STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

February 10, 2021 PG&E Advice Letter 5861-E

Eric Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, California 94177

Subject: Staff Disposition of PG&E's AL 5861-E--Revisions to Peak Day Pricing Program for Commercial, Industrial and Agricultural Customers in Compliance with D.18-08-013.

Dear Mr. Jacobson:

On June 26, 2020 Pacific Gas and Electric Company (PG&E) submitted Advice Letter (AL) 5861-E, pursuant to Decision (D.) D.18-08-013**.**

PG&E's AL 5861-E is approved with an effective date of November 1, 2020 with one exception: PG&E's proposal to cease default enrollment of customers onto the Peak Day Pricing program and replace that process with an opt-in enrollment is inconsistent with the CPUC's direction set in prior decisions. Opt-in enrollment was not ordered by D.18-08-013 and is not appropriate for consideration in an advice letter filing. Hence, PG&E shall file a Tier 1 advice letter that corrects the tariff sheets that describe the termination of default PDP enrollment. PG&E may combine the ordered Tier 1 filing with its planned Tier 1 advice letter that updates rate values for the revenue neutral PDP credits to reflect 2021 sales adopted for implementation by the CPUC earlier this year.

Appendix 1 contains a detailed discussion of the AL and further explanation of the correction directed by Energy Division.

Please contact Paul Phillips of the Energy Division staff at paul.phillips@cpuc.ca.gov if you have any questions.

Sincerely,

FOR

Edward Randolph
Deputy Executive Director for Energy and Climate Policy/
Director, Energy Division
California Public Utilities Commission

<u>Appendix 1</u>:
Background and Disposition for
PG&E's AL 5861-E

Background
In AL 5861-E, PG&E set forth the proposed prices, terms, and conditions for its revised Peak Day Pricing (PDP) program for Commercial and Industrial (C&I) and Agricultural customers.

The key feature of AL 5861-E is a change in the timing of the Peak Day Pricing event hours to 5 – 8 pm (currently, PDP event hours have been 2 – 6 pm). D.18-08-013 directed that PDP event hours shall be changed to 5 – 8 pm by March 2021 in concert with new time-of-use that go into effect. AL 5861-E also contains various administrative changes to the operation of PDP such as notification of participants when a PDP event will be called (moving from 2 pm the day prior to the event, to 4 pm the day prior, and the discontinuance of the use of FAX to notify customers of events).

PG&E also proposes to discontinue default enrollment of all C&I customers on to Peak Day Pricing rates, noting that customers on this rate have not demonstrated significant load reductions. PG&E states that moving to a voluntary enrollment process (or opt-in) will result in better overall performance of the program.

The rates in the AL filing are pro forma and are described by PG&E to be illustrative based on 2020 forecasted sales. PG&E states it will file a separate Tier 1 advice letter or a supplement to AL 5861-E closer to the March 1, 2021 effective date with updated rate values for the revenue neutral PDP credits if 2021 sales are adopted for implementation by the Commission on or prior to March 1, 2021

There have been no protests filed on AL 5861-E.

PG&E's Tier 3 Designation
PG&E designated AL 5861-E as Tier 3 advice letter, noting that such a designation was part of a settlement adopted in D.18-08-013. Energy Division appreciates the filing designation but in this case is electing to process the advice letter as a Tier 2 filing through industry disposition to ensure that the proposed change to the PDP event window is implemented by March 2021 as directed by the CPUC. Rule 7.6.1 of GO 96-B states that the utility's tier designation for an advice letter is "not binding on the reviewing Industry Division." Additionally, the same rule states:

> An advice letter is subject to disposition by the reviewing Industry Division whenever such disposition would be a "ministerial" act, as that term is used regarding advice letter review and disposition. (See Decision 02-02-049.) Industry Division disposition is appropriate where statutes or Commission orders have required the action proposed in the advice letter, or have authorized the action with sufficient specificity, that the Industry Division need only determine as a technical matter whether the proposed action is within the scope of what has already been authorized by statutes or Commission orders.

In this case, AL 5861-E's proposal to change PDP event hours to 5 – 8 pm by March 2021 complies with a past CPUC order. Its request to modify various administrative changes to the rate are ministerial in nature and thus can be appropriately approved by the Division through this disposition letter. PG&E's request to modify the enrollment process is not ministerial in nature and is addressed below.

PG&E's Request to Change PDP Enrollment from Default to Voluntary Opt-In
PG&E's request to modify the enrollment process for PDP from a default process (customers automatically placed on the rate) to a voluntary opt-in process was not directed in D.18-08-013 nor in any other recent Commission decision. The CPUC established several years ago that the PDP enrollment process for non-residential customers would be a default process.[1]

Requests to change CPUC policy should be handled through formal CPUC proceedings and are not appropriate for advice letter filings. As noted in Section 7.6.1 of GO 96-B, the industry division may "reject without prejudice an advice letter whose disposition would require an evidentiary hearing or otherwise require review in a formal proceeding." Energy Division hereby rejects PG&E's proposal to replace the default enrollment process with a voluntary opt-in process because consideration of that change requires review in a formal proceeding. While Energy Division could have rejected PG&E's entire advice letter filing per Section 7.6.1, it has determined such action would be unreasonable when the remainder of the filing is in compliance with a CPUC decision and a rejection of the entire filing at this time could delay the implementation of the new PDP event hours by March 2021.

PG&E is hereby directed to correct all affected tariff sheets in AL 5861-E that contain reference to a voluntary opt-in process. Such language should be removed and replaced with default enrollment process language. PG&E shall file the corrected tariff sheets via a Tier 1 advice letter.

[1] D.06-05-038 and D.08-07-045.

Pacific Gas and Electric Company®

Erik Jacobson
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

June 26, 2020

Advice 5861-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Revisions to Peak Day Pricing Program for Commercial, Industrial and Agricultural Customers in Compliance with D.18-08-013.**

Purpose

In this advice letter, Pacific Gas and Electric (PG&E) sets forth the proposed prices, terms and conditions for its revised Peak Day Pricing (PDP) program for Commercial and Industrial (C&I) and Agricultural customers. PG&E's proposed pro forma tariffs are provided in Attachment 1. PG&E requests approval of this Tier 3 advice letter by November 1, 2020, in order for PG&E to make the required billing system changes and to complete the necessary implementation planning required for the March 1, 2021 effective date.

Background

Decision (D.)18-08-013 – *Decision on Pacific Gas and Electric Company's Proposed Rate Designs and Related Issues*, in PG&E's 2017 General Rate Case Phase II proceeding (Application [A.]16-06-013), adopted rates with new Time-Of-Use (TOU) periods for C&I customers with a later peak period. Similarly, D.18-08-013, and subsequently D.19-05-010, *Decision Granting Petition for Modification and Adopting Settlement*, in PG&E's 2019 Rate Design Window (A.18-11-013), adopted rates with new TOU periods for Agricultural customers with a later peak period. D.18-08-013 also approved settlements[1] that set forth specific steps for PDP. Those settlements anticipated that the default of C&I customers

---

[1] The settlements approved by D.18-08-013 concerning new TOU periods and PDP for non-residential customers were: The Standby and Medium and Large Light and Power Rate Design Settlement Agreement, the Small Light and Power Rate Design Settlement Agreement and the Agricultural Rate Design Settlement Agreement.

to PDP would resume when the new C&I rates became mandatory in November 2020. However, PG&E requested, and the Commission subsequently approved, a four-month delay of the mandatory transition date for C&I to coincide with the mandatory transition date for Agriculture.[2] The steps that were outlined in the adopted settlement agreements with respect to PDP are laid out below, with the necessary revisions to reflect the change to the timing of the C&I mandatory TOU date to March 2021 and noting those steps that have already been taken.

- Suspend default of eligible customers to PDP for the period prior to the date when rates with new, later TOU periods become mandatory for C&I and for Agriculture (currently March 2021 for C&I and Agriculture). This step has been completed.

- Continue the existing PDP program ("Legacy PDP") on an opt in basis during the period prior to when the rates with new TOU time periods become mandatory (currently expected in March 2021). This step is in process; Legacy PDP is continuing on an opt-in basis.

- Ensure the PDP program with revised event hours ("New PDP") is available once the new AG and C&I TOU periods become mandatory: PG&E is required to file a Tier 3 advice letter in 2020 in time to gain Commission approval to establish new PDP rates. That Tier 3 advice letter must include revised pricing and PDP event hours that are the same hours adopted for the residential Smart Rate™ Program.[3] This step is in process and will be completed with the submission of this Advice Letter.

- Resume default of eligible customers to PDP beginning when the new TOU rates become mandatory following approval of a Tier 3 advice letter, provided approval occurs by November 1 of the prior year. PG&E requests approval as of November 1 of this year to provide adequate time for billing system changes and implementation. The November approval date is also consistent with the date that approval of the Tier 3 advice letter was required for

---

[2] The mandatory transition date to the new rates with later TOU hours was delayed by four months for C&I customers, from November 2020 to March 2021, pursuant to Commission approval on April 20, 2020, of Advice 5785-E, submitted March 20, 2020.

[3] Subsequently, in D.19-07-004 in the 2018 RDW, the Commission approved revised residential Smart Rate event hours of 5 p.m. to 8 p.m. (D.19-07-004, pp. 64-67, Conclusion of Law 49 to 51, OPs 20 to 21.)

Agricultural PDP for PDP default in the settlement agreement. This step is planned for March 2021.

- A change to the PDP period applicable to Non-Residential customers to 5 p.m. to 8 p.m., if such a period is adopted by the Commission in a different proceeding. This step is planned for March 2021.

Accordingly, in compliance with D.18-08-013, PG&E is submitting this Tier 3 advice letter to ensure that PDP with event hours of 5 p.m. to 8 p.m. is available to Non-Residential customers so that the revised program can be launched when the new TOU rates become mandatory in March of 2021.[4] [5]

As noted above, the New PDP would be available to customers in conjunction with the rates with new TOU periods once those rates become mandatory. Prior to that date, customers may elect to opt-in to the rates with the new TOU periods but will need to unenroll from Legacy PDP and will not be able to enroll in New PDP until March 2021.

Proposed PDP Terms and Conditions

PG&E proposes the following revisions to the Legacy PDP program for commercial and agricultural customers

Eligibility

Beginning in March 2021, New PDP will be available only to eligible non-residential customers on an available rate including: C&I customers otherwise served under Schedules B-1, B-6, B-10 as well as B-19 and B-20 without Option R or Option S, and Agricultural customers served under Schedules AG-A1, AG-A2, AG-B and AG-C.

Customers that remain on the rate schedules with old TOU periods after March 2021 (for example, solar TOU period grandfathered customers eligible for service under the

---

[4] The change of the mandatory transition date for C&I customers would be accompanied by a change in the date new PDP rates would be available to C&I customers, as outlined in Advice 5785-E which was approved by a letter dated April 20, 2020 from Executive Director. PG&E's proposals herein are consistent with the revised date to convert C&I customers to the new TOU rates on a mandatory basis. Under the revised timeframe, customers currently participating in PDP will have a seamless transition to the new PDP event hours beginning March 2021 for both C&I and Agricultural customers.

[5] PG&E is discussing the provisions of the 2017 Ag Settlement and the potential for a delay in the Agricultural mandatory transition to new TOU rates with the Agricultural settling parties. See p. 11 for further discussion.

old TOU periods, highly impacted bundled agricultural customers[6] or customers without a SmartMeter) will not be eligible for the New PDP program.

Implementation and Timing for PDP

As mentioned above, New PDP will be implemented by March 2021 so that customers can be automatically transitioned from Legacy to New PDP at the same time as they are defaulted into new TOU periods.[7] Customers will receive notification from PG&E at least 45 days before enrollment into the New PDP program and will be able to opt out of enrollment in New PDP. [8]

Conclusion of the Annual Recurring Automatic PDP Default Process

PG&E proposes that the Default Process for the annual automatic enrollment of customers into PDP for the first time[9] conclude as of March 2021 for all C&I and agricultural customers, while retaining the ability for customers to voluntarily enroll, for two primary reasons:

1. Small non-residential customers enrolled in PDP do not provide significant load reduction. The 2018 and 2019 "Statewide Load Impact California Non-residential Critical Peak Pricing Programs" reports, filed with the CPUC in April 2019 and 2020 respectively, showed that despite extensive outreach and education, small (<20kW) and medium ($20 \leq x < 200$ kW) sized customers contributed a negligible amount of load shedding as a result of their participation in the PDP program during 2017, 2018, and 2019.[10] The

---

[6] The availability of rates for grandfathered solar customers was addressed in the Settlement Agreement on TOU Rates for Grandfathered Agricultural Solar Customers and the Settlement Agreement on TOU Rates for Grandfathered Solar Customers (addressing Commercial and Industrial Customers) which were adopted by D.18-08-013. The availability of rates with old TOU periods for non-solar bundled Agricultural Customers was addressed in both D.18-08-013, the Agricultural Rate Design Settlement, and in D.19-05-010, the 2019 Rate Design Window Agricultural Rate Design Settlement (Application 18-11-013.)

[7] Schedules B-1, B-6, B-10, B-19 and B-20 without Option R or Option S, AG-A1, AG-A2, AG-B and AG-C

[8] D.10-02-032 and the 2012-2015 Time-varying Pricing Customer Outreach Plan discuss PDP customer notification.

[9] The process of annual default of new customers into PDP in November (C&I) and March (agricultural) has been described in D.10-02-032 and D.11-11-008, was started in 2010 for C&I and 2011 for Ag.

[10] On June 26, 2020, PG&E filed and served the April 1, 2020 Load Impact Executive Summary with corrected Appendices. The PDP program did not require correction in the Appendices.

measured load reduction values for these customers ranged from 0 to 0.3 kW per customer, corresponding to 0% to 1.3% load impact relative to reference load. In fact, even that small load shed amount dropped every year for medium customers while remaining at 0 kW for the small customer category. On the other hand, large customers (≥200kW), who often leverage technology that assists in load shedding practices, provided almost all the load reduction achieved during these three years (see Tables 1 and 2 below). This pattern could become even more pronounced with the change to later PDP event hours because the number of hours during the event window will be reduced from 4 to 3 hours, resulting in less time for load shedding.

In addition to not benefitting much from PDP, smaller businesses can be more susceptible to the impacts of external factors such as economic downturns or other unexpected developments. They also tend to have less leeway to focus on issues not essential to the survival of the business which may result in these customers remaining on the program, even when they are not able to make the necessary adjustments to produce load reductions and enjoy the resulting cost savings.[11]

2. Since the inception of the PDP program in 2010, PG&E has defaulted the majority of large customers[12] into PDP. In fact, as of June 2020, close to 85% of eligible large customers had either been defaulted to PDP or opted out of the program. In addition, of the approximately 45,000 remaining Service Agreements (SAs) that could be eligible to be defaulted to PDP for the first time in March 2021 (that is, those customers with at least 24 months on TOU that are likely to be eligible to default to PDP but who were not eligible for PDP default in prior years), over 37,000 (~83%) are on the A-1 rate schedule, which is designed for small commercial customers. Based on the 2018 and 2019 load impact reports referenced above, these are the customers who benefitted the least from PDP and provided negligible load shift. Replacing PDP default with optional enrollment will avoid enrollment of customers who are unable to modify their energy use patterns to benefit from PDP while encouraging those who are able to proactively change their energy use to realize savings.

[11] An example is the current difficult circumstances small/medium sized businesses find themselves in as a result of the COVID-19 pandemic. Similar events may occur again in the future and PG&E believes it would be wise to take this possibility into account and avoid creating additional distractions for these businesses, where little load reduction benefit is achieved.

[12] The process of annual default of new customers into PDP in November (C&I) and March (agricultural) has been described in D.10-02-032 and D.11-11-008.

Table 1: PG&E Non-Residential PDP: Previous and Current Ex-Post, Typical Event Day for 2018 and 2019

	Ex-Post Year	# of Accts	Aggregate (MW)		Per-Customer (kW)		% Impact	Event Temp (˚F)
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Large	2018	1,712	445.5	23.9	260.2	14.0	5.4%	93.1
	2019	1,246	472.1	13.7	378.9	11.0	2.9%	97.5
Medium	2018	34,014	750.0	4.9	22.0	0.1	0.3%	93.2
	2019	24,994	571.5	-0.1	22.9	0.0	0.0%	96.1
Small	2018	119,004	243.7	-0.1	2.0	0.0	0.0%	93.0
	2019	91,156	182.4	0.6	2.0	0.0	0.4%	95.2

Source:
2019 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs
Ex-Post and Ex-Ante Load Impacts
AEG Applied Energy Group

Table 2: PG&E Non-Residential PDP: Previous and Current Ex-Post, Typical Event Day for 2017 and 2018

	Ex-Post Year	# of Accts	Aggregate (MW)		Per-Customer (kW)		% Impact	Event Temp (˚F)
			Reference Load	Load Impact	Reference Load	Load Impact		
Large	2017	1,982	528.5	22.4	266.7	11.3	4.2%	92.3
	2018	1,712	445.5	23.9	260.2	14.0	5.4%	93.1
Medium	2017	45,177	988.6	12.5	21.9	0.3	1.3%	94.4
	2018	34,014	750.0	4.9	22.0	0.1	0.3%	93.2
Small	2017	158,006	329.7	2.5	2.1	0.0	0.7%	94.3
	2018	119,004	243.7	-0.1	2.0	0.0	0.0%	93.0

Source:
2018 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs
Ex-Post and Ex-Ante Load Impacts
AEG Applied Energy Group

Operating Provisions

Beginning in March 2021, when the new PDP program would go into effect concurrent with the mandatory default of customers to the rates with new TOU periods, the Legacy PDP program (with event hours from 2 pm to 6 pm) will be eliminated and PDP with new event hours (from 5 pm to 8 pm) will be offered only in conjunction with service on the rate schedules listed in the eligibility section above, with the following provisions for customers and bill stabilization:

1. Agricultural service agreements that are allowed to remain on their legacy rate until March 2022 will be unenrolled from Legacy PDP in March 2021. [13] They will also be notified that they will have the option of re-enrolling in New PDP after March 2022. This notification will be inserted in the communications that these customers will receive regarding their eligibility to remain on legacy rates until March 2022.

2. Bill Stabilization
   Active Legacy PDP customers who have not completed 12 months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will continue with their bill stabilization under New PDP until 12 months have elapsed since their initial enrollment in Legacy PDP, or until they unenroll from New PDP before 12 months. Legacy 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 the New PDP program.

Program Feature Modifications

PG&E proposes that the following feature modifications be implemented with New PDP in order to simplify and streamline the operation of PDP and make the program less confusing and more customer friendly:

1. Event Notification and Cancellation

   Currently, PG&E is required to call events by 2 p.m. the day ahead. PG&E proposes that given the later event hour window for New PDP, PG&E will notify customers by 4 p.m. on a day ahead basis when a PDP event is planned for the next day (deadline is currently 2 p.m.). In addition, PG&E proposes that it may cancel or decline to call PDP events by 4 p.m. on a day-ahead basis or on the Event Day itself in response to an emergency

[13] On November 20, 2018, PG&E filed its 2019 RDW A.18-11-013. Subsequently, D.19-05-010 approved the Settlement in A.18-11-013 and granted the petition for modification in A.16-06-013 that adopts mitigation measures for agricultural customers that are adversely affected by the rate designs approved in D.18-08-013 and D.19-05-010.

situation, such as a proclamation of a state of emergency and/or disaster by a local, state and/or federal government. PG&E has rarely called an event by 2 p.m. on a day-ahead basis and then cancelled it in the next two hours by 4 p.m. Such a cancellation is extremely difficult given the volume of individual customer cancellation notices that may need to be issued across potentially multiple demand response programs in all customer classes. In order to maintain the flexibility to cancel an event in response to emergency situations (which would be rare), PG&E requests the ability to cancel an event up to the event start time, rather than by 4 p.m. the previous day.

2. Removal of Fax Notification

   PG&E proposes the removal of the fax notification option from the Event Notification Preferences (ENPs) for Peak Day Pricing. Customers can currently select up to two notification options including phone call, email, SMS text, and fax. Out of approximately 103k Service Agreements enrolled in PDP, there are only eleven that have selected fax as their only notification option and these customers have a 0% delivery success rate. The cost of maintaining the contract for fax delivery and the corresponding success rate make the fax ENP option costly and the least reliable method of ENP delivery to customers.

3. Outreach Through Email and Text

   PG&E should be able to conduct all outreach or non-event notifications by any available channel (direct mail, email and/or text) for PDP customers. Utilizing alternate channels for customers with valid email addresses and those who have opted into receiving text messages, in lieu of outreach/notification by direct mail, could result in cost savings and improvements in customer satisfaction with the program.

Rate Design

The primary revision to rate design for PDP with new event hours is to adjust the pricing to be consistent with the new 5 p.m. to 8 p.m. event period. PG&E proposes to continue the current practice of operating the program a minimum of 9 events per year, with a maximum of 15 events per year.

For purposes of rate design, an average of 12 events per year (36 hours) is assumed. PG&E's proposed PDP rates are developed to retain the current event charges where possible and, as in the past, to use revenue neutral assumptions for developing PDP credits. To develop the total PDP event sales for the revenue neutral rate design, PG&E first calculated the recorded average demand over 45 peak hours and scaled that average demand to the current sales forecast. The total event sales were then determined by multiplying the average demand by 36 hours to correspond with the average number of events per year. PG&E then multiplied the proposed PDP event charge by the PDP event sales to determine the PDP event revenue. To determine the PDP credit, the PDP event revenue was divided by the billing determinant over which the PDP credit would be applied.

In addition, PG&E proposes to continue to offer both the option for participating in every other event (for customers with lower demands) and the option to establish a PDP reservation capacity (for larger customers). PG&E's proposed PDP rates are provided in the attached tariffs. While PG&E does not anticipate any revisions to the event charges proposed in this advice letter, PDP credits will be recalculated based on forecast data for 2021 if 2021 sales are adopted for implementation by the Commission on or prior to March 1, 2021. PG&E also plans no changes to the treatment of NEM customers eligible for PDP as approved by the Commission in Advice 4932-E-A, other than to make the New PDP program opt-in rather than default for all customers, including NEM customers.

A brief summary of the rate design changes is provided below:

- Schedule B-1 and Schedule B-10. PDP event charges are set on Schedules B-1 and B-10 at $0.60 per kWh and $0.90 per kWh consistent with the level of these charges on Schedules A-1 and A-10. Credits are now applied to summer peak and partial peak hours, rather than to all summer usage.

- Schedule B-6: PDP event charges have been set to be equal to $0.60 per kWh, which is a reduction compared to the event charge on Schedule A-6. The reduction to the PDP event charge is required so that the PDP credits on this schedule do not exceed the level of time differentiation of the generation time of use rates. Because Schedule B-6 does not have a partial peak period, the PDP credits on this schedule are applied only to the summer peak period.

- Schedules B-19 and B-20. PDP event charges are $1.20 per kWh, consistent with the level of the event charge on Schedules E-19 and E-20. PDP event credits are applied to summer peak and partial peak demand as they are applied today on Schedules E-19 and E-20.

- Agricultural Schedules AG-A1, AG-A2, AG-B and AG C. PDP event charges are set at $1.00 per kWh consistent with the current agricultural PDP program. PDP credits on Schedules AG-A1, AG-A2 and AG-B are applied to only the summer peak period on a per kWh basis. Schedule AG-C PDP credits are applied to the summer peak period on a per kW basis. PDP credits are applied only to the summer peak period because these schedules do not have a summer partial peak period. Only new Schedule AG-C offers the PDP reservation capacity framework. Finally, as with the predecessor legacy rate, Schedule AG-R, new opt-in Schedule

AG-F is not directly eligible for PDP rates. However, just as with AG-R, customers over 200 kW on AG-F would be subject to default PDP under the current rules and would be moved to AG-C with PDP if they fail to affirmatively opt-out. Also, agricultural customers under 200 kW in the legacy PDP program have never faced PDP on a default basis, but may opt-in. PG&E proposes that the New PDP program be entirely opt-in for all agricultural customers of all sizes beginning in March 2021.

Tariff Revisions

PG&E's proposed pro forma PDP tariffs are set forth in Attachment 1. PG&E's updated tariffs includes the applicability, terms and conditions, and illustrative rate values for the revised PDP program for C&I and Agricultural customers. Electric rate schedules revised in this advice letter includes C&I Schedules A-1, A-6, A-10, B-1, B-6, B-10, B-19, B-20, E-19, E-20, and Agricultural Schedules AG, AG-1, AG-4, AG-5, AG-F, AG-V and AG-R. The proposed PDP surcharges and PDP credits are illustrative rate values based on 2020 forecasted sales. PG&E will file a separate Tier 1 advice letter or a supplement to this advice letter closer to the March 1, 2021 effective date with updated rate values for the revenue neutral PDP credits if 2021 sales are adopted for implementation by the Commission on or prior to March 1, 2021. For the convenience of the reader, PG&E has provided a redline version of the revised pro forma tariff in Attachment 2.

Implementation Timeline

PG&E respectfully requests that the final resolution on this matter be issued by November 1, 2020 in order to meet the planned implementation timing to coincide with the transition to rates with new TOU time periods in March 2021, to ensure a smooth transition and optimal customer experience.

Impact on PDP of Potential Delay of Agricultural Customers to New TOU Hours

PG&E is currently reviewing the TOU transition period and may request to exercise flexibility in the timing of the mandatory transition of agricultural customers to the new TOU time periods as provided in the 2017 AG Settlement. The precise language in the 2017 AG Settlement provides flexibility beyond the March 2021 date for the automatic transition of agricultural customers to the new TOU time periods. At page A-7, the 2017 AG Settlement states:

> *"The mandatory transition to rates with the new TOU periods will occur in the first March following the opt-in transition period,and shall be no earlier than the start of the customer's March 2021 billing cycle."*

In the event that the mandatory transition of agricultural customers to the rates with new TOU periods is delayed, the associated dates for the availability of New PDP to agricultural customers (as set forth in the currently effective tariffs as well as the proposed tariff revisions herein) will need to be revised. PG&E requests that, the Commission, in its Resolution to be issued on the Tier 3 advice letter herein, authorize PG&E to submit a Tier 1 or Tier 2 advice letter to the Energy Division that will adjust the timing of both the mandatory TOU time period transition for agricultural customers and timing of the availability of New PDP for agricultural customers.

Protests

*****Due to the COVID-19 pandemic and the shelter at home orders, PG&E is currently unable to receive protests or comments to this advice letter via U.S. mail or fax. Please submit protests or comments to this advice letter to EDTariffUnit@cpuc.ca.gov and PGETariffs@pge.com*****

Anyone wishing to protest this submittal may do so by letter sent via U.S. mail, facsimile or E-mail, no later than July 16, 2020 which is 20 days after the date of this submittal. Protests must be submitted to:

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

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

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

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

Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-3582
E-mail: PGETariffs@pge.com

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

Effective Date

Pursuant to General Order (GO) 96-B, Rule 5.3, and the Settlement Agreements adopted by D. 18-08-013, this advice letter is submitted with a Tier 3 designation. PG&E requests that this Tier 3 advice submittal become effective upon Commission approval. PG&E requests approval by November 1, 2020 to enable automatic re-enrollment of customers currently on PDP beginning March 2021.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for A.16-06-013 and A.18-11-013. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Erik Jacobson
Director, Regulatory Relations

Attachments

cc: Service List A.16-06-013, A.18-11-013

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U39E)

Utility type:

- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Kimberly Loo
Phone #: (415)973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: KELM@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 5861-E

Tier Designation: 3

Subject of AL: Revisions to Peak Day Pricing Program for Commercial, Industrial and Agricultural Customers in Compliance with D.18-08-013.

Keywords (choose from CPUC listing): Compliance, Agriculture

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.18-08-013

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? ☑ Yes ☐ No

Requested effective date: 11/1/20

No. of tariff sheets: 136

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: See Attachment 1

Service affected and changes proposed[1]: Revisions to PDP Program for CI&A Customers

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Name: Erik Jacobson, c/o Megan Lawson
Title: Director, Regulatory Relations
Utility Name: Pacific Gas and Electric Company
Address: 77 Beale Street, Mail Code B13U
City: San Francisco, CA 94177
State: California Zip: 94177
Telephone (xxx) xxx-xxxx: (415)973-2093
Facsimile (xxx) xxx-xxxx: (415)973-3582
Email: PGETariffs@pge.com

Name:
Title:
Utility Name:
Address:
City:
State: California Zip:
Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email:

Clear Form

Advice 5861-E
June 26, 2020

Attachment 1

Proforma Tariffs

ELECTRIC SCHEDULE A-1 Sheet 1
SMALL GENERAL SERVICE

APPLICABILITY: Schedule A-1 applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section). Customers that are otherwise eligible to take service on Schedule A-1, but are purchasing power to serve electric vehicle charging equipment, are not eligible to take service on this rate schedule.

Effective March 1, 2021, Schedule A-1 is available only to qualifying solar grandfathered customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to new Schedule B-1 or other applicable new tariffs with later Time-of-Use (TOU) hours as described below. The non-TOU version of Schedule A-1 is not available for solar grandfathering purposes after March 2021. (N)

Effective November 1, 2012, Schedule A-1 is closed to customers with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months, or with usage of 150,000 kWh per year or greater, and who have at least twelve (12) months of hourly usage data available. Eligibility for A-1 will be reviewed annually and migration of ineligible customers will be implemented once per year, on bill cycles each November, using the same procedures described below for TOU rates adopted in Decision 10-02-032 as (T) modified by Decision 11-11-008.

Effective November 1, 2014, new customers establishing service on Schedule A-1 where a Smart Meter™ is already in place will be charged Schedule A-1 TOU rates.

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods adopted in D.18-08-013 will be available on a voluntary basis for qualifying customers beginning November 1, 2019. During this voluntary period from November 1, 2019 through February 2021, as well as thereafter:

> Schedule B-1, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters and less than 75 kW in size.
>
> Schedule A-1 will be closed to all new enrollment. Customers requesting to establish service on Schedule A-1, where an interval data meter that can be read remotely by PG&E is already in place, will be placed on the new Schedule B-1 with revised TOU periods. Customers requesting to establish service on Schedule A-1 that do not have a meter capable of billing on the new Schedule B-1, may take service on this schedule.

(L)
|
(L)

* 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 website at http://www.pge.com/tariffs

(Continued)

APPLICABILITY: (cont'd.)

Customers taking service under Schedule A-1 at the time rates with new TOU periods become available on a voluntary basis, may transfer to new Schedule B-1, may remain on this rate until rates with new TOU periods become mandatory, in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers. (L)

During the period the new rates with revised TOU periods are available on a voluntary basis for qualifying customers, from November 1, 2019 through February 28, 2021, customers who have opted in to the revised TOU periods, may opt out of the revised TOU periods and return to a legacy electric rate schedule with the legacy TOU periods listed in the special condition for "Definition of Time Periods" in this tariff, for the remainder of the period that the new rates with revised TOU periods are voluntary. Opting out of the revised TOU periods before they become mandatory is available on a one-time basis. If the customer opts-out of a new rate with the revised TOU periods less than twelve months before the revised TOU periods become mandatory, the customer may not return to a rate with the revised TOU periods until they become mandatory.

Beginning on March 2021, customers still served on Schedule A-1 will be transitioned to Schedule B-1 as discussed in the Time of Use Rates Section below.

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 non-utility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S, in addition to all applicable Schedule A-1 charges. Exemptions to Standby Charges are outlined in the Standby Applicability Section of this rate schedule.

Peak Day Pricing Rates: Peak Day Pricing (PDP) rates prov ide 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule A-1 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule A-1 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to Schedule B-1 or other applicable non-legacy rate and enroll in the new PDP program. Customers currently participating on both Schedule A-1 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to the new underlying TOU Schedule B-1 or other applicable new non-legacy rate option. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date. (N)

(L)
(L)

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

APPLICABILITY: (cont'd.)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. In addition, master-metered customers are not 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. (L)

Time-of-Use Rates: Decision 10-02-032, as modified by Decision 11-11-008, makes time-of-use (TOU) rates mandatory beginning November 1, 2012, for small and medium Commercial and Industrial (C&I) customers that have at least twelve (12) billing months of hourly usage data available. (L) (L)/(T) (L)

Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The decision also suspends the transition of eligible A1 customers to mandatory TOU rates beginning November 1, 2018 until the rates with new TOU periods adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for small and medium C&I customers in March 2021 concurrent with the resumption of customer transitions to mandatory TOU rates. (L)

Decision 18-08-013 adopted new TOU periods and seasonal definitions for all non-residential customer classes as discussed above. After the voluntary period ends, beginning March 2021, Schedule B-1, with revised TOU periods, will become mandatory for customers served on this schedule, with exceptions for solar grandfathered customers, discussed above.

Beginning in March 2021, Schedule B-1, with revised TOU periods, will become mandatory for customers served on this schedule:

> Customers on Schedule A-1 with an interval meter that have at least twelve (12) billing months of hourly usage data available will transition to new Schedule B-1.
>
> Customers on Schedule A-1 with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months, or, with usage of 150,000 kWh per year or greater when measured kW is not available and who have at least twelve (12) months of hourly usage data available, will transition to new Schedule B-10.
>
> Customers on the non-TOU option of Schedule A-1 eligible for transition to mandatory TOU rates, including Direct Access and Community Choice Aggregation (DA/CCA) customers, will transition to new Schedule B-1.

(L)
(L)

(Continued)

ELECTRIC SCHEDULE A-1 Sheet 4
SMALL GENERAL SERVICE

APPLICABILITY: (Cont'd.)

Time-of-Use Rates (Cont'd)**:** (L)

The transition of customers no longer eligible for A-1 to new Schedule B-1 (or B-10) with revised TOU periods will occur on the start of the customer's March 2021 billing cycle. Customers will have at least 45-days' notice prior to their scheduled transition date, during which they will continue to take service on this rate schedule. Customers may elect any applicable new rate with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule B-1 (or B-10).

Exemptions to the mandatory transitions beginning in March 2021include:

Qualifying customers with solar systems who meet the requirements in Rule 1 Definition of "Behind-the-Meter Solar TOU Period Grandfathering" and the terms of "Behind-the-Meter Solar TOU Period Grandfathering Eligibility Requirements" shall be permitted to maintain their legacy TOU rate periods, until the date ten years after their system received its permission to operate (but in no event beyond December 31, 2027 (for public schools) or July 31, 2027 (for all other qualifying). However, rates for those TOU rate periods will be updated with new rates as authorized in applicable PG&E rate proceedings and advice filings.

