TARGET

November 27, 2017

Mr. Daniel Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: Docket No. E-999/CI-15-115

Dear Mr. Wolf:

Target respectfully submits the following comments in response to the Minnesota Public Utilities Commission's November 13, 2017 notice *In the Matter of a Commission Inquiry into Standby Service Tariffs*. Specifically, the notice asks is the agreement reached by Xcel, the Department and MnSEIA reasonable and in the public interest and if the Commission adopt it.

Target does not offer a recommendation on whether or not the Commission should adopt the partial settlement agreement on the solar capacity credit rider. However, if the Commission adopts the settlement, Target recommends that the effective date of the six year term be moved from the date of the Commission's Order to 180 days from the Commission's Order. In those 180 days existing customers would remain on the current credit.

We make this recommendation reflecting on the purpose of the negotiated six year term and the realities of financing, planning, and interconnecting distributed solar projects in Minnesota. Customers in this docket, including Target, have advocated for credit term certainty in light of the significant capital investment required for behind-the-meter solar projects. Customers already absorb the risk of variations in retail energy rates in financing solar projects. In these large upfront investment projects, it is difficult to absorb additional uncertainty on the solar capacity credit that has arisen from the many revisions proposed in the course of this docket over the last two year, ranging from changing the volumetric basis of the credit to full elimination.

The Commission recognized this certainty need for capital-intensive energy projects in other rates for distributed generation and for the utility in the form of long-term power purchase agreements. Distributed generation customers eligible for the capacity credit face similar capital requirements.

As currently proposed in the partial settlement, the six year term begins with the Commission's Order in this docket; it is not known when the Commission will take up the partial settlement for consideration. It is very difficult for customers and developers to plan projects that rely on the credit term certainty without knowing when the Commission will decide on the partial settlement. Projects require significant time to sign contracts, procure panels during a period of uncertainty from solar import tariff case, interconnection review, and other project steps. Setting the effective date of the six year term at a reasonable time period from the Commission's Order allows customers to plan for new projects while capturing more of the value of the financing certainty provided by the partial settlement.

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As the Commission considers the next methodology review process in this docket, Target wants to inform the Commission that other Commissions have addressed solar's capacity contribution to the grid and the related issue of overpayment of demand charges by solar customers. "Option R" rates that include lower peak demand charges are available in all three California investor-owned utility service territories. The rates vary as to whether they reduce the non-coincident demand charge rate or reduce the peak period demand charge rate. All three utilities disaggregate generation and transmission demand rates from distribution demand rates, a best practice that was identified in the Minnesota Department of Commerce's January 30, 2015 Report on Standby Service to the Commission.[1]

Xcel Energy's Colorado subsidiary, Public Service Company of Colorado, also offers a tariff for demand-metered solar customers. Schedule SPVTOU has been available to eligible customers from at least 2010, and the tariff also disaggregates distribution demand rates (and determination period) from the generation and transmission demand. We've attached current tariff sheets to these comments for reference.

A key feature of these rates is distinguishing distribution demand costs from generation and transmission demand costs. In Minnesota, a customer that sets its peak demand in the evening or other off-peak times is charged the same rate as a customer who sets their peak demand at a time coincident with the utility's system peak costs. The degree to which solar generation aligns with one or both of these peaks is important in rate design. In the last year of this docket there has been discussion on behind the meter solar's capacity accreditation, but less discussion on the interplay between demand billing determination and solar's generation profile. Both approaches may in fact reach the same place in appropriate crediting, but through different rate designs. As a result, the Commission should not abandon the analysis used to create the capacity credit, nor should it doubt the validity of the current credit design as it considers new approaches.

As the Commission considers the partial settlement, Target wants to reiterate that the deep record in this docket shows that the capacity credit is not an incentive, nor is providing certainty around the credit term. Providing certainty around the credit is not harming other ratepayers any more than approving long-term utility power purchase agreements harms ratepayers. Both speak to the realities of project financing and development.

In summary, Target recommends that, if the Commission approves the partial settlement, the Commission modify the effective date of the six year term to start 180 days from the Commission's Order in this docket.

Target appreciates the Commission's consideration. Please contact Holly Lahd at holly.lahd@target.com with questions related to our comments.

Sincerely,

William Crider
Director, Energy & Sustainability

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[1] January 30, 2015 Comments of the Minnesota Department of Commerce, Docket No. E002/M-13-315, E002/M-13-642, E001/M-13-667, E015/M-13-770, and E017/M-13-690, page 11-12.

Attachments:

Attachment 1. Pacific Gas and Electric Schedule E-19
Attachment 2. Southern California Edison Schedule TOU-GS-3
Attachment 3. San Diego Gas and Electric Schedule DG-R
Attachment 4. Public Service Company of Colorado Secondary Photovoltaic Time-of-Use Service (alternative rate schedule: General Service)

33 South Sixth Street, CC-2805, Minneapolis, MN 55402

Attachment 1. Pacific Gas and Electric Schedule E-19

**ELECTRIC SCHEDULE E-19** Sheet 1

MEDIUM GENERAL DEMAND-METERED TOU SERVICE

(D)

1. APPLICABILITY: **Initial Assignment:** A customer must take service under Schedule E-19 if: (1) the customer's load does not meet the Schedule E-20 requirements, but, (2) the customer's maximum billing demand (as defined below) has exceeded 499 kilowatts for at least three consecutive months during the most recent 12-month period (referred to as Schedule E-19). If 70 percent or more of the customer's energy use is for agricultural end-uses, the customer will be served under an agricultural schedule. Schedule E-19 is not applicable to customers for whom residential service would apply, except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section).

Customer accounts which fail to qualify under these requirements will be evaluated for transfer to service under a different applicable rate schedule.

The provisions of Schedule S—Standby Service Special Conditions 1 through 6 shall also apply to customers whose premises are regularly supplied in part (but not in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S, in addition to all applicable Schedule E-19 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

**Voluntary E-19 Service:** This schedule is available on a voluntary basis for customers with maximum billing demands less than 500 kW. Customers voluntarily taking service on this schedule are subject to all the terms and conditions below, unless otherwise specified in Section 14.

Ongoing daily Time-of-Use (TOU) meter charges applicable to customers taking voluntary TOU service under this rate schedule will no longer be applied if the customer has a SmartMeter™ installed.

Depending upon whether or not an Installation or Processing Charge applied prior to May 1, 2006, the customer will be served under one of these rates under Schedule E-19: (L)

Rate V: Applies to customers who were on Rate V as of May 1, 2006.

Rate W: Applies to customers who were on Rate W as of May 1, 2006.

Rate X: Applies to customers who were on Rate X as of May 1, 2006 or who qualify for the voluntary provisions of this tariff and enroll on E-19 on or after May 1, 2006.

(Continued)

1. APPLICABILITY: (Cont'd.)

**Transfers Off of Schedule E-19:** If a customer's maximum demand has failed to exceed 499 kilowatts for 12 consecutive months, PG&E will transfer that customer's account to voluntary E-19 service or to a different applicable rate schedule. After being placed on this schedule due to the 200 kW or greater provisions of this schedule, customers who fail to exceed 199 kilowatts for 12 consecutive months may elect to stay on the time-of-use provisions of this schedule or alternate time-of-use rate schedule.

**Assignment of New Customers:** If a customer is new and PG&E believes that the customer's maximum demand will be 500 through 999 kilowatts and that the customer should not be served under a time-of-use agricultural schedule, PG&E will serve the customer's account under Schedule E-19.

**Peak Day Pricing Default Rates:** Peak Day Pricing (PDP) rates provide customers the opportunity to manage their electric costs by reducing load during high cost periods or shifting load from high cost periods to lower cost periods. Decision 10-02-032 ordered that beginning May 1, 2010, eligible large Commercial and Industrial (C&I) customers default to PDP rates. A customer is eligible for default when 1) it has at least twelve (12) billing months of hourly usage data available, and 2) it has measured demands equal to or exceeding 200 kW for three (3) consecutive months during the past 12 months. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate

Decision 10-02-032, as modified by Decision 11-11-008, ordered that beginning November 1, 2014, eligible small and medium Commercial and Industrial (C&I) customers (those with demands that are not equal to or greater than 200kW for three consecutive months) default to PDP rates. A customer is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate.

Customers that do not meet default eligibility may voluntarily elect to enroll on PDP rates.

Bundled service customers are eligible for PDP. Direct Access (DA) and Customer Choice Aggregation (CCA) service customers are not eligible, including those DA customers on transitional bundled service (TBS). Customers on standby service
(Schedule S), or on net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or (T)
NEMA, are not eligible for PDP. In addition, master-metered customers are not (T)
eligible, except for commercial buildings with submetering as stated in PG&E Rule 1 and Rule 18. Non-residential SmartAC customers are eligible. Smart A/C customers may request PG&E to activate their A/C Cycling switch or Programmable Controllable Thermostat (PCT) when the customer is participating solely in a PDP event.

For additional PDP details and program specifics, see Section 19.

