Management Service Agreement (Form 79-985) and must have an appropriate interval data meter.

5. DEFINITION OF SERVICE VOLTAGE:

The following defines the three voltage classes of Schedule E-20 rates. Standard Service Voltages are listed in Rule 2.

a. Secondary: This is the voltage class if the service voltage is less than 2,400 volts or if the definitions of “primary” and “transmission” do not apply to the service.

b. Primary: This is the voltage class if the customer is served from a “single customer substation” or without transformation from PG&E’s serving distribution system at one of the standard primary voltages specified in PG&E’s Electric Rule 2, Section B.1.

c. Transmission: This is the voltage class if the customer is served without transformation at one of the standard transmission voltages specified in PG&E’s Electric Rule 2, Section B.1.
# ELECTRIC SCHEDULE E-20

**SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE**

(Continued)

## 6. DEFINITION OF TIME PERIODS:

Times of the year and times of the day are defined as follows:

### SUMMER

- **Period A (Service from May 1 through October 31):**
  - **Peak:** 12:00 noon to 6:00 p.m. Monday through Friday (except holidays)
  - **Partial-peak:** 8:30 a.m. to 12:00 noon and 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays)
  - **Off-peak:** 9:30 p.m. to 8:30 a.m. Monday through Friday, all day Saturday, Sunday, and holidays

### WINTER

- **Period B (service from November 1 through April 30):**
  - **Partial-Peak:** 8:30 a.m. to 9:30 p.m. Monday through Friday (except holidays)
  - **Off-Peak:** 9:30 p.m. to 8:30 a.m. Monday through Friday, all day Saturday, Sunday, and holidays

**HOLIDAYS:** “Holidays” for the purposes of this rate schedule are New Year’s Day, President’s Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

**DAYLIGHT SAVING TIME ADJUSTMENT:** The time periods shown 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.

**CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER:** When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents.

## 7. POWER FACTOR ADJUSTMENTS:

The bill will be adjusted based upon the power factor. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent.

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor rate and the kilowatt-hour usage for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill will be increased by the product of the power factor rate and the kilowatt-hour usage for each percentage point below 85 percent.

Power factor adjustments will be assigned to distribution for billing purposes.
ELECTRIC SCHEDULE E-20
SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

8. CHARGES FOR TRANSFORMER AND LINE LOSSES:
The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of Rule 2.

9. STANDARD SERVICE FACILITIES:
If PG&E must install any new or additional facilities to provide the customer with service under Schedule E-20, the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a line extension agreement. See Rules 2, 15, and 16 for details.

Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in the line extension agreement.

10. SPECIAL FACILITIES:
PG&E will normally install only those standard facilities it deems necessary to provide service under Schedule E-20. If the customer requests any additional facilities, those facilities will be treated as “special facilities” in accordance with Section I of Rule 2.

11. ARRANGEMENTS FOR VISUAL-DISPLAY METERING:
If the customer wishes to have visual-display metering equipment in addition to the regular metering equipment, and the customer would like PG&E to install that equipment, the customer must submit a written request to PG&E. PG&E will provide and install the equipment within 180 days of receiving the request. The visual-display metering equipment will be installed near the present metering equipment. The customer will be responsible for providing the required space and associated wiring.

PG&E will continue to use the regular metering equipment for billing purposes.

(Continued)
12. BILLING: A customer’s bill is calculated based on the option applicable to the customer. (L)

**Bundled Service Customers** receive supply and delivery services solely from PG&E. The customer’s bill is based on the Total Rates and Conditions set forth in this schedule.

**Transitional Bundled Service Customers** take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, New System Generation Charges\(^1\), the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

**Direct Access (DA) and Community Choice Aggregation (CCA) Customers** purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, New System Generation Charges\(^1\), the franchise fee surcharge, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS are set forth in Schedules DA CRS and CCA CRS.