Customers that do not have a meter that is capable of billing on the new Schedule B-1 by the beginning of their March 2021 billing cycle, may continue service on this schedule until they receive an interval meter and have at least twelve (12) months of hourly usage data available.

The mandatory transition process will then occur in November 2021 and in each November thereafter to transition all applicable remaining A-1 customers to the rates with revised TOU periods.

TERRITORY: This rate schedule applies everywhere PG&E provides electric service. (L)

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

RATES: Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

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. (L)

TOTAL RATES

A. Non-Time-of-Use Rates

Total Customer Charge Rates	
Customer Charge Single-phase ($ per meter per day)	$0.32854
Customer Charge Poly-phase ($ per meter per day)	$0.82136
Total Energy Rates ($ per kWh)	
Summer	$0.28091
Winter	$0.22036

B. Time-of-Use Rates

Total Customer Charge Rates	
Customer Charge Single-phase ($ per meter per day)	$0.32854
Customer Charge Poly-phase ($ per meter per day)	$0.82136
Total TOU Energy Rates ($ per kWh)	
Peak Summer	$0.29592
Part-Peak Summer	$0.27227
Off-Peak Summer	$0.24491
Part-Peak Winter	$0.25166
Off-Peak Winter	$0.23075

PDP Rates (Consecutive Day and Four-Hour Event Option) *

PDP Charges ($ per kWh)	
All Usage During PDP Event	$0.60
PDP Credits	
Energy ($ per kWh)	
Peak Summer	($0.00905)
Part-Peak Summer	($0.00905)
Off-Peak Summer	($0.00905)

** See PDP Detail, section g, for corresponding reduction in PDP credits and charges if other option(s) elected*. (L)

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

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. (L)

UNBUNDLING OF TOTAL RATES

A. Non-Time-of-Use Rates

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

Energy Rates by Components ($ per kWh)	
Generation:	
Summer	$0.13350
Winter	$0.09336
Distribution**	
Summer	$0.09224
Winter	$0.07183
Transmission* (all usage)	$0.02766
Transmission Rate Adjustments* (all usage)	$0.00314
Reliability Services* (all usage)	($0.00051)
Public Purpose Programs (all usage)	$0.01299
Nuclear Decommissioning (all usage)	$0.00101
Competition Transition Charges (all usage)	$0.00092
Energy Cost Recovery Amount (all usage)	$0.00005
New System Generation Charge (all usage)**	$0.00411
DWR Bond (all usage)	$0.00580
California Climate Credit (all usage)***	$0.00000

(L)

(L)

* 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.

(L)

(Continued)

RATES: (Cont'd.)

UNBUNDLING OF TOTAL RATES (L)

B. Time-of-Use Rates

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

Energy Rates by Components ($ per kWh)	
Generation:	
Peak Summer	$0.14851
Part-Peak Summer	$0.12486
Off-Peak Summer	$0.09750
Part-Peak Winter	$0.12466
Off-Peak Winter	$0.10375
Distribution:**	
Peak Summer	$0.09224
Part-Peak Summer	$0.09224
Off-Peak Summer	$0.09224
Part-Peak Winter	$0.07183
Off-Peak Winter	$0.07183
Transmission* (all usage)	$0.02766
Transmission Rate Adjustments* (all usage)	$0.00314
Reliability Services* (all usage)	($0.00051)
Public Purpose Programs (all usage)	$0.01299
Nuclear Decommissioning (all usage)	$0.00101
Competition Transition Charges (all usage)	$0.00092
Energy Cost Recovery Amount (all usage)	$0.00005
New System Generation Charge (all usage)**	$0.00411
DWR Bond (all usage)	$0.00580
California Climate Credit (all usage)***	$0.00000

(L)

(L)

* 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.

(L)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

TIME PERIODS: Times of the year and times of the day are defined as follows: (L)

SUMMER (Service from May 1 through October 31):

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

WINTER (Service from November 1 through April 30):

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

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

CONTRACT: For customers who use service for only part of the year, this schedule is available only on annual contract. (L)

SEASONS: The summer rate is applicable May 1 through October 31, and the winter rate is applicable November 1 through April 30. When billing includes use in both the summer and winter periods, charges will be prorated based upon the number of days in each period.

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.

In the event that the CPUC substantially reduces the surcharges or 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.

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

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, 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. 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. (L)

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

BILLING: (Cont'd.)

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. (L)

	DA /CCA CRS
Energy Cost Recovery Amount Charge (per kWh)	$0.00005
DWR Bond Charge (per kWh)	$0.00580
CTC Charge (per kWh)	$0.00092
Power Charge Indifference Adjustment (per kWh)	
2009 Vintage	$0.02453
2010 Vintage	$0.02756
2011 Vintage	$0.02990
2012 Vintage	$0.02979
2013 Vintage	$0.03186
2014 Vintage	$0.03230
2015 Vintage	$0.03213
2016 Vintage	$0.03199
2017 Vintage	$0.03194
2018 Vintage	$0.03196
2019 Vintage	$0.03406
2020 Vintage	$0.04065

CARE DISCOUNT:

Nonprofit Group-Living Facilities which meet the eligibility criteria in Rule 19.2 or 19.3 are eligible for a California Alternate Rates for Energy discount pursuant to Schedule E-CARE. CARE customers are exempt from paying the DWR Bond Charge.

STANDBY APPLICABILITY:

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

(Continued)

STANDBY APPLICABILITY: (Cont'd.)

DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use 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 transfer to Schedule A-6 or E-19, 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 time-of-use (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. (L)

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)

PEAK DAY PRICING DETAILS

Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with Schedule B-1 or other applicable non-legacy rate may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible A-1 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for small and medium C&I customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP. (L)

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

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

(Continued)

ELECTRIC SCHEDULE A-1 Sheet 13
SMALL GENERAL SERVICE

PEAK DAY PRICING DETAILS (CONT'D):

c. 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 notification messages of a PDP event from PG&E. (L)

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.

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

e. 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.

f. 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. (L)

(Continued)

PEAK DAY PRICING DETAILS (CONT'D):

g. Program Options: Customers may customize their PDP participation by choosing either a) no limit on the number of consecutive PDP events or b) every other PDP event. Customers electing every other PDP event will be divided into two groups and only be subject to a maximum of one-half of the PDP events called and the corresponding PDP rate credits will be reduced by 50%. Customers that do not elect an option will be defaulted to the no limit on the number of consecutive PDP events. The duration of PDP Event Operations for both options will be from 2:00 p.m. to 6:00 p.m. (four-hour window). (L)

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

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

ELECTRIC SCHEDULE A-10 Sheet 1

MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY: Schedule A-10 is a demand metered rate schedule for general service customers. Schedule A-10 applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section).

Effective March 1, 2021, Schedule A-10 is available only to qualifying solar grandfathered customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to new Schedule B-10 or other applicable new tariffs with later Time-of-Use (TOU) hours as described below. The non-TOU version of Schedule A-10 is not available for solar grandfathering purposes after March 2021. (N)

Under Rate Schedule A-10, there is a limit on the demand (the number of kilowatts (kW)) the customer may require from the PG&E system. If the customer's demand exceeds 499 kW for three consecutive months, the customer's account will be transferred to Schedule E-19 or E-20.

Effective November 1, 2014, new customers establishing service on Schedule A-10 where a Smart Meter™ is already in place will be charged Schedule A-10 TOU rates.

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods will be available on a voluntary basis for qualifying customers beginning November 1, 2019. During this voluntary period from November 1, 2019 through February 2021, as well as thereafter:

> Schedule B-10, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters and less than 500 kW in size.
>
> Schedule A-10 will be closed to all new enrollment. Customers requesting to establish service on Schedule A-10 where an interval data meter that can be read remotely by PG&E is already in place will be placed on the new Schedule B-10. Customers requesting to establish service on Schedule A-10 that do not have a meter that is capable of billing on the new Schedule B-10, may take service on this schedule.
>
> Customers taking service under Schedule A-10 at the time rates with new TOU periods become available on a voluntary basis, may transfer to new Schedule B-10, may remain on this rate until rates with new TOU periods become mandatory, in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers.

* 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.

(Continued)

ELECTRIC SCHEDULE A-10 Sheet 2
MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY (CONT'D):

During the period the new rates with revised TOU periods are available on a voluntary basis for qualifying customers, from November 1, 2019 through February 28, 2021, customers who have opted in to the revised TOU periods, may opt out of the revised TOU periods and return to a legacy electric rate schedule with the legacy TOU periods listed in the special condition for "Definition of Time Periods" in this tariff, for the remainder of the period that the new rates with revised TOU periods are voluntary. Opting out of the revised TOU periods before they become mandatory is available on a one-time basis. If the customer opts-out of a new rate with the revised TOU periods less than twelve months before the revised TOU periods become mandatory, the customer may not return to a rate with the revised TOU periods until they become mandatory.

Beginning on March 2021, customers still served on Schedule A-10 will be transitioned to Schedule B-10 as discussed in the **Time of Use Rates** Section below.

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 A-10 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Transfers Off of Schedule A-10 TOU: Customers are placed on this schedule if they are not eligible for Schedules A-1 or A-6 because their demand exceeded or was expected to exceed 75 kW. Customers who then fail to exceed 75 kilowatts for 12 consecutive months may elect to stay on this schedule.

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will be between 75 through 499 kilowatts and that the customer should not be served under an agricultural or residential rate schedule, PG&E will serve the customer's account under the provisions of time-of-use Rate Schedule A-10.

Peak Day Pricing 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.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule A-10 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule A-10 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to Schedule B-10 or other applicable non-legacy rate and enroll in the new PDP program. Customers currently participating on both Schedule A-10 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to the new underlying TOU Schedule B-10 or other applicable new non-legacy rate option. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date. (N)

Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates.

(L)
(L)

(Continued)

ELECTRIC SCHEDULE A-10 Sheet 3
MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY (CONT'D):

Peak Day Pricing Rate (Cont'd) (L)

Bundled service customers are eligible for PDP. Direct Access (DA) and Community Choice Aggregation (CCA) service customers are not eligible, including those customers on transitional bundled service (TBS). Customers on standby service (Schedule S), or on net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, are not eligible for PDP. In addition, master-metered customers are not 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 details and program specifics, see the Peak Day Pricing Details section below. (L)

Time-of-Use Rates: Decision 10-02-032, as modified by Decision 11-11-008, makes TOU rates mandatory beginning November 1, 2012, for small and medium Commercial and (T) Industrial (C&I) customers that have at least twelve (12) billing months of hourly usage data (T) available.

Decision 18-08-013 suspends the transition of eligible A-10 customers to mandatory TOU rate beginning November 1, 2018 until the rates with revised TOU periods, as adopted in the same Decision, become mandatory.

Decision 18-08-013 adopted new TOU periods and seasonal definitions for all non-residential customer classes as discussed above. After the voluntary period ends, beginning March 2021, new Schedule B-10, with revised TOU periods, will become mandatory for customers served on this rate schedule, with exceptions for solar grandfathered customers, discussed above.

Beginning in March 2021, Schedule B-10, with revised TOU periods, will become mandatory for customers served on this schedule:

Customers on Schedule A-10 with an interval meter and that have at least 12 months of hourly usage data available will transition to the new Schedule B-10.

Customers on the non-TOU option of Schedule A-10 eligible for transition to mandatory TOU rates, including Direct Access and Community Choice Aggregation (DA/CCA) customers, will transition to new Schedule B-10.

The transition of customers no longer eligible for A-10 to new B-10 with revised TOU periods will occur on the start of the customer's March 2021 billing cycle. Customers will have at least 45-days' notice prior to their scheduled transition date, during which they will continue to take service on this rate schedule. Customers may elect any applicable new rate with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule B-10. .

(L)
|
(L)

(Continued)

ELECTRIC SCHEDULE A-10

MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY (CONT'D): **Time-of-Use Rates (**Cont'd) (L)

Exemptions to mandatory transitions beginning in March 2021 include:

Qualifying customers with solar systems who meet the requirements in Rule 1 Definition of "Behind-the-Meter Solar TOU Period Grandfathering" and the terms of "Behind-the-Meter Solar TOU Period Grandfathering Eligibility Requirements" shall be permitted to maintain their legacy TOU rate periods, until the date ten years after their system received its permission to operate (but in no event beyond December 31, 2027 (for public schools) or July 31, 2027 (for all other qualifying). However, rates for those TOU rate periods will be updated with new rates as authorized in applicable PG&E rate proceedings and advice filings.

Customers that do not have a meter that is capable of billing on the new Schedules B-10 by the beginning of their March 2021 billing cycle, may continue service this schedule until they receive an interval meter and have at least twelve (12) months of hourly usage data available.

The mandatory transition process will then occur in November 2021 and in each November thereafter to transition all applicable remaining A-10 customers to the rates with revised TOU periods (L)

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.

All customers taking non TOU service under this rate schedule shall be subject to the rates set forth in Table A. All customers taking TOU service under this rate schedule shall be subject to the rates set forth in Table B.

RATES: Standard Non-Time-of-Use Rate

Table A

TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge ($ per meter per day)	$4.77841	$4.77841	$4.77841
Total Demand Rates ($ per kW)			
Summer	$21.94	$20.68	$14.33
Winter	$13.27	$13.51	$10.38
Total Energy Rates ($ per kWh)			
Summer	$0.18607	$0.17384	$0.13828
Winter	$0.14531	$0.14005	$0.11751

(Continued)

ELECTRIC SCHEDULE A-10 Sheet 6
MEDIUM GENERAL DEMAND-METERED SERVICE

RATES: Time-of-Use Rates for Optional or Real-Time Metering Customers

Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

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.

Table B

TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge ($ per meter per day)	$4.77841	$4.77841	$4.77841
Total Demand Rates ($ per kW)			
Summer	$21.94	$20.68	$14.33
Winter	$13.27	$13.51	$10.38
Total Energy Rates ($ per kWh)			
Peak Summer	$0.23996	$0.22604	$0.18558
Part-Peak Summer	$0.18483	$0.17548	$0.13870
Off-Peak Summer	$0.15676	$0.14885	$0.11340
Part-Peak Winter	$0.15544	$0.15174	$0.12691
Off-Peak Winter	$0.13838	$0.13586	$0.11234
PDP Rates (Consecutive Day and Four-Hour Event Option)*			
PDP Charges ($ per kWh)			
All Usage During PDP Event	$0.90	$0.90	$0.90
PDP Credits			
Demand ($ per kW)			
Maximum Summer	($3.85)	($3.35)	($2.64)
Energy ($ per kWh)			
Peak Summer	($0.00073)	($0.00264)	($0.00429)
Part-Peak Summer	($0.00073)	($0.00264)	($0.00429)
Off-Peak Summer	($0.00073)	($0.00264)	($0.00429)

*See PDP Details, section g, for corresponding reduction in PDP credits and charges if other option(s) elected.

(Continued)

ELECTRIC SCHEDULE A-10 Sheet 13
MEDIUM GENERAL DEMAND-METERED SERVICE

PEAK DAY PRICING DETAILS

Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with Schedule B-10 or other applicable non-legacy rate may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible A-10 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for small and medium C&I customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP.

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

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

c. 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 notification messages of a PDP event from PG&E.

(Continued)

ELECTRIC SCHEDULE A-6 Sheet 1
SMALL GENERAL TIME-OF-USE SERVICE

APPLICABILITY: This time-of-use schedule applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section).

Effective March 1, 2021, Schedule A-6 is available only to qualifying solar grandfathered customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to new Schedule B-6 or other applicable new tariffs with later Time-of-Use (TOU) hours as described below. (N)

Effective April 1, 2017, Schedule A-6 is closed to new customers with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months, or with usage of 150,000 kWh per year or greater, and who have at least twelve (12) months of hourly usage data available. For new customers on or after April 1, 2017, eligibility for A-6 will be reviewed annually and migration of ineligible customers will be implemented once per year, on bill cycles each November, using the same procedures described in Schedule A-1 for TOU rates adopted in Decision 10-02-032 as modified by Decision 11-11-008. (T)

Any customer with a maximum demand of 75 kW or greater, or with usage of 150,000 kWh per year or greater, who sent PG&E a letter (via certified mail with a return receipt to establish a delivery record date on or before March 31, 2017) requesting a rate change pursuant to Electric Rule 12, shall be allowed to take service on Schedule A-6 or Schedule B-6 subject to the requirements of Decision18-08-013.

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods adopted in D.18-08-013, including new Schedule B-6, will be available on a voluntary basis beginning November 1, 2019. During this voluntary period from November 1, 2019 through February 2021, as well as thereafter:

Schedule B-6, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters and less than 75 kW in size. Customers who enroll in any new rate during the voluntary period will be unenrolled from Peak Day Pricing.

Schedule A-6 will be closed to all new enrollment. Customers requesting to establish service on Schedule A-6 where an interval data meter that can be read remotely by PG&E is already in place will be placed on the new Schedule B-6. Customers requesting to establish service on Schedule A-6 that do not have a meter that is capable of billing on the new Schedule B-6, may take service on this 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 website at http://www.pge.com/tariffs.

(Continued)

APPLICABILITY: (Cont'd)

Customers taking service under Schedule A-6 at the time rates with new TOU periods become available on a voluntary basis, may transfer to new Schedule B-6, may remain on this rate until rates with new TOU periods become mandatory, in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers. (L)

During the period the new rates with revised TOU periods are available on a voluntary basis for qualifying customers, from November 1, 2019 through February 28, 2021, customers who have opted in to the revised TOU periods, may opt out of the revised TOU periods and return to a legacy electric rate schedule with the legacy TOU periods listed in the special condition for "Definition of Time Periods" in this tariff, for the remainder of the period that the new rates with revised TOU periods are voluntary. Opting out of the revised TOU periods before they become mandatory is available on a one-time basis. If the customer opts-out of a new rate with the revised TOU periods less than twelve months before the revised TOU periods become mandatory, the customer may not return to a rate with the revised TOU periods until they become mandatory.

Beginning in March 2021, new Schedule B-6 (or B-10 where applicable), with revised TOU periods, will become mandatory for customers served on this schedule:

> Customers on Schedule A-6 with an interval meter that have at least twelve (12) billing months of hourly usage data available will transition to new Schedule B-6.
>
> Customers on Schedule A-6 with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months, or, with usage of 150,000 kWh per year or greater when measured kW is not available and who have at least twelve (12) months of hourly usage data available, will transition to new Schedule B-10.

The transition of customers no longer eligible for A-6 to new Schedule B-6 (or B-10) with revised TOU periods will occur on the start of the customer's March 2021 bill cycle. Customers will have at least 45-days' notice prior to their scheduled transition date, during which they will continue to take service on this rate schedule. Customers may elect any applicable new rate with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule B-1 (or B-10).

Exemptions to the mandatory transitions beginning in March 2021 include:

> Qualifying customers with solar systems who meet the requirements in Rule 1 Definition of "Behind-the-Meter Solar TOU Period Grandfathering" and the terms of "Behind-the-Meter Solar TOU Period Grandfathering Eligibility Requirements" shall be permitted to maintain their legacy TOU rate periods, until the date ten years after their system received its permission to operate (but in no event beyond December 31, 2027 (for public schools) or July 31, 2027 (for all other qualifying). However, rates for those TOU rate periods will be updated with new rates as authorized in applicable PG&E rate proceedings and advice filings.

(L)
(L)

(Continued)

ELECTRIC SCHEDULE A-6 Sheet 3
SMALL GENERAL TIME-OF-USE SERVICE

APPLICABILITY: (Cont'd.)

Customers that do not have a meter that is capable of billing on the new Schedules B-6 by the beginning of their March 2021 billing cycle, may continue service on this schedule until they receive an interval meter and have at least twelve (12) months of hourly usage data available. (L)

The mandatory transition process will then occur in November 2021 and in each November thereafter to transition all applicable remaining A-6 customers to the rates with revised TOU periods.

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 A 6 charges. Exemptions are outlined in the Standby Applicability Section of this rate schedule. (L)

Depending upon whether or not a Time-Of-Use Installation or Time-Of-Use Processing charge applied prior to May 1, 2006, the customer will be served under one of these rates under Schedule A-6

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 enroll on A-6 on or after May 1, 2006.

A-6: Applies to customers who were on A-6 as of May 1, 2006.

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.

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

Peak Day Pricing 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. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule A-6 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule A-6 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to Schedule B-6 or other applicable non-legacy rate and enroll in the new PDP program. Customers currently participating on both Schedule A-6 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to the new underlying TOU Schedule B-6 or other applicable new non-legacy rate option. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date. (N)

(L)
(L)

(Continued)

ELECTRIC SCHEDULE A-6

SMALL GENERAL TIME-OF-USE SERVICE

Sheet 4

APPLICABILITY: (Cont'd.)

Peak Day Pricing Rates (Cont'd): (L)

Bundled service customers are eligible for PDP. Direct Access (DA) and Community Choice Aggregation (CCA) service customers are not eligible, including those customers on transitional bundled service (TBS). Customers on standby service (Schedule S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program, are not eligible for PDP. In addition, master-metered customers are not 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 details and program specifics, see the Peak Day Pricing Details section below. (L)

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

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 RATES

Total Customer/Meter Charge Rates	
Customer Charge Single-phase ($ per meter per day)	$0.32854
Customer Charge Poly-phase ($ per meter per day)	$0.82136
Meter Charge (A-6) ($ per meter per day)	$0.20107
Meter Charge (W) ($ per meter per day)	$0.05914
Meter Charge (X) ($ per meter per day)	$0.20107
Total Energy Rates ($ per kWh)	
Peak Summer	$0.59927
Part-Peak Summer	$0.30245
Off-Peak Summer	$0.23086
Part-Peak Winter	$0.24592
Off-Peak Winter	$0.22767
PDP Rates (Consecutive Day and Four-Hour Event Option) *	
PDP Charges ($ per kWh)	
All Usage During PDP Event	$1.20
PDP Credits	
Energy ($ per kWh)	
Peak Summer	($0.26879)
Part-Peak Summer	($0.05376)

** See PDP Details, section g, for corresponding reduction in PDP credits and charges if other option(s) elected.*

(Continued)

PEAK DAY PRICING DETAILS

Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with Schedule B-6 or other applicable non-legacy rate may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible A-6 customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for small and medium Commercial and (T) Industrial (C&I) customers in March 2021, concurrent with the resumption of the (T) default of eligible customers to PDP.

   Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

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

c. 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 notification messages of a PDP event from PG&E.

(Continued)

1.APPLICABILITY: (Cont'd.)

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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. (N)

(Continued)

ELECTRIC SCHEDULE AG Sheet 4
TIME-OF-USE AGRICULTRUAL POWER

2. TERRITORY: Schedule AG applies everywhere PG&E provides electricity service. (L)

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.

TOTAL RATES

Total Customer/Meter Charge Rates	**Rate AG-A1**	**Rate AG-A2**	**Rate AG-B**	**Rate AG-C**
Customer Charge				
($ per meter per day)	$0.68895	$0.68895	$0.91565	$1.43343
Total Demand Rates ($ per kW)				
Secondary Voltage				
Maximum Peak Demand Summer	—	—	—	$18.69
Maximum Demand Summer	$5.63	$9.50	$6.24	$11.21
Maximum Demand Winter	$5.63	$9.50	$6.24	$11.21
Primary Voltage				
Maximum Peak Demand Summer	—	—	—	$18.69
Maximum Demand Summer	—	—	$5.39	$10.04
Maximum Demand Winter	—	—	$5.39	$10.04
Transmission Voltage				
Maximum Peak Demand Summer	—	—	—	$18.69
Maximum Demand Summer	—	—	$2.09	$2.90
Maximum Demand Winter	—	—	$2.09	$2.90
Total Energy Rates ($ per kWh)				
Peak Summer	$0.39723	$0.33802	$0.40208	$0.18368
Off-Peak Summer	$0.23129	$0.17209	$0.22923	$0.14424
Peak Winter	$0.22092	$0.17898	$0.22516	$0.15589
Off-Peak Winter	$0.19163	$0.14969	$0.19590	$0.13020
Demand Charge Rate Limiter				
($/kWh in all months, see Demand Charge Rate Limiter section)	—	—	—	$0.50

(L)

PDP Rates (Consecutive Day and Three-Hour Event Option)* (N)

PDP Charges ($ per kWh)				
All Usage During PDP Event	$1.00	$1.00	$1.00	$1.00
PDP Credits				
Demand ($ per kW)				
Peak Summer	$0.00000	$0.00000	$0.00000	($4.35)
Energy ($ per kWh)				
Peak Summer	($0.10026)	($0.11075)	($0.10909)	—

* See PDP Detail, section g, for corresponding reduction in PDP credits and charges if other option(s) elected. (N)

(Continued)

ELECTRIC SCHEDULE AG Sheet 5
TIME-OF-USE AGRICULTRUAL POWER

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. (L) (L)/(N) (N)

UNBUNDLING OF TOTAL RATES (L)

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

Demand Charges by Component ($/kW)	Rate AG-A1	Rate AG-A2	Rate AG-B	Rate AG-C
Generation:				
Maximum Peak Demand Summer	—	—	—	$12.52
Distribution:**				
Secondary Voltage				
Maximum Peak Demand Summer	—	—	—	$6.17
Maximum Demand Summer	$5.63	$9.50	$6.24	$11.21
Maximum Demand Winter	$5.63	$9.50	$6.24	$11.21
Primary				
Maximum Peak Demand Summer	—	—	—	$6.17
Maximum Demand Summer	—	—	$5.39	$10.04
Maximum Demand Winter	—	—	$5.39	$10.04
Transmission				
Maximum Peak Demand Summer	—	—	—	$6.17
Maximum Demand Summer	—	—	$2.09	$2.90
Maximum Demand Winter	—	—	$2.09	$2.90

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

(Continued)

ELECTRIC SCHEDULE AG
TIME-OF-USE AGRICULTRUAL POWER

3. RATES: (L)
(Cont'd.)

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Rates by Component ($/kWh)	Rate AG-A1	Rate AG-A2	Rate AG-B	Rate AG-C
Generation:				
Peak Summer	$0.22407	$0.22407	$0.24440	$0.11604
Off-Peak Summer	$0.10439	$0.10439	$0.12133	$0.08656
Peak Winter	$0.10107	$0.10107	$0.11599	$0.10140
Off-Peak Winter	$0.07462	$0.07462	$0.08979	$0.07588
Distribution*:				
Peak Summer	$0.12365	$0.06444	$0.10867	$0.02005
Off-Peak Summer	$0.07739	$0.01819	$0.05889	$0.01009
Peak Winter	$0.07034	$0.02840	$0.06016	$0.00690
Off-Peak Winter	$0.06750	$0.02556	$0.05710	$0.00673
Transmission* (all usage)	$0.02202	$0.02202	$0.02202	$0.02202
Transmission Rate Adjustments* (all usage)	$0.00314	$0.00314	$0.00314	$0.00314
Reliability Services* (all usage)	($0.00041)	($0.00041)	($0.00041)	($0.00041)
Public Purpose Programs (all usage)	$0.01327	$0.01327	$0.01277	$0.01135
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101	$0.00101
Competition Transition Charges (all usage)	$0.00085	$0.00085	$0.00085	$0.00085
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00378	$0.00378	$0.00378	$0.00378
California Climate Credit (all usage)***	$0.00000	$0.00000	$0.00000	$0.00000

* 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. (L)

(Continued)

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. (L)

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

5. TIME PERIODS: Seasons of the year and times of the day are defined as follows:

SUMMER (Service from June 1 through September 30):

For Rates AG-A1, AG-A2, AG-B and AG-C

Peak:	5:00 p.m. to 8:00 p.m.	Every day, including weekends and holidays
Off-peak:	All other Hours.	

WINTER (Service from October 1 through May 31):

For Rates AG-A1, AG-A2, AG-B and AG-C

Peak:	5:00 p.m. to 8:00 p.m.	Every day, including weekends and holidays
Off-peak:	All other Hours.	

(L)

(Continued)

ELECTRIC SCHEDULE AG
TIME-OF-USE AGRICULTRUAL POWER

6. ENERGY CHARGE CALCULATION:	When summer and winter proration is required, charges will be based on the average daily use for the full billing periods times the number of days in each period.	(L)
7. CONTRACTS:	Service under Schedule AG is provided for a minimum of 12 months beginning with the date the customer's service commences. The customer may be required to sign a service contract with a minimum term of one year. After the customer's initial one-year term has expired, the customer's contract will continue in effect until it is cancelled by the customer or PG&E. Where a line extension is required it will be installed under the provisions of Rules 15 and 16.	|
8. MAXIMUM DEMAND	The maximum demand will be the number of kW the customer is using recorded over 15-minute intervals; the highest 15-minute average in any month customers will be the maximum demand for that month. Where the customer's use of electricity is intermittent or subject to abnormal fluctuation, 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 welder load calculation will apply only in the season in which the customer usually uses energy, which will be assumed to be the summer season unless otherwise designated. In billing periods with use in both the summer season and winter season (May/June, September/October), your <u>total demand charge</u> shall be calculated on a pro rata basis depending upon the demand charge and the number of days in each season. The maximum demand used in determining your demand charge for each season of the billing period will be the maximum demand created in each season's portion of the billing month as measured by the meter. For customers 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. 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). 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)

(Continued)

10. MAXIMUM-PEAK-PERIOD DEMAND: 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. (L)

11. DEMAND CHARGE RATE LIMITER: If a customer takes service on rate AG-C under Schedule AG-C, at any voltage level, bills will be controlled by a "demand charge rate limiter" during all months of the year. The bill will be reduced, if necessary, so that the average rate paid per kWh for all demand and energy charges, excluding the monthly customer charge, during all months of the year does not exceed the Demand Charge Rate Limiter shown on this schedule.

The Demand Charge Rate Limiter shall apply to all bundled service, Direct Access (DA), or Community Choice Aggregation (CCA) customers taking service on rate option AG-C under Schedule AG. DA/CCA customers will be billed as if paying full PG&E bundled Generation demand charge and energy charge rates to assess the applicability of the Demand Charge Rate Limiter, and shall receive bill adjustments on that basis, not on the basis of applicable DA/CCA Generation charges, or related PCIA and E-FFS rates. Net Energy Metering (NEM) customers shall be evaluated for the Demand Charge Rate Limiter on the basis of the energy the customer receives from PG&E prior to any bill adjustment for net exports. The Demand Charge Rate Limiter shall also apply to any AG-C customer who elects to receive separate billing for back-up and maintenance service pursuant to Special Condition 7 of Standby Schedule SB.

Demand Charge Rate Limiter applicability shall be evaluated on the basis of the full billing period, and not within a seasonal crossover or other bill segment basis. All revenue shortfalls attributable to the Demand Charge Rate Limiter will be assigned as a reduction to distribution charges. The Demand Charge Rate Limiter will apply to AG-C customer bills without regard to any incentives, charges, surcharges, or penalties associated with such programs as PDP, DRAM, BIP, and CBP.

This Demand Charge Rate Limiter provision will not apply if the customer has elected one of the following:

- Schedule AG, Rate Option AG-A1, AG-A2, or B; or
- Schedule AG-F, Rate Option A, B, or C.
- NEM aggregation, NEMA service on AG-C across multiple meter sites.
- Virtual NEM, NEMCCSF, NEMFC, NEMMT, NEM Paired Storage, NEMBIO, NEMW, or RES-BCT. (L)

(Continued)

12. DEFINITION OF SERVICE VOLTAGE:

The following defines the three voltage classes of Schedule AG 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.

PG&E retains the right to change its line voltage at any time. Customers receiving voltage discounts will get reasonable notice of any impending change. They will then have the option of taking service at the new voltage (and making whatever changes in their systems are necessary) or taking service without a voltage discount through transformers supplied by PG&E.

13. BILLING:

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

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. (L)

(Continued)

13.BILLING: (Cont'd)

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. (L)

	DA / CCA CRS
Energy Cost Recovery Amount Charge (per kWh)	$0.00005
DWR Bond Charge (per kWh)	$0.00580
CTC Charge (per kWh)	$0.00085
Power Charge Indifference Adjustment (per kWh)	
2009 Vintage	$0.02289
2010 Vintage	$0.02571
2011 Vintage	$0.02790
2012 Vintage	$0.02779
2013 Vintage	$0.02972
2014 Vintage	$0.03014
2015 Vintage	$0.02998
2016 Vintage	$0.02985
2017 Vintage	$0.02980
2018 Vintage	$0.02982
2019 Vintage	$0.03178
2020 Vintage	$0.03793 (L)

(Continued)

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

DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use 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 time-of-use service 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 time-of-use (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.

15.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.

16.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 Rate AG-C under Schedule AG, Schedule E-19 or Schedule E-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.

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 E-19 (above 500 kW as defined above), Schedule E-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. (L)

(Continued)

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

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: (L)

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.

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.

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)

ELECTRIC SCHEDULE AG Sheet 14
TIME-OF-USE AGRICULTRUAL POWER

17. PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible agricultural TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The AG rates with new TOU periods will become mandatory for all agricultural customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2 pm – 6 pm PDP Event Hours to a new version of PDP (New PDP) with 5 pm – 8 pm PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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 on the AG-C rate 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.

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

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

(Continued)

17. PEAK DAY PRICING DETAILS (Cont'd.)

c. Bill Stabilization (Cont'd.): (N)

Active Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months.

Legacy 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 the New 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 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.

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.

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

g. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

(Continued)

17. PEAK DAY PRICING DETAILS (Cont'd.)

h. Program Options: Customers on Schedules AG-A1, AG-A2 or AG-B may customize their PDP participation by choosing either a) no limit on the number of consecutive PDP events or b) every other PDP event. Customers electing every other PDP event will be divided into two groups and only be subject to a maximum of one-half of the PDP events called and the corresponding PDP rate credits will be reduced by 50%. Customers that do not elect an option will be defaulted to the no limit on the number of consecutive PDP events. The duration of PDP Event Operations for both options will be from ~~p.m.~~5:00 p.m. to 8:00 p.m. (three-hour window). (N)

i. 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.

j. 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.

k. 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. (N)

(Continued)

ELECTRIC SCHEDULE AG-1 Sheet 1
AGRICULTURAL POWER

1. APPLICABILITY: A customer will be served under this schedule if 70% or more of the annual energy use on the meter is for agricultural end-uses. Agricultural end-uses consist of:

(a) growing crops;

(b) raising livestock;

(c) pumping water for irrigation of crops; or

(d) other uses which involve production for sale.