(Continued)

**ELECTRIC SCHEDULE E-19** Sheet 3
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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, (N)
including voluntary E-19 customers, with PV systems that provide 15% or more of their I
annual electricity usage. For additional Option R details and program specifics, see I
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** Sheet 4
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

3. Rates: (Cont'd.)

**TOTAL RATES**

| Total Customer/Meter Charge Rates | Secondary Voltage | Primary Voltage | Transmission Voltage |
|---|---|---|---|
| **Customer Charge Mandatory E-19** ($ per meter per day) | $19.71253 | $32.85421 | $59.13758 |
| **Customer Charge Voluntary E-19**: | | | |
| Customer Charge with SmartMeter™ ($ per meter per day) | $4.59959 | $4.59959 | $4.59959 |
| Customer Charge without SmartMeter™ | | | |
| Customer Charge Rate V ($ per meter per day) | $4.77700 | $4.77700 | $4.77700 |
| Customer Charge Rate W ($ per meter per day) | $4.63507 | $4.63507 | $4.63507 |
| Customer Charge Rate X ($ per meter per day) | $4.77700 | $4.77700 | $4.77700 |
| Optional Meter Data Access Charge ($ per meter per day) | $0.98563 | $0.98563 | $0.98563 |
| Total Demand Rates ($ per kW) | | | |
| Maximum Peak Demand Summer | $18.64 | $16.60 | $12.42 |
| Maximum Part-Peak Demand Summer | $5.18 | $4.53 | $3.11 |
| Maximum Demand Summer | $17.56 (I) | $14.40 (I) | $9.13 (I) |
| Maximum Part-Peak Demand Winter | $0.12 | $0.15 | $0.00 |
| Maximum Demand Winter | $17.56 (I) | $14.40 (I) | $9.13 (I) |
| Total Energy Rates ($ per kWh) | | | |
| Peak Summer | $0.15178 (R) | $0.14165 (R) | $0.10559 (R) |
| Part-Peak Summer | $0.11127 (R) | $0.10327 (R) | $0.09298 (R) |
| Off-Peak Summer | $0.08445 (R) | $0.07860 (R) | $0.07631 (R) |
| Part-Peak Winter | $0.10573 (R) | $0.09809 (R) | $0.09497 (R) |
| Off-Peak Winter | $0.09111 (R) | $0.08469 (R) | $0.08216 (R) |
| **Power Factor Adjustment Rate** ($/kWh/%) | $0.00005 | $0.00005 | $0.00005 |
| PDP Rates | | | |
| PDP Charges ($ per kWh) | | | |
| All Usage During PDP Event | $1.20 | $1.20 | $1.20 |
| PDP Credits | | | |
| Demand ($ per kW) | | | |
| Peak Summer | ($5.70) | ($5.42) | ($5.18) |
| Part-Peak Summer | ($1.41) | ($1.32) | ($1.30) |
| Energy ($ per kWh) | | | |
| Peak Summer | $0.00000 | $0.00000 | $0.00000 |
| Part-Peak Summer | $0.00000 | $0.00000 | $0.00000 |

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.

(Continued)

**ELECTRIC SCHEDULE E-19** Sheet 5
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

3. Rates: (Cont'd.)

**UNBUNDLING OF TOTAL RATES**

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

| Demand Rates by Components ($ per kW) | Secondary Voltage | | Primary Voltage | | Transmission Voltage | |
|---|---|---|---|---|---|---|
| **Generation:** | | | | | | |
| Maximum Peak Demand Summer | $12.63 | | $11.29 | | $12.42 | |
| Maximum Part-Peak Demand Summer | $3.12 | | $2.75 | | $3.11 | |
| Maximum Demand Summer | $0.00 | | $0.00 | | $0.00 | |
| Maximum Part-Peak Demand Winter | $0.00 | | $0.00 | | $0.00 | |
| Maximum Demand Winter | $0.00 | | $0.00 | | $0.00 | |
| **Distribution**:** | | | | | | |
| Maximum Peak Demand Summer | $6.01 | | $5.31 | | $0.00 | |
| Maximum Part-Peak Demand Summer | $2.06 | | $1.78 | | $0.00 | |
| Maximum Demand Summer | $10.37 | | $7.21 | | $1.94 | |
| Maximum Part-Peak Demand Winter | $0.12 | | $0.15 | | $0.00 | |
| Maximum Demand Winter | $10.37 | | $7.21 | | $1.94 | |
| **Transmission Maximum Demand*** | $7.19 | (I) | $7.19 | (I) | $7.19 | (I) |
| **Reliability Services Maximum Demand*** | $0.00 | | $0.00 | | $0.00 | |

* 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** Sheet 6
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

3. Rates: (Cont'd.)

**UNBUNDLING OF TOTAL RATES (Cont'd.)**

| Energy Charges by Components ($ per kWh) | Secondary Voltage | Primary Voltage | Transmission Voltage |
|---|---|---|---|
| **Generation:** | | | |
| Peak Summer | $0.12552 | $0.11638 | $0.08032 |
| Part-Peak Summer | $0.08501 | $0.07800 | $0.06771 |
| Off-Peak Summer | $0.05819 | $0.05333 | $0.05104 |
| Part-Peak Winter | $0.07947 | $0.07282 | $0.06970 |
| Off-Peak Winter | $0.06485 | $0.05942 | $0.05689 |
| **Distribution**:** | | | |
| Peak Summer | $0.00000 | $0.00000 | $0.00000 |
| Part-Peak Summer | $0.00000 | $0.00000 | $0.00000 |
| Off-Peak Summer | $0.00000 | $0.00000 | $0.00000 |
| Part-Peak Winter | $0.00000 | $0.00000 | $0.00000 |
| Off-Peak Winter | $0.00000 | $0.00000 | $0.00000 |
| **Transmission Rate Adjustments*** (all usage) | $0.00266 (R) | $0.00266 (R) | $0.00266 (R) |
| **Public Purpose Programs** (all usage) | $0.01341 | $0.01242 | $0.01242 |
| **Nuclear Decommissioning** (all usage) | $0.00149 | $0.00149 | $0.00149 |
| **Competition Transition Charge** (all usage) | $0.00084 | $0.00084 | $0.00084 |
| **Energy Cost Recovery Amount** (all usage) | ($0.00001) | ($0.00001) | ($0.00001) |
| **DWR Bond** (all usage) | $0.00549 | $0.00549 | $0.00549 |
| **New System Generation Charge** (all usage)** | $0.00238 | $0.00238 | $0.00238 |
| **California Climate Credit** (all usage – E-19V only)*** | ($0.00484) | ($0.00366) | ($0.00245) |

* 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.

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# ELECTRIC SCHEDULE E-19
## MEDIUM GENERAL DEMAND-METERED TOU SERVICE



3. Rates: (Cont'd.)

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

| Total Customer/Meter Charge Rates | Secondary Voltage | | Primary Voltage | | Transmission Voltage | |
|---|---|---|---|---|---|---|
| **Customer Charge Mandatory E-19** ($ per meter per day) | $19.71253 | | $32.85421 | | $59.13758 | |
| **Customer Charge Voluntary E-19**: | | | | | | |
| Customer Charge with SmartMeter™ ($ per meter per day) | $4.59959 | | $4.59959 | | $4.59959 | |
| Customer Charge without SmartMeter™ | | | | | | |
| Customer Charge Rate V ($ per meter per day) | $4.77700 | | $4.77700 | | $4.77700 | |
| Customer Charge Rate W ($ per meter per day) | $4.63507 | | $4.63507 | | $4.63507 | |
| Customer Charge Rate X ($ per meter per day) | $4.77700 | | $4.77700 | | $4.77700 | |
| Optional Meter Data Access Charge ($ per meter per day) | $0.98563 | | $0.98563 | | $0.98563 | |
| Total Demand Rates ($ per kW) | | | | | | |
| Maximum Peak Demand Summer | $1.50 | | $1.33 | | $0.00 | |
| Maximum Part-Peak Demand Summer | $0.51 | | $0.44 | | $0.00 | |
| Maximum Demand Summer | $17.56 | (I) | $14.40 | (I) | $9.13 | (I) |
| Maximum Part-Peak Demand Winter | $0.03 | | $0.04 | | $0.00 | |
| Maximum Demand Winter | $17.56 | (I) | $14.40 | (I) | $9.13 | (I) |
| Total Energy Rates ($ per kWh) | | | | | | |
| Peak Summer | $0.33953 | (R) | $0.32230 | (R) | $0.27429 | (R) |
| Part-Peak Summer | $0.15930 | (R) | $0.14820 | (R) | $0.13021 | (R) |
| Off-Peak Summer | $0.08445 | (R) | $0.07860 | (R) | $0.07631 | (R) |
| Part-Peak Winter | $0.10622 | (R) | $0.09874 | (R) | $0.09497 | (R) |
| Off-Peak Winter | $0.09111 | (R) | $0.08469 | (R) | $0.08216 | (R) |
| **Power Factor Adjustment Rate** ($/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.

(Continued)

**ELECTRIC SCHEDULE E-19** Sheet 8
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.

| Demand Rates by Components ($ per kW) | Secondary Voltage | | Primary Voltage | | Transmission Voltage | |
|---|---|---|---|---|---|---|
| **Generation:** | | | | | | |
| Maximum Peak Demand Summer | $0.00 | | $0.00 | | $0.00 | |
| Maximum Part-Peak Demand Summer | $0.00 | | $0.00 | | $0.00 | |
| Maximum Demand Summer | $0.00 | | $0.00 | | $0.00 | |
| Maximum Part-Peak Demand Winter | $0.00 | | $0.00 | | $0.00 | |
| Maximum Demand Winter | $0.00 | | $0.00 | | $0.00 | |
| **Distribution**:** | | | | | | |
| Maximum Peak Demand Summer | $1.50 | | $1.33 | | $0.00 | |
| Maximum Part-Peak Demand Summer | $0.51 | | $0.44 | | $0.00 | |
| Maximum Demand Summer | $10.37 | | $7.21 | | $1.94 | |
| Maximum Part-Peak Demand Winter | $0.03 | | $0.04 | | $0.00 | |
| Maximum Demand Winter | $10.37 | | $7.21 | | $1.94 | |
| **Transmission Maximum Demand*** | $7.19 | (I) | $7.19 | (I) | $7.19 | (I) |
| **Reliability Services Maximum Demand*** | $0.00 | | $0.00 | | $0.00 | |

* 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)

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.

