ELECTRIC SCHEDULE B-19

Sheet 1

MEDIUM GENERAL DEMAND-METERED TOU SERVICE

1. APPLICABILITY: **Initial Assignment:** A customer must take service under Schedule B-19 if: (1) the customer's load does not meet the Schedule B-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 B-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 B-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).

Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. Schedules A-1, A-6, A-10, E-19 and E-20 will be retained as legacy rate schedules with their legacy TOU periods until the rates with new TOU periods (T) (Schedules B-1, B-6, B-10, B-19 and B-20) established in the same proceeding, become mandatory in March 2021. Certain qualifying customers with solar systems will be permitted to maintain their existing legacy TOU periods for a (T) certain period of time, per Decision 17-01-006, as described in the Electric Rule 1*, Definitions: Behind-the-Meter Solar Legacy TOU Period Eligibility Requirements. (T)

These new rates with revised TOU periods adopted in D.18-08-013 were available to qualifying customers on a voluntary opt-in basis from November 2019 through February 2021.

Customers eligible for this rate schedule must have an interval data meter that can be read remotely by PG&E. Beginning on March 2021, customers still served on Schedule E-19, with the exception of solar legacy TOU period customers (T) referenced above, will be transitioned to Schedule B-19. The transition notification and default process are further described in the legacy rate Schedule E-19.

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 SB—Standby Service Special Conditions 1 through 6 shall also apply to customers served under this schedule 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 SB, in addition to all applicable Schedule B-19 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Eligibility for Schedule B-19: 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 13. 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 B-19 service or to a different applicable rate schedule.

* The rules referred to in this schedule are part of PG&E's electric tariffs. Copies are available at PG&E's local offices and on the website at http://www.pge.com/tariffs.

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1. APPLICABILITY: (Cont'd.)

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 Mandatory Schedule B-19.

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 13 for the definition of maximum demand for customers voluntarily selecting B-19.

Option R for Standalone Storage: The Option R rate is available to qualifying (T)
customers taking Bundled, Direct Access (DA) or Community Choice Aggregation
(CCA) service under Schedule B-19, or voluntary B-19. Eligible customers (T)
system must have a minimum discharge capacity equal to or greater than 20 I
percent of the customer's annual peak demand, as recorded over the previous 12 I
months to be eligible for Option R. Discharge capacity for Option R will be (T)
calculated using the same method as that used for Option S. For additional Option R details and program specifics, see Sections 3 and 18.

Option R for Renewable Distributed Generation Technologies: The Option R (N)
rate is available to qualifying customers taking Bundled, DA or CCA service under I
Schedule B-19, or voluntary B-19. Eligible customers system with solar, wind, fuel I
cells or other eligible onsite renewable distributed generation technologies as I
defined by the California Solar Initiative program (CSI) or Self Generation Incentive I
Program (SGIP), customers with behind-the-meter storage paired with such I
renewable distributed generation, and Permanent Load Shifting (PLS) I
technologies. Eligible renewable generation systems and PLS systems must have I
a net renewable generating capacity or load shift capacity equal to or greater than I
15 percent of the customer's annual peak demand, as recorded over the previous I
12 months. For additional Option R details and program specifics, including the I
participation cap, see Sections 3 and 18. (N)

Option S for Storage: The Option S rate for storage is available to qualifying customers taking Bundled, DA or CCA service under Schedule B-19 or voluntary B-19. Eligible customers must have storage systems with rated capacity in watts which is at least 10% of the customer's peak demand over the previous 12 months. Option S is available subject to an enrollment cap. For additional Option S details and program specifics see Sections 3 and 20.

Standby Demand: For customers served under this rate schedule and for whom Schedule SB—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.

(L)
(L)

(Continued)

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

1. APPLICABILITY: (Cont'd.)

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 SB Special Condition 1). (L)

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). (L)

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) 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.

Decision10-02-032, as modified by Decision 11-11-008, ordered that beginning November 1, 2014, eligible small and medium C&I customers (those with demands that are not equal to or greater than 200 kW 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 with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

Bundled service customers are eligible for PDP. Direct Access (DA) and Community Choice Aggregation (CCA) service customers are not eligible, including those DA customers on transitional bundled service (TBS). Customers on standby service (Schedule SB) whose premises are regularly supplied in full by electric energy from a nonutility source of supply, net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. Customers that take standby service whose premises are regularly supplied in part (but not in full) by electric energy from a nonutility source of supply are eligible for PDP on the non-standby portion of their service. In addition, master-metered customers are not eligible, except for commercial buildings with submetering as stated in PG&E Rule 1 and Rule 18.