Only agricultural end-uses performed prior to the First Sale of the agricultural product are agricultural end-uses under this criteria, except for the following activities, which are also agricultural end-uses under this criteria: (a) packing and packaging of the agricultural products following the First Sale and before any subsequent sale, and (b) agricultural end-uses by nonprofit cooperatives. Guidelines for interpreting this applicability statement are set forthwith in Section D of the Rule 1 Definition ‘Qualification for Agricultural Rates’.

Schedule AG-1 is a non-Time-of-Use (TOU) rate schedule. Effective March 1, 2021, Schedule AG-1 is available only to qualifying customers without interval meters, and to highly impacted agricultural customers, as specified in greater detail below. Schedule AG-1 is not available for solar grandfathering purposes after March 2021. Customers on this tariff with 12 months of interval data prior to March 2021, or prior to March 2022 if highly impacted, and prior to each March thereafter, must either elect service on new opt-in TOU Schedule AG-F, or must transition to a new default AG Schedule with later TOU hours as described below: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N

None of the above activities may process the agricultural product. Residential dwelling, office, and retail usage are not agricultural end-uses.

The Rule 1 definition ‘Qualification for Agricultural Rates’ specifies additional activities and meters that will also be served on agricultural rates, and guidelines through the following sections: (B) Other Activities and Meters Also Served on Agricultural Rates, (C) Specific Applications of the March 2, 2006 Applicability Criteria, and (D) Guidelines for Applying the Applicability Criteria.

This schedule is not applicable to service for which a residential or commercial/ industrial schedule is applicable, or to customers with a maximum demand of 500 kW or more. This schedule is also not available to customers whose meter indicates a maximum demand of 200 kW or greater for three consecutive months, except customers that are identified as load research sites. Customers with interval data meters who are not eligible for this rate schedule must be placed on a Time-Of-Use (TOU) rate schedule.

Depending upon the end-use of electricity, the customer will be served under one of the two rates under Schedule AG-1: Rate A or Rate B.

(L)
|
(L)

(Continued)

1. APPLICABILITY: (Cont'd.)

Rate A: Applies to single-motor installations with a connected load rated less than 35 horsepower and to all multi-load installations aggregating less than 15 horsepower or kilowatts. (L)

Rate B: Applies to single-motor installations rated 35 horsepower or more, to multi-load installations aggregating 15 horsepower or kilowatts or more, and to "overloaded" motors. The customer's end-use is determined to be overloaded when the measured input to any motor rated 15 horsepower or more is determined by PG&E to exceed one kilowatt per horsepower of nameplate rated output. (L)

Effective November 1, 2014, new customers establishing service where a Smart Meter™ is already in place are not eligible for Schedule AG-1 and must instead be served under an applicable TOU rate schedule, such as Schedule AG-4 or AG-5, or if establishing service (N)
after March 1, 2020, under a new rate with later TOU hours on Schedule AG or AG-F. (N)

Decision 18-08-013 adopted new TOU periods and new seasonal definitions for all non-residential customer classes, as well as new rates for the Agricultural customer class. Schedules AG-1, AG-4, AG-5, AG-R and AG-V will be retained as legacy rate schedules with their current TOU periods until the rates with revised TOU periods (Schedules AG and AG-F) established in the same proceeding, become mandatory in March 2021.

Decision 19-05-010 adopted additional modifications to the agricultural rates adopted in Decision 18-08-013 and delays the mandatory transition until March 2022 for highly impacted agricultural customers, defined as those customers with potential bill increases greater than 7 percent and $100 annually due to the transition to the rates with revised TOU periods. In addition, certain qualifying customers with solar systems will be permitted to maintain their current TOU periods for a certain period of time, per Decision 17-01-006, as described in Electric Rule 1, Definitions: Behind the Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010 will be available on a voluntary basis for qualifying customers beginning March 1, 2020. During this voluntary period from March 1, 2020 through February 28, 2021:

Schedule AG, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters that can be remotely read by PG&E.

Legacy rate schedules, including Schedule AG-1, will be closed to all new enrollment. Customers requesting to establish service on Schedule AG-1, where an interval data meter that can be read remotely by PG&E is already in place, will be placed on the new Schedule AG with revised TOU periods. Customers requesting to establish service on Schedule AG-1 that do not have a meter capable of billing on the new Schedule AG, may take service on this schedule.

Customers taking service under Schedule AG-1 at the time rates with new TOU periods become available, may transfer to new Schedule AG or Schedule AG-F, with revised TOU periods, may remain on this rate until rates with revised TOU periods become mandatory in March 2021 or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers.

Beginning in March 1, 2021, customers still served on Schedule AG-1 will be transitioned to Schedule AG as discussed in the Time of Use Rates Section below.

(Continued)

ELECTRIC SCHEDULE AG-4 Sheet 1
TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: A customer will be served under this schedule if 70% or more of the annual energy use on the meter is for agricultural end-uses. Agricultural end-uses consist of:

   (a) growing crops;

   (b) raising livestock;

   (c) pumping water for irrigation of crops; or

   (d) other uses which involve production for sale.

   Only agricultural end-uses performed prior to the First Sale of the agricultural product are agricultural end-uses under this criteria, except for the following activities, which are also agricultural end-uses under this criteria: (a) packing and packaging of the agricultural products following the First Sale and before any subsequent sale, and (b) agricultural end-uses by nonprofit cooperatives. Guidelines for interpreting this applicability statement are set forthwith in Section D of the Rule 1 Definition 'Qualification for Agricultural Rates'.

   None of the above activities may process the agricultural product. Residential dwelling, office, and retail usage are not agricultural end-uses.

   Effective March 1, 2021, Schedule AG-4 is available only to qualifying solar grandfathered customers, highly impacted agricultural customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to a new AG Schedule with later TOU hours as described below: (N)

   Ag < 35 kW Low Use (AG-A1)
   Ag < 35 kW High Use (AG-A2)
   Ag 35+ kW Med Use (AG-B)
   Ag 35+ kW High Use (AG-C) (N)

   The Rule 1 definition 'Qualification for Agricultural Rates' specifies additional activities and meters that will also be served on agricultural rates, and guidelines through the following sections: (B) Other Activities and Meters Also Served on Agricultural Rates, (C) Specific Applications of the March 2, 2006 Applicability Criteria, and (D) Guidelines for Applying the Applicability Criteria.

   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 <u>not</u> 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 AG-4 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

ELECTRIC SCHEDULE AG-4 Sheet 5

TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

Transfers Off of Schedule AG-4: 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 this schedule or alternate time-of-use rate schedule

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 February 1, 2011, eligible Agricultural 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.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule AG-4 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule AG-4 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to a new AG Schedule non-legacy rate listed below and enroll in the new PDP program. Customers currently participating on both Schedule AG-4 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to a new underlying AG Schedule based on size as listed below. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

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 Community 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 NEMA, are not eligible for PDP.

Decision 18-08-013 temporarily suspends the default of eligible AG-4 customers to PDP beginning March 1, 2019.

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

2. TERRITORY: Schedule AG-4 applies everywhere PG&E provides electricity service.

(Continued)

ELECTRIC SCHEDULE AG-4 Sheet 6
TIME-OF-USE AGRICULTURAL POWER

2. TERRITORY: Schedule AG-4 applies everywhere PG&E provides electricity service.

3. RATES: Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

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.

TOTAL RATES

Total Customer/Meter Charge Rates	Rate A,D	Rate B,E	Rate C,F
Customer Charge ($ per meter per day)	$0.57400	$0.76313	$2.15003
TOU Meter Charge ($ per meter per day) (for rate A, B & C)	$0.22341	$0.19713	$0.19713
TOU Meter Charge ($ per meter per day) (for rate D, E & F)	$0.06571	$0.03943	$0.03943

Total Demand Rates ($ per kW)			
Connected Load Summer	$9.71	–	–
Connected Load Winter	$1.47	–	–
Maximum Demand Summer	–	$11.76	$6.17
Maximum Demand Winter	–	$2.75	$2.98
Maximum Peak Demand Summer	–	$6.15	$14.62
Maximum Part-Peak Demand Summer	–	–	$2.80
Maximum Part-Peak Demand Winter	–	–	$0.67
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–	$1.23	$1.59
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–	$0.43	$0.38
Transmission Voltage Discount			
Maximum Peak Demand Summer	–	–	$7.73
Maximum Part-Peak Demand Summer	–	–	$1.61
Maximum Demand Summer	–	–	$0.29
Maximum Part-Peak Demand Winter	–	–	$0.67
Maximum Demand Winter	–	–	$2.06

Total Energy Rates ($ per kWh)			
Peak Summer	$0.50212	$0.33016	$0.30229
Part-Peak Summer	–	–	$0.17959
Off-Peak Summer	$0.22766	$0.18153	$0.13671
Part-Peak Winter	$0.23514	$0.18196	$0.15083
Off-Peak Winter	$0.19320	$0.15448	$0.13173

(Continued)

16. PEAK DAY PRICING DETAILS:

Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with any Schedule AG rate, as described in the Peak Day Pricing paragraph located in the Applicability Clause above, may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible AG-4 customers to PDP beginning March 1, 2019 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for agricultural customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP.

   The default of eligible customers to PDP will occur once per year with the start of their billing cycle on or after March 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 at least five (5) days before their proposed default date, their service will be defaulted to the PDP version of this rate schedule. 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 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. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

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

(Continued)

ELECTRIC SCHEDULE AG-5 Sheet 1
LARGE TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: A customer will be served under this schedule if 70% or more of the annual energy use on the meter is for agricultural end-uses. Agricultural end-uses consist of:

   (a) growing crops;

   (b) raising livestock;

   (c) pumping water for irrigation of crops; or

   (d) other uses which involve production for sale.

   Only agricultural end-uses performed prior to the First Sale of the agricultural product are agricultural end-uses under this criteria, except for the following activities, which are also agricultural end-uses under this criteria: (a) packing and packaging of the agricultural products following the First Sale and before any subsequent sale, and (b) agricultural end-uses by nonprofit cooperatives. Guidelines for interpreting this applicability statement are set forthwith in Section D of the Rule 1 Definition ‘Qualification for Agricultural Rates’.

   Effective March 1, 2021, Schedule AG-5 is available only to qualifying solar grandfathered customers, highly impacted agricultural customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to a new AG Schedule with later TOU hours as described below: (N)

   Ag < 35 kW Low Use (AG-A1)
   Ag < 35 kW High Use (AG-A2)
   Ag 35+ kW Med Use (AG-B)
   Ag 35+ kW High Use (AG-C) (N)

   None of the above activities may process the agricultural product. Residential dwelling, office, and retail usage are not agricultural end-uses.

   The Rule 1 definition ‘Qualification for Agricultural Rates’ specifies additional activities and meters that will also be served on agricultural rates, and guidelines through the following sections: (B) Other Activities and Meters Also Served on Agricultural Rates, (C) Specific Applications of the March 2, 2006 Applicability Criteria, and (D) Guidelines for Applying the Applicability Criteria.

   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 AG-5 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

1. APPLICABILITY: (Cont'd.)

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 February 1, 2011, eligible large Agricultural 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.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule AG-5 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule AG-5 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to a new AG Schedule non-legacy rate listed below and enroll in the new PDP program. Customers currently participating on both Schedule AG-5 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to a new underlying AG Schedule based on size as listed below. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

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 Community 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 NEMA, are not eligible for PDP.

Decision 18-08-013 temporarily suspends the default of eligible AG-5 customers to PDP beginning March 1, 2019.

For additional PDP details and program specifics, see section 17.

2. TERRITORY: Schedule AG-5 applies everywhere PG&E provides electricity service.

ELECTRIC SCHEDULE AG-5 Sheet 6
LARGE TIME-OF-USE AGRICULTURAL POWER

3. RATES: Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

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.

TOTAL RATES

Total Customer/Meter Charge Rates	Rate A,D	Rate B,E	Rate C,F
Customer Charge ($ per meter per day)	$0.57400	$1.19446	$5.30871
TOU Meter Charge ($ per meter per day) (for rate A, B & C)	$0.22341	$0.19713	$0.19713
TOU Meter Charge ($ per meter per day) (for rate D, E & F)	$0.06571	$0.03943	$0.03943

Total Demand Rates ($ per kW)			
Connected Load Summer	$14.18	–	–
Connected Load Winter	$2.69	–	–
Maximum Demand Summer	–	$18.59	$7.61
Maximum Demand Winter	–	$7.30	$4.75
Maximum Peak Demand Summer	–	$11.75	$20.24
Maximum Part-Peak Demand Summer	–	–	$4.21
Maximum Part-Peak Demand Winter	–	–	$1.13
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–	$2.02	$2.97
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–	$0.22	$0.32
Transmission Voltage Discount			
Maximum Peak Demand Summer	–	–	$12.79
Maximum Part-Peak Demand Summer	–	–	$1.93
Maximum Demand Summer	–	$13.96	$4.33
Maximum Part-Peak Demand Winter	–	–	$1.13
Maximum Demand Winter	–	$6.28	$3.11

(Continued)

17. PEAK DAY PRICING DETAILS: Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with any Schedule AG rate, as described in the Peak Day Pricing paragraph located in the Applicability Clause above, may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible AG-5 customers to PDP beginning March 1, 2019 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for agricultural customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP.

   The default of eligible customers to PDP will occur once per year with the start of their billing cycle on or after March 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 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. 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 17.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.

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.

(L)
(L)

(Continued)

17. PEAK DAY PRICING DETAILS (CONT'D):

b. Capacity Reservation Level (Cont'd): (L)

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).

A customer may only elect to change their CRL once every 12-months. (L)

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

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

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.

(Continued)

ELECTRIC SCHEDULE AG-F Sheet 3
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

1.APPLICABILITY: (Cont'd)

Beginning March 1, 2021, customers still served on legacy rate Schedules AG-1, AG-4, AG-5, AG-R or AG-V, with exception of customers referenced above, will be transitioned to rate plans A1, A2, B, or C under Schedule AG with revised TOU periods. Customers may elect any rate for which they are eligible, including rates under this optional Schedule AG-F with flexible off-peak period days. The transition notification and default process are further described in the legacy rate Schedules AG-1, AG-4, AG-5, AG-R and AG-V.

Each rate plan under Schedule AG-F has three pre-defined options where two days of the week consist solely of off-peak hours and rates (that is, no peak period on these days):

Option I: **Off Peak Days** are Wednesday and Thursday,

Option II: **Off Peak Days** are Saturday and Sunday,

Option III: **Off Peak Days** are Monday and Friday.

A customer will be assigned to their selected option above for off-peak period days. PG&E reserves the right to eliminate the availability of some options for off-peak period days on Schedule AG-F on some circuits based on or due to local system constraints. Customers will be made aware if their first choice for the AG-F option for off-peak period days is not available at the time of enrollment, and if another option is available. AG-F enrollment will not be possible through an online self-service option and will require a live discussion with a Customer Service Representative at PG&E's Agricultural Customer Service Line (877-311-3276).

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. In addition, master-metered customers are not eligible, except for commercial buildings with submetering as stated in PG&E Rule 1 and Rule 18.

PDP rate options are not available to customers under this Schedule. Customers taking service on Schedule AG-F who wish to take service on PDP rates must transfer service to Schedule AG on rate options AG-A1, AG-A2, AG-B, or AG-C, under applicable eligibility rules, in order to voluntarily opt-in and enroll in the PDP program. (N)

2. TERRITORY: Schedule AG-F applies everywhere PG&E provides electricity service.

(Continued)

ELECTRIC SCHEDULE AG-R Sheet 1

SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: This schedule is closed to new customers. Customers taking service on this schedule as of May 1, 2012 must maintain continuous service on this schedule to remain eligible for service on this schedule. An exception to this rule will apply only to customers electing to migrate to Peak Day Pricing who subsequently elect to return to this schedule (see Peak Day Pricing Default Rates section).

A customer will be served under this schedule if 70% or more of the annual energy use on the meter is for agricultural end-uses. Agricultural end-uses consist of:

(a) growing crops;

(b) raising livestock;

(c) pumping water for irrigation of crops; or

(d) other uses which involve production for sale.

Only agricultural end-uses performed prior to the First Sale of the agricultural product are agricultural end-uses under this criteria, except for the following activities, which are also agricultural end-uses under this criteria: (a) packing and packaging of the agricultural products following the First Sale and before any subsequent sale, and (b) agricultural end-uses by nonprofit cooperatives. Guidelines for interpreting this applicability statement are set forthwith in Section D of the Rule 1 Definition 'Qualification for Agricultural Rates'.

Effective March 1. 2021, Schedule AG-R is available only to qualifying solar grandfathered customers, highly impacted agricultural customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to a new AG Schedule with later TOU hours as described below: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

None of the above activities may process the agricultural product. Residential dwelling, office, and retail usage are not agricultural end-uses.

The Rule 1 definition 'Qualification for Agricultural Rates' specifies additional activities and meters that will also be served on agricultural rates, and guidelines through the following sections: (B) Other Activities and Meters Also Served on Agricultural Rates, (C) Specific Applications of the March 2, 2006 Applicability Criteria, and (D) Guidelines for Applying the Applicability Criteria.

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 AG-R charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

ELECTRIC SCHEDULE AG-R Sheet 5
SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (cont'd)

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 February 1, 2011, eligible large Agricultural 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 served on this schedule will be placed on AG-4C PDP rates unless they opt-out.

Decision 18-08-013 temporarily suspends the default of eligible AG-R customers to PDP beginning March 1, 2019.

Customers that do not meet default eligibility may voluntarily elect to enroll on PDP rates. An AG-R customer that defaulted or voluntarily elected to enroll in a PDP rate may return back to rate schedule AG-R as long as the rate is in effect. For additional PDP details and program specifics, see rate schedule AG-4.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with any legacy agricultural rate schedule. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any legacy PDP customer remaining on the legacy Schedule AG-4 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to a new AG Schedule non-legacy rate listed below and enroll in the new PDP program. Customers currently participating on both Schedule AG-4 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to a new underlying AG Schedule based on size as listed below. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

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 S) and net-energy metering (NEM, NEMFC, NEMBIO, etc.) are not eligible for PDP.

2. TERRITORY: Schedule AG-R applies everywhere PG&E provides electricity service.

(Continued)

ELECTRIC SCHEDULE AG-V Sheet 1
SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: This schedule is closed to new customers. Customers taking service on this schedule as of May 1, 2012 must maintain continuous service on this schedule to remain eligible for service on this schedule. An exception to this rule will apply only to customers electing to migrate to Peak Day Pricing who subsequently elect to return to this schedule (see Peak Day Pricing Default Rates section).

A customer will be served under this schedule if 70% or more of the annual energy use on the meter is for agricultural end-uses. Agricultural end-uses consist of:

(a) growing crops;

(b) raising livestock;

(c) pumping water for irrigation of crops; or

(d) other uses which involve production for sale.

Only agricultural end-uses performed prior to the First Sale of the agricultural product are agricultural end-uses under this criteria, except for the following activities, which are also agricultural end-uses under this criteria: (a) packing and packaging of the agricultural products following the First Sale and before any subsequent sale, and (b) agricultural end-uses by nonprofit cooperatives. Guidelines for interpreting this applicability statement are set forthwith in Section D of the Rule 1 Definition 'Qualification for Agricultural Rates'.

None of the above activities may process the agricultural product. Residential dwelling, office, and retail usage are not agricultural end-uses.

Effective March 1, 2021, Schedule AG-V is available only to qualifying solar grandfathered customers, highly impacted agricultural customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to a new AG Schedule with later TOU hours as described below: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

The Rule 1 definition 'Qualification for Agricultural Rates' specifies additional activities and meters that will also be served on agricultural rates, and guidelines through the following sections: (B) Other Activities and Meters Also Served on Agricultural Rates, (C) Specific Applications of the March 2, 2006 Applicability Criteria, and (D) Guidelines for Applying the Applicability Criteria.

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 AG-V charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

1. APPLICABILITY: (cont'd)

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 February 1, 2011, eligible large Agricultural 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 served on this schedule will be placed on AG-4C PDP rates unless they opt-out.

Decision 18-08-013 temporarily suspends the default of eligible AG-V customers to PDP beginning March 1, 2019.Customers that do not meet default eligibility may voluntarily elect to enroll on PDP rates. An AG-V customer that defaulted or voluntarily elected to enroll in a PDP rate may return back to rate schedule AG-V as long as the rate is in effect. For additional PDP details and program specifics, see rate schedule AG-4.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with any legacy agricultural rate schedule. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any legacy PDP customer remaining on the legacy Schedule AG-4 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to a new AG Schedule non-legacy rate listed below and enroll in the new PDP program. Customers currently participating on both Schedule AG-4 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to a new underlying AG Schedule based on size as listed below. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

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 S) and net-energy metering (NEM, NEMFC, NEMBIO, etc.) are not eligible for PDP.

2. TERRITORY: Schedule AG-V applies everywhere PG&E provides electricity service

(Continued)

ELECTRIC SCHEDULE B-1
SMALL GENERAL SERVICE

APPLICABILITY: Schedule B-1 applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section). Customers that are otherwise eligible to take service on Schedule B-1 but are purchasing power to serve electric vehicle charging equipment, are not eligible to take service on this rate schedule.

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

These new rates with revised TOU periods adopted in D.18-08-013, including Schedule B-1, will be available to qualifying customers on a voluntary basis beginning in November 2019 through February 2021. During that period, eligible customers have a one-time opportunity to opt-in..

Customers eligible for this rate schedule must have an interval data meter that can be read remotely by PG&E. Beginning March 2021, customers still served on Schedule A-1, with the exception of solar grandfathered customers referenced above, will be transitioned to Schedule B-1 with revised TOU periods. The mandatory transition process is further described in the legacy rate Schedule A-1.

Customers with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months are not eligible for continued service under this rate schedule. Eligibility for B-1 will be reviewed annually and the transition of customers that are no longer eligible for service on this rate schedule to Schedule B-10 will occur on the start of the customer's November billing cycle, or to Schedule B-19 Mandatory for customers with a maximum demand of 499 kW or greater for three consecutive months in the most recent twelve months. These customers will have at least 45-day notice prior to their planned transition date, during which they will continue to take service on this rate schedule. Customers may elect any other applicable rate schedule up to five (5) days prior to the planned transition date to Schedule B-10.

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 non-utility 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-1 charges. Exemptions to Standby Charges are outlined in the Standby Applicability Section of this rate schedule.

(L)
(L)

* 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 website at http://www.pge.com/tariffs

(Continued)

APPLICABILITY: (Cont'd)

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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 (N)

TERRITORY: This rate schedule applies everywhere PG&E provides electric service. (L)

(Continued)

ELECTRIC SCHEDULE B-1
SMALL GENERAL SERVICE

Sheet 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.

Time-of-Use Rates	Rate
Total Customer Charge Rates	
Customer Charge Single-phase ($ per meter per day)	$0.32854
Customer Charge Poly-phase ($ per meter per day)	$0.82136
Total TOU Energy Rates ($ per kWh)	
Peak Summer	$0.32805
Part-Peak Summer	$0.27882
Off-Peak Summer	$0.25801
Peak Winter	$0.25263
Off-Peak Winter	$0.23651
Super Off-Peak Winter	$0.22009

PDP Rates (Consecutive Day and Three-Hour Event Option)* (N)

PDP Charges ($ per kWh)	
All Usage During PDP Event	$0.60000
PDP Credits	
Energy ($ per kWh)	
Peak Summer	($0.03330)
Part-Peak Summer	($0.00990)

* See PDP Detail, section g, for corresponding reduction in PDP credits and charges if other option(s) elected. (N)

(Continued)

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. (N) (N)

UNBUNDLING OF TOTAL RATES

Time-of-Use Rates	Rate	
Customer Charge Rates: Customer charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.		
Energy Rates by Components ($ per kWh)		
Generation:		
Peak Summer	$0.17737	(I)
Part-Peak Summer	$0.12814	(I)
Off-Peak Summer	$0.10733	(I)
Peak Winter	$0.12212	(I)
Off-Peak Winter	$0.10600	(I)
Super Off-Peak Winter	$0.08958	(I)
Distribution:**		
Peak Summer	$0.09551	(I)
Part-Peak Summer	$0.09551	(I)
Off-Peak Summer	$0.09551	(I)
Peak Winter	$0.07534	(I)
Off-Peak Winter	$0.07534	(I)
Super Off-Peak Winter	$0.07534	(I)
Transmission* (all usage)	$0.02766	
Transmission Rate Adjustments* (all usage)	$0.00314	
Reliability Services* (all usage)	($0.00051)	
Public Purpose Programs (all usage)	$0.01299	(R)
Nuclear Decommissioning (all usage)	$0.00101	(I)
Competition Transition Charges (all usage)	$0.00092	(R)
Energy Cost Recovery Amount (all usage)	$0.00005	(I)
New System Generation Charge (all usage)**	$0.00411	(I)
DWR Bond (all usage)	$0.00580	
California Climate Credit (all usage)***	$0.00000	

* 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)

PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible A-1 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The B-1 rates with new TOU periods will become mandatory for small Commercial and Industrial (C&I) customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2:00 p.m. – 6:00 p.m. PDP Event Hours to a new version of PDP (New PDP) with 5:00 p.m. – 8:00 p.m. PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

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

Active Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months.

Legacy 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 the New PDP. (N)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd)

c. 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 notification messages of a PDP event from PG&E. (N)

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.

d. 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.

e. 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.

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

f. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

(Continued)

PEAK DAY PRICING DETAILS (CONT'D):

g. Program Options: Customers may customize their PDP participation by choosing either a) no limit on the number of consecutive PDP events or b) every other PDP event. Customers electing every other PDP event will be divided into two groups and only be subject to a maximum of one-half of the PDP events called and the corresponding PDP rate credits will be reduced by 50%. Customers that do not elect an option will be defaulted to the no limit on the number of consecutive PDP events. The duration of PDP Event Operations for both options will be from 5:00 p.m. to 8:00 p.m. (three-hour window). (N)

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.

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

k. 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. (N)

(Continued)

ELECTRIC SCHEDULE B-10

MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY: Schedule B-10 is a demand metered rate schedule for general service customers. Schedule B-10 applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

These new rates with revised TOU periods adopted in D.18-08-013, including Schedule B-10, will be available to qualifying customers on a voluntary basis beginning in November 2019 through February 2021. During that period, eligible customers have a one-time opportunity to opt-in.

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 A-10, with the exception of solar grandfathered customers referenced above, will be transitioned to Schedule B-10 with revised TOU periods. The transition notification and default process are further described in the legacy rate Schedule A-10.

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-10 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Eligibility for Schedule B-10: Under Rate Schedule B-10, there is a limit on the demand (the number of kilowatts (kW)) the customer may require from the PG&E system. If the customer's demand exceeds 499 kW for three consecutive months, the customer's account will be transferred to Schedule B-19 or B-20. However, there is no minimum demand requirement to be served under this rate Schedule.

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will be between 75 and 499 kilowatts and that the customer should not be served under an agricultural or residential rate schedule, PG&E will serve the customer's account under the provisions of Rate Schedule B-10.

(L)
|
(L)

* 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.

(Continued)

ELECTRIC SCHEDULE B-10 Sheet 2
MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY: (Cont'd.)

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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. (N)

TERRITORY: This rate schedule applies everywhere PG&E provides electric service. (L)

ELECTRIC SCHEDULE B-10 Sheet 3
MEDIUM GENERAL DEMAND-METERED SERVICE

RATE: (L)

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

TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge ($ per meter per day)	$4.77841	$4.77841	$4.77841
Total Demand Rates ($ per kW)			
Summer	$13.59	$13.36	$10.49
Winter	$13.59	$13.36	$10.49
Total Energy Rates ($ per kWh)			
Peak Summer	$0.27409	$0.25976	$0.20988
Part-Peak Summer	$0.21240	$0.20145	$0.15314
Off-Peak Summer	$0.17983	$0.17062	$0.12307
Peak Winter	$0.19781	$0.18690	$0.15683
Off-Peak Winter	$0.16233	$0.15327	$0.12400
Super Off-Peak Winter	$0.12599	$0.11693	$0.08766

(L)

PDP Rates (Consecutive Day and Three-Hour Event Option)* (N)

	Secondary Voltage	Primary Voltage	Transmission Voltage
PDP Charges ($ per kWh)			
All Usage During PDP Event	$0.90000	$0.90000	$0.90000
PDP Credits			
Energy ($ per kWh)			
Peak Summer	($0.04756)	($0.04756)	($0.04756)
Part-Peak Summer	($0.01647)	($0.01647)	($0.01647)

* See PDP Details, section g, for corresponding reduction in PDP credits and charges if other option(s) elected. (N)

(Continued)

ELECTRIC SCHEDULE B-10 Sheet 4
MEDIUM GENERAL DEMAND-METERED SERVICE

RATES:

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. (L) (L)/(N) (L)

UNBUNDLING OF TOTAL RATES

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

	Secondary Voltage	Primary Voltage	Transmission Voltage
Demand Rate by Components ($ per kW)			
Generation:			
Summer	-	-	-
Winter	-	-	-
Distribution:**			
Summer	$4.75	$4.52	$1.65
Winter	$4.75	$4.52	$1.65
Transmission Maximum Demand*	$9.01	$9.01	$9.01
Reliability Services Maximum Demand*	($0.17)	($0.17)	($0.17)
Energy Rate by Components ($ per kWh)			
Generation:			
Peak Summer	$0.20191	$0.18769	$0.17531
Part-Peak Summer	$0.14022	$0.12938	$0.11857
Off-Peak Summer	$0.10765	$0.09855	$0.08850
Peak Winter	$0.14386	$0.13305	$0.12226
Off-Peak Winter	$0.10838	$0.09942	$0.08943
Super Off-Peak Winter	$0.07204	$0.06308	$0.05309
Distribution:**			
Summer	$0.04539	$0.04540	$0.00806
Winter	$0.02716	$0.02718	$0.00806
Transmission Rate Adjustments* (all usage)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01205	$0.01193	$0.01177
Competition Transition Charge (all usage)	$0.00099	$0.00099	$0.00099
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00375	$0.00375	$0.00375
California Climate Credit (all usage)***	$0.00000	$0.00000	$0.00000

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-10 Sheet 5
MEDIUM GENERAL DEMAND-METERED SERVICE

TIME PERIODS: Times of the year and times of the day are defined as follows: (L)

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 only, including weekends and holidays
Off-peak:	All other Hours.	

SEASONS: The summer rate is applicable June 1 through September 30, and the winter rate is applicable October 1 through May 31. When billing includes use in both the summer and winter periods, charges will be prorated based upon the number of days in each period. (L)

(Continued)

ELECTRIC SCHEDULE B-10 Sheet 6
MEDIUM GENERAL DEMAND-METERED SERVICE

BASIS FOR DEMAND CHARGE: The customer will be billed for demand according to the customer's "maximum demand" each month. The number of kW used will be recorded over 15-minute intervals; the highest 15-minute average in the month will be the customer's maximum demand. (L)

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.

DEFINITION OF SERVICE VOLTAGE: The following defines the three voltage classes of Schedule B-10 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.

PG&E retains the right to change its line voltage at any time. Customers receiving voltage discounts will get reasonable notice of any impending change. They will then have the option of taking service at the new voltage (and making whatever changes in their systems are necessary) or taking service without a voltage discount through transformers supplied by PG&E.

CONTRACT: For customers who use service for only part of the year, this schedule is available only on an annual contract. (L)

(Continued)

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.

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

Bundled Service Customers receive supply and delivery services solely from PG&E. The customer's bill is based on the total rates and conditions in this schedule.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23, 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. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear
decommissioning, public purpose programs, New System Generation Charges, the DA CRS pursuant to Schedule DA CRS and short-term commodity prices as set forth in Schedule TBCC. (L)

(Continued)

ELECTRIC SCHEDULE B-10 Sheet 8
MEDIUM GENERAL DEMAND-METERED SERVICE

BILLING: (Cont'd.)

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. (L)

Energy Cost Recovery Amount Charge (per kWh)	$0.00005
DWR Bond Charge (per kWh)	$0.00580
CTC Charge (per kWh)	$0.00099
Power Charge Indifference Adjustment (per kWh)	
2009 Vintage	$0.02643
2010 Vintage	$0.02969
2011 Vintage	$0.03222
2012 Vintage	$0.03209
2013 Vintage	$0.03432
2014 Vintage	$0.03480
2015 Vintage	$0.03461
2016 Vintage	$0.03447
2017 Vintage	$0.03441
2018 Vintage	$0.03443
2019 Vintage	$0.03669
2020 Vintage	$0.04379

CARE DISCOUNT:

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. (L)

(Continued)

ELECTRIC SCHEDULE B-10 Sheet 9
MEDIUM GENERAL DEMAND-METERED SERVICE

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

DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use 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 transfer to Schedule E-19, 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 time-of-use (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.

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 bundled sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts. (L)

PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible A-10 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The B-10 rates with new TOU periods will become mandatory for medium Commercial and Industrial (C&I) customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2:00 p.m. – 6:00 p.m. PDP Event Hours to a new version of PDP (New PDP) with 5:00 p.m. – 8:00 p.m. PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021. (N)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd)

a. Enrollment (cont'd): (N)

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

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

Active Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months.

Legacy 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 the New PDP. (N)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd):

c. 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 notification messages of a PDP event from PG&E. (N)

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.\

d. 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.

e. 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.

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

f. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

(Continued)

PEAK DAY PRICING DETAILS (CONT'D):

g. Program Options: Customers may customize their PDP participation by choosing either a) no limit on the number of consecutive PDP events or b) every other PDP event. Customers electing every other PDP event will be divided into two groups and only be subject to a maximum of one-half of the PDP events called and the corresponding PDP rate credits will be reduced by 50%. Customers that do not elect an option will be defaulted to the no limit on the number of consecutive PDP events. The duration of PDP Event Operations for both options will be from 5:00 p.m. to 8:00 p.m. (three-hour window). (N)

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. (N)

(Continued)

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

Option R for Solar: The Option R rate is available to qualifying customers taking Bundled, Direct Access (DA) or Community Choice Aggregation (CCA) service under Schedule B-19, or voluntary B-19. Eligible customers must have PV systems that provide 15% or more of their annual electricity usage. For additional Option R details and program specifics, see Sections 3 and 18.