<table>
<thead>
<tr>
<th>DA / CCA CRS</th>
<th>Secondary Voltage</th>
<th>Primary Voltage</th>
<th>Transmission Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Cost Recovery Amount Charge (per kWh)</td>
<td>($0.00504)</td>
<td>($0.00504)</td>
<td>($0.00504)</td>
</tr>
<tr>
<td>DWR Bond Charge (per kWh)</td>
<td>$0.00526</td>
<td>$0.00526</td>
<td>$0.00526</td>
</tr>
<tr>
<td>CTC Rate (per kWh)</td>
<td>$0.00047</td>
<td>$0.00045</td>
<td>$0.00040</td>
</tr>
<tr>
<td>Power Charge Indifference Adjustment (per kWh)</td>
<td></td>
<td></td>
<td></td>
</tr>
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<td>Pre-2009 Vintage</td>
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\(^1\) Per Decision 11-12-031, New System Generation Charges are effective 1/1/2012.
13. CARE DISCOUNT FOR NONPROFIT GROUP- LIVING AND SPECIAL EMPLOYEE HOUSING FACILITIES:

Facilities which meet the eligibility criteria in Rule 19.2 or 19.3 are eligible for a California Alternate Rates for Energy discount under Schedule E-CARE. CARE customers are exempt from paying the DWR Bond Charge. For CARE customers, no portion of the rates shall be used to pay the DWR Bond Charge. Generation is calculated residually based on the total rate less the sum of the following: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charge (CTC), and Energy Cost Recovery Amount.

14. ELECTRIC EMERGENCY PLAN ROTATING BLOCK OUTAGES:

As set forth in CPUC Decision 01-04-006, all transmission level customers except essential use customers, Optional Binding Mandatory Curtailment (OBMC) plan participants, net suppliers to the electrical grid, or others exempt by the Commission, are to be included in rotating outages in the event of an emergency. A transmission level customer who refuses or fails to drop load shall be added to the next rotating outage group so that the customer does not escape curtailment. If the transmission level customer fails to cooperate and drop load at PG&E’s request, automatic equipment controlled by PG&E will be installed at the customer’s expense per Electric Rule 2. A transmission level customer who refuses to drop load before installation of the equipment shall be subject to a penalty of $6/kWh for all load requested to be curtailed that is not curtailed. The $6/kWh penalty shall not apply if the customer’s generation suffers a verified, forced outage and during times of scheduled maintenance. The scheduled maintenance must be approved by both the ISO and PG&E, but approval may not be unreasonably withheld.

15. STANDBY APPLICATION:

SOLAR GENERATION FACILITIES EXEMPTION: Customers who utilize solar generating facilities which are less than or equal to one megawatt to serve load and who do not sell power or make more than incidental export of power into PG&E’s power grid and who have not elected service under Schedule NEM, will be exempt from paying the otherwise applicable standby reservation charges.

DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use (TOU) rate schedule using electric generation technology that meets the criteria as defined in Electric Rule 1 for Distributed Energy Resources is exempt from the otherwise applicable standby reservation charges. Customers qualifying for this exemption shall be subject to the following requirements. Customers qualifying for an exemption from standby charges under Public Utilities (PU) Code Sections 353.1 and 353.3, as described above, must take service on a TOU schedule in order to receive this exemption until a real-time pricing program, as described in PU Code 353.3, is made available. Once available, customers qualifying for the standby charge exemption must participate in the real-time program referred to above. Qualification for and receipt of this distributed energy resources exemption does not exempt the customer from metering charges applicable to TOU and real-time pricing, or exempt the customer from reasonable interconnection charges, non-bypassable charges as required in Preliminary Statement BB - Competition Transition Charge Responsibility for All Customers and CTC Procurement, or obligations determined by the Commission to result from participation in the purchase of power through the California Department of Water Resources, as provided in PU Code Section 353.7.

(Continued)
ELECTRIC SCHEDULE E-20
SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

16. DWR BOND CHARGE: The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers’ total billed amounts.

17. PEAK DAY PRICING DETAILS:
   a. Default Provision: The default of eligible customers to PDP will occur once per year with the start of their billing cycle on or after November 1. Eligible customers will have at least 45-days notice prior to their planned default date when they may opt-out of PDP rates to take service on TOU rates. During the 45-day period, customers will continue to take service on their non-PDP rate. Customers will be defaulted to PDP unless they opt-out to a TOU rate at least five (5) days prior to their planned default date. Existing customers on a PDP rate eligible demand response program will have the option to enroll.
   b. Capacity Reservation Level: Customers may elect a capacity reservation level (CRL) and pay for a fixed level of capacity, specified in kW. While the CRL is applicable year round, customers electing a CRL will be billed under a take-or-pay basis up to the specified CRL under the non-PDP rate of this schedule during the summer period (May 1 through October 31). This means that customers will be billed for summer peak generation demand charges up to the level of their CRL, even in summer months when the actual demand might be less than their CRL. Customers will receive PDP credits on summer usage above the CRL on summer period non-PDP days. All usage during a PDP event protected under the CRL will be billed at the non-PDP rate. All usage above the CRL (as measured in 15-minute intervals), and not protected during a PDP event, will be billed at the PDP rate.