For additional details and program specifics, see the Peak Day Pricing Details section below.

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

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ELECTRIC SCHEDULE B-19 Sheet 4
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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

TOTAL BUNDLED TIME-OF-USE RATES

	Secondary Voltage		Primary Voltage		Transmission Voltage	
Total Customer Charge Rates						
Customer Charge Mandatory B-19 ($ per meter per day)	$58.62824	(R)	$87.34546	(R)	$117.10726	(R)
Customer Charge Voluntary B-19 ($ per meter per day)	$11.36882	(R)	$11.36882	(R)	$11.36882	(R)
Total Demand Rates ($ per kW**)**						
Maximum Peak Demand Summer	$46.16	(R)	$37.89	(R)	$14.67	
Maximum Part-Peak Demand Summer	$10.52	(R)	$8.54	(R)	$3.67	
Maximum Demand Summer	$37.37	(R)	$29.11	(R)	$16.94	(R)
Maximum Peak Demand Winter	$2.31		$1.69		$1.41	
Maximum Demand Winter	$37.37	(R)	$29.11	(R)	$16.94	(R)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.18648	(I)	$0.16454	(I)	$0.14803	(I)
Part-Peak Summer	$0.14775	(I)	$0.13500	(I)	$0.13556	(I)
Off-Peak Summer	$0.12037	(I)	$0.10931	(I)	$0.10902	(I)
Peak Winter	$0.16188	(I)	$0.14737	(I)	$0.14719	(I)
Off-Peak Winter	$0.12026	(I)	$0.10963	(I)	$0.10961	(I)
Super Off-Peak Winter	$0.06442	(I)	$0.05594	(I)	$0.05433	(I)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	
PDP Rates						
PDP Charges ($ per kWh)						
All Usage During PDP Event	$0.90		$0.90		$0.90	
PDP Credits						
Demand ($ per kW)						
Peak Summer	($6.72)		($6.61)		($5.46)	
Part-Peak Summer	($0.98)		($0.97)		($1.37)	
Energy ($ per kWh)						
Peak Summer	$0.00000		$0.00000		$0.00000	
Part-Peak Summer	$0.00000		$0.00000		$0.00000	

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3. Rates:
(Cont'd.)

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.

UNBUNDLING OF TOTAL RATES

Customer Charge Rates: Customer 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	$19.46		$16.43		$14.67	
Maximum Part-Peak Demand Summer	$2.83		$2.41		$3.67	
Maximum Demand Summer	$0.00		$0.00		$0.00	
Maximum Peak-Demand Winter	$2.31		$1.69		$1.41	
Distribution:**						
Maximum Peak Demand Summer	$26.70	(R)	$21.46	(R)	$0.00	
Maximum Part-Peak Demand Summer	$7.69	(R)	$6.13	(R)	$0.00	
Maximum Demand Summer	$28.24	(R)	$19.98	(R)	$7.81	(R)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$28.24	(R)	$19.98	(R)	$7.81	(R)
Transmission Maximum Demand*	$9.10		$9.10		$9.10	
Reliability Services Maximum Demand*	$0.03		$0.03		$0.03	

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.
** Distribution and New System Generation Charges are combined for presentation on customer bills.

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ELECTRIC SCHEDULE B-19
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

3. Rates:
(Cont'd.)

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.

UNBUNDLING OF TOTAL RATES (Cont'd.)

Customer Charge Rates: Customer 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	$0.15495		$0.13518		$0.12217	
Part-Peak Summer	$0.11622		$0.10564		$0.10970	
Off-Peak Summer	$0.08884		$0.07995		$0.08316	
Peak Winter	$0.13035		$0.11801		$0.12133	
Off-Peak Winter	$0.08873		$0.08027		$0.08375	
Super Off-Peak Winter	$0.03289		$0.02658		$0.02847	
Distribution:						
Peak Summer	($0.00297)	(R)	($0.00266)	(R)	($0.00222)	(R)
Part-Peak Summer	($0.00297)	(R)	($0.00266)	(R)	($0.00222)	(R)
Off-Peak Summer	($0.00297)	(R)	($0.00266)	(R)	($0.00222)	(R)
Peak Winter	($0.00297)	(R)	($0.00266)	(R)	($0.00222)	(R)
Off-Peak Winter	($0.00297)	(R)	($0.00266)	(R)	($0.00222)	(R)
Super Off-Peak Winter	($0.00297)	(R)	($0.00266)	(R)	($0.00222)	(R)