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.

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).

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).

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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. (N)

(L)
(L)

(Continued)

2. TERRITORY: This rate schedule applies everywhere PG&E provides electricity service. **(L)**

BUNDLED TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage	
Total Customer Charge Rates				
Customer Charge Mandatory B-19 ($ per meter per day)	$24.77594	$37.82037	$48.05297	
Customer Charge with SmartMeter™ ($ per meter per day)	$4.77841	$4.77841	$4.77841	
Total Demand Rates ($ per kW)				
Maximum Peak Demand Summer	$25.79	$22.95	$9.76	
Maximum Part-Peak Demand Summer	$5.30	$4.78	$2.44	
Maximum Demand Summer	$21.44	$17.64	$12.11	
Maximum Peak Demand Winter	$1.77	$1.31	$0.94	
Maximum Demand Winter	$21.44	$17.64	$12.11	
Total Energy Rates ($ per kWh)				
Peak Summer	$0.16520	$0.14902	$0.13589	
Part-Peak Summer	$0.13541	$0.12640	$0.12665	
Off-Peak Summer	$0.11434	$0.10673	$0.10698	
Peak Winter	$0.14628	$0.13676	$0.13712	
Off-Peak Winter	$0.11426	$0.10686	$0.10724	
Super Off-Peak Winter	$0.07130	$0.06432	$0.06329	
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005	
PDP Rates				(N)
PDP Charges ($ per kWh)				|
All Usage During PDP Event	$1.20	$1.20	$1.20	|
PDP Credits				|
Demand ($ per kW)				|
Peak Summer	($6.48)	($5.89)	($4.84)	|
Part-Peak Summer	($0.94)	($0.86)	($1.21)	|
Energy ($ per kWh)				|
Peak Summer	$0.00	$0.00	$0.00	|
Part-Peak Summer	$0.00	$0.00	$0.00	(N)

(Continued)

ELECTRIC SCHEDULE B-19 Sheet 4
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. (N)

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	$14.92	$12.76	$9.76
Maximum Part-Peak Demand Summer	$2.17	$1.87	$2.44
Maximum Demand Summer	$0.00	$0.00	$0.00
Maximum Peak-Demand Winter	$1.77	$1.31	$0.94
Distribution:**			
Maximum Peak Demand Summer	$10.87	$10.19	$0.00
Maximum Part-Peak Demand Summer	$3.13	$2.91	$0.00
Maximum Demand Summer	$12.53	$8.73	$3.20
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$12.53	$8.73	$3.20
Transmission Maximum Demand*	$9.01	$9.01	$9.01
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)

* 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 B-19 Sheet 5
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. (N)

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	$0.13878	$0.12298	$0.10985
Part-Peak Summer	$0.10899	$0.10036	$0.10061
Off-Peak Summer	$0.08792	$0.08069	$0.08094
Peak Winter	$0.11986	$0.11072	$0.11108
Off-Peak Winter	$0.08784	$0.08082	$0.08120
Super Off-Peak Winter	$0.04488	$0.03828	$0.03725
Transmission Rate Adjustments* (all usage)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01177	$0.01139	$0.01139
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00090	$0.00090	$0.00090
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00375	$0.00375	$0.00375
California Climate Credit (all usage – B-19V only)***	$0.00000	$0.00000	$0.00000

* 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)

21. PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible E-19 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The B-19 rates with new TOU periods will become mandatory for medium and large Commercial and Industrial (C&I) customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2:00 p.m. – 6:00 p.m. PDP Event Hours to a new version of PDP (New PDP) with 5:00 p.m. – 8:00 p.m. PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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.

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

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

(Continued)

21. PEAK DAY PRICING DETAILS (Cont'd)

c. Bill Stabilization (Cont'd): (N)

Active Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months.

Legacy 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 the New 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 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.

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.

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

(Continued)

21. PEAK DAY PRICING DETAILS (Cont'd)

g. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

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. (N)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 2
SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

1. APPLICABILITY: (Cont'd.)

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

Standby Demand: For customers 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.

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).

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

Option R for Solar: The Option R rate is available to qualifying Bundled, DA and CCA B-20 customers, with solar photovoltaic (PV) systems that provide 15% or more of their annual electricity usage. For additional Option R details and program specifics, see Sections 3 and 16.

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

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

Option S for Storage: The Option S rate for storage is available to qualifying Bundled, DA and CCA service under Schedule B-20 customers with storage systems with a 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, sett Sections 3 and 18.

(L)
(L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 3
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

1. APPLICABILITY: (Cont'd.)

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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. (N)

2. TERRITORY: Schedule B-20 applies everywhere PG&E provides electric service. (L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 4

SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

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. (L)

BUNDLED TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage	
Total Customer Charge Rates				
Customer Charge Mandatory B-20 ($ per meter per day)	$45.08771	$45.16384	$57.74500	
Total Demand Rates ($ per kW)				
Maximum Peak Demand Summer	$25.74	$26.14	$17.83	
Maximum Part-Peak Demand Summer	$5.31	$5.07	$4.25	
Maximum Demand Summer	$21.41	$19.33	$10.80	
Maximum Peak Demand Winter	$1.86	$1.84	$2.38	
Maximum Demand Winter	$21.41	$19.33	$10.80	
Total Energy Rates ($ per kWh)				
Peak Summer	$0.15792	$0.15326	$0.13226	
Part-Peak Summer	$0.13101	$0.12487	$0.11500	
Off-Peak Summer	$0.10976	$0.10507	$0.09574	
Peak Winter	$0.14189	$0.13519	$0.13143	
Off-Peak Winter	$0.10959	$0.10512	$0.09225	
Super Off-Peak Winter	$0.06632	$0.06246	$0.05312	
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005	(L)
PDP Rates				(N)
PDP Charges ($ per kWh)				
All Usage During PDP Event	$1.20	$1.20	$1.20	
PDP Credits				
Demand ($ per kW)				
Peak Summer	($6.30)	($7.10)	($6.25)	
Part-Peak Summer	($0.91)	($0.98)	($1.49)	
Energy ($ per kWh)				
Peak Summer	$0.00	0.00	$0.00	
Part-Peak Summer	$0.00	$0.00	$0.00	(N)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 5
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(Cont'd.)

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown 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. PDP charges and credits are all generation and are not included below. (L) (L)/(N) (N)

Demand Rates by Components ($ per kW)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Maximum Peak Demand Summer	$14.61	$15.99	$17.83
Maximum Part-Peak Demand Summer	$2.12	$2.20	$4.25
Maximum Demand Summer	$0.00	$0.00	$0.00
Maximum Peak Demand Winter	$1.86	$1.84	$2.38
Maximum Demand Winter	---	---	---
Distribution:**			
Maximum Peak Demand Summer	$11.13	$10.15	$0.00
Maximum Part-Peak Demand Summer	$3.19	$2.87	$0.00
Maximum Demand Summer	$11.66	$9.58	$1.05
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$11.66	$9.58	$1.05
Transmission Maximum Demand*	$9.85	$9.85	$9.85
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 6
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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. (L)/(N)

UNBUNDLING OF TOTAL RATES

Customer Charge Rates: Customer charge rates provided in the Total Rate 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	$0.13233	$0.12810	$0.10781
Part-Peak Summer	$0.10542	$0.09971	$0.09055
Off-Peak Summer	$0.08417	$0.07991	$0.07129
Peak Winter	$0.11630	$0.11003	$0.10698
Off-Peak Winter	$0.08400	$0.07996	$0.06780
Super Off-Peak Winter	$0.04073	$0.03730	$0.02867
Transmission Rate Adjustments* (all usage)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01146	$0.01106	$0.01041
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00326	$0.00326	$0.00326

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 7
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 RATES FOR OPTION R
(for qualifying solar customers as set forth in Section 16)

Total Customer Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory B-20 ($ per meter per day)	$45.08771	$45.16384	$57.74500
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$2.78	$2.54	$0.00
Maximum Part-Peak Demand Summer	$0.80	$0.72	$0.00
Maximum Demand Summer	$21.41	$19.33	$10.80
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$21.41	$19.33	$10.80
Total Energy Rates ($ per kWh)			
Peak Summer	$0.35949	$0.33728	$0.26896
Part-Peak Summer	$0.17666	$0.16612	$0.15034
Off-Peak Summer	$0.11763	$0.11355	$0.10009
Peak Winter	$0.15741	$0.14923	$0.15017
Off-Peak Winter	$0.11368	$0.10916	$0.09716
Super Off-Peak Winter	$0.07793	$0.07341	$0.06436
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 8
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 16)

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	$2.78	$2.54	$0.00
Maximum Part-Peak Demand Summer	$0.80	$0.72	$0.00
Maximum Demand Summer	$11.66	$9.58	$1.05
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$11.66	$9.58	$1.05
Transmission Maximum Demand*	$9.85	$9.85	$9.85
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 9
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 16)

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	$0.25843	$0.24755	$0.24450
Part-Peak Summer	$0.12568	$0.11865	$0.12588
Off-Peak Summer	$0.08822	$0.08395	$0.07563
Peak Winter	$0.13182	$0.12407	$0.12572
Off-Peak Winter	$0.08809	$0.08400	$0.07271
Super Off-Peak Winter	$0.05234	$0.04825	$0.03991
Distribution:**			
Peak Summer	$0.07547	$0.06457	$0.00001
Part-Peak Summer	$0.02539	$0.02231	$0.00001
Off-Peak Summer	$0.00382	$0.00444	$0.00001
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)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01146	$0.01106	$0.01041
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00326	$0.00326	$0.00326

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 RATES FOR OPTION S
(for qualifying storage customers as set forth in Section 18)

Total Customer Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory B-20 ($ per meter per day)	$45.08771	$45.16384	$57.74500
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer (per day)	$0.54	$0.43	$0.04
Maximum Part-Peak Demand Summer (per day)	$0.03	$0.03	
Maximum Demand Summer (per monthly billing, all hours except 9 am to 2 pm)	$2.36	$1.94	$0.21
Maximum Demand Summer (per monthly billing)	$9.75	$9.75	$9.75
Maximum Peak Demand Winter (per day)	$0.45	$0.35	$0.04
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.36	$1.94	$0.21
Maximum Demand Winter (per billing month)	$9.75	$9.75	$9.75
Total Energy Rates ($ per kWh)			
Peak Summer	$0.35949	$0.33728	$0.26896
Part-Peak Summer	$0.17666	$0.16612	$0.15034
Off-Peak Summer	$0.11763	$0.11355	$0.10009
Peak Winter	$0.15741	$0.14923	$0.15017
Off-Peak Winter	$0.11368	$0.10916	$0.09716
Super Off-Peak Winter	$0.07793	$0.07341	$0.06436
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005 (L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 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 (per day)	$0.54	$0.43	$0.04
Maximum Part-Peak Demand Summer (per day)	$0.03	$0.03	
Maximum Demand Summer (per monthly billing, all hours except 9 am to 2 pm)	$2.36	$1.94	$0.21
Maximum Demand Summer (per monthly billing)	$0.00	$0.00	$0.00
Maximum Peak Demand Winter (per day)	$0.45	$0.35	$0.04
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.36	$1.94	$0.21
Maximum Demand Winter (per billing month)	$0.00	$0.00	$0.00
Transmission Maximum Demand*	$9.85	$9.85	$9.85
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)

* 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. (L)

ELECTRIC SCHEDULE B-20

SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 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	$0.25843	$0.24755	$0.24450
Part-Peak Summer	$0.12568	$0.11865	$0.12588
Off-Peak Summer	$0.08822	$0.08395	$0.07563
Peak Winter	$0.13182	$0.12407	$0.12572
Off-Peak Winter	$0.08809	$0.08400	$0.07271
Super Off-Peak Winter	$0.05234	$0.04825	$0.03991
Distribution:**			
Peak Summer	$0.07547	$0.06457	$0.00001
Part-Peak Summer	$0.02539	$0.02231	$0.00001
Off-Peak Summer	$0.00382	$0.00444	$0.00001
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)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01146	$0.01106	$0.01041
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00326	$0.00326	$0.00326

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 13
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. RATES: (Cont'd.)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule B-20 is the sum of a customer charge, demand charges, and energy charges: (L)

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

– Schedule B-20 has three **demand charges**, a maximum-peak-period-demand charge, a maximum-part-peak-period demand charge, and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum-part-peak-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. 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 voltage at which service is taken. Service voltages are defined in Section 5 below.

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

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

(Continued)

5. DEFINITION OF SERVICE VOLTAGE: The following defines the three voltage classes of Schedule B-20 rates. Standard Service Voltages are listed in Rule 2. (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 at one of the standard transmission voltages specified in PG&E's Electric 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)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

(L)

7. POWER FACTOR ADJUSTMENTS: The bill will be adjusted based upon the power factor. The power factor is computed from the cosine of the arctangent 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.

   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 Schedule B-20, the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a line extension agreement. See Rules 2, 15, and 16 for details.

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

10. SPECIAL FACILITIES: PG&E will normally install only those standard facilities it deems necessary to provide service under Schedule B-20. 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)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

11. BILLING: A customer's bill is calculated based on the option applicable to the customer. (L)

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

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

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, New System Generation Charges, 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.

	Secondary Voltage	Primary Voltage	Transmission Voltage
Energy Cost Recovery Amount Charge (per kWh)	$0.00005	$0.00005	$0.00005
DWR Bond Charge (per kWh)	$0.00580	$0.00580	$0.00580
CTC Rate (per kWh)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount Charge (per kWh)			
2009 Vintage	$0.02330	$0.02240	$0.02079
2010 Vintage	$0.02617	$0.02516	$0.02335
2011 Vintage	$0.02840	$0.02730	$0.02534
2012 Vintage	$0.02829	$0.02720	$0.02524
2013 Vintage	$0.03026	$0.02908	$0.02699
2014 Vintage	$0.03068	$0.02949	$0.02737
2015 Vintage	$0.03051	$0.02933	$0.02722
2016 Vintage	$0.03039	$0.02921	$0.02711
2017 Vintage	$0.03033	$0.02916	$0.02706
2018 Vintage	$0.03036	$0.02918	$0.02708
2019 Vintage	$0.03235	$0.03109	$0.02886
2020 Vintage	$0.03861	$0.03711	$0.03445

(L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 17

SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

12. 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. (L)

13. ELECTRIC EMER-GENCY PLAN ROTATING BLOCK OUTAGES: See Electric Rule 14.

14. 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.

15. 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)

16. Option R — The Option R rate is available to qualifying customers with PV systems that provide 15% or more of their annual electricity usage[1] as described below. No Benefitting* or Aggregated* account is eligible for Option R unless there is PV interconnected at that account that independently meets the requirements of Option R. i.e., the PV interconnected on that account meets 15% of the load at that account. (L)

Customers:

a) Installing a new PV system with no existing generation or with existing non-PV generation; or
b) With existing PV and non-PV generation (as an existing NEMMT)

Must meet the following eligibility requirement:

$$\frac{\text{Annual PV system output}^2}{\text{Annual electricity usage}^1} \geq 15\,\%$$

Customers:

a) With an existing PV system, that are installing new PV system
b) Adding new solar to existing PV and Non-PV generation

Must meet the following eligibility requirement:

$$\frac{\text{Annual PV system (new + existing) output}^2}{\text{Annual PV system (new + existing) output}^2 + \text{Annual electricity usage}^1} \geq 15\,\%$$

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

1 Annual electricity usage (kWh): for customers with no generation will be the most recent usage over twelve billing periods, and for customers with existing generation it will be the net of imports and exports (if any, for all generators), measured at the PG&E meter over the most recent 12 billing periods. In cases where the most recent 12-month usage is not available PG&E will offer an alternate method.

2 Annual PV system Output (kWh) = CEC_{AC} rating of the panels (kW) x 8760 hours/year x 18% capacity factor where:

$$CEC_{AC}\text{ Rating of the panels (kW)} = \frac{\text{(Quantity of PV Modules (W) x PTC Rating of PV Modules x CEC Inverter Efficiency Rating)}}{1000}$$

Where the PTC and CEC inverter Efficiency Rating can be found at:
The PTC rating can be found here:
http://www.gosolarcalifornia.ca.gov/equipment/documents/PV_Module_List_Simplified_Data.xlsx
and the CEC inverter efficiency rating here:
http://www.gosolarcalifornia.ca.gov/equipment/documents/Inverter_List_Simplified_Data.xlsx
The above Annual PV System Output formula can be modified based on the following alternatives:

a) For customers with existing PV system, the customer may choose to supply PG&E with reliable metered data measuring Annual PV system Output, if such data is available.
b) Customers with trackers can use the alternate capacity factors of:

Have single axis	21%
Have dual axis	24%

(L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 19
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

17. 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 DA and CCA 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)

17. 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)

18. 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)

ELECTRIC SCHEDULE B-20 Sheet 22
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

19. PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible E-20 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The B-20 rates with new TOU periods will become mandatory for large Commercial and Industrial (C&I) customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2:00 p.m. – 6:00 p.m. PDP Event Hours to a new version of PDP (New PDP) with 5:00 p.m. – 8:00 p.m. PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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.

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. (N)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 23
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

19. PEAK DAY PRICING DETAILS (Cont'd)

c. Bill Stabilization (Cont'd): (N)

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 Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months.

Legacy 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 the New 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 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.

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.

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

(Continued)

19. PEAK DAY PRICING DETAILS (Cont'd)

g. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

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. (N)

(Continued)

ELECTRIC SCHEDULE B-6 Sheet 1
SMALL GENERAL TIME-OF-USE SERVICE

APPLICABILITY: Schedule B-6, a time-of-use schedule, applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

These new rates with revised TOU periods adopted in D.18-08-013, including Schedule B-6, will be available to qualifying customers on a voluntary basis beginning in November 2019 through February 2021. During that period, eligible customers have a one-time opportunity to opt-in.

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 A-6, with the exception of solar grandfathered customers referenced above, will be transitioned to Schedule B-6 with revised TOU periods. The mandatory transition process is further described in the legacy rate Schedule A-6.

Customers with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months are not eligible for service on this rate schedule except as noted: customers served on Schedule A-6 or who sent PG&E a letter (via certified mail with a return receipt to establish a delivery record date) requesting a rate change pursuant to Electric Rule 12, on or before March 31, 2017 shall be allowed to take service on Schedule B-6 and will be exempt from annual 75 kW eligibility reviews, but will be subject to placement on Mandatory B-19 if over 499 kW for three consecutive months. Eligibility for B-6 will be reviewed annually and the transition of customers that are no longer eligible for service on this rate schedule to Schedule B-10 will occur on the start of the customers' November billing cycle. These customers will have at least 45-days' notice prior to their planned transition, during which they will continue to take service on this rate schedule. Customers may elect any other applicable rate schedule up to five (5) days prior to the planned transition date to Schedule B-10.

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-6 charges. Exemptions are outlined in the Standby Applicability Section of this rate schedule.

(L)
(L)

* 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 website at http://www.pge.com/tariffs.

(Continued)

ELECTRIC SCHEDULE B-6 Sheet 2
SMALL GENERAL TIME-OF-USE SERVICE

APPLICABILITY: (Cont'd.) **Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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. (N)

TERRITORY: This rate schedule applies everywhere PG&E provides electric service. (L)

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.

TOTAL RATES

Total Customer/Meter Charge Rates

Customer Charge Single-phase ($ per meter per day)	$0.32854
Customer Charge Poly-phase ($ per meter per day)	$0.82136

Total Energy Rates ($ per kWh)

Peak Summer	$0.36038
Off-Peak Summer	$0.24244
Peak Winter	$0.25277
Off-Peak Winter	$0.23302
Super Off-Peak Winter	$0.21661

PDP Rates (Consecutive Day and Three-Hour Event Option)* (N)

PDP Charges ($ per kWh)	
All Usage During PDP Event	$0.60000
PDP Credits	
Energy ($ per kWh)	
Peak Summer	($0.04090)

** See PDP Details, section g, for corresponding reduction in PDP credits and charges if other option(s) elected.* (N)

RATES: (Cont'd.)

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

UNBUNDLING OF TOTAL RATES

Customer Charge Rates: Customer charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component. PDP charges and credits are all generation and are not included below. (N) (N)

Energy Rates by Components ($ per kWh)	Rates
Generation:	
Peak Summer	$0.18197
Off-Peak Summer	$0.11081
Peak Winter	$0.11845
Off Peak Winter	$0.10139
Super Off-Peak Winter	$0.08498
Distribution:**	
Peak Summer	$0.12429
Off-Peak Summer	$0.07751
Peak Winter	$0.08020
Off Peak Winter	$0.07751
Super Off-Peak Winter	$0.07751
Transmission* (all usage)	$0.02766
DWR Bond (all usage)	$0.00580
Transmission Rate Adjustments* (all usage)	$0.00314
Reliability Services* (all usage)	($0.00051)
Public Purpose Programs (all usage)	$0.01194
Nuclear Decommissioning (all usage)	$0.00101
Competition Transition Charges (all usage)	$0.00092
Energy Cost Recovery Amount (all usage)	$0.00005
New System Generation Charge (all usage)**	$0.00411
California Climate Credit (all usage)***	$0.00000

* 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)

PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible A-6 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The B-6 rates with new TOU periods will become mandatory for small Commercial and Industrial (C&I) customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2:00 p.m. – 6:00 p.m. PDP Event Hours to a new version of PDP (New PDP) with 5:00 p.m. – 8:00 p.m. PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

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

Active Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months. (N)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd)

b. Bill Stabilization (Cont'd): (N)

Legacy 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 the New PDP.

c. 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 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.

d. 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.

e. 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.

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

f. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd)

g. Program Options: Customers may customize their PDP participation by choosing either a) no limit on the number of consecutive PDP events or b) every other PDP event. Customers electing every other PDP event will be divided into two groups and only be subject to a maximum of one-half of the PDP events called and the corresponding PDP rate credits will be reduced by 50%. Customers that do not elect an option will be defaulted to the no limit on the number of consecutive PDP events. The duration of PDP Event Operations for both options will be from 5:00 p.m. to 8:00 p.m. (three-hour window). (N)

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. (N)

(Continued)

ELECTRIC SCHEDULE E-19 Sheet 1

MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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.

Effective March 1, 2021, Schedule E-19 is available only to qualifying solar grandfathered customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to new Schedule B-19 or other applicable new tariffs with later Time-of-Use (TOU) hours as described below. (N)

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1*, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods will be available on a voluntary basis for qualifying customers beginning November 1, 2019. During this voluntary period from November 1, 2019 through February 2021, as well as thereafter:

Schedule B-19, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters and less than 1000 kW in size. Customers who enroll in any new rate during the voluntary period will be unenrolled from Peak Day Pricing.

Schedule E-19 will be closed to all new enrollment. Customers requesting to establish service on Schedule E-19 where an interval data meter that can be read remotely by PG&E is already in place will be placed on the new Schedule B-19. Customers requesting to establish service on Schedule E-19 that do not have a meter that is capable of billing on the new Schedule B-19, may take service on this schedule.

Customers taking service under Schedule E-19 at the time rates with new TOU periods become available on a voluntary basis, may transfer to new Schedule B-19, may remain on this rate until rates with new TOU periods become mandatory, in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers.

* 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.

(Continued)

1. APPLICABILITY: During the period the new rates with revised TOU periods are available on a voluntary basis for qualifying customers, from November 1, 2019 through February 28, 2021, customers who have opted in to the revised TOU periods, may opt out of the revised TOU periods and return to a legacy electric rate schedule with the legacy TOU periods listed in the special condition for “Definition of Time Periods” in this tariff, for the remainder of the period that the new rates with revised TOU periods are voluntary. Opting out of the revised TOU periods before they become mandatory is available on a one-time basis. If the customer opts-out of a new rate with the revised TOU periods less than twelve months before the revised TOU periods become mandatory, the customer may not return to a rate with the revised TOU periods until they become mandatory. (N)

Beginning March 2021, Schedule B-19, with revised TOU periods, will become mandatory for customers served on this rate schedule.

Mandatory transitions to Schedule B-19 will occur at the start of the customer’s March billing cycle.

Customers eligible to transition to the new rates must have an interval data meter and have at least twelve (12) billing months of hourly usage data available.

All transitioning customers will be notified at least 45 days prior to their scheduled transition date. Customers may elect any applicable rate with new TOU periods (that they are eligible for) up to five (5) days prior to their scheduled transition to B-19.

Exemptions to mandatory transitions beginning in March 2021 include:

Qualifying customers with solar systems who meet the requirements in Rule 1 Definition of “Behind-the-Meter Solar TOU Period Grandfathering” and the terms of “Behind-the-Meter Solar TOU Period Grandfathering Eligibility Requirements” shall be permitted to maintain their legacy TOU rate periods and service under Schedule E-19, until the date ten years after their system received its permission to operate (but in no event beyond December 31, 2027 (for public schools) or July 31, 2027 (for all other qualifying customers). However, rates for those TOU rate periods will be updated with new rates as authorized in applicable PG&E rate proceedings and advice filings.

Customers that do not have a meter that is capable of billing on the new Schedules B-19 by the beginning of their March 2021 billing cycle, may continue service on this schedule until they receive an interval meter and have at least twelve (12) months of hourly usage data available.

This mandatory transition process will then occur in November 2021 and in each November thereafter to transition all applicable remaining E-19 customers to the rates with revised TOU periods.

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.

(Continued)

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

1. APPLICABILITY: (Cont'd.)

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:

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.

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.

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 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.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule E-19 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule E-19 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to Schedule B-19 or other applicable non-legacy rate and enroll in the new PDP program. Customers currently participating on both Schedule E-19 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to the new underlying TOU Schedule B-19 or other applicable new non-legacy rate option. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date. (N)

Customers with a SmartMeter system, or interval meter, installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates.

(L)
(L)

(Continued)

1. APPLICABILITY: (Cont'd.)

Peak Day Pricing Rates (Cont'd): (L)

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 S), or on net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, are not eligible for PDP. In addition, master-metered customers are not 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. (L)

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.

Option R for Solar: The Option R rate is available to qualifying customers taking Bundled, DA or CCA service under Schedule E-19, or voluntary E-19. Eligible customers must have solar photovoltaic (PV) systems that provide 15% or more of their annual electricity usage. For additional Option R details and program specifics, see Sections 3 and 20.

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.

(Continued)

ELECTRIC SCHEDULE E-19 Sheet 5
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.

Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

TOTAL RATES

Total Customer/Meter Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory E-19 ($ per meter per day)	$24.77594	$37.82037	$48.05297
Customer Charge Voluntary E-19:			
Customer Charge with SmartMeter™ ($ per meter per day)	$4.77841	$4.77841	$4.77841
Customer Charge without SmartMeter™			
Customer Charge Rate V ($ per meter per day)	$4.95582	$4.95582	$4.95582
Customer Charge Rate W ($ per meter per day)	$4.81389	$4.81389	$4.81389
Customer Charge Rate X ($ per meter per day)	$4.95582	$4.95582	$4.95582
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$21.94	$19.53	$14.56
Maximum Part-Peak Demand Summer	$6.10	$5.33	$3.65
Maximum Demand Summer	$21.10	$17.47	$12.11
Maximum Part-Peak Demand Winter	$0.14	$0.17	$0.00
Maximum Demand Winter	$21.10	$17.47	$12.11
Total Energy Rates ($ per kWh)			
Peak Summer	$0.17427	$0.16241	$0.12020
Part-Peak Summer	$0.12656	$0.11744	$0.10543
Off-Peak Summer	$0.09496	$0.08853	$0.08588
Part-Peak Winter	$0.12002	$0.11137	$0.10775
Off-Peak Winter	$0.10280	$0.09567	$0.09274
Power Factor Adjustment Rate ($/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	($5.29)	($5.18)	($5.01)
Part-Peak Summer	($1.31)	($1.26)	($1.25)
Energy ($ per kWh)			
Peak Summer	$0.00000	$0.00000	$0.00000
Part-Peak Summer	$0.00000	$0.00000	$0.00000

(Continued)

18. PEAK DAY PRICING DETAILS:

Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with Schedule B-19 or other applicable non-legacy rate may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible E-19 customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for medium and large Commercial and Industrial (C&I) customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP. (T)

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 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.

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.

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).

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

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 1

SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

1. APPLICABILITY: **Initial Assignment:** A customer is eligible for service under Schedule E-20 if the customer's maximum demand (as defined below) has exceeded 999 kilowatts for at least three consecutive months during the most recent 12-month period. 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.

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

Effective March 1, 2021, Schedule E-20 is available only to qualifying solar grandfathered customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to new Schedule B-20 or other applicable new tariffs with later Time-of-Use (TOU) hours as described below. (N)

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new legacy TOU periods (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 (i.e., be grandfathered on) their existing TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods will be available on a voluntary basis for qualifying customers beginning November 1, 2019. During this voluntary period from November 1, 2019 through February 2021, as well as thereafter.

Schedule B-20, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters and greater than 999 kW in size. Customers who enroll in any new rate during the voluntary period will be unenrolled from Peak Day Pricing.

Schedule E-20 will be closed to all new enrollment. Customers requesting to establish service on Schedule E-20 where an interval data meter that can be read remotely by PG&E is already in place will be placed on the new Schedule B-20. Customers requesting to establish service on Schedule E-20 that do not have a meter that is capable of billing on the new Schedule B-20, may take service on this schedule.

Customers taking service under Schedule E-19 at the time rates with new TOU periods become available on a voluntary basis, may transfer to new Schedule B-19, may remain on this rate until rates with new TOU periods become mandatory, in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers.

(L)

(L)

* 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.

(Continued)

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

1. APPLICABILITY: (Cont'd.)

During the period the new rates with revised TOU periods are available on a voluntary basis for qualifying customers, from November 1, 2019 through February 28, 2021, customers who have opted in to the revised TOU periods, may opt out of the revised TOU periods and return to a legacy electric rate schedule with the legacy TOU periods listed in the special condition for "Definition of Time Periods" in this tariff, for the remainder of the period that the new rates with revised TOU periods are voluntary. Opting out of the revised TOU periods before they become mandatory is available on a one-time basis. If the customer opts-out of a new rate with the revised TOU periods less than twelve months before the revised TOU periods become mandatory, the customer may not return to a rate with the revised TOU periods until they become mandatory. (L)

Beginning March 2021, Schedule B-20, with revised TOU periods, will become mandatory for customers served on this rate schedule.

Mandatory transitions to Schedule B-20 will occur at the start of the customer's March billing cycle.

Customers eligible to transition to the new rates must have an interval data meter and have at least twelve (12) billing months of hourly usage data available.

All transitioning customers will be notified at least 45 days prior to their scheduled transition date. Customers may elect any applicable rate with new TOU periods (that they are eligible for) up to five (5) days prior to their scheduled transition to B-20

Exemptions to mandatory transitions beginning in March 2021 include:

Qualifying customers with solar systems who meet the requirements in Rule 1 Definition of "Behind-the-Meter Solar TOU Period Grandfathering" and the terms of "Behind-the-Meter Solar TOU Period Grandfathering Eligibility Requirements" shall be permitted to maintain their legacy TOU rate periods and service under Schedule E-20, until the date ten years after their system received its permission to operate (but in no event beyond December 31, 2027 (for public schools) or July 31, 2027 (for all other qualifying). However, rates for those TOU rate periods will be updated with new rates as authorized in applicable PG&E rate proceedings and advice filings.

Customers that do not have a meter that is capable of billing on the new Schedules B-20 by the beginning of their March 2021 billing cycle, may continue service on this schedule until they receive an interval meter and have at least twelve (12) months of hourly usage data available.

This mandatory transition process will then occur each November 2021 and in each November thereafter to transition all applicable remaining E-20 customers to the rates with revised TOU periods.

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 <u>not</u> 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-20 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(L)
(L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 3
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

1. APPLICABILITY: (Cont'd.)

Transfers Off of Schedule E-20: PG&E will review its Schedule E-20 accounts annually. A customer will be eligible for continued service on Schedule E-20 if its maximum demand has either: (1) Exceeded 999 kilowatts for at least 5 of the previous 12 billing months; or (2) Exceeded 999 kilowatts for any 3 consecutive billing months of the previous 14 billing months. If a customer's demand history fails both of these tests, PG&E will transfer that customer's account to service under a different applicable rate schedule. (L)

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will exceed 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-20.

Peak Day Pricing 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.

Customers may voluntarily elect to enroll on PDP rates. (L)

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule E-20 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule E-20 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to Schedule B-20 or other applicable non-legacy rate and enroll in the new PDP program. Customers currently participating on both Schedule E-20 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to the new underlying TOU Schedule B-20 or other applicable new non-legacy rate option. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date. (N)

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 S), or on net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, are not eligible for PDP. In addition, master-metered customers are not eligible, except for commercial buildings with submetering as stated in PG&E Rule 1 and Rule 18. Non-residential SmartAC customers are eligible.

For additional PDP details and program specifics, see section 17.

(L)
(L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 4
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

1.APPLICABILITY: (Cont'd.)