| Energy Charges by Components ($ per kWh) | Secondary Voltage | | Primary Voltage | | Transmission Voltage | |
|---|---|---|---|---|---|---|
| **Generation:** | | | | | | |
| Peak Summer | $0.26474 | | $0.24990 | | $0.24902 | |
| Part-Peak Summer | $0.11750 | | $0.10836 | | $0.10494 | |
| Off-Peak Summer | $0.05819 | | $0.05333 | | $0.05104 | |
| Part-Peak Winter | $0.07947 | | $0.07282 | | $0.06970 | |
| Off-Peak Winter | $0.06485 | | $0.05942 | | $0.05689 | |
| **Distribution**:** | | | | | | |
| Peak Summer | $0.04853 | | $0.04713 | | $0.00000 | |
| Part-Peak Summer | $0.01554 | | $0.01457 | | $0.00000 | |
| Off-Peak Summer | $0.00000 | | $0.00000 | | $0.00000 | |
| Part-Peak Winter | $0.00049 | | $0.00065 | | $0.00000 | |
| Off-Peak Winter | $0.00000 | | $0.00000 | | $0.00000 | |
| **Transmission Rate Adjustments*** (all usage) | $0.00266 | (R) | $0.00266 | (R) | $0.00266 | (R) |
| **Public Purpose Programs** (all usage) | $0.01341 | | $0.01242 | | $0.01242 | |
| **Nuclear Decommissioning** (all usage) | $0.00149 | | $0.00149 | | $0.00149 | |
| **Competition Transition Charge** (all usage) | $0.00084 | | $0.00084 | | $0.00084 | |
| **Energy Cost Recovery Amount** (all usage) | ($0.00001) | | ($0.00001) | | ($0.00001) | |
| **DWR Bond** (all usage) | $0.00549 | | $0.00549 | | $0.00549 | |
| **New System Generation Charge** (all usage)** | $0.00238 | | $0.00238 | | $0.00238 | |
| **California Climate Credit** (all usage – E-19V only)*** | ($0.00484) | | ($0.00366) | | ($0.00245) | |

* 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.

(Continued)

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: (L)

– 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. (L)

(Continued)

**ELECTRIC SCHEDULE E-19** Sheet 11
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

4. METERING REQUIRE-MENTS: 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. (L)

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. (L)

(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<br>AND 6:00 p.m. to 9:30 p.m. | Monday through<br>Friday (except holidays) |
| Off-peak: | 9:30 p.m. to 8:30 a.m.<br>All day | Monday through Friday<br>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.<br>All day | Monday through Friday (except holidays)<br>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 a trigonometric function of the (T) 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.

(Continued)

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. (L)

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-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. (L)

(Continued)

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. (L)

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. (L)

(Continued)

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. (L)

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. (L)

(Continued)

**ELECTRIC SCHEDULE E-19** Sheet 16
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

14. BILLING: (Cont'd.)

**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, 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. (T)

**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, 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. (T)

| | DA / CCA CRS |
|---|---|
| Energy Cost Recovery Amount Charge (per kWh) | ($0.00001) |
| DWR Bond Charge (per kWh) | $0.00549 |
| CTC Charge (per kWh) | $0.00084 |
| Power Charge Indifference Adjustment (per kWh) | |
| 2009 Vintage | $0.01598 |
| 2010 Vintage | $0.01813 |
| 2011 Vintage | $0.01890 |
| 2012 Vintage | $0.01950 |
| 2013 Vintage | $0.01941 |
| 2014 Vintage | $0.01907 |
| 2015 Vintage | $0.01882 |
| 2016 Vintage | $0.01888 |
| 2017 Vintage | $0.01888 |

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 Charges[1], Competition Transition Charges (CTC), and Energy Cost Recovery Amount.

(D)

(Continued)

16. ELECTRIC EMERGENCY PLAN ROTATING BLOCK OUTAGES — See Electric Rule 14. (N) (D)

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(D)

(Continued)

17. STANDBY APPLICABILITY: (L)

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. (L)

(Continued)

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.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for default and opt-in PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in 19.c, may be independent 12 month periods. After the first year on PDP, NEM credits can offset PDP charges. All PDP billing for NEM customers will be based on net usage during each 15-minute interval. Net positive usage above the CRL, as well as net exports in excess of the CRL, in each 15-minute interval will be subject to PDP credits and charges as applicable. (N)

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 all summer-period 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. (T) (T)

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). The CRL for all customers, including NEM customers, must be greater than or equal to zero (0). (T) (N) (N)

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

(L)
(L)

(Continued)

19. PEAK DAY PRICING DETAILS: (cont.)

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. (L)

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. (L)

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.

(Continued)

19. PEAK DAY PRICING DETAILS: (cont.)

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. (L)

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. (L)

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. If a NEM customer is on PDP, the customer cannot participate in a third party Demand Response program unless it ceases to be a PDP customer. If a third party signs a NEM customer up under Rule 24 at the CAISO, the customer is automatically removed from PDP. (N)

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.

# Attachment 2. Southern California Edison Schedule TOU-GS-3

Schedule TOU-GS-3 Sheet 1

TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

## APPLICABILITY

Applicable to single- and three-phase general service including lighting and power customers whose monthly Maximum Demand registers, or in the opinion of SCE is expected to register 200 kW through 500 kW. The customer whose monthly Maximum Demand, in the opinion of SCE, is expected to exceed 500 kW or has exceeded 500 kW for any three months during the preceding 12 months is ineligible for service under this Schedule and effective with the date of ineligibility, such customer's account shall be transferred to Schedule TOU-8. Further, any customer served under this Schedule whose monthly Maximum Demand has registered below 200 kW for 12 consecutive months is ineligible for service under this Schedule and shall be transferred to Schedule TOU-GS-2. Except for interruptible customers, a customer who makes a permanent change in operating conditions that SCE, in its sole opinion, anticipates will reduce the customer's demand to below 200 kW, may transfer to Schedule TOU-GS-2 before completing 12 consecutive months at the reduced demand levels. Such customer shall be required to sign the Permanent Change in Operating Conditions Declaration, Form 14-548. Service under this Schedule is subject to meter availability.

This Schedule contains four rate structures: Option Critical Peak Pricing (CPP), Option A, Option B, and Option R. CPP is also referred to as the Summer Advantage Incentive Program.

Option CPP is the default rate structure of this Schedule. (T)

Customers receiving service on Schedule RES-BCT must take service under Option A or Option B of this Schedule. (N)
(N)

(Continued)

Schedule TOU-GS-3 Sheet 2
TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

(Continued)

APPLICABILITY (Continued)

CPP

CPP of this Schedule is available to all customers eligible to receive service under Option B of this Schedule. Except for customers transferring from Schedule CPP or another rate schedule with CPP, eligible Bundled Service Customers newly receiving service on this Schedule will be served under TOU-GS-3 Option B for an interim 60-day period and will be defaulted to CPP with a Capacity Reservation Level (CRL) as specified in Special Condition 3.f. on the customer's next regularly scheduled meter read date after the interim 60-day period if such Customer does not opt out within the interim 60-day period. Customers participating in Schedules GS-APS-E, the Day-of Option of CBP, TOU-BIP, a negotiated Demand Response Contract or a Net Energy Metering rate schedule will not be defaulted to CPP.

In addition, such customers may select to receive service under Option A, Option B, or Option R of this Schedule or another applicable rate schedule within the same interim 60-day period. For Direct Access customers transferring to Bundled Service, the 60-day interim period will occur during the last two months of their six-month notice period to transfer to Bundled Service. For these customers defaulted to CPP, Bill Protection will be provided for the first 12 months and effective on the customer's next regularly scheduled meter read date that customers are defaulted to Option CPP.

Option R

Option R of this Schedule is available to customers who install, own, or operate solar, wind, fuel cells, or other eligible onsite Renewable Distributed Generation Technologies as defined by the California Solar Initiative (CSI) or the Self-Generation Incentive Program (SGIP). Eligible systems must have a net renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand, as recorded over the previous 12 months. For generating systems that have received incentives through either CSI or the SGIP, the renewable generating capacity shall be the net generator output value, net of inverter losses, established in the customer's Generating Facility Interconnection Agreement required in Rule 21. For customers without 12-months of demand data. SCE will determine the annual peak demand once the customer has three months of demand data and SCE has verified the customer has equipment installed reflecting the anticipated annual peak demand. All other applicants must provide net generator output values, net of inverter losses based on the methodology for establishing such values described in the CSI or if applicable the SGIP handbooks. Participation on this rate option is limited to a cumulative installed distributed generation output capacity of 400 MW for all eligible rate groups. If a customer's generating system is removed or becomes inoperable, such that the customer is no longer eligible for this rate option, the customer may be removed from this option in accordance with Rule 11.G. This option is not available to customers receiving service under Schedule S, nor is this option available to service accounts interconnected with non-Renewable Distributed Generation Technologies.

Customers served under Option R of this Schedule whose monthly Maximum Demand has registered below 20 kW for 12 consecutive months as a result of operating the eligible renewable generating facility, will remain eligible to be served under Option R of this Schedule. (N)
|
(N)

TERRITORY
Within the entire territory served.