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ELECTRIC SCHEDULE B-19 Sheet 7
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	
Transmission Rate Adjustments* (all usage)	$0.00470	(I)	$0.00470	(I)	$0.00470	(I)
Public Purpose Programs (all usage)	$0.02590	(I)	$0.02373	(I)	$0.02023	(I)
Nuclear Decommissioning (all usage)	($0.00002)		($0.00002)		($0.00002)	
Competition Transition Charge (all usage)	$0.00027		$0.00027		$0.00027	
Energy Cost Recovery Amount (all usage)	$0.00002		$0.00002		$0.00002	
Wildfire Fund Charge (all usage)	$0.00591		$0.00591		$0.00591	
New System Generation Charge (all usage)**	$0.00462		$0.00462		$0.00462	
California Climate Credit (all usage – B-19V only)***	$0.00000		$0.00000		$0.00000	
Wildfire Hardening Charge (all usage)	$0.00297	(I)	$0.00266	(I)	$0.00222	(I)
Recovery Bond Charge (all usage)	$0.00857	(I)	$0.00857	(I)	$0.00857	(I)
Recovery Bond Credit (all usage)	($0.00857)	(R)	($0.00857)	(R)	($0.00857)	(R)
Bundled Power Charge Indifference Adjustment (all usage)****	($0.00987)		($0.00987)		($0.00987)	

* 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.
**** Direct Access, Community Choice Aggregation and Transitional Bundled Service Customers pay the applicable Vintaged Power Charge Indifference Adjustment. Generation and Bundled PCIA are combined for presentation on bundled customer bills.

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ELECTRIC SCHEDULE B-19 Sheet 8
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

3. Rates:
(Cont'd.)

Total bundled service charges are calculated using the total rates shown below. DA and CCA charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

TOTAL BUNDLED TIME-OF-USE RATES FOR OPTION R
(for qualifying solar customers as set forth in Section 18)

Total Customer Charge Rates	Secondary Voltage		Primary Voltage		Transmission Voltage	
Customer Charge Mandatory B-19 ($ per meter per day)	$58.62824	(R)	$87.34546	(R)	$117.10726	(R)
Customer Charge Voluntary B-19:	$11.36882	(R)	$11.36882	(R)	$11.36882	(R)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$6.50	(R)	$5.20	(R)	$0.00	
Maximum Part-Peak Demand Summer	$1.87	(R)	$1.49	(R)	$0.00	
Maximum Demand Summer	$36.61	(R)	$28.43	(R)	$16.26	(R)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$36.61	(R)	$28.43	(R)	$16.26	(R)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.43568	(R)	$0.39207	(R)	$0.24804	(I)
Part-Peak Summer	$0.25184	(R)	$0.21733	(R)	$0.16654	(I)
Off-Peak Summer	$0.19137	(R)	$0.16028	(R)	$0.12439	(I)
Peak Winter	$0.18276	(I)	$0.16296	(I)	$0.15828	(I)
Off-Peak Winter	$0.14044	(I)	$0.12531	(I)	$0.12460	(I)
Super Off-Peak Winter	$0.10462	(I)	$0.08949	(I)	$0.08878	(I)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

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3. Rates:
(Cont'd.)

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below.

UNBUNDLING OF TOTAL RATES FOR OPTION R
(for qualifying solar customers as set forth in Section 18)

Customer Charge Rates: Customer 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
Distribution:**			
Maximum Peak Demand Summer	$6.50 (R)	$5.20 (R)	$0.00
Maximum Part-Peak Demand Summer	$1.87 (R)	$1.49 (R)	$0.00
Maximum Demand Summer	$27.48 (R)	$19.30 (R)	$7.13 (R)
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$27.48 (R)	$19.30 (R)	$7.13 (R)
Transmission Maximum Demand*	$9.10	$9.10	$9.10
Reliability Services Maximum Demand*	$0.03	$0.03	$0.03

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.
** Distribution and New System Generation Charges are combined for presentation on customer bills.

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3. Rates:
(Cont'd.)
Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below.