   If a customer fails to elect an initial CRL, the customer’s initial CRL will be set at 50% of its most recent six (6) summer months’ average peak-period maximum demand and may go back to the previous year to make a full summer season (if available). If the customer has not established any historic summer billing demand, the CRL will be set at zero (0).

   A customer may only elect to change their CRL once every 12 months.

   c. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12 months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

   If a customer terminates its participation on the PDP rate prior to the initial 12 month period expiring, the customer will receive bill stabilization up to the date when the customer terminates its participation. Bill stabilization benefits will be computed on a cumulative basis, based on the earlier of 1) when a customer terminates its participation on the PDP rate or 2) at the end of the initial 12-month period. Any applicable credits will be applied to the customer’s account on a subsequent regular bill. Bill stabilization is only available one time per customer. If a customer un-enrolls or terminates its participation on a PDP rate, bill stabilization will not be offered again.
17. PEAK DAY PRICING DETAILS (continued):

d. Notification Equipment: Customers, at their expense, must have access to the Internet and an e-mail address or a phone number to receive notification of a PDP event. In addition, all customers can have, at their expense, an alphanumeric pager or cellular telephone that is capable of receiving a text message sent via the Internet, and/or a facsimile machine to receive notification messages.

If a PDP event occurs, customers will be notified using one or more of the above-mentioned systems. Receipt of such notice is the responsibility of the participating customer. PG&E will make reasonable efforts to notify customers; however it is the customer’s responsibility to maintain accurate notification contact information, receive such notice and to check the PG&E website to see if an event is activated. PG&E does not guarantee the reliability of the phone, text messaging, e-mail system or Internet site by which the customer receives notification.

PG&E may conduct notification test events once a month to ensure a customer’s contact information is up to date. These are not actual PDP events and no load reduction is required.

e. Demand Response Operations Website: Customers can use PG&E’s demand response operations website located at https://inter-act.pge.com for load curtailment event notifications and communications.

The customer’s actual energy usage is available at PG&E’s demand response operations website. This data may not match billing quality data, and the customer understands and agrees that the data posted to PG&E’s demand response operations website may be different from the actual bill.

f. Program Operations: A maximum of fifteen (15) PDP events and a minimum of nine (9) PDP events may be called in any calendar year. PG&E will notify customers by 2:00 p.m. on a day-ahead basis when a PDP event will occur the next day. The PDP program will operate year-round and PDP events may be called for any day of the week. PDP events will be called from 2:00 p.m. to 6:00 p.m.

g. Event Cancellation: PG&E may initiate the cancellation of a PDP event before 4:00 p.m. the day-ahead of a noticed PDP event. If PG&E cancels an event, it will count the cancelled event toward the PDP limits.

h. Event Trigger: PG&E will trigger a PDP event when the day-ahead temperature forecast trigger is reached. The trigger will be the average of the day-ahead maximum temperature forecasts for San Jose, Concord, Red Bluff, Sacramento and Fresno.

Beginning May 1 of each summer season, the PDP events on non-holiday weekdays will be triggered at 98 degrees Fahrenheit (°F), and will be triggered at 105°F on holidays and weekends. If needed, PG&E will adjust the non-holiday weekday trigger up or down over the course of the summer to achieve the range of 9 to 15 PDP events in any calendar year. Such adjustments would be made no more than twice per month and would be posted to the demand response operations website.
ELECTRIC SCHEDULE E-20
SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

17. PEAK DAY PRICING DETAILS (continued):

PDP events may also be initiated as warranted on a day-ahead basis by 1) extreme system conditions such as special alerts issued by the California Independent System Operator, 2) under conditions of high forecasted California spot market power prices, 3) to meet annual PDP event limits for a calendar year, or 4) for testing/evaluation purposes.

i. Program Terms: A customer may opt-out anytime during their initial 12 months on a PDP rate. After the initial 12 months, customer’s participation will be in accordance with Electric Rule 12.