(Continued)

Schedule TOU-GS-3 — Sheet 3

TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

(Continued)

RATES

The rates below will apply to all customers receiving service under this Schedule. In addition, the customer will be charged the applicable rates under Option CPP, Option A, Option B or Option R, as listed below. Except for the portion of the customer's firm load that is designated as the Capacity Reservation Level (CRL), CPP Event Charges and CPP Non-Event Credits will apply to all load greater than 0 kW.

| | Delivery Service | | | | | | | | Generation[9] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Trans[1] | Distrbtn[2] | NSGC[3] | NDC[4] | PPPC[5] | DWRBC[6] | PUCRF[7] | Total[8] | UG** | DWREC[10] |
| **Option CPP** | | | | | | | | | | |
| Energy Charge - $/kWh/Meter/Month | | | | | | | | | | |
| Summer Season On-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.08819 | 0.00000 |
| Mid-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.05095 | 0.00000 |
| Off-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.03226 | 0.00000 |
| Winter Season On-Peak | | | | | | | | | | |
| Mid-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.04662 | 0.00000 |
| Off-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.03712 | 0.00000 |
| Customer Charge - $/Meter/Month | | 446.13 | | | | | | 446.13 | | |
| Demand Charge - $/kW of Billing Demand/Meter/Month | | | | | | | | | | |
| Facilities Related | 4.64 | 13.17 | | | | | | 17.81 | | |
| Time Related | | | | | | | | | | |
| Summer Season - On-Peak | | 0.00 | | | | | | 0.00 | 17.42 | |
| Mid-Peak | | 0.00 | | | | | | 0.00 | 3.43 | |
| Winter Season - On-Peak | | 0.00 | | | | | | 0.00 | 0.00 | |
| Mid-Peak | | 0.00 | | | | | | 0.00 | 0.00 | |
| Voltage Discount, Demand - $/kW | | | | | | | | | | |
| Facilities Related | | | | | | | | | | |
| From 2 kV to 50 kV | 0.00 | (0.21) | | | | | | (0.21) | | |
| Above 50 kV but below 220 kV | 0.00 | (7.11) | | | | | | (7.11) | | |
| At 220 kV | 0.00 | (13.17) | | | | | | (13.17) | | |
| Time Related | | | | | | | | | | |
| From 2 kV to 50 kV | 0.00 | 0.00 | | | | | | 0.00 | (0.34) | |
| Above 50 kV but below 220 kV | 0.00 | 0.00 | | | | | | 0.00 | (0.93) | |
| At 220 kV | 0.00 | 0.00 | | | | | | 0.00 | (0.94) | |
| Voltage Discount, Energy - $/kWh | | | | | | | | | | |
| From 2 kV to 50 kV | 0.00000 | 0.00000 | | | | | | 0.00000 | (0.00121) | |
| Above 50 kV but below 220 kV | 0.00000 | 0.00000 | | | | | | 0.00000 | (0.00269) | |
| At 220 kV | 0.00000 | 0.00000 | | | | | | 0.00000 | (0.00271) | |
| Power Factor Adjustment - $/kVAR | | | | | | | | | | |
| Greater than 50 kV | | 0.47 | | | | | | 0.47 | | |
| 50 kV or less | | 0.55 | | | | | | 0.55 | | |
| California Alternate Rates for Energy Discount - % | | 100.00* | | | | | | 100.00* | | |
| CPP Event Energy Charge - $/kWh | | | | | | | | | 1.37453 | |
| Summer CPP Non-Event Credit | | | | | | | | | | |
| On-Peak Demand Credit - $/kW | | | | | | | | | (11.44) | |
| Maximum Available Credit - $/kW** | | | | | | | | | | |
| On-Peak | | | | | | | | | (19.81) | |
| Mid-Peak | | | | | | | | | (3.90) | |

(Continued)

Schedule TOU-GS-3 — Sheet 4

TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

(Continued)

RATES (Continued)

| | Delivery Service | | | | | | | | Generation[9] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Trans[1] | Distrbtn[2] | NSGC[3] | NDC[4] | PPPC[5] | DWRBC[6] | PUCRF[7] | Total[8] | UG** | DWREC[10] |
| **Option A** | | | | | | | | | | |
| Energy Charge - $/kWh/Meter/Month | | | | | | | | | | |
| Summer Season On-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.28916 | 0.00000 |
| Mid-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.08281 | 0.00000 |
| Off-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.03226 | 0.00000 |
| Winter Season On-Peak | | | | | | | | | | |
| Mid-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.04662 | 0.00000 |
| Off-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.03712 | 0.00000 |
| Customer Charge - $/Meter/Month | | 446.13 | | | | | | 446.13 | | |
| Demand Charge - $/kW of Billing Demand/Meter/Month | | | | | | | | | | |
| Facilities Related | 4.64 | 13.17 | | | | | | 17.81 | | |
| Voltage Discount, Demand - $/kW | | | | | | | | | | |
| Facilities Related | | | | | | | | | | |
| From 2 kV to 50 kV | 0.00 | (0.21) | | | | | | (0.21) | | |
| Above 50 kV but below 220 kV | 0.00 | (7.11) | | | | | | (7.11) | | |
| At 220 kV | 0.00 | (13.17) | | | | | | (13.17) | | |
| Voltage Discount, Energy - $/kWh | | | | | | | | | | |
| From 2 kV to 50 kV | 0.00000 | 0.00000 | | | | | | 0.00000 | (0.00192) | |
| Above 50 kV but below 220 kV | 0.00000 | 0.00000 | | | | | | 0.00000 | (0.00461) | |
| At 220 kV | 0.00000 | 0.00000 | | | | | | 0.00000 | (0.00466) | |
| Power Factor Adjustment - $/kVAR | | | | | | | | | | |
| Greater than 50 kV | | 0.47 | | | | | | 0.47 | | |
| 50 kV or less | | 0.55 | | | | | | 0.55 | | |
| California Alternate Rates for Energy Discount - % | | 100.00* | | | | | | 100.00* | | |

(Continued)

## Schedule TOU-GS-3 Sheet 5
## TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

(Continued)

RATES (Continued)

| | Delivery Service | | | | | | | | Generation[9] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Trans[1] | Distrbtn[2] | NSGC[3] | NDC[4] | PPPC[5] | DWRBC[6] | PUCRF[7] | Total[8] | UG** | DWREC[10] |
| **Option B** | | | | | | | | | | |
| Energy Charge - $/kWh/Meter/Month | | | | | | | | | | |
| Summer Season - On-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.08819 | 0.00000 |
| Mid-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.05095 | 0.00000 |
| Off-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.03226 | 0.00000 |
| Winter Season - On-Peak | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Mid-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.04662 | 0.00000 |
| Off-Peak | (0.00213) | 0.00230 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.02570 (R) | 0.03712 | 0.00000 |
| Customer Charge - $/Meter/Month | | 446.13 | | | | | | 446.13 | | |
| Demand Charge - $/kW of Billing Demand/Meter/Month | | | | | | | | | | |
| Facilities Related | 4.64 | 13.17 | | | | | | 17.81 | | |
| Time Related | | | | | | | | | | |
| Summer Season - On-Peak | | 0.00 | | | | | | 0.00 | 17.42 | |
| Mid-Peak | | 0.00 | | | | | | 0.00 | 3.43 | |
| Winter Season - Mid-Peak | | 0.00 | | | | | | 0.00 | 0.00 | |
| Off-Peak | | 0.00 | | | | | | 0.00 | 0.00 | |
| Voltage Discount, Demand - $/kW | | | | | | | | | | |
| Facilities Related | | | | | | | | | | |
| From 2 kV to 50 kV | 0.00 | (0.21) | | | | | | (0.21) | | |
| Above 50 kV but below 220 kV | 0.00 | (7.11) | | | | | | (7.11) | | |
| At 220 kV | 0.00 | (13.17) | | | | | | (13.17) | | |
| Time Related | | | | | | | | | | |
| From 2 kV to 50 kV | 0.00 | 0.00 | | | | | | 0.00 | (0.34) | |
| Above 50 kV but below 220 kV | 0.00 | 0.00 | | | | | | 0.00 | (0.93) | |
| At 220 kV | 0.00 | 0.00 | | | | | | 0.00 | (0.94) | |
| Voltage Discount, Energy - $/kWh | | | | | | | | | | |
| From 2 kV to 50 kV | 0.00000 | 0.00000 | | | | | | 0.00000 | (0.00121) | |
| Above 50 kV but below 220 kV | 0.00000 | 0.00000 | | | | | | 0.00000 | (0.00269) | |
| At 220 kV | 0.00000 | 0.00000 | | | | | | 0.00000 | (0.00271) | |
| Power Factor Adjustment - $/kVAR | | | | | | | | | | |
| Greater than 50 kV | | 0.47 | | | | | | 0.47 | | |
| 50 kV or less | | 0.55 | | | | | | 0.55 | | |
| California Alternate Rates for Energy Discount - % | | 100.00* | | | | | | 100.00* | | |

(Continued)

Schedule TOU-GS-3 Sheet 6

TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

(Continued)

RATES (Continued)

| **Option R** | Delivery Service | | | | | | | | Generation[9] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Trans[1] | Distrbtn[2] | NSGC[3] | NDC[4] | PPPC[5] | DWRBC[6] | PUCRF[7] | Total[8] | UG** | DWREC[10] |
| Energy Charge - $/kWh/Meter/Month | | | | | | | | | | |
| Summer Season - On-Peak | (0.00213) | 0.02132 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.04472 (R) | 0.28916 | 0.00000 |
| Mid-Peak | (0.00213) | 0.02132 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.04472 (R) | 0.08281 | 0.00000 |
| Off-Peak | (0.00213) | 0.02132 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.04472 (R) | 0.03226 | 0.00000 |
| Winter Season - Mid-Peak | (0.00213) | 0.02132 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.04472 (R) | 0.04662 | 0.00000 |
| Off-Peak | (0.00213) | 0.02132 | 0.00866 | 0.00001 | 0.01094 (R) | 0.00549 | 0.00043 | 0.04472 (R) | 0.03712 | 0.00000 |
| Customer Charge - $/Meter/Month | | 446.13 | | | | | | 446.13 | | |
| Demand Charge - $/kW of Billing Demand/Meter/Month | | | | | | | | | | |
| Facilities Related | 4.64 | 6.51 | | | | | | 11.15 | | |
| Voltage Discount, Facilities Related Demand - $/kW | | | | | | | | | | |
| From 2 kV to 50 kV | 0.00 | (0.10) | | | | | | (0.10) | | |
| Above 50 kV but below 220 kV | 0.00 | (3.51) | | | | | | (3.51) | | |
| At 220 kV | 0.00 | (6.51) | | | | | | (6.51) | | |
| Voltage Discount, Energy - $/kWh | | | | | | | | | | |
| From 2 kV to 50 kV | 0.00000 | (0.00030) | | | | | | (0.00030) | (0.00192) | |
| Above 50 kV but below 220 kV | 0.00000 | (0.01027) | | | | | | (0.01027) | (0.00461) | |
| At 220 kV | 0.00000 | (0.01902) | | | | | | (0.01902) | (0.00466) | |
| Power Factor Adjustment - $/kVAR | | | | | | | | | | |
| Greater than 50 kV | | 0.47 | | | | | | 0.47 | | |
| 50 kV or less | | 0.55 | | | | | | 0.55 | | |
| California Alternate Rates for Energy Discount - % | | 100.00* | | | | | | 100.00* | | |

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.