UNBUNDLING OF TOTAL RATES FOR OPTION R (Cont'd.)
(for qualifying solar customers as set forth in Section 18)

Customer Charge Rates: Customer 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	$0.28009		$0.25211		$0.21996	
Part-Peak Summer	$0.14452		$0.12857		$0.13846	
Off-Peak Summer	$0.10601		$0.09318		$0.09631	
Peak Winter	$0.14826		$0.13094		$0.13020	
Off-Peak Winter	$0.10594		$0.09329		$0.09652	
Super Off-Peak Winter	$0.07012		$0.05747		$0.06070	
Distribution:**						
Peak Summer	$0.12109	(R)	$0.10794	(R)	$0.00000	
Part-Peak Summer	$0.07282	(R)	$0.05674	(R)	$0.00000	
Off-Peak Summer	$0.05086	(R)	$0.03508	(R)	$0.00000	
Peak Winter	$0.00000		$0.00000		$0.00000	
Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Super Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Transmission Rate Adjustments* (all usage)	$0.00470	(I)	$0.00470	(I)	$0.00470	(I)
Public Purpose Programs (all usage)	$0.02590	(I)	$0.02373	(I)	$0.02023	(I)
Nuclear Decommissioning (all usage)	($0.00002)		($0.00002)		($0.00002)	
Competition Transition Charge (all usage)	$0.00027		$0.00027		$0.00027	
Energy Cost Recovery Amount (all usage)	$0.00002		$0.00002		$0.00002	
Wildfire Fund Charge (all usage)	$0.00591		$0.00591		$0.00591	
New System Generation Charge (all usage)**	$0.00462		$0.00462		$0.00462	
California Climate Credit (all usage – B-19V only)***	$0.00000		$0.00000		$0.00000	
Wildfire Hardening Charge (all usage)	$0.00297	(I)	$0.00266	(I)	$0.00222	(I)
Recovery Bond Charge (all usage)	$0.00857	(I)	$0.00857	(I)	$0.00857	(I)
Recovery Bond Credit (all usage)	($0.00857)	(R)	($0.00857)	(R)	($0.00857)	(R)
Bundled Power Charge Indifference Adjustment (all usage)****	($0.00987)		($0.00987)		($0.00987)	

* 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.
**** Direct Access, Community Choice Aggregation and Transitional Bundled Service Customers pay the applicable Vintaged Power Charge Indifference Adjustment. Generation and Bundled PCIA are combined for presentation on bundled customer bills.

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3. Rates:
(Cont'd.)

Total bundled service charges are calculated using the total rates shown below. DA and CCA charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

TOTAL BUNDLED TIME-OF-USE RATES FOR OPTION S
(for qualifying storage customers as set forth in Section 20)

Total Customer Charge Rates	Secondary Voltage		Primary Voltage		Transmission Voltage	
Customer Charge Mandatory B-19 ($ per meter per day)	$58.62824	(R)	$87.34546	(R)	$117.10726	(R)
Customer Charge Voluntary B-19:	$11.36882	(R)	$11.36882	(R)	$11.36882	(R)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer (per day)	$1.60	(R)	$1.07	(R)	$0.36	(R)
Maximum Part-Peak Demand Summer (per day)	$0.08	(R)	$0.07			
Maximum Demand Summer (per monthly billing, all hours except 9 am to 2 pm)	$6.35	(R)	$3.95	(R)	$1.40	(R)
Maximum Demand Summer (per monthly billing)	$9.13		$9.13		$9.13	
Maximum Peak Demand Winter (per day)	$1.22	(R)	$0.79	(R)	$0.36	(R)
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$6.35	(R)	$3.95	(R)	$1.40	(R)
Maximum Demand Winter (per monthly billing)	$9.13		$9.13		$9.13	
Total Energy Rates ($ per kWh)						
Peak Summer	$0.43568	(R)	$0.39207	(R)	$0.24804	(I)
Part-Peak Summer	$0.25184	(R)	$0.21733	(R)	$0.16654	(I)
Off-Peak Summer	$0.19137	(R)	$0.16028	(R)	$0.12439	(I)
Peak Winter	$0.18276	(I)	$0.16296	(I)	$0.15828	(I)
Off-Peak Winter	$0.14044	(I)	$0.12531	(I)	$0.12460	(I)
Super Off-Peak Winter	$0.10462	(I)	$0.08949	(I)	$0.08878	(I)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

(Continued)

3. Rates:
   (Cont'd.)

   Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below.

   UNBUNDLING OF TOTAL RATES FOR OPTION S
   (for qualifying storage customers as set forth in Section 20)

   Customer Charge Rates: Customer 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
Distribution:**			
Maximum Peak Demand Summer (per day)	$1.60 (R)	$1.07 (R)	$0.36 (R)
Maximum Part-Peak Demand Summer (per day)	$0.08 (R)	$0.07	
Maximum Demand Summer (per monthly billing, all hours except 9 am to 2 pm)	$6.35 (R)	$3.95 (R)	$1.40 (R)
Maximum Demand Summer (per monthly billing)	$0.00	$0.00	$0.00
Maximum Peak Demand Winter (per day)	$1.22 (R)	$0.79 (R)	$0.36 (R)
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$6.35 (R)	$3.95 (R)	$1.40 (R)
Maximum Demand Winter (per monthly billing)	$0.00	$0.00	$0.00
Transmission Maximum Demand*	9.10	$9.10	$9.10
Reliability Services Maximum Demand*	0.03	0.03	$0.03

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ELECTRIC SCHEDULE B-19 Sheet 13
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

3. Rates:
(Cont'd.)

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below.

UNBUNDLING OF TOTAL RATES FOR OPTION S (Cont'd.)
(for qualifying storage customers as set forth in Section 20)

Customer Charge Rates: Customer 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	$0.28009		$0.25211		$0.21996	
Part-Peak Summer	$0.14452		$0.12857		$0.13846	
Off-Peak Summer	$0.10601		$0.09318		$0.09631	
Peak Winter	$0.14826		$0.13094		$0.13020	
Off-Peak Winter	$0.10594		$0.09329		$0.09652	
Super Off-Peak Winter	$0.07012		$0.05747		$0.06070	
Distribution:**						
Peak Summer	$0.12109	(R)	$0.10794	(R)	$0.00000	
Part-Peak Summer	$0.07282	(R)	$0.05674	(R)	$0.00000	
Off-Peak Summer	$0.05086	(R)	$0.03508	(R)	$0.00000	
Peak Winter	$0.00000		$0.00000		$0.00000	
Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Super Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Transmission Rate Adjustments* (all usage)	$0.00470	(I)	$0.00470	(I)	$0.00470	(I)
Public Purpose Programs (all usage)	$0.02590	(I)	$0.02373	(I)	$0.02023	(I)
Nuclear Decommissioning (all usage)	($0.00002)		($0.00002)		($0.00002)	
Competition Transition Charge (all usage)	$0.00027		$0.00027		$0.00027	
Energy Cost Recovery Amount (all usage)	$0.00002		$0.00002		$0.00002	
Wildfire Fund Charge (all usage)	$0.00591		$0.00591		$0.00591	
New System Generation Charge (all usage)**	$0.00462		$0.00462		$0.00462	
California Climate Credit (all usage – B-19V only)***	$0.00000		$0.00000		$0.00000	
Wildfire Hardening Charge (all usage)	$0.00297	(I)	$0.00266	(I)	$0.00222	(I)
Recovery Bond Charge (all usage)	$0.00857	(I)	$0.00857	(I)	$0.00857	(I)
Recovery Bond Credit (all usage)	($0.00857)	(R)	($0.00857)	(R)	($0.00857)	(R)
Bundled Power Charge Indifference Adjustment (all usage)****	($0.00987)		($0.00987)		($0.00987)	

* 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.
**** Direct Access, Community Choice Aggregation and Transitional Bundled Service Customers pay the applicable Vintaged Power Charge Indifference Adjustment. Generation and Bundled PCIA are combined for presentation on bundled customer bills.

(Continued)

3. Rates: (Cont'd.)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule B-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 <u>all</u> of these demand charges. Option S includes variations of these basic demand charge types assessed on a (1) daily basis by time period and (2) maximum monthly basis applied to all hours except 9 am to 2 pm. (Time periods are defined in Section 6.)

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

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

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

4. METERING REQUIRE-MENTS:

An interval data meter that measures and registers the amount of electricity a customer uses and can be read remotely by PG&E is required for all customers on this schedule.

For customers taking service under the provisions of Direct Access, see Electric Rule 22 for metering requirements. (L)

(Continued)

ELECTRIC SCHEDULE B-19 Sheet 15
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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

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

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

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

6. DEFINITION OF TIME PERIODS: Times of the year and times of the day are defined as follows:

SUMMER (Service from June 1 through September 30):

Peak:	4:00 p.m. to 9:00 p.m.	Every day, including weekends and holidays
Partial-peak:	2:00 p.m. to 4:00 pm AND 9:00 p.m. to 11:00 p.m.	Every day, including weekends and holidays
Off-peak:	All other Hours.	

WINTER (Service from October 1 through May 31):

Peak:	4:00 p.m. to 9:00 p.m.	Every day, including weekends and holidays
Super Off-Peak	9:00 a.m. to 2:00 p.m.	Every day in March, April and May, including weekends and holidays
Off-peak:	All other Hours.	