Customers may opt-out of a PDP rate at anytime to enroll in another demand response program beginning May 1, 2011.

j. Interaction with Other PG&E Demand Response Programs: Customers on a PDP rate may participate in a day-of dispatchable demand response program as established in D.09-08-027.

18. Option R

The Option R rate is available to qualifying E-20 customers with PV systems that provide 15% or more of their annual electricity usage.

For a customer installing a new PV system, this eligibility requirement will be calculated as follows:

\[
\frac{\text{Annual PV system output}}{\text{Annual electricity usage}} \geq 15\%
\]

For a customer with an existing PV system, this eligibility requirement will be calculated as follows:

\[
\frac{\text{Annual PV system output}}{(\text{Annual PV system output} + \text{Annual electricity usage})} \geq 15\%
\]

1 For a customer installing a new system, annual PV system output (kWh) will be estimated as CEC rating of the panels (kW) × 8,760 hours/year × 18% capacity factor.

2 Annual electricity usage (kWh) will be measured at the PG&E meter over the last 12 months.

3 For a customer with an existing system, the customer may choose to supply PG&E with reliable metered data measuring annual PV system output, if such data are available. Alternatively, annual PV system output will be estimated using the formula in footnote 1.
# ELECTRIC TABLE OF CONTENTS

## TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>SCHEDULE</th>
<th>TITLE OF SHEET</th>
<th>CAL P.U.C. SHEET NO.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Title Page</td>
<td></td>
<td>35078-E (T)</td>
</tr>
<tr>
<td>Rate Schedules</td>
<td>34511, 34559, 35079, 34620, 34536, 34621, 32705, 31541, 34517-E (T)</td>
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</tr>
<tr>
<td>Preliminary</td>
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</tr>
<tr>
<td>Rules</td>
<td></td>
<td>34623, 34624, 35035-E</td>
</tr>
<tr>
<td>Maps, Contracts</td>
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<td>A-1</td>
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<td>Small General Time-of-Use Service</td>
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<tr>
<td>A-10</td>
<td>Medium General Demand-Metered Service</td>
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<tr>
<td>A-15</td>
<td>Direct-Current General Service</td>
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<td>Distribution Bypass Deferral Rate</td>
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<tr>
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(Continued)
AT&T
Albion Power Company
Alcantar & Kahl LLP
Anderson & Poole
BART
Barkovich & Yap, Inc.
Bartle Wells Associates
Braun Blaising McLaughlin, P.C.

CENERGY POWER
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
California State Association of Counties
Calpine
Casner, Steve
Center for Biological Diversity
City of Palo Alto
City of San Jose
Clean Power
Coast Economic Consulting
Commercial Energy
Cool Earth Solar, Inc.
County of Tehama - Department of Public Works
Crossborder Energy
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Dept of General Services
Division of Ratepayer Advocates
Douglass & Liddell
Downey & Brand
Ellison Schneider & Harris LLP
G. A. Krause & Assoc.
GenOn Energy Inc.
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
In House Energy
International Power Technology
Intestate Gas Services, Inc.
K&L Gates LLP
Kelly Group
Linde
Los Angeles County Integrated Waste Management Task Force
Los Angeles Dept of Water & Power
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenna Long & Aldridge LLP
McKenzie & Associates
Modesto Irrigation District
Morgan Stanley
NLine Energy, Inc.
NRG Solar
Nexant, Inc.

Occidental Energy Marketing, Inc.
OnGrid Solar
Pacific Gas and Electric Company
Praxair
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
SCE
SDG&E and SoCalGas
SPURR
Seattle City Light
Sempra Utilities
SoCalGas
Southern California Edison Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
Tiger Natural Gas, Inc.
TransCanada
Utility Cost Management
Utility Power Solutions
Utility Specialists
Verizon
Water and Energy Consulting
Wellhead Electric Company
Western Manufactured Housing
Communities Association (WMA)
YEP Energy