** The ongoing Competition Transition Charge (CTC) of $(0.00023) per kWh is recovered in the UG component of Generation.

*** The Maximum Available Credit is the capped credit amount for CPP customers dual participating in other demand response programs.

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00129) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00016 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $(0.00100) per kWh.

2 Distrbtn = Distribution

3 NSGC = New System Generation Charge

4 NDC = Nuclear Decommissioning Charge

5 PPPC = Public Purpose Programs Charge (including California Alternate Rates for Energy Surcharge where applicable.)

6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.

7 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.

8 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) Customers, except DA and CCA Service Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.

9 Generation = The Generation rates are applicable only to Bundled Service Customers.

10 DWREC = Department of Water Resources (DWR) Energy Credit – For more information on the DWR Energy Credit, see the Billing Calculation Special Condition of this Schedule.

(Continued)

(To be inserted by utility)
Advice 3659-E
Decision 16-06-006
6C10

Issued by
Caroline Choi
Senior Vice President

(To be inserted by Cal. PUC)
Date Filed Sep 20, 2017
Effective Oct 1, 2017
Resolution

Schedule TOU-GS-3 Sheet 7
TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

(Continued)

SPECIAL CONDITIONS

1. Applicable rate time periods are defined as follows: (T)

| | |
|---|---|
| On-Peak: | Noon to 6:00 p.m. summer weekdays except holidays. |
| Mid-Peak: | 8:00 a.m. to Noon and 6:00 p.m. to 11:00 p.m. summer weekdays except holidays.<br><br>8:00 a.m. to 9:00 p.m. winter weekdays except holidays. |
| Off-Peak: | All other hours. |
| CPP Event Energy Charge Periods: | 2:00 p.m. to 6:00 p.m. summer and winter weekdays except holidays during a CPP Event only. (T) |

(T)

CPP Non-Event Demand Credit Period: Summer On-Peak hours.

Holidays are New Year's Day (January 1), Presidents' Day (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday.

The summer season shall commence at 12:00 a.m. on June 1 and continue until 12:00 a.m. on October 1 of each year. The winter season shall commence at 12:00 a.m. on October 1 of each year and continue until 12:00 a.m. on June 1 of the following year.

2. Voltage: Service will be supplied at one standard voltage.

(Continued)

SPECIAL CONDITIONS (Continued)

3. Critical Peak Pricing: Critical Peak Pricing is an event-based pricing option which provides credits during summer CPP Non-Event Credit Periods and incremental bill charges during Critical Peak Event Charge Periods.

   a. CPP Events: SCE may, at its discretion, call a CPP Event any non-holiday weekday. CPP Events will be called based on any one of the following criteria:

      (1) California Independent System Operator (CAISO) Alert or Warning Notice,
      (2) Forecasts of SCE system emergencies – may be declared at the generation, transmission, or distribution circuit level
      (3) Forecasts of extreme or unusual temperature conditions impacting system demand
      (4) Day-ahead load and/or price forecasts

   b. Number of CPP Events: There will be 12 CPP Events per calendar year.

   c. Notification of a CPP Event: SCE will notify customers of a CPP Event via SCE's notification system. Customers are responsible for providing SCE with contact information consisting of a telephone number, fax number, electronic mail address, and/or SMS text number for notification of Events. Customers are responsible for updating customer contact information as necessary. SCE will begin to notify customers no later than 3:00 p.m. the business day before a CPP Event. Customers are responsible for all charges incurred during a CPP Event, even if notice is not received. Customers who fail to provide the necessary contact information prior to CPP Events are responsible for all charges incurred during CPP Events.

   d. Participation in other Programs: Only Bundled Service Customers shall be served under CPP. Direct Access Customers and Community Choice Aggregators are ineligible for service under CPP of this Schedule. CPP customers served under this Schedule are eligible for service under Schedules GS-APS-E, TOU-BIP, NEM or (T)
NEM-ST, OBMC, and the Day-Of Option of CBP. CPP customers served under this (N)
Schedule are not eligible for service under Option A or R of this Schedule, Schedules TOU-GS-3-SOP, DBP, S, SLRP, or the Day-Ahead Option of CBP.

      For CPP customers dual participating with Schedules TOU-BIP, GS-APS-E, or the Day-Of Option of CBP, the sum of credits provided by the dual participating demand response program and CPP of this Schedule will be capped. The capped credit amount, also known as the Maximum Available Credit, is listed in the applicable CPP of this Schedule.

Schedule TOU-GS-3 Sheet 9
TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

(Continued)

SPECIAL CONDITIONS (Continued

3. Critical Peak Pricing (Continued)

e. Bill Protection: The purpose of Bill Protection is to ensure, over the initial 12-month period of service on CPP, that the customer is billed an amount no greater than the customer would otherwise be billed under Option B of this Schedule. (T)

(1) A CPP customer will receive a Bill Protection credit for the positive difference, if any, in total charges calculated under CPP minus total charges as calculated under Option B as measured over a period of 12 months from the date the customer is defaulted to or elects CPP; (T)

(2) If a CPP customer opts-out of Option CPP prior to the completion of 12 months of service, the customer shall not receive Bill Protection credits for the period the customer was billed under CPP;

(3) At the end of the 12-month period one of the following will occur:

If a customer's bill calculated under CPP, is equal to or less than their bill as calculated under Option B over the 12-month period, the customers Bill Protection Credit is zero;

If a customer's bill calculated under CPP is greater than their bill as calculated under Option B over the 12-month period, the customer will receive a Bill Protection Credit equal to the CPP charges minus the applicable Option B charges; (T)

(4) If a participating customer is removed from this Schedule and receives service under another schedule without a CPP rate structure prior to the completion of 12 months on this Schedule, such customer shall not be eligible for any Bill Protection credits for the period the customer was served under this Schedule. However, if a participating customer is removed from this Schedule and receives service under another schedule without a CPP rate structure that provides for Bill Protection, then Bill Protection shall continue and any available cumulated credits will be applied to the customer's bill upon completion of 12-months on any schedule with a CPP rate structure. If a participating customer's service account served under this Schedule is closed prior to the completion of 12 months, and such customer receives service at a new location under a schedule with a CPP rate structure that provides for Bill Protection, such customer shall not be eligible for any Bill Protection credits for the period the customer was served under this Schedule at the prior location; however will be eligible for Bill Protection at the new location.

(Continued)

SPECIAL CONDITIONS (Continued

3. Critical Peak Pricing (Continued)

f. Capacity Reservation Level (CRL): The CRL is the Maximum Demand specified in kW of firm load that is not subject to CPP Event Charges or CPP Non-Event Credits. (T)

(1) Initial Setting of the CRL:

a) For customers participating under another schedule with CPP-Lite and who are transferred to this Schedule, a CRL of 50 percent of the customer’s average summer on-peak demand in kW over the last 12 months or less will be set.

b) For customers participating under another schedule with CPP with a specified CRL and who are transferred to this Schedule, no change to the customer’s CRL will be made.

c) For all other customers who are defaulted or transferred to this Schedule, the customer’s CRL will be set at 0 kW.

(2) CRL Adjustment: All customers newly receiving service under this Schedule with an initial CRL set by SCE, may select a new CRL at anytime thereafter; however, after the customer makes a selection, the CRL must not change for 12 months pursuant to SCE’s Rule 12. Adjustment of the CRL may be made no more than once per year. The CRL shall be set at zero kW or greater. (N)

(Continued)

Schedule TOU-GS-3 Sheet 11 (T)
TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

(Continued)

SPECIAL CONDITIONS (Continued)

4. Maximum Demand: Maximum Demand shall be established for the On-Peak, Mid-Peak, and Off-Peak Time Periods. The Maximum Demand for each period shall be the measured maximum average kilowatt (kW) input, indicated or recorded by instruments, such as SCE metering, during any 15-minute metered interval, but where applicable, not less than the diversified resistance welder load computed in accordance with the section designated Welder Service in Rule 2. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used. (T)

5. Billing Demand: The Billing Demand shall be the kW of Maximum Demand, determined to the nearest kW. The Demand Charge shall include the following billing components. The Facilities Related Demand Component shall be for the kW of Maximum Demand recorded during (or established for) the monthly billing period. However, when SCE determines the customer's meter will record little or no energy use for extended periods of time or when the customer's meter has not recorded a Maximum Demand in the preceding eleven months, the Facilities Related Component of the Demand Charge may be established at 50 percent of the customer's connected load. Separate Demand Charge(s) for the On-Peak, Mid-Peak, and Off-Peak Time Periods shall be established for each monthly billing period. The Demand Charge for each time period shall be based on the Maximum Demand for that time period occurring during the respective monthly billing period. (T)

6. Voltage Discount: Bundled Service, CCA Service, and Direct Access customers will have the Distribution rate component of the applicable Delivery Service charges reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the RATES section above. In addition, Bundled Service Customers will have the Utility Generation (UG) rate component of the applicable Generation charges reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the RATES section.