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. (L)

(Continued)

7. POWER FACTOR ADJUSTMENTS: Bills will be adjusted based on the power factor for all customers except those selecting voluntary B-19 service. The power factor is computed from a trigonometric function of the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent. (L)

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

Power factor adjustments will be assigned to distribution for billing purposes.

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

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

(Continued)

11. COMMON-AREA ACCOUNTS: Common-area accounts are those accounts that provide electric service to Common Use Areas as defined in Rule 1. 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, had 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. These accounts remain eligible for service under this rate schedule if the customer did not invoke this first right of return. (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.

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.

12. VOLUNTARY SERVICE PROVISIONS: Customers voluntarily taking service on Schedule B-19 (see Applicability Section) shall be governed by all the terms and conditions shown in Sections 1 through 12, unless different terms and conditions are shown below.

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

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

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

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

(Continued)

13. BILLING: A customer's bill is calculated based on the option applicable to the customer.

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

Transitional Bundled Service (TBS) Customers take TBS as prescribed in Rules 22.1 and 23.1, or take PG&E bundled service prior to the end of the six (6) month advance notice period required to elect PG&E bundled service as prescribed in Rules 22.1 and 23.1. TBS customers shall pay all charges shown in the Unbundling of Total Rates except for the Bundled Power Charge Indifference Adjustment and the generation charge. TBS customers shall also pay for their applicable Vintaged Power Charge Indifference Adjustment provided in the table below, and the short-term commodity prices as set forth in Schedule TBCC.

Direct Access (DA) and Community Choice Aggregation (CCA) Generation Service Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. These customers shall pay all charges shown in the Unbundling of Total Rates except for the Bundled Power Charge Indifference Adjustment and the generation charge. These customers shall also pay for their applicable Vintaged Power Charge Indifference Adjustment provided in the table below, the franchise fee surcharge provided in Schedule E-FFS, and the Generation Service from their non-utility provider. Exemptions to charges for DA and CCA customers are set forth in Schedules DA CRS and CCA CRS.

Vintaged Power Charge Indifference Adjustment (per kWh)	Rate	
2009 Vintage	$0.02903	(I)
2010 Vintage	$0.03286	(I)
2011 Vintage	$0.03410	(I)
2012 Vintage	$0.03589	(I)
2013 Vintage	$0.03620	(I)
2014 Vintage	$0.03599	(I)
2015 Vintage	$0.03593	(I)
2016 Vintage	$0.03600	(I)
2017 Vintage	$0.03574	(I)
2018 Vintage	$0.03592	(I)
2019 Vintage	$0.03637	(I)
2020 Vintage	$0.03546	(I)
2021 Vintage	$0.05140	(I)
2022 Vintage	$0.05147	(I)
2023 Vintage	$0.05253	(I)
2024 Vintage	$0.04946	(I)
2025 Vintage	($0.00987)	(I)
2026 Vintage	($0.00987)	(N)

(Continued)

ELECTRIC SCHEDULE B-19 Sheet 19
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

14.	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 Wildfire Fund Charge rate component, Recovery Bond Charge, Recovery Bond Credit, and the CARE surcharge portion of the public purpose program charge.	(L)
15.	ELECTRIC EMERGENCY PLAN ROTATING BLOCK OUTAGES	See Electric Rule 14.	
16.	STANDBY APPLICA-BILITY:	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.	
17.	WILDFIRE FUND CHARGE:	The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.	(L)

(Continued)

18. Option R

The Option R rate is available to qualifying customers with eligible technologies as described in the applicability section of this tariff. Across all applicable rate schedules, Option R participation is capped at 600 MW of generating or storage discharge capacity. Eligible Permanent Load Shift (PLS) technologies are not subject to this cap. (L)

For eligible stand-alone storage, the qualifying capacity counted towards the Option R cap is the discharge capacity of the storage system or systems, calculating using the same method as is used for Option S.

For eligible renewable technologies, the qualifying capacity counted towards the Option R participation cap is based on net renewable generating capacity (i.e., the amount of power actually delivered by the generator or generators net of any losses such as auxiliary loads, thermal management loads, etc.).

For paired storage systems, the qualifying capacity counted towards the Option R cap is the larger of the system's California Energy Commission (CEC) alternating current (AC) solar capacity or the discharge capacity of the storage system calculated using the same method as that used for Option S (but not both). No Benefitting* or Aggregated* account is eligible for Option R unless there is an eligible technology interconnected at that account that independently meets the Option R minimum size requirements relative to peak load, as described in the applicability section of this tariff.