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

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

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

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

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

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

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

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

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 5
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

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 (L)

Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

TOTAL RATES (L)

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge Mandatory E-20 ($ per meter per day)	$45.08771	$45.16384	$57.74500
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$21.19	$22.77	$18.80
Maximum Part-Peak Demand Summer	$5.88	$6.07	$4.48
Maximum Demand Summer	$21.30	$18.82	$10.80
Maximum Part-Peak Demand Winter	$0.06	$0.15	$0.00
Maximum Demand Winter	$21.30	$18.82	$10.80
Total Energy Rates ($ per kWh)			
Peak Summer	$0.16299	$0.16528	$0.11670
Part-Peak Summer	$0.11960	$0.11759	$0.10223
Off-Peak Summer	$0.08981	$0.08825	$0.08307
Part-Peak Winter	$0.11330	$0.11130	$0.10450
Off-Peak Winter	$0.09716	$0.09546	$0.08979
Power Factor Adjustment Rate ($/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	($5.10)	($5.57)	($5.95)
Part-Peak Summer	($1.26)	($1.32)	($1.42)
Energy ($ per kWh)			
Peak Summer	$0.00000	$0.00000	$0.00000
Part-Peak Summer	$0.00000	$0.00000	$0.00000

(L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 6
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. RATES: (Cont'd.) (L)

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

Demand Rates by Component ($ per kW)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Maximum Peak Demand Summer	$14.41	$15.78	$18.80
Maximum Part-Peak Demand Summer	$3.56	$3.73	$4.48
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	$6.78	$6.99	$0.00
Maximum Part-Peak Demand Summer	$2.32	$2.34	$0.00
Maximum Demand Summer	$11.55	$9.07	$1.05
Maximum Part-Peak Demand Winter	$0.06	$0.15	$0.00
Maximum Demand Winter	$11.55	$9.07	$1.05
Transmission Maximum Demand*	$9.85	$9.85	$9.85
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)
Energy Rates by Component ($ per kWh)			
Generation:			
Peak Summer	$0.13740	$0.14012	$0.09225
Part-Peak Summer	$0.09401	$0.09243	$0.07778
Off-Peak Summer	$0.06422	$0.06309	$0.05862
Part-Peak Winter	$0.08771	$0.08614	$0.08005
Off-Peak Winter	$0.07157	$0.07030	$0.06534
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**)**	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01146	$0.01106	$0.01041
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00326	$0.00326	$0.00326

(L)

* 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-20 Sheet 7
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. RATES: (Cont'd.) (L)

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

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge Mandatory E-20 ($ per meter per day)	$45.08771	$45.16384 (	$57.74500
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$1.69	$1.75	$0.00
Maximum Part-Peak Demand Summer	$0.58	$0.58	$0.00
Maximum Demand Summer	$21.30	$18.82	$10.80
Maximum Part-Peak Demand Winter	$0.01	$0.04	$0.00
Maximum Demand Winter	$21.30	$18.82	$10.80
Total Energy Rates ($ per kWh)			
Peak Summer	$0.35511	$0.37280	$0.31425
Part-Peak Summer	$0.17270	$0.17028	$0.14562
Off-Peak Summer	$0.09371	$0.09246	$0.08555
Part-Peak Winter	$0.11660	$0.11526	$0.10626
Off-Peak Winter	$0.10080	$0.09943	$0.09204
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 8
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (Cont'd.) (L)

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

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

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	$1.69	$1.75	$0.00
Maximum Part-Peak Demand Summer	$0.58	$0.58	$0.00
Maximum Demand Summer	$11.55	$9.07	$1.05
Maximum Part-Peak Demand Winter	$0.01	$0.04	$0.00
Maximum Demand Winter	$11.55	$9.07	$1.05
Transmission Maximum Demand*	$9.85	$9.85	$9.85
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)
Energy Rates by Component ($ per kWh)			
Generation:			
Peak Summer	$0.28018	$0.29749	$0.28980
Part-Peak Summer	$0.13026	$0.12893	$0.12117
Off-Peak Summer	$0.06705	$0.06606	$0.06110
Part-Peak Winter	$0.08972	$0.08834	$0.08181
Off-Peak Winter	$0.07414	$0.07303	$0.06759
Distribution:**			
Peak Summer	$0.04934	$0.05015	$0.00000
Part-Peak Summer	$0.01685	$0.01619	$0.00000
Off-Peak Summer	$0.00107	$0.00124	$0.00000
Part-Peak Winter	$0.00129	$0.00176	$0.00000
Off-Peak Winter	$0.00107	$0.00124	$0.00000
Transmission Rate Adjustments* (all usage)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01146	$0.01106	$0.01041
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00326	$0.00326	$0.00326

* 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. (L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 9
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. RATES: (Cont'd.)

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

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

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

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

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

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

4. METERING REQUIREMENTS:

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

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

5. DEFINITION OF SERVICE VOLTAGE:

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

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

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

c. Transmission: This is the voltage class if the customer is served without transformation at one of the standard transmission voltages specified in PG&E's Electric Rule 2, Section B.1. (L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 10
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

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

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

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

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

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

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

DAYLIGHT SAVING TIME ADJUSTMENT: The time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

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

7. POWER FACTOR ADJUSTMENTS: The bill will be adjusted based upon the power factor. The power factor is computed from the cosine of the arctangent 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.

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. (L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 11
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

8.	CHARGES FOR TRANSFORMER AND LINE LOSSES:	The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of Rule 2.	(L)
9.	STANDARD SERVICE FACILITIES:	If PG&E must install any new or additional facilities to provide the customer with service under Schedule E-20, the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a line extension agreement. See Rules 2, 15, and 16 for details.	|
		Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in the line extension agreement.	|
10.	SPECIAL FACILITIES:	PG&E will normally install only those standard facilities it deems necessary to provide service under Schedule E-20. If the customer requests any additional facilities, those facilities will be treated as “special facilities” in accordance with Section I of Rule 2.	(L)

(Continued)

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

11. BILLING: A customer's bill is calculated based on the option applicable to the customer. (L)

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

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

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

DA / CCA CRS	Secondary Voltage	Primary Voltage	Transmission Voltage	
Energy Cost Recovery Amount Charge (per kWh)	$0.00005	$0.00005	$0.00005	
DWR Bond Charge (per kWh)	$0.00580	$0.00580	$0.00580	
CTC Rate (per kWh)	$0.00087	$0.00084	$0.00078	
Power Charge Indifference Adjustment (per kWh)				
2009 Vintage	$0.02330	$0.02240	$0.02079	
2010 Vintage	$0.02617	$0.02516	$0.02335	
2011 Vintage	$0.02840	$0.02730	$0.02534	
2012 Vintage	$0.02829	$0.02720	$0.02524	
2013 Vintage	$0.03026	$0.02908	$0.02699	
2014 Vintage	$0.03068	$0.02949	$0.02737	
2015 Vintage	$0.03051	$0.02933	$0.02722	
2016 Vintage	$0.03039	$0.02921	$0.02711	
2017 Vintage	$0.03033	$0.02916	$0.02706	
2018 Vintage	$0.03036	$0.02918	$0.02708	
2019 Vintage	$0.03235	$0.03109	$0.02886	
2020 Vintage	$0.03861	$0.03711	$0.03445	(L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 13

SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

12. 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. (L)

13. ELECTRIC EMER-GENCY PLAN ROTATING BLOCK OUTAGES: See Electric Rule 14.

14. 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. (L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 14
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

15. 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)

16. PEAK DAY PRICING DETAILS: Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with Schedule B-20 or other applicable non-legacy rate may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible E-20 customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for medium and large Commercial and Industrial (C&I) customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP. (L)/(T)

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 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 17.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.

b. Capacity Reservation Level: Customers may elect a capacity reservation level (CRL) and pay for a fixed level of capacity, specified in kW. While the CRL is applicable year round, customers electing a CRL will be billed under a take-or-pay basis up to the specified CRL under the non-PDP rate of this schedule during the summer period (May 1 through October 31). This means that customers will be billed for summer peak generation demand charges up to the level of their CRL, even in summer months when the actual demand might be less than their CRL. Customers will receive PDP credits on summer usage above the CRL on 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 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).

A customer may only elect to change their CRL once every 12-months. (L)

(Continued)

16. PEAK DAY PRICING DETAILS (continued):

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 unenrolls or terminates its participation on a PDP rate, bill stabilization will not be offered again.

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

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

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

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

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

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

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

(Continued)

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

16. PEAK DAY PRICING DETAILS (continued):

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.

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

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

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

j. Interaction with Other PG&E Demand Response Programs: 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)

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

17. Option R The Option R rate is available to qualifying customers with PV systems that provide 15% or more of their annual electricity usage[1] as described below. No Benefitting* or Aggregated* account is eligible for Option R unless there is PV interconnected at that account that independently meets the requirements of Option R. i.e., the PV interconnected on that account meets 15% of the load at that account. (L)

Customers:
a) Installing a new PV system with no existing generation or with existing non-PV generation; or
b) With existing PV and non-PV generation (as an existing NEMMT)

Must meet the following eligibility requirement:

$$\frac{\text{Annual PV system output}_2}{\text{Annual electricity usage}_1} \geq 15\ \%$$

Customers:
a) With an existing PV system, that are installing new PV system
b) Adding new solar to existing PV and Non-PV generation

Must meet the following eligibility requirement:

$$\frac{\text{Annual PV system (new + existing) output}_2}{\text{Annual PV system (new + existing) output}_2 + \text{Annual electricity usage}_1} \geq 15\ \%$$

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

[1] Annual electricity usage (kWh): for customers with no generation will be the most recent usage over twelve billing periods, and for customers with existing generation it will be the net of imports and exports (if any, for all generators), measured at the PG&E meter over the most recent 12 billing periods. In cases where the most recent 12-month usage is not available PG&E will offer an alternate method.

[2] Annual PV system Output (kWh) = CEC_{AC} rating of the panels (kW) * 8760 hours/year * 18% capacity factor where:

CEC_{AC} Rating of the panels (kW) =

$$\frac{\text{(Quantity of PV Modules (W) x PTC Rating of PV Modules x CEC Inverter Efficiency Rating)}}{1000}$$

Where the PTC and CEC inverter Efficiency Rating can be found at:
The PTC rating can be found here:
http://www.gosolarcalifornia.ca.gov/equipment/documents/PV_Module_List_Simplified_Data.xlsx
and the CEC inverter efficiency rating here:
http://www.gosolarcalifornia.ca.gov/equipment/documents/Inverter_List_Simplified_Data.xlsx

The above Annual PV System Output formula can be modified based on the following alternatives:
a) For customers with existing PV system, the customer may choose to supply PG&E with reliable metered data measuring Annual PV system Output, if such data is available.
b) Customers with trackers can use the alternate capacity factors of:

Have single axis	21%
Have dual axis	24%

(L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 18
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

18. 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 AG-5 (C) and (F) rates, Schedule E-19 or Schedule E-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 E-19 (above 500 kW as defined above), Schedule E-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 E-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

18. 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)

ELECTRIC RATE SCHEDULE RES-BCT Sheet 4

SCHEDULE FOR LOCAL GOVERNMENT
RENEWABLE ENERGY SELF-GENERATON BILL CREDIT TRANSFER

APPLICABLITY (Cont'd):

INTERCONNECTION: If a Generating Account Eligible Renewable Generating Facility has not been previously approved for interconnection by PG&E, or where any modification to the previously approved Generating Account Eligible Renewable Generating Facility has been made, the Local Government must complete the Rule 21 and RES-BCT interconnection process, and must designate all the Generating Accounts and Benefiting Accounts to be included in a Arrangement in the RES-BCT Application and the accompanying Appendix A (as described in Special Condition 3 of this tariff). A Local Government shall provide the PG&E with not less than 60 days' notice prior to a eligible renewable generating facility for a Generating Account from becoming operational.

Not more frequently than once per year, and upon providing PG&E with a minimum of 60 days' notice, the Local Government may elect to change [add or delete] a Benefiting Account or reassign the Generating or Benefiting Accounts Allocation Percentages, as defined in Special Condition 2(b). Bill credits for such changes will be handled in accordance Special Condition 2 (g).

TERMINATION: A Local Government may terminate service on RES-BCT upon providing PG&E with a minimum of 60 days' notice. Should a Local Government sell its interest in an Eligible Renewable Generating Facility served on RES-BCT, or sell the electricity generated by the Eligible Renewable Generating Facility, in a manner other than required by RES-BCT, upon the date of either event, and the earliest date if both events occur, no further Bill Credit pursuant to Special Condition 2 of this tariff may be earned. Only credit earned prior to that date shall be made to a Benefiting Account.

PEAK DAY PRICING: Nothing in this tariff shall restrict the Local Government's ability of their Arrangement's Generating and Benefiting Accounts from taking service under the Peak Day Pricing program. If the Local Government is enrolled in the Peak Day Pricing program, the RES-BCT generation credit will be based on the non-Peak Day Pricing rate component of the Generating Account OAS. (T)

(Continued)

Attachment 2

Redline Tariff Revisions

Note: For the ease of the reader, the redlines tariff revisions in this Advice Letter reflects edits that adds or deletes text from the tariffs. The “(L)” change symbol on the right-hand margin is used to identify the relocation of text to another tariff sheet, but the text itself is not redlined.

ELECTRIC SCHEDULE A-1 Sheet 1
SMALL GENERAL SERVICE

APPLICABILITY: Schedule A-1 applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section). Customers that are otherwise eligible to take service on Schedule A-1, but are purchasing power to serve electric vehicle charging equipment, are not eligible to take service on this rate schedule.

Effective March 1, 2021, Schedule A-1 is available only to qualifying solar grandfathered customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to new Schedule B-1 or other applicable new tariffs with later Time-of-Use (TOU) hours as described below. The non-TOU version of Schedule A-1 is not available for solar grandfathering purposes after March 2021. (N)

Effective November 1, 2012, Schedule A-1 is closed to customers with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months, or with usage of 150,000 kWh per year or greater, and who have at least twelve (12) months of hourly usage data available. Eligibility for A-1 will be reviewed annually and migration of ineligible customers will be implemented once per year, on bill cycles each November, using the same procedures described below for ~~Time-of-Use (~~TOU~~)~~ rates adopted in Decision 10-02-032 as modified by Decision 11-11-008. (T)

Effective November 1, 2014, new customers establishing service on Schedule A-1 where a Smart Meter™ is already in place will be charged Schedule A-1 TOU rates.

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods adopted in D.18-08-013 will be available on a voluntary basis for qualifying customers beginning November 1, 2019. During this voluntary period from November 1, 2019 through February 2021, as well as thereafter:

> Schedule B-1, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters and less than 75 kW in size.
>
> Schedule A-1 will be closed to all new enrollment. Customers requesting to establish service on Schedule A-1, where an interval data meter that can be read remotely by PG&E is already in place, will be placed on the new Schedule B-1 with revised TOU periods. Customers requesting to establish service on Schedule A-1 that do not have a meter capable of billing on the new Schedule B-1, may take service on this schedule.

(L)
(L)

* 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 website at http://www.pge.com/tariffs

(Continued)

APPLICABILITY: (cont'd.)

Customers taking service under Schedule A-1 at the time rates with new TOU periods become available on a voluntary basis, may transfer to new Schedule B-1, may remain on this rate until rates with new TOU periods become mandatory, in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers. (L)

During the period the new rates with revised TOU periods are available on a voluntary basis for qualifying customers, from November 1, 2019 through February 28, 2021, customers who have opted in to the revised TOU periods, may opt out of the revised TOU periods and return to a legacy electric rate schedule with the legacy TOU periods listed in the special condition for "Definition of Time Periods" in this tariff, for the remainder of the period that the new rates with revised TOU periods are voluntary. Opting out of the revised TOU periods before they become mandatory is available on a one-time basis. If the customer opts-out of a new rate with the revised TOU periods less than twelve months before the revised TOU periods become mandatory, the customer may not return to a rate with the revised TOU periods until they become mandatory.

Beginning on March 2021, customers still served on Schedule A-1 will be transitioned to Schedule B-1 as discussed in the Time of Use Rates Section below.

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 non-utility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S, in addition to all applicable Schedule A-1 charges. Exemptions to Standby Charges are outlined in the Standby Applicability Section of this rate schedule.

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule A-1 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule A-1 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to Schedule B-1 or other applicable non-legacy rate and enroll in the new PDP program. Customers currently participating on both Schedule A-1 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to the new underlying TOU Schedule B-1 or other applicable new non-legacy rate option. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date. (N)

(L)

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

APPLICABILITY: (cont'd.)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. In addition, master-metered customers are not 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. (L)

Time-of-Use Rates: Decision 10-02-032, as modified by Decision 11-11-008, makes time-of-use (TOU) rates mandatory beginning November 1, 2012, for small and medium Commercial and Industrial (C&I) customers that have at least twelve (12) billing months of hourly usage data available. (L)/(T)

Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The decision also suspends the transition of eligible A1 customers to mandatory TOU rates beginning November 1, 2018 until the rates with new TOU periods adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for small and medium C&I customers in March 2021 concurrent with the resumption of customer transitions to mandatory TOU rates. (L)

Decision 18-08-013 adopted new TOU periods and seasonal definitions for all non-residential customer classes as discussed above. After the voluntary period ends, beginning March 2021, Schedule B-1, with revised TOU periods, will become mandatory for customers served on this schedule, with exceptions for solar grandfathered customers, discussed above.

Beginning in March 2021, Schedule B-1, with revised TOU periods, will become mandatory for customers served on this schedule:

Customers on Schedule A-1 with an interval meter that have at least twelve (12) billing months of hourly usage data available will transition to new Schedule B-1.

Customers on Schedule A-1 with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months, or, with usage of 150,000 kWh per year or greater when measured kW is not available and who have at least twelve (12) months of hourly usage data available, will transition to new Schedule B-10.

Customers on the non-TOU option of Schedule A-1 eligible for transition to mandatory TOU rates, including Direct Access and Community Choice Aggregation (DA/CCA) customers, will transition to new Schedule B-1.

(L)
(L)

(Continued)

APPLICABILITY: (Cont'd.)

Time-of-Use Rates (Cont'd)**:** (L)

The transition of customers no longer eligible for A-1 to new Schedule B-1 (or B-10) with revised TOU periods will occur on the start of the customer's March 2021 billing cycle. Customers will have at least 45-days' notice prior to their scheduled transition date, during which they will continue to take service on this rate schedule. Customers may elect any applicable new rate with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule B-1 (or B-10).

Exemptions to the mandatory transitions beginning in March 2021 include:

Qualifying customers with solar systems who meet the requirements in Rule 1 Definition of "Behind-the-Meter Solar TOU Period Grandfathering" and the terms of "Behind-the-Meter Solar TOU Period Grandfathering Eligibility Requirements" shall be permitted to maintain their legacy TOU rate periods, until the date ten years after their system received its permission to operate (but in no event beyond December 31, 2027 (for public schools) or July 31, 2027 (for all other qualifying). However, rates for those TOU rate periods will be updated with new rates as authorized in applicable PG&E rate proceedings and advice filings.

Customers that do not have a meter that is capable of billing on the new Schedule B-1 by the beginning of their March 2021 billing cycle, may continue service on this schedule until they receive an interval meter and have at least twelve (12) months of hourly usage data available.

The mandatory transition process will then occur in November 2021 and in each November thereafter to transition all applicable remaining A-1 customers to the rates with revised TOU periods.

TERRITORY: This rate schedule applies everywhere PG&E provides electric service. (L)

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

RATES: Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

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. (L)

TOTAL RATES

A. Non-Time-of-Use Rates

Total Customer Charge Rates	
Customer Charge Single-phase ($ per meter per day)	$0.32854
Customer Charge Poly-phase ($ per meter per day)	$0.82136
Total Energy Rates ($ per kWh)	
Summer	$0.28091
Winter	$0.22036

B. Time-of-Use Rates

Total Customer Charge Rates	
Customer Charge Single-phase ($ per meter per day)	$0.32854
Customer Charge Poly-phase ($ per meter per day)	$0.82136
Total TOU Energy Rates ($ per kWh)	
Peak Summer	$0.29592
Part-Peak Summer	$0.27227
Off-Peak Summer	$0.24491
Part-Peak Winter	$0.25166
Off-Peak Winter	$0.23075
PDP Rates (Consecutive Day and Four-Hour Event Option) *	
PDP Charges ($ per kWh)	
All Usage During PDP Event	$0.60
PDP Credits	
Energy ($ per kWh)	
Peak Summer	($0.00905)
Part-Peak Summer	($0.00905)
Off-Peak Summer	($0.00905)

** See PDP Detail, section g, for corresponding reduction in PDP credits and charges if other option(s) elected.* (L)

(Continued)

ELECTRIC SCHEDULE A-1 Sheet 6
SMALL GENERAL SERVICE

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. (L)

UNBUNDLING OF TOTAL RATES

A. Non-Time-of-Use Rates

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

Energy Rates by Components ($ per kWh)	
Generation:	
Summer	$0.13350
Winter	$0.09336
Distribution**	
Summer	$0.09224
Winter	$0.07183
Transmission* (all usage)	$0.02766
Transmission Rate Adjustments* (all usage)	$0.00314
Reliability Services* (all usage)	($0.00051)
Public Purpose Programs (all usage)	$0.01299
Nuclear Decommissioning (all usage)	$0.00101
Competition Transition Charges (all usage)	$0.00092
Energy Cost Recovery Amount (all usage)	$0.00005
New System Generation Charge (all usage)**	$0.00411
DWR Bond (all usage)	$0.00580
California Climate Credit (all usage)***	$0.00000

(L)

(L)

* 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.

(L)

(Continued)

RATES: (Cont'd.)

UNBUNDLING OF TOTAL RATES (L)

B. Time-of-Use Rates

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

Energy Rates by Components ($ per kWh)

Generation:	
Peak Summer	$0.14851
Part-Peak Summer	$0.12486
Off-Peak Summer	$0.09750
Part-Peak Winter	$0.12466
Off-Peak Winter	$0.10375
Distribution:**	
Peak Summer	$0.09224
Part-Peak Summer	$0.09224
Off-Peak Summer	$0.09224
Part-Peak Winter	$0.07183
Off-Peak Winter	$0.07183
Transmission* (all usage)	$0.02766
Transmission Rate Adjustments* (all usage)	$0.00314
Reliability Services* (all usage)	($0.00051)
Public Purpose Programs (all usage)	$0.01299
Nuclear Decommissioning (all usage)	$0.00101
Competition Transition Charges (all usage)	$0.00092
Energy Cost Recovery Amount (all usage)	$0.00005
New System Generation Charge (all usage)**	$0.00411
DWR Bond (all usage)	$0.00580
California Climate Credit (all usage)***	$0.00000 (L)

(L)

* 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. (L)

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

Sheet 8

TIME PERIODS: Times of the year and times of the day are defined as follows: (L)

SUMMER (Service from May 1 through October 31):

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

WINTER (Service from November 1 through April 30):

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

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

CONTRACT: For customers who use service for only part of the year, this schedule is available only on annual contract. (L)

SEASONS: The summer rate is applicable May 1 through October 31, and the winter rate is applicable November 1 through April 30. When billing includes use in both the summer and winter periods, charges will be prorated based upon the number of days in each period.

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.

In the event that the CPUC substantially reduces the surcharges or 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.

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

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, 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. 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. (L)

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

BILLING: (Cont'd.)

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. (L)

	DA /CCA CRS
Energy Cost Recovery Amount Charge (per kWh)	$0.00005
DWR Bond Charge (per kWh)	$0.00580
CTC Charge (per kWh)	$0.00092
Power Charge Indifference Adjustment (per kWh)	
2009 Vintage	$0.02453
2010 Vintage	$0.02756
2011 Vintage	$0.02990
2012 Vintage	$0.02979
2013 Vintage	$0.03186
2014 Vintage	$0.03230
2015 Vintage	$0.03213
2016 Vintage	$0.03199
2017 Vintage	$0.03194
2018 Vintage	$0.03196
2019 Vintage	$0.03406
2020 Vintage	$0.04065

CARE DISCOUNT:

Nonprofit Group-Living Facilities which meet the eligibility criteria in Rule 19.2 or 19.3 are eligible for a California Alternate Rates for Energy discount pursuant to Schedule E-CARE. CARE customers are exempt from paying the DWR Bond Charge.

STANDBY APPLICABILITY:

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

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

STANDBY APPLICABILITY: (Cont'd.)	DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use 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 transfer to Schedule A-6 or E-19, 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 time-of-use (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.	(L)
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)

PEAK DAY PRICING DETAILS

Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with Schedule B-1 or other applicable non-legacy rate may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible A-1 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for small and medium C&I customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP. (L)

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

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

(Continued)

PEAK DAY PRICING DETAILS (CONT'D):

c. 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 notification messages of a PDP event from PG&E. (L)

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.

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

e. 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.

f. 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. (L)

(Continued)

PEAK DAY PRICING DETAILS (CONT'D):

g. Program Options: Customers may customize their PDP participation by choosing either a) no limit on the number of consecutive PDP events or b) every other PDP event. Customers electing every other PDP event will be divided into two groups and only be subject to a maximum of one-half of the PDP events called and the corresponding PDP rate credits will be reduced by 50%. Customers that do not elect an option will be defaulted to the no limit on the number of consecutive PDP events. The duration of PDP Event Operations for both options will be from 2:00 p.m. to 6:00 p.m. (four-hour window). (L)

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

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

APPLICABILITY: Schedule A-10 is a demand metered rate schedule for general service customers. Schedule A-10 applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section).

Effective March 1, 2021, Schedule A-10 is available only to qualifying solar grandfathered customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to new Schedule B-10 or other applicable new tariffs with later Time-of-Use (TOU) hours as described below. The non-TOU version of Schedule A-10 is not available for solar grandfathering purposes after March 2021. (N)

Under Rate Schedule A-10, there is a limit on the demand (the number of kilowatts (kW)) the customer may require from the PG&E system. If the customer's demand exceeds 499 kW for three consecutive months, the customer's account will be transferred to Schedule E-19 or E-20.

Effective November 1, 2014, new customers establishing service on Schedule A-10 where a Smart Meter™ is already in place will be charged Schedule A-10 TOU rates.

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods will be available on a voluntary basis for qualifying customers beginning November 1, 2019. During this voluntary period from November 1, 2019 through February 2021, as well as thereafter:

Schedule B-10, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters and less than 500 kW in size.

Schedule A-10 will be closed to all new enrollment. Customers requesting to establish service on Schedule A-10 where an interval data meter that can be read remotely by PG&E is already in place will be placed on the new Schedule B-10. Customers requesting to establish service on Schedule A-10 that do not have a meter that is capable of billing on the new Schedule B-10, may take service on this schedule.

Customers taking service under Schedule A-10 at the time rates with new TOU periods become available on a voluntary basis, may transfer to new Schedule B-10, may remain on this rate until rates with new TOU periods become mandatory, in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers.

* 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.

(Continued)

ELECTRIC SCHEDULE A-10 Sheet 2
MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY (CONT'D):

During the period the new rates with revised TOU periods are available on a voluntary basis for qualifying customers, from November 1, 2019 through February 28, 2021, customers who have opted in to the revised TOU periods, may opt out of the revised TOU periods and return to a legacy electric rate schedule with the legacy TOU periods listed in the special condition for "Definition of Time Periods" in this tariff, for the remainder of the period that the new rates with revised TOU periods are voluntary. Opting out of the revised TOU periods before they become mandatory is available on a one-time basis. If the customer opts-out of a new rate with the revised TOU periods less than twelve months before the revised TOU periods become mandatory, the customer may not return to a rate with the revised TOU periods until they become mandatory.

Beginning on March 2021, customers still served on Schedule A-10 will be transitioned to Schedule B-10 as discussed in the **Time of Use Rates** Section below.

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 A-10 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Transfers Off of Schedule A-10 TOU: Customers are placed on this schedule if they are not eligible for Schedules A-1 or A-6 because their demand exceeded or was expected to exceed 75 kW. Customers who then fail to exceed 75 kilowatts for 12 consecutive months may elect to stay on this schedule.

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will be between 75 through 499 kilowatts and that the customer should not be served under an agricultural or residential rate schedule, PG&E will serve the customer's account under the provisions of time-of-use Rate Schedule A-10.

Peak Day Pricing 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.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule A-10 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule A-10 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to Schedule B-10 or other applicable non-legacy rate and enroll in the new PDP program. Customers currently participating on both Schedule A-10 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to the new underlying TOU Schedule B-10 or other applicable new non-legacy rate option. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date. (N)

Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates.

(L)

(Continued)

APPLICABILITY (CONT'D):

Peak Day Pricing Rate (Cont'd) (L)

Bundled service customers are eligible for PDP. Direct Access (DA) and Community Choice Aggregation (CCA) service customers are not eligible, including those customers on transitional bundled service (TBS). Customers on standby service (Schedule S), or on net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, are not eligible for PDP. In addition, master-metered customers are not 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 details and program specifics, see the Peak Day Pricing Details section below. (L)

Time-of-Use Rates: Decision 10-02-032, as modified by Decision 11-11-008, makes TOU rates mandatory beginning November 1, 2012, for small and medium Commercial and Industrial (C&I) customers that have at least twelve (12) billing months of hourly usage data available. (T) (T)

Decision 18-08-013 suspends the transition of eligible A-10 customers to mandatory TOU rate beginning November 1, 2018 until the rates with revised TOU periods, as adopted in the same Decision, become mandatory.

Decision 18-08-013 adopted new TOU periods and seasonal definitions for all non-residential customer classes as discussed above. After the voluntary period ends, beginning March 2021, new Schedule B-10, with revised TOU periods, will become mandatory for customers served on this rate schedule, with exceptions for solar grandfathered customers, discussed above.

Beginning in March 2021, Schedule B-10, with revised TOU periods, will become mandatory for customers served on this schedule:

> Customers on Schedule A-10 with an interval meter and that have at least 12 months of hourly usage data available will transition to the new Schedule B-10.
>
> Customers on the non-TOU option of Schedule A-10 eligible for transition to mandatory TOU rates, including Direct Access and Community Choice Aggregation (DA/CCA) customers, will transition to new Schedule B-10.

The transition of customers no longer eligible for A-10 to new B-10 with revised TOU periods will occur on the start of the customer's March 2021 billing cycle. Customers will have at least 45-days' notice prior to their scheduled transition date, during which they will continue to take service on this rate schedule. Customers may elect any applicable new rate with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule B-10. .

(L)
(L)

(Continued)

ELECTRIC SCHEDULE A-10
MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY (CONT'D): **Time-of-Use Rates (**Cont'd) (L)

Exemptions to mandatory transitions beginning in March 2021 include:

Qualifying customers with solar systems who meet the requirements in Rule 1 Definition of "Behind-the-Meter Solar TOU Period Grandfathering" and the terms of "Behind-the-Meter Solar TOU Period Grandfathering Eligibility Requirements" shall be permitted to maintain their legacy TOU rate periods, until the date ten years after their system received its permission to operate (but in no event beyond December 31, 2027 (for public schools) or July 31, 2027 (for all other qualifying). However, rates for those TOU rate periods will be updated with new rates as authorized in applicable PG&E rate proceedings and advice filings.

Customers that do not have a meter that is capable of billing on the new Schedules B-10 by the beginning of their March 2021 billing cycle, may continue service this schedule until they receive an interval meter and have at least twelve (12) months of hourly usage data available.

The mandatory transition process will then occur in November 2021 and in each November thereafter to transition all applicable remaining A-10 customers to the rates with revised TOU periods (L)

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.

All customers taking non TOU service under this rate schedule shall be subject to the rates set forth in Table A. All customers taking TOU service under this rate schedule shall be subject to the rates set forth in Table B.

RATES: Standard Non-Time-of-Use Rate

Table A

TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge ($ per meter per day)	$4.77841	$4.77841	$4.77841
Total Demand Rates ($ per kW)			
Summer	$21.94	$20.68	$14.33
Winter	$13.27	$13.51	$10.38
Total Energy Rates ($ per kWh)			
Summer	$0.18607	$0.17384	$0.13828
Winter	$0.14531	$0.14005	$0.11751

(Continued)

ELECTRIC SCHEDULE A-10 Sheet 6
MEDIUM GENERAL DEMAND-METERED SERVICE

RATES: Time-of-Use Rates for Optional or Real-Time Metering Customers

Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

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.

Table B

TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge ($ per meter per day)	$4.77841	$4.77841	$4.77841
Total Demand Rates ($ per kW)			
Summer	$21.94	$20.68	$14.33
Winter	$13.27	$13.51	$10.38
Total Energy Rates ($ per kWh)			
Peak Summer	$0.23996	$0.22604	$0.18558
Part-Peak Summer	$0.18483	$0.17548	$0.13870
Off-Peak Summer	$0.15676	$0.14885	$0.11340
Part-Peak Winter	$0.15544	$0.15174	$0.12691
Off-Peak Winter	$0.13838	$0.13586	$0.11234
PDP Rates (Consecutive Day and Four-Hour Event Option)*			
PDP Charges ($ per kWh)			
All Usage During PDP Event	$0.90	$0.90	$0.90
PDP Credits			
Demand ($ per kW)			
Maximum Summer	($3.85)	($3.35)	($2.64)
Energy ($ per kWh)			
Peak Summer	($0.00073)	($0.00264)	($0.00429)
Part-Peak Summer	($0.00073)	($0.00264)	($0.00429)
Off-Peak Summer	($0.00073)	($0.00264)	($0.00429)

*See PDP Details, section g, for corresponding reduction in PDP credits and charges if other option(s) elected.

(Continued)

ELECTRIC SCHEDULE A-10 Sheet 13
MEDIUM GENERAL DEMAND-METERED SERVICE

PEAK DAY PRICING DETAILS

Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with Schedule B-10 or other applicable non-legacy rate may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible A-10 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for small and medium C&I customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP.

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

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

c. 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 notification messages of a PDP event from PG&E.

(Continued)

ELECTRIC SCHEDULE A-6
SMALL GENERAL TIME-OF-USE SERVICE

APPLICABILITY: This time-of-use schedule applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section).

Effective March 1, 2021, Schedule A-6 is available only to qualifying solar grandfathered customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to new Schedule B-6 or other applicable new tariffs with later Time-of-Use (TOU) hours as described below. (N)

Effective April 1, 2017, Schedule A-6 is closed to new customers with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months, or with usage of 150,000 kWh per year or greater, and who have at least twelve (12) months of hourly usage data available. For new customers on or after April 1, 2017, eligibility for A-6 will be reviewed annually and migration of ineligible customers will be implemented once per year, on bill cycles each November, using the same procedures described in Schedule A-1 for ~~Time-of-Use (~~TOU~~)~~ rates adopted in Decision 10-02-032 as modified by Decision 11-11-008. (T)

Any customer with a maximum demand of 75 kW or greater, or with usage of 150,000 kWh per year or greater, who sent PG&E a letter (via certified mail with a return receipt to establish a delivery record date on or before March 31, 2017) requesting a rate change pursuant to Electric Rule 12, shall be allowed to take service on Schedule A-6 or Schedule B-6 subject to the requirements of Decision18-08-013.

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods adopted in D.18-08-013, including new Schedule B-6, will be available on a voluntary basis beginning November 1, 2019. During this voluntary period from November 1, 2019 through February 2021, as well as thereafter:

> Schedule B-6, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters and less than 75 kW in size. Customers who enroll in any new rate during the voluntary period will be unenrolled from Peak Day Pricing.
>
> Schedule A-6 will be closed to all new enrollment. Customers requesting to establish service on Schedule A-6 where an interval data meter that can be read remotely by PG&E is already in place will be placed on the new Schedule B-6. Customers requesting to establish service on Schedule A-6 that do not have a meter that is capable of billing on the new Schedule B-6, may take service on this 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 website at http://www.pge.com/tariffs.