7. Power Factor Adjustment: The customer's bill will be increased each month for power factor by the amount shown in the Rates section above for service metered and delivered at the applicable voltage level, based on the per kilovar of maximum reactive demand imposed by SCE.

   The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering during any 15 minute metered interval in the month. The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.

(Continued)

Schedule TOU-GS-3 Sheet 12

TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

(Continued)

SPECIAL CONDITIONS (Continued)

8. Temporary Discontinuance of Service: When the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

9. Customer-Owned Electrical Generating Facilities:

   a. Where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation.

   b. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted to allow the customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service.

10. California Alternate Rates for Energy Discount: Customers who meet the definition of a Group Living Facility, Agricultural Employee Housing, or Migrant Farm Worker Housing Center as defined in Preliminary Statement, Part O, Section 3, may qualify for a 27.9% (I) discount off of their bill prior to application of the PUC Reimbursement Fee and any applicable user fees, taxes, and late payment charges. Customers eligible for the California Alternate Rates for Energy (CARE) Discount will not be required to pay the CARE Surcharge, as set forth in Preliminary Statement, Part O, Section 4 and are not subject to the DWRBC rate component of the Total charges for Delivery Service. An application and eligibility declaration, as defined in Preliminary Statement, Part O, Section 3, is required for service under this Special Condition. Eligible customers shall be billed on this Schedule commencing no later than one billing period after receipt and approval of the customer's application by SCE. Customers may be rebilled on the applicable rate schedule for periods in which they do not meet the eligibility requirements for the CARE discount as defined in Preliminary Statement, Part O, Section 3.

11. Removal From Schedule: Customers receiving service under this Schedule whose monthly Maximum Demand has registered 200 kW or less for 12 consecutive months shall be changed to an applicable rate schedule effective with the date the customer became ineligible for service under this Schedule.

(Continued)

Schedule TOU-GS-3 Sheet 13 (T)
TIME-OF-USE - GENERAL SERVICE - DEMAND METERED

(Continued)

SPECIAL CONDITIONS (Continued)

12. Billing Calculation: A customer's bill is calculated according to the rates and conditions above.

The charges listed in the Rates section are calculated by multiplying the Total Delivery Service rates and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatthour [kWh], kilovar [kVAR], etc.).

As of January 1, 2012, all generation supplied to Bundled Service Customers is provided by SCE. The DWR Energy Credit provided to Bundled Service Customers is determined by multiplying the DWR Energy Credit rate component by the customer's total kWhs.

a. Bundled Service Customers receive Delivery Service and Generation service from SCE. The customer's bill is the sum of the charges for Delivery Service and Generation service determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

b. Direct Access Customers receive Delivery Service from SCE and purchase energy from an Energy Service Provider. The customer's bill is the sum of the charges for Delivery Service determined as described in this Special Condition except that the DWRBC rate component is subtracted from the Total Delivery Service rates before the billing determinants are multiplied by such resulting Total rates; plus the applicable charges as shown in Schedule DA-CRS and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

c. CCA Service Customers receive Delivery Service from SCE and purchase energy from their Community Choice Aggregator (CCA). SCE will read the meters and present the bill for both Delivery and Generation Services to the CCA Service Customer. The customer's bill is the sum of the charges for Delivery Service as displayed in this Rate Schedule and Generation charges determined by the CCA plus the applicable charges as shown in Schedule CCA-CRS, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

13. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages.

Sub-transmission customers, except for those customers exempt from rotating outages, are to be included in controlled, rotating outages when required by the California Independent System Operator (CAISO) and/or SCE. To the extent feasible, SCE will coordinate rotating outages applicable to Sub-transmission customers who are fossil fuel producers and pipeline operators and users to minimize disruption to public health and safety. SCE shall not include a Sub-transmission customer in an applicable rotating outage group if the customer's inclusion would jeopardize electric system integrity. Sub-transmission customers who are not exempt from rotating outages, and seek such exemption, may submit an Optional Binding Mandatory Curtailment (OBMC) Plan to SCE in accordance with Schedule OBMC. If SCE approves a customer's OBMC Plan, the customer will become exempt from rotating outages and will be subject to the terms and conditions of Schedule OBMC and its associated contract.

(Continued)

SPECIAL CONDITIONS (Continued)

13. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued)

    Non-exempt Sub-transmission customers shall be required to drop their entire electrical load during applicable rotating outages by either (1) implementing the load reduction on their own initiative, in accordance with subsection a, below; or (2) having SCE implement the load reduction through remote-controlled load drop equipment (control equipment) in accordance with subsection b, below. A Sub-transmission customer shall normally be subject to the provisions of subsection a. If SCE approves a customer's request to have SCE implement the load reduction or if the customer does not did not comply with prior required load reductions, as specified in subsection c, the customer will be subject to the provisions of subsection b.

    a. Customer-Implemented Load Reduction.

        (1) Notification of Required Load Reduction. At the direction of the CAISO or when SCE otherwise determines there is a need for Rotating Outage, SCE shall notify each Sub-transmission customers in an affected rotating outage group to drop its entire load. Within 30 minutes of such notification, the customer must drop its entire load. The customer shall not return the dropped load to service until 90 minutes after SCE sent the notification to the customer to drop its load, unless SCE notifies the customer that it may return its load to service prior to the expiration of the 90 minutes.

        (2) Method of Notification. SCE will notify Sub-transmission customers who are required to implement their own load reduction via telephone, by either an automated calling system or a manual call to a business telephone number or cellular phone number designated by the customer. The designated telephone number will be used for the sole purpose of receiving SCE's rotating outage notification and must be available to receive the notification at all times. When SCE sends the notification to the designated telephone number the customer is responsible for dropping its entire load in accordance with subsection a.(1), above. The customer is responsible for informing SCE, in writing, of the telephone number and contact name for purposes of receiving the notification of a rotating outage.

        (3) Excess Energy Charges. If a Sub-transmission customer fails to drop its entire load within 30 minutes of notification by SCE, and/or fails to maintain the entire load drop until 90 minutes after the time notification was sent to the customer, unless SCE otherwise notified the customer that it may return its load to service earlier in accordance with subsection a.(1) above, SCE shall assess Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during the applicable rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage penalty period in hours. Excess Energy Charges will be determined and applied by SCE subsequent to the Sub-transmission customer's regularly scheduled meter read date following the applicable rotating outage.

(Continued)

SPECIAL CONDITIONS (Continued)

13. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued)

    a. Customer-Implemented Load Reduction. (Continued)

        (4) Authorized Residual Ancillary Load. Authorized Residual Ancillary Load is load that is deemed to be equivalent to five percent of the Sub-transmission customer's prior billing month's recorded Maximum Demand. This minimum load level is used as a proxy to allow for no-load transformer losses and/or load attributed to minimum grid parallel operation for generators connected under Rule 21.

    b. SCE-Implemented Load Reduction.

    Non-exempt Sub-transmission customers may request, in writing, to have SCE drop the customer's entire load during all applicable rotating outages using SCE's remote-controlled load drop equipment (control equipment). If SCE agrees to such arrangement, SCE will implement the load drop by using one of the following methods:

        (1) Control Equipment Installed. For a Sub-transmission customer whose load can be dropped by SCE's existing control equipment, SCE will implement the load drop during a rotating outage applicable to the customer. The customer will not be subject to the Notification and or Excess Energy Charge provisions set forth in subsection a, above.

        (2) Control Equipment Pending Installation. For a Sub-transmission customer whose load can not be dropped by SCE's existing control equipment, the customer must request the installation of such equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities. Pending the installation of the control equipment, the customer will be responsible for dropping load in accordance with the provisions of subsection a, above, including subject the Notification and Excess Energy Charge provisions.

(Continued)

(Continued)

SPECIAL CONDITIONS (Continued)

13. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued)

    c. Non-compliance: A non-exempt Sub-transmission customer subject to subsection a, above, who fails to drop load during three rotating outages in a three year period to a demand level of 20% or less of the customer's prior billing month's recorded Maximum Demand averaged over the applicable rotating outage period, is not in compliance with this tariff. The three year period shall commence with the first failure to drop load as specified in this subsection. A customer not in compliance with this condition will be placed at the top of the Sub-transmission customer rotating outage group list and will be expected to comply with subsequent applicable rotating outages. In addition, the customer must select one of the two options below within fifteen days after receiving written notice of non-compliance from SCE. A customer failing to make a selection within the specified time frame will be subject to subsection c. (2) below.

        (1) Subject to Schedule OBMC: The customer shall submit an OBMC Plan, in accordance with Schedule OBMC, within 30 calendar days of receiving written notice of non-compliance from SCE. Pending the submittal of the OBMC Plan by the customer and pending the review and acceptance of the OBMC Plan by SCE, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy charge provisions. If the customer fails to submit an OBMC Plan within 30 days of receiving notice of non-compliance from SCE, or if the customer's OBMC Plan is not approved by SCE, or if the customer fails to meet the requirements of Schedule OBMC once the OBMC Plan is approved, the customer shall be subject subsection c. (2), below.

        (2) Installation of Control Equipment. The customer shall be subject to the installation of control equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities, if such equipment is not currently installed. If such switching capability is installed, SCE will drop the customer's load for all applicable subsequent rotating outages in accordance with the provisions of subsection b, above. Pending the installation of control equipment, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

(Continued)

SPECIAL CONDITIONS (Continued)

13. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued)

d. Net-Generators

Sub-transmission customers who are also net-generators are normally exempt from rotating outages, but they must be net suppliers of power to the grid during all rotating outages. For the purpose of this Special Condition, a net-generator is an SCE customer who operates an electric generating facility as part of its industrial or commercial process, and the generating facility normally produces more electrical power than is consumed in the industrial or commercial process, with the excess power supplied to the grid. Sub-transmission customers whose primary business purpose is to generate power are not included in this Special Condition.