* Benefiting and Aggregated accounts are defined in rate schedules that allows for such accounts for example, NEM2, RES-BCT and other tariffs. (L)

(Continued)

19. OPTIMAL BILLING PERIOD SERVICE: The Optimal Billing Period (OBP) service is a voluntary program available to bundled, direct access and community choice aggregation customers taking service on Schedule B-19 or Schedule B-20. To qualify, a meter must have registered a demand of 500 kW or greater at least once during the most recent 12 months. The OBP service is limited to 50 service accounts with interval billed meters. (L)

Customers electing this service must complete the “Optimal Billing Period Service Election Form” (Form 79-1111).

Decision 18-08-013 expanded the eligibility of OBP to Schedule B-19 (above 500 kW as defined above), Schedule B-20, and to direct access and community choice aggregation customers taking service on eligible schedules. Decision 18-08-013 retained the participation cap of 50 positions, and reserved 36 positions for agricultural accounts, and 14 positions for commercial and industrial accounts. Before declining participation of any otherwise eligible account based on these participation limits, PG&E will verify that all other enrolled accounts are still eligible for the program.

Customers on net energy metering Schedules VNEM, NEMBIO, NEMFC, NEMCCSF, NEMA or RES-BCT are not eligible for OBP service.

The OBP service allows a billing cycle(s) to coincide with the customer’s high seasonal production cycle. The customer designates the OBP by selecting one or both of the following:

a) a specific month and day for the start of the OBP; and/or

b) a specific month and day for the end of the OBP.

PG&E will use the customer’s usage from the preceding twelve (12) billing months to determine eligibility for the OBP service. To qualify, the average of the previous high season monthly maximum demand must be at least double the average of the low season monthly maximum demand. The customer must also specify which six consecutive months will be their high season optimal billing period.

The start and end dates must fall within the customer’s high seasonal production cycle. In no event shall any revised billing period exceed forty-five (45) days or be less than fifteen (15) days. To qualify for this option, the customer must designate an OBP of not more than six (6) months in duration.

To designate the specific date for the start or end of the OBP, a participating customer must email PG&E at least seventy-two (72) hours in advance and such email shall state in its subject line “OBP Notification.” The designation may not be implemented if it is not received or if it does not contain the specified information. (L)

(Continued)

ELECTRIC SCHEDULE B-19
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

19. OPTIMAL BILLING PERIOD SERVICE: (Cont'd.)

Prior to receiving OBP service, the customer must pay an annual OBP fee of $160.00 per meter. In order to retain the OBP service option in each subsequent year, the annual participation fee must be received by PG&E by the anniversary date of the contract. PG&E will bill the annual OBP fee upon the anniversary date of the contract unless the customer terminates the contract. For billing purposes, the annual participation fee shall be assigned to Distribution. (L)

A. No Retroactive Application

No customer shall be entitled to a refund associated with the OBP service for costs that might have been avoided had the service been available at an earlier point in time.

B. Customer Notification to PG&E

A customer must have at least 12 months of usage on a specific meter before the OBP service can be received on that particular meter. Also, a customer must provide notice to PG&E of their intention to obtain OBP service at least ninety (90) days before the start of the program. (L)

(Continued)

20. OPTION S

The Option S rate for storage is available to qualifying customers taking Bundled, DA or CCA service under Schedule B-19 or voluntary B-19. Eligible customers must have storage systems with rated capacity in watts which is at least 10% of the customer's peak demand over the previous 12 months. Customers do not need to participate in the Self Generation Incentive Program to participate in this program. (L)

The cap for Option S enrollment will be considered reached when the MW value hits 50 MW per rate schedule, separately for B-19V, B-19 and B-20.

For purposes of determining eligibility for Option S, the usage of the customer over the previous 12 months will be determined by the max demand. Storage rated capacity will be determined by PTO agreement.

When a customer first moves to a location with installed storage, the minimum 30 days of usage history required to evaluate whether the battery capacity is at least 10% of the customer's peak demand will not yet be available. Thus, qualifying customers starting a B19 Service Agreement at a new location will not be on Option S on day 1 of their new SA activation.