(Continued)

ELECTRIC SCHEDULE A-6 Sheet 2
SMALL GENERAL TIME-OF-USE SERVICE

APPLICABILITY: (Cont'd)

Customers taking service under Schedule A-6 at the time rates with new TOU periods become available on a voluntary basis, may transfer to new Schedule B-6, may remain on this rate until rates with new TOU periods become mandatory, in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers. (L)

During the period the new rates with revised TOU periods are available on a voluntary basis for qualifying customers, from November 1, 2019 through February 28, 2021, customers who have opted in to the revised TOU periods, may opt out of the revised TOU periods and return to a legacy electric rate schedule with the legacy TOU periods listed in the special condition for "Definition of Time Periods" in this tariff, for the remainder of the period that the new rates with revised TOU periods are voluntary. Opting out of the revised TOU periods before they become mandatory is available on a one-time basis. If the customer opts-out of a new rate with the revised TOU periods less than twelve months before the revised TOU periods become mandatory, the customer may not return to a rate with the revised TOU periods until they become mandatory.

Beginning in March 2021, new Schedule B-6 (or B-10 where applicable), with revised TOU periods, will become mandatory for customers served on this schedule:

Customers on Schedule A-6 with an interval meter that have at least twelve (12) billing months of hourly usage data available will transition to new Schedule B-6.

Customers on Schedule A-6 with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months, or, with usage of 150,000 kWh per year or greater when measured kW is not available and who have at least twelve (12) months of hourly usage data available, will transition to new Schedule B-10.

The transition of customers no longer eligible for A-6 to new Schedule B-6 (or B-10) with revised TOU periods will occur on the start of the customer's March 2021 bill cycle. Customers will have at least 45-days' notice prior to their scheduled transition date, during which they will continue to take service on this rate schedule. Customers may elect any applicable new rate with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule B-1 (or B-10).

Exemptions to the mandatory transitions beginning in March 2021 include:

Qualifying customers with solar systems who meet the requirements in Rule 1 Definition of "Behind-the-Meter Solar TOU Period Grandfathering" and the terms of "Behind-the-Meter Solar TOU Period Grandfathering Eligibility Requirements" shall be permitted to maintain their legacy TOU rate periods, until the date ten years after their system received its permission to operate (but in no event beyond December 31, 2027 (for public schools) or July 31, 2027 (for all other qualifying). However, rates for those TOU rate periods will be updated with new rates as authorized in applicable PG&E rate proceedings and advice filings.

(L)

(Continued)

ELECTRIC SCHEDULE A-6
SMALL GENERAL TIME-OF-USE SERVICE

APPLICABILITY: (Cont'd.)

Customers that do not have a meter that is capable of billing on the new Schedules B-6 by the beginning of their March 2021 billing cycle, may continue service on this schedule until they receive an interval meter and have at least twelve (12) months of hourly usage data available. (L)

The mandatory transition process will then occur in November 2021 and in each November thereafter to transition all applicable remaining A-6 customers to the rates with revised TOU periods.

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 A 6 charges. Exemptions are outlined in the Standby Applicability Section of this rate schedule. (L)

Depending upon whether or not a Time-Of-Use Installation or Time-Of-Use Processing charge applied prior to May 1, 2006, the customer will be served under one of these rates under Schedule A-6

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 enroll on A-6 on or after May 1, 2006.

A-6: Applies to customers who were on A-6 as of May 1, 2006.

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.

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

Peak Day Pricing 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. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule A-6 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule A-6 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to Schedule B-6 or other applicable non-legacy rate and enroll in the new PDP program. Customers currently participating on both Schedule A-6 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to the new underlying TOU Schedule B-6 or other applicable new non-legacy rate option. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date. (N)

(L)
(L)

(Continued)

APPLICABILITY: (Cont'd.)

Peak Day Pricing Rates (Cont'd): (L)

Bundled service customers are eligible for PDP. Direct Access (DA) and Community Choice Aggregation (CCA) service customers are not eligible, including those customers on transitional bundled service (TBS). Customers on standby service (Schedule S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program, are not eligible for PDP. In addition, master-metered customers are not 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 details and program specifics, see the Peak Day Pricing Details section below. (L)

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

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 RATES

Total Customer/Meter Charge Rates	
Customer Charge Single-phase ($ per meter per day)	$0.32854
Customer Charge Poly-phase ($ per meter per day)	$0.82136
Meter Charge (A-6) ($ per meter per day)	$0.20107
Meter Charge (W) ($ per meter per day)	$0.05914
Meter Charge (X) ($ per meter per day)	$0.20107
Total Energy Rates ($ per kWh)	
Peak Summer	$0.59927
Part-Peak Summer	$0.30245
Off-Peak Summer	$0.23086
Part-Peak Winter	$0.24592
Off-Peak Winter	$0.22767
PDP Rates (Consecutive Day and Four-Hour Event Option) *	
PDP Charges ($ per kWh)	
All Usage During PDP Event	$1.20
PDP Credits	
Energy ($ per kWh)	
Peak Summer	($0.26879)
Part-Peak Summer	($0.05376)

** See PDP Details, section g, for corresponding reduction in PDP credits and charges if other option(s) elected.*

(Continued)

ELECTRIC SCHEDULE A-6 Sheet 9
SMALL GENERAL TIME-OF-USE SERVICE

PEAK DAY PRICING DETAILS

Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with Schedule B-6 or other applicable non-legacy rate may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible A-6 customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for small and medium Commercial and Industrial (C&I) customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP. (T)

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

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

c. 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 notification messages of a PDP event from PG&E.

(Continued)

ELECTRIC SCHEDULE AG
TIME-OF-USE AGRICULTRAL POWER

Sheet 3

1.APPLICABILITY: (Cont'd.)

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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. (N)

(Continued)

ELECTRIC SCHEDULE AG Sheet 4
TIME-OF-USE AGRICULTRUAL POWER

2. TERRITORY: Schedule AG applies everywhere PG&E provides electricity service. (L)

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.

TOTAL RATES

Total Customer/Meter Charge Rates	Rate AG-A1	Rate AG-A2	Rate AG-B	Rate AG-C	
Customer Charge ($ per meter per day)	$0.68895	$0.68895	$0.91565	$1.43343	
Total Demand Rates ($ per kW)					
Secondary Voltage					
Maximum Peak Demand Summer	—	—	—	$18.69	
Maximum Demand Summer	$5.63	$9.50	$6.24	$11.21	
Maximum Demand Winter	$5.63	$9.50	$6.24	$11.21	
Primary Voltage					
Maximum Peak Demand Summer	—	—	—	$18.69	
Maximum Demand Summer	—	—	$5.39	$10.04	
Maximum Demand Winter	—	—	$5.39	$10.04	
Transmission Voltage					
Maximum Peak Demand Summer	—	—	—	$18.69	
Maximum Demand Summer	—	—	$2.09	$2.90	
Maximum Demand Winter	—	—	$2.09	$2.90	
Total Energy Rates ($ per kWh)					
Peak Summer	$0.39723	$0.33802	$0.40208	$0.18368	
Off-Peak Summer	$0.23129	$0.17209	$0.22923	$0.14424	
Peak Winter	$0.22092	$0.17898	$0.22516	$0.15589	
Off-Peak Winter	$0.19163	$0.14969	$0.19590	$0.13020	
Demand Charge Rate Limiter ($/kWh in all months, see Demand Charge Rate Limiter section)	—	—	—	$0.50	(L)
PDP Rates (Consecutive Day and Three-Hour Event Option)*					(N)
PDP Charges ($ per kWh)					
All Usage During PDP Event	$1.00	$1.00	$1.00	$1.00	
PDP Credits					
Demand ($ per kW)					
Peak Summer	$0.00000	$0.00000	$0.00000	($4.35)	
Energy ($ per kWh)					
Peak Summer	($0.10026)	($0.11075)	($0.10909)	—	

* See PDP Detail, section g, for corresponding reduction in PDP credits and charges if other option(s) elected. (N)

(Continued)

ELECTRIC SCHEDULE AG Sheet 5
TIME-OF-USE AGRICULTRUAL POWER

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. (L) (L)/(N) (N)

UNBUNDLING OF TOTAL RATES (L)

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

Demand Charges by Component ($/kW)	Rate AG-A1	Rate AG-A2	Rate AG-B	Rate AG-C
Generation:				
Maximum Peak Demand Summer	—	—	—	$12.52
Distribution:**				
Secondary Voltage				
Maximum Peak Demand Summer	—	—	—	$6.17
Maximum Demand Summer	$5.63	$9.50	$6.24	$11.21
Maximum Demand Winter	$5.63	$9.50	$6.24	$11.21
Primary				
Maximum Peak Demand Summer	—	—	—	$6.17
Maximum Demand Summer	—	—	$5.39	$10.04
Maximum Demand Winter	—	—	$5.39	$10.04
Transmission				
Maximum Peak Demand Summer	—	—	—	$6.17
Maximum Demand Summer	—	—	$2.09	$2.90
Maximum Demand Winter	—	—	$2.09	$2.90

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

(Continued)

3. RATES: (L)
(Cont'd.)

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Rates by Component ($/kWh)	Rate AG-A1	Rate AG-A2	Rate AG-B	Rate AG-C
Generation:				
Peak Summer	$0.22407	$0.22407	$0.24440	$0.11604
Off-Peak Summer	$0.10439	$0.10439	$0.12133	$0.08656
Peak Winter	$0.10107	$0.10107	$0.11599	$0.10140
Off-Peak Winter	$0.07462	$0.07462	$0.08979	$0.07588
Distribution*:				
Peak Summer	$0.12365	$0.06444	$0.10867	$0.02005
Off-Peak Summer	$0.07739	$0.01819	$0.05889	$0.01009
Peak Winter	$0.07034	$0.02840	$0.06016	$0.00690
Off-Peak Winter	$0.06750	$0.02556	$0.05710	$0.00673
Transmission* (all usage)	$0.02202	$0.02202	$0.02202	$0.02202
Transmission Rate Adjustments* (all usage)	$0.00314	$0.00314	$0.00314	$0.00314
Reliability Services* (all usage)	($0.00041)	($0.00041)	($0.00041)	($0.00041)
Public Purpose Programs (all usage)	$0.01327	$0.01327	$0.01277	$0.01135
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101	$0.00101
Competition Transition Charges (all usage)	$0.00085	$0.00085	$0.00085	$0.00085
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00378	$0.00378	$0.00378	$0.00378
California Climate Credit (all usage)***	$0.00000	$0.00000	$0.00000	$0.00000

* 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. (L)

(Continued)

ELECTRIC SCHEDULE AG
TIME-OF-USE AGRICULTRUAL POWER

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. (L)

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

5. TIME PERIODS: Seasons of the year and times of the day are defined as follows:

SUMMER (Service from June 1 through September 30):

For Rates AG-A1, AG-A2, AG-B and AG-C

Peak:	5:00 p.m. to 8:00 p.m.	Every day, including weekends and holidays
Off-peak:	All other Hours.	

WINTER (Service from October 1 through May 31):

For Rates AG-A1, AG-A2, AG-B and AG-C

Peak:	5:00 p.m. to 8:00 p.m.	Every day, including weekends and holidays
Off-peak:	All other Hours.	

(L)

(Continued)

ELECTRIC SCHEDULE AG Sheet 8
TIME-OF-USE AGRICULTRUAL POWER

6. ENERGY CHARGE CALCULATION: When summer and winter proration is required, charges will be based on the average daily use for the full billing periods times the number of days in each period. (L)

7. CONTRACTS: Service under Schedule AG is provided for a minimum of 12 months beginning with the date the customer’s service commences. The customer may be required to sign a service contract with a minimum term of one year. After the customer’s initial one-year term has expired, the customer’s contract will continue in effect until it is cancelled by the customer or PG&E.

Where a line extension is required it will be installed under the provisions of Rules 15 and 16.

8. MAXIMUM DEMAND The maximum demand will be the number of kW the customer is using recorded over 15-minute intervals; the highest 15-minute average in any month customers will be the maximum demand for that month. Where the customer’s use of electricity is intermittent or subject to abnormal fluctuation, 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 welder load calculation will apply only in the season in which the customer usually uses energy, which will be assumed to be the summer season unless otherwise designated.

In billing periods with use in both the summer season and winter season (May/June, September/October), your total demand charge shall be calculated on a pro rata basis depending upon the demand charge and the number of days in each season. The maximum demand used in determining your demand charge for each season of the billing period will be the maximum demand created in each season's portion of the billing month as measured by the meter.

For customers 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.

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).

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)

(Continued)

10.MAXIMUM-PEAK-PERIOD DEMAND

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. (L)

11.DEMAND CHARGE RATE LIMITER:

If a customer takes service on rate AG-C under Schedule AG-C, at any voltage level, bills will be controlled by a "demand charge rate limiter" during all months of the year. The bill will be reduced, if necessary, so that the average rate paid per kWh for all demand and energy charges, excluding the monthly customer charge, during all months of the year does not exceed the Demand Charge Rate Limiter shown on this schedule.

The Demand Charge Rate Limiter shall apply to all bundled service, Direct Access (DA), or Community Choice Aggregation (CCA) customers taking service on rate option AG-C under Schedule AG. DA/CCA customers will be billed as if paying full PG&E bundled Generation demand charge and energy charge rates to assess the applicability of the Demand Charge Rate Limiter, and shall receive bill adjustments on that basis, not on the basis of applicable DA/CCA Generation charges, or related PCIA and E-FFS rates. Net Energy Metering (NEM) customers shall be evaluated for the Demand Charge Rate Limiter on the basis of the energy the customer receives from PG&E prior to any bill adjustment for net exports. The Demand Charge Rate Limiter shall also apply to any AG-C customer who elects to receive separate billing for back-up and maintenance service pursuant to Special Condition 7 of Standby Schedule SB.

Demand Charge Rate Limiter applicability shall be evaluated on the basis of the full billing period, and not within a seasonal crossover or other bill segment basis. All revenue shortfalls attributable to the Demand Charge Rate Limiter will be assigned as a reduction to distribution charges. The Demand Charge Rate Limiter will apply to AG-C customer bills without regard to any incentives, charges, surcharges, or penalties associated with such programs as PDP, DRAM, BIP, and CBP.

This Demand Charge Rate Limiter provision will not apply if the customer has elected one of the following:

- Schedule AG, Rate Option AG-A1, AG-A2, or B; or
- Schedule AG-F, Rate Option A, B, or C.
- NEM aggregation, NEMA service on AG-C across multiple meter sites.
- Virtual NEM, NEMCCSF, NEMFC, NEMMT, NEM Paired Storage, NEMBIO, NEMW, or RES-BCT. (L)

(Continued)

12.DEFINITION OF SERVICE VOLTAGE: The following defines the three voltage classes of Schedule AG 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.

PG&E retains the right to change its line voltage at any time. Customers receiving voltage discounts will get reasonable notice of any impending change. They will then have the option of taking service at the new voltage (and making whatever changes in their systems are necessary) or taking service without a voltage discount through transformers supplied by PG&E.

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

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. (L)

(Continued)

13.BILLING: (Cont'd)

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. (L)

	DA / CCA CRS
Energy Cost Recovery Amount Charge (per kWh)	$0.00005
DWR Bond Charge (per kWh)	$0.00580
CTC Charge (per kWh)	$0.00085
Power Charge Indifference Adjustment (per kWh)	
2009 Vintage	$0.02289
2010 Vintage	$0.02571
2011 Vintage	$0.02790
2012 Vintage	$0.02779
2013 Vintage	$0.02972
2014 Vintage	$0.03014
2015 Vintage	$0.02998
2016 Vintage	$0.02985
2017 Vintage	$0.02980
2018 Vintage	$0.02982
2019 Vintage	$0.03178
2020 Vintage	$0.03793 (L)

(Continued)

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

DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use 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 time-of-use service 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 time-of-use (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.

15. 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.

16. 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 Rate AG-C under Schedule AG, Schedule E-19 or Schedule E-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.

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 E-19 (above 500 kW as defined above), Schedule E-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. (L)

(Continued)

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

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: (L)

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.

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.

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)

17. a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible agricultural TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The AG rates with new TOU periods will become mandatory for all agricultural customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2 pm – 6 pm PDP Event Hours to a new version of PDP (New PDP) with 5 pm – 8 pm PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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 on the AG-C rate 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.

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

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

(Continued)

17. PEAK DAY PRICING DETAILS (Cont'd.)

c. Bill Stabilization (Cont'd.): (N)

Active Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months.

Legacy 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 the New 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 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.

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.

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

~~e.~~g. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

(Continued)

17. PEAK DAY PRICING DETAILS (Cont'd.)

h. Program Options: Customers on Schedules AG-A1, AG-A2 or AG-B may customize their PDP participation by choosing either a) no limit on the number of consecutive PDP events or b) every other PDP event. Customers electing every other PDP event will be divided into two groups and only be subject to a maximum of one-half of the PDP events called and the corresponding PDP rate credits will be reduced by 50%. Customers that do not elect an option will be defaulted to the no limit on the number of consecutive PDP events. The duration of PDP Event Operations for both options will be from ~~p.m.~~5:00 p.m. to 8:00 p.m. (three-hour window). (N)

i. 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.

j. 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.

~~h.~~k. 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. (N)

ELECTRIC SCHEDULE AG-1
AGRICULTURAL POWER

1. APPLICABILITY: A customer will be served under this schedule if 70% or more of the annual energy use on the meter is for agricultural end-uses. Agricultural end-uses consist of:

(a) growing crops;

(b) raising livestock;

(c) pumping water for irrigation of crops; or

(d) other uses which involve production for sale.

Only agricultural end-uses performed prior to the First Sale of the agricultural product are agricultural end-uses under this criteria, except for the following activities, which are also agricultural end-uses under this criteria: (a) packing and packaging of the agricultural products following the First Sale and before any subsequent sale, and (b) agricultural end-uses by nonprofit cooperatives. Guidelines for interpreting this applicability statement are set forthwith in Section D of the Rule 1 Definition ‘Qualification for Agricultural Rates’.

Schedule AG-1 is a non-Time-of-Use (TOU) rate schedule. Effective March 1, 2021, Schedule AG-1 is available only to qualifying customers without interval meters, and to highly impacted agricultural customers, as specified in greater detail below. Schedule AG-1 is not available for solar grandfathering purposes after March 2021. Customers on this tariff with 12 months of interval data prior to March 2021, or prior to March 2022 if highly impacted, and prior to each March thereafter, must either elect service on new opt-in TOU Schedule AG-F, or must transition to a new default AG Schedule with later TOU hours as described below: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

None of the above activities may process the agricultural product. Residential dwelling, office, and retail usage are not agricultural end-uses.

The Rule 1 definition ‘Qualification for Agricultural Rates’ specifies additional activities and meters that will also be served on agricultural rates, and guidelines through the following sections: (B) Other Activities and Meters Also Served on Agricultural Rates, (C) Specific Applications of the March 2, 2006 Applicability Criteria, and (D) Guidelines for Applying the Applicability Criteria.

This schedule is not applicable to service for which a residential or commercial/ industrial schedule is applicable, or to customers with a maximum demand of 500 kW or more. This schedule is also not available to customers whose meter indicates a maximum demand of 200 kW or greater for three consecutive months, except customers that are identified as load research sites. Customers with interval data meters who are not eligible for this rate schedule must be placed on a Time-Of-Use (TOU) rate schedule.

Depending upon the end-use of electricity, the customer will be served under one of the two rates under Schedule AG-1: Rate A or Rate B.

(L)
(L)

(Continued)

ELECTRIC SCHEDULE AG-1
AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

Rate A: Applies to single-motor installations with a connected load rated less than 35 horsepower and to all multi-load installations aggregating less than 15 horsepower or kilowatts. (L)

Rate B: Applies to single-motor installations rated 35 horsepower or more, to multi-load installations aggregating 15 horsepower or kilowatts or more, and to "overloaded" motors. The customer's end-use is determined to be overloaded when the measured input to any motor rated 15 horsepower or more is determined by PG&E to exceed one kilowatt per horsepower of nameplate rated output. (L)

Effective November 1, 2014, new customers establishing service where a Smart Meter™ is already in place are not eligible for Schedule AG-1 and must instead be served under an applicable TOU rate schedule, such as Schedule AG-4 or AG-5, or if establishing service after March 1, 2020, under a new rate with later TOU hours on Schedule AG or AG-F. (N)

Decision 18-08-013 adopted new TOU periods and new seasonal definitions for all non-residential customer classes, as well as new rates for the Agricultural customer class. Schedules AG-1, AG-4, AG-5, AG-R and AG-V will be retained as legacy rate schedules with their current TOU periods until the rates with revised TOU periods (Schedules AG and AG-F) established in the same proceeding, become mandatory in March 2021 .

Decision 19-05-010 adopted additional modifications to the agricultural rates adopted in Decision 18-08-013 and delays the mandatory transition until March 2022 for highly impacted agricultural customers, defined as those customers with potential bill increases greater than 7 percent and $100 annually due to the transition to the rates with revised TOU periods. In addition, certain qualifying customers with solar systems will be permitted to maintain their current TOU periods for a certain period of time, per Decision 17-01-006, as described in Electric Rule 1, Definitions: Behind the Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010 will be available on a voluntary basis for qualifying customers beginning March 1, 2020. During this voluntary period from March 1, 2020 through February 28, 2021:

Schedule AG, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters that can be remotely read by PG&E.

Legacy rate schedules, including Schedule AG-1, will be closed to all new enrollment. Customers requesting to establish service on Schedule AG-1, where an interval data meter that can be read remotely by PG&E is already in place, will be placed on the new Schedule AG with revised TOU periods. Customers requesting to establish service on Schedule AG-1 that do not have a meter capable of billing on the new Schedule AG, may take service on this schedule.

Customers taking service under Schedule AG-1 at the time rates with new TOU periods become available, may transfer to new Schedule AG or Schedule AG-F, with revised TOU periods, may remain on this rate until rates with revised TOU periods become mandatory in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers.

Beginning on March 1, 2021, customers still served on Schedule AG-1 will be transitioned to Schedule AG as discussed in the **Time of Use Rates** Section below.

(Continued)

ELECTRIC SCHEDULE AG-4
TIME-OF-USE AGRICULTURAL POWER

Sheet 1

1. APPLICABILITY: A customer will be served under this schedule if 70% or more of the annual energy use on the meter is for agricultural end-uses. Agricultural end-uses consist of:

(a) growing crops;

(b) raising livestock;

(c) pumping water for irrigation of crops; or

(d) other uses which involve production for sale.

Only agricultural end-uses performed prior to the First Sale of the agricultural product are agricultural end-uses under this criteria, except for the following activities, which are also agricultural end-uses under this criteria: (a) packing and packaging of the agricultural products following the First Sale and before any subsequent sale, and (b) agricultural end-uses by nonprofit cooperatives. Guidelines for interpreting this applicability statement are set forthwith in Section D of the Rule 1 Definition 'Qualification for Agricultural Rates'.

None of the above activities may process the agricultural product. Residential dwelling, office, and retail usage are not agricultural end-uses.

Effective March 1, 2021, Schedule AG-4 is available only to qualifying solar grandfathered customers, highly impacted agricultural customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to a new AG Schedule with later TOU hours as described below: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

The Rule 1 definition 'Qualification for Agricultural Rates' specifies additional activities and meters that will also be served on agricultural rates, and guidelines through the following sections: (B) Other Activities and Meters Also Served on Agricultural Rates, (C) Specific Applications of the March 2, 2006 Applicability Criteria, and (D) Guidelines for Applying the Applicability Criteria.

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 AG-4 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

ELECTRIC SCHEDULE AG-4
TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

Transfers Off of Schedule AG-4: 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 this schedule or alternate time-of-use rate schedule

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 February 1, 2011, eligible Agricultural 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.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule AG-4 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule AG-4 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to a new AG Schedule non-legacy rate listed below and enroll in the new PDP program. Customers currently participating on both Schedule AG-4 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to a new underlying AG Schedule based on size as listed below. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

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 Community 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 NEMA, are not eligible for PDP.

Decision 18-08-013 temporarily suspends the default of eligible AG-4 customers to PDP beginning March 1, 2019.

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

2. TERRITORY: Schedule AG-4 applies everywhere PG&E provides electricity service.

(Continued)

2. TERRITORY: Schedule AG-4 applies everywhere PG&E provides electricity service.

3. RATES: Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

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.

TOTAL RATES

Total Customer/Meter Charge Rates	Rate A,D	Rate B,E	Rate C,F
Customer Charge ($ per meter per day)	$0.57400	$0.76313	$2.15003
TOU Meter Charge ($ per meter per day) (for rate A, B & C)	$0.22341	$0.19713	$0.19713
TOU Meter Charge ($ per meter per day) (for rate D, E & F)	$0.06571	$0.03943	$0.03943

Total Demand Rates ($ per kW)	Rate A,D	Rate B,E	Rate C,F
Connected Load Summer	$9.71	–	–
Connected Load Winter	$1.47	–	–
Maximum Demand Summer	–	$11.76	$6.17
Maximum Demand Winter	–	$2.75	$2.98
Maximum Peak Demand Summer	–	$6.15	$14.62
Maximum Part-Peak Demand Summer	–	–	$2.80
Maximum Part-Peak Demand Winter	–	–	$0.67
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–	$1.23	$1.59
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–	$0.43	$0.38
Transmission Voltage Discount			
Maximum Peak Demand Summer	–	–	$7.73
Maximum Part-Peak Demand Summer	–	–	$1.61
Maximum Demand Summer	–	–	$0.29
Maximum Part-Peak Demand Winter	–	–	$0.67
Maximum Demand Winter	–	–	$2.06

Total Energy Rates ($ per kWh)	Rate A,D	Rate B,E	Rate C,F
Peak Summer	$0.50212	$0.33016	$0.30229
Part-Peak Summer	–	–	$0.17959
Off-Peak Summer	$0.22766	$0.18153	$0.13671
Part-Peak Winter	$0.23514	$0.18196	$0.15083
Off-Peak Winter	$0.19320	$0.15448	$0.13173

(Continued)

16. PEAK DAY PRICING DETAILS: Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with any Schedule AG rate, as described in the Peak Day Pricing paragraph located in the Applicability Clause above, may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible AG-4 customers to PDP beginning March 1, 2019 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for agricultural customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP.

   The default of eligible customers to PDP will occur once per year with the start of their billing cycle on or after March 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 at least five (5) days before their proposed default date, their service will be defaulted to the PDP version of this rate schedule. 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 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. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

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

(Continued)

ELECTRIC SCHEDULE AG-5 Sheet 1
LARGE TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: A customer will be served under this schedule if 70% or more of the annual energy use on the meter is for agricultural end-uses. Agricultural end-uses consist of:

(a) growing crops;

(b) raising livestock;

(c) pumping water for irrigation of crops; or

(d) other uses which involve production for sale.

Only agricultural end-uses performed prior to the First Sale of the agricultural product are agricultural end-uses under this criteria, except for the following activities, which are also agricultural end-uses under this criteria: (a) packing and packaging of the agricultural products following the First Sale and before any subsequent sale, and (b) agricultural end-uses by nonprofit cooperatives. Guidelines for interpreting this applicability statement are set forthwith in Section D of the Rule 1 Definition 'Qualification for Agricultural Rates'.

Effective March 1, 2021, Schedule AG-5 is available only to qualifying solar grandfathered customers, highly impacted agricultural customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to a new AG Schedule with later TOU hours as described below: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

None of the above activities may process the agricultural product. Residential dwelling, office, and retail usage are not agricultural end-uses.

The Rule 1 definition 'Qualification for Agricultural Rates' specifies additional activities and meters that will also be served on agricultural rates, and guidelines through the following sections: (B) Other Activities and Meters Also Served on Agricultural Rates, (C) Specific Applications of the March 2, 2006 Applicability Criteria, and (D) Guidelines for Applying the Applicability Criteria.

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 AG-5 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

1. APPLICABILITY: (Cont'd.)

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 February 1, 2011, eligible large Agricultural 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.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule AG-5 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule AG-5 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to a new AG Schedule non-legacy rate listed below and enroll in the new PDP program. Customers currently participating on both Schedule AG-5 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to a new underlying AG Schedule based on size as listed below. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

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 Community 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 NEMA, are not eligible for PDP.

Decision 18-08-013 temporarily suspends the default of eligible AG-5 customers to PDP beginning March 1, 2019.

For additional PDP details and program specifics, see section 17.

2. TERRITORY: Schedule AG-5 applies everywhere PG&E provides electricity service.

(Continued)

3. RATES: Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

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.

TOTAL RATES

Total Customer/Meter Charge Rates	Rate A,D	Rate B,E	Rate C,F
Customer Charge ($ per meter per day)	$0.57400	$1.19446	$5.30871
TOU Meter Charge ($ per meter per day) (for rate A, B & C)	$0.22341	$0.19713	$0.19713
TOU Meter Charge ($ per meter per day) (for rate D, E & F)	$0.06571	$0.03943	$0.03943

Total Demand Rates ($ per kW)	Rate A,D	Rate B,E	Rate C,F
Connected Load Summer	$14.18	–	–
Connected Load Winter	$2.69	–	–
Maximum Demand Summer	–	$18.59	$7.61
Maximum Demand Winter	–	$7.30	$4.75
Maximum Peak Demand Summer	–	$11.75	$20.24
Maximum Part-Peak Demand Summer	–	–	$4.21
Maximum Part-Peak Demand Winter	–	–	$1.13
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–	$2.02	$2.97
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–	$0.22	$0.32
Transmission Voltage Discount			
Maximum Peak Demand Summer	–	–	$12.79
Maximum Part-Peak Demand Summer	–	–	$1.93
Maximum Demand Summer	–	$13.96	$4.33
Maximum Part-Peak Demand Winter	–	–	$1.13
Maximum Demand Winter	–	$6.28	$3.11

(Continued)

17. PEAK DAY PRICING DETAILS:

Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with any Schedule AG rate, as described in the Peak Day Pricing paragraph located in the Applicability Clause above, may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible AG-5 customers to PDP beginning March 1, 2019 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for agricultural customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP.

   The default of eligible customers to PDP will occur once per year with the start of their billing cycle on or after March 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 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. 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 17.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.

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.

(L)
(L)

(Continued)

17. PEAK DAY PRICING DETAILS (CONT'D):

b. Capacity Reservation Level (Cont'd): (L)

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).

A customer may only elect to change their CRL once every 12-months. (L)

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

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

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.

(Continued)

ELECTRIC SCHEDULE AG-F Sheet 3
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

1.APPLICABILITY: (Cont'd)

Beginning on March 1, 2021 customers still served on legacy rate Schedules AG-1, AG-4, AG-5, AG-R or AG-V, with exception of customers referenced above, will be transitioned to rate plans A1, A2, B, or C under Schedule AG with revised TOU periods. Customers may elect any rate for which they are eligible, including rates under this optional Schedule AG-F with flexible off-peak period days. The transition notification and default process are further described in the legacy rate Schedules AG-1, AG-4, AG-5, AG-R and AG-V.

Each rate plan under Schedule AG-F has three pre-defined options where two days of the week consist solely of off-peak hours and rates (that is, no peak period on these days):

Option I: **Off Peak Days** are Wednesday and Thursday,

Option II: **Off Peak Days** are Saturday and Sunday,

Option III: **Off Peak Days** are Monday and Friday.

A customer will be assigned to their selected option above for off-peak period days. PG&E reserves the right to eliminate the availability of some options for off-peak period days on Schedule AG-F on some circuits based on or due to local system constraints. Customers will be made aware if their first choice for the AG-F option for off-peak period days is not available at the time of enrollment, and if another option is available. AG-F enrollment will not be possible through an online self-service option and will require a live discussion with a Customer Service Representative at PG&E's Agricultural Customer Service Line (877-311-3276).

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. In addition, master-metered customers are not eligible, except for commercial buildings with submetering as stated in PG&E Rule 1 and Rule 18.

PDP rate options are not available to customers under this Schedule. Customers taking service on Schedule AG-F who wish to take service on PDP rates must transfer service to Schedule AG on rate options AG-A1, AG-A2, AG-B, or AG-C, under applicable eligibility rules, in order to voluntarily opt-in and enroll in the PDP program. (N)

2. TERRITORY: Schedule AG-F applies everywhere PG&E provides electricity service.

(Continued)

ELECTRIC SCHEDULE AG-R Sheet 1
SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: This schedule is closed to new customers. Customers taking service on this schedule as of May 1, 2012 must maintain continuous service on this schedule to remain eligible for service on this schedule. An exception to this rule will apply only to customers electing to migrate to Peak Day Pricing who subsequently elect to return to this schedule (see Peak Day Pricing Default Rates section).

A customer will be served under this schedule if 70% or more of the annual energy use on the meter is for agricultural end-uses. Agricultural end-uses consist of:

(a) growing crops;

(b) raising livestock;

(c) pumping water for irrigation of crops; or

(d) other uses which involve production for sale.

Only agricultural end-uses performed prior to the First Sale of the agricultural product are agricultural end-uses under this criteria, except for the following activities, which are also agricultural end-uses under this criteria: (a) packing and packaging of the agricultural products following the First Sale and before any subsequent sale, and (b) agricultural end-uses by nonprofit cooperatives. Guidelines for interpreting this applicability statement are set forthwith in Section D of the Rule 1 Definition ‘Qualification for Agricultural Rates’.

Effective March 1, 2021, Schedule AG-R is available only to qualifying solar grandfathered customers, highly impacted agricultural customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to a new AG Schedule with later TOU hours as described below: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

None of the above activities may process the agricultural product. Residential dwelling, office, and retail usage are not agricultural end-uses.

The Rule 1 definition ‘Qualification for Agricultural Rates’ specifies additional activities and meters that will also be served on agricultural rates, and guidelines through the following sections: (B) Other Activities and Meters Also Served on Agricultural Rates, (C) Specific Applications of the March 2, 2006 Applicability Criteria, and (D) Guidelines for Applying the Applicability Criteria.