(1) Notification of Rotating Outages. SCE will notify sub-transmission customers who are net-generators of all rotating outages applicable to customers within SCE's service territory. Within 30 minutes of notification, the customer must ensure it is a net supplier of power to the grid throughout the entire rotating outage period. Failure to do so will result in the customer losing its exemption from rotating outages, and the customer will be subject to Excess Energy Charges, as provided below.

(2) Excess Energy Charges. Net generators who are not net suppliers to the grid during each rotating outage period will be subject to Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during a rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage period hours. Excess Energy Charges will be determined and applied by SCE subsequent to the customer's regularly scheduled meter read date following the applicable rotating outage. Excess Energy Charges shall not apply during periods of verifiable scheduled generator maintenance or if the customer's generator suffers a verifiable forced outage. The scheduled maintenance must be approved in advance by either the CAISO or SCE, but approval may not be unreasonably withheld.

# Attachment 3. San Diego Gas and Electric Schedule DG-R

# SCHEDULE DG-R



DISTRIBUTED GENERATION RENEWABLE - TIME METERED

## APPLICABILITY

Service under this Schedule is available on a voluntary basis for all metered non-residential customers whose peak annual load is equal to or less than 2MW, and who have operational, distributed generation, and the capacity of that operational distributed generation is equal to or greater than 10% of their peak annual load. Distributed generation that qualifies for service under this Schedule is limited to solar, fuel cells (regardless of fuel source), and other renewable distributed generation, as more fully defined in Special Condition 17, fueled with gas derived from biomass, digester gas, or landfill gas. This Schedule is not applicable to residential customers. Customers on this Schedule whose Monthly Maximum Demand is not less than 20 kW for three consecutive months will also take commodity service on Schedule EECC-CPP-D. Customers on this Schedule whose Monthly Maximum Demand is less than 20 kW for three consecutive months must also take commodity service; they may optionally elect Schedule EECC-CPP-D or they may choose Schedule EECC-TOU-A-P in which case their Utility Distribution Company service rate would be Schedule TOU-A. In addition, customers may exercise the right to opt-out of the applicable dynamic rate (e.g., EECC-CPP-D or EECC-TOU-A-P) to their otherwise applicable Utility Distribution Company and commodity rates. For opt-out provisions, refer to the applicable commodity tariff.

Non-profit group living facilities taking service under this schedule may be eligible for a 20% California Alternate Rates for Energy (CARE) discount on their bill, if such facilities qualify to receive service under the terms and conditions of Schedule E-CARE.

Agricultural Employee Housing Facilities, as defined in Schedule E-CARE, may qualify for a 20% CARE discount on the bill if all eligibility criteria set forth in Form 142-4032 or Form 142-4035 is met.

Small Business Customers, as defined in Rule 1 and not identified by the California Air Resources Board as Emission Intensive, Trade-Exposed Entities (EITE), qualify for a California Climate Credit of $(0.00140) per kWh, which will display as a separate line item per Schedule GHG-ARR. I

## TERRITORY

Within the entire territory served by the Utility.

## RATES

| Description DG-R | Transm | Distr | PPP | ND | CTC | LGC | RS | TRAC | UDC Total |
|---|---|---|---|---|---|---|---|---|---|
| Basic Service Fees | | | | | | | | | |
| ($/month) | | | | | | | | | |
| 0-500 kW | | | | | | | | | |
| Secondary | | 116.44 | | | | | | | 116.44 |
| Primary | | 31.40 | | | | | | | 31.40 |
| Secondary Substation | | 16,630.12 | | | | | | | 16,630.12 |
| Primary Substation | | 16,630.12 | | | | | | | 16,630.12 |
| Transmission | | 169.34 | | | | | | | 169.34 |
| > 500 kW | | | | | | | | | |
| Secondary | | 465.74 | | | | | | | 465.74 |
| Primary | | 37.35 | | | | | | | 37.35 |
| Secondary Substation | | 16,630.12 | | | | | | | 16,630.12 |
| Primary Substation | | 16,630.12 | | | | | | | 16,630.12 |
| Transmission | | 677.54 | | | | | | | 677.54 |
| Trans. Multiple Bus | | 3,000.00 | | | | | | | 3,000.00 |
| Distance Adjust. Fee | | | | | | | | | |
| Secondary - OH | | 1.23 | | | | | | | 1.23 |
| Secondary - UG | | 3.17 | | | | | | | 3.17 |
| Primary - OH | | 1.22 | | | | | | | 1.22 |
| Primary - UG | | 3.13 | | | | | | | 3.13 |

(Continued)

# SCHEDULE DG-R



## DISTRIBUTED GENERATION RENEWABLE - TIME METERED

RATES (Continued)

| Description DG-R | Transm | Distr | PPP | ND | CTC | LGC | RS | TRAC | UDC Total |
|---|---|---|---|---|---|---|---|---|---|
| Demand Charges ($/kW) | | | | | | | | | |
| Maximum Demand | | | | | | | | | |
| Secondary | 12.05 I | 0.16 I | | | | | 0.05 I | | 12.26 I |
| Primary | 11.63 I | 0.28 I | | | | | 0.04 | | 11.95 I |
| Secondary Substation | 12.05 I | | | | | | 0.05 I | | 12.10 I |
| Primary Substation | 11.63 I | | | | | | 0.04 | | 11.67 I |
| Transmission | 11.58 I | | | | | | 0.04 | | 11.62 I |
| Maximum On-Peak | | | | | | | | | |
| Summer | | | | | | | | | |
| Secondary | 2.13 I | | | | | | | | 2.13 I |
| Primary | 2.06 I | | | | | | | | 2.06 I |
| Secondary Substation | 2.13 I | | | | | | | | 2.13 I |
| Primary Substation | 2.06 I | | | | | | | | 2.06 I |
| Transmission | 2.05 I | | | | | | | | 2.05 I |
| Winter | | | | | | | | | |
| Secondary | 0.66 I | | | | | | | | 0.66 I |
| Primary | 0.63 I | | | | | | | | 0.63 I |
| Secondary Substation | 0.66 I | | | | | | | | 0.66 I |
| Primary Substation | 0.63 I | | | | | | | | 0.63 I |
| Transmission | 0.63 I | | | | | | | | 0.63 I |
| Power Factor ($/kvar) | | | | | | | | | |
| Secondary | | 0.25 | | | | | | | 0.25 |
| Primary | | 0.25 | | | | | | | 0.25 |
| Secondary Substation | | 0.25 | | | | | | | 0.25 |
| Primary Substation | | 0.25 | | | | | | | 0.25 |
| Transmission | | | | | | | | | |

(Continued)

# SCHEDULE DG-R



DISTRIBUTED GENERATION RENEWABLE - TIME METERED

## RATES (Continued)

| Description DG-R | Transm | Distr | PPP | ND | CTC | LGC | RS | TRAC | UDC Total |
|---|---|---|---|---|---|---|---|---|---|
| Energy Charges ($/kWh) | | | | | | | | | |
| On-Peak - Summer | | | | | | | | | |
| Secondary | (0.01065) | 0.04879 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05168 I |
| Primary | (0.01065) | 0.04856 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05145 I |
| Secondary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Primary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Transmission | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Semi-Peak – Summer | | | | | | | | | |
| Secondary | (0.01065) | 0.04879 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05168 I |
| Primary | (0.01065) | 0.04856 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05145 I |
| Secondary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Primary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Transmission | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Off-Peak – Summer | | | | | | | | | |
| Secondary | (0.01065) | 0.04879 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05168 I |
| Primary | (0.01065) | 0.04856 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05145 I |
| Secondary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Primary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Transmission | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| On-Peak – Winter | | | | | | | | | |
| Secondary | (0.01065) | 0.04879 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05168 I |
| Primary | (0.01065) | 0.04856 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05145 I |
| Secondary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Primary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Transmission | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Semi-Peak – Winter | | | | | | | | | |
| Secondary | (0.01065) | 0.04879 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05168 I |
| Primary | (0.01065) | 0.04856 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05145 I |
| Secondary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Primary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Transmission | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Off-Peak - Winter | | | | | | | | | |
| Secondary | (0.01065) | 0.04879 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05168 I |
| Primary | (0.01065) | 0.04856 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.05145 I |
| Secondary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Primary Substation | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |
| Transmission | (0.01065) | 0.00135 | 0.01029 | (0.00049) | 0.00152 R | 0.00220 I | 0.00002 | | 0.00424 I |

Notes: Transmission Energy charges include the Transmission Revenue Balancing Account Adjustment (TRBAA) of $(0.00170) per kWh and the Transmission Access Charge Balancing Account Adjustment (TACBAA) of $(0.00895) per kWh. PPP rate is composed of: Low Income PPP rate (LI-PPP) $0.00426 /kWh, Non-low Income PPP rate (Non-LI-PPP) $0.00107 kWh (pursuant to PU Code Section 399.8, the Non-LI-PPP rate may not exceed January 1, 2000 levels), and Procurement Energy Efficiency Surcharge Rate of $0.00496 /kWh.

(Continued)

# SCHEDULE DG-R



DISTRIBUTED GENERATION RENEWABLE - TIME METERED

RATES (Continued)

Rate Components
The Utility Distribution Company Total Rates (UDC Total) shown above are comprised of the following components (if applicable): (1) Transmission (Trans) Charges, (2) Distribution (Distr) Charges, (3) Public Purpose Program (PPP) Charges, (4) Nuclear Decommissioning (ND) Charge, (5) Ongoing Competition Transition Charges (CTC), (6) Local Generation Charge (LGC), (7) Reliability Services (RS), and (8) Total Rate Adjustment Component (TRAC).

Utility Distribution Company (UDC) Total Rate shown above excludes any applicable commodity charges associated with Schedule EECC (Electric Energy Commodity Cost) and Schedule DWR-BC (Department of Water Resources Bond Charge), or any other applicable commodity rate schedule.

Certain Direct Access customers are exempt from the TRAC, as defined in Rule 1 – Definitions.

Time Periods
All time periods listed are applicable to local time. The definition of time will be based upon the date service is rendered.

| | **Summer May 1 – Oct 31** | **Winter - All Other** |
|---|---|---|
| On-Peak | 11 a.m. - 6 p.m. Weekdays | 5 p.m. - 8 p.m. Weekdays |
| Semi-Peak | 6 a.m. - 11 a.m. Weekdays | 6 a.m. - 5 p.m. Weekdays |
| | 6 p.m. - 10 p.m. Weekdays | 8 p.m. - 10 p.m. Weekdays |
| Off-Peak | 10 p.m. - 6 a.m. Weekdays | 10 p.m. - 6 a.m. Weekdays |
| | Plus Weekends & Holidays | Plus Weekends & Holidays |

D

Where the billing month contains time from both April and May or October and November, the on-peak period demand charges will be based on the demands registered in each month, weighted by the number of days billed in each month. Energy will be billed on the basis of the time period and season in which the usage occurred.

Non-Standard Seasonal Changeover
Customers may select on an optional basis to start the summer billing period on the first Monday of May and to start the winter billing period on the first Monday of October. Customers electing this option will be charged an additional $100 per year for metering equipment and programming.

Franchise Fee Differential
A Franchise Fee Differential of 5.78% will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits of the City of San Diego. Such Franchise Fee Differential shall be so indicated and added as a separate item to bills rendered to such customers.

(Continued)

# SCHEDULE DG-R

## DISTRIBUTED GENERATION RENEWABLE - TIME METERED

SPECIAL CONDITIONS

1. Definitions: The Definitions of terms used in this schedule are found either herein or in Rule 1.

2. Voltage: Service under this schedule normally will be supplied at a standard available Voltage in accordance with Rule 2.

3. Voltage Regulators: Voltage Regulators, if required by the customer, shall be furnished, installed, owned, and maintained by the customer.

4. Reconnection Charge: Any customer resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

D

5. Maximum Demand Charge: The Maximum Demand Charge shall be based on the Maximum Monthly Demand. T

6. Peak Annual Load: The Peak Annual Load shall be determined based on the customer's Maximum Annual Demand or, as applicable, the highest sum resulting from the recorded demand on the billing meter plus the recorded output on the Generator Output Meter(s), during the same 15-minute interval for the current and prior eleven months. T

7. Generator Output Meter: A Utility-owned meter(s) that registers the net output of an electric generator on the customer's property. T

8. Power Factor: The Power Factor rate shall apply to those customers that have a Power Factor Test Failure and will be based on the Maximum Kilovar billing demand. Those customers that have a Power Factor Test Failure will be required to pay for the Power Factor Metering that the utility will install. T

9. Parallel Generation Limitation. This schedule is not applicable to standby, auxiliary service or service operated in parallel with a customer's generating plant, except as specified in Rule 1 under the definition of Parallel Generation Limitation. T

(Continued)

# SCHEDULE DG-R



DISTRIBUTED GENERATION RENEWABLE - TIME METERED

SPECIAL CONDITIONS (Continued)

10. Terms of Optional Service. A customer receiving service under this schedule may elect to change to another applicable rate schedule. If a customer elects to discontinue service on this schedule, the customer will not be permitted to return to this schedule for a period of one year.

11. Basic Service Fee Determination. The basic service fee will be determined each month based on the customer's Maximum Annual Demand.

12. Transmission Multiple Bus Basic Service Fee. This fee shall apply where a customer has at their option elected to be billed at this rate and is limited to where the customer is delivering power and taking service at one or more than one transmission service level bus even if at two or more different voltage levels, for service to a generation facility that is located on a single premise owned or operated by the customer. In such a case, the Utility shall, for the purposes of applying retail rates, combine by subtracting any generation delivered from any loads served provided, however, that for purposes of applying retail rates the difference resulting from this combining may not be less than zero. All other charges on this tariff shall also apply to the resulting combined loads.

    Any customer selecting this optional billing no later than six (6) months from the first effective date of this new rate shall, for billing purposes, have any previously incurred demand ratchet treated as a "zero" from the effective date of the change in billing forward. In addition, any standby charges shall be adjusted to the customer's contract level from the effective date of the change in billing forward until the customer's demand triggers a future change.

13. Billing. A customer's bill is first calculated according to the total rates and conditions listed above. The following adjustments are made depending on the option applicable to the customer:

    a. **UDC Bundled Service Customers** receive supply and delivery services solely from the Utility. The customer's bill is based on the Total Rates set forth above. The EECC component is determined by multiplying the applicable EECC price for this schedule during the last month by the customer's total usage. T

    b. **Direct Access (DA) and Community Choice Aggregation (CCA) Customers** purchase energy from a non-utility provider and continue to receive delivery services from the Utility. The bills for a DA and CCA Customer will be calculated as if they were a UDC Bundled Service Customer, then crediting the bill by the amount of the EECC component, as determined for a UDC Bundled Customer, and including the appropriate Cost Responsibility Surcharge (CRS) if applicable.

    Nothing in this service schedule prohibits a marketer or broker from negotiating with customers the method by which their customer will pay the CTC charge.

(Continued)

# SCHEDULE DG-R



DISTRIBUTED GENERATION RENEWABLE - TIME METERED

SPECIAL CONDITIONS (Continued)

14. Electric Emergency Load Curtailment Plan: As set forth in CPUC Decision 01-04-006, all transmission level customers except essential use customers, OBMC 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 curtailment block so that the customer does not escape curtailment. If the transmission level customer fails to cooperate and drop load at SDG&E's request, automatic equipment controlled by SDG&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 SDG&E, but approval may not be unreasonably withheld. T

15. Other Applicable Tariffs: Rules 21, 23 and Schedule E-Depart apply to customers with generators. T

16. Net Energy Metering. Eligible customers receiving service under Schedule NEM, Schedule NEM-BIO, or Schedule NEM-FC shall not be precluded from receiving service in combination with service provided under this schedule. T

17. As determined annually and on a total energy input basis, a facility utilizing gas derived from biomass, digester gas, or landfill gas shall not use more than 25 percent fossil fuel. T

# Attachment 4. Public Service Company of Colorado Secondary Photovoltaic Time-of-Use Service

(alternative rate schedule to General Service)

ELECTRIC RATES

SECONDARY PHOTOVOLTAIC TIME-OF-USE SERVICE

SCHEDULE SPVTOU – SECTION B

| | RATE |
|---|---|
| **MONTHLY RATE** | |
| Service and Facility Charge: | $ 34.40 |
| Production Meter Charge: | 9.30 |
| Demand Charge: | |
| All Kilowatts of Billing Demand, per kW | |
| Distribution Demand | 5.63 |
| Generation and Transmission Demand – Summer Season | 4.11 |
| Generation and Transmission Demand – Winter Season | 2.33 |
| Energy Charge: | |
| On-peak Energy Charge | |
| All Kilowatt-Hours of On-peak energy, per kWh | 0.10307 |
| Off-peak Energy Charge | |
| All Kilowatt-Hours of Off-peak energy, per kWh | 0.01824 |

## DEFINITION OF SEASONS

### Summer Season

The Summer Season shall be from June 1 through September 30.

### Winter Season

The Winter Season shall be from October 1 through May 31.

## MONTHLY MINIMUM

The Service and Facility Charge plus the Demand Charge, plus the Production Meter Charge if applicable.

## ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this Electric Tariff. Customer shall be billed the Time-of-Use Electric Commodity Adjustment (ECA) for Secondary Voltage.

## PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fourteen (14) business days from date of bill. A business day for purposes under this Payment and Late Payment Charge section is all non-Holiday weekdays. Any amounts in excess of fifty dollars ($50.00) not paid on or before three (3) business days after the due date of the bill shall be subject to a late payment charge of one and one half percent (1.5%) per Month.

(Continued on Sheet No. 49E)

ELECTRIC RATES | RATE

## SECONDARY PHOTOVOLTAIC TIME-OF-USE SERVICE

### SCHEDULE SPVTOU – SECTION B

DETERMINATION OF BILLING DEMAND

Billing Demand, determined by meter measurement, shall be the maximum sixty (60) minute integrated Measured Demand used, net of Customer’s generation, during the Month, except as otherwise set forth in the Commercial and Industrial Rules and Regulations.

Billing Demand for the Generation and Transmission Demand Charge, shall be the Measured Demand used between 2:00 p.m. and 6:00 p.m. Mountain Time on all non-Holiday weekdays.

Billing Demand for the Distribution Demand Charge shall be the greater of: Measured Demand used during the Month, or fifty percent (50%) of the highest Measured Demand, net of Customer’s generation, occurring during the preceding (12) Months.

BILLING PERIOD

The On-peak and Off-peak periods applicable to service hereunder shall be as follows:

On-peak energy Period: Summer weekdays except Holidays, between 12:00 p.m. and 8:00 p.m. Mountain Time

Off-peak Period: All other hours of the Year.

SERVICE PERIOD

All service under this schedule shall be for a minimum period of twelve (12) consecutive Months and Monthly thereafter until terminated. If service is no longer required by Customer, service may be terminated on thirty (30) days’ notice. Greater minimum periods may be required by contract in situations involving large or unusual loads.

PRODUCTION METER INSTALLATION

The Company shall install, own, operate and maintain the metering to measure the electric power and energy supplied by the Customer’s generation to allow for proper billing of the Customer under this schedule. Applicability for the Production Meter Charge can be found under the Net Metering Service Schedule.

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company’s Rules and Regulations on file with the Commission.