The rated capacity (W) for energy storage technologies is calculated as follows:

- DC/AC systems: The nominal voltage multiplied by the amp-hour capacity multiplied by the applicable efficiency divided by the duration of discharge ((VDC x Amp-Hours x (1 kW/1000W) x Applicable Efficiency) / Duration of Discharge).
  - The following specifications must be provided to calculate rated capacity:
    - Duration of discharge (hours)
    - DC dischargeable amp-hour capacity, associated with the duration of discharge specified, including all losses and ancillary loads (such as power conditioning and thermal management)
    - Nominal voltage (VDC)
    - Applicable efficiency (if necessary), which accounts for conversion, transformation, or other efficiency losses (e.g. Inverter CEC weighted efficiency, DC-DC converter efficiency, etc.) systems, this is rated in DC, and for AC systems, this is rated in AC.
    - The continuous maximum power output capability of the system. For DC systems, this is rated in DC, and for AC systems, this is rated in AC.

The following are not eligible for Option S:

- 100% Standby customers
- SAs enrolled in Option R are not eligible for Option S and vice versa
- SAs on Virtual NEM, NEM Aggregation, NEMBIO, NEMFC, RES-BCT
- Customers with EMR meters

Note: PG&E expects to be able to allow customers to take service on Schedule E-BIP with Option S by March 31, 2020.

PG&E will provide on PGE.com monthly reporting of the Option S enrollment MWs broken out by rate schedules as well as for eligible interconnected projects that could sign up for Option S, broken up by eligible rates.
(L)

(Continued)

21. 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 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. (L)

In March 2022, customers who are enrolled in the version of PDP with 5:00 p.m. – 8:00 p.m. PDP Event Hours (5 to 8 PDP) will be transitioned to a new version of PDP with 4:00 p.m. – 9:00 p.m. PDP Event Hours (4 to 9 PDP).

Starting in March 2022, 5 to 8 PDP will be discontinued, and 4 to 9 PDP will be available only on the new rates with later TOU hours.

Pursuant to a modification granted by the CPUC Executive Director by letter dated June 14, 2021, PG&E was allowed an extension to March 2022 to default eligible non-residential and non-agricultural customers to PDP rate plans as required by Ordering Paragraph 1 of D.10-02-032 and Ordering Paragraph 1(d) of D.11-11-008.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for default to PDP and to opt-in to 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 section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

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 (June 1 through September 30). 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. If a customer fails to elect an initial CRL, the customer's initial CRL will be set at 50% of its most recent full summer season 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). A customer may only elect to change their CRL once every 12-months. (L)

(Continued)

21. PEAK DAY PRICING DETAILS (Cont'd.):

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.

Active 5 to 8 PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to 4 to 9 PDP in their March 2022 billing cycle will seamlessly continue with their bill stabilization under 4 to 9 PDP until 12-months have elapsed since their initial enrollment in 5 to 8 PDP, or until they optionally unenroll from 4 to 9 PDP before 12-months.

5 to 8 PDP customers who have already received 12-months of bill stabilization, will not receive bill stabilization for a second time when they are transitioned to 4 to 9 PDP.

d. **Notification Equipment**: At the customer's option and expense, it is recommended, but not required that a customer provide a phone number or an e-mail address to receive automated voice, text, or email notification messages of a PDP event from PG&E.

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 receive such notice and to check the PG&E website to see if a PDP event has been activated. It is also the customer's responsibility to maintain accurate notification contact information. PG&E does not guarantee the reliability of the phone, 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. **PG&E Website**: The customer's actual energy usage is available at PG&E's "Your Account" website. This data may not match billing quality data, and the customer understands and agrees that the data posted to PG&E's "Your Account" website may be different from the actual bill. (L)

(Continued)

21. PEAK DAY PRICING DETAILS (Cont'd.):

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 4:00 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. (L)

PG&E may conduct outreach/notification by any available channel (direct mail, phone call, email and/or text) for PDP customers.

g. **Event Cancellation or Reduction**: PG&E may initiate the cancellation of a PDP event before 5:00 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. PG&E may also cancel PDP events by 5:00 p.m. on a day-ahead basis or on the Event Day itself in response to an emergency situation, such as a proclamation of a state of emergency and/or disaster by a local, state and/or federal government.

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

Beginning June 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 on PG&E's PDP Website.

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

i. **Program Terms:** A customer may opt-out anytime during its 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**: Pursuant to D.18-11-029, customers on a PDP rate may no longer participate in another demand response program offered by PG&E or a third-party demand response provider as of October 26, 2018. If dual enrolled in BIP and PDP prior to October 26, 2018 then participation will be capped at the customer's subscribed megawatt level as of December 10, 2018. New dual enrollment in BIP and PDP as of October 26, 2018 is no longer available. 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. (L)