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 AG-R charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

ELECTRIC SCHEDULE AG-R Sheet 5
SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (cont'd)

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 February 1, 2011, eligible large Agricultural 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 served on this schedule will be placed on AG-4C PDP rates unless they opt-out.

Decision 18-08-013 temporarily suspends the default of eligible AG-R customers to PDP beginning March 1, 2019.

Customers that do not meet default eligibility may voluntarily elect to enroll on PDP rates. An AG-R customer that defaulted or voluntarily elected to enroll in a PDP rate may return back to rate schedule AG-R as long as the rate is in effect. For additional PDP details and program specifics, see rate schedule AG-4.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with any legacy agricultural rate schedule. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any legacy PDP customer remaining on the legacy Schedule AG-4 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to a new AG Schedule non-legacy rate listed below and enroll in the new PDP program. Customers currently participating on both Schedule AG-4 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to a new underlying AG Schedule based on size as listed below. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

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 S) and net-energy metering (NEM, NEMFC, NEMBIO, etc.) are not eligible for PDP.

2. TERRITORY: Schedule AG-R applies everywhere PG&E provides electricity service.

(Continued)

ELECTRIC SCHEDULE AG-V Sheet 1

SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: This schedule is closed to new customers. Customers taking service on this schedule as of May 1, 2012 must maintain continuous service on this schedule to remain eligible for service on this schedule. An exception to this rule will apply only to customers electing to migrate to Peak Day Pricing who subsequently elect to return to this schedule (see Peak Day Pricing Default Rates section).

A customer will be served under this schedule if 70% or more of the annual energy use on the meter is for agricultural end-uses. Agricultural end-uses consist of:

(a) growing crops;

(b) raising livestock;

(c) pumping water for irrigation of crops; or

(d) other uses which involve production for sale.

Only agricultural end-uses performed prior to the First Sale of the agricultural product are agricultural end-uses under this criteria, except for the following activities, which are also agricultural end-uses under this criteria: (a) packing and packaging of the agricultural products following the First Sale and before any subsequent sale, and (b) agricultural end-uses by nonprofit cooperatives. Guidelines for interpreting this applicability statement are set forthwith in Section D of the Rule 1 Definition 'Qualification for Agricultural Rates'.

None of the above activities may process the agricultural product. Residential dwelling, office, and retail usage are not agricultural end-uses.

Effective March 1, 2021, Schedule AG-V is available only to qualifying solar grandfathered customers, highly impacted agricultural customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to a new AG Schedule with later TOU hours as described below: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

The Rule 1 definition 'Qualification for Agricultural Rates' specifies additional activities and meters that will also be served on agricultural rates, and guidelines through the following sections: (B) Other Activities and Meters Also Served on Agricultural Rates, (C) Specific Applications of the March 2, 2006 Applicability Criteria, and (D) Guidelines for Applying the Applicability Criteria.

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 AG-V charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

1. APPLICABILITY: (cont'd)

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 February 1, 2011, eligible large Agricultural 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 served on this schedule will be placed on AG-4C PDP rates unless they opt-out.

Decision 18-08-013 temporarily suspends the default of eligible AG-V customers to PDP beginning March 1, 2019.Customers that do not meet default eligibility may voluntarily elect to enroll on PDP rates. An AG-V customer that defaulted or voluntarily elected to enroll in a PDP rate may return back to rate schedule AG-V as long as the rate is in effect. For additional PDP details and program specifics, see rate schedule AG-4.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with any legacy agricultural rate schedule. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any legacy PDP customer remaining on the legacy Schedule AG-4 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to a new AG Schedule non-legacy rate listed below and enroll in the new PDP program. Customers currently participating on both Schedule AG-4 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to a new underlying AG Schedule based on size as listed below. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date: (N)

Ag < 35 kW Low Use (AG-A1)
Ag < 35 kW High Use (AG-A2)
Ag 35+ kW Med Use (AG-B)
Ag 35+ kW High Use (AG-C) (N)

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 S) and net-energy metering (NEM, NEMFC, NEMBIO, etc.) are not eligible for PDP.

2. TERRITORY: Schedule AG-V applies everywhere PG&E provides electricity service

(Continued)

ELECTRIC SCHEDULE B-1
SMALL GENERAL SERVICE

APPLICABILITY: Schedule B-1 applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section). Customers that are otherwise eligible to take service on Schedule B-1 but are purchasing power to serve electric vehicle charging equipment, are not eligible to take service on this rate schedule.

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

These new rates with revised TOU periods adopted in D.18-08-013, including Schedule B-1, will be available to qualifying customers on a voluntary basis beginning in November 2019 through February 2021. During that period, eligible customers have a one-time opportunity to opt-in..

Customers eligible for this rate schedule must have an interval data meter that can be read remotely by PG&E. Beginning March 2021, customers still served on Schedule A-1, with the exception of solar grandfathered customers referenced above, will be transitioned to Schedule B-1 with revised TOU periods. The mandatory transition process is further described in the legacy rate Schedule A-1.

Customers with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months are not eligible for continued service under this rate schedule. Eligibility for B-1 will be reviewed annually and the transition of customers that are no longer eligible for service on this rate schedule to Schedule B-10 will occur on the start of the customer’s November billing cycle, or to Schedule B-19 Mandatory for customers with a maximum demand of 499 kW or greater for three consecutive months in the most recent twelve months. These customers will have at least 45-day notice prior to their planned transition date, during which they will continue to take service on this rate schedule. Customers may elect any other applicable rate schedule up to five (5) days prior to the planned transition date to Schedule B-10.

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 non-utility 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-1 charges. Exemptions to Standby Charges are outlined in the Standby Applicability Section of this rate schedule.

~~TERRITORY:~~ ~~This rate schedule applies everywhere PG&E provides electric service.~~ (L)
(L)

* 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 website at http://www.pge.com/tariffs

(Continued)

APPLICABILITY: (Cont'd)

Peak Day Pricing 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. Customers with a SmartMeter^{TM} system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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 (N)

TERRITORY: This rate schedule applies everywhere PG&E provides electric service. (L)

(Continued)

ELECTRIC SCHEDULE B-1
SMALL GENERAL SERVICE

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.

Time-of-Use Rates	Rate
Total Customer Charge Rates	
Customer Charge Single-phase ($ per meter per day)	$0.32854
Customer Charge Poly-phase ($ per meter per day)	$0.82136
Total TOU Energy Rates ($ per kWh)	
Peak Summer	$0.32805
Part-Peak Summer	$0.27882
Off-Peak Summer	$0.25801
Peak Winter	$0.25263
Off-Peak Winter	$0.23651
Super Off-Peak Winter	$0.22009

PDP Rates (Consecutive Day and Three-Hour Event Option)*		(N)
PDP Charges ($ per kWh)		|
All Usage During PDP Event	$0.60000	|
PDP Credits		|
Energy ($ per kWh)		|
Peak Summer	($0.03330)	|
Part-Peak Summer	($0.00990)	|

* See PDP Detail, section g, for corresponding reduction in PDP credits and charges if other option(s) elected. (N)

(Continued)

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. (N) (N)

UNBUNDLING OF TOTAL RATES

Time-of-Use Rates	Rate	
Customer Charge Rates: Customer charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.		
Energy Rates by Components ($ per kWh)		
Generation:		
Peak Summer	$0.17737	(I)
Part-Peak Summer	$0.12814	(I)
Off-Peak Summer	$0.10733	(I)
Peak Winter	$0.12212	(I)
Off-Peak Winter	$0.10600	(I)
Super Off-Peak Winter	$0.08958	(I)
Distribution:**		
Peak Summer	$0.09551	(I)
Part-Peak Summer	$0.09551	(I)
Off-Peak Summer	$0.09551	(I)
Peak Winter	$0.07534	(I)
Off-Peak Winter	$0.07534	(I)
Super Off-Peak Winter	$0.07534	(I)
Transmission* (all usage)	$0.02766	
Transmission Rate Adjustments* (all usage)	$0.00314	
Reliability Services* (all usage)	($0.00051)	
Public Purpose Programs (all usage)	$0.01299	(R)
Nuclear Decommissioning (all usage)	$0.00101	(I)
Competition Transition Charges (all usage)	$0.00092	(R)
Energy Cost Recovery Amount (all usage)	$0.00005	(I)
New System Generation Charge (all usage)**	$0.00411	(I)
DWR Bond (all usage)	$0.00580	
California Climate Credit (all usage)***	$0.00000	

* 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)

ELECTRIC SCHEDULE B-1
SMALL GENERAL SERVICE

PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible A-1 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The B-1 rates with new TOU periods will become mandatory for small Commercial and Industrial (C&I) customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2:00 p.m. – 6:00 p.m. PDP Event Hours to a new version of PDP (New PDP) with 5:00 p.m. – 8:00 p.m. PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

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

Active Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months.

Legacy 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 the New PDP. (N)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd)

c. 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 notification messages of a PDP event from PG&E. (N)

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.

d. 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.

e. 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.

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

~~c.~~f. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

(Continued)

PEAK DAY PRICING DETAILS (CONT'D):

g. Program Options: Customers may customize their PDP participation by choosing either a) no limit on the number of consecutive PDP events or b) every other PDP event. Customers electing every other PDP event will be divided into two groups and only be subject to a maximum of one-half of the PDP events called and the corresponding PDP rate credits will be reduced by 50%. Customers that do not elect an option will be defaulted to the no limit on the number of consecutive PDP events. The duration of PDP Event Operations for both options will be from 5:00 p.m. to 8:00 p.m. (three-hour window). (N)

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.

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

~~g.~~k. 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. (N)

(Continued)

ELECTRIC SCHEDULE B-10 Sheet 1
MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY: Schedule B-10 is a demand metered rate schedule for general service customers. Schedule B-10 applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

These new rates with revised TOU periods adopted in D.18-08-013, including Schedule B-10, will be available to qualifying customers on a voluntary basis beginning in November 2019 through February 2021. During that period, eligible customers have a one-time opportunity to opt-in.

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 A-10, with the exception of solar grandfathered customers referenced above, will be transitioned to Schedule B-10 with revised TOU periods. The transition notification and default process are further described in the legacy rate Schedule A-10.

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-10 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Eligibility for Schedule B-10: Under Rate Schedule B-10, there is a limit on the demand (the number of kilowatts (kW)) the customer may require from the PG&E system. If the customer's demand exceeds 499 kW for three consecutive months, the customer's account will be transferred to Schedule B-19 or B-20. However, there is no minimum demand requirement to be served under this rate Schedule.

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will be between 75 and 499 kilowatts and that the customer should not be served under an agricultural or residential rate schedule, PG&E will serve the customer's account under the provisions of Rate Schedule B-10.

(L)
|
(L)

* 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.

(Continued)

ELECTRIC SCHEDULE B-10 Sheet 2
MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY: (Cont'd.)

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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. (N)

TERRITORY: This rate schedule applies everywhere PG&E provides electric service. (L)

(Continued)

ELECTRIC SCHEDULE B-10
MEDIUM GENERAL DEMAND-METERED SERVICE

RATE: (L)

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

TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge ($ per meter per day)	$4.77841	$4.77841	$4.77841
Total Demand Rates ($ per kW)			
Summer	$13.59	$13.36	$10.49
Winter	$13.59	$13.36	$10.49
Total Energy Rates ($ per kWh)			
Peak Summer	$0.27409	$0.25976	$0.20988
Part-Peak Summer	$0.21240	$0.20145	$0.15314
Off-Peak Summer	$0.17983	$0.17062	$0.12307
Peak Winter	$0.19781	$0.18690	$0.15683
Off-Peak Winter	$0.16233	$0.15327	$0.12400
Super Off-Peak Winter	$0.12599	$0.11693	$0.08766

(L)

PDP Rates (Consecutive Day and Three-Hour Event Option)* (N)

	Secondary Voltage	Primary Voltage	Transmission Voltage
PDP Charges ($ per kWh)			
All Usage During PDP Event	$0.90000	$0.90000	$0.90000
PDP Credits			
Energy ($ per kWh)			
Peak Summer	($0.04756)	($0.04756)	($0.04756)
Part-Peak Summer	($0.01647)	($0.01647)	($0.01647)

* See PDP Details, section g, for corresponding reduction in PDP credits and charges if other option(s) elected. (N)

(Continued)

ELECTRIC SCHEDULE B-10 Sheet 4
MEDIUM GENERAL DEMAND-METERED SERVICE

RATES:

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. (L) (L)/(N) (L)

UNBUNDLING OF TOTAL RATES

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

	Secondary Voltage	Primary Voltage	Transmission Voltage
Demand Rate by Components ($ per kW)			
Generation:			
Summer	-	-	-
Winter	-	-	-
Distribution:**			
Summer	$4.75	$4.52	$1.65
Winter	$4.75	$4.52	$1.65
Transmission Maximum Demand*	$9.01	$9.01	$9.01
Reliability Services Maximum Demand*	($0.17)	($0.17)	($0.17)
Energy Rate by Components ($ per kWh)			
Generation:			
Peak Summer	$0.20191	$0.18769	$0.17531
Part-Peak Summer	$0.14022	$0.12938	$0.11857
Off-Peak Summer	$0.10765	$0.09855	$0.08850
Peak Winter	$0.14386	$0.13305	$0.12226
Off-Peak Winter	$0.10838	$0.09942	$0.08943
Super Off-Peak Winter	$0.07204	$0.06308	$0.05309
Distribution:**			
Summer	$0.04539	$0.04540	$0.00806
Winter	$0.02716	$0.02718	$0.00806
Transmission Rate Adjustments* (all usage)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01205	$0.01193	$0.01177
Competition Transition Charge (all usage)	$0.00099	$0.00099	$0.00099
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00375	$0.00375	$0.00375
California Climate Credit (all usage)***	$0.00000	$0.00000	$0.00000

* 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. (L)

(Continued)

TIME PERIODS: Times of the year and times of the day are defined as follows: (L)

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 only, including weekends and holidays
Off-peak:	All other Hours.	

SEASONS: The summer rate is applicable June 1 through September 30, and the winter rate is applicable October 1 through May 31. When billing includes use in both the summer and winter periods, charges will be prorated based upon the number of days in each period. (L)

(Continued)

ELECTRIC SCHEDULE B-10 Sheet 6
MEDIUM GENERAL DEMAND-METERED SERVICE

BASIS FOR DEMAND CHARGE: The customer will be billed for demand according to the customer's "maximum demand" each month. The number of kW used will be recorded over 15-minute intervals; the highest 15-minute average in the month will be the customer's maximum demand. (L)

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.

DEFINITION OF SERVICE VOLTAGE: The following defines the three voltage classes of Schedule B-10 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.

PG&E retains the right to change its line voltage at any time. Customers receiving voltage discounts will get reasonable notice of any impending change. They will then have the option of taking service at the new voltage (and making whatever changes in their systems are necessary) or taking service without a voltage discount through transformers supplied by PG&E.

CONTRACT: For customers who use service for only part of the year, this schedule is available only on an annual contract. (L)

(Continued)

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.

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

Bundled Service Customers receive supply and delivery services solely from PG&E. The customer's bill is based on the total rates and conditions in this schedule.

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23, 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. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear
decommissioning, public purpose programs, New System Generation Charges, the DA CRS pursuant to Schedule DA CRS and short-term commodity prices as set forth in Schedule TBCC. (L)

(Continued)

ELECTRIC SCHEDULE B-10
MEDIUM GENERAL DEMAND-METERED SERVICE

BILLING: (Cont'd.)

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. (L)

Energy Cost Recovery Amount Charge (per kWh)	$0.00005
DWR Bond Charge (per kWh)	$0.00580
CTC Charge (per kWh)	$0.00099
Power Charge Indifference Adjustment (per kWh)	
2009 Vintage	$0.02643
2010 Vintage	$0.02969
2011 Vintage	$0.03222
2012 Vintage	$0.03209
2013 Vintage	$0.03432
2014 Vintage	$0.03480
2015 Vintage	$0.03461
2016 Vintage	$0.03447
2017 Vintage	$0.03441
2018 Vintage	$0.03443
2019 Vintage	$0.03669
2020 Vintage	$0.04379

CARE DISCOUNT:

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. (L)

(Continued)

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

DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use 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 transfer to Schedule E-19, 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 time-of-use (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.

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 bundled sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts. (L)

PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible A-10 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The B-10 rates with new TOU periods will become mandatory for medium Commercial and Industrial (C&I) customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2:00 p.m. – 6:00 p.m. PDP Event Hours to a new version of PDP (New PDP) with 5:00 p.m. – 8:00 p.m. PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021. (N)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd)

a. Enrollment (cont'd): (N)

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

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

Active Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months.

Legacy 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 the New PDP. (N)

ELECTRIC SCHEDULE B-10 Sheet 11
MEDIUM GENERAL DEMAND-METERED SERVICE

PEAK DAY PRICING DETAILS (Cont'd):

c. 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 notification messages of a PDP event from PG&E. (N)

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.\

d. 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.

e. 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.

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

~~c.~~f. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

(Continued)

PEAK DAY PRICING DETAILS (CONT'D):

g. Program Options: Customers may customize their PDP participation by choosing either a) no limit on the number of consecutive PDP events or b) every other PDP event. Customers electing every other PDP event will be divided into two groups and only be subject to a maximum of one-half of the PDP events called and the corresponding PDP rate credits will be reduced by 50%. Customers that do not elect an option will be defaulted to the no limit on the number of consecutive PDP events. The duration of PDP Event Operations for both options will be from 5:00 p.m. to 8:00 p.m. (three-hour window). (N)

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.

~~g.~~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. (N)

ELECTRIC SCHEDULE B-19 Sheet 2
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 13 for the definition of maximum demand for customers voluntarily selecting B-19.

Option R for Solar: The Option R rate is available to qualifying customers taking Bundled, Direct Access (DA) or Community Choice Aggregation (CCA) service under Schedule B-19, or voluntary B-19. Eligible customers must have PV systems that provide 15% or more of their annual electricity usage. For additional Option R details and program specifics, see Sections 3 and 18.

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.

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).

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).

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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. (N)
(L)
(L)

(Continued)

ELECTRIC SCHEDULE B-19

MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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

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.

BUNDLED TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage	
Total Customer Charge Rates				
Customer Charge Mandatory B-19 ($ per meter per day)	$24.77594	$37.82037	$48.05297	
Customer Charge with SmartMeter™ ($ per meter per day)	$4.77841	$4.77841	$4.77841	
Total Demand Rates ($ per kW)				
Maximum Peak Demand Summer	$25.79	$22.95	$9.76	
Maximum Part-Peak Demand Summer	$5.30	$4.78	$2.44	
Maximum Demand Summer	$21.44	$17.64	$12.11	
Maximum Peak Demand Winter	$1.77	$1.31	$0.94	
Maximum Demand Winter	$21.44	$17.64	$12.11	
Total Energy Rates ($ per kWh)				
Peak Summer	$0.16520	$0.14902	$0.13589	
Part-Peak Summer	$0.13541	$0.12640	$0.12665	
Off-Peak Summer	$0.11434	$0.10673	$0.10698	
Peak Winter	$0.14628	$0.13676	$0.13712	
Off-Peak Winter	$0.11426	$0.10686	$0.10724	
Super Off-Peak Winter	$0.07130	$0.06432	$0.06329	
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005	
PDP Rates				(N)
PDP Charges ($ per kWh)				|
All Usage During PDP Event	$1.20	$1.20	$1.20	|
PDP Credits				|
Demand ($ per kW)				|
Peak Summer	($6.48)	($5.89)	($4.84)	|
Part-Peak Summer	($0.94)	($0.86)	($1.21)	|
Energy ($ per kWh)				|
Peak Summer	$0.00	$0.00	$0.00	|
Part-Peak Summer	$0.00	$0.00	$0.00	(N)

(Continued)

ELECTRIC SCHEDULE B-19 Sheet 4
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. (N)

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	$14.92	$12.76	$9.76
Maximum Part-Peak Demand Summer	$2.17	$1.87	$2.44
Maximum Peak-Demand Winter	$1.77	$1.31	$0.94
Distribution:**			
Maximum Peak Demand Summer	$10.87	$10.19	$0.00
Maximum Part-Peak Demand Summer	$3.13	$2.91	$0.00
Maximum Demand Summer	$12.53	$8.73	$3.20
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$12.53	$8.73	$3.20
Transmission Maximum Demand*	$9.01	$9.01	$9.01
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)

* 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 B-19 Sheet 5
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. (N)

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	$0.13878	$0.12298	$0.10985
Part-Peak Summer	$0.10899	$0.10036	$0.10061
Off-Peak Summer	$0.08792	$0.08069	$0.08094
Peak Winter	$0.11986	$0.11072	$0.11108
Off-Peak Winter	$0.08784	$0.08082	$0.08120
Super Off-Peak Winter	$0.04488	$0.03828	$0.03725
Transmission Rate Adjustments* (all usage)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01177	$0.01139	$0.01139
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00090	$0.00090	$0.00090
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00375	$0.00375	$0.00375
California Climate Credit (all usage – B-19V only)***	$0.00000	$0.00000	$0.00000

* 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)

ELECTRIC SCHEDULE B-19 Sheet 22
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

a. PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible E-19 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The B-19 rates with new TOU periods will become mandatory for medium and large Commercial and Industrial (C&I) customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2:00 p.m. – 6:00 p.m. PDP Event Hours to a new version of PDP (New PDP) with 5:00 p.m. – 8:00 p.m. PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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.

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

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

(Continued)

21. PEAK DAY PRICING DETAILS (Cont'd)

c. Bill Stabilization (Cont'd): (N)

Active Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months.

Legacy 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 the New 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 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.

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.

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

(Continued)

21. PEAK DAY PRICING DETAILS (Cont'd)

g. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

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.

~~g.~~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. (N)

(Continued)

1. APPLICABILITY: (Cont'd.)

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

Standby Demand: For customers 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.

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).

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

Option R for Solar: The Option R rate is available to qualifying Bundled, DA and CCA B-20 customers, with solar photovoltaic (PV) systems that provide 15% or more of their annual electricity usage. For additional Option R details and program specifics, see Sections 3 and 16.

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

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

Option S for Storage: The Option S rate for storage is available to qualifying Bundled, DA and CCA service under Schedule B-20 customers with storage systems with a 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, sett Sections 3 and 18.

(L)
(L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

1. APPLICABILITY: (Cont'd.)

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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. (N)

2. TERRITORY: Schedule B-20 applies everywhere PG&E provides electric service. (L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 4
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

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. (L)

BUNDLED TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer Charge Rates			
Customer Charge Mandatory B-20 ($ per meter per day)	$45.08771	$45.16384	$57.74500
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$25.74	$26.14	$17.83
Maximum Part-Peak Demand Summer	$5.31	$5.07	$4.25
Maximum Demand Summer	$21.41	$19.33	$10.80
Maximum Peak Demand Winter	$1.86	$1.84	$2.38
Maximum Demand Winter	$21.41	$19.33	$10.80
Total Energy Rates ($ per kWh)			
Peak Summer	$0.15792	$0.15326	$0.13226
Part-Peak Summer	$0.13101	$0.12487	$0.11500
Off-Peak Summer	$0.10976	$0.10507	$0.09574
Peak Winter	$0.14189	$0.13519	$0.13143
Off-Peak Winter	$0.10959	$0.10512	$0.09225
Super Off-Peak Winter	$0.06632	$0.06246	$0.05312
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005 (L)
PDP Rates			(N)
PDP Charges ($ per kWh)			
All Usage During PDP Event	$1.20	$1.20	$1.20
PDP Credits			
Demand ($ per kW)			
Peak Summer	($6.30)	($7.10)	($6.25)
Part-Peak Summer	($0.91)	($0.98)	($1.49)
Energy ($ per kWh)			
Peak Summer	$0.00	$0.00	$0.00
Part-Peak Summer	$0.00	$0.00	$0.00 (N)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 5
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(Cont'd.)

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown 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. PDP charges and credits are all generation and are not included below. (L) (L)/(N) (N)

Demand Rates by Components ($ per kW)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Maximum Peak Demand Summer	$14.61	$15.99	$17.83
Maximum Part-Peak Demand Summer	$2.12	$2.20	$4.25
Maximum Demand Summer	$0.00	$0.00	$0.00
Maximum Peak Demand Winter	$1.86	$1.84	$2.38
Maximum Demand Winter			
Distribution:**			
Maximum Peak Demand Summer	$11.13	$10.15	$0.00
Maximum Part-Peak Demand Summer	$3.19	$2.87	$0.00
Maximum Demand Summer	$11.66	$9.58	$1.05
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$11.66	$9.58	$1.05
Transmission Maximum Demand*	$9.85	$9.85	$9.85
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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. (L) (L)/(N) (L)

UNBUNDLING OF TOTAL RATES

Customer Charge Rates: Customer charge rates provided in the Total Rate 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	$0.13233	$0.12810	$0.10781
Part-Peak Summer	$0.10542	$0.09971	$0.09055
Off-Peak Summer	$0.08417	$0.07991	$0.07129
Peak Winter	$0.11630	$0.11003	$0.10698
Off-Peak Winter	$0.08400	$0.07996	$0.06780
Super Off-Peak Winter	$0.04073	$0.03730	$0.02867
Transmission Rate Adjustments* (all usage)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01146	$0.01106	$0.01041
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00326	$0.00326	$0.00326

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 RATES FOR OPTION R
(for qualifying solar customers as set forth in Section 16)

Total Customer Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory B-20 ($ per meter per day)	$45.08771	$45.16384	$57.74500
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$2.78	$2.54	$0.00
Maximum Part-Peak Demand Summer	$0.80	$0.72	$0.00
Maximum Demand Summer	$21.41	$19.33	$10.80
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$21.41	$19.33	$10.80
Total Energy Rates ($ per kWh)			
Peak Summer	$0.35949	$0.33728	$0.26896
Part-Peak Summer	$0.17666	$0.16612	$0.15034
Off-Peak Summer	$0.11763	$0.11355	$0.10009
Peak Winter	$0.15741	$0.14923	$0.15017
Off-Peak Winter	$0.11368	$0.10916	$0.09716
Super Off-Peak Winter	$0.07793	$0.07341	$0.06436
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 16)

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	$2.78	$2.54	$0.00
Maximum Part-Peak Demand Summer	$0.80	$0.72	$0.00
Maximum Demand Summer	$11.66	$9.58	$1.05
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$11.66	$9.58	$1.05
Transmission Maximum Demand*	$9.85	$9.85	$9.85
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 16)

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	$0.25843	$0.24755	$0.24450
Part-Peak Summer	$0.12568	$0.11865	$0.12588
Off-Peak Summer	$0.08822	$0.08395	$0.07563
Peak Winter	$0.13182	$0.12407	$0.12572
Off-Peak Winter	$0.08809	$0.08400	$0.07271
Super Off-Peak Winter	$0.05234	$0.04825	$0.03991
Distribution:**			
Peak Summer	$0.07547	$0.06457	$0.00001
Part-Peak Summer	$0.02539	$0.02231	$0.00001
Off-Peak Summer	$0.00382	$0.00444	$0.00001
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)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01146	$0.01106	$0.01041
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00326	$0.00326	$0.00326

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 RATES FOR OPTION S
(for qualifying storage customers as set forth in Section 18)

Total Customer Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory B-20 ($ per meter per day)	$45.08771	$45.16384	$57.74500
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer (per day)	$0.54	$0.43	$0.04
Maximum Part-Peak Demand Summer (per day)	$0.03	$0.03	
Maximum Demand Summer (per monthly billing, all hours except 9 am to 2 pm)	$2.36	$1.94	$0.21
Maximum Demand Summer (per monthly billing)	$9.75	$9.75	$9.75
Maximum Peak Demand Winter (per day)	$0.45	$0.35	$0.04
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.36	$1.94	$0.21
Maximum Demand Winter (per billing month)	$9.75	$9.75	$9.75
Total Energy Rates ($ per kWh)			
Peak Summer	$0.35949	$0.33728	$0.26896
Part-Peak Summer	$0.17666	$0.16612	$0.15034
Off-Peak Summer	$0.11763	$0.11355	$0.10009
Peak Winter	$0.15741	$0.14923	$0.15017
Off-Peak Winter	$0.11368	$0.10916	$0.09716
Super Off-Peak Winter	$0.07793	$0.07341	$0.06436
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 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 (per day)	$0.54	$0.43	$0.04
Maximum Part-Peak Demand Summer (per day)	$0.03	$0.03	
Maximum Demand Summer (per monthly billing, all hours except 9 am to 2 pm)	$2.36	$1.94	$0.21
Maximum Demand Summer (per monthly billing)	$0.00	$0.00	$0.00
Maximum Peak Demand Winter (per day)	$0.45	$0.35	$0.04
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.36	$1.94	$0.21
Maximum Demand Winter (per billing month)	$0.00	$0.00	$0.00
Transmission Maximum Demand*	$9.85	$9.85	$9.85
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. Rates: (L)
(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 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	$0.25843	$0.24755	$0.24450
Part-Peak Summer	$0.12568	$0.11865	$0.12588
Off-Peak Summer	$0.08822	$0.08395	$0.07563
Peak Winter	$0.13182	$0.12407	$0.12572
Off-Peak Winter	$0.08809	$0.08400	$0.07271
Super Off-Peak Winter	$0.05234	$0.04825	$0.03991
Distribution:**			
Peak Summer	$0.07547	$0.06457	$0.00001
Part-Peak Summer	$0.02539	$0.02231	$0.00001
Off-Peak Summer	$0.00382	$0.00444	$0.00001
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)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01146	$0.01106	$0.01041
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00326	$0.00326	$0.00326

* 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. (L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. RATES: (Cont'd.)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule B-20 is the sum of a customer charge, demand charges, and energy charges: (L)

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

– Schedule B-20 has three **demand charges**, a maximum-peak-period-demand charge, a maximum-part-peak-period demand charge, and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum-part-peak-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. 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 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-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

5. DEFINITION OF SERVICE VOLTAGE: The following defines the three voltage classes of Schedule B-20 rates. Standard Service Voltages are listed in Rule 2. (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 at one of the standard transmission voltages specified in PG&E's Electric 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)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

7.	POWER FACTOR ADJUST-MENTS:	The bill will be adjusted based upon the power factor. The power factor is computed from the cosine of the arctangent 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. 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.	(L)
8.	CHARGES FOR TRANSFORMER AND LINE LOSSES:	The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of Rule 2.	
9.	STANDARD SERVICE FACILITIES:	If PG&E must install any new or additional facilities to provide the customer with service under Schedule B-20, the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a line extension agreement. See Rules 2, 15, and 16 for details. Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in the line extension agreement.	
10.	SPECIAL FACILITIES:	PG&E will normally install only those standard facilities it deems necessary to provide service under Schedule B-20. 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)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

11. BILLING: A customer's bill is calculated based on the option applicable to the customer. (L)

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

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

Direct Access (DA) and Community Choice Aggregation (CCA) Customers purchase energy from their non-utility provider and continue receiving delivery services from PG&E. Bills are equal to the sum of charges for transmission, transmission rate adjustments, reliability services, distribution, public purpose programs, nuclear decommissioning, New System Generation Charges, 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.

	Secondary Voltage	Primary Voltage	Transmission Voltage
Energy Cost Recovery Amount Charge (per kWh)	$0.00005	$0.00005	$0.00005
DWR Bond Charge (per kWh)	$0.00580	$0.00580	$0.00580
CTC Rate (per kWh)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount Charge (per kWh)			
2009 Vintage	$0.02330	$0.02240	$0.02079
2010 Vintage	$0.02617	$0.02516	$0.02335
2011 Vintage	$0.02840	$0.02730	$0.02534
2012 Vintage	$0.02829	$0.02720	$0.02524
2013 Vintage	$0.03026	$0.02908	$0.02699
2014 Vintage	$0.03068	$0.02949	$0.02737
2015 Vintage	$0.03051	$0.02933	$0.02722
2016 Vintage	$0.03039	$0.02921	$0.02711
2017 Vintage	$0.03033	$0.02916	$0.02706
2018 Vintage	$0.03036	$0.02918	$0.02708
2019 Vintage	$0.03235	$0.03109	$0.02886
2020 Vintage	$0.03861	$0.03711	$0.03445 (L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 17
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

12. 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. (L)

13. ELECTRIC EMER-GENCY PLAN ROTATING BLOCK OUTAGES: See Electric Rule 14.

14. 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.

15. 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)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

16. Option R

The Option R rate is available to qualifying customers with PV systems that provide 15% or more of their annual electricity usage[1] as described below. No Benefitting* or Aggregated* account is eligible for Option R unless there is PV interconnected at that account that independently meets the requirements of Option R. i.e., the PV interconnected on that account meets 15% of the load at that account. (L)

Customers:
a) Installing a new PV system with no existing generation or with existing non-PV generation; or
b) With existing PV and non-PV generation (as an existing NEMMT)

Must meet the following eligibility requirement:

$$\frac{\text{Annual PV system output}^{2}}{\text{Annual electricity usage}^{1}} \geq 15\ \%$$

Customers:
a) With an existing PV system, that are installing new PV system
b) Adding new solar to existing PV and Non-PV generation

Must meet the following eligibility requirement:

$$\frac{\text{Annual PV system (new + existing) output}^{2}}{\text{Annual PV system (new + existing) output}^{2} + \text{Annual electricity usage}^{1}} \geq 15\ \%$$

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

[1] Annual electricity usage (kWh): for customers with no generation will be the most recent usage over twelve billing periods, and for customers with existing generation it will be the net of imports and exports (if any, for all generators), measured at the PG&E meter over the most recent 12 billing periods. In cases where the most recent 12-month usage is not available PG&E will offer an alternate method.

[2] Annual PV system Output (kWh) = CEC_{AC} rating of the panels (kW) x 8760 hours/year x 18% capacity factor where:

$$CEC_{AC}\text{ Rating of the panels (kW)} = \frac{\text{(Quantity of PV Modules (W) x PTC Rating of PV Modules x CEC Inverter Efficiency Rating)}}{1000}$$

Where the PTC and CEC inverter Efficiency Rating can be found at:
The PTC rating can be found here:
http://www.gosolarcalifornia.ca.gov/equipment/documents/PV_Module_List_Simplified_Data.xlsx
and the CEC inverter efficiency rating here:
http://www.gosolarcalifornia.ca.gov/equipment/documents/Inverter_List_Simplified_Data.xlsx
The above Annual PV System Output formula can be modified based on the following alternatives:

a) For customers with existing PV system, the customer may choose to supply PG&E with reliable metered data measuring Annual PV system Output, if such data is available.
b) Customers with trackers can use the alternate capacity factors of:

Have single axis	21%
Have dual axis	24%

(L)

(Continued)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

17. 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 DA and CCA 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-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

17. 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)

ELECTRIC SCHEDULE B-20
SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

18. 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)

ELECTRIC SCHEDULE B-20 Sheet 22
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

19. PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible E-20 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The B-20 rates with new TOU periods will become mandatory for large Commercial and Industrial (C&I) customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2:00 p.m. – 6:00 p.m. PDP Event Hours to a new version of PDP (New PDP) with 5:00 p.m. – 8:00 p.m. PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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.

~~a.~~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. (N)

(Continued)

a. PEAK DAY PRICING DETAILS (Cont'd)

c. Bill Stabilization (Cont'd): (N)

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 Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months.

Legacy 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 the New 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 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.

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.

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

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 24
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

19. PEAK DAY PRICING DETAILS (Cont'd)

g. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

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.

~~g.~~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. (N)

(Continued)

ELECTRIC SCHEDULE B-6
SMALL GENERAL TIME-OF-USE SERVICE

APPLICABILITY: Schedule B-6, a time-of-use schedule, applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2*). This schedule is not available to residential or agricultural service for which a residential or agricultural schedule is applicable, 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

These new rates with revised TOU periods adopted in D.18-08-013, including Schedule B-6, will be available to qualifying customers on a voluntary basis beginning in November 2019 through February 2021. During that period, eligible customers have a one-time opportunity to opt-in.

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 A-6, with the exception of solar grandfathered customers referenced above, will be transitioned to Schedule B-6 with revised TOU periods. The mandatory transition process is further described in the legacy rate Schedule A-6.

Customers with a maximum demand of 75 kW or greater for three consecutive months in the most recent twelve months are not eligible for service on this rate schedule except as noted: customers served on Schedule A-6 or who sent PG&E a letter (via certified mail with a return receipt to establish a delivery record date) requesting a rate change pursuant to Electric Rule 12, on or before March 31, 2017 shall be allowed to take service on Schedule B-6 and will be exempt from annual 75 kW eligibility reviews, but will be subject to placement on Mandatory B-19 if over 499 kW for three consecutive months. Eligibility for B-6 will be reviewed annually and the transition of customers that are no longer eligible for service on this rate schedule to Schedule B-10 will occur on the start of the customers' November billing cycle. These customers will have at least 45-days' notice prior to their planned transition, during which they will continue to take service on this rate schedule. Customers may elect any other applicable rate schedule up to five (5) days prior to the planned transition date to Schedule B-10.

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-6 charges. Exemptions are outlined in the Standby Applicability Section of this rate schedule.

(L)
(L)

* 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 website at http://www.pge.com/tariffs.

(Continued)

ELECTRIC SCHEDULE B-6
SMALL GENERAL TIME-OF-USE SERVICE

Sheet 2

APPLICABILITY: (Cont'd.)

Peak Day Pricing 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. Customers with a SmartMeter™ system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates. (N)

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 S), net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, or an energy payment demand response program are not eligible for PDP. 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. (N)

TERRITORY: This rate schedule applies everywhere PG&E provides electric service. (L)

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.

TOTAL RATES

Total Customer/Meter Charge Rates

Customer Charge Single-phase ($ per meter per day)	$0.32854
Customer Charge Poly-phase ($ per meter per day)	$0.82136

Total Energy Rates ($ per kWh)

Peak Summer	$0.36038
Off-Peak Summer	$0.24244
Peak Winter	$0.25277
Off-Peak Winter	$0.23302
Super Off-Peak Winter	$0.21661

PDP Rates (Consecutive Day and Three-Hour Event Option)* (N)

PDP Charges ($ per kWh)	
All Usage During PDP Event	$0.60000
PDP Credits	
Energy ($ per kWh)	
Peak Summer	($0.04090)

** See PDP Details, section g, for corresponding reduction in PDP credits and charges if other option(s) elected.* (N)

(Continued)

ELECTRIC SCHEDULE B-6
SMALL GENERAL TIME-OF-USE SERVICE

RATES: (Cont'd.)

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

UNBUNDLING OF TOTAL RATES

Customer Charge Rates: Customer charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component. PDP charges and credits are all generation and are not included below. (N)

Energy Rates by Components ($ per kWh)	Rates
Generation:	
Peak Summer	$0.18197
Off-Peak Summer	$0.11081
Peak Winter	$0.11845
Off Peak Winter	$0.10139
Super Off-Peak Winter	$0.08498
Distribution:**	
Peak Summer	$0.12429
Off-Peak Summer	$0.07751
Peak Winter	$0.08020
Off Peak Winter	$0.07751
Super Off-Peak Winter	$0.07751
Transmission* (all usage)	$0.02766
DWR Bond (all usage)	$0.00580
Transmission Rate Adjustments* (all usage)	$0.00314
Reliability Services* (all usage)	($0.00051)
Public Purpose Programs (all usage)	$0.01194
Nuclear Decommissioning (all usage)	$0.00101
Competition Transition Charges (all usage)	$0.00092
Energy Cost Recovery Amount (all usage)	$0.00005
New System Generation Charge (all usage)**	$0.00411
California Climate Credit (all usage)***	$0.00000

* 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)

ELECTRIC SCHEDULE B-6 Sheet 7
SMALL GENERAL TIME-OF-USE SERVICE

PEAK DAY PRICING DETAILS

a. Enrollment: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspended the default of eligible A-6 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The B-6 rates with new TOU periods will become mandatory for small Commercial and Industrial (C&I) customers in March 2021, concurrent with the transition of customers who are enrolled in the current version of PDP (Legacy PDP) with 2:00 p.m. – 6:00 p.m. PDP Event Hours to a new version of PDP (New PDP) with 5:00 p.m. – 8:00 p.m. PDP Event Hours. (N)

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only as an optional program. The process of defaulting eligible new customers into the New PDP program will be discontinued as of March 2021.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for 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 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. Bill Stabilization: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate.

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

Active Legacy PDP customers who have not completed 12-months of bill stabilization by the time they are transitioned to New PDP in their March 2021 billing cycle will seamlessly continue with their bill stabilization under New PDP until 12-months have elapsed since their initial enrollment in Legacy PDP, or until they optionally unenroll from New PDP before 12-months. (N)

(Continued)

ELECTRIC SCHEDULE B-6 Sheet 8
SMALL GENERAL TIME-OF-USE SERVICE

PEAK DAY PRICING DETAILS (Cont'd)

b. Bill Stabilization (Cont'd): (N)

Legacy 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 the New PDP.

c. 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 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.

d. 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.

e. 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.

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

~~e.~~f. Event Cancellation or Reduction: 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. PG&E may also cancel or decline to call PDP events by 4:00 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. (N)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd)

g. Program Options: Customers may customize their PDP participation by choosing either a) no limit on the number of consecutive PDP events or b) every other PDP event. Customers electing every other PDP event will be divided into two groups and only be subject to a maximum of one-half of the PDP events called and the corresponding PDP rate credits will be reduced by 50%. Customers that do not elect an option will be defaulted to the no limit on the number of consecutive PDP events. The duration of PDP Event Operations for both options will be from 5:00 p.m. to 8:00 p.m. (three-hour window). (N)

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.

~~g.~~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. (N)

(Continued)

ELECTRIC SCHEDULE E-19 Sheet 1
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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.

Effective March 1, 2021, Schedule E-19 is available only to qualifying solar grandfathered customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to new Schedule B-19 or other applicable new tariffs with later Time-of-Use (TOU) hours as described below. (N)

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new TOU periods (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 (i.e., be grandfathered on) their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1*, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods will be available on a voluntary basis for qualifying customers beginning November 1, 2019. During this voluntary period from November 1, 2019 through February 2021, as well as thereafter:

Schedule B-19, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters and less than 1000 kW in size. Customers who enroll in any new rate during the voluntary period will be unenrolled from Peak Day Pricing.

Schedule E-19 will be closed to all new enrollment. Customers requesting to establish service on Schedule E-19 where an interval data meter that can be read remotely by PG&E is already in place will be placed on the new Schedule B-19. Customers requesting to establish service on Schedule E-19 that do not have a meter that is capable of billing on the new Schedule B-19, may take service on this schedule.

Customers taking service under Schedule E-19 at the time rates with new TOU periods become available on a voluntary basis, may transfer to new Schedule B-19, may remain on this rate until rates with new TOU periods become mandatory, in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers.

* 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.

(Continued)

ELECTRIC SCHEDULE E-19 Sheet 2
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

1. APPLICABILITY: During the period the new rates with revised TOU periods are available on a voluntary basis for qualifying customers, from November 1, 2019 through February 28, 2021, customers who have opted in to the revised TOU periods, may opt out of the revised TOU periods and return to a legacy electric rate schedule with the legacy TOU periods listed in the special condition for "Definition of Time Periods" in this tariff, for the remainder of the period that the new rates with revised TOU periods are voluntary. Opting out of the revised TOU periods before they become mandatory is available on a one-time basis. If the customer opts-out of a new rate with the revised TOU periods less than twelve months before the revised TOU periods become mandatory, the customer may not return to a rate with the revised TOU periods until they become mandatory. (N)

Beginning March 2021, Schedule B-19, with revised TOU periods, will become mandatory for customers served on this rate schedule.

Mandatory transitions to Schedule B-19 will occur at the start of the customer's March billing cycle.

Customers eligible to transition to the new rates must have an interval data meter and have at least twelve (12) billing months of hourly usage data available.

All transitioning customers will be notified at least 45 days prior to their scheduled transition date. Customers may elect any applicable rate with new TOU periods (that they are eligible for) up to five (5) days prior to their scheduled transition to B-19.

Exemptions to mandatory transitions beginning in March 2021 include:

Qualifying customers with solar systems who meet the requirements in Rule 1 Definition of "Behind-the-Meter Solar TOU Period Grandfathering" and the terms of "Behind-the-Meter Solar TOU Period Grandfathering Eligibility Requirements" shall be permitted to maintain their legacy TOU rate periods and service under Schedule E-19, until the date ten years after their system received its permission to operate (but in no event beyond December 31, 2027 (for public schools) or July 31, 2027 (for all other qualifying customers). However, rates for those TOU rate periods will be updated with new rates as authorized in applicable PG&E rate proceedings and advice filings.

Customers that do not have a meter that is capable of billing on the new Schedules B-19 by the beginning of their March 2021 billing cycle, may continue service on this schedule until they receive an interval meter and have at least twelve (12) months of hourly usage data available.

This mandatory transition process will then occur in November 2021 and in each November thereafter to transition all applicable remaining E-19 customers to the rates with revised TOU periods.

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.

(Continued)

1. APPLICABILITY: (Cont'd.)

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:

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.

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.

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 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.

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule E-19 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule E-19 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to Schedule B-19 or other applicable non-legacy rate and enroll in the new PDP program. Customers currently participating on both Schedule E-19 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to the new underlying TOU Schedule B-19 or other applicable new non-legacy rate option. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date. (N)

Customers with a SmartMeter system, or interval meter, installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates.

(L)
|
(L)

(Continued)

1. APPLICABILITY: (Cont'd.)

Peak Day Pricing Rates (Cont'd): (L)

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 S), or on net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, are not eligible for PDP. In addition, master-metered customers are not 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. (L)

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.

Option R for Solar: The Option R rate is available to qualifying customers taking Bundled, DA or CCA service under Schedule E-19, or voluntary E-19. Eligible customers must have solar photovoltaic (PV) systems that provide 15% or more of their annual electricity usage. For additional Option R details and program specifics, see Sections 3 and 20.

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.

(Continued)

ELECTRIC SCHEDULE E-19 Sheet 5
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.

Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

TOTAL RATES

Total Customer/Meter Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory E-19			
($ per meter per day)	$24.77594	$37.82037	$48.05297
Customer Charge Voluntary E-19:			
Customer Charge with SmartMeter™ ($ per meter per day)	$4.77841	$4.77841	$4.77841
Customer Charge without SmartMeter™			
Customer Charge Rate V ($ per meter per day)	$4.95582	$4.95582	$4.95582
Customer Charge Rate W ($ per meter per day)	$4.81389	$4.81389	$4.81389
Customer Charge Rate X ($ per meter per day)	$4.95582	$4.95582	$4.95582
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$21.94	$19.53	$14.56
Maximum Part-Peak Demand Summer	$6.10	$5.33	$3.65
Maximum Demand Summer	$21.10	$17.47	$12.11
Maximum Part-Peak Demand Winter	$0.14	$0.17	$0.00
Maximum Demand Winter	$21.10	$17.47	$12.11
Total Energy Rates ($ per kWh)			
Peak Summer	$0.17427	$0.16241	$0.12020
Part-Peak Summer	$0.12656	$0.11744	$0.10543
Off-Peak Summer	$0.09496	$0.08853	$0.08588
Part-Peak Winter	$0.12002	$0.11137	$0.10775
Off-Peak Winter	$0.10280	$0.09567	$0.09274
Power Factor Adjustment Rate ($/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	($5.29)	($5.18)	($5.01)
Part-Peak Summer	($1.31)	($1.26)	($1.25)
Energy ($ per kWh)			
Peak Summer	$0.00000	$0.00000	$0.00000
Part-Peak Summer	$0.00000	$0.00000	$0.00000

(Continued)

18. PEAK DAY PRICING DETAILS:

Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with Schedule B-19 or other applicable non-legacy rate may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible E-19 customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for medium and large Commercial and Industrial (C&I) customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP. (T)

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 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.

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.

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).

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

ELECTRIC SCHEDULE E-20 Sheet 1
SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

1. APPLICABILITY: **Initial Assignment:** A customer is eligible for service under Schedule E-20 if the customer's maximum demand (as defined below) has exceeded 999 kilowatts for at least three consecutive months during the most recent 12-month period. 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.

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

Effective March 1, 2021, Schedule E-20 is available only to qualifying solar grandfathered customers, or to qualifying customers without interval meters, as specified in greater detail below. This tariff is currently scheduled to expire in 2027, at which time all legacy customers must transition to new Schedule B-20 or other applicable new tariffs with later Time-of-Use (TOU) hours as described below. (N)

Decision 18-08-013 adopted new TOU periods and seasonal definitions 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 current TOU periods until the rates with new legacy TOU periods (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 (i.e., be grandfathered on) their existing TOU rate periods for a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar TOU Grandfathering and Eligibility Requirements.

The new rates with revised TOU periods will be available on a voluntary basis for qualifying customers beginning November 1, 2019. During this voluntary period from November 1, 2019 through February 2021, as well as thereafter.

Schedule B-20, with revised TOU periods, will be available for voluntary enrollment for customers with interval meters and greater than 999 kW in size. Customers who enroll in any new rate during the voluntary period will be unenrolled from Peak Day Pricing.

Schedule E-20 will be closed to all new enrollment. Customers requesting to establish service on Schedule E-20 where an interval data meter that can be read remotely by PG&E is already in place will be placed on the new Schedule B-20. Customers requesting to establish service on Schedule E-20 that do not have a meter that is capable of billing on the new Schedule B-20, may take service on this schedule.

Customers taking service under Schedule E-19 at the time rates with new TOU periods become available on a voluntary basis, may transfer to new Schedule B-19, may remain on this rate until rates with new TOU periods become mandatory, in March 2021, or, on an exceptions basis, may request to transfer to another legacy rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers.

(L)

* 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.

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 2
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

1. APPLICABILITY: (Cont'd.)

During the period the new rates with revised TOU periods are available on a voluntary basis for qualifying customers, from November 1, 2019 through February 28, 2021, customers who have opted in to the revised TOU periods, may opt out of the revised TOU periods and return to a legacy electric rate schedule with the legacy TOU periods listed in the special condition for "Definition of Time Periods" in this tariff, for the remainder of the period that the new rates with revised TOU periods are voluntary. Opting out of the revised TOU periods before they become mandatory is available on a one-time basis. If the customer opts-out of a new rate with the revised TOU periods less than twelve months before the revised TOU periods become mandatory, the customer may not return to a rate with the revised TOU periods until they become mandatory. (L)

Beginning March 2021, Schedule B-20, with revised TOU periods, will become mandatory for customers served on this rate schedule.

Mandatory transitions to Schedule B-20 will occur at the start of the customer's March billing cycle.

Customers eligible to transition to the new rates must have an interval data meter and have at least twelve (12) billing months of hourly usage data available.

All transitioning customers will be notified at least 45 days prior to their scheduled transition date. Customers may elect any applicable rate with new TOU periods (that they are eligible for) up to five (5) days prior to their scheduled transition to B-20

Exemptions to mandatory transitions beginning in March 2021 include:

Qualifying customers with solar systems who meet the requirements in Rule 1 Definition of "Behind-the-Meter Solar TOU Period Grandfathering" and the terms of "Behind-the-Meter Solar TOU Period Grandfathering Eligibility Requirements" shall be permitted to maintain their legacy TOU rate periods and service under Schedule E-20, until the date ten years after their system received its permission to operate (but in no event beyond December 31, 2027 (for public schools) or July 31, 2027 (for all other qualifying). However, rates for those TOU rate periods will be updated with new rates as authorized in applicable PG&E rate proceedings and advice filings.

Customers that do not have a meter that is capable of billing on the new Schedules B-20 by the beginning of their March 2021 billing cycle, may continue service on this schedule until they receive an interval meter and have at least twelve (12) months of hourly usage data available.

This mandatory transition process will then occur each November 2021 and in each November thereafter to transition all applicable remaining E-20 customers to the rates with revised TOU periods.

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-20 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(L)
(L)

(Continued)

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

1. APPLICABILITY: (Cont'd.)

Transfers Off of Schedule E-20: PG&E will review its Schedule E-20 accounts annually. A customer will be eligible for continued service on Schedule E-20 if its maximum demand has either: (1) Exceeded 999 kilowatts for at least 5 of the previous 12 billing months; or (2) Exceeded 999 kilowatts for any 3 consecutive billing months of the previous 14 billing months. If a customer's demand history fails both of these tests, PG&E will transfer that customer's account to service under a different applicable rate schedule. (L)

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will exceed 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-20.

Peak Day Pricing 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.

Customers may voluntarily elect to enroll on PDP rates. (L)

Effective March 1, 2021, PDP rates will no longer be available in conjunction with this legacy Schedule E-20 rate option. The legacy PDP program with 2:00 p.m. to 6:00 p.m. PDP Event Hours will be discontinued in March 2021. Any customer remaining on this legacy Schedule E-20 rate option after March 2021 will be unenrolled from the legacy PDP program. Any customer wishing to opt-in to the new PDP program with revised 5:00 p.m. to 8:00 p.m. PDP Event Hours must transition to Schedule B-20 or other applicable non-legacy rate and enroll in the new PDP program. Customers currently participating on both Schedule E-20 and the legacy PDP program in the months leading up to March 2021 will be auto-enrolled in the new PDP program upon transition in March 2021 to the new underlying TOU Schedule B-20 or other applicable new non-legacy rate option. Notice of this change in the PDP program will be provided to affected customers at least 45 days prior to the transition date. (N)

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 S), or on net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or NEMA, are not eligible for PDP. In addition, master-metered customers are not eligible, except for commercial buildings with submetering as stated in PG&E Rule 1 and Rule 18. Non-residential SmartAC customers are eligible.

For additional PDP details and program specifics, see section 17.

(L)
(L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 4
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

1.APPLICABILITY: (Cont'd.)

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

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

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

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

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

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

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

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

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 5
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

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 (L)

Effective March 1, 2021, the legacy PDP program rate details provided below will no longer be valid. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. (N)

TOTAL RATES (L)

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge Mandatory E-20 ($ per meter per day)	$45.08771	$45.16384	$57.74500
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$21.19	$22.77	$18.80
Maximum Part-Peak Demand Summer	$5.88	$6.07	$4.48
Maximum Demand Summer	$21.30	$18.82	$10.80
Maximum Part-Peak Demand Winter	$0.06	$0.15	$0.00
Maximum Demand Winter	$21.30	$18.82	$10.80
Total Energy Rates ($ per kWh)			
Peak Summer	$0.16299	$0.16528	$0.11670
Part-Peak Summer	$0.11960	$0.11759	$0.10223
Off-Peak Summer	$0.08981	$0.08825	$0.08307
Part-Peak Winter	$0.11330	$0.11130	$0.10450
Off-Peak Winter	$0.09716	$0.09546	$0.08979
Power Factor Adjustment Rate ($/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	($5.10)	($5.57)	($5.95)
Part-Peak Summer	($1.26)	($1.32)	($1.42)
Energy ($ per kWh)			
Peak Summer	$0.00000	$0.00000	$0.00000
Part-Peak Summer	$0.00000	$0.00000	$0.00000

(L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 6
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. RATES: (Cont'd.) (L)

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

Demand Rates by Component ($ per kW)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Maximum Peak Demand Summer	$14.41	$15.78	$18.80
Maximum Part-Peak Demand Summer	$3.56	$3.73	$4.48
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	$6.78	$6.99	$0.00
Maximum Part-Peak Demand Summer	$2.32	$2.34	$0.00
Maximum Demand Summer	$11.55	$9.07	$1.05
Maximum Part-Peak Demand Winter	$0.06	$0.15	$0.00
Maximum Demand Winter	$11.55	$9.07	$1.05
Transmission Maximum Demand*	$9.85	$9.85	$9.85
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)
Energy Rates by Component ($ per kWh)			
Generation:			
Peak Summer	$0.13740	$0.14012	$0.09225
Part-Peak Summer	$0.09401	$0.09243	$0.07778
Off-Peak Summer	$0.06422	$0.06309	$0.05862
Part-Peak Winter	$0.08771	$0.08614	$0.08005
Off-Peak Winter	$0.07157	$0.07030	$0.06534
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**)**	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01146	$0.01106	$0.01041
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00326	$0.00326	$0.00326 (L)

* 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-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. RATES: (Cont'd.) (L)

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

Total Customer/Meter Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory E-20 ($ per meter per day)	$45.08771	$45.16384 (	$57.74500
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$1.69	$1.75	$0.00
Maximum Part-Peak Demand Summer	$0.58	$0.58	$0.00
Maximum Demand Summer	$21.30	$18.82	$10.80
Maximum Part-Peak Demand Winter	$0.01	$0.04	$0.00
Maximum Demand Winter	$21.30	$18.82	$10.80
Total Energy Rates ($ per kWh)			
Peak Summer	$0.35511	$0.37280	$0.31425
Part-Peak Summer	$0.17270	$0.17028	$0.14562
Off-Peak Summer	$0.09371	$0.09246	$0.08555
Part-Peak Winter	$0.11660	$0.11526	$0.10626
Off-Peak Winter	$0.10080	$0.09943	$0.09204
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(L)

(Continued)

3. Rates: (Cont'd.) (L)

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

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

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	$1.69	$1.75	$0.00
Maximum Part-Peak Demand Summer	$0.58	$0.58	$0.00
Maximum Demand Summer	$11.55	$9.07	$1.05
Maximum Part-Peak Demand Winter	$0.01	$0.04	$0.00
Maximum Demand Winter	$11.55	$9.07	$1.05
Transmission Maximum Demand*	$9.85	$9.85	$9.85
Reliability Services Maximum Demand*	($0.10)	($0.10)	($0.10)
Energy Rates by Component ($ per kWh)			
Generation:			
Peak Summer	$0.28018	$0.29749	$0.28980
Part-Peak Summer	$0.13026	$0.12893	$0.12117
Off-Peak Summer	$0.06705	$0.06606	$0.06110
Part-Peak Winter	$0.08972	$0.08834	$0.08181
Off-Peak Winter	$0.07414	$0.07303	$0.06759
Distribution:**			
Peak Summer	$0.04934	$0.05015	$0.00000
Part-Peak Summer	$0.01685	$0.01619	$0.00000
Off-Peak Summer	$0.00107	$0.00124	$0.00000
Part-Peak Winter	$0.00129	$0.00176	$0.00000
Off-Peak Winter	$0.00107	$0.00124	$0.00000
Transmission Rate Adjustments* (all usage)	$0.00314	$0.00314	$0.00314
Public Purpose Programs (all usage)	$0.01146	$0.01106	$0.01041
Nuclear Decommissioning (all usage)	$0.00101	$0.00101	$0.00101
Competition Transition Charge (all usage)	$0.00087	$0.00084	$0.00078
Energy Cost Recovery Amount (all usage)	$0.00005	$0.00005	$0.00005
DWR Bond (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00326	$0.00326	$0.00326

* 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. (L)

(Continued)

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

3. RATES: (Cont'd.)

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

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

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

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

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

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

4. METERING REQUIREMENTS:

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

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

5. DEFINITION OF SERVICE VOLTAGE:

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

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

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

c. Transmission: This is the voltage class if the customer is served without transformation at one of the standard transmission voltages specified in PG&E's Electric Rule 2, Section B.1. (L)

(Continued)

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

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

SUMMER	Period A (Service from May 1 through October 31):	
Peak:	12:00 noon to 6:00 p.m.	Monday through Friday (except holidays)
Partial-peak:	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m.	Monday through Friday (except holidays)
Off-peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday Saturday, Sunday, and holidays
WINTER	Period B (service from November 1 through April 30):	
Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday (except holidays)
Off-Peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday (except holidays) Saturday, Sunday, and holidays

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

DAYLIGHT SAVING TIME ADJUSTMENT: The time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

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

7. POWER FACTOR ADJUSTMENTS: The bill will be adjusted based upon the power factor. The power factor is computed from the cosine of the arctangent 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.

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. (L)

(Continued)

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

8.	CHARGES FOR TRANSFORMER AND LINE LOSSES:	The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of Rule 2.	(L)
9.	STANDARD SERVICE FACILITIES:	If PG&E must install any new or additional facilities to provide the customer with service under Schedule E-20, the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a line extension agreement. See Rules 2, 15, and 16 for details.	|
		Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in the line extension agreement.	|
10.	SPECIAL FACILITIES:	PG&E will normally install only those standard facilities it deems necessary to provide service under Schedule E-20. If the customer requests any additional facilities, those facilities will be treated as “special facilities” in accordance with Section I of Rule 2.	(L)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 12
SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

11. BILLING: A customer's bill is calculated based on the option applicable to the customer. (L)

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

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

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

DA / CCA CRS	Secondary Voltage	Primary Voltage	Transmission Voltage	
Energy Cost Recovery Amount Charge (per kWh)	$0.00005	$0.00005	$0.00005	
DWR Bond Charge (per kWh)	$0.00580	$0.00580	$0.00580	
CTC Rate (per kWh)	$0.00087	$0.00084	$0.00078	
Power Charge Indifference Adjustment (per kWh)				
2009 Vintage	$0.02330	$0.02240	$0.02079	
2010 Vintage	$0.02617	$0.02516	$0.02335	
2011 Vintage	$0.02840	$0.02730	$0.02534	
2012 Vintage	$0.02829	$0.02720	$0.02524	
2013 Vintage	$0.03026	$0.02908	$0.02699	
2014 Vintage	$0.03068	$0.02949	$0.02737	
2015 Vintage	$0.03051	$0.02933	$0.02722	
2016 Vintage	$0.03039	$0.02921	$0.02711	
2017 Vintage	$0.03033	$0.02916	$0.02706	
2018 Vintage	$0.03036	$0.02918	$0.02708	
2019 Vintage	$0.03235	$0.03109	$0.02886	
2020 Vintage	$0.03861	$0.03711	$0.03445	(L)

(Continued)

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

12. 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. (L)

13. ELECTRIC EMER-GENCY PLAN ROTATING BLOCK OUTAGES: See Electric Rule 14.

14. 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. (L)

(Continued)

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

15. 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)

16. PEAK DAY PRICING DETAILS: Effective March 1, 2021, the legacy Peak Day Pricing (PDP) program details provided below in sub-paragraphs a to j will no longer be applicable. The legacy PDP program will be discontinued on all legacy rates after March 2021. Please see the Peak Day Pricing paragraph located in the Applicability Clause above. Any legacy PDP customer within the applicable 12-month bill stabilization period as of March 2021 that is transitioned to new PDP with Schedule B-20 or other applicable non-legacy rate may carry over the remaining period of its 12-month bill stabilization period on the new PDP program. (N)

a. Default Provision: Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the default of eligible E-20 customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory. The rates with new TOU periods are expected to become mandatory for medium and large Commercial and Industrial (C&I) customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP. (L)/(T)

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 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 17.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.

b. Capacity Reservation Level: Customers may elect a capacity reservation level (CRL) and pay for a fixed level of capacity, specified in kW. While the CRL is applicable year round, customers electing a CRL will be billed under a take-or-pay basis up to the specified CRL under the non-PDP rate of this schedule during the summer period (May 1 through October 31). This means that customers will be billed for summer peak generation demand charges up to the level of their CRL, even in summer months when the actual demand might be less than their CRL. Customers will receive PDP credits on summer usage above the CRL on 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 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).

A customer may only elect to change their CRL once every 12-months. (L)

(Continued)

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

16. PEAK DAY PRICING DETAILS (continued):

d. 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 unenrolls or terminates its participation on a PDP rate, bill stabilization will not be offered again.

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

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

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

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

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

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

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

(Continued)

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

16. PEAK DAY PRICING DETAILS (continued):

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.

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

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

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

j. Interaction with Other PG&E Demand Response Programs: 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)

ELECTRIC SCHEDULE E-20 Sheet 17
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

17. Option R The Option R rate is available to qualifying customers with PV systems that provide 15% or more of their annual electricity usage[1] as described below. No Benefitting* or Aggregated* account is eligible for Option R unless there is PV interconnected at that account that independently meets the requirements of Option R. i.e., the PV interconnected on that account meets 15% of the load at that account. (L)

Customers:
- c) Installing a new PV system with no existing generation or with existing non-PV generation; or
- d) With existing PV and non-PV generation (as an existing NEMMT)

Must meet the following eligibility requirement:

$$\frac{\text{Annual PV system output}_2}{\text{Annual electricity usage}_1} \geq 15\ \%$$

Customers:
- c) With an existing PV system, that are installing new PV system
- d) Adding new solar to existing PV and Non-PV generation

Must meet the following eligibility requirement:

$$\frac{\text{Annual PV system (new + existing) output}_2}{\text{Annual PV system (new + existing) output}_2 + \text{Annual electricity usage}_1} \geq 15\ \%$$

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

[1] Annual electricity usage (kWh): for customers with no generation will be the most recent usage over twelve billing periods, and for customers with existing generation it will be the net of imports and exports (if any, for all generators), measured at the PG&E meter over the most recent 12 billing periods. In cases where the most recent 12-month usage is not available PG&E will offer an alternate method.

[2] Annual PV system Output (kWh) = CEC_{AC} rating of the panels (kW) * 8760 hours/year * 18% capacity factor where:

CEC_{AC} Rating of the panels (kW) =

$$\frac{\text{(Quantity of PV Modules (W) x PTC Rating of PV Modules x CEC Inverter Efficiency Rating)}}{1000}$$

Where the PTC and CEC inverter Efficiency Rating can be found at:
The PTC rating can be found here:
http://www.gosolarcalifornia.ca.gov/equipment/documents/PV_Module_List_Simplified_Data.xlsx
and the CEC inverter efficiency rating here:
http://www.gosolarcalifornia.ca.gov/equipment/documents/Inverter_List_Simplified_Data.xlsx
The above Annual PV System Output formula can be modified based on the following alternatives:
- c) For customers with existing PV system, the customer may choose to supply PG&E with reliable metered data measuring Annual PV system Output, if such data is available.
- d) Customers with trackers can use the alternate capacity factors of:

Have single axis	21%
Have dual axis	24%

(L)

(Continued)

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

18. 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 AG-5 (C) and (F) rates, Schedule E-19 or Schedule E-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 E-19 (above 500 kW as defined above), Schedule E-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 E-20
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

18. 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)

ELECTRIC RATE SCHEDULE RES-BCT Sheet 4

SCHEDULE FOR LOCAL GOVERNMENT
RENEWABLE ENERGY SELF-GENERATON BILL CREDIT TRANSFER

APPLICABLITY (Cont'd):

INTERCONNECTION: If a Generating Account Eligible Renewable Generating Facility has not been previously approved for interconnection by PG&E, or where any modification to the previously approved Generating Account Eligible Renewable Generating Facility has been made, the Local Government must complete the Rule 21 and RES-BCT interconnection process, and must designate all the Generating Accounts and Benefiting Accounts to be included in a Arrangement in the RES-BCT Application and the accompanying Appendix A (as described in Special Condition 3 of this tariff). A Local Government shall provide the PG&E with not less than 60 days' notice prior to a eligible renewable generating facility for a Generating Account from becoming operational.

Not more frequently than once per year, and upon providing PG&E with a minimum of 60 days' notice, the Local Government may elect to change [add or delete] a Benefiting Account or reassign the Generating or Benefiting Accounts Allocation Percentages, as defined in Special Condition 2(b). Bill credits for such changes will be handled in accordance Special Condition 2 (g).

TERMINATION: A Local Government may terminate service on RES-BCT upon providing PG&E with a minimum of 60 days' notice. Should a Local Government sell its interest in an Eligible Renewable Generating Facility served on RES-BCT, or sell the electricity generated by the Eligible Renewable Generating Facility, in a manner other than required by RES-BCT, upon the date of either event, and the earliest date if both events occur, no further Bill Credit pursuant to Special Condition 2 of this tariff may be earned. Only credit earned prior to that date shall be made to a Benefiting Account.

PEAK DAY PRICING: Nothing in this tariff shall restrict the Local Government's ability of their Arrangement's Generating and Benefiting Accounts from taking service under the Peak Day Pricing program. If the Local Government is enrolled in the Peak Day Pricing program, the RES-BCT generation credit will be based on the non-Peak Day Pricing rate component of the Generating Account OAS. (T)

(Continued)

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company
Alcantar & Kahl LLP

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
California State Association of Counties
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Cenergy Power
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

Downey & Brand
East Bay Community Energy
Ellison Schneider & Harris LLP
Energy Management Service
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
IGS Energy
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions

SCE
SDG&E and SoCalGas

SPURR
San Francisco Water Power and Sewer
Seattle City Light
Sempra Utilities
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Troutman Sanders LLP
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy