PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE

March 22, 2021

Advice Letter 6090-E/E-A

Erik Jacobson
Director, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

SUBJECT: Electric Rate Change Effective March 1, 2021 and TOU Rate Structure for Non-residential customers.

Dear Mr. Jacobson:

Advice Letter 6090-E/E-A is effective as of March 1, 2021.

Sincerely,

Edward Randolph

Edward Randolph
Deputy Executive Director for Energy and Climate Policy/
Director, Energy Division

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

Facsimile: (415) 973-3582

February 26, 2021

Advice 6090-E-A
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

<u>Subject</u>: Supplemental: Electric Rate Change Effective March 1, 2021

<u>Purpose</u>

Pacific Gas and Electric Company (PG&E) submits this supplemental advice letter to provide the final tariffs which reflect the consolidated electric rate changes effective March 1, 2021. The final tariffs are provided as Attachment 2 and redlined tariffs are provided as Attachment 3. The rate values included in the final tariffs are the same as the rate values presented in Advice 6090-E.

This supplemental advice letter supplements the original advice letter.

<u>Background</u>

On February 18, 2021, PG&E submitted Advice 6090-E to change electric rates effective March 1, 2021 for the following revenue requirement and rate design changes:

1. 2020 General Rate Case (GRC) Phase 1
2. Pension Contribution
3. Residential Rate Reform Memorandum Account (RRRMA)
4. Risk Transfer Balancing Account (RTBA)
5. 2020 Cost of Capital Adjustment
6. Energy Efficiency (EE)
7. Assembly Bill (AB) 841 – School Energy Efficiency Stimulus Program
8. Transmission Access Charge Balancing Account Adjustment (TACBAA)
9. Refund of Unspent and Uncommitted Electric Program Investment Charge (EPIC) Funds for EPIC I and II
10. Refund of Unspent California Energy Systems for the 21st Century Balancing Account
11. Non-Residential Peak Day Pricing (PDP) and Residential SmartRate™ Adjustments
12. Legacy Time of Use (TOU) Commercial and Industrial (C&I) and Agricultural Electric Rate Schedules

13. Legacy Non-TOU Agricultural Electric Rate Schedules AG-1A and AG-1B
14. Renewable Energy Self Generation Bill Credit Transfer (RES-BCT)

While Advice 6090-E included a complete set of proposed rates, it did not include those rates in final tariffs. Instead, PG&E indicated final tariffs would be provided before March 1, 2021 in a supplemental advice letter.

Tariff Revisions

In this supplemental advice letter, PG&E is submitting final tariffs for the consolidated electric rate change effective March 1, 2021. The rate values included in the final tariffs are the same as the rate values presented in Advice 6090-E. In addition to including rate value changes, PG&E has made various revisions to tariff language under the following categories:

Non-Residential Peak Day Pricing (PDP) and Residential SmartRate™

PG&E has modified tariffs for the C&I and Agricultural rate schedules on the new TOU periods to reflect the implementation of the revised PDP program for these rate schedules. In accordance with the disposition issued for Advice 5861-E, PG&E has modified the language originally proposed in Advice 5861-E to reflect that the PDP program will remain with default enrollment rather than rely on customers to opt-in. Additionally, PG&E has removed PDP rates from the legacy rate schedules in this advice letter and has included language on the legacy rate schedule tariffs describing this change.[1]

Legacy C&I and Agricultural Electric Rate Schedules

Non-exempt C&I and agricultural customers will be transitioned to the rate schedules on new TOU periods effective beginning March 1, 2021. As a result, only customers exempt from the mandatory transition are eligible to remain on the legacy C&I and agricultural rate schedules. PG&E has made modifications to the legacy rate schedule tariffs to reflect these changes. While customers will be transitioned from Schedule S to Schedule SB beginning March 1, 2021, PG&E will retain Schedule S until all customers have been transferred off the rate schedule.

Additionally, as outlined in Advice 6090-E, PG&E is implementing the approved generation rate credit for eligible A-6 RES-BCT customers, effective March 1, 2021. The

[1] The Settlements approved by D.18-08-013 (the Small Light and Power Rate Design Settlement dated January 19, 2018, the Standby and Medium and Large Light and Power Rate Design Settlement dated January 31, 2018, and the Agricultural Rate Design Settlement dated March 30, 2018) specify that PG&E will maintain PDP on legacy rates until the rates with new TOU periods become mandatory.

tariff sheets in this advice letter include these rates as approved in Advice 5379-E-A, along with accompanying language describing the program.

Finally, PG&E has made ministerial modifications to all legacy electric rate schedules and Electric Rule 1, including referring to customers exempt from the mandatory transition to the rate schedules on new TOU rates as “legacy” customers rather than “grandfathered” customers.

The final tariffs with text and rate value changes are provided as Attachment 2 to this advice letter. Redlined tariffs with language changes are provided as Attachment 3 to this advice letter. The redlines only represent revisions to the text of the tariff and do not represent changes in rate values within the tariff. Changes to the rate values within the tariffs are noted with the revision marks on the right margin of the final tariffs in Attachment 2. Revision marks in the primary color (red) represents tariff revisions that were submitted with the proforma tariffs that were approved in Advice 5861-E. Revision marks in the secondary color (blue), represents new revisions that are being made in this advice letter.

Electric Preliminary Statement GC
As outlined in Advice 6090-E, PG&E is retiring PG&E’s Electric Preliminary *Statement GC for California Energy Systems for the 21st Century Balancing Account – Electric (CES21BA-E)*.

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*****

Pursuant to G.O. 96-B, Section 7.5.1, PG&E respectfully requests to maintain the original protest designated in Advice 6090-E, which is March 10, 2021. 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

PG&E respectfully requests that this Tier 1 advice letter become effective concurrent with original Advice Letter 6090-E, which is March 1, 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 service lists A. 18-12-009, A. 19-04-015, A. 17-04-028, A. 16-06-013, A. 20-07-002, R. 13-11-005, A. 11-07-008 and A. 18-11-013. Address changes to the General Order 96-B service list should be directed to email 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:
Attachment 1 – Proposed Revenues and Average Rates Summary
Attachment 2 – Final Tariffs
Attachment 3 – Redlined Tariffs

cc: Service Lists for:
A. 18-12-009 (2020 GRC Phase I)
A. 19-04-015 (2020 Cost of Capital)
A. 17-04-028 (EPIC)
A. 16-06-013 (2017 GRC Phase II)
A. 20-07-002 (2021 ERRA Forecast)
R. 13-11-005 (AB 841)
A. 11-07-008 (CES-21)
A. 18-11-013 (2019 RDW)

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 U39 E)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Annie Ho
Phone #: (415) 973-8794
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: AMHP@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6090-E-A Tier Designation: 1

Subject of AL: Supplemental: Electric Rate Change Effective March 1, 2021

Keywords (choose from CPUC listing): Compilance

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:

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 [x] 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 [x] No

Requested effective date: 3/1/21 No. of tariff sheets: 309

Estimated system annual revenue effect (%): 3.5%

Estimated system average rate effect (%): 2.8% (average bundled rate impact)

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 2

Service affected and changes proposed[1]: N/A

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: District of Columbia Zip: Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email:

Clear Form

Advice 6090-E-A
February 26, 2021

Attachment 1

Proposed Revenues and Average Rates Summary

BDLD RESULTS

Class/Schedule	Total Revenue At Present	Generation Revenue	TO Revenue	TAC Revenue	TRBAA Revenue	T-ECRA Revenue	RS Revenue	Dist Revenue	PPP Revenue	ND Revenue	WFC Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	Residential & Small Business AB32 Credit Revenue	Climate Credit & EITE Revenue	CIA Revenue	PCIA Revenue	Total Proposed Revenue
RESIDENTIAL																			
E-1	$2,323,922,162	$972,251,185	$315,345,031	$6,471,216	-$27,587,815	$0	$1,464,137	$946,964,109	$134,134,436	$7,886,439	$46,508,302	$303,113	$2,701,026	$37,646,310	$0	-$51,419,549	$17,656,647		$2,410,324,587
D-CARE	$791,893,137	$529,006,244	$171,580,772	$3,521,020	-$15,010,665	$0	$796,637	$151,244,403	$24,957,483	$4,291,091	$0	$164,926	$1,469,644	$20,483,579	$0	-$26,188,531	($44,579,971)		$821,736,632
TOTAL RES	$3,115,815,299	$1,501,257,429	$486,925,804	$9,992,236	-$42,598,480	$0	$2,260,774	$1,098,208,511	$159,091,918	$12,177,530	$46,508,302	$468,039	$4,170,669	$58,129,889	$0	-$77,608,080	($26,923,324)		$3,232,061,219
SMALL L&P																			
B-1	$529,162,096	$216,951,021	$54,854,700	$1,497,488	-$6,384,027	$0	$254,690	$229,462,531	$31,627,546	$1,824,977	$11,411,007	$67,195	$625,037	$6,275,316	$0	-$1,716,284			$546,751,195
B-6	$127,766,312	$54,949,162	$14,256,873	$388,959	-$1,658,195	$0	$66,196	$51,692,541	$7,573,897	$474,022	$2,966,403	$17,453	$162,348	$1,629,958	$0	-$222,073			$132,297,544
B-15	$13,852	$1,377	$351	$10	-$41	$0	$2	$11,933	$203	$12	$73	$0	$4	$40	$0	$0			$13,964
TC-1	$3,602,495	$1,454,448	$398,898	$10,890	-$46,427	$0	$1,852	$1,700,049	$77,432	$13,272	$83,149	$489	$4,545	$45,636	$0	$0			$3,744,233
TOTAL SMALL	$660,544,755	$273,356,008	$69,510,822	$1,897,347	-$8,088,690	$0	$322,739	$282,867,054	$39,279,077	$2,312,282	$14,460,633	$85,138	$791,934	$7,950,950	$0	-$1,938,357			$682,806,937
MEDIUM L&P																			
B-10 T	$172,307	$94,046	$27,416	$805	-$3,431	$0	$128	$27,154	$15,381	$981	$6,144	$39	$336	$3,074	$0	$0			$172,073
B-10 P	$5,387,884	$2,567,730	$847,317	$18,530	-$78,995	$0	$3,957	$1,520,268	$359,539	$22,582	$141,477	$896	$7,734	$70,792	$0	$0			$5,481,826
B-10 S	$583,656,606	$288,428,956	$81,594,872	$1,869,058	-$7,968,089	$0	$381,021	$169,654,188	$36,611,579	$2,277,806	$14,224,409	$90,354	$780,126	$7,140,666	$0	-$257,970			$594,826,976
TOTAL MEDIUM	$589,216,797	$291,090,732	$82,469,605	$1,888,392	-$8,050,514	$0	$385,105	$171,201,610	$36,986,499	$2,301,369	$14,372,030	$91,289	$788,196	$7,214,532	$0	-$257,970			$600,480,875
B-19 CLASS																			
B-19 FIRM T	$1,277,710	$711,432	$236,751	$5,157	-$21,984	$0	$1,106	$182,069	$94,999	$6,285	$39,373	$228	$2,152	$19,701	$0	-$1,787			$1,275,482
B-19 V T	$1,541,001	$960,584	$239,406	$7,370	-$31,422	$0	$1,118	$114,139	$135,779	$8,982	$56,275	$327	$3,076	$28,159	$0	$0			$1,523,793
Total B-19 T	$2,818,711	$1,672,016	$476,157	$12,527	-$53,406	$0	$2,224	$296,208	$230,777	$15,267	$95,648	$555	$5,229	$47,860	$0	-$1,787			$2,799,276
B-19 FIRM P	$58,316,640	$30,514,071	$7,823,355	$236,952	-$1,010,163	$0	$36,537	$13,955,301	$4,364,744	$288,771	$1,809,165	$10,497	$98,901	$905,266	$0	-$200,208			$58,833,188
B-19 V P	$22,146,478	$11,715,032	$2,977,308	$92,321	-$393,580	$0	$13,903	$4,985,861	$1,695,277	$112,511	$701,912	$4,090	$38,534	$352,709	$0	$0			$22,295,878
Total B-19 P	$80,463,118	$42,229,103	$10,800,662	$329,273	-$1,403,742	$0	$50,440	$18,941,161	$6,060,021	$401,282	$2,511,077	$14,586	$137,435	$1,257,975	$0	-$200,208			$81,129,066
B-19 FIRM S	$192,000,748	$100,926,715	$22,579,190	$684,904	-$2,919,854	$0	$105,441	$52,431,067	$13,090,065	$834,687	$5,229,353	$30,340	$285,872	$2,616,651	$0	-$893,477			$195,000,954
B-19 V S	$428,865,840	$226,566,797	$46,887,604	$1,577,436	-$6,724,857	$0	$218,950	$115,880,070	$30,078,796	$1,922,408	$12,005,036	$69,878	$658,406	$6,026,534	$0	$0			$435,167,058
Total B-19 S	$620,866,588	$327,493,512	$69,466,794	$2,262,340	-$9,644,711	$0	$324,392	$168,311,137	$43,168,861	$2,757,096	$17,234,389	$100,218	$944,278	$8,643,185	$0	-$893,477			$630,168,013
B-19 T	$2,818,711	$1,672,016	$476,157	$12,527	-$53,406	$0	$2,224	$296,208	$230,777	$15,267	$95,648	$555	$5,229	$47,860	$0	-$1,787			$2,799,276
B-19 P	$80,463,118	$42,229,103	$10,800,662	$329,273	-$1,403,742	$0	$50,440	$18,941,161	$6,060,021	$401,282	$2,511,077	$14,586	$137,435	$1,257,975	$0	-$200,208			$81,129,066
B-19 S	$620,866,588	$327,493,512	$69,466,794	$2,262,340	-$9,644,711	$0	$324,392	$168,311,137	$43,168,861	$2,757,096	$17,234,389	$100,218	$944,278	$8,643,185	$0	-$893,477			$630,168,013
TOTAL B-19	$704,148,417	$371,394,630	$80,743,613	$2,604,140	-$11,101,860	$0	$377,055	$187,548,506	$49,459,660	$3,173,645	$19,841,114	$115,359	$1,086,942	$9,949,020	$0	-$1,095,471			$714,096,354
STREETLIGHTS	$22,840,040	$6,987,130	$1,826,461	$58,409	-$249,007	$0	$8,480	$13,282,403	$447,605	$71,183	$445,962	$2,181	$24,379	$228,783	$0	$0			$23,133,969
STANDBY																			
STANDBY T	$51,952,985	$25,642,499	$16,123,010	$239,433	-$1,020,742	$0	$77,140	$6,396,051	$4,691,422	$291,796	$1,828,112	$8,104	$99,937	$1,938,454	$0	-$4,673,131			$51,642,086
STANDBY P	$3,763,099	$854,716	$503,046	$6,309	-$26,896	$0	$2,408	$2,626,375	$147,239	$7,689	$48,169	$214	$2,633	$51,077	$0	-$194,836			$4,028,142
STANDBY S	$1,209,371	$451,393	$169,878	$3,821	-$16,291	$0	$811	$566,779	$86,129	$4,657	$29,177	$129	$1,595	$30,938	$0	-$88,351			$1,240,666
TOTAL STANDBY	$56,925,456	$26,948,609	$16,795,934	$249,564	-$1,063,929	$0	$80,359	$9,589,205	$4,924,790	$304,141	$1,905,458	$8,446	$104,165	$2,020,469	$0	-$4,956,317			$56,910,894
AGRICULTURE																			
AG-A	$144,701,723	$43,221,325	$9,847,103	$325,093	-$1,385,922	$0	$45,723	$89,548,801	$7,089,299	$396,188	$2,482,137	$13,611	$135,691	$1,253,168	$0	-$13,909			$152,958,306
AG-B	$247,284,324	$87,369,430	$17,263,861	$569,950	-$2,429,788	$0	$80,160	$137,749,513	$11,905,252	$694,594	$4,351,662	$23,862	$237,892	$2,197,043	$0	-$115,194			$259,898,237
AG-C	$800,709,657	$377,424,510	$86,477,490	$2,854,974	-$12,171,204	$0	$401,537	$274,290,781	$52,145,354	$3,479,334	$21,798,183	$119,530	$1,191,638	$11,005,348	$0	-$842,026			$818,175,449
TOTAL AG	$1,192,695,703	$508,015,266	$113,588,453	$3,750,017	-$15,986,914	$0	$527,420	$501,589,095	$71,139,905	$4,570,116	$28,631,982	$157,004	$1,565,220	$14,455,559	$0	-$971,128			$1,231,031,993
B-20 CLASS																			
B-20 FIRM T	$263,656,068	$178,646,330	$42,888,846	$1,459,352	-$6,221,450	$0	$200,454	$3,039,734	$24,461,758	$1,778,501	$11,142,390	$55,483	$609,119	$4,849,671	$0	-$5,332,820			$257,577,369
FPP T																			
TOTAL	$263,656,068	$178,646,330	$42,888,846	$1,459,352	-$6,221,450	$0	$200,454	$3,039,734	$24,461,758	$1,778,501	$11,142,390	$55,483	$609,119	$4,849,671	$0	-$5,332,820			$257,577,369
B-20 FIRM P	$310,712,316	$176,499,453	$40,050,877	$1,346,075	-$5,738,529	$0	$187,055	$63,807,850	$24,168,802	$1,640,451	$10,277,496	$55,146	$561,838	$4,473,230	$0	-$5,135,241			$312,194,503
FPP P																			
TOTAL	$310,712,316	$176,499,453	$40,050,877	$1,346,075	-$5,738,529	$0	$187,055	$63,807,850	$24,168,802	$1,640,451	$10,277,496	$55,146	$561,838	$4,473,230	$0	-$5,135,241			$312,194,503
B-20 FIRM S	$99,744,046	$53,700,966	$12,962,703	$392,662	-$1,673,979	$0	$60,533	$25,467,910	$7,343,030	$478,534	$2,998,035	$16,734	$163,893	$1,304,880	$0	-$2,277,314			$100,938,587
FPP S																			
TOTAL	$99,744,046	$53,700,966	$12,962,703	$392,662	-$1,673,979	$0	$60,533	$25,467,910	$7,343,030	$478,534	$2,998,035	$16,734	$163,893	$1,304,880	$0	-$2,277,314			$100,938,587
B-20 T	$263,656,068	$178,646,330	$42,888,846	$1,459,352	-$6,221,450	$0	$200,454	$3,039,734	$24,461,758	$1,778,501	$11,142,390	$55,483	$609,119	$4,849,671	$0	-$5,332,820			$257,577,369
B-20 P	$310,712,316	$176,499,453	$40,050,877	$1,346,075	-$5,738,529	$0	$187,055	$63,807,850	$24,168,802	$1,640,451	$10,277,496	$55,146	$561,838	$4,473,230	$0	-$5,135,241			$312,194,503
B-20 S	$99,744,046	$53,700,966	$12,962,703	$392,662	-$1,673,979	$0	$60,533	$25,467,910	$7,343,030	$478,534	$2,998,035	$16,734	$163,893	$1,304,880	$0	-$2,277,314			$100,938,587
TOTAL B-20	$674,112,431	$408,846,750	$95,902,426	$3,198,089	-$13,633,957	$0	$448,042	$92,315,494	$55,973,590	$3,897,486	$24,417,921	$127,363	$1,334,850	$10,627,781	$0	-$12,745,374			$670,710,459
SYSTEM	**$7,016,298,898**	**$3,387,896,554**	**$947,763,118**	**$23,638,193**	**-$100,773,351**	**$0**	**$4,409,975**	**$2,356,601,878**	**$417,303,044**	**$28,807,751**	**$150,583,401**	**$1,054,819**	**$9,866,356**	**$110,576,983**	**$0**	**-$99,572,699**	**-$26,923,324**	**$0**	**$7,211,232,699**

Pacific Gas & Electric Company
Rate Change - 2020 GRC Phase I Decision & TACBAA
Monday, March 1, 2021

BDLD RESULTS

Class/Schedule	Total Sales (kWh)	Revenue At Present Rates	Generation Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	WFC Rates	CTC Rates	ECRA Rates	NSGC Rates	Residential & Small Business AB32 Credit Rates	Climate Credit & EITE Rates	CIA Rates	PCIA Rates	Total Proposed Rates	Percent Change
RESIDENTIAL																					
E-1	8,514,772,192	$0.27293	$0.11418	$0.03704	$0.00076	-$0.00324	$0.00000	$0.00017	$0.11121	$0.01575	$0.00093	$0.00546	$0.00004	$0.00032	$0.00442	$0.00000	-$0.00604	$0.00207		$0.28308	3.7%
D-CARE	4,632,937,662	$0.17093	$0.11418	$0.03703	$0.00076	-$0.00324	$0.00000	$0.00017	$0.03265	$0.00539	$0.00093	$0.00000	$0.00004	$0.00032	$0.00442	$0.00000	-$0.00565	-$0.00962		$0.17737	3.8%
TOTAL RES	13,147,709,854	$0.23699	$0.11418	$0.03704	$0.00076	-$0.00324	$0.00000	$0.00017	$0.08353	$0.01210	$0.00093	$0.00354	$0.00004	$0.00032	$0.00442	$0.00000	-$0.00590	-$0.00205		$0.24583	3.7%
SMALL L&P																					
B-1	1,970,378,771	$0.26856	$0.11011	$0.02784	$0.00076	-$0.00324	$0.00000	$0.00013	$0.11646	$0.01605	$0.00093	$0.00579	$0.00003	$0.00032	$0.00318	$0.00000	-$0.00087			$0.27749	3.3%
B-6	511,788,493	$0.24965	$0.10737	$0.02786	$0.00076	-$0.00324	$0.00000	$0.00013	$0.10100	$0.01480	$0.00093	$0.00580	$0.00003	$0.00032	$0.00318	$0.00000	-$0.00043			$0.25850	3.5%
B-15	12,624	$1.09725	$0.10911	$0.02784	$0.00076	-$0.00324	$0.00000	$0.00013	$0.94524	$0.01607	$0.00093	$0.00580	$0.00003	$0.00032	$0.00318	$0.00000	$0.00000			$1.10618	0.8%
TC-1	14,329,292	$0.25141	$0.10150	$0.02784	$0.00076	-$0.00324	$0.00000	$0.00013	$0.11864	$0.00540	$0.00093	$0.00580	$0.00003	$0.00032	$0.00318	$0.00000	$0.00000			$0.26130	3.9%
TOTAL SMALL	2,496,509,180	$0.26459	$0.10950	$0.02784	$0.00076	-$0.00324	$0.00000	$0.00013	$0.11331	$0.01573	$0.00093	$0.00579	$0.00003	$0.00032	$0.00318	$0.00000	-$0.00078			$0.27350	3.4%
MEDIUM L&P																					
B-10 T	1,058,800	$0.16274	$0.08882	$0.02589	$0.00076	-$0.00324	$0.00000	$0.00012	$0.02565	$0.01453	$0.00093	$0.00580	$0.00004	$0.00032	$0.00290	$0.00000	$0.00000			$0.16252	-0.1%
B-10 P	24,381,091	$0.22099	$0.10532	$0.03475	$0.00076	-$0.00324	$0.00000	$0.00016	$0.06235	$0.01475	$0.00093	$0.00580	$0.00004	$0.00032	$0.00290	$0.00000	$0.00000			$0.22484	1.7%
B-10 S	2,459,286,627	$0.23733	$0.11728	$0.03318	$0.00076	-$0.00324	$0.00000	$0.00015	$0.06899	$0.01489	$0.00093	$0.00578	$0.00004	$0.00032	$0.00290	$0.00000	-$0.00010			$0.24187	1.9%
TOTAL MEDIUM	2,484,726,518	$0.23714	$0.11715	$0.03319	$0.00076	-$0.00324	$0.00000	$0.00015	$0.06890	$0.01489	$0.00093	$0.00578	$0.00004	$0.00032	$0.00290	$0.00000	-$0.00010			$0.24167	1.9%
B-19 CLASS																					
B-19 FIRM T	6,785,294	$0.18831	$0.10485	$0.03489	$0.00076	-$0.00324	$0.00000	$0.00016	$0.02683	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00026			$0.18798	-0.2%
B-19 V T	9,698,022	$0.15890	$0.09905	$0.02469	$0.00076	-$0.00324	$0.00000	$0.00012	$0.01177	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	$0.00000			$0.15712	-1.1%
Total B-19 T	16,483,316	$0.17100	$0.10144	$0.02889	$0.00076	-$0.00324	$0.00000	$0.00013	$0.01797	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00011			$0.16982	-0.7%
B-19 FIRM P	311,778,662	$0.18705	$0.09787	$0.02509	$0.00076	-$0.00324	$0.00000	$0.00012	$0.04476	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00064			$0.18870	0.9%
B-19 V P	121,475,160	$0.18231	$0.09644	$0.02451	$0.00076	-$0.00324	$0.00000	$0.00011	$0.04104	$0.01396	$0.00093	$0.00578	$0.00003	$0.00032	$0.00290	$0.00000	$0.00000			$0.18354	0.7%
Total B-19 P	433,253,822	$0.18572	$0.09747	$0.02493	$0.00076	-$0.00324	$0.00000	$0.00012	$0.04372	$0.01399	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00046			$0.18726	0.8%
B-19 FIRM S	901,189,624	$0.21305	$0.11199	$0.02505	$0.00076	-$0.00324	$0.00000	$0.00012	$0.05818	$0.01453	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00099			$0.21638	1.6%
B-19 V S	2,075,573,104	$0.20663	$0.10916	$0.02259	$0.00076	-$0.00324	$0.00000	$0.00011	$0.05583	$0.01449	$0.00093	$0.00578	$0.00003	$0.00032	$0.00290	$0.00000	$0.00000			$0.20966	1.5%
Total B-19 S	2,976,762,727	$0.20857	$0.11002	$0.02334	$0.00076	-$0.00324	$0.00000	$0.00011	$0.05654	$0.01450	$0.00093	$0.00579	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00030			$0.21170	1.5%
B-19 T	16,483,316	$0.17100	$0.10144	$0.02889	$0.00076	-$0.00324	$0.00000	$0.00013	$0.01797	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00011			$0.16982	-0.7%
B-19 P	433,253,822	$0.18572	$0.09747	$0.02493	$0.00076	-$0.00324	$0.00000	$0.00012	$0.04372	$0.01399	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00046			$0.18726	0.8%
B-19 S	2,976,762,727	$0.20857	$0.11002	$0.02334	$0.00076	-$0.00324	$0.00000	$0.00011	$0.05654	$0.01450	$0.00093	$0.00579	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00030			$0.21170	1.5%
TOTAL B-19	3,426,499,865	$0.20550	$0.10839	$0.02356	$0.00076	-$0.00324	$0.00000	$0.00011	$0.05473	$0.01443	$0.00093	$0.00579	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00032			$0.20840	1.4%
STREETLIGHTS	76,853,926	$0.29719	$0.09091	$0.02377	$0.00076	-$0.00324	$0.00000	$0.00011	$0.17283	$0.00582	$0.00093	$0.00580	$0.00003	$0.00032	$0.00298	$0.00000	$0.00000			$0.30101	1.3%
STANDBY																					
STANDBY T	315,043,911	$0.16491	$0.08139	$0.05118	$0.00076	-$0.00324	$0.00000	$0.00024	$0.02030	$0.01489	$0.00093	$0.00580	$0.00003	$0.00032	$0.00615	$0.00000	-$0.01483			$0.16392	-0.6%
STANDBY P	8,301,158	$0.45332	$0.10296	$0.06060	$0.00076	-$0.00324	$0.00000	$0.00029	$0.31639	$0.01774	$0.00093	$0.00580	$0.00003	$0.00032	$0.00615	$0.00000	-$0.02347			$0.48525	7.0%
STANDBY S	5,028,099	$0.24052	$0.08977	$0.03379	$0.00076	-$0.00324	$0.00000	$0.00016	$0.11272	$0.01713	$0.00093	$0.00580	$0.00003	$0.00032	$0.00615	$0.00000	-$0.01757			$0.24675	2.6%
TOTAL STANDBY	328,373,169	$0.17336	$0.08207	$0.05115	$0.00076	-$0.00324	$0.00000	$0.00024	$0.02920	$0.01500	$0.00093	$0.00580	$0.00003	$0.00032	$0.00615	$0.00000	-$0.01509			$0.17331	0.0%
AGRICULTURE																					
AG-A	427,753,847	$0.33828	$0.10104	$0.02302	$0.00076	-$0.00324	$0.00000	$0.00011	$0.20935	$0.01657	$0.00093	$0.00580	$0.00003	$0.00032	$0.00293	$0.00000	-$0.00003			$0.35758	5.7%
AG-B	749,934,570	$0.32974	$0.11650	$0.02302	$0.00076	-$0.00324	$0.00000	$0.00011	$0.18368	$0.01588	$0.00093	$0.00580	$0.00003	$0.00032	$0.00293	$0.00000	-$0.00015			$0.34656	5.1%
AG-C	3,756,544,418	$0.21315	$0.10047	$0.02302	$0.00076	-$0.00324	$0.00000	$0.00011	$0.07302	$0.01388	$0.00093	$0.00580	$0.00003	$0.00032	$0.00293	$0.00000	-$0.00022			$0.21780	2.2%
TOTAL AG	4,934,232,835	$0.24172	$0.10296	$0.02302	$0.00076	-$0.00324	$0.00000	$0.00011	$0.10165	$0.01442	$0.00093	$0.00580	$0.00003	$0.00032	$0.00293	$0.00000	-$0.00020			$0.24949	3.2%
B-20 CLASS																					
B-20 FIRM T	1,920,200,469	$0.13731	$0.09304	$0.02234	$0.00076	-$0.00324	$0.00000	$0.00010	$0.00158	$0.01274	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00278			$0.13414	-2.3%
FPP T																					
TOTAL	1,920,200,469	$0.13731	$0.09304	$0.02234	$0.00076	-$0.00324	$0.00000	$0.00010	$0.00158	$0.01274	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00278			$0.13414	-2.3%
B-20 FIRM P	1,771,150,850	$0.17543	$0.09965	$0.02261	$0.00076	-$0.00324	$0.00000	$0.00011	$0.03603	$0.01365	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00290			$0.17627	0.5%
FPP P																					
TOTAL	1,771,150,850	$0.17543	$0.09965	$0.02261	$0.00076	-$0.00324	$0.00000	$0.00011	$0.03603	$0.01365	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00290			$0.17627	0.5%
B-20 FIRM S	516,660,094	$0.19306	$0.10394	$0.02509	$0.00076	-$0.00324	$0.00000	$0.00012	$0.04929	$0.01421	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00441			$0.19537	1.2%
FPP S																					
TOTAL	516,660,094	$0.19306	$0.10394	$0.02509	$0.00076	-$0.00324	$0.00000	$0.00012	$0.04929	$0.01421	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00441			$0.19537	1.2%
B-20 T	1,920,200,469	$0.13731	$0.09304	$0.02234	$0.00076	-$0.00324	$0.00000	$0.00010	$0.00158	$0.01274	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00278			$0.13414	-2.3%
B-20 P	1,771,150,850	$0.17543	$0.09965	$0.02261	$0.00076	-$0.00324	$0.00000	$0.00011	$0.03603	$0.01365	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00290			$0.17627	0.5%
B-20 S	516,660,094	$0.19306	$0.10394	$0.02509	$0.00076	-$0.00324	$0.00000	$0.00012	$0.04929	$0.01421	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00441			$0.19537	1.2%
TOTAL B-20	4,208,011,413	$0.16020	$0.09716	$0.02279	$0.00076	-$0.00324	$0.00000	$0.00011	$0.02194	$0.01330	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00303			$0.15939	-0.5%
SYSTEM	**31,102,916,759**	**$0.22558**	**$0.10893**	**$0.03047**	**$0.00076**	**-$0.00324**	**$0.00000**	**$0.00014**	**$0.07577**	**$0.01342**	**$0.00093**	**$0.00484**	**$0.00003**	**$0.00032**	**$0.00356**	**$0.00000**	**-$0.00320**	**-$0.00087**	**$0.00000**	**$0.23185**	**2.8%**

Pacific Gas & Electric Company
Rate Change - 2020 GRC Phase I Decision & TACBAA
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DA/CCA RESULTS

Class/Schedule	Total Revenue At Present	TO Revenue	TAC Revenue	TRBAA Revenue	T-ECRA Revenue	RS Revenue	Dist Revenue	PPP Revenue	ND Revenue	WFC Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	Residential & Small Business AB32 Credit Revenue	Climate Credit & EITE Revenue	CIA Revenue	PCIA Revenue	Total Proposed Revenue
RESIDENTIAL																		
E-1	$2,559,818,794	$461,724,123	$9,475,071	-$40,393,723	$0	$2,143,776	$1,399,182,351	$196,397,908	$11,547,223	$70,294,390	$443,816	$3,954,816	$55,121,376	$0	-$77,881,050	$51,090,104	$561,616,798	$2,704,716,978
D-CARE	$225,661,951	$88,745,504	$1,821,152	-$7,763,860	$0	$412,052	$77,303,505	$12,908,582	$2,219,450	$0	$85,306	$760,157	$10,594,908	$0	-$16,808,104	-$24,166,780	$97,278,514	$243,390,387
TOTAL RES	$2,785,480,745	$550,469,627	$11,296,223	-$48,157,582	$0	$2,555,828	$1,476,485,856	$209,306,490	$13,766,673	$70,294,390	$529,122	$4,714,974	$65,716,284	$0	-$94,689,153	$26,923,324	$658,895,312	$2,948,107,365
SMALL L&P																		
B-1	$747,520,778	$106,916,365	$2,918,886	-$12,443,672	$0	$496,410	$418,939,641	$61,638,589	$3,557,224	$22,234,739	$130,976	$1,218,314	$12,231,773	$0	-$19,130		$170,540,221	$788,360,336
B-6	$153,295,867	$23,410,737	$638,791	-$2,723,267	$0	$108,697	$83,430,279	$12,390,807	$778,489	$4,838,841	$28,664	$266,625	$2,676,893	$0	-$1,193		$36,350,658	$162,195,022
B-15	$207,799	$8,864	$242	-$1,032	$0	$41	$178,810	$5,118	$295	$1,837	$11	$101	$1,014	$0	$0		$16,074	$211,375
TC-1	$4,783,573	$689,974	$18,837	-$80,305	$0	$3,204	$2,940,240	$133,934	$22,956	$143,823	$845	$7,862	$78,937	$0	$0		$1,109,048	$5,069,356
TOTAL SMALL	$905,808,017	$131,025,940	$3,576,756	-$15,248,275	$0	$608,352	$505,488,971	$74,168,447	$4,358,964	$27,219,240	$160,496	$1,492,902	$14,988,617	$0	-$20,322		$208,016,001	$955,836,089
MEDIUM L&P																		
B-10 T	$129,235	$29,745	$736	-$3,140	$0	$139	$33,978	$14,077	$898	$5,623	$36	$307	$2,814	$0	$0		$46,766	$131,979
B-10 P	$6,806,846	$1,281,051	$34,477	-$146,979	$0	$5,982	$2,627,172	$666,025	$42,016	$261,588	$1,667	$14,390	$131,717	$0	$0		$2,125,754	$7,044,860
B-10 S	$808,786,413	$150,599,756	$3,811,310	-$16,248,218	$0	$703,253	$350,568,633	$74,594,547	$4,644,814	$28,970,953	$184,246	$1,590,803	$14,560,970	$0	-$13,316		$226,698,888	$840,666,640
TOTAL MEDIUM	$815,722,494	$151,910,552	$3,846,523	-$16,398,337	$0	$709,374	$353,229,783	$75,274,649	$4,687,728	$29,238,164	$185,949	$1,605,501	$14,695,501	$0	-$13,316		$228,871,408	$847,843,478
B-19 CLASS																		
B-19 FIRM T	$587,568	$139,775	$3,711	-$15,820	$0	$653	$133,308	$68,361	$4,522	$28,333	$164	$1,549	$14,177	$0	-$302		$215,619	$594,052
B-19 V T	$718,142	$139,601	$5,848	-$24,931	$0	$652	$78,390	$107,732	$7,127	$44,651	$259	$2,441	$22,342	$0	$0		$332,076	$716,188
Total B-19 T	$1,305,710	$279,376	$9,559	-$40,751	$0	$1,305	$211,699	$176,094	$11,649	$72,984	$423	$3,990	$36,519	$0	-$302		$547,695	$1,310,239
B-19 FIRM P	$64,882,829	$12,291,569	$407,839	-$1,738,681	$0	$57,398	$23,460,079	$7,512,546	$497,030	$3,113,914	$18,067	$170,228	$1,558,133	$0	-$93,647		$19,072,777	$66,327,251
B-19 V P	$25,524,245	$5,153,995	$148,784	-$634,292	$0	$24,069	$8,942,344	$2,740,668	$181,322	$1,135,993	$6,591	$62,101	$568,426	$0	$0		$7,813,265	$26,143,267
Total B-19 P	$90,407,074	$17,445,564	$556,623	-$2,372,972	$0	$81,467	$32,402,423	$10,253,214	$678,352	$4,249,907	$24,658	$232,329	$2,126,558	$0	-$93,647		$26,886,042	$92,470,518
B-19 FIRM S	$355,429,395	$60,997,270	$2,074,950	-$8,845,839	$0	$284,843	$147,479,343	$39,592,300	$2,528,725	$15,806,370	$91,917	$866,063	$7,927,269	$0	-$188,759		$97,455,904	$366,070,356
B-19 V S	$760,400,969	$125,589,449	$4,616,161	-$19,679,422	$0	$586,466	$319,912,816	$87,898,823	$5,625,679	$34,979,963	$204,489	$1,926,739	$17,635,872	$0	$0		$202,981,891	$782,278,925
Total B-19 S	$1,115,830,364	$186,586,719	$6,691,111	-$28,525,261	$0	$871,309	$467,392,159	$127,491,123	$8,154,404	$50,786,333	$296,405	$2,792,803	$25,563,141	$0	-$188,759		$300,437,795	$1,148,349,281
B-19 T	$1,305,710	$279,376	$9,559	-$40,751	$0	$1,305	$211,699	$176,094	$11,649	$72,984	$423	$3,990	$36,519	$0	-$302		$547,695	$1,310,239
B-19 P	$90,407,074	$17,445,564	$556,623	-$2,372,972	$0	$81,467	$32,402,423	$10,253,214	$678,352	$4,249,907	$24,658	$232,329	$2,126,558	$0	-$93,647		$26,886,042	$92,470,518
B-19 S	$1,115,830,364	$186,586,719	$6,691,111	-$28,525,261	$0	$871,309	$467,392,159	$127,491,123	$8,154,404	$50,786,333	$296,405	$2,792,803	$25,563,141	$0	-$188,759		$300,437,795	$1,148,349,281
TOTAL B-19	$1,207,543,148	$204,311,659	$7,257,293	-$30,938,984	$0	$954,081	$500,006,281	$137,920,431	$8,844,405	$55,109,223	$321,486	$3,029,122	$27,726,218	$0	-$282,708		$327,871,533	$1,242,130,039
STREETLIGHTS	$29,944,926	$3,610,484	$115,461	-$492,228	$0	$16,763	$19,521,143	$823,891	$140,711	$881,562	$4,311	$48,192	$452,251	$0	$0		$5,587,287	$30,709,829
STANDBY																		
STANDBY T	$6,039,745	$2,138,056	$30,884	-$131,662	$0	$10,230	$1,588,308	$605,129	$37,638	$235,801	$1,045	$12,891	$250,034	$0	$0		$1,286,269	$6,064,621
STANDBY P	$2,387,491	$374,292	$4,961	-$21,151	$0	$1,792	$1,963,876	$115,791	$6,046	$37,881	$168	$2,071	$40,168	$0	$0		$58,604	$2,584,498
STANDBY S	$411,132	$55,752	$1,307	-$5,570	$0	$266	$281,428	$29,450	$1,592	$9,976	$44	$545	$10,579	$0	-$300		$54,175	$439,244
TOTAL STANDBY	$8,838,367	$2,568,099	$37,152	-$158,383	$0	$12,288	$3,833,611	$750,370	$45,276	$283,659	$1,257	$15,507	$300,780	$0	-$300		$1,399,048	$9,088,364
AGRICULTURE																		
AG-A	$21,902,332	$1,907,365	$62,970	-$268,451	$0	$8,856	$16,406,671	$1,373,184	$76,741	$480,727	$2,636	$26,283	$242,736	$0	$0		$3,282,368	$23,602,087
AG-B	$44,419,897	$4,264,249	$140,780	-$600,168	$0	$19,800	$31,153,303	$2,940,649	$171,568	$1,074,880	$5,894	$58,760	$542,679	$0	$0		$7,743,614	$47,516,009
AG-C	$109,659,129	$18,804,625	$620,817	-$2,646,642	$0	$87,315	$44,492,068	$11,339,064	$756,585	$4,740,039	$25,992	$259,123	$2,393,125	$0	-$31,560		$31,821,919	$112,662,470
TOTAL AG	$175,981,358	$24,976,239	$824,567	-$3,515,260	$0	$115,971	$92,052,042	$15,652,897	$1,004,894	$6,295,645	$34,523	$344,166	$3,178,540	$0	-$31,560		$42,847,902	$183,780,566
B-20 CLASS																		
B-20 FIRM T	$207,530,234	$64,694,042	$2,643,779	-$11,270,847	$0	$302,108	-$3,599,927	$44,315,193	$3,221,953	$17,081,986	$100,513	$1,103,487	$8,785,717	$0	-$2,456,606		$71,993,478	$196,914,875
FPP T	$4,214,639	$0	$0	$0	$0	$0	$467,129	$3,519,543	$281,754	$0	$0	$0	$0	$0	$0		$0	$4,268,427
TOTAL	$211,744,873	$64,694,042	$2,643,779	-$11,270,847	$0	$302,108	-$3,132,798	$47,834,736	$3,503,707	$17,081,986	$100,513	$1,103,487	$8,785,717	$0	-$2,456,606		$71,993,478	$201,183,302
B-20 FIRM P	$454,224,902	$99,022,483	$3,435,500	-$14,646,078	$0	$462,455	$161,084,364	$61,684,481	$4,186,817	$26,230,593	$140,745	$1,433,943	$11,416,737	$0	-$4,386,445		$108,558,300	$458,623,895
FPP P	$564,472	$0	$0	$0	$0	$0	$343,321	$245,248	$18,206	$0	$0	$0	$0	$0	$0		$0	$606,776
TOTAL	$454,789,375	$99,022,483	$3,435,500	-$14,646,078	$0	$462,455	$161,427,685	$61,929,729	$4,205,023	$26,230,593	$140,745	$1,433,943	$11,416,737	$0	-$4,386,445		$108,558,300	$459,230,670
B-20 FIRM S	$183,501,191	$36,159,996	$1,226,573	-$5,229,076	$0	$168,856	$70,994,714	$22,937,723	$1,494,815	$9,365,084	$52,274	$511,959	$4,076,107	$0	-$932,027		$46,542,994	$187,369,994
FPP S	$2,887,641	$0	$0	$0	$0	$0	$1,781,571	$1,253,961	$89,046	$0	$0	$0	$0	$0	$0		$0	$3,124,578
TOTAL	$186,388,832	$36,159,996	$1,226,573	-$5,229,076	$0	$168,856	$72,776,285	$24,191,684	$1,583,861	$9,365,084	$52,274	$511,959	$4,076,107	$0	-$932,027		$46,542,994	$190,494,572
B-20 T	$211,744,873	$64,694,042	$2,643,779	-$11,270,847	$0	$302,108	-$3,132,798	$47,834,736	$3,503,707	$17,081,986	$100,513	$1,103,487	$8,785,717	$0	-$2,456,606		$71,993,478	$201,183,302
B-20 P	$454,789,375	$99,022,483	$3,435,500	-$14,646,078	$0	$462,455	$161,427,685	$61,929,729	$4,205,023	$26,230,593	$140,745	$1,433,943	$11,416,737	$0	-$4,386,445		$108,558,300	$459,230,670
B-20 S	$186,388,832	$36,159,996	$1,226,573	-$5,229,076	$0	$168,856	$72,776,285	$24,191,684	$1,583,861	$9,365,084	$52,274	$511,959	$4,076,107	$0	-$932,027		$46,542,994	$190,494,572
TOTAL B-20	$852,923,079	$199,876,521	$7,305,852	-$31,146,001	$0	$933,419	$231,071,172	$133,956,150	$9,292,591	$52,677,663	$293,532	$3,049,390	$24,278,562	$0	-$7,775,079		$227,094,772	$850,908,545
SYSTEM	**$6,782,242,136**	**$1,268,749,121**	**$34,259,827**	**-$146,055,051**	**$0**	**$5,906,076**	**$3,181,688,858**	**$647,853,325**	**$42,141,243**	**$241,999,546**	**$1,530,676**	**$14,299,753**	**$151,336,753**	**$0**	**-$102,812,439**	**$26,923,324**	**$1,700,583,263**	**$7,068,404,274**

Pacific Gas & Electric Company
Rate Change - 2020 GRC Phase I Decision & TACBAA
Monday, March 1, 2021

DA/CCA RESULTS

Class/Schedule	Total Sales (kWh)	Revenue At Present Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	WFC Rates	CTC Rates	ECRA Rates	NSGC Rates	Residential & Small Business AB32 Credit Rates	Climate Credit & EITE Rates	CIA Rates	PCIA Rates	Total Proposed Rates	Percent Change
RESIDENTIAL																				
E-1	12,467,249,973	$0.20532	$0.03703	$0.00076	-$0.00324	$0.00000	$0.00017	$0.11223	$0.01575	$0.00093	$0.00564	$0.00004	$0.00032	$0.00442	$0.00000	-$0.00625	$0.00410	$0.04505	$0.21695	5.7%
D-CARE	2,396,336,546	$0.09417	$0.03703	$0.00076	-$0.00324	$0.00000	$0.00017	$0.03226	$0.00539	$0.00093	$0.00000	$0.00004	$0.00032	$0.00442	$0.00000	-$0.00701	-$0.01008	$0.04059	$0.10157	7.9%
TOTAL RES	14,863,586,518	$0.18740	$0.03703	$0.00076	-$0.00324	$0.00000	$0.00017	$0.09934	$0.01408	$0.00093	$0.00473	$0.00004	$0.00032	$0.00442	$0.00000	-$0.00637	$0.00181	$0.04433	$0.19834	5.8%
SMALL L&P																				
B-1	3,840,639,573	$0.19463	$0.02784	$0.00076	-$0.00324	$0.00000	$0.00013	$0.10908	$0.01605	$0.00093	$0.00579	$0.00003	$0.00032	$0.00318	$0.00000	$0.00000		$0.04440	$0.20527	5.5%
B-6	840,514,384	$0.18238	$0.02785	$0.00076	-$0.00324	$0.00000	$0.00013	$0.09926	$0.01474	$0.00093	$0.00576	$0.00003	$0.00032	$0.00318	$0.00000	$0.00000		$0.04325	$0.19297	5.8%
B-15	318,424	$0.65259	$0.02784	$0.00076	-$0.00324	$0.00000	$0.00013	$0.56155	$0.01607	$0.00093	$0.00577	$0.00003	$0.00032	$0.00318	$0.00000	$0.00000		$0.05048	$0.66382	1.7%
TC-1	24,785,359	$0.19300	$0.02784	$0.00076	-$0.00324	$0.00000	$0.00013	$0.11863	$0.00540	$0.00093	$0.00580	$0.00003	$0.00032	$0.00318	$0.00000	$0.00000		$0.04475	$0.20453	6.0%
TOTAL SMALL	4,706,257,741	$0.19247	$0.02784	$0.00076	-$0.00324	$0.00000	$0.00013	$0.10741	$0.01576	$0.00093	$0.00578	$0.00003	$0.00032	$0.00318	$0.00000	$0.00000		$0.04420	$0.20310	5.5%
MEDIUM L&P																				
B-10 T	969,064	$0.13336	$0.03069	$0.00076	-$0.00324	$0.00000	$0.00014	$0.03506	$0.01453	$0.00093	$0.00580	$0.00004	$0.00032	$0.00290	$0.00000	$0.00000		$0.04826	$0.13619	2.1%
B-10 P	45,363,975	$0.15005	$0.02824	$0.00076	-$0.00324	$0.00000	$0.00013	$0.05791	$0.01468	$0.00093	$0.00577	$0.00004	$0.00032	$0.00290	$0.00000	$0.00000		$0.04686	$0.15530	3.5%
B-10 S	5,014,882,006	$0.16128	$0.03003	$0.00076	-$0.00324	$0.00000	$0.00014	$0.06991	$0.01487	$0.00093	$0.00578	$0.00004	$0.00032	$0.00290	$0.00000	$0.00000		$0.04521	$0.16763	3.9%
TOTAL MEDIUM	5,061,215,045	$0.16117	$0.03001	$0.00076	-$0.00324	$0.00000	$0.00014	$0.06979	$0.01487	$0.00093	$0.00578	$0.00004	$0.00032	$0.00290	$0.00000	$0.00000		$0.04522	$0.16752	3.9%
B-19 CLASS																				
B-19 FIRM T	4,882,730	$0.12034	$0.02863	$0.00076	-$0.00324	$0.00000	$0.00013	$0.02730	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000			$0.04416	$0.12166	1.1%
B-19 V T	7,694,789	$0.09333	$0.01814	$0.00076	-$0.00324	$0.00000	$0.00008	$0.01019	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000			$0.04316	$0.09307	-0.3%
Total B-19 T	12,577,519	$0.10381	$0.02221	$0.00076	-$0.00324	$0.00000	$0.00010	$0.01683	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000			$0.04355	$0.10417	0.3%
B-19 FIRM P	536,629,819	$0.12091	$0.02291	$0.00076	-$0.00324	$0.00000	$0.00011	$0.04372	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00017		$0.03554	$0.12360	2.2%
B-19 V P	195,769,050	$0.13038	$0.02633	$0.00076	-$0.00324	$0.00000	$0.00012	$0.04568	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	$0.00000		$0.03991	$0.13354	2.4%
Total B-19 P	732,398,870	$0.12344	$0.02382	$0.00076	-$0.00324	$0.00000	$0.00011	$0.04424	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00013		$0.03671	$0.12626	2.3%
B-19 FIRM S	2,730,197,142	$0.13018	$0.02234	$0.00076	-$0.00324	$0.00000	$0.00010	$0.05402	$0.01450	$0.00093	$0.00579	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00007		$0.03570	$0.13408	3.0%
B-19 V S	6,073,895,711	$0.12519	$0.02068	$0.00076	-$0.00324	$0.00000	$0.00010	$0.05267	$0.01447	$0.00093	$0.00576	$0.00003	$0.00032	$0.00290	$0.00000	$0.00000		$0.03342	$0.12879	2.9%
Total B-19 S	8,804,092,853	$0.12674	$0.02119	$0.00076	-$0.00324	$0.00000	$0.00010	$0.05309	$0.01448	$0.00093	$0.00577	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00002		$0.03412	$0.13043	2.9%
B-19 T	12,577,519	$0.10381	$0.02221	$0.00076	-$0.00324	$0.00000	$0.00010	$0.01683	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00002		$0.04355	$0.10417	0.3%
B-19 P	732,398,870	$0.12344	$0.02382	$0.00076	-$0.00324	$0.00000	$0.00011	$0.04424	$0.01400	$0.00093	$0.00580	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00013		$0.03671	$0.12626	2.3%
B-19 S	8,804,092,853	$0.12674	$0.02119	$0.00076	-$0.00324	$0.00000	$0.00010	$0.05309	$0.01448	$0.00093	$0.00577	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00002		$0.03412	$0.13043	2.9%
TOTAL B-19	9,549,069,242	$0.12646	$0.02140	$0.00076	-$0.00324	$0.00000	$0.00010	$0.05236	$0.01444	$0.00093	$0.00577	$0.00003	$0.00032	$0.00290	$0.00000	-$0.00003		$0.03434	$0.13008	2.9%
STREETLIGHTS	151,922,128	$0.19711	$0.02377	$0.00076	-$0.00324	$0.00000	$0.00011	$0.12849	$0.00542	$0.00093	$0.00580	$0.00003	$0.00032	$0.00298	$0.00000	$0.00000		$0.03678	$0.20214	2.6%
STANDBY																				
STANDBY T	40,636,305	$0.14863	$0.05261	$0.00076	-$0.00324	$0.00000	$0.00025	$0.03909	$0.01489	$0.00093	$0.00580	$0.00003	$0.00032	$0.00615	$0.00000	$0.00000		$0.03165	$0.14924	0.4%
STANDBY P	6,528,165	$0.36572	$0.05733	$0.00076	-$0.00324	$0.00000	$0.00027	$0.30083	$0.01774	$0.00093	$0.00580	$0.00003	$0.00032	$0.00615	$0.00000	$0.00000		$0.00898	$0.39590	8.3%
STANDBY S	1,719,265	$0.23913	$0.03243	$0.00076	-$0.00324	$0.00000	$0.00015	$0.16369	$0.01713	$0.00093	$0.00580	$0.00003	$0.00032	$0.00615	$0.00000	-$0.00017		$0.03151	$0.25548	6.8%
TOTAL STANDBY	48,883,735	$0.18080	$0.05253	$0.00076	-$0.00324	$0.00000	$0.00025	$0.07842	$0.01535	$0.00093	$0.00580	$0.00003	$0.00032	$0.00615	$0.00000	-$0.00001		$0.02862	$0.18592	2.8%
AGRICULTURE																				
AG-A	82,855,100	$0.26435	$0.02302	$0.00076	-$0.00324	$0.00000	$0.00011	$0.19802	$0.01657	$0.00093	$0.00580	$0.00003	$0.00032	$0.00293	$0.00000	$0.00000		$0.03962	$0.28486	7.8%
AG-B	185,237,132	$0.23980	$0.02302	$0.00076	-$0.00324	$0.00000	$0.00011	$0.16818	$0.01588	$0.00093	$0.00580	$0.00003	$0.00032	$0.00293	$0.00000	$0.00000		$0.04180	$0.25651	7.0%
AG-C	816,864,687	$0.13424	$0.02302	$0.00076	-$0.00324	$0.00000	$0.00011	$0.05447	$0.01388	$0.00093	$0.00580	$0.00003	$0.00032	$0.00293	$0.00000	-$0.00004		$0.03896	$0.13792	2.7%
TOTAL AG	1,084,956,919	$0.16220	$0.02302	$0.00076	-$0.00324	$0.00000	$0.00011	$0.08484	$0.01443	$0.00093	$0.00580	$0.00003	$0.00032	$0.00293	$0.00000	-$0.00003		$0.03949	$0.16939	4.4%
B-20 CLASS																				
B-20 FIRM T	3,478,656,573	$0.05966	$0.01860	$0.00076	-$0.00324	$0.00000	$0.00009	-$0.00103	$0.01274	$0.00093	$0.00491	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00071		$0.02070	$0.05661	-5.1%
FPP T	304,202,831	$0.01385	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00154	$0.01157	$0.00093	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.01403	1.3%
TOTAL	3,782,859,404	$0.05597	$0.01710	$0.00070	-$0.00298	$0.00000	$0.00008	-$0.00083	$0.01265	$0.00093	$0.00452	$0.00003	$0.00029	$0.00232	$0.00000	-$0.00065		$0.01903	$0.05318	-5.0%
B-20 FIRM P	4,520,394,471	$0.10048	$0.02191	$0.00076	-$0.00324	$0.00000	$0.00010	$0.03564	$0.01365	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00097		$0.02402	$0.10146	1.0%
FPP P	19,657,019	$0.02872	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.01747	$0.01248	$0.00093	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.03087	7.5%
TOTAL	4,540,051,490	$0.10017	$0.02181	$0.00076	-$0.00323	$0.00000	$0.00010	$0.03556	$0.01364	$0.00093	$0.00578	$0.00003	$0.00032	$0.00251	$0.00000	-$0.00097		$0.02391	$0.10115	1.0%
B-20 FIRM S	1,613,912,242	$0.11370	$0.02241	$0.00076	-$0.00324	$0.00000	$0.00010	$0.04399	$0.01421	$0.00093	$0.00580	$0.00003	$0.00032	$0.00253	$0.00000	-$0.00058		$0.02884	$0.11610	2.1%
FPP S	96,140,150	$0.03004	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.01853	$0.01304	$0.00093	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		$0.00000	$0.03250	8.2%
TOTAL	1,710,052,392	$0.10900	$0.02115	$0.00072	-$0.00306	$0.00000	$0.00010	$0.04256	$0.01415	$0.00093	$0.00548	$0.00003	$0.00030	$0.00238	$0.00000	-$0.00055		$0.02722	$0.11140	2.2%
B-20 T	3,782,859,404	$0.05597	$0.01710	$0.00070	-$0.00298	$0.00000	$0.00008	-$0.00083	$0.01265	$0.00093	$0.00452	$0.00003	$0.00029	$0.00232	$0.00000	-$0.00065		$0.01903	$0.05318	-5.0%
B-20 P	4,540,051,490	$0.10017	$0.02181	$0.00076	-$0.00323	$0.00000	$0.00010	$0.03556	$0.01364	$0.00093	$0.00578	$0.00003	$0.00032	$0.00251	$0.00000	-$0.00097		$0.02391	$0.10115	1.0%
B-20 S	1,710,052,392	$0.10900	$0.02115	$0.00072	-$0.00306	$0.00000	$0.00010	$0.04256	$0.01415	$0.00093	$0.00548	$0.00003	$0.00030	$0.00238	$0.00000	-$0.00055		$0.02722	$0.11140	2.2%
TOTAL B-20	10,032,963,286	$0.08501	$0.01992	$0.00073	-$0.00310	$0.00000	$0.00009	$0.02303	$0.01335	$0.00093	$0.00525	$0.00003	$0.00030	$0.00242	$0.00000	-$0.00077		$0.02263	$0.08481	-0.2%
SYSTEM	**45,498,854,614**	**$0.14906**	**$0.02789**	**$0.00075**	**-$0.00321**	**$0.00000**	**$0.00013**	**$0.06993**	**$0.01424**	**$0.00093**	**$0.00532**	**$0.00003**	**$0.00031**	**$0.00333**	**$0.00000**	**-$0.00226**	**$0.00059**	**$0.03738**	**$0.15535**	**4.2%**

Advice 6090-E-A
February 26, 2021

Attachment 2

Final Tariffs

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
48879-E	ELECTRIC PRELIMINARY STATEMENT PART I RATE SCHEDULE SUMMARY Sheet 1	48083-E
48880-E	ELECTRIC PRELIMINARY STATEMENT PART I RATE SCHEDULE SUMMARY Sheet 2	48084-E
48881-E	ELECTRIC PRELIMINARY STATEMENT PART I RATE SCHEDULE SUMMARY Sheet 3	48085-E
48882-E	ELECTRIC PRELIMINARY STATEMENT PART I RATE SCHEDULE SUMMARY Sheet 4	48086-E
48883-E	ELECTRIC PRELIMINARY STATEMENT PART I RATE SCHEDULE SUMMARY Sheet 6	48088-E
48884-E	ELECTRIC PRELIMINARY STATEMENT PART I RATE SCHEDULE SUMMARY Sheet 7	48089-E
48885-E	ELECTRIC SCHEDULE A-1 SMALL GENERAL SERVICE Sheet 1	46347-E
48886-E	ELECTRIC SCHEDULE A-1 SMALL GENERAL SERVICE Sheet 2	46348-E
48887-E	ELECTRIC SCHEDULE A-1 SMALL GENERAL SERVICE Sheet 3	46349-E
48888-E	ELECTRIC SCHEDULE A-1 SMALL GENERAL SERVICE Sheet 4	48090-E
48889-E	ELECTRIC SCHEDULE A-1 SMALL GENERAL SERVICE Sheet 5	48091-E
48890-E	ELECTRIC SCHEDULE A-1 SMALL GENERAL SERVICE Sheet 6	48092-E
48891-E	ELECTRIC SCHEDULE A-1 SMALL GENERAL SERVICE Sheet 9	48093-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
48892-E	ELECTRIC SCHEDULE A-1 SMALL GENERAL SERVICE Sheet 10	47399-E, 46350-E, 47140-E, 45186-E
48893-E	ELECTRIC SCHEDULE A-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 1	46351-E
48894-E	ELECTRIC SCHEDULE A-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 2	46352-E
48895-E	ELECTRIC SCHEDULE A-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 3	46353-E
48896-E	ELECTRIC SCHEDULE A-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 4	48094-E
48897-E	ELECTRIC SCHEDULE A-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 5	48095-E
48898-E	ELECTRIC SCHEDULE A-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 6	48096-E
48899-E	ELECTRIC SCHEDULE A-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 7	48097-E
48900-E	ELECTRIC SCHEDULE A-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 10	48098-E
48901-E	ELECTRIC SCHEDULE A-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 12	47405-E, 46354-E, 47141-E, 44487-E
48902-E	ELECTRIC SCHEDULE A-15 DIRECT-CURRENT GENERAL SERVICE Sheet 1	48099-E
48903-E	ELECTRIC SCHEDULE A-15 DIRECT-CURRENT GENERAL SERVICE Sheet 2	48100-E
48904-E	ELECTRIC SCHEDULE A-15 DIRECT-CURRENT GENERAL SERVICE Sheet 4	48101-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
48905-E	ELECTRIC SCHEDULE A-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 1	46355-E
48906-E	ELECTRIC SCHEDULE A-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 2	46356-E
48907-E	ELECTRIC SCHEDULE A-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 3	45199-E
48908-E	ELECTRIC SCHEDULE A-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 4	48102-E
48909-E	ELECTRIC SCHEDULE A-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 5	48103-E
48910-E	ELECTRIC SCHEDULE A-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 7	48104-E
48911-E	ELECTRIC SCHEDULE A-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 9	46357-E, 47142-E, 45207-E
48912-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 2	48520-E
48913-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 3	
48914-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 4	48521-E
48915-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 5	48522-E
48916-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 6	48523-E
48917-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 7	48524-E
48918-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 8	48525-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
48919-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 9	48526-E
48920-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 10	48527-E
48921-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 11	48528-E
48922-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 12	48529-E
48923-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 13	48530-E
48924-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 14	
48925-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 15	
48926-E	ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER Sheet 16	
48927-E	ELECTRIC SCHEDULE AG-1 AGRICULTURAL POWER Sheet 1	45787-E
48928-E	ELECTRIC SCHEDULE AG-1 AGRICULTURAL POWER Sheet 2	45788-E
48929-E	ELECTRIC SCHEDULE AG-1 AGRICULTURAL POWER Sheet 3	45789-E
48930-E	ELECTRIC SCHEDULE AG-1 AGRICULTURAL POWER Sheet 4	45790-E
48931-E	ELECTRIC SCHEDULE AG-1 AGRICULTURAL POWER Sheet 5	48109-E
48932-E	ELECTRIC SCHEDULE AG-1 AGRICULTURAL POWER Sheet 6	48110-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
48933-E	ELECTRIC SCHEDULE AG-1 AGRICULTURAL POWER Sheet 9	48111-E
48934-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 1	25909-E
48935-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 2	45797-E
48936-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 3	45798-E
48937-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 4	45799-E
48938-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 5	45800-E
48939-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 6	48112-E, 48113-E
48940-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 7	48114-E
48941-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 8	48115-E, 48116-E
48942-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 9	45806-E
48943-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 10	45807-E
48944-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 11	45808-E
48945-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 12	45809-E
48946-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 13	48117-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
48947-E	ELECTRIC SCHEDULE AG-4 TIME-OF-USE AGRICULTURAL POWER Sheet 14	47427-E, 45812-E, 47143-E, 45814-E
48948-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 1	25911-E
48949-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 2	45815-E
48950-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 3	45816-E
48951-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 4	45817-E
48952-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 5	45818-E
48953-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 6	48118-E
48954-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 7	48119-E
48955-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 8	48120-E
48956-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 9	48121-E
48957-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 10	48122-E
48958-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 16	48123-E
48959-E	ELECTRIC SCHEDULE AG-5 LARGE TIME-OF-USE AGRICULTURAL POWER Sheet 18	46447-E, 46448-E, 46449-E, 47144-E, 46451-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
48960-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 2	46233-E
48961-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 3	46234-E
48962-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 4	
48963-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 5	48124-E
48964-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 6	48125-E
48965-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 7	48126-E
48966-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 8	46238-E
48967-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 9	46239-E
48968-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 10	46240-E
48969-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 11	48127-E
48970-E	ELECTRIC SCHEDULE AG-F FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 12	47439-E
48971-E	ELECTRIC SCHEDULE AG-R SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER Sheet 1	35785-E
48972-E	ELECTRIC SCHEDULE AG-R SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER Sheet 2	45836-E
48973-E	ELECTRIC SCHEDULE AG-R SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER Sheet 3	45837-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
48974-E	ELECTRIC SCHEDULE AG-R SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER Sheet 4	45838-E
48975-E	ELECTRIC SCHEDULE AG-R SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER Sheet 5	45839-E
48976-E	ELECTRIC SCHEDULE AG-R SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER Sheet 6	48128-E
48977-E	ELECTRIC SCHEDULE AG-R SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER Sheet 7	48129-E
48978-E	ELECTRIC SCHEDULE AG-R SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER Sheet 12	48130-E
48979-E	ELECTRIC SCHEDULE AG-V SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 1	35786-E
48980-E	ELECTRIC SCHEDULE AG-V SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 2	45847-E
48981-E	ELECTRIC SCHEDULE AG-V SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 3	45848-E
48982-E	ELECTRIC SCHEDULE AG-V SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 4	45849-E
48983-E	ELECTRIC SCHEDULE AG-V SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 5	45850-E
48984-E	ELECTRIC SCHEDULE AG-V SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 6	48131-E
48985-E	ELECTRIC SCHEDULE AG-V SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 7	48132-E
48986-E	ELECTRIC SCHEDULE AG-V SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER Sheet 12	48133-E
48987-E	ELECTRIC SCHEDULE B-1 SMALL GENERAL SERVICE Sheet 1	46856-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
48988-E	ELECTRIC SCHEDULE B-1 SMALL GENERAL SERVICE Sheet 2	46857-E
48989-E	ELECTRIC SCHEDULE B-1 SMALL GENERAL SERVICE Sheet 3	48134-E
48990-E	ELECTRIC SCHEDULE B-1 SMALL GENERAL SERVICE Sheet 4	48135-E
48991-E	ELECTRIC SCHEDULE B-1 SMALL GENERAL SERVICE Sheet 6	48136-E
48992-E	ELECTRIC SCHEDULE B-1 SMALL GENERAL SERVICE Sheet 9	
48993-E	ELECTRIC SCHEDULE B-1 SMALL GENERAL SERVICE Sheet 10	
48994-E	ELECTRIC SCHEDULE B-1 SMALL GENERAL SERVICE Sheet 11	
48995-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 1	46359-E
48996-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 2	
48997-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 3	48137-E
48998-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 4	48138-E
48999-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 5	45572-E
49000-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 6	45573-E
49001-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 7	45574-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49002-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 8	48139-E
49003-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 9	47455-E
49004-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 10	
49005-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 11	
49006-E	ELECTRIC SCHEDULE B-10 MEDIUM GENERAL DEMAND-METERED SERVICE Sheet 12	
49007-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 1	46360-E
49008-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 2	46361-E
49009-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 3	
49010-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 4	48140-E
49011-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 5	48141-E
49012-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 6	48142-E
49013-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 7	48143-E
49014-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 8	48144-E
49015-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 9	48145-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49016-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 10	48146-E
49017-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 11	48147-E
49018-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 12	48148-E
49019-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 13	45588-E
49020-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 14	45589-E*
49021-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 15	45590-E
49022-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 16	45591-E
49023-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 17	48149-E
49024-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 18	47466-E
49025-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 19	47145-E
49026-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 20	45595-E
49027-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 21	45596-E
49028-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 22	45597-E
49029-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 23	

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49030-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 24	
49031-E	ELECTRIC SCHEDULE B-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 25	
49032-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 1	46362-E
49033-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 2	45599-E
49034-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 3	
49035-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 4	48150-E
49036-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 5	48151-E
49037-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 6	48152-E
49038-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 7	48153-E
49039-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 8	48154-E
49040-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 9	48155-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49041-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 10	48156-E
49042-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 11	48157-E
49043-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 12	48158-E
49044-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 13	45609-E
49045-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 14	45610-E
49046-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 15	45611-E
49047-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 16	48159-E
49048-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 17	47477-E
49049-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 18	47146-E
49050-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 19	45615-E
49051-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 20	45616-E

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
49052-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 21	47147-E
49053-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 22	
49054-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 23	
49055-E	ELECTRIC SCHEDULE B-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 24	
49056-E	ELECTRIC SCHEDULE B-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 1	46363-E
49057-E	ELECTRIC SCHEDULE B-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 2	
49058-E	ELECTRIC SCHEDULE B-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 3	48160-E
49059-E	ELECTRIC SCHEDULE B-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 4	48161-E
49060-E	ELECTRIC SCHEDULE B-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 5	45621-E
49061-E	ELECTRIC SCHEDULE B-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 6	48162-E
49062-E	ELECTRIC SCHEDULE B-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 7	47481-E
49063-E	ELECTRIC SCHEDULE B-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 8	
49064-E	ELECTRIC SCHEDULE B-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 9	

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49065-E	ELECTRIC SCHEDULE B-6 SMALL GENERAL TIME-OF-USE SERVICE Sheet 10	
49066-E	ELECTRIC SCHEDULE BEV BUSINESS ELECTRIC VEHICLES Sheet 2	48163-E
49067-E	ELECTRIC SCHEDULE BEV BUSINESS ELECTRIC VEHICLES Sheet 4	48164-E
49068-E	ELECTRIC SCHEDULE D-CARE LINE-ITEM DISCOUNT FOR CALIFORNIA ALTERNATE RATES FOR ENERGY (CARE) CUSTOMERS Sheet 1	48165-E
49069-E	ELECTRIC SCHEDULE E-1 RESIDENTIAL SERVICES Sheet 1	48166-E
49070-E	ELECTRIC SCHEDULE E-1 RESIDENTIAL SERVICES Sheet 2	48167-E
49071-E	ELECTRIC SCHEDULE E-1 RESIDENTIAL SERVICES Sheet 5	48168-E
49072-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 1	46364-E
49073-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 2	46365-E
49074-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 3	45210-E
49075-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 5	48169-E
49076-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 6	48170-E
49077-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 7	48171-E

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
49078-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 8	48172-E
49079-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 9	48173-E
49080-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 10	48174-E
49081-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 16	48175-E
49082-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 18	47501-E, 46366-E, 48288-E
49083-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 19	47150-E
49084-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 20	44813-E
49085-E	ELECTRIC SCHEDULE E-19 MEDIUM GENERAL DEMAND-METERED TOU SERVICE Sheet 21	44814-E
49086-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 1	46367-E
49087-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 2	46368-E
49088-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 3	45223-E
49089-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 4	48176-E
49090-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 5	48177-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49091-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 6	48178-E
49092-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 7	48179-E
49093-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 11	48180-E
49094-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 13	47508-E, 47151-E, 44823-E
49095-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 14	47152-E
49096-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 15	44825-E
49097-E	ELECTRIC SCHEDULE E-20 SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE Sheet 16	44826-E
49098-E	ELECTRIC SCHEDULE E-6 RESIDENTIAL TIME-OF-USE SERVICE Sheet 2	48181-E
49099-E	ELECTRIC SCHEDULE E-6 RESIDENTIAL TIME-OF-USE SERVICE Sheet 3	48182-E
49100-E	ELECTRIC SCHEDULE E-6 RESIDENTIAL TIME-OF-USE SERVICE Sheet 7	48186-E
49101-E	ELECTRIC SCHEDULE E-CARE CARE PROG SERV FOR QUALIF NONPROF GRP-LIV & QUALIF AGRI EMPL HOUSING FACILS Sheet 1	48187-E
49102-E	ELECTRIC SCHEDULE E-ECR ENHANCED COMMUNITY RENEWABLES PROGRAM Sheet 3	48188-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49103-E	ELECTRIC SCHEDULE E-ECR ENHANCED COMMUNITY RENEWABLES PROGRAM Sheet 4	48189-E
49104-E	ELECTRIC SCHEDULE E-ECR ENHANCED COMMUNITY RENEWABLES PROGRAM Sheet 5	48190-E
49105-E	ELECTRIC SCHEDULE E-ERA ENERGY RATE ADJUSTMENTS Sheet 1	48191-E
49106-E	ELECTRIC SCHEDULE E-FFS FRANCHISE FEE SURCHARGE Sheet 2	48192-E
49107-E	ELECTRIC SCHEDULE E-FFS FRANCHISE FEE SURCHARGE Sheet 3	48193-E
49108-E	ELECTRIC SCHEDULE E-GT GREEN TARIFF PROGRAM Sheet 2	48194-E
49109-E	ELECTRIC SCHEDULE E-GT GREEN TARIFF PROGRAM Sheet 3	48195-E
49110-E	ELECTRIC SCHEDULE E-GT GREEN TARIFF PROGRAM Sheet 4	48196-E
49111-E	ELECTRIC SCHEDULE E-TOU-B RESIDENTIAL TIME-OF-USE SERVICE Sheet 2	48197-E
49112-E	ELECTRIC SCHEDULE E-TOU-B RESIDENTIAL TIME-OF-USE SERVICE Sheet 4	48198-E
49113-E	ELECTRIC SCHEDULE E-TOU-C RESIDENTIAL TIME-OF-USE (PEAK PRICING 4 - 9 p.m. EVERY DAY) Sheet 2	48199-E
49114-E	ELECTRIC SCHEDULE E-TOU-C RESIDENTIAL TIME-OF-USE (PEAK PRICING 4 - 9 p.m. EVERY DAY) Sheet 3	48200-E
49115-E	ELECTRIC SCHEDULE E-TOU-C RESIDENTIAL TIME-OF-USE (PEAK PRICING 4 - 9 p.m. EVERY DAY) Sheet 7	48201-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49116-E	ELECTRIC SCHEDULE E-TOU-D RESIDENTIAL TIME-OF-USE PEAK PRICING 5 - 8 p.m. NON-HOLIDAY WEEKDAYS Sheet 2	48202-E
49117-E	ELECTRIC SCHEDULE E-TOU-D RESIDENTIAL TIME-OF-USE PEAK PRICING 5 - 8 p.m. NON-HOLIDAY WEEKDAYS Sheet 5	48203-E
49118-E	ELECTRIC SCHEDULE EM MASTER-METERED MULTIFAMILY SERVICE Sheet 1	48204-E
49119-E	ELECTRIC SCHEDULE EM MASTER-METERED MULTIFAMILY SERVICE Sheet 2	48205-E
49120-E	ELECTRIC SCHEDULE EM MASTER-METERED MULTIFAMILY SERVICE Sheet 5	48206-E
49121-E	ELECTRIC SCHEDULE EM-TOU RESIDENTIAL TIME OF USE SERVICE Sheet 2	48207-E
49122-E	ELECTRIC SCHEDULE EM-TOU RESIDENTIAL TIME OF USE SERVICE Sheet 3	48208-E
49123-E	ELECTRIC SCHEDULE EM-TOU RESIDENTIAL TIME OF USE SERVICE Sheet 7	48212-E
49124-E	ELECTRIC SCHEDULE ES MULTIFAMILY SERVICE Sheet 1	48213-E
49125-E	ELECTRIC SCHEDULE ES MULTIFAMILY SERVICE Sheet 2	48214-E
49126-E	ELECTRIC SCHEDULE ES MULTIFAMILY SERVICE Sheet 5	48215-E
49127-E	ELECTRIC SCHEDULE ESR RESIDENTIAL RV PARK AND RESIDENTIAL MARINA SERVICE Sheet 1	48216-E
49128-E	ELECTRIC SCHEDULE ESR RESIDENTIAL RV PARK AND RESIDENTIAL MARINA SERVICE Sheet 2	48217-E

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
49129-E	ELECTRIC SCHEDULE ESR RESIDENTIAL RV PARK AND RESIDENTIAL MARINA SERVICE Sheet 5	48218-E
49130-E	ELECTRIC SCHEDULE ET MOBILEHOME PARK SERVICE Sheet 1	48219-E
49131-E	ELECTRIC SCHEDULE ET MOBILEHOME PARK SERVICE Sheet 2	48220-E
49132-E	ELECTRIC SCHEDULE ET MOBILEHOME PARK SERVICE Sheet 5	48221-E
49133-E	ELECTRIC SCHEDULE EV RESIDENTIAL TIME-OF-USE SERVICE FOR PLUG-IN ELECTRIC VEHICLE CUSTOMERS Sheet 2	48222-E
49134-E	ELECTRIC SCHEDULE EV RESIDENTIAL TIME-OF-USE SERVICE FOR PLUG-IN ELECTRIC VEHICLE CUSTOMERS Sheet 3	48223-E
49135-E	ELECTRIC SCHEDULE EV RESIDENTIAL TIME-OF-USE SERVICE FOR PLUG-IN ELECTRIC VEHICLE CUSTOMERS Sheet 5	48224-E
49136-E	ELECTRIC SCHEDULE EV2 RESIDENTIAL TIME-OF-USE SERVICE FOR PLUG-IN ELECTRIC VEHICLE CUSTOMERS Sheet 2	48225-E
49137-E	ELECTRIC SCHEDULE EV2 RESIDENTIAL TIME-OF-USE SERVICE FOR PLUG-IN ELECTRIC VEHICLE CUSTOMERS Sheet 4	48226-E
49138-E	ELECTRIC SCHEDULE LS-1 PG&E-OWNED STREET AND HIGHWAY LIGHTING Sheet 2	48227-E
49139-E	ELECTRIC SCHEDULE LS-1 PG&E-OWNED STREET AND HIGHWAY LIGHTING Sheet 4	48228-E
49140-E	ELECTRIC SCHEDULE LS-1 PG&E-OWNED STREET AND HIGHWAY LIGHTING Sheet 5	48229-E
49141-E	ELECTRIC SCHEDULE LS-1 PG&E-OWNED STREET AND HIGHWAY LIGHTING Sheet 6	48230-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49142-E	ELECTRIC SCHEDULE LS-1 PG&E-OWNED STREET AND HIGHWAY LIGHTING Sheet 7	48231-E
49143-E	ELECTRIC SCHEDULE LS-1 PG&E-OWNED STREET AND HIGHWAY LIGHTING Sheet 8	48232-E
49144-E	ELECTRIC SCHEDULE LS-1 PG&E-OWNED STREET AND HIGHWAY LIGHTING Sheet 9	48233-E
49145-E	ELECTRIC SCHEDULE LS-1 PG&E-OWNED STREET AND HIGHWAY LIGHTING Sheet 21	48234-E
49146-E	ELECTRIC SCHEDULE LS-2 CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING Sheet 2	48235-E
49147-E	ELECTRIC SCHEDULE LS-2 CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING Sheet 3	48236-E
49148-E	ELECTRIC SCHEDULE LS-2 CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING Sheet 4	48237-E
49149-E	ELECTRIC SCHEDULE LS-2 CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING Sheet 5	48238-E
49150-E	ELECTRIC SCHEDULE LS-2 CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING Sheet 6	48239-E
49151-E	ELECTRIC SCHEDULE LS-2 CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING Sheet 7	48240-E
49152-E	ELECTRIC SCHEDULE LS-2 CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING Sheet 9	48296-E
49153-E	ELECTRIC SCHEDULE LS-2 CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING Sheet 17	48242-E
49154-E	ELECTRIC SCHEDULE LS-3 CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE Sheet 1	48243-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49155-E	ELECTRIC SCHEDULE LS-3 CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE Sheet 5	48244-E
49156-E	ELECTRIC SCHEDULE OL-1 OUTDOOR AREA LIGHTING SERVICE Sheet 1	48245-E
49157-E	ELECTRIC SCHEDULE OL-1 OUTDOOR AREA LIGHTING SERVICE Sheet 2	48246-E
49158-E	ELECTRIC SCHEDULE OL-1 OUTDOOR AREA LIGHTING SERVICE Sheet 3	48247-E
49159-E	ELECTRIC SCHEDULE OL-1 OUTDOOR AREA LIGHTING SERVICE Sheet 4	48248-E
49160-E	ELECTRIC SCHEDULE OL-1 OUTDOOR AREA LIGHTING SERVICE Sheet 5	48249-E
49161-E	ELECTRIC SCHEDULE OL-1 OUTDOOR AREA LIGHTING SERVICE Sheet 6	48250-E
49162-E	ELECTRIC SCHEDULE OL-1 OUTDOOR AREA LIGHTING SERVICE Sheet 10	48251-E
49163-E	ELECTRIC SCHEDULE S STANDBY SERVICE Sheet 4	48252-E
49164-E	ELECTRIC SCHEDULE S STANDBY SERVICE Sheet 5	48253-E
49165-E	ELECTRIC SCHEDULE S STANDBY SERVICE Sheet 15	48254-E
49166-E	ELECTRIC SCHEDULE SB STANDBY SERVICE Sheet 3	48255-E
49167-E	ELECTRIC SCHEDULE SB STANDBY SERVICE Sheet 4	48256-E
49168-E	ELECTRIC SCHEDULE SB STANDBY SERVICE Sheet 5	48257-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49169-E	ELECTRIC SCHEDULE SB STANDBY SERVICE Sheet 14	48258-E
49170-E	ELECTRIC SCHEDULE TC-1 TRAFFIC CONTROL SERVICE Sheet 1	48259-E
49171-E	ELECTRIC SCHEDULE TC-1 TRAFFIC CONTROL SERVICE Sheet 4	48260-E
49172-E	ELECTRIC RULE NO. 1 DEFINITIONS Sheet 2	41423-E
49173-E	ELECTRIC RULE NO. 1 DEFINITIONS Sheet 3	41424-E
49174-E	ELECTRIC RULE NO. 1 DEFINITIONS Sheet 4	45657-E
49175-E	ELECTRIC RULE NO. 1 DEFINITIONS Sheet 5	46388-E
49176-E	ELECTRIC RULE NO. 1 DEFINITIONS Sheet 6	46389-E
49177-E	ELECTRIC TABLE OF CONTENTS Sheet 1	48749-E
49178-E	ELECTRIC TABLE OF CONTENTS Sheet 2	48262-E
49179-E	ELECTRIC TABLE OF CONTENTS Sheet 3	48263-E
49180-E	ELECTRIC TABLE OF CONTENTS Sheet 4	48044-E
49181-E	ELECTRIC TABLE OF CONTENTS Sheet 5	48298-E
49182-E	ELECTRIC TABLE OF CONTENTS Sheet 6	48538-E
49183-E	ELECTRIC TABLE OF CONTENTS Sheet 7	48539-E
49184-E	ELECTRIC TABLE OF CONTENTS Sheet 10	48268-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
49185-E	ELECTRIC TABLE OF CONTENTS Sheet 11	48269-E
49186-E	ELECTRIC TABLE OF CONTENTS Sheet 17	47088-E
49187-E	ELECTRIC TABLE OF CONTENTS Sheet 18	48750-E

ELECTRIC PRELIMINARY STATEMENT PART I
RATE SCHEDULE SUMMARY

I. Rate Summary

The following rates are used to separate billed revenue for accounting purposes.

Billed Component	Subcomponent	Applicability	Rate (per kWh)	
Distribution	California Public Utilities Commission Fee	All rate schedules, all customers.	$0.00131	
Distribution	CEE Incentive Rate	All rate schedules, all customers.	$0.00013	
Transmission	Transmission Access Charge (FERC Jurisdictional)	All rate schedules, all customers.	$0.00076	(R)
Transmission	End-Use Customer Refund Adjustment (ECRA)	Residential Small L&P Medium L&P E-19/B-19 Streetlights Standby Agriculture E-20/B-20	$0.00000 $0.00000 $0.00000 $0.00000 $0.00000 $0.00000 $0.00000 $0.00000	
Public Purpose Programs	CARE Surcharge	All rate schedules except CARE schedules, Schedules TC-1, LS-1, LS-2, and LS-3, and qualifying CARE usage under Schedules ESL, ESRL, ETL, and E-CARE all customers.	$0.01037	

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART I Sheet 2
RATE SCHEDULE SUMMARY

I. Rate Summary (Cont'd.)

The following rates are used to separate billed revenue for accounting purposes. (Cont'd.)

Billed Component	Subcomponent	Applicability	Rate (per kWh)	
Public Purpose Programs	Procurement Energy Efficiency Revenue Adjustment Mechanism (PEERAM)	All rate schedules, all customers.	$0.00175	(I)
Public Purpose Programs	Electric Program Investment Charge (EPIC)	All rate schedules, all customers.	$0.00066	(R)
Public Purpose Programs	Electric Program Investment Charge Revenue Adjustment Mechanism - NSHP	All rate schedules, all customers.	$0.00000	
Public Purpose Program	Tree Mortality Non-Bypassable Charge (TMNBC)	All rate schedules, all customers	$0.00084	
Public Purpose Program	Public Policy Charge Balancing Account (PPCBA)	All rate schedules, all customers	$0.00018	
Generation	Power Charge Collection Balancing Account (PCCBA)	All rate schedules, bundled service, except Schedules E-GT and E-ECR.	($0.00009)	
Generation	DWR Franchise Fees	All bundled service customer rate schedules except Schedules E-GT and E-ECR,	$0.00004	
Generation	Portfolio Allocation Balance Account (PABA)	All rate schedules, all bundled customers except E-GT and E-ECR.	See uncapped incremental PCIA rates below by rate group, excludes DWR Franchise Fees	

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART I Sheet 3
RATE SCHEDULE SUMMARY

I. Rate Summary (Cont'd.)

The following rates are used to separate billed revenue for accounting purposes. (Cont'd.)

Uncapped Incremental PCIA Rates by Rate Group, Excludes DWR Franchise Fees

Rate Group	Legacy Utility-Owned Generation (UOG)		2009 Vintage		2010 Vintage		2011 Vintage	
Residential	$0.00858	(I)	$0.02459	(R)	$0.00661	(R)	$0.00171	(R)
Small Commercial	$0.00832	(I)	$0.02386	(R)	$0.00641	(R)	$0.00166	(R)
Medium Commercial	$0.00893	(I)	$0.02558	(R)	$0.00687	(R)	$0.00179	(R)
Large Commercial	$0.00818	(I)	$0.02344	(R)	$0.00630	(R)	$0.00164	(R)
Streetlights	$0.00683	(I)	$0.01958	(R)	$0.00526	(R)	$0.00137	(R)
Standby	$0.00621	(I)	$0.01779	(R)	$0.00478	(R)	$0.00124	(R)
Agriculture	$0.00775	(I)	$0.02219	(R)	$0.00596	(R)	$0.00155	(R)
E-20 T / B-20-T	$0.00700	(I)	$0.02006	(R)	$0.00539	(R)	$0.00140	(R)
E-20 P / B-20-P	$0.00750	(I)	$0.02150	(R)	$0.00578	(R)	$0.00150	(R)
E-20 S / B-20-S	$0.00784	(I)	$0.02246	(R)	$0.00604	(R)	$0.00157	(R)
BEV1	$0.00698	(I)	$0.01998	(R)	$0.00538	(R)	$0.00139	(R)
BEV2	$0.00820	(I)	$0.02349	(R)	$0.00632	(R)	$0.00164	(R)

Rate Group	2012 Vintage		2013 Vintage		2014 Vintage		2015 Vintage	
Residential	$0.00227	(R)	$0.00054	(R)	$0.00008		$0.00030	(R)
Small Commercial	$0.00220	(R)	$0.00052	(R)	$0.00008	(R)	$0.00029	
Medium Commercial	$0.00235	(R)	$0.00057		$0.00008	(I)	$0.00031	
Large Commercial	$0.00215	(R)	$0.00052		$0.00008		$0.00029	
Streetlights	$0.00180	(R)	$0.00044	(R)	$0.00006	(I)	$0.00024	
Standby	$0.00163	(R)	$0.00040	(I)	$0.00006	(R)	$0.00021	(R)
Agriculture	$0.00204	(R)	$0.00049		$0.00008	(I)	$0.00027	(R)
E-20 T / B-20-T	$0.00184	(R)	$0.00045		$0.00006	(R)	$0.00025	(I)
E-20 P / B-20-P	$0.00198	(R)	$0.00048	(R)	$0.00007		$0.00026	(R)
E-20 S / B-20-S	$0.00207	(R)	$0.00050		$0.00007	(R)	$0.00027	
BEV1	$0.00184	(R)	$0.00045	(I)	$0.00006		$0.00025	
BEV2	$0.00216	(R)	$0.00052	(R)	$0.00008	(I)	$0.00028	(R)

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART I Sheet 4
RATE SCHEDULE SUMMARY

I. Rate Summary (Cont'd.)

The following rates are used to separate billed revenue for accounting purposes. (Cont'd.)

Uncapped Incremental PCIA Rates by Rate Group, Excludes DWR Franchise Fees

Rate Group	2016 Vintage		2017 Vintage		2018 Vintage		2019 Vintage	
Residential	$0.00021	(R)	$0.00013		($0.00024)		($0.00043)	
Small Commercial	$0.00021		$0.00012	(I)	($0.00023)		($0.00042)	(R)
Medium Commercial	$0.00022	(R)	$0.00013		($0.00025)	(I)	($0.00044)	(R)
Large Commercial	$0.00020		$0.00012		($0.00023)		($0.00041)	(R)
Streetlights	$0.00017	(R)	$0.00010		($0.00019)		($0.00034)	
Standby	$0.00016	(I)	$0.00009		($0.00018)	(R)	($0.00030)	(I)
Agriculture	$0.00019		$0.00011		($0.00022)	(R)	($0.00038)	(I)
E-20 T / B-20-T	$0.00017	(R)	$0.00010		($0.00019)		($0.00035)	(R)
E-20 P / B-20-P	$0.00018	(R)	$0.00011		($0.00021)		($0.00037)	(I)
E-20 S / B-20-S	$0.00020		$0.00011	(R)	($0.00022)		($0.00039)	
BEV1	$0.00017	(R)	$0.00010	(I)	($0.00020)	(R)	($0.00034)	(I)
BEV2	$0.00021		$0.00012		($0.00023)		($0.00041)	

Rate Group	2020 Vintage		2021 Vintage
Residential	($0.01552)		$0.00000
Small Commercial	($0.01505)	(I)	$0.00000
Medium Commercial	($0.01615)		$0.00000
Large Commercial	($0.01480)		$0.00000
Streetlights	($0.01236)		$0.00000
Standby	($0.01123)		$0.00000
Agriculture	($0.01401)		$0.00000
E-20 T / B-20-T	($0.01266)		$0.00000
E-20 P / B-20-P	($0.01357)		$0.00000
E-20 S / B-20-S	($0.01418)		$0.00000
BEV1	($0.01262)	(R)	$0.00000
BEV2	($0.01483)	(I)	$0.00000

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART I Sheet 6
RATE SCHEDULE SUMMARY

I. Rate Summary (Cont'd.)

The following rates are used to separate billed revenue for accounting purposes. (Cont'd.)

Community Choice Aggregation Service Customer and Non-exempt Departing Load Customer Incremental PCIA Rates by Rate Group, Excludes DWR Franchise Fees

Rate Group	Legacy Utility-Owned Generation (UOG)		2009 Vintage		2010 Vintage		2011 Vintage	
Residential	$0.00858	(I)	$0.02649	(R)	$0.00716	(R)	$0.00190	(R)
Small Commercial	$0.00832	(I)	$0.02570	(R)	$0.00694	(R)	$0.00185	(R)
Medium Commercial	$0.00893	(I)	$0.02755	(R)	$0.00745	(R)	$0.00198	(R)
Large Commercial	$0.00818	(I)	$0.02525	(R)	$0.00683	(R)	$0.00181	(R)
Streetlights	$0.00683	(I)	$0.02109	(R)	$0.00571	(R)	$0.00151	(R)
Standby	$0.00621	(I)	$0.01916	(R)	$0.00518	(R)	$0.00137	(R)
Agriculture	$0.00775	(I)	$0.02390	(R)	$0.00646	(R)	$0.00172	(R)
E-20 T / B-20-T	$0.00700	(I)	$0.02160	(R)	$0.00585	(R)	$0.00155	(R)
E-20 P / B-20-P	$0.00750	(I)	$0.02316	(R)	$0.00627	(R)	$0.00166	(R)
E-20 S / B-20-S	$0.00784	(I)	$0.02420	(R)	$0.00654	(R)	$0.00174	(R)
BEV1	$0.00698	(I)	$0.02153	(R)	$0.00582	(R)	$0.00155	(R)
BEV2	$0.00820	(I)	$0.02531	(R)	$0.00684	(R)	$0.00181	(R)

Rate Group	2012 Vintage		2013 Vintage		2014 Vintage		2015 Vintage	
Residential	$0.00260	(R)	$0.00022	(R)	$0.00004	(I)	$0.00022	
Small Commercial	$0.00252	(R)	$0.00022	(R)	$0.00003	(I)	$0.00021	
Medium Commercial	$0.00271	(R)	$0.00023	(R)	$0.00003	(R)	$0.00023	(I)
Large Commercial	$0.00248	(R)	$0.00021		$0.00004		$0.00021	(I)
Streetlights	$0.00207	(R)	$0.00018		$0.00003	(I)	$0.00017	(R)
Standby	$0.00189	(R)	$0.00016		$0.00002	(R)	$0.00016	(I)
Agriculture	$0.00235	(R)	$0.00020	(R)	$0.00003		$0.00020	
E-20 T / B-20-T	$0.00212	(R)	$0.00018	(R)	$0.00003		$0.00018	(I)
E-20 P / B-20-P	$0.00227	(R)	$0.00020	(I)	$0.00003	(R)	$0.00019	
E-20 S / B-20-S	$0.00238	(R)	$0.00020	(R)	$0.00003	(I)	$0.00020	(R)
BEV1	$0.00211	(R)	$0.00018	(R)	$0.00003		$0.00018	(I)
BEV2	$0.00249	(R)	$0.00021		$0.00004		$0.00021	

ELECTRIC PRELIMINARY STATEMENT PART I Sheet 7
RATE SCHEDULE SUMMARY

I. Rate Summary (Cont'd.)

The following rates are used to separate billed revenue for accounting purposes. (Cont'd.)

Community Choice Aggregation Service Customer and Non-exempt Departing Load Customer
Incremental PCIA Rates by Rate Group, Excludes DWR Franchise Fees

Rate Group	2016 Vintage		2017 Vintage		2018 Vintage		2019 Vintage	
Residential	$0.00031		$0.00004	(R)	($0.00055)	(R)	($0.01122)	
Small Commercial	$0.00030	(R)	$0.00004		($0.00053)		($0.01088)	
Medium Commercial	$0.00032	(R)	$0.00005	(I)	($0.00057)	(R)	($0.01168)	
Large Commercial	$0.00029	(R)	$0.00004		($0.00052)	(R)	($0.01070)	
Streetlights	$0.00025	(I)	$0.00003	(R)	($0.00043)		($0.00894)	
Standby	$0.00023		$0.00002	(R)	($0.00039)		($0.00812)	
Agriculture	$0.00028	(I)	$0.00003	(R)	($0.00049)	(I)	($0.01013)	
E-20 T / B-20-T	$0.00025	(R)	$0.00003		($0.00044)		($0.00916)	(R)
E-20 P / B-20-P	$0.00027		$0.00003	(R)	($0.00047)	(I)	($0.00981)	
E-20 S / B-20-S	$0.00028	(R)	$0.00004		($0.00050)		($0.01025)	
BEV1	$0.00025	(R)	$0.00004	(I)	($0.00045)	(R)	($0.00912)	(R)
BEV2	$0.00029	(R)	$0.00004	(R)	($0.00052)		($0.01072)	(I)

Rate Group	2020 Vintage		2021 Vintage
Residential	($0.00696)		$0.00000
Small Commercial	($0.00675)	(I)	$0.00000
Medium Commercial	($0.00724)		$0.00000
Large Commercial	($0.00664)		$0.00000
Streetlights	($0.00554)		$0.00000
Standby	($0.00503)	(I)	$0.00000
Agriculture	($0.00628)	(I)	$0.00000
E-20 T / B-20-T	($0.00567)	(I)	$0.00000
E-20 P / B-20-P	($0.00609)		$0.00000
E-20 S / B-20-S	($0.00636)		$0.00000
BEV1	($0.00566)	(R)	$0.00000
BEV2	($0.00665)	(I)	$0.00000

ELECTRIC SCHEDULE A-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 legacy customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 TOU hours as described below. The non-TOU version of Schedule A-1 is not available for solar legacy 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 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 their existing legacy TOU rate periods for a certain period of time, per Decision 17-01-006, (T) as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar Legacy TOU (T) Eligibility Requirements.

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

(D)

(D)

* 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-1 Sheet 2
SMALL GENERAL SERVICE

APPLICABILITY: (cont'd.) (D)

(D)

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 SB—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 SB, in addition to all applicable Schedule A-1 charges. Exemptions to Standby Charges are outlined in the Standby Applicability Section of this rate schedule. (T) (T)

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. (D) (D)

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) (N)

(D)

(D)

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. (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.

(Continued)

APPLICABILITY: (cont'd.)

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.

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 Legacy TOU Period" and the terms of (T) "Behind-the-Meter Solar Legacy TOU Period Eligibility Requirements" shall be (T) 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.

(Continued)

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

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	$0.28465	(I)
Winter	$0.22766	(I)

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	$0.28729	(R)
Part-Peak Summer	$0.28729	(I)
Off-Peak Summer	$0.26258	(I)
Part-Peak Winter	$0.23969	(R)
Off-Peak Winter	$0.23911	(I)

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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. (D)

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	$0.12847	(I)
Winter	$0.08833	(I)
Distribution**		
Summer	$0.10436	(I)
Winter	$0.08751	(I)
Transmission* (all usage)	$0.02784	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00013	
Public Purpose Programs (all usage)	$0.01607	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032	
New System Generation Charge (all usage)**	$0.00318	
Wildfire Fund Charge (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.

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ELECTRIC SCHEDULE A-1 Sheet 6
SMALL GENERAL SERVICE

RATES:
(Cont'd.)

UNBUNDLING OF TOTAL RATES

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	$0.13111	(R)
Part-Peak Summer	$0.13111	(I)
Off-Peak Summer	$0.10640	(I)
Part-Peak Winter	$0.10036	(R)
Off-Peak Winter	$0.09978	(I)
Distribution:**		
Peak Summer	$0.10436	(I)
Part-Peak Summer	$0.10436	(I)
Off-Peak Summer	$0.10436	(I)
Part-Peak Winter	$0.08751	(I)
Off-Peak Winter	$0.08751	(I)
Transmission* (all usage)	$0.02784	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00013	
Public Purpose Programs (all usage)	$0.01607	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032	
New System Generation Charge (all usage)**	$0.00318	
Wildfire Fund Charge (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)

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.

	DA /CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03406	(I)
2010 Vintage	$0.04100	(I)
2011 Vintage	$0.04285	(I)
2012 Vintage	$0.04537	(I)
2013 Vintage	$0.04559	(I)
2014 Vintage	$0.04562	(I)
2015 Vintage	$0.04583	(I)
2016 Vintage	$0.04613	(I)
2017 Vintage	$0.04617	(I)
2018 Vintage	$0.04564	(I)
2019 Vintage	$0.03476	(I)
2020 Vintage	$0.02801	(I)
2021 Vintage	$0.02801	(I)

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 Wildfire Fund 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.

(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.

WILDFIRE FUND CHARGE:

The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

(D)

(D)

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 legacy customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 legacy 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 their existing legacy TOU rate periods for a certain period of time, (T) per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar Legacy TOU Eligibility Requirements. (T)

The new rates with revised TOU periods were available on a voluntary opt-in basis for qualifying customers from November 2019 through February 2021. (T)

(D)

(D)

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

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

APPLICABILITY (CONT'D): (D)

(D)

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 SB—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 SB, in addition to all applicable Schedule A-10 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule. (T) (T)

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.

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) (N)

(D)

(D)

(Continued)

APPLICABILITY (CONT'D):

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.

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 Legacy TOU Period" and the terms of "Behind-the-Meter Solar Legacy TOU Period 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. (T) (T)
>
> 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.

(Continued)

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

APPLICABILITY (CONT'D):

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)	$5.47664	(I)	$5.47664	(I)	$5.47664	(I)
Total Demand Rates ($ per kW)						
Summer	$15.68	(R)	$15.41	(R)	$10.64	(R)
Winter	$15.68	(I)	$15.41	(I)	$10.64	(I)
Total Energy Rates ($ per kWh)						
Summer	$0.19174	(I)	$0.17986	(I)	$0.13334	(R)
Winter	$0.15413	(I)	$0.14465	(I)	$0.11622	(I)

(Continued)

RATES: Standard Non-Time-of-Use Rates

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

Table A (Cont'd.)

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 Rate by Components ($ per kW)	Secondary Voltage		Primary Voltage		Transmission Voltage	
Generation:						
Summer	$0.00	(R)	$0.00	(R)	$0.00	(R)
Winter	$0.00		$0.00		$0.00	
Distribution:**						
Summer	$6.84	(R)	$6.57	(R)	$1.80	(I)
Winter	$6.84	(I)	$6.57	(I)	$1.80	(I)
Transmission Maximum Demand*	$8.80		$8.80		$8.80	
Reliability Services Maximum Demand*	$0.04		$0.04		$0.04	
Energy Rate by Components ($ per kWh)						
Generation:						
Summer	$0.12788	(I)	$0.11599	(I)	$0.10139	(I)
Winter	$0.10612	(I)	$0.09717	(I)	$0.08427	(I)
Distribution:**						
Summer	$0.04143	(I)	$0.04161	(I)	$0.00991	(I)
Winter	$0.02558	(I)	$0.02522	(I)	$0.00991	(I)
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01492	(I)	$0.01475	(I)	$0.01453	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00004		$0.00004		$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290		$0.00290		$0.00290	
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.

(Continued)

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

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)	$5.47664	(I)	$5.47664	(I)	$5.47664	(I)
Total Demand Rates ($ per kW)						
Summer	$15.68	(R)	$15.41	(R)	$10.64	(R)
Winter	$15.68	(I)	$15.41	(I)	$10.64	(I)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.20499	(R)	$0.19416	(R)	$0.14850	(R)
Part-Peak Summer	$0.20499	(I)	$0.19416	(I)	$0.14850	(I)
Off-Peak Summer	$0.17820	(I)	$0.16884	(I)	$0.12385	(I)
Part-Peak Winter	$0.15452	(I)	$0.14503	(R)	$0.11661	(R)
Off-Peak Winter	$0.15381	(I)	$0.14436	(I)	$0.11595	(I)

(D)

(D)

ELECTRIC SCHEDULE A-10 Sheet 7
MEDIUM GENERAL DEMAND-METERED SERVICE

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

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below. (T)

Table B (Cont'd.)

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.

	Secondary Voltage		Primary Voltage		Transmission Voltage	
Demand Rate by Components ($ per kW)						
Generation:						
Summer	$0.00	(R)	$0.00	(R)	$0.00	(R)
Winter	$0.00		$0.00		$0.00	
Distribution:**						
Summer	$6.84	(R)	$6.57	(R)	$1.80	(I)
Winter	$6.84	(I)	$6.57	(I)	$1.80	(I)
Transmission Maximum Demand*	$8.80		$8.80		$8.80	
Reliability Services Maximum Demand*	$0.04		$0.04		$0.04	
Energy Rate by Components ($ per kWh)						
Generation:						
Peak Summer	$0.14113	(R)	$0.13029	(R)	$0.11655	(R)
Part-Peak Summer	$0.14113	(I)	$0.13029	(I)	$0.11655	(I)
Off-Peak Summer	$0.11434	(I)	$0.10497	(I)	$0.09190	(I)
Part-Peak Winter	$0.10651	(I)	$0.09755	(I)	$0.08466	(R)
Off-Peak Winter	$0.10580	(I)	$0.09688	(I)	$0.08400	(I)
Distribution:**						
Summer	$0.04143	(I)	$0.04161	(I)	$0.00991	(I)
Winter	$0.02558	(I)	$0.02522	(I)	$0.00991	(I)
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01492	(I)	$0.01475	(I)	$0.01453	(I)
Competition Transition Charge (all usage)	$0.00004		$0.00004		$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290		$0.00290		$0.00290	
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.

(Continued)

ELECTRIC SCHEDULE A-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.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03652	(I)
2010 Vintage	$0.04397	(I)
2011 Vintage	$0.04595	(I)
2012 Vintage	$0.04866	(I)
2013 Vintage	$0.04889	(I)
2014 Vintage	$0.04892	(I)
2015 Vintage	$0.04915	(I)
2016 Vintage	$0.04947	(I)
2017 Vintage	$0.04952	(I)
2018 Vintage	$0.04895	(I)
2019 Vintage	$0.03727	(I)
2020 Vintage	$0.03003	(I)
2021 Vintage	$0.03003	(I)

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 Wildfire Fund Charge.

(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.

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.

WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

(D)

(D)

ELECTRIC SCHEDULE A-15 Sheet 1
DIRECT-CURRENT GENERAL SERVICE

APPLICABILITY: This schedule is applicable to direct current lighting service, including lamp socket appliances and, at the customer's option, to direct current service for power and heating alone or combined with lighting on the same meter. This schedule is applicable only to those establishments which continued service under this schedule on and after February 13, 1971.

TERRITORY: Certain downtown areas of San Francisco and Oakland where direct current is available.

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 Charge Rates		
Customer Charge ($ per meter per day)	$0.32854	
Facility Charge ($ per meter per day)	$0.82136	
Total Energy Rates ($ per kWh)		
Summer	$0.28465	(I)
Winter	$0.22766	(I)

(Continued)

ELECTRIC SCHEDULE A-15
DIRECT-CURRENT GENERAL 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 and Facility Charge Rates: Customer charge and Facility rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.

Energy Rates by Components ($ per kWh)

Generation:		
Summer	$0.12847	(I)
Winter	$0.08833	(I)
Distribution:**		
Summer	$0.10436	(I)
Winter	$0.08751	(I)
Transmission* (all usage)	$0.02784	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00013	
Public Purpose Programs (all usage)	$0.01607	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charge (all usage)	$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032	
Wildfire Fund Charge (all usage)	$0.00580	
New System Generation Charge (all usage)**	$0.00318	
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 A-15 Sheet 4
DIRECT-CURRENT GENERAL SERVICE

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.

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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03406	(I)
2010 Vintage	$0.04100	(I)
2011 Vintage	$0.04285	(I)
2012 Vintage	$0.04537	(I)
2013 Vintage	$0.04559	(I)
2014 Vintage	$0.04562	(I)
2015 Vintage	$0.04583	(I)
2016 Vintage	$0.04613	(I)
2017 Vintage	$0.04617	(I)
2018 Vintage	$0.04564	(I)
2019 Vintage	$0.03476	(I)
2020 Vintage	$0.02801	(I)
2021 Vintage	$0.02801	(I)

WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082

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 legacy customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 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 Legacy TOU Eligibility Requirements. (T)

The new rates with revised TOU periods adopted in D.18-08-013 were available on a voluntary opt-in basis from November 2019 through February 2021. (T)

(D)

(D)

* 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) (D)

(D)

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 Legacy TOU Period" and the terms of "Behind- (T) the-Meter Solar Legacy TOU Period Eligibility Requirements" shall be permitted to (T) 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-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.

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 SB—Standby Service Special Conditions 1 through 6 shall also (T) 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 SB, in addition to all (T) applicable Schedule A 6 charges. Exemptions are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

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

APPLICABILITY: (Cont'd.)

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. (D)
(D)

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)

(D)

(D)

(Continued)

ELECTRIC SCHEDULE A-6 Sheet 4
SMALL GENERAL TIME-OF-USE SERVICE

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	$0.44244	(R)
Part-Peak Summer	$0.30221	(R)
Off-Peak Summer	$0.25295	(I)
Part-Peak Winter	$0.24390	(R)
Off-Peak Winter	$0.24286	(I)

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(D)

(Continued)

RATES:
(Cont'd.)

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

UNBUNDLING OF TOTAL RATES

Customer/Meter Charge Rates: Customer/Meter 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	$0.23853	(R)
Part-Peak Summer	$0.13981	(R)
Off-Peak Summer	$0.10928	(I)
Part-Peak Winter	$0.09990	(R)
Off-Peak Winter	$0.09919	(R)
Distribution:**		
Peak Summer	$0.15335	(R)
Part-Peak Summer	$0.11184	(I)
Off-Peak Summer	$0.09311	(I)
Part-Peak Winter	$0.09344	(I)
Off-Peak Winter	$0.09311	(I)
Transmission* (all usage)	$0.02784	
Wildfire Fund Charge (all usage)	$0.00580	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00013	
Public Purpose Programs (all usage)	$0.01481	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032	
New System Generation Charge (all usage)**	$0.00318	
California Climate Credit (all usage)***	$0.00000	

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* 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)

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[1], the applicable Cost Responsibility Surcharge (CRS) pursuant to Schedule DA CRS or Schedule CCA CRS, and short-term commodity prices as set forth in Schedule TBCC.

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

	DA /CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03406	(I)
2010 Vintage	$0.04100	(I)
2011 Vintage	$0.04285	(I)
2012 Vintage	$0.04537	(I)
2013 Vintage	$0.04559	(I)
2014 Vintage	$0.04562	(I)
2015 Vintage	$0.04583	(I)
2016 Vintage	$0.04613	(I)
2017 Vintage	$0.04617	(I)
2018 Vintage	$0.04564	(I)
2019 Vintage	$0.03476	(I)
2020 Vintage	$0.02801	(I)
2021 Vintage	$0.02801	(I)

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 under Schedule E-CARE. CARE customers are exempt from the Wildfire Fund Charge.

(Continued)

(D)

(D)

RATES FOR LEGACY RES-BCT CUSTOMERS

Pursuant to D.18-08-013 and the Commission's approval of Advice Letter 5379-E-A, solar customers that are eligible for legacy treatment under D.17-01-006 as defined in Rule 1, may take service under legacy rate schedules that retain Time-Of-Use (TOU) periods that include a peak period of noon to 6 pm. Starting on March 1, 2021, the rates shown in the table below will be used to calculate the generation credit for eligible A-6 RES BCT customers. These rates apply only to the calculation of the generation credit for eligible A-6 RES-BCT customers. The rate for load served under Schedule A-6, including for legacy customers, will be charged the applicable rates as shown in the earlier section of this tariff. The generation credit rate will change annually using the rates shown in the table below on the effective date of the Annual Electric True Up Advice Letter. (N)

	2021	2022	2023
	($/kWh)	($/kWh)	($/kWh)
TOU Period			
Summer Peak	0.34978	0.34601	0.34224
Summer Partial Peak	0.12010	0.11881	0.11751
Summer Off Peak	0.06422	0.06352	0.06283
Winter Partial Peak	0.08863	0.08768	0.08672
Winter Off Peak	0.07186	0.07108	0.07031

Time of Use Periods: The rates provided in the table above will be applied to energy delivered to PG&E in the TOU periods established for Schedule A-6 to determine the applicable generation credit. (N)

(Continued)

ELECTRIC SCHEDULE AG Sheet 2
TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

The customer will be served under one of the following default rate plans AG-A1, AG-A2, AG-B, or AG-C, under Schedule AG but may elect any rate for which they are eligible, including rate plans under optional Schedule AG-F with flexible off-peak period days, as set forth in the separate tariff for rate Schedule AG-F.

Rates AG-A1 and AG-A2:

Applies to single-motor installations rated less than 35 kilowatts (kW) and to all multi-load installations aggregating less than 35 kW.

Rates AG-B and AG-C:

Applies to single-motor installations rated 35 kW or more, to multi-load installations aggregating 35 kW or more.

Generally, AG-A1 and AG-B are designed for lower load factor customers with fewer operating hours and contains lower demand charges and higher energy charges than AG-A2 and AG-C respectively. By contrast, AG-A2 and AG-C are generally designed for higher load factor customers with more operating hours, and have higher demand charges and lower energy charges than AG-A1 and AG-B respectively.

Decision 18-08-013 adopted new TOU periods and seasonal definitions for all non-residential customer classes. Agricultural rate 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 new TOU periods, 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 of certain qualifying agricultural customers until March 2022. Certain qualifying customers with solar systems will be permitted to maintain 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 Legacy TOU Eligibility Requirements. (T)

The rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010, including AG-A1, AG-A2, AG-B, and AG-C under Schedule AG were (T)
available to qualifying customers on a voluntary opt-in basis from March 2020 |
through February 2021. Customers eligible for this rate schedule must have an (T)
interval data meter that can be read remotely by PG&E.

Any agricultural customers establishing service on or after March 1, 2020 with an interval meter already in place will be charged the new Schedule AG (or optional Schedule AG-F) rates and are not eligible for legacy agricultural rates.

Beginning on March 1, 2021 customers still served on legacy rate Schedules AG-1, AG-4, AG-5, AG-R or AG-V, with the exception of customers referenced above, will be transitioned to AG-A1, AG-A2, AG-B, or AG-C under Schedule AG with revised TOU periods. Customers may elect any rate for which they are eligible, including rates under 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.

(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. (N)

A customer exceeding 200 kW as described above is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter^{TM} system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

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

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

(L)

(L)

(Continued)

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

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)

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	—		—		—		$18.57	(I)	|
Maximum Demand Summer	$6.47	(I)	$11.70	(I)	$6.66	(I)	$11.95	(I)	|
Maximum Demand Winter	$6.47	(I)	$11.70	(I)	$6.66	(I)	$11.95	(I)	|
Primary Voltage									|
Maximum Peak Demand Summer	—		—		—		$18.57	(I)	|
Maximum Demand Summer	—		—		$5.75	(I)	$10.70	(I)	|
Maximum Demand Winter	—		—		$5.75	(I)	$10.70	(I)	|
Transmission Voltage									|
Maximum Peak Demand Summer	—		—		—		$18.57	(I)	|
Maximum Demand Summer	—		—		$2.23	(I)	$3.09	(I)	|
Maximum Demand Winter	—		—		$2.23	(I)	$3.09	(I)	|
Total Energy Rates ($ per kWh)									|
Peak Summer	$0.40610	(I)	$0.34136	(I)	$0.39871	(I)	$0.17760	(R)	|
Off-Peak Summer	$0.24016	(I)	$0.17543	(I)	$0.22586	(I)	$0.13816	(R)	|
Peak Winter	$0.22979	(I)	$0.18232	(I)	$0.22179	(I)	$0.14981	(R)	|
Off-Peak Winter	$0.20050	(I)	$0.15303	(I)	$0.19253	(I)	$0.12412	(R)	|
Demand Charge Rate Limiter ($/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	(N)	$1.00	(N)	$1.00	(N)	$1.00	(N)	|
PDP Credits									|
Demand ($ per kW)									|
Peak Summer	—		-		—		($3.99)	(N)	|
Energy ($ per kWh)									|
Peak Summer	($0.09209)	(N)	($0.09997)	(N)	($0.10572)	(N)	-		|

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

(Continued)

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	—		—		—		$12.00	(I)
Distribution:**								
Secondary Voltage								
Maximum Peak Demand Summer	—		—		—		$6.57	(I)
Maximum Demand Summer	$6.47	(I)	$11.70	(I)	$6.66	(I)	$11.95	(I)
Maximum Demand Winter	$6.47	(I)	$11.70	(I)	$6.66	(I)	$11.95	(I)
Primary								
Maximum Peak Demand Summer	—		—		—		$6.57	(I)
Maximum Demand Summer	—		—		$5.75	(I)	$10.70	(I)
Maximum Demand Winter	—		—		$5.75	(I)	$10.70	(I)
Transmission								
Maximum Peak Demand Summer	—		—		—		$6.57	(I)
Maximum Demand Summer	—		—		$2.23	(I)	$3.09	(I)
Maximum Demand Winter	—		—		$2.23	(I)	$3.09	(I)

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

(Continued)

ELECTRIC SCHEDULE AG
TIME-OF-USE AGRICULTURAL 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	$0.22392	(I)	$0.22392	(I)	$0.23936	(I)	$0.11254	(I)
Off-Peak Summer	$0.10424	(I)	$0.10424	(I)	$0.11629	(I)	$0.08306	(I)
Peak Winter	$0.10092	(I)	$0.10092	(I)	$0.11095	(I)	$0.09790	(I)
Off-Peak Winter	$0.07447	(I)	$0.07447	(I)	$0.08475	(I)	$0.07238	(I)
Distribution*:								
Peak Summer	$0.13495	(I)	$0.07021	(I)	$0.11281	(I)	$0.02052	(I)
Off-Peak Summer	$0.08869	(I)	$0.02396	(I)	$0.06303	(I)	$0.01056	(I)
Peak Winter	$0.08164	(I)	$0.03417	(I)	$0.06430	(I)	$0.00737	(I)
Off-Peak Winter	$0.07880	(I)	$0.03133	(I)	$0.06124	(I)	$0.00720	(I)
Transmission* (all usage)	$0.02302		$0.02302		$0.02302		$0.02302	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00011		$0.00011		$0.00011		$0.00011	
Public Purpose Programs (all usage)	$0.01657	(I)	$0.01657	(I)	$0.01588	(I)	$0.01388	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00003		$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00293		$0.00293		$0.00293		$0.00293	
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 Sheet 7
TIME-OF-USE AGRICULTURAL 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)

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)

ELECTRIC SCHEDULE AG Sheet 10
TIME-OF-USE AGRICULTURAL POWER

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)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03169	(I)
2010 Vintage	$0.03815	(I)
2011 Vintage	$0.03987	(I)
2012 Vintage	$0.04222	(I)
2013 Vintage	$0.04242	(I)
2014 Vintage	$0.04245	(I)
2015 Vintage	$0.04265	(I)
2016 Vintage	$0.04293	(I)
2017 Vintage	$0.04296	(I)
2018 Vintage	$0.04247	(I)
2019 Vintage	$0.03234	(I)
2020 Vintage	$0.02606	(I)
2021 Vintage	$0.02606	(I)

(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. WILDFIRE FUND CHARGE The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

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
TIME-OF-USE AGRICULTURAL POWER

17. PEAK DAY PRICING

a. **Default Provision**: The default of eligible customers to PDP will occur once per year with the start of their billing cycle 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 rate at least five (5) days before their proposed default date, their service will be defaulted to the PDP version of this rate schedule on their default date. (N)

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for default to PDP and to opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **Capacity Reservation Level**: Customers 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.

(N)

(Continued)

17. PEAK DAY PRICING (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 voice, text, or email notification messages of a PDP event from PG&E.

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

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

e. **PG&E website**. 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, phone call, email and/or text) for PDP customers. (N)

(Continued)

17. PEAK DAY PRICING (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. **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).

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)

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 that can be read remotely by PG&E, and to highly impacted agricultural customers, as specified in greater detail below. Schedule AG-1 is not available for solar legacy 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. (T)

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 Legacy TOU Eligibility Requirements. (T)

The new rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010 were available on a voluntary opt-in basis for qualifying customers from March 2020 through February 2021: (T)

(D)

(D)

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)

1.APPLICABILITY: (Cont'd.)

The provisions of Schedule SB—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 SB, in addition to all applicable Schedule AG-1 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule. (T) (T)

Time-of-Use Rates: Decision 10-02-032, as modified by Decision 11-11-008, makes TOU rates mandatory beginning March 1, 2013, for Agricultural customers that have at least twelve (12) billing months of hourly usage data available.

Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the transition of eligible AG-1 customers to mandatory TOU rates beginning March 1, 2019 until the 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 customer transitions to mandatory TOU rates.

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

Beginning March 2021, customers served under Schedule AG-1 will transition to the rate plans under Schedule AG with revised TOU periods on a mandatory basis or may elect service under optional Schedule AG-F or any other rate plan for which they are eligible.

Customers on AG-1A with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand less than 35 kW, will transition to AG-A1 under Schedule AG, or may elect to enroll in AG-A2 or AG-FA under Schedule AG-F.

Customers on AG-1A with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand of 35 kW or greater, for three consecutive months in the most recent twelve months, will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Customers on AG-1B, with an interval meter that have at least twelve (12) billing months hourly usage data available, will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Summarized below: (L)

Legacy Rate	Defaults to service under Schedule AG:	Or May Opt-In to
AG-1A < 35 kW	AG-A1	AG-A2, AG-FA
AG-1A >= 35 kW, AG-1B	AG-B	AG-C, AG-FB, AG-FC

(L)

(Continued)

1.APPLICABILITY: (Cont'd.) (L)
|
|
(L)

The transition of customers no longer eligible for AG-1 to Schedule AG with revised TOU periods will occur on the start of the customer's March 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 rate plan with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule AG.

Customers on Schedule AG-1 transitioning to the new rates with later TOU periods in March 2021 or each March thereafter will also be subject to default Peak Day Pricing (PDP) if over 200 kW, and opt-in PDP if below 200 kW. See Schedules AG and AG-F for the terms applicable to the PDP program. (N)

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 Legacy TOU Period" and the terms of (T) "Behind-the-Meter Solar Legacy TOU Period Eligibility Requirements" shall be (T) 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.

"Highly impacted" customers, defined as those agricultural customers with potential bill increases greater than 7 percent and $100 annually due to the transition, may remain on their legacy rate schedule for an additional year but must transition to the new rates with revised TOU periods in March 2022. Decision 19-05-010 delays the mandatory transition to rates with revised TOU periods for these "highly impacted" customers and clarifies that net energy metering (NEM) customers, direct access customers, and community choice aggregation customers and accounts beginning service on or after August 9, 2018 are not eligible for "highly impacted" subgroup exemptions from the mandatory TOU transition in March 2021. However, direct access and community choice (N) aggregation customers are also allowed to qualify as highly impacted customers pursuant to a modification granted by the CPUC Executive Director by letter dated November 16, 2020. Schedule AG-1 customers are evaluated on AG-4 to assess highly impacted determinations. (N)

Customers that do not have a meter that is capable of billing on the new Schedule AG on or after March 2021, 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 occur each March to transition all applicable remaining AG-1 customers to the rates with revised TOU periods as described above.

All AG-1A customers will remain on a connected load basis and will not covert to metered demand.

(Continued)

2. TERRITORY: Schedule AG-1 applies everywhere PG&E provides electricity service.

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

TOTAL RATES

	Rate A		Rate B	
Total Customer Charge Rates ($ per meter per day)	$0.57400		$0.76313	
Total Demand Rates ($ per kW)				
Connected Load Summer	$7.69	(R)	–	
Connected Load Winter	$5.76	(I)	–	
Maximum Demand Summer	–		$11.53	(R)
Maximum Demand Winter	–		$8.34	(I)
Primary Voltage Discount Summer	–		$1.02	(R)
Primary Voltage Discount Winter	–		$0.75	(I)
	–			
Total Energy Rates ($ per kWh)				
Summer	$0.24962	(R)	$0.19235	(R)
Winter	$0.20262	(R)	$0.14043	(R)

(Continued)

ELECTRIC SCHEDULE AG-1
AGRICULTURAL POWER

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

UNBUNDLING OF TOTAL RATES

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

Demand Rate by Components ($ per kW)	Rate A		Rate B	
Generation:				
Connected Load Summer	$1.93	(I)	–	
Connected Load Winter	$0.00		–	
Maximum Demand Summer	–		$3.19	(I)
Maximum Demand Winter	–		$0.00	
Primary Voltage Discount Summer	–		$0.00	(R)
Primary Voltage Discount Winter	–		$0.00	
Distribution:**				
Connected Load Summer	$5.76	(R)	–	
Connected Load Winter	$5.76	(I)	–	
Maximum Demand Summer	–		$8.34	(R)
Maximum Demand Winter	–		$8.34	(I)
Primary Voltage Discount Summer	–		$1.02	(I)
Primary Voltage Discount Winter	–		$0.75	(I)

Energy Rate by Components ($ per kWh)	Rate A		Rate B	
Generation				
Summer	$0.09112	(R)	$0.10038	(R)
Winter	$0.07810	(R)	$0.07284	(R)
Distribution**				
Summer	$0.11127	(R)	$0.04543	(R)
Winter	$0.07729	(R)	$0.02105	(R)
Transmission*	$0.02302		$0.02302	
Transmission Rate Adjustments*	($0.00248)	(R)	($0.00248)	(R)
Reliability Services*	$0.00011		$0.00011	
Public Purpose Programs	$0.01657	(I)	$0.01588	(I)
Nuclear Decommissioning	$0.00093		$0.00093	
Competition Transition Charges	$0.00003		$0.00003	
Energy Cost Recovery Amount	$0.00032		$0.00032	
Wildfire Fund Charge	$0.00580		$0.00580	
New System Generation Charge**	$0.00293		$0.00293	
California Climate Credit (all usage)***	$0.00000		$0.00000	

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* 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)

9. SEASONS: Summer season begins on May 1 and ends on October 31.

10. 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.

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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03169	(I)
2010 Vintage	$0.03815	(I)
2011 Vintage	$0.03987	(I)
2012 Vintage	$0.04222	(I)
2013 Vintage	$0.04242	(I)
2014 Vintage	$0.04245	(I)
2015 Vintage	$0.04265	(I)
2016 Vintage	$0.04293	(I)
2017 Vintage	$0.04296	(I)
2018 Vintage	$0.04247	(I)
2019 Vintage	$0.03234	(I)
2020 Vintage	$0.02606	(I)
2021 Vintage	$0.02606	(I)

(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 legacy customers, highly impacted agricultural customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 SB—Standby Service Special Conditions 1 through 6 shall (T) 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 SB, in addition (T) 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 2
TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

Depending upon the end-use of electricity and 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 the rates under Schedule AG-4: Rate A, B, C, D, E or F.

Rates A and D: 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. Rate D applies to customers who were on Rate D as of May 1, 2006 and are not billed via SmartMeter™. Rate A applies to all other customers.

Rates B, C, E, and F: 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. Rates E and F apply to customers who were on Rates E and F as of May 1, 2006 and are not billed via SmartMeter™. Rates B and C apply to all other customers.

Rates B and C will apply to those customers whose maximum demand is 200 kW or greater for three consecutive months and select this schedule upon the initial installation of the interval data meter, unless the customer was on Rate E or F as of May 1, 2006 and is not billed via SmartMeter™.

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 Legacy TOU Eligibility Requirements. (T)

(Continued)

1. APPLICABILITY: (Cont'd.)

The new rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010 were available on a voluntary opt-in basis for qualifying customers (T) from March 2020 through February 2021. (T)

(D)

(D)

Beginning March 2021, customers served under Schedule AG-4 will transition to the rate plans under Schedule AG with revised TOU periods on a mandatory basis or may elect service under optional Schedule AG-F or any other rate plan for which they are eligible.

Customers on AG-4A or AG-4D, with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand less than 35 kW, will transition to rate AG-A1 under Schedule AG, or may elect to enroll in AG-A2 or AG-FA under Schedule AG-F.

Customers on AG-4A or AG-4D, with a maximum demand of 35 kW or greater, for three consecutive months in the most recent twelve months, or on AG-4B, AG-4C, AG-4E or AG-4F will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Summarized below:

Legacy Rate	Defaults to service under Schedule AG:	Or May Opt-In to
AG-4A/D < 35 kW	AG-A1	AG-A2, AG-FA
AG-4A/D >= 35 kW	AG-B	AG-C, AG-FB, AG-FC
AG-4B/E, AG-4C/F	AG-B	AG-C, AG-FB, AG-FC

(Continued)

1. APPLICABILITY: (Cont'd.)

The transition of customers no longer eligible for AG-4 to Schedule AG with revised TOU periods will occur on the start of the customer's March 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 rate plan with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule AG.

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.

"Highly impacted" customers, defined as those agricultural customers with potential bill increases greater than 7 percent and $100 annually due to the transition, may remain on their legacy rate schedule for an additional year but must transition to the new rates with revised TOU periods in March 2022. Decision 19-05-010 delays the mandatory transition to rates with revised TOU periods for these "highly impacted" customers and clarifies that net energy metering (NEM) customers, direct access customers, and community choice aggregation customers and accounts beginning service on or after August 9, 2018 are not eligible for "highly impacted" subgroup exemptions from the mandatory TOU transition in March 2021. However, direct access and community choice aggregation customers are also allowed to qualify as highly impacted customers pursuant to a modification granted by the CPUC Executive Director by letter dated November 16, 2020. (T)

Customers that do not have a meter that is capable of billing on the new Schedule AG on or after March 2021, 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 occur each March to transition all applicable remaining AG-4 customers to the rates with revised TOU periods as described above.

All AG-4Aand AG-4D customers will convert from connected load demand to metered demand in March 2022 for customers with meters having that capability.

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.

(Continued)

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.

(D)

. (D)

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

(D)
(D)

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

(Continued)

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

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 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	$6.98	(R)	–		–	
Connected Load Winter	$5.46	(I)	–		–	
Maximum Demand Summer	–		$10.63	(R)	$7.44	(I)
Maximum Demand Winter	–		$7.89	(I)	$7.44	(I)
Maximum Peak Demand Summer	–		$4.26	(R)	$9.01	(R)
Maximum Part-Peak Demand Summer	–		–		$3.72	(I)
Maximum Part-Peak Demand Winter	–		–		$1.08	(I)
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–		$1.13	(R)	$0.94	(R)
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–		$0.49	(I)	$0.32	(R)
Transmission Voltage Discount						
Maximum Peak Demand Summer	–		–		$4.38	(R)
Maximum Part-Peak Demand Summer	–		–		$0.97	(R)
Maximum Demand Summer	–		–		$5.58	(I)
Maximum Part-Peak Demand Winter	–		–		$1.08	(I)
Maximum Demand Winter	–		–		$5.58	(I)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.37508	(R)	$0.25949	(R)	$0.20589	(R)
Part-Peak Summer	–		–		$0.15126	(R)
Off-Peak Summer	$0.25019	(I)	$0.19246	(I)	$0.13216	(R)
Part-Peak Winter	$0.21410	(R)	$0.18102	(I)	$0.14067	(R)
Off-Peak Winter	$0.21338	(I)	$0.18033	(I)	$0.13996	(I)

(D)
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(D)

(Continued)

ELECTRIC SCHEDULE AG-4 Sheet 7
TIME-OF-USE AGRICULTURAL POWER

3. RATES: (Cont'd.): Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below. (T)/(L)

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 Rates by Component ($ per kW)	Rate A,D		Rate B,E		Rate C,F	
Generation:						
Connected Load Summer	$1.52	(I)	–		–	
Connected Load Winter	$0.00		–		–	
Maximum Demand Summer	–		$2.74	(I)	$0.00	
Maximum Demand Winter	–		$0.00		$0.00	
Maximum Peak Demand Summer			$1.46	(R)	$4.60	(R)
Maximum Part-Peak Demand Summer			–		$2.75	(I)
Maximum Part-Peak Demand Winter	–		–		$0.00	
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–		$0.68	(I)	$0.56	(R)
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–		$0.00		$0.00	
Transmission Voltage Discount						
Maximum Peak Demand Summer	–		–		$1.03	(R)
Maximum Part-Peak Demand Summer	–		–		$0.00	(I)
Maximum Demand Summer	–		–		$0.00	
Maximum Part-Peak Demand Winter	–		–		$0.00	
Maximum Demand Winter	–		–		$0.00	
Distribution:**						
Connected Load Summer	$5.46	(R)	–		–	
Connected Load Winter	$5.46	(I)	–		–	
Maximum Demand Summer	–		$7.89	(R)	$7.44	(I)
Maximum Demand Winter	–		$7.89	(I)	$7.44	(I)
Maximum Peak Demand Summer	–		$2.80	(R)	$4.41	(R)
Maximum Part-Peak Demand Summer	–		–		$0.97	(R)
Maximum Part-Peak Demand Winter	–		–		$1.08	(I)
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–		$0.45	(R)	$0.38	(R)
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–		$0.49	(I)	$0.32	(R)
Transmission Voltage Discount						
Maximum Peak Demand Summer	–		–		$3.35	(R)
Maximum Part-Peak Demand Summer	–		–		$0.97	(R)
Maximum Demand Summer	–		–		$5.58	(I)
Maximum Part-Peak Demand Winter	–		–		$1.08	(I)
Maximum Demand Winter	–		–		$5.58	(I)

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

(Continued)

ELECTRIC SCHEDULE AG-4 Sheet 8
TIME-OF-USE AGRICULTURAL POWER

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

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Rates by Component ($ per kWh)	Rate A,D		Rate B,E		Rate C,F		
Generation:							|
Peak Summer	$0.12941	(R)	$0.11361	(R)	$0.10484	(R)	|
Part-Peak Summer	–		–		$0.07462	(R)	|
Off-Peak Summer	$0.08426	(I)	$0.08807	(I)	$0.06363	(R)	|
Part-Peak Winter	$0.07641	(R)	$0.08409	(I)	$0.06972	(R)	|
Off-Peak Winter	$0.07570	(I)	$0.08340	(I)	$0.06901	(I)	|
Distribution:**							|
Peak Summer	$0.19844	(R)	$0.09934	(R)	$0.05451	(R)	|
Part-Peak Summer	–		–		$0.03010	(R)	|
Off-Peak Summer	$0.11870	(I)	$0.05785	(I)	$0.02199	(I)	|
Part-Peak Winter	$0.09046	(R)	$0.05039	(R)	$0.02441	(R)	|
Off-Peak Winter	$0.09045	(I)	$0.05039	(I)	$0.02441	(I)	|
Transmission* (all usage)	$0.02302		$0.02302		$0.02302		|
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)	|
Reliability Services* (all usage)	$0.00011		$0.00011		$0.00011		|
Public Purpose Programs (all usage)	$0.01657	(I)	$0.01588	(I)	$0.01588	(I)	|
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093		|
Competition Transition Charges (all usage)	$0.00003		$0.00003		$0.00003		|
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032		|
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580		|
New System Generation Charge (all usage)**	$0.00293		$0.00293		$0.00293		|
California Climate Credit (all usage)* **	$0.00000		$0.00000		$0.00000		(L)

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

(Continued)

4. METERING REQUIREMENTS:

PG&E will install a time-of-use meter that is appropriate for this schedule that measures and registers the amount of electricity a customer uses. (L)

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

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

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

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

(Continued)

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

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

SUMMER: Service from May 1 through October 31.

For Rates A, B, D, and E

Peak:	12:00 noon to 6:00 p.m.	Monday through Friday*
Off-Peak:	All other hours	Monday through Friday
	All day	Saturday, Sunday, Holidays

For Rates C and F

Peak:	12:00 noon to 6:00 p.m.	Monday through Friday*
Partial-Peak:	8:30 a.m. to 12:00 p.m.	Monday through Friday*
	6:00 p.m. to 9:30 p.m.	Monday through Friday*
Off-Peak:	9:30 p.m. to 8:30 a.m.	Monday through Friday
	All day	Saturday, Sunday, Holidays

WINTER: Service from November 1 through April 30.

For Rates A, B, C, D, E, and F

Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday*
Off-Peak:	All other hours	Monday through Friday
	All day	Saturday, Sunday, Holidays

“Holidays” for the purpose 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.

*Except holidays.

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.

6. ENERGY CHARGE CALCULATION: When summer and winter proration is required, charges will be based on the average daily use for the full billing period times the number of days in each period. (L)

(Continued)

7. SERVICE CONTRACT: Service under Schedule AG-4 is provided for a minimum of 12 months beginning with the date service commences. The customer may be required to sign a service contract with a minimum term of one year. After the initial one-year term has expired, the contract will continue in effect until it is cancelled by the customer or PG&E. (L)

   Where a line extension is required, it will be installed under the provisions of Rules 15 and 16.

8. CONNECTED LOAD (Rates A and D only): Connected load is defined as the sum of the rated capacities (as determined in accordance with Rule 2) of all equipment that is served through one metering point and that may be operated at the same time. When charges are based on connected load, in no case will charges be based on less than two horsepower/kilowatts for single-phase service, nor less than three horsepower/kilowatts for three-phase service.

   The customer's account will be adjusted for permanent connected-load changes that take place during the contract year. It is the customer's responsibility to notify PG&E of such changes. No adjustment will be made for a temporary reduction in connected load. If the load is reconnected within 12 months of being disconnected, the charges will be recalculated and applied retroactively as though no reduction in load had taken place.

9. MAXIMUM DEMAND (Rates B, C, E, and F Only): 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 for Rates B, C, E and F 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. (L)

(Continued)

ELECTRIC SCHEDULE AG-4 Sheet 12
TIME-OF-USE AGRICULTURAL POWER

9. MAXIMUM DEMAND (Rates B, C, E, and F Only): (Cont'd.)

In billing periods with use in both the summer season and winter season (April/May, October/November), the customer's 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 the customer's demand charge for each season of the billing period will be: (1) the maximum demand created in each season's portion of the billing month as measured by a meter with such capability; or (2) the maximum demand for the billing month where the installed meter is incapable of measuring time-varying demands. (L)

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).

10. MAXIMUM-PEAK-PERIOD DEMAND (Rates B, C, E and F Only):

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.

11. MAXIMUM-PART-PEAK-PERIOD DEMAND (Rates C and F Only):

The customer's maximum-part-peak-period demand will be the highest of all the 15-minute averages for the part-peak period during the billing month. (L)

(Continued)

ELECTRIC SCHEDULE AG-4 Sheet 13
TIME-OF-USE AGRICULTURAL POWER

12. DEFINITION OF SERVICE VOLTAGE: The following defines the three voltage classes of Schedule AG-4 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.

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 not taking service at the new voltage (and making whatever changes in their system 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.

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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03169	(I)
2010 Vintage	$0.03815	(I)
2011 Vintage	$0.03987	(I)
2012 Vintage	$0.04222	(I)
2013 Vintage	$0.04242	(I)
2014 Vintage	$0.04245	(I)
2015 Vintage	$0.04265	(I)
2016 Vintage	$0.04293	(I)
2017 Vintage	$0.04296	(I)
2018 Vintage	$0.04247	(I)
2019 Vintage	$0.03234	(I)
2020 Vintage	$0.02606	(I)
2021 Vintage	$0.02606	(I)

(L)

(Continued)

14. STANDBY APPLICABILITY: (L)

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

DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use 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. WILDFIRE FUND CHARGE:

The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082 (L)

(D)

(D)

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 legacy customers, highly impacted agricultural customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 Time-of-use (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 SB—Standby Service Special Conditions 1 through 6 shall (T) 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 SB, in addition (T) to all applicable Schedule AG-5 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

ELECTRIC SCHEDULE AG-5 Sheet 2
LARGE TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

Depending upon the end-use of electricity and 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 the rates under Schedule AG-5: Rate A, B, C, D, E or F.

Rates A and D: 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. Rate D applies to customers who were on Rate D as of May 1, 2006 and are not billed via SmartMeter™. Rate A applies to all other customers.

Rates B, C, E, and F: 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. Rates E and F apply to customers who were on Rates E and F as of May 1, 2006 and are not billed via SmartMeter™. Rates B and C apply to all other customers.

Rates B and C will apply to customers whose maximum demand is 200 kW or greater for three consecutive months and select this schedule upon the initial installation of the interval data meter, unless the customer was on Rate E or F as of May 1, 2006 and is not billed via SmartMeter™.

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 Legacy TOU Eligibility Requirements. (T)

(Continued)

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

1. APPLICABILITY: (Cont'd.)

The new rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010 were available on a voluntary opt-in basis for qualifying customers from March 2020 through February 2021: (T) (T)

(D)

(D)

Beginning March 2021, customers served under Schedule AG-5 will transition to the rate plans under Schedule AG with revised TOU periods on a mandatory basis or may elect service under optional Schedule AG-F or any other rate plan for which they are eligible.

Customers on AG-5A or AG-5D, with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand less than 35 kW, will transition to rate AG-A2 under Schedule AG, or may elect to enroll in AG-A1 or AG-FA under Schedule AG-F.

Customers on AG-5A or AG-5D, with a maximum demand of 35 kW or greater, for three consecutive months in the most recent twelve months, will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Customers on AG-5B, AG-5C, AG-5E or AG-5F will transition to AG-C under Schedule AG, or may elect to enroll in AG-B, or AG-FB or AG-FC under Schedule AG-F.

Summarized below:

Legacy Rate	Defaults to service under Schedule AG:	Or May Opt-In to
AG-5A/D < 35 kW	AG-A2	AG-A1, AG-FA
AG-5A/D >= 35 kW	AG-B	AG-C, AG-FB, AG-FC
AG-5B/E, AG-5C/F	AG-C	AG-B, AG-FB, AG-FC

(Continued)

1. APPLICABILITY: (Cont'd.)

The mandatory transition of customers no longer eligible for AG-5 to Schedule AG with revised TOU periods will occur on the start of the customer's March 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 rate plan with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule AG. (T)

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 Legacy TOU Period" and the terms of "Behind-the-Meter Solar Legacy TOU Period 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. (T) (T)

"Highly impacted" customers, defined as those agricultural customers with potential bill increases greater than 7 percent and $100 annually due to the transition, may remain on their legacy rate schedule for an additional year but must transition to the new rates with revised TOU periods in March 2022. Decision 19-05-010 delays the mandatory transition to rates with revised TOU periods for these "highly impacted" customers and clarifies that net energy metering (NEM) customers , direct access customers, and community choice aggregation customers and accounts beginning service on or after August 9, 2018 are not eligible for "highly impacted" subgroup exemptions from the mandatory TOU transition in March 2021. However, direct access and community choice aggregation customers are also allowed to qualify as highly impacted customers pursuant to a modification granted by the CPUC Executive Director by letter dated November 16, 2020. (N) | | (N)

Customers that do not have a meter that is capable of billing on the new Schedule AG on or after March 2021, 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 occur each March to transition all applicable remaining AG-5 customers to the rates with revised TOU periods as described above.

All AG-5A and AG-5D customers will convert from connected load demand to metered demand in March 2022 for customers with meters having that capability.

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.

Transfers Off of Schedule AG-5: 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.

(Continued)

ELECTRIC SCHEDULE AG-5 Sheet 5
LARGE 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 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.

(D)

(D)

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

(D)

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

(Continued)

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

3. RATES: (D)

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	$11.33	(R)	–		–	
Connected Load Winter	$7.15	(I)	–		–	
Maximum Demand Summer	–		$14.97	(R)	$5.93	(R)
Maximum Demand Winter	–		$9.76	(I)	$5.93	(I)
Maximum Peak Demand Summer	–		$8.86	(R)	$13.96	(R)
Maximum Part-Peak Demand Summer	–		–		$7.61	(I)
Maximum Part-Peak Demand Winter	–		–		$1.40	(I)
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–		$1.99	(I)	$1.78	(R)
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–		$0.33	(I)	$0.52	(I)
Transmission Voltage Discount						
Maximum Peak Demand Summer	–		–		$7.39	(R)
Maximum Part-Peak Demand Summer	–		–		$1.73	(R)
Maximum Demand Summer	–		$7.40	(R)	$5.70	(I)
Maximum Part-Peak Demand Winter	–		–		$0.00	(R)
Maximum Demand Winter	–		$4.55	(R)	$5.70	(I)

(Continued)

3. RATES:
(Cont'd.)

TOTAL RATES (Cont'd.)

Total Energy Rates ($ per kWh)	Rate A, D		Rate B, E		Rate C, F	
Peak Summer	$0.26884	(R)	$0.19409	(R)	$0.14751	(R)
Part-Peak Summer	–		–		$0.12221	(R)
Off-Peak Summer	$0.19390	(I)	$0.13509	(I)	$0.11279	(I)
Part-Peak Winter	$0.17584	(R)	$0.13831	(I)	$0.12713	(I)
Off-Peak Winter	$0.17513	(I)	$0.13763	(I)	$0.12642	(I)

(D)
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(D)

(Continued)

ELECTRIC SCHEDULE AG-5 Sheet 8
LARGE TIME-OF-USE AGRICULTURAL POWER

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

UNBUNDLING OF TOTAL RATES

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

Demand Rates by Component ($ per kW)	Rate A,D		Rate B,E		Rate C,F	
Generation:						
Connected Load Summer	$4.18	(I)	–		–	
Connected Load Winter	$0.00		–		–	
Maximum Demand Summer	–		$5.21	(I)	$0.00	
Maximum Demand Winter	–		$0.00		$0.00	
Maximum Peak Demand Summer	–		$3.27	(R)	$8.84	(R)
Maximum Part-Peak Demand Summer	–		–		$5.88	(I)
Maximum Part-Peak Demand Winter	–		–		$0.00	
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–		$1.64	(I)	$1.22	(R)
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–		$0.00		$0.00	
Transmission Voltage Discount						
Maximum Peak Demand Summer	–		–		$2.27	(R)
Maximum Part-Peak Demand Summer	–		–		$0.00	
Maximum Demand Summer	–		$2.85	(I)	$0.00	
Maximum Part-Peak Demand Winter	–		–		$0.00	
Maximum Demand Winter	–		$0.00		$0.00	

(Continued)

3.RATES:
(Cont'd.)

UNBUNDLING OF TOTAL RATES (Cont'd.)

Demand Rates by Component ($ per kW) (Cont'd)	Rate A,D		Rate B,E		Rate C,F	
Distribution:**						
Connected Load Summer	$7.15	(R)	–		–	
Connected Load Winter	$7.15	(I)	–		–	
Maximum Demand Summer	–		$9.76	(R)	$5.93	(R)
Maximum Demand Winter	–		$9.76	(I)	$5.93	(I)
Maximum Peak Demand Summer	–		$5.59	(I)	$5.12	(R)
Maximum Part-Peak Demand Summer	–		–		$1.73	(R)
Maximum Part-Peak Demand Winter	–		–		$1.40	(I)
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–		$0.35	(R)	$0.56	(I)
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–		$0.33	(I)	$0.52	(I)
Transmission Voltage Discount						
Maximum Peak Demand Summer	–		–		$5.12	(R)
Maximum Part-Peak Demand Summer	–		–		$1.73	(R)
Maximum Demand Summer	–		$4.55	(R)	$5.70	(I)
Maximum Part-Peak Demand Winter	–		–		$0.00	(R)
Maximum Demand Winter	–		$4.55	(R)	$5.70	(I)

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

(Continued)

ELECTRIC SCHEDULE AG-5 Sheet 10
LARGE TIME-OF-USE AGRICULTURAL POWER

3. RATES:
(Cont'd.):

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Rates by Component ($ per kWh)	Rate A,D		Rate B,E		Rate C,F	
Generation:						
Peak Summer	$0.12589	(R)	$0.12003	(R)	$0.09457	(R)
Part-Peak Summer	–		–		$0.06927	(R)
Off-Peak Summer	$0.08829	(I)	$0.07182	(I)	$0.05985	(I)
Part-Peak Winter	$0.08262	(R)	$0.07641	(R)	$0.06898	(I)
Off-Peak Winter	$0.08191	(I)	$0.07573	(I)	$0.06827	(I)
Distribution:**						
Peak Summer	$0.09572	(R)	$0.02952	(I)	$0.00840	(I)
Part-Peak Summer	–		–		$0.00840	(I)
Off-Peak Summer	$0.05838	(I)	$0.01873	(I)	$0.00840	(I)
Part-Peak Winter	$0.04599	(R)	$0.01736	(I)	$0.01361	(I)
Off-Peak Winter	$0.04599	(I)	$0.01736	(I)	$0.01361	(I)
Transmission* (all usage)	$0.02302		$0.02302		$0.02302	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00011		$0.00011		$0.00011	
Public Purpose Programs (all usage)	$0.01657	(I)	$0.01388	(I)	$0.01388	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00293		$0.00293		$0.00293	
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.

(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.

	DA /CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03169	(I)
2010 Vintage	$0.03815	(I)
2011 Vintage	$0.03987	(I)
2012 Vintage	$0.04222	(I)
2013 Vintage	$0.04242	(I)
2014 Vintage	$0.04245	(I)
2015 Vintage	$0.04265	(I)
2016 Vintage	$0.04293	(I)
2017 Vintage	$0.04296	(I)
2018 Vintage	$0.04247	(I)
2019 Vintage	$0.03234	(I)
2020 Vintage	$0.02606	(I)
2021 Vintage	$0.02606	(I)

(Continued)

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

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:

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.

(D)

(D)

ELECTRIC SCHEDULE AG-F Sheet 2
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

1.APPLICABILITY: (Cont'd)

The provisions of Schedule SB—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 SB, in addition to all applicable Schedule AG-F charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Agricultural customers applying for service under the optional rate Schedule AG-F will be served under one of the rate plans as set forth below:

Rate FA: Applies to single-motor installations rated less than 35 kilowatts (kW)and to all multi-load installations aggregating less than 35 kW.

Rates FB and FC: Applies to single-motor installations rated 35 kW or more, to multi-load installations aggregating 35 kW or more.

Generally, AG-FB is designed for lower load factor customers with fewer operating hours and contains lower demand charges and higher energy charges than AG-FC. By contrast, AG-FC is generally designed for higher load factor customers with more operating hours and has higher demand charges and lower energy charges than AG-FB.

Decision 18-08-013 adopted new TOU periods and seasonal definitions for all non-residential customer classes. Agricultural rate 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 rate options with new TOU periods, 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 of certain qualifying agricultural customers until March 2022. 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 Legacy TOU Eligibility (T) Requirements.

The rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010, including rates FA, FB, and FC under this Schedule AG-F were (T) available to qualifying customers on a voluntary opt-in basis from March 2020 | through February 2021. Customers eligible for this rate schedule must have an (T) interval data meter that can be read remotely by PG&E.

Any agricultural customers establishing service on or after March 1, 2020 with an interval meter that can be read remotely by PG&E already in place will be charged the Schedule AG or Schedule AG-F rates with revised TOU periods and are not eligible for legacy agricultural rates.

(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).

(L)

(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. (N)

A customer exceeding 200 kW as described above is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

PDP rate options are not available to customers under this Schedule. However, all PDP default eligibility criteria also apply to Schedule AG-F. Customers taking service on Schedule AG-F who are eligible for default to PDP or 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 default or voluntarily opt-in and enroll in the PDP programrules, in order to default or voluntarily opt-in and enroll in the PDP program (N)

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

(Continued)

ELECTRIC SCHEDULE AG-F Sheet 5
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

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)

TOTAL RATES

Total Customer/Meter Charge Rates	**Rate A**		**Rate B**		**Rate C**	
Customer Charge ($ per meter per day)	$0.68895		$0.91565		$1.43343	
Total Demand Rates ($ per kW)						
Secondary Voltage						
Maximum Peak Demand Summer	—		—		$18.57	(I)
Maximum Demand Summer	$6.47	(I)	$6.66	(I)	$11.95	(I)
Maximum Demand Winter	$6.47	(I)	$6.66	(I)	$11.95	(I)
Primary Voltage						
Maximum Peak Demand Summer	—		—		$18.57	(I)
Maximum Demand Summer	—		$5.75	(I)	$10.70	(I)
Maximum Demand Winter	—		$5.75	(I)	$10.70	(I)
Transmission Voltage						
Maximum Peak Demand Summer	—		—		$18.57	(I)
Maximum Demand Summer	—		$2.23	(I)	$3.09	(I)
Maximum Demand Winter	—		$2.23	(I)	$3.09	(I)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.44633	(I)	$0.42119	(I)	$0.20190	(R)
Off-Peak Summer	$0.24272	(I)	$0.23036	(I)	$0.15717	(R)
Peak Winter	$0.27723	(I)	$0.25825	(I)	$0.17087	(R)
Off-Peak Winter	$0.19681	(I)	$0.18992	(I)	$0.14292	(R)

(L)

—

(Continued)

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

UNBUNDLING OF TOTAL RATES

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

Demand Charge by Component ($/kW)	**Rate A**		**Rate B**		**Rate C**	
Generation:						
Maximum Peak Demand Summer	—		—		$12.00	(I)
Distribution:**						
Secondary Voltage						
Maximum Peak Demand Summer	—		—		$6.57	(I)
Maximum Demand Summer	$6.47	(I)	$6.66	(I)	$11.95	(I)
Maximum Demand Winter	$6.47	(I)	$6.66	(I)	$11.95	(I)
Primary Voltage						
Maximum Peak Demand Summer	—		—		$6.57	(I)
Maximum Demand Summer	—		$5.75	(I)	$10.70	(I)
Maximum Demand Winter	—		$5.75	(I)	$10.70	(I)
Transmission Voltage						
Maximum Peak Demand Summer	—		—		$6.57	(I)
Maximum Demand Summer	—		$2.23	(I)	$3.09	(I)
Maximum Demand Winter	—		$2.23	(I)	$3.09	(I)

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

(Continued)

ELECTRIC SCHEDULE AG-F Sheet 7
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

3. RATES: (Cont'd.) **UNBUNDLING OF TOTAL RATES** (Cont'd) (L)

Energy Rate by Components ($ per kWh)	**Rate A**		**Rate B**		**Rate C**	
Generation:						
Peak Summer	$0.18944	(I)	$0.20647	(I)	$0.12714	(I)
Off-Peak Summer	$0.11230	(I)	$0.12516	(I)	$0.09713	(I)
Peak Winter	$0.10210	(I)	$0.11310	(I)	$0.11272	(I)
Off-Peak Winter	$0.07565	(I)	$0.08665	(I)	$0.08627	(I)
Distribution**:						
Peak Summer	$0.20966	(I)	$0.16818	(I)	$0.03022	(I)
Off-Peak Summer	$0.08319	(I)	$0.05866	(I)	$0.01550	(I)
Peak Winter	$0.12790	(I)	$0.09861	(I)	$0.01361	(I)
Off-Peak Winter	$0.07393	(I)	$0.05673	(I)	$0.01211	(I)
Transmission* (all usage)	$0.02302		$0.02302		$0.02302	
Reliability Services* (all usage)	$0.00011		$0.00011		$0.00011	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01657	(I)	$0.01588	(I)	$0.01388	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00293		$0.00293		$0.00293	
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 AG-F Sheet 8
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

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)

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 A, B, and C on Schedule AG-F:

Peak:

Option I 5:00 p.m. to 8:00 p.m.
Option II 5:00 p.m. to 8:00 p.m.
Option III 5:00 p.m. to 8:00 p.m.

The above peak hours apply every day of the year, including weekends and holidays, except for the special off-peak days by Group as follows:

Off-Peak * All other hours All 365 days of the year

Option I * Wednesday and Thursday,
Option II * Saturday and Sunday,
Option III * Monday and Friday.

The above off-peak hours by Group shall begin at midnight on the designated day and shall continue until midnight 24 hours later. However, peak hours do not begin until 5:00 p.m. on the five days of the week on which the peak hours apply.

WINTER: Service from October 1 through May 31.

Peak: Same as shown above for the summer period

Off-Peak: Same as shown above for the summer period

* Providing space is available, you may have the option of choosing the applicable Group and days for off-peak hours as set forth above and under the terms provided in the Applicability clause. (L)

(Continued)

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-F is provided for a minimum of 12 months beginning with the date your service commences. You may be required to sign a service contract with a minimum term of one year. After your initial one-year term has expired, your contract will continue in effect until it is cancelled by you or PG&E.

9. 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 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), the customer's 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 the customer's demand charge for each season of the billing period will be: (1) the maximum demand created in each season's portion of the billing month as measured by a meter with such capability; or (2) the maximum demand for the billing month where the installed meter is incapable of measuring time-varying demands.

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 (Rates B and E Only): 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. DEFINITION OF SERVICE VOLTAGE: The following defines the three voltage classes of Schedule AG-F rates. Standard Service Voltages are listed in Rule 2, Section B.1.

a. <u>Secondary</u>: 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. <u>Primary</u>: 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. <u>Transmission</u>: This is the voltage class if the customer is served <u>without transformation</u> 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. (L)

(Continued)

ELECTRIC SCHEDULE AG-F Sheet 11
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

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

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

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, New System Generation Charges, 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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03169	(I)
2010 Vintage	$0.03815	(I)
2011 Vintage	$0.03987	(I)
2012 Vintage	$0.04222	(I)
2013 Vintage	$0.04242	(I)
2014 Vintage	$0.04245	(I)
2015 Vintage	$0.04265	(I)
2016 Vintage	$0.04293	(I)
2017 Vintage	$0.04296	(I)
2018 Vintage	$0.04247	(I)
2019 Vintage	$0.03234	(I)
2020 Vintage	$0.02606	(I)
2021 Vintage	$0.02606	(I)

(L)

(Continued)

ELECTRIC SCHEDULE AG-F Sheet 12
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

13. 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.

14. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082. (L)

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’.

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-R is available only to qualifying solar legacy customers, highly impacted agricultural customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 SB—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 SB, in addition to all applicable Schedule AG-R charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule. (T)

(Continued)

ELECTRIC SCHEDULE AG-R Sheet 2
SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

Depending upon the end-use of electricity and 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 the rates under Schedule AG-R: Rate A, B, D or E.

Rates A and D: 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. Rate D applies to customers who were on Rate D as of May 1, 2006 and are not billed via SmartMeter™. Rate A applies to all other customers.

Rates B and E: 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. Rate E applies to customers who were on Rate E as of May 1, 2006 and are not billed via SmartMeter™. Rate B applies to all other customers.

Rate B will apply to those customers whose maximum demand is 200 kW or greater for three consecutive months and select this schedule upon the initial installation of the interval data meter, unless the customer was on Rate E as of May 1, 2006 and is not billed via SmartMeter™.

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 Legacy TOU Eligibility Requirements. (T)

The new rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010 were available on a voluntary opt-in basis for (T)
qualifying customers from March 2020 through February 2021. (T)
(D)

(Continued)

ELECTRIC SCHEDULE AG-R Sheet 3
SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (D)
(Cont'd.)

(D)

Beginning March 2021, customers served under Schedule AG-R will transition to the rate plans under Schedule AG with revised TOU periods on a mandatory basis or may elect service under optional Schedule AG-F or any other rate plan for which they are eligible.

Customers on AG-RA or AG-RD, with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand less than 35 kW, will transition to rate AG-A1 under Schedule AG, or may elect to enroll in AG-A2 or AG-FA under Schedule AG-F.

Customers on AG-RA or AG-RD, with a maximum demand of 35 kW or greater, for three consecutive months in the most recent twelve months, or on AG-RB or AG-RE will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Summarized below:

Legacy Rate	Defaults to service under Schedule AG:	Or May Opt-In to
AG-RA/D < 35 kW	AG-A1	AG-A2, AG-FA
AG-RA/D >= 35 kW	AG-B	AG-C, AG-FB, AG-FC
AG-RB/E	AG-B	AG-C, AG-FB, AG-FC

The transition of customers no longer eligible for AG-R to Schedule AG with revised TOU periods will occur on the start of the customer's March 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 rate plan with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule AG.

(Continued)

ELECTRIC SCHEDULE AG-R Sheet 4
SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

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 Legacy TOU Period" and the terms of "Behind-the-Meter Solar Legacy TOU Period 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. (T) (T)

"Highly impacted" customers, defined as those agricultural customers with potential bill increases greater than 7 percent and $100 annually due to the transition, may remain on their legacy rate schedule for an additional year but must transition to the new rates with revised TOU periods in March 2022. Decision 19-05-010 delays the mandatory transition to rates with revised TOU periods for these "highly impacted" customers and clarifies that net energy metering (NEM) customers, direct access customers, and community choice aggregation customers and accounts beginning service on or after August 9, 2018 are not eligible for "highly impacted" subgroup exemptions from the mandatory TOU transition in March 2021. However, direct access and community choice aggregation customers are also allowed to qualify as highly impacted customers pursuant to a modification granted by the CPUC Executive Director by letter dated November 16, 2020. (N) I I (N)

Customers that do not have a meter that is capable of billing on the new Schedule AG on or after March 2021, 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 occur each March to transition all applicable remaining AG-R customers to the rates with revised TOU periods as described above.

All AG-RA and AG-RD customers will convert from connected load demand to metered demand in March 2022 for customers with meters having that capability.

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.

Transfers Off of Schedule AG-R: 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.

(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.

(D)
|
(D)

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)

(D)
|
. (D)

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

(Continued)

ELECTRIC SCHEDULE AG-R Sheet 6
SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

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 A,D		Rate B,E	
Customer Charge ($ per meter per day)	$0.57400		$0.76313	
TOU Meter Charge ($ per meter per day) (for rate A & B)	$0.22341		$0.19713	
TOU Meter Charge ($ per meter per day) (for rate D & E)	$0.06571		$0.03943	
Total Demand Rates ($ per kW)				
Connected Load Summer	$6.51	(R)	–	
Connected Load Winter	$5.05	(I)	–	
Maximum Peak Demand Summer	–		$4.17	(R)
Maximum Demand Summer	–		$10.15	(R)
Maximum Demand Winter	–		$7.97	(I)
Primary Voltage Discount Summer	–		$0.39	(R)
Primary Voltage Discount Winter	–		$0.44	(I)
Total Energy Rates ($ per kWh)				
Peak Summer	$0.39536	(R)	$0.35480	(R)
Off-Peak Summer	$0.22428	(I)	$0.20476	(I)
Part-Peak Winter	$0.19051	(R)	$0.18323	(R)
Off-Peak Winter	$0.18980	(I)	$0.18252	(I)

(Continued)

3. RATES: (Cont'd.)

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

UNBUNDLING OF TOTAL RATES

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

Demand by Components ($ per kW)	Rate A,D		Rate B,E	
Generation:				
Connected Load Summer	$1.46		–	
Connected Load Winter	$0.00		–	
Maximum Peak Demand Summer	–		$1.23	(R)
Maximum Demand Summer	–		$2.18	(I)
Maximum Demand Winter	–		$0.00	
Primary Voltage Discount Summer	–		$0.00	(R)
Primary Voltage Discount Winter	–		$0.00	
Distribution:**				
Connected Load Summer	$5.05	(R)	–	
Connected Load Winter	$5.05	(I)	–	
Maximum Peak Demand Summer	–		$2.94	(I)
Maximum Demand Summer	–		$7.97	(R)
Maximum Demand Winter	–		$7.97	(I)
Primary Voltage Discount Summer	–		$0.39	(R)
Primary Voltage Discount Winter	–		$0.44	(I)

Energy Rate by Components ($ per kWh)	Rate A,D		Rate B,E	
Generation:				
Peak Summer	$0.18439	(R)	$0.16744	(R)
Off-Peak Summer	$0.08438	(I)	$0.08014	(I)
Part-Peak Winter	$0.07493	(R)	$0.07541	(I)
Off-Peak Winter	$0.07422	(I)	$0.07470	(I)
Distribution:**				
Peak Summer	$0.16374	(R)	$0.14082	(R)
Off-Peak Summer	$0.09267	(I)	$0.07808	(I)
Part-Peak Winter	$0.06835	(R)	$0.06128	(R)
Off-Peak Winter	$0.06835	(I)	$0.06128	(I)
Transmission* (all usage)	$0.02302		$0.02302	
Reliability Services* (all usage)	$0.00011		$0.00011	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01657	(I)	$0.01588	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00293		$0.00293	
California Climate Credit (all usage)***	$0.00000		$0.00000	

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* 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 AG-R Sheet 12
SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

12. 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.

	DA /CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03169	(I)
2010 Vintage	$0.03815	(I)
2011 Vintage	$0.03987	(I)
2012 Vintage	$0.04222	(I)
2013 Vintage	$0.04242	(I)
2014 Vintage	$0.04245	(I)
2015 Vintage	$0.04265	(I)
2016 Vintage	$0.04293	(I)
2017 Vintage	$0.04296	(I)
2018 Vintage	$0.04247	(I)
2019 Vintage	$0.03234	(I)
2020 Vintage	$0.02606	(I)
2021 Vintage	$0.02606	(I)

(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 legacy customers, highly impacted agricultural customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 SB—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 SB, in addition to all applicable Schedule AG-V charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule. (T)

(Continued)

ELECTRIC SCHEDULE AG-V Sheet 2
SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

Depending upon the end-use of electricity and 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 the rates under Schedule AG-V: Rate A, B, D or E.

Rates A and D: 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. Rate D applies to customers who were on Rate D as of May 1, 2006 and are not billed via SmartMeter™. Rate A applies to all other customers.

Rates B and E: 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. Rate E applies to customers who were on Rate E as of May 1, 2006 and are not billed via SmartMeter™. Rate B applies to all other customers.

Rate B will apply to those customers whose maximum demand is 200 kW or greater for three consecutive months and select this schedule upon the initial installation of the interval data meter, unless the customer was on Rate E as of May 1, 2006 and is not billed via SmartMeter™.

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 Legacy TOU Eligibility Requirements. (T)

The new rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010 were available on a voluntary opt-in basis for (T)
qualifying customers from March 2020 through February 2021: (T)
(D)

(Continued)

ELECTRIC SCHEDULE AG-V Sheet 3
SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.) (D)

(D)

Beginning March 2021, customers served under Schedule AG-V will transition to the rate plans under Schedule AG with revised TOU periods on a mandatory basis or may elect service under optional Schedule AG-F or any other rate plan for which they are eligible.

Customers on AG-VA or AG-VD, with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand less than 35 kW, will transition to rate AG-A1 under Schedule AG, or may elect to enroll in AG-A2 or AG-FA under Schedule AG-F.

Customers on AG-VA or AG-VD, with a maximum demand of 35 kW or greater, for three consecutive months in the most recent twelve months, or on AG-VB or AG-VE will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Summarized below:

Legacy Rate	Defaults to service under Schedule AG:	Or May Opt-In to
AG-VA/D < 35 kW	AG-A1	AG-A2, AG-FA
AG-VA/D >= 35 kW	AG-B	AG-C, AG-FB, AG-FC
AG-VB/E	AG-B	AG-C, AG-FB, AG-FC

The transition of customers no longer eligible for AG-V to Schedule AG with revised TOU periods will occur on the start of the customer's March 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 rate plan with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule AG.

(Continued)

1. APPLICABILITY: (Cont'd.)

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 Legacy TOU Period" and the terms of "Behind-the-Meter Solar Legacy TOU Period 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. (T) (T)

"Highly impacted" customers, defined as those agricultural customers with potential bill increases greater than 7 percent and $100 annually due to the transition, may remain on their legacy rate schedule for an additional year but must transition to the new rates with revised TOU periods in March 2022. Decision 19-05-010 delays the mandatory transition to rates with revised TOU periods for these "highly impacted" customers and clarifies that net energy metering (NEM) customers, direct access customers, and community choice aggregation customers and accounts beginning service on or after August 9, 2018 are not eligible for "highly impacted" subgroup exemptions from the mandatory TOU transition in March 2021. However, direct access and community choice aggregation customers are also allowed to qualify as highly impacted customers pursuant to a modification granted by the CPUC Executive Director by letter dated November 16, 2020. (N) I I (N)

Customers that do not have a meter that is capable of billing on the new Schedule AG on or after March 2021, 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 occur each March to transition all applicable remaining AG-V customers to the rates with revised TOU periods as described above.

All AG-VA and AG-VD customers will convert from connected load demand to metered demand in March 2022 for customers with meters having that capability.

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.

Transfers Off of Schedule AG-V: 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.

(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.

(D)
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|
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(D)

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)

(D)
|
|
|
(D)

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

ELECTRIC SCHEDULE AG-V Sheet 6

SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER

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

Total Demand Rates ($ per kW)	Rate A,D		Rate B,E	
Connected Load Summer	$6.39	(R)	–	
Connected Load Winter	$4.85	(I)	–	
Maximum Peak Demand Summer	–		$3.87	(R)
Maximum Demand Summer	–		$10.20	(R)
Maximum Demand Winter	–		$8.19	(I)
Primary Voltage Discount Summer	–		$0.53	(R)
Primary Voltage Discount Winter	–		$0.50	(I)

Total Energy Rates ($ per kWh)	Rate A,D		Rate B,E	
Peak Summer	$0.38370	(R)	$0.33114	(R)
Off-Peak Summer	$0.22837	(I)	$0.19602	(R)
Part-Peak Winter	$0.19523	(R)	$0.17179	(R)
Off-Peak Winter	$0.19452	(I)	$0.17108	(I)

(Continued)

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

3. RATES: (Cont'd.)

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

UNBUNDLING OF TOTAL RATES

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

Demand Rates by Component ($ per kW)	Rate A,D		Rate B,E	
Generation:				
Connected Load Summer	$1.54	(I)	–	
Connected Load Winter	$0.00		–	
Maximum Peak Demand Summer	–		$1.29	(R)
Maximum Demand Summer	–		$2.00	(R)
Maximum Demand Winter	–		$0.00	
Primary Voltage Discount Summer	–		$0.00	(R)
Primary Voltage Discount Winter	–		$0.00	
Distribution:**				
Connected Load Summer	$4.85	(R)	–	
Connected Load Winter	$4.85	(I)	–	
Maximum Peak Demand Summer	–		$2.58	(I)
Maximum Demand Summer	–		$8.20	(R)
Maximum Demand Winter	–		$8.19	(I)
Primary Voltage Discount Summer	–		$0.53	(I)
Primary Voltage Discount Winter	–		$0.50	(I)

Energy Rate by Components ($ per kWh)	Rate A,D		Rate B,E	
Generation:				
Peak Summer	$0.16649	(R)	$0.15313	(R)
Off-Peak Summer	$0.08184	(I)	$0.07764	(I)
Part-Peak Winter	$0.07388	(R)	$0.06973	(R)
	$0.07317	(I)	$0.06902	(I)
Distribution:**				
Peak Summer	$0.16998	(R)	$0.13147	(R)
Off-Peak Sumer	$0.09930	(I)	$0.07184	(R)
Part-Peak Winter	$0.07412	(R)	$0.05552	(R)
Off-Peak Winter	$0.07412	(I)	$0.05552	(I)

Transmission* (all usage)	$0.02302		$0.02302	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00011		$0.00011	
Public Purpose Programs (all usage)	$0.01657	(I)	$0.01588	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00293		$0.00293	
California Climate Credit (all usage)***	$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 AG-V
SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER

12. 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.

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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03169	(I)
2010 Vintage	$0.03815	(I)
2011 Vintage	$0.03987	(I)
2012 Vintage	$0.04222	(I)
2013 Vintage	$0.04242	(I)
2014 Vintage	$0.04245	(I)
2015 Vintage	$0.04265	(I)
2016 Vintage	$0.04293	(I)
2017 Vintage	$0.04296	(I)
2018 Vintage	$0.04247	(I)
2019 Vintage	$0.03234	(I)
2020 Vintage	$0.02606	(I)
2021 Vintage	$0.02606	(I)

(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 their existing legacy TOU rate periods for (T) a certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar Legacy TOU Eligibility Requirements. (T)

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

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 legacy customers referenced above, will be (T) 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 service under this rate (T) 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.

* 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-1
SMALL GENERAL SERVICE

APPLICABILITY: (Cont'd)

B1-ST for Storage: The B1-ST rate for storage is an optional rate available to qualifying customers taking Bundled, DA or CCA service under Schedule B-1.

The B1-ST rate is a pilot program that will be offered with a cap on the number of participants of 15,000. The B1-ST rate for storage is available to customers who are subject to the maximum demand eligibility requirements for the class of 75 kW or usage in excess of 150,000 kWh per year (as defined in each rate schedule) and have a minimum energy storage capacity equal to the greater of either 4.8 kWh or at least 0.05 percent of the customer's annual usage (in kWh) for the previous 12 months. Customer under 75 kW that are eligible to take service on Schedule B-1 may elect to take service on B1-ST for Storage. For additional B1-ST details and program specifics see the Special Condition "B1-ST FOR STORAGE" provided further below in this tariff.

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

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

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

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

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

(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	B-1 Rates		B1-ST Rates		
Total Customer Charge Rates					
Customer Charge Single-phase ($ per meter per day)	$0.32854		$0.32854		
Customer Charge Poly-phase ($ per meter per day)	$0.82136		$0.82136		
Demand Charge (for B1-ST only) Total Demand Rate (per metered kW/month assessed from 2:00 p.m. to 11:00 p.m. only)					
Summer	---		$4.22	(I)	
Winter	---		$4.22	(I)	
Total TOU Energy Rates ($ per kWh)					
Peak Summer	$0.33337	(I)	$0.39702	(I)	
Part-Peak Summer	$0.28414	(I)	$0.25572	(I)	
Off-Peak Summer	$0.26333	(I)	$0.20839	(I)	
Peak Winter	$0.25794	(I)	$0.29907	(I)	
Partial-Peak Winter (for B1-ST only)	---		$0.26957	(I)	
Off-Peak Winter	$0.24182	(I)	$0.18052	(I)	
Super Off-Peak Winter	$0.22540	(I)	$0.16410	(I)	
PDP Rates (Consecutive Day and Three-Hour Event Option)*					(N)
PDP Charges ($ per kWh)					|
All Usage During PDP Event	$0.60	(N)			|
PDP Credits					|
Energy ($ per kWh)					|
Peak Summer	($0.03468)	(N)			|
Part-Peak Summer	($0.01030)	(N)			|

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

(Continued)

ELECTRIC SCHEDULE B-1 Sheet 4
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. (N) (N)

UNBUNDLING OF TOTAL RATES

Time-of-Use Rates	B-1 Rate		B1-ST Rate	
Customer and Demand Charge Rates: Customer and demand 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	$0.17224	(I)	$0.17701	(I)
Part-Peak Summer	$0.12301	(I)	$0.13455	(I)
Off-Peak Summer	$0.10220	(I)	$0.09880	(I)
Peak Winter	$0.11699	(I)	$0.12643	(I)
Partial-Peak Winter (For B1-ST Only)	---		$0.11409	(I)
Off-Peak Winter	$0.10087	(I)	$0.09209	(I)
Super Off-Peak Winter	$0.08445	(I)	$0.07567	(I)
Distribution:**				
Peak Summer	$0.10931	(I)	$0.16819	(I)
Part-Peak Summer	$0.10931	(I)	$0.06935	(I)
Off-Peak Summer	$0.10931	(I)	$0.05777	(I)
Peak Winter	$0.08913	(I)	$0.12082	(I)
Partial-Peak Winter (For B1-ST Only)	---		$0.10366	(I)
Off-Peak Winter	$0.08913	(I)	$0.03661	(I)
Super Off-Peak Winter	$0.08913	(I)	$0.03661	(I)
Transmission* (all usage)	$0.02784		$0.02784	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00013		$0.00013	
Public Purpose Programs (all usage)	$0.01607	(I)	$0.01607	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032	
New System Generation Charge (all usage)**	$0.00318		$0.00318	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580	
California Climate Credit (all usage)***	$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.

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.

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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03406	(I)
2010 Vintage	$0.04100	(I)
2011 Vintage	$0.04285	(I)
2012 Vintage	$0.04537	(I)
2013 Vintage	$0.04559	(I)
2014 Vintage	$0.04562	(I)
2015 Vintage	$0.04583	(I)
2016 Vintage	$0.04613	(I)
2017 Vintage	$0.04617	(I)
2018 Vintage	$0.04564	(I)
2019 Vintage	$0.03476	(I)
2020 Vintage	$0.02801	(I)
2021 Vintage	$0.02801	(I)

(Continued)

PEAK DAY PRICING DETAILS

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

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for default to PDP and to opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **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 voice, text, or email 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, phone call, 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**.**

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)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd.).

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. (N)

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)

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 their existing legacy TOU rate periods for a (T) certain period of time, per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar Legacy TOU Eligibility Requirements. (T)

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

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 legacy customers referenced above, (T) 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)

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

Decision10-02-032, as modified by Decision 11-11-008, ordered that beginning November 1, 2014, eligible small and medium C&I customers (those with demands that are not equal to or greater than 200 kW for three consecutive months) default to PDP rates. A customer is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

For additional details and program specifics, see the Peak Day Pricing Details section below. (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)	$5.47664	(I)	$5.47664	(I)	$5.47664	(I)	
Total Demand Rates ($ per kW)							
Summer	$14.31	(I)	$14.03	(I)	$10.78	(I)	
Winter	$14.31	(I)	$14.03	(I)	$10.78	(I)	
Total Energy Rates ($ per kWh)							
Peak Summer	$0.27100	(I)	$0.25569	(I)	$0.19753	(R)	
Part-Peak Summer	$0.20931	(I)	$0.19739	(I)	$0.14079	(R)	
Off-Peak Summer	$0.17674	(I)	$0.16655	(I)	$0.11072	(R)	
Peak Winter	$0.19472	(I)	$0.18284	(I)	$0.14448	(R)	
Off-Peak Winter	$0.15924	(I)	$0.14920	(I)	$0.11164	(R)	
Super Off-Peak Winter	$0.12290	(I)	$0.11286	(I)	$0.07530	(R)	(L)
PDP Rates (Consecutive Day and Three-Hour Event Option							(N)
PDP Charges ($ per kWh)							
All Usage During PDP Event	$0.90	(N)	$0.90	(N)	$0.90	(N)	
PDP Credits							
Energy ($ per kWh)							
Peak Summer	($0.04900)	(N)	($0.04900)	(N)	($0.04900)	(N)	
Part-Peak Summer	($0.01697)	(N)	($0.01697)	(N)	($0.01697)	(N)	

* 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	$5.47	(I)	$5.19	(I)	$1.94	(I)
Winter	$5.47	(I)	$5.19	(I)	$1.94	(I)
Transmission Maximum Demand*	$8.80		$8.80		$8.80	
Reliability Services Maximum Demand*	$0.04		$0.04		$0.04	
Energy Rate by Components ($ per kWh)						
Generation:						
Peak Summer	$0.19812	(I)	$0.18311	(I)	$0.16601	(I)
Part-Peak Summer	$0.13643	(I)	$0.12481	(I)	$0.10927	(I)
Off-Peak Summer	$0.10386	(I)	$0.09397	(I)	$0.07920	(I)
Peak Winter	$0.14007	(I)	$0.12848	(I)	$0.11296	(I)
Off-Peak Winter	$0.10459	(I)	$0.09484	(I)	$0.08012	(I)
Super Off-Peak Winter	$0.06825	(I)	$0.05850	(I)	$0.04378	(I)
Distribution:**						
Summer	$0.05045	(I)	$0.05032	(I)	$0.00948	(I)
Winter	$0.03222	(I)	$0.03210	(I)	$0.00948	(I)
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01492	(I)	$0.01475	(I)	$0.01453	(I)
Competition Transition Charge (all usage)	$0.00004		$0.00004		$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290		$0.00290		$0.00290	
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
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)

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)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03652	(I)
2010 Vintage	$0.04397	(I)
2011 Vintage	$0.04595	(I)
2012 Vintage	$0.04866	(I)
2013 Vintage	$0.04889	(I)
2014 Vintage	$0.04892	(I)
2015 Vintage	$0.04915	(I)
2016 Vintage	$0.04947	(I)
2017 Vintage	$0.04952	(I)
2018 Vintage	$0.04895	(I)
2019 Vintage	$0.03727	(I)
2020 Vintage	$0.03003	(I)
2021 Vintage	$0.03003	(I)

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 Wildfire Fund 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.

WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082. (L)

PEAK DAY PRICING DETAILS

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

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for default to PDP and to opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **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)

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 voice, text, or email 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, phone call, 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)

ELECTRIC SCHEDULE B-19 Sheet 1

MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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

Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. Schedules A-1, A-6, A-10, E-19 and E-20 will be retained as legacy rate schedules with their 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 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 Legacy TOU Eligibility Requirements. (T) (T)

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

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

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

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

Eligibility for Schedule B-19: This schedule is available on a voluntary basis for customers with maximum billing demands less than 500 kW. Customers voluntarily taking service on this schedule are subject to all the terms and conditions below, unless otherwise specified in Section 13. If a customer's maximum demand has failed to exceed 499 kilowatts for 12 consecutive months, PG&E will transfer that customer's account to voluntary B-19 service or to a different applicable rate schedule..

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

(Continued)

ELECTRIC SCHEDULE B-19 Sheet 2
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

1. APPLICABILITY: (Cont'd.)

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

Definition of Maximum Demand: Demand will be averaged over 15-minute intervals for customers whose maximum demand exceeds 499 kW. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month. (See Section 6 for a definition of "Peak-Period.") See Section 13 for the definition of maximum demand for customers voluntarily selecting B-19.

Option R for 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).

(L)

(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 May 1, 2010, eligible large Commercial and Industrial (C&I) customers default to PDP rates. A customer is eligible for default when 1) it has at least twelve (12) months of hourly usage data available, and 2) it has measured demands equal to or exceeding 200 kW for three (3) consecutive months during the past 12 months. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. (N)

Decision10-02-032, as modified by Decision 11-11-008, ordered that beginning November 1, 2014, eligible small and medium C&I customers (those with demands that are not equal to or greater than 200 kW for three consecutive months) default to PDP rates. A customer is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

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

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

(Continued)

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

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

BUNDLED TOTAL RATES

	Secondary Voltage		Primary Voltage		Transmission Voltage		
Total Customer Charge Rates							
Customer Charge Mandatory B-19 ($ per meter per day)	$27.57709	(I)	$42.06396	(I)	$51.71562	(I)	
Customer Charge with SmartMeter™ ($ per meter per day)	$5.47664	(I)	$5.47664	(I)	$5.47664	(I)	
Total Demand Rates ($ per kW**)**							
Maximum Peak Demand Summer	$26.56	(I)	$23.40	(I)	$9.66	(I)	
Maximum Part-Peak Demand Summer	$5.59	(I)	$4.98	(I)	$2.42	(I)	
Maximum Demand Summer	$22.77	(I)	$18.45	(I)	$12.29	(I)	
Maximum Peak Demand Winter	$1.72	(I)	$1.25	(I)	$0.93	(I)	
Maximum Demand Winter	$22.77	(I)	$18.45	(I)	$12.29	(I)	
Total Energy Rates ($ per kWh)							
Peak Summer	$0.15666	(R)	$0.13897	(R)	$0.13019	(R)	
Part-Peak Summer	$0.12776	(R)	$0.11736	(R)	$0.12105	(R)	
Off-Peak Summer	$0.10733	(R)	$0.09857	(R)	$0.10159	(R)	
Peak Winter	$0.13831	(R)	$0.12726	(R)	$0.13141	(R)	
Off-Peak Winter	$0.10725	(R)	$0.09870	(R)	$0.10184	(R)	
Super Off-Peak Winter	$0.06557	(R)	$0.05806	(R)	$0.05836	(R)	
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005		(L)
PDP Rates							(N)
PDP Charges ($ per kWh)							
All Usage During PDP Event	$1.20	(N)	$1.20	(N)	$1.20	(N)	
PDP Credits							
Demand ($ per kW)							
Peak Summer	($6.34)	(N)	($6.01)	(N)	($4.91)	(N)	
Part-Peak Summer	($0.92)	(N)	($0.88)	(N)	($1.23)	(N)	
Energy ($ per kWh)							
Peak Summer	$0.00000	(N)	$0.00000	(N)	$0.00000	(N)	
Part-Peak Summer	$0.00000	(N)	$0.00000	(N)	$0.00000	(N)	(N)

(Continued)

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)

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. (L)

Demand Rates by Components ($ per kW)	Secondary Voltage		Primary Voltage		Transmission Voltage	
Generation:						
Maximum Peak Demand Summer	$14.48	(I)	$12.19	(I)	$9.66	(I)
Maximum Part-Peak Demand Summer	$2.11	(I)	$1.78	(I)	$2.42	(I)
Maximum Peak-Demand Winter	$1.72	(I)	$1.25	(I)	$0.93	(I)
Distribution:**						
Maximum Peak Demand Summer	$12.08	(I)	$11.21	(I)	$0.00	
Maximum Part-Peak Demand Summer	$3.48	(I)	$3.20	(I)	$0.00	
Maximum Demand Summer	$13.93	(I)	$9.61	(I)	$3.45	(I)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$13.93	(I)	$9.61	(I)	$3.45	(I)
Transmission Maximum Demand*	$8.80		$8.80		$8.80	
Reliability Services Maximum Demand*	$0.04		$0.04		$0.04	

* 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)

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 (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	$0.13463	(I)	$0.11747	(I)	$0.10869	(I)
Part-Peak Summer	$0.10573	(I)	$0.09586	(I)	$0.09955	(I)
Off-Peak Summer	$0.08530	(I)	$0.07707	(I)	$0.08009	(I)
Peak Winter	$0.11628	(I)	$0.10576	(I)	$0.10991	(I)
Off-Peak Winter	$0.08522	(I)	$0.07720	(I)	$0.08034	(I)
Super Off-Peak Winter	$0.04354	(I)	$0.03656	(I)	$0.03686	(I)
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01453	(I)	$0.01400	(I)	$0.01400	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charge (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290		$0.00290		$0.00290	
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. (L)

(Continued)

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 18)

Total Customer Charge Rates	Secondary Voltage		Primary Voltage		Transmission Voltage	
Customer Charge Mandatory B-19 ($ per meter per day)	$27.57709	(I)	$42.06396	(I)	$51.71562	(I)
Customer Charge Voluntary B-19:	$5.47664	(I)	$5.47664	(I)	$5.47664	(I)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$3.02	(I)	$2.80	(I)	$0.00	
Maximum Part-Peak Demand Summer	$0.87	(I)	$0.80	(I)	$0.00	
Maximum Demand Summer	$22.77	(I)	$18.45	(I)	$12.29	(I)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$22.77	(I)	$18.45	(I)	$12.29	(I)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.36430	(I)	$0.34171	(I)	$0.22967	(R)
Part-Peak Summer	$0.18046	(I)	$0.16696	(I)	$0.14817	(R)
Off-Peak Summer	$0.11999	(I)	$0.10992	(I)	$0.10602	(R)
Peak Winter	$0.15367	(R)	$0.13914	(R)	$0.13991	(R)
Off-Peak Winter	$0.11136	(R)	$0.10149	(R)	$0.10623	(R)
Super Off-Peak Winter	$0.07554	(R)	$0.06567	(R)	$0.07041	(R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

(L)

(Continued)

3. Rates:
(Cont'd.)

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

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

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

Demand Rates by Components ($ per kW)	Secondary Voltage		Primary Voltage		Transmission Voltage	
Distribution:**						
Maximum Peak Demand Summer	$3.02	(I)	$2.80	(I)	$0.00	
Maximum Part-Peak Demand Summer	$0.87	(I)	$0.80	(I)	$0.00	
Maximum Demand Summer	$13.93	(I)	$9.61	(I)	$3.45	(I)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$13.93	(I)	$9.61	(I)	$3.45	(I)
Transmission Maximum Demand*	$8.80		$8.80		$8.80	
Reliability Services Maximum Demand*	$0.04		$0.04		$0.04	

* 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)

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 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	$0.26347	(I)	$0.23881	(I)	$0.20817	(I)
Part-Peak Summer	$0.12790	(I)	$0.11527	(I)	$0.12667	(I)
Off-Peak Summer	$0.08939	(I)	$0.07988	(I)	$0.08452	(I)
Peak Winter	$0.13164	(I)	$0.11764	(I)	$0.11841	(I)
Off-Peak Winter	$0.08933	(I)	$0.07999	(I)	$0.08473	(I)
Super Off-Peak Winter	$0.05351	(I)	$0.04417	(I)	$0.04891	(I)
Distribution:**						
Peak Summer	$0.07880	(I)	$0.08140	(I)	$0.00000	
Part-Peak Summer	$0.03053	(I)	$0.03019	(I)	$0.00000	
Off-Peak Summer	$0.00857	(I)	$0.00854	(I)	$0.00000	
Peak Winter	$0.00000		$0.00000		$0.00000	
Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Super Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01453	(I)	$0.01400	(I)	$0.01400	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charge (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290		$0.00290		$0.00290	
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. (L)

(Continued)

ELECTRIC SCHEDULE B-19 Sheet 10
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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 20)

Total Customer Charge Rates	Secondary Voltage		Primary Voltage		Transmission Voltage	
Customer Charge Mandatory B-19 ($ per meter per day)	$27.57709	(I)	$42.06396	(I)	$51.71562	(I)
Customer Charge Voluntary B-19:	$5.47664	(I)	$5.47664	(I)	$5.47664	(I)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer (per day)	$0.60	(I)	$0.49	(I)	$0.15	(I)
Maximum Part-Peak Demand Summer (per day)	$0.04	(I)	$0.04	(I)		
Maximum Demand Summer (per monthly billing, all hours except 9 am to 2 pm)	$2.82	(I)	$1.94	(I)	$0.70	(I)
Maximum Demand Summer (per monthly billing)	$8.84		$8.84		$8.84	
Maximum Peak Demand Winter (per day)	$0.51	(I)	$0.39	(I)	$0.16	(I)
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.82	(I)	$1.95	(I)	$0.70	(I)
Maximum Demand Winter (per monthly billing)	$8.84		$8.84		$8.84	
Total Energy Rates ($ per kWh)						
Peak Summer	$0.36430	(I)	$0.34171	(I)	$0.22967	(R)
Part-Peak Summer	$0.18046	(I)	$0.16696	(I)	$0.14817	(R)
Off-Peak Summer	$0.11999	(I)	$0.10992	(I)	$0.10602	(R)
Peak Winter	$0.15367	(R)	$0.13914	(R)	$0.13991	(R)
Off-Peak Winter	$0.11136	(R)	$0.10149	(R)	$0.10623	(R)
Super Off-Peak Winter	$0.07554	(R)	$0.06567	(R)	$0.07041	(R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

(L)

(Continued)

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

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

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

Demand Rates by Components ($ per kW)	Secondary Voltage		Primary Voltage		Transmission Voltage	
Distribution:**						
Maximum Peak Demand Summer (per day)	$0.60	(I)	$0.49	(I)	$0.15	(I)
Maximum Part-Peak Demand Summer (per day)	$0.04	(I)	$0.04	(I)		
Maximum Demand Summer (per monthly billing, all hours except 9 am to 2 pm)	$2.82	(I)	$1.94	(I)	$0.70	(I)
Maximum Demand Summer (per monthly billing)	$0.00		$0.00		$0.00	
Maximum Peak Demand Winter (per day)	$0.51	(I)	$0.39	(I)	$0.16	(I)
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.82	(I)	$1.95	(I)	$0.70	(I)
Maximum Demand Winter (per monthly billing)	$0.00		$0.00		$0.00	
Transmission Maximum Demand*	8.80		$8.80		$8.80	
Reliability Services Maximum Demand*	0.04		0.04		$0.04	

(L)

(Continued)

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

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

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

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

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

Energy Charges by Components ($ per kWh)	Secondary Voltage		Primary Voltage		Transmission Voltage	
Generation:						
Peak Summer	$0.26347	(I)	$0.23881	(I)	$0.20817	(I)
Part-Peak Summer	$0.12790	(I)	$0.11527	(I)	$0.12667	(I)
Off-Peak Summer	$0.08939	(I)	$0.07988	(I)	$0.08452	(I)
Peak Winter	$0.13164	(I)	$0.11764	(I)	$0.11841	(I)
Off-Peak Winter	$0.08933	(I)	$0.07999	(I)	$0.08473	(I)
Super Off-Peak Winter	$0.05351	(I)	$0.04417	(I)	$0.04891	(I)
Distribution:**						
Peak Summer	$0.07880	(I)	$0.08140	(I)	$0.00000	
Part-Peak Summer	$0.03053	(I)	$0.03019	(I)	$0.00000	
Off-Peak Summer	$0.00857	(I)	$0.00854	(I)	$0.00000	
Peak Winter	$0.00000		$0.00000		$0.00000	
Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Super Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01453	(I)	$0.01400	(I)	$0.01400	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charge (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290		$0.00290		$0.00290	
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. (L)

(Continued)

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

3. Rates: (Cont'd.)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule B-19 is the sum of a customer charge, demand charges, and energy charges: (L)

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

– This schedule has three **demand charges,** a maximum-peak-period-demand charge, a maximum part-peak-period and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum part-peak-period demand charge per kilowatt applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include <u>all</u> of these demand charges. Option S includes variations of these basic demand charge types assessed on a (1) daily basis by time period and (2) maximum monthly basis applied to all hours except 9 am to 2 pm. (Time periods are defined in Section 6.)

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

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

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

4. METERING REQUIRE-MENTS:

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

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

(Continued)

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

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

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

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

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

SUMMER (Service from June 1 through September 30):

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

WINTER (Service from October 1 through May 31):

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

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

(Continued)

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

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

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

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

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

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

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

(Continued)

11. COMMON-AREA ACCOUNTS: Common-area accounts are those accounts that provide electric service to Common Use Areas as defined in Rule 1. Common-area accounts that are separately metered by PG&E and which took electric service from PG&E on or prior to January 16, 2003, had a one-time opportunity to return to a residential rate schedule from April 1, 2004 to May 31, 2004, by notifying PG&E in writing. These accounts remain eligible for service under this rate schedule if the customer did not invoke this first right of return. (L)

In the event that the CPUC substantially amends any or all of PG&E's commercial or residential rate schedules, the Executive Council of Homeowners (ECHO) can direct PG&E to begin an optional second right-of-return period lasting 105 days.

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

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

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

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

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

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

(Continued)

13. BILLING: A customer's bill is calculated based on the option applicable to the customer. (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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03347	(I)
2010 Vintage	$0.04030	(I)
2011 Vintage	$0.04211	(I)
2012 Vintage	$0.04459	(I)
2013 Vintage	$0.04480	(I)
2014 Vintage	$0.04484	(I)
2015 Vintage	$0.04505	(I)
2016 Vintage	$0.04534	(I)
2017 Vintage	$0.04538	(I)
2018 Vintage	$0.04486	(I)
2019 Vintage	$0.03416	(I)
2020 Vintage	$0.02752	(I)
2021 Vintage	$0.02752	(I)

14. CARE DISCOUNT FOR NONPROFIT GROUP-LIVING AND SPECIAL EMPLOYEE HOUSING FACILITIES: Facilities which meet the eligibility criteria in Rule 19.2 or 19.3 are eligible for a California Alternate Rates for Energy discount under Schedule E-CARE. CARE customers are exempt from paying the Wildfire Fund Charge rate component. For CARE customers, no portion of the rates shall be used to pay the Wildfire Fund Charge. (L)

(Continued)

15. ELECTRIC EMERGENCY PLAN ROTATING BLOCK OUTAGES: See Electric Rule 14. (L)

16. STANDBY APPLICABILITY:

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

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

17. WILDFIRE FUND CHARGE:

The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082. (L)

(Continued)

18. Option R

The Option R rate is available to qualifying customers with 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:

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

Where the PTC and CEC inverter Efficiency Rating can be found at:
The PTC rating can be found here:
https://www.energy.ca.gov/programs-and-topics/topics/renewable-energy/solar-equipment-lists

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)

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

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

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

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

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

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

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

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

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

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

(Continued)

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

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

A. No Retroactive Application

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

B. Customer Notification to PG&E

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

(Continued)

20. OPTION S

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

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

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

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

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

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

The following are not eligible for Option S:

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

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

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

(Continued)

ELECTRIC SCHEDULE B-19 Sheet 23
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

21. PEAK DAY PRICING DETAILS:

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

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for default to PDP and to opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **Capacity Reservation Level**: Customers may elect a capacity reservation level (CRL) and pay for a fixed level of capacity, specified in kW. While the CRL is applicable year round, customers electing a CRL will be billed on a take-or-pay basis up to the specified CRL under the non-PDP rate of this schedule during the summer period (June 1 through September 30). This means that customers will be billed for summer peak generation demand charges up to the level of their CRL, even in summer months when the actual demand might be less than their CRL. Customers will receive PDP credits on summer usage above the CRL on all summer-period days. All usage during a PDP event protected under the CRL will be billed at the non-PDP rate. All usage above the CRL (as measured in 15-minute intervals), and not protected during a PDP event, will be billed at the PDP rate. If a customer fails to elect an initial CRL, the customer's initial CRL will be set at 50% of its most recent full summer season average peak-period maximum demand and may go back to the previous year to make a full summer season (if available). If the customer has not established any historic summer billing demand, the CRL will be set at zero (0). The CRL for all customers, including NEM customers, must be greater than or equal to zero (0). A customer may only elect to change their CRL once every 12-months. (N)

(Continued)

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

c. **Bill Stabilization**: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate. (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 voice, text, or email notification messages of a PDP event from PG&E.

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

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

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

(Continued)

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

f. **Program Operations**: A maximum of fifteen (15) PDP events and a minimum of nine (9) PDP events may be called in any calendar year. PG&E will notify customers by 4:00 p.m. on a day-ahead basis when a PDP event will occur the next day. The PDP program will operate year-round and PDP events may be called for any day of the week. (N)

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

g. **Event Cancellation or Reduction**: PG&E may initiate the cancellation of a PDP event before 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.

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)

ELECTRIC SCHEDULE B-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 B-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.

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 their existing (T) 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 Legacy TOU Eligibility (T) Requirements.

These new rates with revised TOU periods were available to qualifying customers on a (T) voluntary opt-in basis from November 2019 through February 2021. | (T)

Customers eligible for this rate schedule must have an interval data meter that can be read remotely by PG&E. Beginning on March 2021, customers still served on Schedule E-20, with the exception of solar legacy customers referenced above, will be transitioned to (T) Schedule B-20. The transition notification and default process are further described in the legacy rate Schedule E-20.

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 S, in addition to all applicable Schedule B-20 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Transfers Off of Schedule B-20: PG&E will review its Schedule E-20 accounts annually. A customer will be eligible for continued service on Schedule B-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.

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 B-20.

(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)

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

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

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

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

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

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)	$50.04986	(I)	$49.95670	(I)	$48.33253	(I)	
Total Demand Rates ($ per kW)							
Maximum Peak Demand Summer	$26.38	(I)	$26.68	(I)	$17.33	(I)	
Maximum Part-Peak Demand Summer	$5.57	(I)	$5.29	(I)	$4.13	(I)	
Maximum Demand Summer	$22.81	(I)	$20.50	(I)	$10.82	(I)	
Maximum Peak Demand Winter	$1.80	(I)	$1.78	(I)	$2.31	(I)	
Maximum Demand Winter	$22.81	(I)	$20.50	(I)	$10.82	(I)	
Total Energy Rates ($ per kWh)							
Peak Summer	$0.14893	(R)	$0.14484	(R)	$0.12466	(R)	
Part-Peak Summer	$0.12298	(R)	$0.11735	(R)	$0.10788	(R)	
Off-Peak Summer	$0.10249	(R)	$0.09816	(R)	$0.08915	(R)	
Peak Winter	$0.13347	(R)	$0.12734	(R)	$0.12385	(R)	
Off-Peak Winter	$0.10233	(R)	$0.09822	(R)	$0.08577	(R)	
Super Off-Peak Winter	$0.06061	(R)	$0.05690	(R)	$0.04773	(R)	
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005		(L)
PDP Rates							(N)
PDP Charges ($ per kWh)							
All Usage During PDP Event	$1.20	(N)	$1.20	(N)	$1.20	(N)	
PDP Credits							
Demand ($ per kW)							
Peak Summer	($6.31)	(N)	($6.93)	(N)	($6.43)	(N)	
Part-Peak Summer	($0.91)	(N)	($0.95)	(N)	($1.53)	(N)	
Energy ($ per kWh)							
Peak Summer	$0.00000	(N)	$0.00000	(N)	$0.00000	(N)	
Part-Peak Summer	$0.00000	(N)	$0.00000	(N)	$0.00000	(N)	(N)

(Continued)

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)
(L)

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	$14.09	(I)	$15.48	(I)	$17.33	(I)
Maximum Part-Peak Demand Summer	$2.04	(I)	$2.13	(I)	$4.13	(I)
Maximum Demand Summer	$0.00		$0.00		$0.00	
Maximum Peak Demand Winter	$1.80	(I)	$1.78	(I)	$2.31	(I)
Maximum Demand Winter						
Distribution:**						
Maximum Peak Demand Summer	$12.29	(I)	$11.20	(I)	$0.00	
Maximum Part-Peak Demand Summer	$3.53	(I)	$3.16	(I)	$0.00	
Maximum Demand Summer	$12.87	(I)	$10.56	(I)	$0.88	(I)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$12.87	(I)	$10.56	(I)	$0.88	(I)
Transmission Maximum Demand*	$9.89		$9.89		$9.89	
Reliability Services Maximum Demand*	$0.05		$0.05		$0.05	

* 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) (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	$0.12759	(I)	$0.12406	(I)	$0.10479	(I)
Part-Peak Summer	$0.10164	(I)	$0.09657	(I)	$0.08801	(I)
Off-Peak Summer	$0.08115	(I)	$0.07738	(I)	$0.06928	(I)
Peak Winter	$0.11213	(I)	$0.10656	(I)	$0.10398	(I)
Off-Peak Winter	$0.08099	(I)	$0.07744	(I)	$0.06590	(I)
Super Off-Peak Winter	$0.03927	(I)	$0.03612	(I)	$0.02786	(I)
Distribution:**						
Peak Summer	-		-		-	
Part-Peak Summer	-		-		-	
Off-Peak Summer	-		-		-	
Peak Winter	-		-		-	
Off-Peak Winter	-		-		-	
Super Off-Peak Winter	-		-		-	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01421	(I)	$0.01365	(I)	$0.01274	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charge (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00253		$0.00253		$0.00253	

* 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)	$50.04986 (I)	$49.95670 (I)	$48.33253 (I)
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$3.07 (I)	$2.80 (I)	$0.00
Maximum Part-Peak Demand Summer	$0.88 (I)	$0.79 (I)	$0.00
Maximum Demand Summer	$22.81 (I)	$20.50 (I)	$10.82 (I)
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$22.81 (I)	$20.50 (I)	$10.82 (I)
Total Energy Rates ($ per kWh)			
Peak Summer	$0.35579 (R)	$0.33346 (R)	$0.26213 (R)
Part-Peak Summer	$0.17297 (R)	$0.16229 (R)	$0.14351 (R)
Off-Peak Summer	$0.11394 (R)	$0.10972 (R)	$0.09326 (R)
Peak Winter	$0.14995 (R)	$0.14238 (R)	$0.14335 (R)
Off-Peak Winter	$0.10622 (R)	$0.10231 (R)	$0.09034 (R)
Super Off-Peak Winter	$0.07047 (R)	$0.06656 (R)	$0.05754 (R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(L)

(Continued)

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	$3.07	(I)	$2.80	(I)	$0.00	
Maximum Part-Peak Demand Summer	$0.88	(I)	$0.79	(I)	$0.00	
Maximum Demand Summer	$12.87	(I)	$10.56	(I)	$0.88	(I)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$12.87	(I)	$10.56	(I)	$0.88	(I)
Transmission Maximum Demand*	$9.89		$9.89		$9.89	
Reliability Services Maximum Demand*	$0.05		$0.05		$0.05	

* 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	$0.25522	(I)	$0.24509	(I)	$0.24226	(I)
Part-Peak Summer	$0.12247	(I)	$0.11619	(I)	$0.12364	(I)
Off-Peak Summer	$0.08502	(I)	$0.08149	(I)	$0.07339	(I)
Peak Winter	$0.12861	(I)	$0.12160	(I)	$0.12348	(I)
Off-Peak Winter	$0.08488	(I)	$0.08153	(I)	$0.07047	(I)
Super Off-Peak Winter	$0.04913	(I)	$0.04578	(I)	$0.03767	(I)
Distribution:**						
Peak Summer	$0.07923	(I)	$0.06759	(I)	$0.00000	
Part-Peak Summer	$0.02916	(I)	$0.02532	(I)	$0.00000	
Off-Peak Summer	$0.00758	(I)	$0.00745	(I)	$0.00000	
Peak Winter	$0.00000		$0.00000		$0.00000	
Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Super Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01421	(I)	$0.01365	(I)	$0.01274	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charge (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00253		$0.00253		$0.00253	

* 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.) (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 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)	$50.04986	(I)	$49.95670	(I)	$48.33253	(I)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer (per day)	$0.59	(I)	$0.47	(I)	$0.03	
Maximum Part-Peak Demand Summer (per day)	$0.04	(I)	$0.03			
Maximum Demand Summer (per monthly billing, all hours except 9 am to 2 pm)	$2.60	(I)	$2.14	(I)	$0.18	
Maximum Demand Summer (per monthly billing)	$9.94		$9.94		$9.94	
Maximum Peak Demand Winter (per day)	$0.49	(I)	$0.39	(I)	$0.03	
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.61	(I)	$2.14	(I)	$0.18	
Maximum Demand Winter (per billing month)	$9.94		$9.94		$9.94	
Total Energy Rates ($ per kWh)						
Peak Summer	$0.35579	(R)	$0.33346	(R)	$0.26213	(R)
Part-Peak Summer	$0.17297	(R)	$0.16229	(R)	$0.14351	(R)
Off-Peak Summer	$0.11394	(R)	$0.10972	(R)	$0.09326	(R)
Peak Winter	$0.14995	(R)	$0.14238	(R)	$0.14335	(R)
Off-Peak Winter	$0.10622	(R)	$0.10231	(R)	$0.09034	(R)
Super Off-Peak Winter	$0.07047	(R)	$0.06656	(R)	$0.05754	(R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

(L)

(Continued)

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)	$0.59	(I)	$0.47	(I)	$0.03
Maximum Part-Peak Demand Summer (per day)	$0.04	(I)	$0.03		
Maximum Demand Summer (per monthly billing, all hours except 9 am to 2 pm)	$2.60	(I)	$2.14	(I)	$0.18
Maximum Demand Summer (per monthly billing)	$0.00		$0.00		$0.00
Maximum Peak Demand Winter (per day)	$0.49	(I)	$0.39	(I)	$0.03
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.61	(I)	$2.14	(I)	$0.18
Maximum Demand Winter (per billing month)	$0.00		$0.00		$0.00
Transmission Maximum Demand*	$9.89		$9.89		$9.89
Reliability Services Maximum Demand*	$0.05		$0.05		$0.05

* 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)

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	$0.25522	(I)	$0.24509	(I)	$0.24226	(I)
Part-Peak Summer	$0.12247	(I)	$0.11619	(I)	$0.12364	(I)
Off-Peak Summer	$0.08502	(I)	$0.08149	(I)	$0.07339	(I)
Peak Winter	$0.12861	(I)	$0.12160	(I)	$0.12348	(I)
Off-Peak Winter	$0.08488	(I)	$0.08153	(I)	$0.07047	(I)
Super Off-Peak Winter	$0.04913	(I)	$0.04578	(I)	$0.03767	(I)
Distribution:**						
Peak Summer	$0.07923	(I)	$0.06759	(I)	$0.00000	
Part-Peak Summer	$0.02916	(I)	$0.02532	(I)	$0.00000	
Off-Peak Summer	$0.00758	(I)	$0.00745	(I)	$0.00000	
Peak Winter	$0.00000		$0.00000		$0.00000	
Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Super Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01421	(I)	$0.01365	(I)	$0.01274	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charge (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00253		$0.00253		$0.00253	

* 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.) (L)

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:

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 <u>all</u> of these demand charges. Option S includes variations of these basic demand charge types assessed on a (1) daily basis by time period and (2) maximum monthly basis applied to all hours except 9 am to 2 pm. (Time periods are defined in Section 6.)

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

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

– As shown on the rate chart, which set of customer, demand, and energy charges is paid depends on the 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)

ELECTRIC SCHEDULE B-20 Sheet 14
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 Sheet 15
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

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. (L)

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

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

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

9. STANDARD SERVICE FACILITIES: If PG&E must install any new or additional facilities to provide the customer with service under 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 Sheet 16
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)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580		$0.00580		$0.00580	
CTC Rate (per kWh)	$0.00003		$0.00003		$0.00003	
Power Charge Indifference Adjustment (per kWh)						
2009 Vintage	$0.03208	(I)	$0.03070	(I)	$0.02864	(I)
2010 Vintage	$0.03862	(I)	$0.03697	(I)	$0.03449	(I)
2011 Vintage	$0.04036	(I)	$0.03863	(I)	$0.03604	(I)
2012 Vintage	$0.04274	(I)	$0.04090	(I)	$0.03816	(I)
2013 Vintage	$0.04294	(I)	$0.04110	(I)	$0.03834	(I)
2014 Vintage	$0.04297	(I)	$0.04113	(I)	$0.03837	(I)
2015 Vintage	$0.04317	(I)	$0.04132	(I)	$0.03855	(I)
2016 Vintage	$0.04345	(I)	$0.04159	(I)	$0.03880	(I)
2017 Vintage	$0.04349	(I)	$0.04162	(I)	$0.03883	(I)
2018 Vintage	$0.04299	(I)	$0.04115	(I)	$0.03839	(I)
2019 Vintage	$0.03274	(I)	$0.03134	(I)	$0.02923	(I)
2020 Vintage	$0.02638	(I)	$0.02525	(I)	$0.02356	(I)
2021 Vintage	$0.02638	(I)	$0.02525	(I)	$0.02356	(I)

(L)

(Continued)

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 Wildfire Fund 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. WILDFIRE FUND CHARGE The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082. (L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 18
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:
https://www.energy.ca.gov/programs-and-topics/topics/renewable-energy/solar-equipment-lists

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)

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)

18. OPTION S

The Option S rate for storage is available to qualifying customers taking Bundled, DA or CCA service under Schedule B-20 or voluntary B-20. 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 B-20 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)

19. PEAK DAY PRICING DETAILS

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

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours.

Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for default to PDP and to opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **Capacity Reservation Level**: Customers may elect a capacity reservation level (CRL) and pay for a fixed level of capacity, specified in kW. While the CRL is applicable year round, customers electing a CRL will be billed on a take-or-pay basis up to the specified CRL under the non-PDP rate of this schedule during the summer period (June 1 through September 30). This means that customers will be billed for summer peak generation demand charges up to the level of their CRL, even in summer months when the actual demand might be less than their CRL. Customers will receive PDP credits on summer usage above the CRL on all summer-period days. All usage during a PDP event protected under the CRL will be billed at the non-PDP rate. All usage above the CRL (as measured in 15-minute intervals), and not protected during a PDP event, will be billed at the PDP rate. If a customer fails to elect an initial CRL, the customer's initial CRL will be set at 50% of its most recent full summer season average peak-period maximum demand and may go back to the previous year to make a full summer season (if available). If the customer has not established any historic summer billing demand, the CRL will be set at zero (0). The CRL for all customers, including NEM customers, must be greater than or equal to zero (0). A customer may only elect to change their CRL once every 12-months. (N)

(Continued)

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

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

c. **Bill Stabilization**: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate. (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 voice, text, or email notification messages of a PDP event from PG&E.

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

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

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

(Continued)

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

f. **Program Operations**: A maximum of fifteen (15) PDP events and a minimum of nine (9) PDP events may be called in any calendar year. PG&E will notify customers by 4:00 p.m. on a day-ahead basis when a PDP event will occur the next day. The PDP program will operate year-round and PDP events may be called for any day of the week. (N)

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

g. **Event Cancellation or Reduction:** PG&E may initiate the cancellation of a PDP event before 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.

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 (N) removed from PDP.

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 their existing legacy TOU rate periods for a (T)
certain period of time, per Decision 17-01-006, as described in the Electric Rule 1,
Definitions: Behind-the-Meter Solar Legacy TOU Eligibility Requirements. (T)

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

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 legacy customers referenced above, will (T)
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)

* 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

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 May 1, 2010, eligible large Commercial and Industrial (C&I) customers default to PDP rates. A customer is eligible for default when 1) it has at least twelve (12) months of hourly usage data available, and 2) it has measured demands equal to or exceeding 200 kW for three (3) consecutive months during the past 12 months. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. (N)

Decision10-02-032, as modified by Decision 11-11-008, ordered that beginning November 1, 2014, eligible small and medium C&I customers (those with demands that are not equal to or greater than 200 kW for three consecutive months) default to PDP rates. A customer is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

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

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

(Continued)

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)

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	$0.36375	(I)
Off-Peak Summer	$0.24581	(I)
Peak Winter	$0.25614	(I)
Off-Peak Winter	$0.23639	(I)
Super Off-Peak Winter	$0.21998	(I) (L)

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

PDP Charges ($ per kWh)		
All Usage During PDP Event	$0.60	(N)
PDP Credits		
Energy ($ per kWh)		
Peak Summer	($0.04291)	(N)

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

(Continued)

ELECTRIC SCHEDULE B-6 Sheet 4
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. PDP charges and credits are all generation and are not included below. (L) (L)/(N) (N)

UNBUNDLING OF TOTAL RATES (L)

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)	Rates	
Generation:		
Peak Summer	$0.17524	(I)
Off-Peak Summer	$0.10408	(I)
Peak Winter	$0.11172	(I)
Off Peak Winter	$0.09466	(I)
Super Off-Peak Winter	$0.07825	(I)
Distribution:**		
Peak Summer	$0.13795	(I)
Off-Peak Summer	$0.09117	(I)
Peak Winter	$0.09386	(I)
Off Peak Winter	$0.09117	(I)
Super Off-Peak Winter	$0.09117	(I)
Transmission* (all usage)	$0.02784	
Wildfire Fund Charge (all usage)	$0.00580	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00013	
Public Purpose Programs (all usage)	$0.01481	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032	
New System Generation Charge (all usage)**	$0.00318	
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. (L)

(Continued)

ELECTRIC SCHEDULE B-6 Sheet 5
SMALL GENERAL TIME-OF-USE 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
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.	

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.

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

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. (L)

(Continued)

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

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

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

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

	DA /CCA CRS		
Energy Cost Recovery Amount Charge (per kWh)	$0.00032		
Wildfire Fund Charge (per kWh)	$0.00580		
CTC Charge (per kWh)	$0.00003		
Power Charge Indifference Adjustment (per kWh)			
2009 Vintage	$0.03406	(I)	
2010 Vintage	$0.04100	(I)	
2011 Vintage	$0.04285	(I)	
2012 Vintage	$0.04537	(I)	
2013 Vintage	$0.04559	(I)	
2014 Vintage	$0.04562	(I)	
2015 Vintage	$0.04583	(I)	
2016 Vintage	$0.04613	(I)	
2017 Vintage	$0.04617	(I)	
2018 Vintage	$0.04564	(I)	
2019 Vintage	$0.03476	(I)	
2020 Vintage	$0.02801	(I)	
2021 Vintage	$0.02801	(I)	(L)

(Continued)

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 Wildfire Fund Charge. (L)

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

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

WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082. (L)

(Continued)

PEAK DAY PRICING DETAILS

(N)

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

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours. Bundled service Net Energy Metering (NEM) customers taking service on Schedule NEM, NEMV, NEMVMASH, NEM2, NEM2V, or NEM2VMSH are eligible for default to PDP and to opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **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)

ELECTRIC SCHEDULE B-6 Sheet 9
SMALL GENERAL TIME-OF-USE 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 voice, text, or email 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, phone call, 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.

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)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd.):

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. (N)

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)

ELECTRIC SCHEDULE BEV Sheet 2
BUSINESS ELECTRIC VEHICLES

RATES:(Cont'd.)

TOTAL RATE

Total Energy Rates ($ per kWh)	**BEV-1**		**BEV-2-S (Secondary)**		**BEV-2-P (Primary / Transmission)**	
Peak	$0.32455	(R)	$0.33974	(R)	$0.33195	(R)
Off-Peak	$0.13254	(R)	$0.12651	(R)	$0.12307	(R)
Super Off-Peak	$0.10588	(R)	$0.10324	(R)	$0.10041	(R)
Block Size (kW)	10		50		50	
Subscription Charge (per block)	$12.41		$95.56		$85.98	
Subscription Charge ($ per kW)*	$1.24		$1.91		$1.72	
Overage Fee ($ per kW)	$2.48		$3.82		$3.44	

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

UNBUNDLING OF TOTAL RATES

Energy Rates by Component ($ per kWh)	**BEV-1**		**BEV-2-S (Secondary)**		**BEV-2-P (Primary / Transmission)**	
Generation:						
Peak	$0.25786	(I)	$0.27713	(I)	$0.26675	(I)
Off-Peak	$0.07530	(I)	$0.07377	(I)	$0.07077	(I)
Super Off-Peak	$0.04991	(I)	$0.04837	(I)	$0.04657	(I)
Distribution*:**						
Peak	$0.01487		$0.01261		$0.01573	
Off-Peak	$0.00542		$0.00274		$0.00283	
Super Off-Peak	$0.00415		$0.00487		$0.00437	
Transmission** (all usage)	$0.02784		$0.02784		$0.02784	
Transmission Rate Adjustments** (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00013		$0.00013		$0.00013	
Public Purpose Programs (all usage)	$0.01607	(I)	$0.01453	(I)	$0.01400	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)***	$0.00318		$0.00290		$0.00290	

* $/kW for informational purposes only. This does not constitute an additional charge.
** 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 BEV
BUSINESS ELECTRIC VEHICLES

SPECIAL CONDITIONS: (Cont'd)

4. 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, the new system generation charge, 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, including exemptions continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA / CCA CRS	
	BEV-1	BEV-2
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	$0.00032
Wildfire Fund Charge (per kWh)	$0.00580	$0.00580
CTC Charge (per kWh)	$0.00003	$0.00003

Power Charge Indifference Adjustment (per kWh)	BEV-1		BEV-2	
2009	$0.02855	(I)	$0.03355	(I)
2010	$0.03437	(I)	$0.04039	(I)
2011	$0.03592	(I)	$0.04220	(I)
2012	$0.03803	(I)	$0.04469	(I)
2013	$0.03821	(I)	$0.04490	(I)
2014	$0.03824	(I)	$0.04494	(I)
2015	$0.03842	(I)	$0.04515	(I)
2016	$0.03867	(I)	$0.04544	(I)
2017	$0.03871	(I)	$0.04548	(I)
2018	$0.03826	(I)	$0.04496	(I)
2019	$0.02914	(I)	$0.03424	(I)
2020	$0.02348	(I)	$0.02759	(I)
2021	$0.02348	(I)	$0.02759	(I)

(Continued)

ELECTRIC SCHEDULE D-CARE Sheet 1

LINE-ITEM DISCOUNT FOR CALIFORNIA ALTERNATE RATES FOR ENERGY (CARE) CUSTOMERS

APPLICABILITY: This schedule is applicable to single-phase and polyphase residential service in single-family dwellings and in flats and apartments separately metered by PG&E and domestic submetered tenants residing in multifamily accommodations, mobilehome parks and to qualifying recreational vehicle parks and marinas and to farm service on the premises operated by the person whose residence is supplied through the same meter, where the applicant qualifies for California Alternate Rates for Energy (CARE) under the eligibility and certification criteria set forth in Electric Rule 19.1. CARE service is available on Schedules E-1, E-6, E-TOU-B, E-TOU-C, E-TOU-D, EV2, EM, ES, ESR, ET and EM-TOU.

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

RATES: Customers taking service on this rate schedule will receive a percentage discount (“A” below) on their total bundled charges on their otherwise applicable rate schedule (except for the California Climate Credit, which will not be discounted). In addition, customers will receive a percentage discount (“B” below) on the delivery minimum bill amount, if applicable. The CARE discount will be calculated for direct access and community choice aggregation customers based on the total charges as if they were subject to bundled service rates. Discounts will be applied as a residual reduction to distribution charges, after D-CARE customers are exempted from the Wildfire Fund Charge and the CARE surcharge portion of the public purpose program charge used to fund the CARE discount. These conditions also apply to master-metered customers and to qualified sub-metered tenants where the master-meter customer is jointly served under PG&E’s Rate Schedule D-CARE and either Schedule EM, ES, ESR, ET, or EM-TOU.

For master-metered customers where one or more of the submetered tenants qualifies for CARE rates under the eligibility and certification criteria set forth in Rule 19.1, 19.2, or 19.3, the CARE discount is equal to a percentage (“C” below) of the total bundled charges, multiplied by the number of CARE units divided by the total number of units. In addition, master-metered customers eligible for D-CARE will receive a percentage discount (“D” below) on the delivery minimum bill amount, if applicable.

It is the responsibility of the master-metered customer to advise PG&E within 15 days following any change in the number of dwelling units and/or any decrease in the number of qualifying CARE applicants that results when such applicants move out of their submetered or non-submetered dwelling unit, or submetered permanent-residence RV or permanent-residence boat.

A.	D-CARE Discount:	34.951 % (Percent)	(I)
B.	Delivery Minimum Bill Discount:	50.000 % (Percent)	
C.	Master-Meter D-CARE Discount:	34.951 % (Percent)	(I)
D.	Master-Meter Delivery Minimum Bill Discount:	50.000 % (Percent)	

SPECIAL CONDITIONS: 1. OTHERWISE APPLICABLE SCHEDULE: The Special Conditions of the Customer’s otherwise applicable rate schedule will apply to this schedule.

(Continued)

ELECTRIC SCHEDULE E-1 Sheet 1
RESIDENTIAL SERVICES

APPLICABILITY: This schedule is applicable to single-phase and polyphase residential service in single-family dwellings and in flats and apartments separately metered by PG&E; to single-phase and polyphase service in common areas in a multifamily complex (see Special Condition 8); and to all single-phase and polyphase farm service on the premises operated by the person whose residence is supplied through the same meter.

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-1 charges. See Special Conditions 11 and 12 of this rate schedule for exemptions to standby charges.

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

RATES: Total bundled service charges are calculated using the total rates below. Customers on this schedule are subject to the delivery minimum bill amount shown below applied to the delivery portion of the bill (i.e. to all rate components other than the generation rate). In addition, total bundled charges will include applicable generation charges per kWh for all kWh usage.

Customers receiving a medical baseline allowance shall pay for all usage in excess of 200 percent of baseline at a rate $0.04000 per kWh less than the applicable rate for usage in excess of 200 percent of baseline. No portion of the rates paid by customers that receive a Medical Baseline allowance shall be used to pay the Wildfire Fund Charge. For these customers, the Conservation Incentive Adjustment is calculated residually based on the total rate less the sum of: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Generation, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges (CTC), New System Generation Charges, and Energy Cost Recovery Amount. Customers receiving a medical baseline allowance shall also receive a 50 percent discount on the delivery minimum bill amount 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 Energy Rates ($ per kWh)		
Baseline Usage	$0.25902	(I)
101% - 400% of Baseline	$0.32596	(I)
High Usage Over 400% of Baseline	$0.40745	(I)
Delivery Minimum Bill Amount ($ per meter per day)	$0.32854	
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)	

(Continued)

RATES:
(Cont'd.)

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.***

UNBUNDLING OF TOTAL RATES

Energy Rates by Component ($ per kWh)

Generation:	$0.11418	(I)
Distribution:**	$0.11210	(I)
Conservation Incentive Adjustment:		
Baseline Usage	($0.02925)	(R)
101% - 400% of Baseline	$0.03769	(I)
High Usage Over 400% of Baseline	$0.11918	(I)
Transmission* (all usage)	$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032	
Wildfire Fund Charge (all usage)	$0.00580	
New System Generation Charge (all usage)**	$0.00442	

* 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.
*** This same assignment of revenues applies to direct access and community choice aggregation customers.

(Continued)

ELECTRIC SCHEDULE E-1
RESIDENTIAL SERVICES

SPECIAL CONDITIONS: (Cont'd.)

9. 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, conservation incentive adjustment, 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, conservation incentive adjustment, public purpose programs, nuclear decommissioning, the franchise fee surcharge, New System Generation Charges, and the applicable CRS. The CRS is equal to the sum of the individual charges set forth below. Exemptions to the CRS, including exemptions for Medical Baseline and continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA /CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

10. 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.

(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 legacy customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 their existing legacy TOU rate periods for a certain period of time, (T) per Decision 17-01-006, as described in the Electric Rule 1*, Definitions: Behind-the-Meter Solar Legacy TOU Eligibility Requirements. (T)

The new rates with revised TOU periods were available on a voluntary opt-in basis for qualifying customers from November 2019 through February 2021. (T)

(D)

* 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: (D)

(D)

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 Legacy TOU Period" and the terms of (T) "Behind-the-Meter Solar Legacy TOU Period Eligibility Requirements" shall be (T) 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 SB—Standby Service Special Conditions 1 through 6 shall (T) 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 SB, in addition to all (T) 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)

(D)

(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.

TOTAL RATES

Total Customer/Meter Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory E-19 ($ per meter per day)	$27.57709 (I)	$42.06396 (I)	$51.71562 (I)
Customer Charge Voluntary E-19:			
Customer Charge with SmartMeter™ ($ per meter per day)	$5.47664 (I)	$5.47664 (I)	$5.47664 (I)
Customer Charge without SmartMeter™			
Customer Charge Rate V ($ per meter per day)	$5.65405 (I)	$5.65405 (I)	$5.65405 (I)
Customer Charge Rate W ($ per meter per day)	$5.51212 (I)	$5.51212 (I)	$5.51212 (I)
Customer Charge Rate X ($ per meter per day)	$5.65405 (I)	$5.65405 (I)	$5.65405 (I)
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$13.63 (R)	$11.60 (R)	$8.90 (R)
Maximum Part-Peak Demand Summer	$11.12 (I)	$9.70 (I)	$8.90 (I)
Maximum Demand Summer	$24.93 (I)	$20.64 (I)	$12.29 (I)
Maximum Part-Peak Demand Winter	$0.00 (R)	$0.00 (R)	$0.00
Maximum Demand Winter	$24.93 (I)	$20.64 (I)	$12.29 (I)
Total Energy Rates ($ per kWh)			
Peak Summer	$0.11325 (R)	$0.10377 (R)	$0.09649 (R)
Part-Peak Summer	$0.11325 (R)	$0.10377 (R)	$0.09649 (R)
Off-Peak Summer	$0.10727 (I)	$0.09805 (I)	$0.09083 (I)
Part-Peak Winter	$0.10468 (R)	$0.09558 (R)	$0.08840 (R)
Off-Peak Winter	$0.10397 (I)	$0.09491 (I)	$0.08774 (R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(D)

(D)

(Continued)

3. Rates: (Cont'd.)

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

UNBUNDLING OF TOTAL RATES

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

Demand Rates by Components ($ per kW)	Secondary Voltage		Primary Voltage		Transmission Voltage	
Generation:						
Maximum Peak Demand Summer	$9.29	(R)	$8.08	(R)	$8.90	(R)
Maximum Part-Peak Demand Summer	$9.29	(I)	$8.08	(I)	$8.90	(I)
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	$4.34	(R)	$3.52	(R)	$0.00	
Maximum Part-Peak Demand Summer	$1.83	(R)	$1.62	(R)	$0.00	
Maximum Demand Summer	$16.09	(I)	$11.80	(I)	$3.45	(I)
Maximum Part-Peak Demand Winter	$0.00	(R)	$0.00	(R)	$0.00	
Maximum Demand Winter	$16.09	(I)	$11.80	(I)	$3.45	(I)
Transmission Maximum Demand*	$8.80		$8.80		$8.80	
Reliability Services Maximum Demand*	$0.04		$0.04		$0.04	

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

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

(Continued)

3. Rates: (Cont'd.)

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

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Charges by Components ($ per kWh)	Secondary Voltage		Primary Voltage		Transmission Voltage	
Generation:						
Peak Summer	$0.09122	(R)	$0.08227	(R)	$0.07499	(R)
Part-Peak Summer	$0.09122	(R)	$0.08227	(R)	$0.07499	(R)
Off-Peak Summer	$0.08524	(I)	$0.07655	(I)	$0.06933	(I)
Part-Peak Winter	$0.08265	(R)	$0.07408	(R)	$0.06690	(R)
Off-Peak Winter	$0.08194	(I)	$0.07341	(I)	$0.06624	(I)
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)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01453	(I)	$0.01400	(I)	$0.01400	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charge (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290		$0.00290		$0.00290	
California Climate Credit (all usage – E-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 E-19
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

3. Rates: (Cont'd.)

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

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

Total Customer/Meter Charge Rates	Secondary Voltage		Primary Voltage		Transmission Voltage	
Customer Charge Mandatory E-19 ($ per meter per day)	$27.57709	(I)	$42.06396	(I)	$51.71562	(I)
Customer Charge Voluntary E-19:						
Customer Charge with SmartMeter™ ($ per meter per day)	$5.47664	(I)	$5.47664	(I)	$5.47664	(I)
Customer Charge without SmartMeter™						
Customer Charge Rate V ($ per meter per day)	$5.65405	(I)	$5.65405	(I)	$5.65405	(I)
Customer Charge Rate W ($ per meter per day)	$5.51212	(I)	$5.51212	(I)	$5.51212	(I)
Customer Charge Rate X ($ per meter per day)	$5.65405	(I)	$5.65405	(I)	$5.65405	(I)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$1.09	(R)	$0.88	(R)	$0.00	
Maximum Part-Peak Demand Summer	$0.46	(R)	$0.41	(R)	$0.00	
Maximum Demand Summer	$24.93	(I)	$20.64	(I)	$12.29	(I)
Maximum Part-Peak Demand Winter	$0.00	(R)	$0.00	(R)	$0.00	
Maximum Demand Winter	$24.93	(I)	$20.64	(I)	$12.29	(I)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.26148	(R)	$0.24280	(R)	$0.16342	(R)
Part-Peak Summer	$0.21053	(I)	$0.19821	(I)	$0.13622	(R)
Off-Peak Summer	$0.12298	(I)	$0.11381	(I)	$0.11648	(I)
Part-Peak Winter	$0.12039	(R)	$0.11134	(R)	$0.11405	(I)
Off-Peak Winter	$0.11968	(I)	$0.11067	(I)	$0.11339	(I)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

(Continued)

3. Rates: (Cont'd.)

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

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

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	$1.09	(R)	$0.88	(R)	$0.00	
Maximum Part-Peak Demand Summer	$0.46	(R)	$0.41	(R)	$0.00	
Maximum Demand Summer	$16.09	(I)	$11.80	(I)	$3.45	(I)
Maximum Part-Peak Demand Winter	$0.00	(R)	$0.00	(R)	$0.00	
Maximum Demand Winter	$16.09	(I)	$11.80	(I)	$3.45	(I)
Transmission Maximum Demand*	$8.80		$8.80		$8.80	
Reliability Services Maximum Demand*	$0.04		$0.04		$0.04	

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

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

(Continued)

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

3. Rates: (Cont'd.)

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

UNBUNDLING OF TOTAL RATES FOR OPTION R (Cont'd.)
(for qualifying solar customers as set forth in Section 18) (T)

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

Energy Charges by Components ($ per kWh)	Secondary Voltage		Primary Voltage		Transmission Voltage	
Generation:						
Peak Summer	$0.16116	(R)	$0.14575	(R)	$0.14192	(R)
Part-Peak Summer	$0.12642	(R)	$0.11487	(R)	$0.11472	(R)
Off-Peak Summer	$0.10095	(I)	$0.09231	(I)	$0.09498	(I)
Part-Peak Winter	$0.09836	(I)	$0.08984	(I)	$0.09255	(I)
Off-Peak Winter	$0.09765	(I)	$0.08917	(I)	$0.09189	(I)
Distribution:**						
Peak Summer	$0.07829	(I)	$0.07555	(I)	$0.00000	
Part-Peak Summer	$0.06208	(I)	$0.06184	(I)	$0.00000	
Off-Peak Summer	$0.00000	(R)	$0.00000	(R)	$0.00000	
Part-Peak Winter	$0.00000	(R)	$0.00000	(R)	$0.00000	
Off-Peak Winter	$0.00000	(R)	$0.00000	(R)	$0.00000	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01453	(I)	$0.01400	(I)	$0.01400	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charge (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290		$0.00290		$0.00290	
California Climate Credit (all usage – E-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 E-19 Sheet 16

MEDIUM GENERAL DEMAND-METERED TOU SERVICE

13. BILLING: (Cont'd.)

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

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

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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03347	(I)
2010 Vintage	$0.04030	(I)
2011 Vintage	$0.04211	(I)
2012 Vintage	$0.04459	(I)
2013 Vintage	$0.04480	(I)
2014 Vintage	$0.04484	(I)
2015 Vintage	$0.04505	(I)
2016 Vintage	$0.04534	(I)
2017 Vintage	$0.04538	(I)
2018 Vintage	$0.04486	(I)
2019 Vintage	$0.03416	(I)
2020 Vintage	$0.02752	(I)
2021 Vintage	$0.02752	(I)

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

Facilities which meet the eligibility criteria in Rule 19.2 or 19.3 are eligible for a California Alternate Rates for Energy discount under Schedule E-CARE. CARE customers are exempt from paying the Wildfire Fund Charge rate component.

(Continued)

ELECTRIC SCHEDULE E-19 Sheet 18
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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

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

17. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

(D)

(D)

(Continued)

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

18. 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. (T)/(L) (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:
https://www.energy.ca.gov/programs-and-topics/topics/renewable-energy/solar-equipment-lists

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)

19. OPTIMAL BILLING PERIOD SERVICE: The Optimal Billing Period (OBP) service is a voluntary program available to bundled, direct access and community choice aggregation customers taking service on Schedule 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. (T)/(L) (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)

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

Prior to receiving OBP service, the customer must pay an annual OBP fee of $160.00 per meter. In order to retain the OBP service option in each subsequent year, the annual participation fee must be received by PG&E by the anniversary date of the contract. PG&E will bill the annual OBP fee upon the anniversary date of the contract unless the customer terminates the contract. For billing purposes, the annual participation fee shall be assigned to Distribution. (T)/(L) (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 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 legacy customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 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 Legacy TOU and Eligibility Requirements. (T)

The new rates with revised TOU periods were available on a voluntary opt-in basis for qualifying customers from November 2019 through February 2021. (T)

(D)

* 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.)

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 Legacy TOU Period" and the terms of (T) "Behind-the-Meter Solar Legacy TOU Period Eligibility Requirements" shall be (T) 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 SB—Standby Service Special Conditions 1 through 6 shall also (T) 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 SB, in addition to all (T) applicable Schedule E-20 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

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.

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.

(D)

(Continued)

1. APPLICABILITY: (Cont'd.)

Peak Day Pricing Default Rates (Cont'd):

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)

(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 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.

(Continued)

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

1. APPLICABILITY: (Cont'd.) **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.

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

TOTAL RATES

	Secondary Voltage		Primary Voltage		Transmission Voltage	
Total Customer/Meter Charge Rates						
Customer Charge Mandatory E-20 ($ per meter per day)	$50.04986	(I)	$49.95670	(I)	$48.33253	(I)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$13.82	(R)	$13.76	(R)	$11.37	(R)
Maximum Part-Peak Demand Summer	$10.88	(I)	$11.37	(I)	$11.37	(I)
Maximum Demand Summer	$24.60	(I)	$22.34	(I)	$10.82	(I)
Maximum Part-Peak Demand Winter	$0.00	(R)	$0.00	(R)	$0.00	
Maximum Demand Winter	$24.60	(I)	$22.34	(I)	$10.82	(I)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.10793	(R)	$0.10462	(R)	$0.09343	(R)
Part-Peak Summer	$0.10793	(R)	$0.10462	(R)	$0.09343	(R)
Off-Peak Summer	$0.10201	(I)	$0.09885	(I)	$0.08777	(I)
Part-Peak Winter	$0.09942	(R)	$0.09638	(R)	$0.08534	(R)
Off-Peak Winter	$0.09871	(I)	$0.09571	(I)	$0.08468	(R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

(D)

(D)

(Continued)

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

3. RATES: (Cont'd.)

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

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	$8.92	(R)	$9.55	(R)	$11.37	(R)
Maximum Part-Peak Demand Summer	$8.92	(I)	$9.55	(I)	$11.37	(I)
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	$4.90	(R)	$4.21	(R)	$0.00	
Maximum Part-Peak Demand Summer	$1.96	(R)	$1.82	(R)	$0.00	
Maximum Demand Summer	$14.66	(I)	$12.40	(I)	$0.88	(I)
Maximum Part-Peak Demand Winter	$0.00	(R)	$0.00	(R)	$0.00	
Maximum Demand Winter	$14.66	(I)	$12.40	(I)	$0.88	(I)
Transmission Maximum Demand*	$9.89		$9.89		$9.89	
Reliability Services Maximum Demand*	$0.05		$0.05		$0.05	
Energy Rates by Component ($ per kWh)						
Generation:						
Peak Summer	$0.08659	(R)	$0.08384	(R)	$0.07356	(R)
Part-Peak Summer	$0.08659	(R)	$0.08384	(R)	$0.07356	(R)
Off-Peak Summer	$0.08067	(I)	$0.07807	(I)	$0.06790	(I)
Part-Peak Winter	$0.07808	(R)	$0.07560	(R)	$0.06547	(R)
Off-Peak Winter	$0.07737	(I)	$0.07493	(I)	$0.06481	(I)
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**)**	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01421	(I)	$0.01365	(I)	$0.01274	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charge (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00253		$0.00253		$0.00253	

* 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 6
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. RATES: (Cont'd.)

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

TOTAL RATES FOR OPTION R
(for qualifying solar customers as set forth in Section 16) (T)

	Secondary Voltage		Primary Voltage		Transmission Voltage	
Total Customer/Meter Charge Rates						
Customer Charge Mandatory E-20 ($ per meter per day)	$50.04986	(I)	$49.95670	(I)	$48.33253	(I)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$1.22	(R)	$1.05	(R)	$0.00	
Maximum Part-Peak Demand Summer	$0.49	(R)	$0.45	(R)	$0.00	
Maximum Demand Summer	$24.60	(I)	$22.34	(I)	$10.82	(I)
Maximum Part-Peak Demand Winter	$0.00	(R)	$0.00	(R)	$0.00	
Maximum Demand Winter	$24.60	(I)	$22.34	(I)	$10.82	(I)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.24562	(R)	$0.24303	(R)	$0.16432	(R)
Part-Peak Summer	$0.19849	(I)	$0.19348	(I)	$0.12944	(R)
Off-Peak Summer	$0.11774	(I)	$0.11351	(I)	$0.10581	(I)
Part-Peak Winter	$0.11515	(I)	$0.11104	(R)	$0.10338	(I)
Off-Peak Winter	$0.11444	(I)	$0.11037	(I)	$0.10272	(I)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

(Continued)

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

3. Rates: (Cont'd.)

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

UNBUNDLING OF TOTAL RATES FOR OPTION R
(for qualifying solar customers as set forth in Section 16) (T)

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	$1.22	(R)	$1.05	(R)	$0.00	
Maximum Part-Peak Demand Summer	$0.49	(R)	$0.45	(R)	$0.00	
Maximum Demand Summer	$14.66	(I)	$12.40	(I)	$0.88	(I)
Maximum Part-Peak Demand Winter	$0.00	(R)	$0.00	(R)	$0.00	
Maximum Demand Winter	$14.66	(I)	$12.40	(I)	$0.88	(I)
Transmission Maximum Demand*	$9.89		$9.89		$9.89	
Reliability Services Maximum Demand*	$0.05		$0.05		$0.05	
Energy Rates by Component ($ per kWh)						
Generation:						
Peak Summer	$0.15005	(R)	$0.15162	(R)	$0.14445	(R)
Part-Peak Summer	$0.12011	(R)	$0.11667	(R)	$0.10957	(R)
Off-Peak Summer	$0.09640	(I)	$0.09273	(I)	$0.08594	(I)
Part-Peak Winter	$0.09381	(I)	$0.09026	(I)	$0.08351	(I)
Off-Peak Winter	$0.09310	(I)	$0.08959	(I)	$0.08285	(I)
Distribution:**						
Peak Summer	$0.07423	(I)	$0.07063	(I)	$0.00000	
Part-Peak Summer	$0.05704	(I)	$0.05603	(I)	$0.00000	
Off-Peak Summer	$0.00000	(R)	$0.00000	(R)	$0.00000	
Part-Peak Winter	$0.00000	(R)	$0.00000	(R)	$0.00000	
Off-Peak Winter	$0.00000	(R)	$0.00000	(R)	$0.00000	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Public Purpose Programs (all usage)	$0.01421	(I)	$0.01365	(I)	$0.01274	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charge (all usage)	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00253		$0.00253		$0.00253	

* 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 11
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.

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)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580		$0.00580		$0.00580	
CTC Rate (per kWh)	$0.00003		$0.00003		$0.00003	
Power Charge Indifference Adjustment (per kWh)						
2009 Vintage	$0.03208	(I)	$0.03070	(I)	$0.02864	(I)
2010 Vintage	$0.03862	(I)	$0.03697	(I)	$0.03449	(I)
2011 Vintage	$0.04036	(I)	$0.03863	(I)	$0.03604	(I)
2012 Vintage	$0.04274	(I)	$0.04090	(I)	$0.03816	(I)
2013 Vintage	$0.04294	(I)	$0.04110	(I)	$0.03834	(I)
2014 Vintage	$0.04297	(I)	$0.04113	(I)	$0.03837	(I)
2015 Vintage	$0.04317	(I)	$0.04132	(I)	$0.03855	(I)
2016 Vintage	$0.04345	(I)	$0.04159	(I)	$0.03880	(I)
2017 Vintage	$0.04349	(I)	$0.04162	(I)	$0.03883	(I)
2018 Vintage	$0.04299	(I)	$0.04115	(I)	$0.03839	(I)
2019 Vintage	$0.03274	(I)	$0.03134	(I)	$0.02923	(I)
2020 Vintage	$0.02638	(I)	$0.02525	(I)	$0.02356	(I)
2021 Vintage	$0.02638	(I)	$0.02525	(I)	$0.02356	(I)

(Continued)

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

15. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

(D)

(D)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 14
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. (T)/(L) (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:

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

Where the PTC and CEC inverter Efficiency Rating can be found at:
https://www.energy.ca.gov/programs-and-topics/topics/renewable-energy/solar-equipment-lists

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 15
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 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. (T)/(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)

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. (T)/(L) (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 SCHEDULE E-6 Sheet 2
RESIDENTIAL TIME-OF-USE SERVICE

RATES: Total bundled service charges are calculated using the total rates below. On-peak, part-peak, and off-peak usage is assigned to tiers on a pro-rated basis. For example, if twenty percent of a customer's usage is in the on-peak period, then twenty percent of the total usage in each tier will be treated as on-peak usage. Customers on this schedule are subject to the delivery minimum bill amount shown below applied to the delivery portion of the bill (i.e. to all rate components other than the generation rate). In addition, total bundled charges will include applicable generation charges per kWh for all kWh usage.

Customers receiving a medical baseline allowance shall pay for all usage in excess of 200 percent of baseline at a rate $0.04000 per kWh less than the applicable rate for usage in excess of 200 percent of baseline. No portion of the rates paid by customers that receive a Medical Baseline allowance shall be used to pay the Wildfire Fund Charge. For these customers, the Conservation Incentive Adjustment is calculated residually based on the total rate less the sum of: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Generation, Public Purpose Programs, Nuclear Decommissioning, New System Generation Charges, Competition Transition Charges (CTC), and Energy Cost Recovery Amount. Customers receiving a medical baseline allowance shall also receive a 50 percent discount on the delivery minimum bill amount 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 Energy Rates $ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Summer						
Baseline Usage	$0.42018	(I)	$0.30174	(I)	$0.22651	(I)
Over 100% of Baseline	$0.49602	(I)	$0.37758	(I)	$0.30235	(I)
Winter						
Baseline Usage	–		$0.24768	(I)	$0.23085	(I)
Over 100% of Baseline	–		$0.32352	(I)	$0.30669	(I)

Total Meter Charge Rate ($ per meter per day)	$0.25298
Delivery Minimum Bill Amount ($ per meter per day)	$0.32854
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)

Total bundled service charges shown on customer's bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.*

* This same assignment of revenues applies to direct access and community choice aggregation customers.

(Continued)

ELECTRIC SCHEDULE E-6
RESIDENTIAL TIME-OF-USE SERVICE

RATES: (Cont'd.)

UNBUNDLING OF TOTAL RATES

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

Energy Rates by Component ($ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Generation:						
Summer	$0.25218	(I)	$0.13506	(I)	$0.08725	(I)
Winter	–		$0.11379	(I)	$0.10064	(I)
Distribution:**						
Summer	$0.34433	(I)	$0.13955	(I)	$0.07128	(I)
Winter	–		$0.13419	(I)	$0.09047	(I)
Conservation Incentive Adjustment:						
Summer						
Baseline Usage	($0.23832)	(R)	($0.03486)	(R)	$0.00599	(I)
Over 100% of Baseline	($0.16248)	(R)	$0.04098	(R)	$0.08183	(I)
Winter						
Baseline Usage	–		($0.06229)	(R)	($0.02225)	(I)
Over 100% of Baseline	–		$0.01355	(I)	$0.05359	(I)
Transmission* (all usage)	$0.03704		$0.03704		$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017		$0.00017		$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)	$0.01575	(I)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00004		$0.00004		$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00442		$0.00442		$0.00442	

* 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)

SPECIAL CONDITIONS: (Cont'd.)

8. BILLING (Cont'd):

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

9. 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.

10. 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 service on a time-of-use (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 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.

11. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

ELECTRIC SCHEDULE E-CARE Sheet 1

CARE PROG SERV FOR QUALIF NONPROF GRP-LIV & QUALIF AGRI EMPL HOUSING FACILS

APPLICABILITY: This schedule is applicable to Facilities which meet the criteria for California Alternate Rates for Energy (CARE) set forth in Rules 19.2 or 19.3.*

TERRITORY: The entire territory served.

RATES: If the Facility qualifies for residential service, the facility's account will be served on the appropriate residential CARE rate schedule.

Qualified Facilities served on a nonresidential rate schedule will pay all charges applicable on the otherwise applicable commercial rate schedule, less the following rate per kWh discount:

Rate Schedule	Distribution		PPP	Wildfire Fund Charge	Total Discount	
B-1/A-1	$0.07564	(I)	$0.01037	$0.00580	$0.09181	(I)
B-6/A-6	$0.07004	(I)	$0.01037	$0.00580	$0.08621	(I)
A-15	$0.07564	(I)	$0.01037	$0.00580	$0.09181	(I)
B-10/A-10	$0.06516	(I)	$0.01037	$0.00580	$0.08133	(I)
B-19/E-19	$0.05537	(I)	$0.01037	$0.00580	$0.07154	(I)
B-20/E-20	$0.04095	(I)	$0.01037	$0.00580	$0.05712	(I)

The above commercial CARE discount per kWh by rate schedule shall be updated by PG&E with each future electric rate change based on the overall percentage distribution and generation discount for the residential CARE customer class, and assigned to the commercial distribution rate component, with the additional waiver of the Wildfire Fund Charge, and the CARE Surcharge portion of the PPP rate component otherwise applicable to each commercial rate schedule from Preliminary Statement Part I. Should commercial CARE customers take service on a rate schedule not listed above, PG&E shall use the most appropriate rate schedule currently listed above, until such time as a new corresponding rate per kWh is developed and available for billing purposes with Commission approval.

COMMUNITY CHOICE AGGREGATION AND DIRECT ACCESS: Direct access (DA) and Community Choice Aggregation (CCA) customers shall pay charges for transmission, transmission adjustment rates, reliability services, distribution, public purpose programs, nuclear decommissioning, the franchise fee surcharge in accordance with Schedule E-EFFS and any applicable portions of the applicable Cost Responsibility Surcharge (CRS), as provided in the otherwise applicable rate schedule and Schedule DA CRS or Schedule CCA CRS (as applicable), except that distribution and public purpose program charges will be discounted, and Wildfire Fund Charge waived as described above.

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* 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.

ELECTRIC SCHEDULE E-ECR Sheet 3
ENHANCED COMMUNITY RENEWABLES PROGRAM

RATES:
(Cont'd.)

Customer Class	Solar Charge	Generation Credit		Program Charge**	PCIA		Total	
Residential								
-- 2015 Vintage	$0.00000	($0.11418)	(R)	$0.01400	$0.04472	(I)	($0.05546)	(I)
-- 2016 Vintage	$0.00000	($0.11418)	(R)	$0.01400	$0.04493	(I)	($0.05525)	(I)
-- 2017 Vintage	$0.00000	($0.11418)	(R)	$0.01400	$0.04506	(I)	($0.05512)	(I)
-- 2018 Vintage	$0.00000	($0.11418)	(R)	$0.01400	$0.04482	(I)	($0.05536)	(I)
-- 2019 Vintage	$0.00000	($0.11418)	(R)	$0.01400	$0.04439	(I)	($0.05579)	(I)
-- 2020 Vintage	$0.00000	($0.11418)	(R)	$0.01400	$0.02887	(I)	($0.07131)	(I)
-- 2021 Vintage	$0.00000	($0.11418)	(R)	$0.01400	$0.02887	(I)	($0.07131)	(I)
Schedule A-1 / B-1								
-- 2015 Vintage	$0.00000	($0.10950)	(R)	$0.01400	$0.04338	(I)	($0.05212)	(I)
-- 2016 Vintage	$0.00000	($0.10950)	(R)	$0.01400	$0.04359	(I)	($0.05191)	(I)
-- 2017 Vintage	$0.00000	($0.10950)	(R)	$0.01400	$0.04371	(I)	($0.05179)	(I)
-- 2018 Vintage	$0.00000	($0.10950)	(R)	$0.01400	$0.04348	(I)	($0.05202)	(I)
-- 2019 Vintage	$0.00000	($0.10950)	(R)	$0.01400	$0.04306	(I)	($0.05244)	(I)
-- 2020 Vintage	$0.00000	($0.10950)	(R)	$0.01400	$0.02801	(I)	($0.06749)	(I)
-- 2021 Vintage	$0.00000	($0.10950)	(R)	$0.01400	$0.02801	(I)	($0.06749)	(I)
Schedule A-10 / B-10								
-- 2015 Vintage	$0.00000	($0.11715)	(R)	$0.01400	$0.04652	(I)	($0.05663)	(I)
-- 2016 Vintage	$0.00000	($0.11715)	(R)	$0.01400	$0.04674	(I)	($0.05641)	(I)
-- 2017 Vintage	$0.00000	($0.11715)	(R)	$0.01400	$0.04687	(I)	($0.05628)	(I)
-- 2018 Vintage	$0.00000	($0.11715)	(R)	$0.01400	$0.04662	(I)	($0.05653)	(I)
-- 2019 Vintage	$0.00000	($0.11715)	(R)	$0.01400	$0.04618	(I)	($0.05697)	(I)
-- 2020 Vintage	$0.00000	($0.11715)	(R)	$0.01400	$0.03003	(I)	($0.07312)	(I)
-- 2021 Vintage	$0.00000	($0.11715)	(R)	$0.01400	$0.03003	(I)	($0.07312)	(I)

(Continued)

ELECTRIC SCHEDULE E-ECR Sheet 4
ENHANCED COMMUNITY RENEWABLES PROGRAM

RATES: (Cont'd.)

Customer Class	Solar Charge	Generation Credit		Program Charge**	PCIA		Total	
Schedule E-19 / B-19								
-- 2015 Vintage	$0.00000	($0.10839)	(R)	$0.01400	$0.04264	(I)	($0.05175)	(I)
-- 2016 Vintage	$0.00000	($0.10839)	(R)	$0.01400	$0.04284	(I)	($0.05155)	(I)
-- 2017 Vintage	$0.00000	($0.10839)	(R)	$0.01400	$0.04296	(I)	($0.05143)	(I)
-- 2018 Vintage	$0.00000	($0.10839)	(R)	$0.01400	$0.04273	(I)	($0.05166)	(I)
-- 2019 Vintage	$0.00000	($0.10839)	(R)	$0.01400	$0.04232	(I)	($0.05207)	(I)
-- 2020 Vintage	$0.00000	($0.10839)	(R)	$0.01400	$0.02752	(I)	($0.06687)	(I)
-- 2021 Vintage	$0.00000	($0.10839)	(R)	$0.01400	$0.02752	(I)	($0.06687)	(I)
Schedule LS-3								
-- 2015 Vintage	$0.00000	($0.09091)	(R)	$0.01400	$0.03562	(I)	($0.04129)	(I)
-- 2016 Vintage	$0.00000	($0.09091)	(R)	$0.01400	$0.03579	(I)	($0.04112)	(I)
-- 2017 Vintage	$0.00000	($0.09091)	(R)	$0.01400	$0.03589	(I)	($0.04102)	(I)
-- 2018 Vintage	$0.00000	($0.09091)	(R)	$0.01400	$0.03570	(I)	($0.04121)	(I)
-- 2019 Vintage	$0.00000	($0.09091)	(R)	$0.01400	$0.03536	(I)	($0.04155)	(I)
-- 2020 Vintage	$0.00000	($0.09091)	(R)	$0.01400	$0.02300	(I)	($0.05391)	(I)
-- 2021 Vintage	$0.00000	($0.09091)	(R)	$0.01400	$0.02300	(I)	($0.05391)	(I)
Agriculture and Schedule E-37								
-- 2015 Vintage	$0.00000	($0.10296)	(R)	$0.01400	$0.04037	(I)	($0.04859)	(I)
-- 2016 Vintage	$0.00000	($0.10296)	(R)	$0.01400	$0.04056	(I)	($0.04840)	(I)
-- 2017 Vintage	$0.00000	($0.10296)	(R)	$0.01400	$0.04067	(I)	($0.04829)	(I)
-- 2018 Vintage	$0.00000	($0.10296)	(R)	$0.01400	$0.04045	(I)	($0.04851)	(I)
-- 2019 Vintage	$0.00000	($0.10296)	(R)	$0.01400	$0.04007	(I)	($0.04889)	(I)
-- 2020 Vintage	$0.00000	($0.10296)	(R)	$0.01400	$0.02606	(I)	($0.06290)	(I)
-- 2021 Vintage	$0.00000	($0.10296)	(R)	$0.01400	$0.02606	(I)	($0.06290)	(I)

(Continued)

ELECTRIC SCHEDULE E-ECR Sheet 5
ENHANCED COMMUNITY RENEWABLES PROGRAM

RATES: (Cont'd.)

Customer Class	Solar Charge	Generation Credit		Program Charge**	PCIA		Total	
Schedule E-20 T / B-20 T								
-- 2015 Vintage	$0.00000	($0.09304)	(R)	$0.01400	$0.03649	(I)	($0.04255)	(I)
-- 2016 Vintage	$0.00000	($0.09304)	(R)	$0.01400	$0.03666	(I)	($0.04238)	(I)
-- 2017 Vintage	$0.00000	($0.09304)	(R)	$0.01400	$0.03676	(I)	($0.04228)	(I)
-- 2018 Vintage	$0.00000	($0.09304)	(R)	$0.01400	$0.03657	(I)	($0.04247)	(I)
-- 2019 Vintage	$0.00000	($0.09304)	(R)	$0.01400	$0.03622	(I)	($0.04282)	(I)
-- 2020 Vintage	$0.00000	($0.09304)	(R)	$0.01400	$0.02356	(I)	($0.05548)	(I)
-- 2021 Vintage	$0.00000	($0.09304)	(R)	$0.01400	$0.02356	(I)	($0.05548)	(I)
Schedule E-20 P / B-20 P								
-- 2015 Vintage	$0.00000	($0.09965)	(R)	$0.01400	$0.03911	(I)	($0.04654)	(I)
-- 2016 Vintage	$0.00000	($0.09965)	(R)	$0.01400	$0.03929	(I)	($0.04636)	(I)
-- 2017 Vintage	$0.00000	($0.09965)	(R)	$0.01400	$0.03940	(I)	($0.04625)	(I)
-- 2018 Vintage	$0.00000	($0.09965)	(R)	$0.01400	$0.03919	(I)	($0.04646)	(I)
-- 2019 Vintage	$0.00000	($0.09965)	(R)	$0.01400	$0.03882	(I)	($0.04683)	(I)
-- 2020 Vintage	$0.00000	($0.09965)	(R)	$0.01400	$0.02525	(I)	($0.06040)	(I)
-- 2021 Vintage	$0.00000	($0.09965)	(R)	$0.01400	$0.02525	(I)	($0.06040)	(I)
Schedule E-20 S / B-20 S								
-- 2015 Vintage	$0.00000	($0.10394)	(R)	$0.01400	$0.04086	(I)	($0.04908)	(I)
-- 2016 Vintage	$0.00000	($0.10394)	(R)	$0.01400	$0.04106	(I)	($0.04888)	(I)
-- 2017 Vintage	$0.00000	($0.10394)	(R)	$0.01400	$0.04117	(I)	($0.04877)	(I)
-- 2018 Vintage	$0.00000	($0.10394)	(R)	$0.01400	$0.04095	(I)	($0.04899)	(I)
-- 2019 Vintage	$0.00000	($0.10394)	(R)	$0.01400	$0.04056	(I)	($0.04938)	(I)
-- 2020 Vintage	$0.00000	($0.10394)	(R)	$0.01400	$0.02638	(I)	($0.06356)	(I)
-- 2021 Vintage	$0.00000	($0.10394)	(R)	$0.01400	$0.02638	(I)	($0.06356)	(I)

* The Schedule A-1/ B-1 class includes Schedules A-1, B1, A-6, B-6, A-15 and TC-1.

** The Solar Value Adjustment (SVA) time of delivery (TOD) and resource adequacy (RA) values included in the program charge are illustrative only and are included to provide an approximation for the expected 2018 credit value for the ECR option. Actual SVA TOD and SVA RA credits will be based on actual ECR projects.

The program charge includes a marketing and administration charge:

Marketing ($/kWh)	Administration ($/kWh)	Total ($/kWh)
$0.00080	$0.00184	$0.00264

(Continued)

ELECTRIC SCHEDULE E-ERA
ENERGY RATE ADJUSTMENTS

APPLICABILITY: This schedule applies to electric customers as described below. The energy rate adjustments apply only in the specific instances mentioned below.

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

RATES: Commercial/Industrial Schedule:

The adjustment rates listed below shall be used in calculating adjustments pursuant to Schedule E-31, which requires that the generation component of the otherwise applicable schedule be reduced by the charges provided in Schedule E-ERA to determine the generation portion of rates available for discounting.

Adjustments per Rate Schedule ($/kWh)

Period	A-1		A-15	
Summer	$0.15082	(I)	$0.10480	(I)
Winter	$0.13593	(I)	$0.08315	(I)

Period	A-1 Time-Of-Use		A-6	
Summer On-Peak	$0.15346	(R)	$0.23312	(R)
Summer Partial-Peak	$0.15346	(I)	$0.20962	(R)
Summer Off-Peak	$0.12875	(I)	$0.20239	(I)
Winter Partial Peak	$0.14795	(R)	$0.13984	(R)
Winter Off-Peak	$0.14738	(I)	$0.17834	(I)

Period	A-10 Transmission		A-10 Primary		A-10 Secondary	
Summer	$0.04419	(R)	$0.09070	(I)	$0.10259	(I)
Winter	$0.04342	(I)	$0.07185	(I)	$0.08134	(I)

Period	A-10 Time-Of-Use Transmission		A-10 Time-Of-Use Primary		A-10 Time-Of-Use Secondary	
Summer On-Peak	$0.05935	(R)	$0.10500	(R)	$0.11583	(R)
Summer Partial-Peak	$0.05935	(I)	$0.10500	(I)	$0.11583	(I)
Summer Off-Peak	$0.03470	(I)	$0.07968	(I)	$0.08905	(I)
Winter Partial Peak	$0.04382	(R)	$0.07224	(R)	$0.08172	(I)
Winter Off-Peak	$0.04316	(I)	$0.07157	(I)	$0.08101	(I)

Period	E-19 Transmission		E-19 Primary		E-19 Secondary	
Summer On-Peak	$0.00974	(R)	$0.04106	(R)	$0.02552	(R)
Summer Partial-Peak	$0.03070	(R)	$0.05509	(R)	$0.05515	(R)
Summer Off-Peak	$0.02903	(I)	$0.05122	(I)	$0.05668	(I)
Winter Partial Peak	$0.00726	(R)	$0.03858	(R)	$0.04076	(R)
Winter Off-Peak	$0.02095	(R)	$0.04709	(I)	$0.05359	(I)

Period	E-20 Transmission		E-20 Primary		E-20 Secondary	
Summer On-Peak	$0.04024	(R)	$0.04682	(R)	$0.02517	(R)
Summer Partial-Peak	$0.05413	(R)	$0.06071	(R)	$0.05458	(R)
Summer Off-Peak	$0.05111	(I)	$0.05679	(I)	$0.05611	(I)
Winter Partial Peak	$0.03596	(R)	$0.04445	(R)	$0.04030	(R)
Winter Off-Peak	$0.04479	(R)	$0.05283	(I)	$0.05302	(I)

ELECTRIC SCHEDULE E-FFS Sheet 2
FRANCHISE FEE SURCHARGE

RATES: (Cont'd)

Customer Class	DA/CCA Franchise Fee Surcharge Rate per kWh					
	Pre-2009 Vintage		2009 Vintage		2010 Vintage	
Residential	$0.00083	(R)	$0.00057	(R)	$0.00052	(R)
Small L&P	$0.00080	(R)	$0.00055	(R)	$0.00050	(R)
Medium L&P	$0.00085	(R)	$0.00059	(R)	$0.00053	(R)
E-19	$0.00079	(R)	$0.00055	(R)	$0.00050	(R)
Streetlights	$0.00066	(R)	$0.00046	(R)	$0.00042	(R)
Standby	$0.00060	(R)	$0.00041	(R)	$0.00038	(R)
Agriculture	$0.00074	(R)	$0.00051	(R)	$0.00047	(R)
E-20T	$0.00066	(R)	$0.00045	(R)	$0.00041	(R)
E-20P	$0.00073	(R)	$0.00050	(R)	$0.00046	(R)
E-20S	$0.00075	(R)	$0.00052	(R)	$0.00047	(R)
BEV-1	$0.00080	(R)	$0.00055	(R)	$0.00050	(R)
BEV-2	$0.00079	(R)	$0.00055	(R)	$0.00050	(R)
	2011 Vintage		2012 Vintage		2013 Vintage	
Residential	$0.00051	(R)	$0.00049	(R)	$0.00049	(R)
Small L&P	$0.00048	(R)	$0.00047	(R)	$0.00046	(R)
Medium L&P	$0.00052	(R)	$0.00050	(R)	$0.00050	(R)
E-19	$0.00049	(R)	$0.00047	(R)	$0.00047	(R)
Streetlights	$0.00040	(R)	$0.00039	(R)	$0.00039	(R)
Standby	$0.00037	(R)	$0.00035	(R)	$0.00035	(R)
Agriculture	$0.00045	(R)	$0.00044	(R)	$0.00043	(R)
E-20T	$0.00040	(R)	$0.00038	(R)	$0.00038	(R)
E-20P	$0.00045	(R)	$0.00043	(R)	$0.00043	(R)
E-20S	$0.00046	(R)	$0.00044	(R)	$0.00044	(R)
BEV-1	$0.00048	(R)	$0.00047	(R)	$0.00046	(R)
BEV-2	$0.00049	(R)	$0.00047	(R)	$0.00047	(R)
	2014 Vintage		2015 Vintage		2016 Vintage	
Residential	$0.00048	(R)	$0.00048	(R)	$0.00048	(R)
Small L&P	$0.00046	(R)	$0.00046	(R)	$0.00046	(R)
Medium L&P	$0.00050	(R)	$0.00050	(R)	$0.00049	(R)
E-19	$0.00047	(R)	$0.00046	(R)	$0.00046	(R)
Streetlights	$0.00039	(R)	$0.00039	(R)	$0.00039	(R)
Standby	$0.00035	(R)	$0.00035	(R)	$0.00035	(R)
Agriculture	$0.00043	(R)	$0.00043	(R)	$0.00043	(R)
E-20T	$0.00038	(R)	$0.00038	(R)	$0.00038	(R)
E-20P	$0.00043	(R)	$0.00043	(R)	$0.00043	(R)
E-20S	$0.00044	(R)	$0.00043	(R)	$0.00043	(R)
BEV-1	$0.00046	(R)	$0.00046	(R)	$0.00046	(R)
BEV-2	$0.00047	(R)	$0.00046	(R)	$0.00046	(R)

(Continued)

ELECTRIC SCHEDULE E-FFS
FRANCHISE FEE SURCHARGE

Sheet 3

RATES: (Cont'd)

Customer Class	DA/CCA Franchise Fee Surcharge Rate per kWh					
	2017 Vintage		2018 Vintage		2019 Vintage	
Residential	$0.00048	(R)	$0.00048	(R)	$0.00057	(R)
Small L&P	$0.00046	(R)	$0.00046	(R)	$0.00054	(R)
Medium L&P	$0.00049	(R)	$0.00050	(R)	$0.00058	(R)
E-19	$0.00046	(R)	$0.00047	(R)	$0.00054	(R)
Streetlights	$0.00038	(R)	$0.00039	(R)	$0.00045	(R)
Standby	$0.00035	(R)	$0.00035	(R)	$0.00041	(R)
Agriculture	$0.00043	(R)	$0.00043	(R)	$0.00051	(R)
E-20T	$0.00038	(R)	$0.00038	(R)	$0.00045	(R)
E-20P	$0.00043	(R)	$0.00043	(R)	$0.00050	(R)
E-20S	$0.00043	(R)	$0.00044	(R)	$0.00051	(R)
BEV-1	$0.00046	(R)	$0.00046	(R)	$0.00054	(R)
BEV-2	$0.00046	(R)	$0.00047	(R)	$0.00054	(R)

Customer Class	DA/CCA Franchise Fee Surcharge Rate per kWh			
	2020 Vintage		2021 Vintage	
Residential	$0.00062	(R)	$0.00062	(R)
Small L&P	$0.00059	(R)	$0.00059	(R)
Medium L&P	$0.00064	(R)	$0.00064	(R)
E-19	$0.00059	(R)	$0.00059	(R)
Streetlights	$0.00049	(R)	$0.00049	(R)
Standby	$0.00045	(R)	$0.00045	(R)
Agriculture	$0.00055	(R)	$0.00055	(R)
E-20T	$0.00049	(R)	$0.00049	(R)
E-20P	$0.00054	(R)	$0.00054	(R)
E-20S	$0.00056	(R)	$0.00056	(R)
BEV-1	$0.00059	(R)	$0.00059	(R)
BEV-2	$0.00059	(R)	$0.00059	(R)

ELECTRIC SCHEDULE E-GT
GREEN TARIFF PROGRAM

RATES: (Cont'd.)

Power Charge Indifference Adjustment (PCIA): The customer taking service under Schedule E-GT will pay an amount for PCIA which is set to ensure stranded generation costs are not shifted to non-participating customers when the customer switches to E-GT. PCIA will be assigned based on the date that the customer begins service on E-GT. If a customer begins service in the first six months of the calendar year (e.g., 2016), they are assigned the prior year's vintage (i.e., 2015). If they begin service on or after July 1, they are assigned the vintage for the current year (2016 in this example).

Schedule E-GT charges and credits are shown in the table below, and subject to adjustment annually and as approved by the Commission. No discounts (e.g., FERA, CARE) are applicable to the rates stated herein. The customer will be billed based on the sum of the Solar Charge, the Generation Credit, the Program Charge and the applicable PCIA. A customer will pay the applicable Program Charge based on the year service under this schedule was started.

Customer Class	Solar Charge	Generation Credit		Program Charge**	PCIA		Total	
Residential								
-- 2015 Vintage	$0.06407	($0.11418)	(R)	$0.00996	$0.04472	(I)	$0.00457	(I)
-- 2016 Vintage	$0.06407	($0.11418)	(R)	$0.00996	$0.04493	(I)	$0.00478	(I)
-- 2017 Vintage	$0.06407	($0.11418)	(R)	$0.00996	$0.04506	(I)	$0.00491	(I)
-- 2018 Vintage	$0.06407	($0.11418)	(R)	$0.00996	$0.04482	(I)	$0.00467	(I)
-- 2019 Vintage	$0.06407	($0.11418)	(R)	$0.00996	$0.04439	(I)	$0.00424	(I)
-- 2020 Vintage	$0.06407	($0.11418)	(R)	$0.00996	$0.02887	(I)	($0.01128)	(I)
-- 2021 Vintage	$0.06407	($0.11418)	(R)	$0.00996	$0.02887	(I)	($0.01128)	(I)
Schedule A-1 / B-1								
-- 2015 Vintage	$0.06407	($0.10950)	(R)	$0.00996	$0.04338	(I)	$0.00791	(I)
-- 2016 Vintage	$0.06407	($0.10950)	(R)	$0.00996	$0.04359	(I)	$0.00812	(I)
-- 2017 Vintage	$0.06407	($0.10950)	(R)	$0.00996	$0.04371	(I)	$0.00824	(I)
-- 2018 Vintage	$0.06407	($0.10950)	(R)	$0.00996	$0.04348	(I)	$0.00801	(I)
-- 2019 Vintage	$0.06407	($0.10950)	(R)	$0.00996	$0.04306	(I)	$0.00759	(I)
-- 2020 Vintage	$0.06407	($0.10950)	(R)	$0.00996	$0.02801	(I)	($0.00746)	(I)
-- 2021 Vintage	$0.06407	($0.10950)	(R)	$0.00996	$0.02801	(I)	($0.00746)	(I)
Schedule A-10 / B-10								
-- 2015 Vintage	$0.06407	($0.11715)	(R)	$0.00996	$0.04652	(I)	$0.00340	(I)
-- 2016 Vintage	$0.06407	($0.11715)	(R)	$0.00996	$0.04674	(I)	$0.00362	(I)
-- 2017 Vintage	$0.06407	($0.11715)	(R)	$0.00996	$0.04687	(I)	$0.00375	(I)
-- 2018 Vintage	$0.06407	($0.11715)	(R)	$0.00996	$0.04662	(I)	$0.00350	(I)
-- 2019 Vintage	$0.06407	($0.11715)	(R)	$0.00996	$0.04618	(I)	$0.00306	(I)
-- 2020 Vintage	$0.06407	($0.11715)	(R)	$0.00996	$0.03003	(I)	($0.01309)	(I)
-- 2021 Vintage	$0.06407	($0.11715)	(R)	$0.00996	$0.03003	(I)	($0.01309)	(I)

(Continued)

ELECTRIC SCHEDULE E-GT Sheet 3
GREEN TARIFF PROGRAM

RATES: (Cont'd.)

Customer Class	Solar Charge	Generation Credit		Program Charge**	PCIA		Total	
Schedule E-19 / B-19								
-- 2015 Vintage	$0.06407	($0.10839)	(R)	$0.00996	$0.04264	(I)	$0.00828	(I)
-- 2016 Vintage	$0.06407	($0.10839)	(R)	$0.00996	$0.04284	(I)	$0.00848	(I)
-- 2017 Vintage	$0.06407	($0.10839)	(R)	$0.00996	$0.04296	(I)	$0.00860	(I)
-- 2018 Vintage	$0.06407	($0.10839)	(R)	$0.00996	$0.04273	(I)	$0.00837	(I)
-- 2019 Vintage	$0.06407	($0.10839)	(R)	$0.00996	$0.04232	(I)	$0.00796	(I)
-- 2020 Vintage	$0.06407	($0.10839)	(R)	$0.00996	$0.02752	(I)	($0.00684)	(I)
-- 2021 Vintage	$0.06407	($0.10839)	(R)	$0.00996	$0.02752	(I)	($0.00684)	(I)
Schedule LS-3								
-- 2015 Vintage	$0.06407	($0.09091)	(R)	$0.00996	$0.03562	(I)	$0.01874	(I)
-- 2016 Vintage	$0.06407	($0.09091)	(R)	$0.00996	$0.03579	(I)	$0.01891	(I)
-- 2017 Vintage	$0.06407	($0.09091)	(R)	$0.00996	$0.03589	(I)	$0.01901	(I)
-- 2018 Vintage	$0.06407	($0.09091)	(R)	$0.00996	$0.03570	(I)	$0.01882	(I)
-- 2019 Vintage	$0.06407	($0.09091)	(R)	$0.00996	$0.03536	(I)	$0.01848	(I)
-- 2020 Vintage	$0.06407	($0.09091)	(R)	$0.00996	$0.02300	(I)	$0.00612	(I)
-- 2021 Vintage	$0.06407	($0.09091)	(R)	$0.00996	$0.02300	(I)	$0.00612	(I)
Agriculture and Schedule E-37								
-- 2015 Vintage	$0.06407	($0.10296)	(R)	$0.00996	$0.04037	(I)	$0.01144	(I)
-- 2016 Vintage	$0.06407	($0.10296)	(R)	$0.00996	$0.04056	(I)	$0.01163	(I)
-- 2017 Vintage	$0.06407	($0.10296)	(R)	$0.00996	$0.04067	(I)	$0.01174	(I)
-- 2018 Vintage	$0.06407	($0.10296)	(R)	$0.00996	$0.04045	(I)	$0.01152	(I)
-- 2019 Vintage	$0.06407	($0.10296)	(R)	$0.00996	$0.04007	(I)	$0.01114	(I)
-- 2020 Vintage	$0.06407	($0.10296)	(R)	$0.00996	$0.02606	(I)	($0.00287)	(I)
-- 2021 Vintage	$0.06407	($0.10296)	(R)	$0.00996	$0.02606	(I)	($0.00287)	(I)

(Continued)

ELECTRIC SCHEDULE E-GT Sheet 4
GREEN TARIFF PROGRAM

RATES: (Cont'd.)

Customer Class	Solar Charge	Generation Credit		Program Charge**	PCIA		Total	
Schedule E-20 T / B-20 T								
-- 2015 Vintage	$0.06407	($0.09304)	(R)	$0.00996	$0.03649	(I)	$0.01748	(I)
-- 2016 Vintage	$0.06407	($0.09304)	(R)	$0.00996	$0.03666	(I)	$0.01765	(I)
-- 2017 Vintage	$0.06407	($0.09304)	(R)	$0.00996	$0.03676	(I)	$0.01775	(I)
-- 2018 Vintage	$0.06407	($0.09304)	(R)	$0.00996	$0.03657	(I)	$0.01756	(I)
-- 2019 Vintage	$0.06407	($0.09304)	(R)	$0.00996	$0.03622	(I)	$0.01721	(I)
-- 2020 Vintage	$0.06407	($0.09304)	(R)	$0.00996	$0.02356	(I)	$0.00455	(I)
-- 2021 Vintage	$0.06407	($0.09304)	(R)	$0.00996	$0.02356	(I)	$0.00455	(I)
Schedule E-20 P / B-20 P								
-- 2015 Vintage	$0.06407	($0.09965)	(R)	$0.00996	$0.03911	(I)	$0.01349	(I)
-- 2016 Vintage	$0.06407	($0.09965)	(R)	$0.00996	$0.03929	(I)	$0.01367	(I)
-- 2017 Vintage	$0.06407	($0.09965)	(R)	$0.00996	$0.03940	(I)	$0.01378	(I)
-- 2018 Vintage	$0.06407	($0.09965)	(R)	$0.00996	$0.03919	(I)	$0.01357	(I)
-- 2019 Vintage	$0.06407	($0.09965)	(R)	$0.00996	$0.03882	(I)	$0.01320	(I)
-- 2020 Vintage	$0.06407	($0.09965)	(R)	$0.00996	$0.02525	(I)	($0.00037)	(I)
-- 2021 Vintage	$0.06407	($0.09965)	(R)	$0.00996	$0.02525	(I)	($0.00037)	(I)
Schedule E-20 S / B-20 S								
-- 2015 Vintage	$0.06407	($0.10394)	(R)	$0.00996	$0.04086	(I)	$0.01095	(I)
-- 2016 Vintage	$0.06407	($0.10394)	(R)	$0.00996	$0.04106	(I)	$0.01115	(I)
-- 2017 Vintage	$0.06407	($0.10394)	(R)	$0.00996	$0.04117	(I)	$0.01126	(I)
-- 2018 Vintage	$0.06407	($0.10394)	(R)	$0.00996	$0.04095	(I)	$0.01104	(I)
-- 2019 Vintage	$0.06407	($0.10394)	(R)	$0.00996	$0.04056	(I)	$0.01065	(I)
-- 2020 Vintage	$0.06407	($0.10394)	(R)	$0.00996	$0.02638	(I)	($0.00353)	(I)
-- 2021 Vintage	$0.06407	($0.10394)	(R)	$0.00996	$0.02638	(I)	($0.00353)	(I)

* The Schedule A-1/B-1 class includes Schedules A-1, B-1, A-6, B-6, A-15 and TC-1.
** The program charge includes a marketing and administration charge:

Marketing ($/kWh)	Administration ($/kWh)	Total ($/kWh)
$0.00033	$0.00184	$0.00217

(Continued)

ELECTRIC SCHEDULE E-TOU-B
RESIDENTIAL TIME-OF-USE SERVICE

RATES:

SCHEDULE E-TOU-B RATES

Total Energy Rates ($ per kWh)	PEAK		OFF-PEAK	
Summer (all usage)	$0.41418	(I)	$0.31112	(I)
Winter (all usage)	$0.27671	(I)	$0.25791	(I)

Delivery Minimum Bill Amount ($ per meter per day)	$0.32854
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)

Total bundled service charges shown on customer's bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.***

UNBUNDLING OF SCHEDULE E-TOU-B TOTAL RATES

Generation	PEAK		OFF-PEAK	
Summer (all usage)	$0.21899	(I)	$0.11593	(I)
Winter (all usage)	$0.11215	(I)	$0.09335	(I)
Distribution**				
Summer (all usage)	$0.13320	(I)	$0.13320	(I)
Winter (all usage)	$0.10257	(I)	$0.10257	(I)

Transmission* (all usage)	$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032	
Wildfire Fund Charge (all usage)	$0.00580	
New System Generation Charge (all usage)**	$0.00442	

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* 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.
*** This same assignment of revenues applies to direct access and community choice aggregation customers.

(Continued)

SPECIAL CONDITIONS (Cont'd.):

5. 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, conservation incentive adjustment, 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, conservation incentive adjustment, 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, including exemptions for Medical Baseline and continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

(Continued)

ELECTRIC SCHEDULE E-TOU-C Sheet 2
RESIDENTIAL TIME-OF-USE (PEAK PRICING 4 - 9 p.m. EVERY DAY)

RATES:
(Cont'd.)

E-TOU-C TOTAL RATES

Total Energy Rates ($ per kWh)	PEAK		OFF-PEAK	
Summer				
Total Usage	$0.41813	(I)	$0.35469	(I)
Baseline Credit (Applied to Baseline Usage Only)	($0.07584)	(R)	($0.07584)	(R)
Winter				
Total Usage	$0.32104	(I)	$0.30372	(I)
Baseline Credit (Applied to Baseline Usage Only)	($0.07584)	(R)	($0.07584)	(R)
Delivery Minimum Bill Amount ($ per meter per day)	$0.32854			
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)			

Total bundled service charges shown on customer's bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.

(Continued)

ELECTRIC SCHEDULE E-TOU-C Sheet 3
RESIDENTIAL TIME-OF-USE (PEAK PRICING 4 - 9 p.m. EVERY DAY)

RATES: (Cont'd.)

UNBUNDLING OF E-TOU-C TOTAL RATES

Energy Rates by Component ($ per kWh)	PEAK		OFF-PEAK	
Generation:				
Summer (all usage)	$0.16397	(I)	$0.11053	(I)
Winter (all usage)	$0.11521	(I)	$0.10018	(I)
Distribution:**				
Summer (all usage)	$0.14292	(I)	$0.13292	(I)
Winter (all usage)	$0.09459	(I)	$0.09229	(I)

Conservation Incentive Adjustment (Baseline Usage)	($0.02659)	(R)
Conservation Incentive Adjustment (Over Baseline Usage)	$0.04925	(I)
Transmission* (all usage)	$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032	
Wildfire Fund Charge (all usage)	$0.00580	
New System Generation Charge (all usage)**	$0.00442	

* 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-TOU-C Sheet 7

RESIDENTIAL TIME-OF-USE (PEAK PRICING 4 - 9 p.m. EVERY DAY)

SPECIAL CONDITIONS: (Cont'd.)

2. Opt-in customers: All bundled PG&E customers who are eligible to enroll on this rate will receive bill protection for 12 months from the date that they enroll onto the rate or up to the date that they are unenrolled from this rate, whichever occurs first. Customers must enroll onto the rate before April 2019 to receive bill protection.

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, conservation incentive adjustment, 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.

Community Choice Aggregation and Direct Access (CCA/DA) Customers receive solely delivery services from PG&E. The customer's bill is based on the delivery rate components and conditions set forth in this schedule along with the generation rate components determined by either their CCA or DA provider.

CCA/DA 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, conservation incentive adjustment, 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, including exemptions for Medical Baseline and continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

(Continued)

ELECTRIC SCHEDULE E-TOU-D Sheet 2

RESIDENTIAL TIME-OF-USE PEAK PRICING 5 - 8 p.m. NON-HOLIDAY WEEKDAYS

RATES: (Cont'd.)

TOTAL RATES

Total Energy Rates ($ per kWh)	PEAK		OFF-PEAK	
Summer (all usage)	$0.37644	(I)	$0.28148	(I)
Winter (all usage)	$0.30257	(I)	$0.28519	(I)

Delivery Minimum Bill Amount ($ per meter per day) $0.32854

California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles) ($17.20)

Total bundled service charges shown on customer's bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.***

UNBUNDLING OF TOTAL RATES

Generation	PEAK		OFF-PEAK	
Summer (all usage)	$0.17618	(I)	$0.09122	(I)
Winter (all usage)	$0.13488	(I)	$0.11980	(I)
Distribution**				
Summer (all usage)	$0.13827	(I)	$0.12827	(I)
Winter (all usage)	$0.10570	(I)	$0.10340	(I)

Transmission* (all usage)	$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032	
Wildfire Fund Charge (all usage)	$0.00580	
New System Generation Charge (all usage)**	$0.00442	

* 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.

*** This same assignment of revenues applies to direct access and community choice aggregation customers.

(Continued)

ELECTRIC SCHEDULE E-TOU-D Sheet 5
RESIDENTIAL TIME-OF-USE PEAK PRICING 5 - 8 p.m. NON-HOLIDAY WEEKDAYS

SPECIAL CONDITIONS (Cont'd.):

5. BILLING (Cont'd.):

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

6. 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.

7. 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 service on a time-of-use (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 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.

8. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

(Continued)

ELECTRIC SCHEDULE EM Sheet 1
MASTER-METERED MULTIFAMILY SERVICE

APPLICABILITY: This schedule is applicable to service for residential single-phase and polyphase service supplied to a multifamily accommodation through one meter on a single premises where all of the residential dwelling units are not separately submetered in accordance with Rule 18. This schedule also applies to residential hotels as defined in Rule 1 and to residential RV parks which rent at least 50 percent of their spaces on a month-to-month basis for at least 9 months of the year to RV units used as permanent residences. This schedule is closed to new installations and additions to existing meters. Master meters currently being served under this schedule will be allowed to continue on the rate schedule following a change of ownership provided that no additional units or submeters are added. Customers served under rate schedule EM are also eligible for schedule EM-TOU which is a time-of-use rate schedule.

The provisions of Schedule S—Standby Service Special Conditions 1 through 6 shall also apply to customers whose premises are regularly supplied in part (but not in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S, in addition to all applicable Schedule EM charges. See Special Conditions 12 and 13 of this rate schedule for exemptions to standby charges.

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

RATES: Total bundled service charges are calculated using the total rates below. Customers on this schedule are subject to the delivery minimum bill amount shown below applied to the delivery portion of the bill (i.e. to all rate components other than the generation rate). In addition, total bundled charges will include applicable generation charges per kWh for all kWh usage.

Customers receiving a medical baseline allowance shall pay for all usage in excess of 200 percent of baseline at a rate $0.04000 per kWh less than the applicable rate for usage in excess of 200 percent of baseline. No portion of the rates paid by customers that receive a Medical Baseline allowance shall be used to pay the Wildfire Fund Charge. For these customers, the Conservation Incentive Adjustment is calculated residually based on the total rate less the sum of: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Generation, Public Purpose Programs, Nuclear Decommissioning, New System Generation Charges, Competition Transition Charges (CTC), and Energy Cost Recovery Amount. Customers receiving a medical baseline allowance shall also receive a 50 percent discount on the delivery minimum bill amount 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 Energy Rates ($ per kWh)		
Baseline Usage	$0.25902	(I)
101% - 400% of Baseline	$0.32596	(I)
High Usage Over 400% of Baseline	$0.40745	(I)
Delivery Minimum Bill Amount ($ per meter per day)	$0.32854	
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)	

(Continued)

RATES: (Cont'd.)

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.***

UNBUNDLING OF TOTAL RATES

Energy Rates by Components ($ per kWh)

Generation:	$0.11418	(I)
Distribution:**	$0.11210	(I)
Conservation Incentive Adjustment:		
Baseline Usage	($0.02925)	(R)
101% - 400% of Baseline	$0.03769	(I)
High Usage Over 400% of Baseline	$0.11918	(I)
Transmission* (all usage)	$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032	
Wildfire Fund Charge (all usage)	$0.00580	
New System Generation Charge (all usage)**	$0.00442	

* 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.

*** This same assignment of revenues applies to direct access and community choice aggregation customers.

(Continued)

ELECTRIC SCHEDULE EM Sheet 5
MASTER-METERED MULTIFAMILY SERVICE

SPECIAL CONDITIONS: (Cont'd.)

10. BILLING: (Cont'd.)

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

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, conservation incentive adjustment, 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, conservation incentive adjustment, 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, including exemptions for Medical Baseline and continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA CRS/CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

11. 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.

(Continued)

RATES: Total bundled service charges are calculated using the total rates below. On-peak, part-peak, and off-peak usage is assigned to tiers on a pro-rated basis. For example, if twenty percent of a customer's usage is in the on-peak period, then twenty percent of the total usage in each tier will be treated as on-peak usage. Customers on this schedule are subject to the delivery minimum bill amount shown below applied to the delivery portion of the bill (i.e. to all rate components other than the generation rate). In addition, total bundled charges will include applicable generation charges per kWh for all kWh usage.

Customers receiving a medical baseline allowance shall pay for all usage in excess of 200 percent of baseline at a rate $0.04000 per kWh less than the applicable rate for usage in excess of 200 percent of baseline. No portion of the rates paid by customers that receive a Medical Baseline allowance shall be used to pay the Wildfire Fund Charge. For these customers, the Conservation Incentive Adjustment is calculated residually based on the total rate less the sum of: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Generation, Public Purpose Programs, Nuclear Decommissioning, New System Generation Charges, Competition Transition Charges (CTC), and Energy Cost Recovery Amount. Customers receiving a medical baseline allowance shall also receive a 50 percent discount on the delivery minimum bill amount 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 Energy Rates ($ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Summer						
Baseline Usage	$0.42018	(I)	$0.30174	(I)	$0.22651	(I)
Over100%ofBaseline	$0.49602	(I)	$0.37758	(I)	$0.30235	(I)
Winter						
Baseline Usage	–		$0.24768	(I)	$0.23085	(I)
Over100%ofBaseline	–		$0.32352	(I)	$0.30669	(I)

Total Meter Charge Rate ($ per meter per day)	$0.25298
Delivery Minimum Bill Amount ($ per meter per day)	$0.32854
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)

Total bundled service charges shown on customer's bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.*

* This same assignment of revenues applies to direct access and community choice aggregation customers

(Continued)

ELECTRIC SCHEDULE EM-TOU Sheet 3
RESIDENTIAL TIME OF USE SERVICE

RATES:
(Cont'd.)

UNBUNDLING OF TOTAL RATES

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

Energy Rates by Component ($ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Generation:						
Summer	$0.25218	(I)	$0.13506	(I)	$0.08725	(I)
Winter	–		$0.11379	(I)	$0.10064	(I)
Distribution:**						
Summer	$0.34433	(I)	$0.13955	(I)	$0.07128	(I)
Winter	–		$0.13419	(I)	$0.09047	(I)
Conservation Incentive Adjustment:						
Summer						
Baseline Usage	($0.23832)	(R)	($0.03486)	(R)	$0.00599	(I)
Over 100% of Baseline	($0.16248)	(R)	$0.04098	(R)	$0.08183	(I)
Winter						
Baseline Usage	–		($0.06229)	(R)	($0.02225)	(I)
Over 100% of Baseline	–		$0.01355	(I)	$0.05359	(I)
Transmission* (all usage)	$0.03704		$0.03704		$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017		$0.00017		$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)	$0.01575	(I)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00004		$0.00004		$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00442		$0.00442		$0.00442	

* 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)

SPECIAL CONDITIONS: (Cont'd.)

11. BILLING (Cont'd):
transmission rate adjustments, reliability services, distribution, conservation incentive adjustment, 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, including exemptions for Medical Baseline and continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

12. 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.

13. 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 service on a time-of-use (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 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.

14. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

ELECTRIC SCHEDULE ES
MULTIFAMILY SERVICE

APPLICABILITY: This schedule is applicable to service for residential single-phase and polyphase service supplied to multifamily accommodations in other than a mobile-home park through one meter on a single premises and submetered to all individual tenants in accordance with Rule 18. This rate schedule is closed to new installations as defined in Decision 05-05-026. A customer whose building was constructed prior to December 14, 1981, and was served as a master-meter customer shall be eligible to convert from its master-meter rate schedule to a submetered rate schedule. Buildings originally constructed for a non-residential purpose that have converted to residential use before December 1981 or without the need for a building permit on or after July 1, 1982, shall be eligible to convert from their master-meter rate schedule to a submetered rate schedule.

The provisions of Schedule S—Standby Service Special Conditions 1 through 6 shall also apply to customers whose premises are regularly supplied in part (but not in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S, in addition to all applicable Schedule ES charges. See Special Conditions 12 and 13 of this rate schedule for exemptions to standby charges.

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

RATES: Total bundled service charges are calculated using the total rates below. Customers on this schedule are subject to the delivery minimum bill amount shown below applied to the delivery portion of the bill (i.e. to all rate components other than the generation rate). In addition, total bundled charges will include applicable generation charges per kWh for all kWh usage.

Customers receiving a medical baseline allowance shall pay for all usage in excess of 200 percent of baseline at a rate $0.04000 per kWh less than the applicable rate for usage in excess of 200 percent of baseline. No portion of the rates paid by customers that receive a Medical Baseline allowance shall be used to pay the Wildfire Fund Charge. For these customers, the Conservation Incentive Adjustment generation is calculated residually based on the total rate less the sum of: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Generation, Public Purpose Programs, Nuclear Decommissioning, New System Generation Charges, Competition Transition Charges (CTC), and Energy Cost Recovery Amount. Customers receiving a medical baseline allowance shall also receive a 50 percent discount on the delivery minimum bill amount 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 Energy Rates ($ per kWh)		
Baseline Usage	$0.25902	(I)
101% - 400% of Baseline	$0.32596	(I)
High Usage Over 400% of Baseline	$0.40745	(I)
Total Minimum Average Rate Limiter ($ per kWh)	$0.04892	
Delivery Minimum Bill Amount ($ per meter per day)	$0.32854	
Total Discount ($ per dwelling unit per day)	$0.03115	
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)	

(Continued)

ELECTRIC SCHEDULE ES
MULTIFAMILY SERVICE

RATES: (Cont'd.)

Total bundled service charges shown on customers' bills are unbundled according to component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.***

UNBUNDLING OF TOTAL RATES

Discount: Discount rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.

Energy Rates by Component ($ per kWh)

Generation:	$0.11418	(I)
Distribution:**	$0.11210	(I)
Conservation Incentive Adjustment:		
Baseline Usage	($0.02925)	(R)
101% - 400% of Baseline	$0.03769	(I)
High Usage Over 400% of Baseline	$0.11918	(I)
Transmission* (all usage)	$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032	
Wildfire Fund Charge (all usage)	$0.00580	
New System Generation Charge (all usage)**	$0.00442	

Minimum Average Rate Limiter by Components ($ per kWh)

Generation	$0.03834
Competition Transition Charges	$0.00004
Energy Cost Recovery Amount	$0.00032
Wildfire Fund Charge	$0.00580
New System Generation Charge**	$0.00442

* 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.
*** This same assignment of revenues applies to direct access and community choice aggregation customers.

(Continued)

SPECIAL CONDITIONS: (Cont'd.)

10. 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, conservation incentive adjustment, 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, conservation incentive adjustment, 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, including exemptions for Medical Baseline and continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA CRS/ CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

11. 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.

(Continued)

ELECTRIC SCHEDULE ESR Sheet 1

RESIDENTIAL RV PARK AND RESIDENTIAL MARINA SERVICE

APPLICABILIT: This schedule is applicable to single-phase and polyphase service supplied to a residential recreational vehicle (RV) park or a residential marina through a master meter on a single premises where all of the RV spaces or marina slips/berths are submetered in accordance with Rule 18 and rented to a prepaid monthly basis to RVs or boats used as permanent residences.

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 ESR charges. See Special Conditions 12 and 13 of this rate schedule for exemptions to standby charges.

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

RATES: Total bundled service charges are calculated using the total rates below. Customers on this schedule are subject to the delivery minimum bill amount shown below applied to the delivery portion of the bill (i.e. to all rate components other than the generation rate). In addition, total bundled charges will include applicable generation charges per kWh for all kWh usage.

Customers receiving a medical baseline allowance shall pay for all usage in excess of 200 percent of baseline at a rate $0.04000 per kWh less than the applicable rate for usage in excess of 200 percent of baseline. No portion of the rates paid by customers that receive a Medical Baseline allowance shall be used to pay the Wildfire Fund Charge. For these customers, the Conservation Incentive Adjustment is calculated residually based on the total rate less the sum of: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Generation, Public Purpose Programs, Nuclear Decommissioning, New System Generation Charges, Competition Transition Charges (CTC), and Energy Cost Recovery Amount. Customers receiving a medical baseline allowance shall also receive a 50 percent discount on the delivery minimum bill amount 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 Energy Rates ($ per kWh)		
Baseline Usage	$0.25902	(I)
101% - 400% of Baseline	$0.32596	(I)
High Usage Over 400% of Baseline	$0.40745	(I)
Delivery Minimum Bill Amount ($ per meter per day)	$0.32854	
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)	

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.*

* This same assignment of revenues applies to direct access and community choice aggregation customers*

(Continued)

ELECTRIC SCHEDULE ESR Sheet 2

RESIDENTIAL RV PARK AND RESIDENTIAL MARINA SERVICE

RATES:
(Cont'd.)

UNBUNDLING OF TOTAL RATES

Energy Rates by Component ($ per kWh)

Generation:	$0.11418	(I)
Distribution:**	$0.11210	(I)
Conversation Incentive Adjustment:		
Baseline Usage	($0.02925)	(R)
101% - 400% of Baseline	$0.03769	(I)
High Usage Over 400% of Baseline	$0.11918	(I)
Transmission* (all usage)	$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032	
Wildfire Fund Charge (all usage)	$0.00580	
New System Generation Charge (all usage)**	$0.00442	

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* 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)

SPECIAL CONDITIONS: (Cont'd.)

10. BILLING: (Cont'd.)

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

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, conservation incentive adjustment, 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, conservation incentive adjustment, 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, including exemptions for Medical Baseline and continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

11. 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.

(Continued)

ELECTRIC SCHEDULE ET
MOBILEHOME PARK SERVICE

APPLICABILITY: This schedule is applicable to single-phase and polyphase service supplied to a mobilehome park through a master meter on a single premises and submetered to all individual tenants in accordance with Rule 18. This schedule is closed to the new mobilehome parks and manufactured housing communities for which construction commenced after January 1, 1997.

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 ET charges. See Special Conditions 13 and 14 of this rate schedule for exemptions to standby charges.

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

RATES: Total bundled service charges are calculated using the total rates below. Customers on this schedule are subject to the delivery minimum bill amount shown below applied to the delivery portion of the bill (i.e. to all rate components other than the generation rate). In addition, total bundled charges will include applicable generation charges per kWh for all kWh usage.

Customers receiving a medical baseline allowance shall pay for all usage in excess of 200 percent of baseline at a rate $0.04000 per kWh less than the applicable rate for usage in excess of 200 percent of baseline. No portion of the rates paid by customers that receive a Medical Baseline allowance shall be used to pay the Wildfire Fund Charge. For these customers, the Conservation Incentive Adjustment is calculated residually based on the total rate less the sum of: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Generation, Public Purpose Programs, Nuclear Decommissioning, New System Generation Charges, Competition Transition Charges (CTC), and Energy Cost Recovery Amount. Customers receiving a medical baseline allowance shall also receive a 50 percent discount on the delivery minimum bill amount 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 Energy Rates ($ per kWh)		
Baseline Usage	$0.25902	(I)
101% - 400% of Baseline	$0.32596	(I)
High Usage Over 400% of Baseline	$0.40745	(I)
Total Minimum Average Rate Limiter ($ per kWh)	$0.04892	
Delivery Minimum Bill Amount ($ per meter per day)	$0.32854	
Total Discount ($ per dwelling unit per day)	$0.06181	
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)	

(Continued)

RATES:
(Cont'd.)

TOTAL RATES (Cont'd)

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.***

UNBUNDLING OF TOTAL RATES

Discount: Discount rates provided in the Total Rates section above are assigned entirely to the unbundled distribution component.

Energy Rates by Component ($ per kWh)

Generation:	$0.11418	(I)
Distribution:**	$0.11210	(I)
Conservation Incentive Adjustment:		
Baseline Usage	($0.02925)	(R)
101% - 400% of Baseline	$0.03769	(I)
High Usage Over 400% of Baseline	$0.11918	(I)
Transmission* (all usage)	$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093	
Competition Transition Charges (all usage)	$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032	
Wildfire Fund Charge (all usage)	$0.00580	
New System Generation Charge (all usage)**	$0.00442	

Minimum Average Rate Limiter by Components ($ per kWh)

Generation	$0.03834
Competition Transition Charges	$0.00004
Energy Cost Recovery Amount	$0.00032
Wildfire Fund Charge	$0.00580
New System Generation Charge**	$0.00442

* 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.
*** This same assignment of revenues applies to direct access and community choice aggregation customers.

(Continued)

SPECIAL CONDITIONS: (Cont'd.)

11. 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, conservation incentive adjustment, 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, conservation incentive adjustment, 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, including exemptions for Medical Baseline and continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

12. 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.

(Continued)

ELECTRIC SCHEDULE EV Sheet 2
RESIDENTIAL TIME-OF-USE
SERVICE FOR PLUG-IN ELECTRIC VEHICLE CUSTOMERS

RATES:(Cont'd.)

TOTAL RATE

Rate A

Total Energy Rates ($ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Summer Usage	$0.56201	(I)	$0.30714	(I)	$0.14381	(R)
Winter Usage	$0.40828	(I)	$0.24768	(I)	$0.14722	(R)

Delivery Minimum Bill Amount ($ per meter per day)	$0.32854
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)

Total bundled service charges shown on a customer's bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.***

UNBUNDLING OF TOTAL RATES

Energy Rates by Component ($ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Generation:						
Summer Usage	$0.26927	(I)	$0.12977	(I)	$0.06521	(I)
Winter Usage	$0.10062	(I)	$0.06286	(I)	$0.06754	(I)
Distribution:**						
Summer Usage	$0.23075	(I)	$0.11538	(I)	$0.01661	(I)
Winter Usage	$0.24567	(I)	$0.12283	(I)	$0.01769	(I)
Transmission* (all usage)	$0.03704		$0.03704		$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017		$0.00017		$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)	$0.01575	(I)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00004		$0.00004		$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00442		$0.00442		$0.00442	

* 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.
*** This same assignment of revenues applies to direct access and community choice aggregation customers.

(Continued)

ELECTRIC SCHEDULE EV Sheet 3
RESIDENTIAL TIME-OF-USE
SERVICE FOR PLUG-IN ELECTRIC VEHICLE CUSTOMERS

RATES: (Cont'd.)

TOTAL RATES

Rate B

Total Energy Rates ($ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Summer Usage	$0.55602	(I)	$0.30415	(I)	$0.14338	(R)
Winter Usage	$0.40191	(I)	$0.24450	(I)	$0.14676	(R)

Total Meter Charge Per Day $0.04928

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

UNBUNDLING OF TOTAL RATES

Meter Charge Rate: Meter charge rate provided in the Total Rate section above are assigned entirely to the unbundled distribution component.

Energy Rates by Component ($ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Generation:						
Summer	$0.26927	(I)	$0.12977	(I)	$0.06521	(I)
Winter	$0.10062	(I)	$0.06286	(I)	$0.06754	(I)
Distribution:**						
Summer	$0.22476	(I)	$0.11239	(I)	$0.01618	(I)
Winter	$0.23930	(I)	$0.11965	(I)	$0.01723	(I)
Transmission* (all usage)	$0.03704		$0.03704		$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017		$0.00017		$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)	$0.01575	(I)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00004		$0.00004		$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00442		$0.00442		$0.00442	

* 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 EV Sheet 5
RESIDENTIAL TIME-OF-USE
SERVICE FOR PLUG-IN ELECTRIC VEHICLE CUSTOMERS

SPECIAL CONDITIONS: (Cont'd.)

4. 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, the new system generation charge, 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, including exemptions continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

(Continued)

ELECTRIC SCHEDULE EV2 Sheet 2
RESIDENTIAL TIME-OF-USE
SERVICE FOR PLUG-IN ELECTRIC VEHICLE CUSTOMERS

RATES:(Cont'd.)

TOTAL RATE

Total Energy Rates ($ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Summer Usage	$0.49616	(I)	$0.38567	(I)	$0.18366	(I)
Winter Usage	$0.36905	(I)	$0.35235	(I)	$0.18366	(I)

Delivery Minimum Bill Amount ($ per meter per day)	$0.32854
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($17.20)

Total bundled service charges shown on a customer's bills are unbundled according to the component rates shown below. Where the delivery minimum bill amount applies, the customer's bill will equal the sum of (1) the delivery minimum bill amount plus (2) for bundled service, the generation rate times the number of kWh used. For revenue accounting purposes, the revenues from the delivery minimum bill amount will be assigned to the Transmission, Transmission Rate Adjustments, Reliability Services, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges, Energy Cost Recovery Amount, Wildfire Fund Charge, and New System Generation Charges based on kWh usage times the corresponding unbundled rate component per kWh, with any residual revenue assigned to Distribution.***

UNBUNDLING OF TOTAL RATES

Energy Rates by Component ($ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Generation:						
Summer Usage	$0.18150	(I)	$0.13679	(I)	$0.09565	(I)
Winter Usage	$0.12462	(I)	$0.11214	(I)	$0.08866	(I)
Distribution:**						
Summer Usage	$0.25267	(I)	$0.18689	(I)	$0.02602	(I)
Winter Usage	$0.18244	(I)	$0.17822	(I)	$0.03301	(I)
Transmission* (all usage)	$0.03704		$0.03704		$0.03704	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00017		$0.00017		$0.00017	
Public Purpose Programs (all usage)	$0.01575	(I)	$0.01575	(I)	$0.01575	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges (all usage)	$0.00004		$0.00004		$0.00004	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00442		$0.00442		$0.00442	

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* 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.
*** This same assignment of revenues applies to direct access and community choice aggregation customers.

(Continued)

ELECTRIC SCHEDULE EV2 Sheet 4
RESIDENTIAL TIME-OF-USE
SERVICE FOR PLUG-IN ELECTRIC VEHICLE CUSTOMERS

SPECIAL CONDITIONS: (Cont'd.)

4. 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, the new system generation charge, 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, including exemptions continuous DA service, are set forth in Schedules DA CRS and CCA CRS.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03511	(I)
2010 Vintage	$0.04227	(I)
2011 Vintage	$0.04417	(I)
2012 Vintage	$0.04677	(I)
2013 Vintage	$0.04699	(I)
2014 Vintage	$0.04703	(I)
2015 Vintage	$0.04725	(I)
2016 Vintage	$0.04756	(I)
2017 Vintage	$0.04760	(I)
2018 Vintage	$0.04705	(I)
2019 Vintage	$0.03583	(I)
2020 Vintage	$0.02887	(I)
2021 Vintage	$0.02887	(I)

(Continued)

ELECTRIC SCHEDULE LS-1 Sheet 2
PG&E-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

Facilities Charge Per Lamp Per Month

CLASS	A	B	C**	D	E	F
	$6.849	$7.126	$6.680	$9.331	$9.664	$7.828
LED Program Incremental Facility Charge	$0.000		$0.000	$12.768	$0.000	$0.000

Energy Charge Per Lamp Per Month
All Night Rates

LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS	All Night Rate		Half-Hour Adjustment	
INCANDESCENTLAMPS*:						
58	20	600	$3.751	(I)	$0.171	(I)
92	31	1,000	$5.814	(I)	$0.264	(I)
189	65	2,500	$12.190	(I)	$0.554	(I)
295	101	4,000	$18.942	(I)	$0.861	(I)
405	139	6,000	$26.068	(I)	$1.185	(I)
MERCURYVAPORLAMPS*:						
100	40	3,500	$7.502	(I)	$0.341	(I)
175	68	7,500	$12.753	(I)	$0.580	(I)
250	97	11,000	$18.191	(I)	$0.827	(I)
400	152	21,000	$28.506	(I)	$1.296	(I)
700	266	37,000	$49.886	(I)	$2.268	(I)
HIGHPRESSURESODIUMVAPORLAMPS***:						
120 Volts						
70	29	5,800	$5.439	(I)	$0.247	(I)
100	41	9,500	$7.689	(I)	$0.350	(I)
150	60	16,000	$11.252	(I)	$0.511	(I)
200	80	22,000	$15.003	(I)	$0.682	(I)
250	100	26,000	$18.754	(I)	$0.852	(I)
400	154	46,000	$28.881	(I)	$1.313	(I)
240 Volts						
70	34	5,800	$6.376	(I)	$0.290	(I)
100	47	9,500	$8.814	(I)	$0.401	(I)
150	69	16,000	$12.940	(I)	$0.588	(I)
200	81	22,000	$15.191	(I)	$0.691	(I)
250	100	25,500	$18.754	(I)	$0.852	(I)
400	154	46,000	$28.881	(I)	$1.313	(I)

* Closed to new installations per Advice 669-E, effective June 8, 1978.
** Closed to new mixed ownership installations. See Special Condition 4.
*** Closed to new installations for all Classes except D per Advice 5652-E

(Continued)

ELECTRIC SCHEDULE LS-1 Sheet 4
PG&E-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT-EMITTING DIODE (LED) LAMPS: 120-240 VOLTS

Nominal Lamp Ratings					
LAMP WATTS***	kWh per MONTH****	A, C, D, E and F Only Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
0.0-5.0	0.9	$0.169	(I)	$0.008	
5.1-10.0	2.6	$0.488	(I)	$0.022	
10.1-15.0	4.3	$0.806	(I)	$0.037	(I)
15.1-20.0	6.0	$1.125	(I)	$0.051	(I)
20.1-25.0	7.7	$1.444	(I)	$0.066	(I)
25.1-30.0	9.4	$1.763	(I)	$0.080	(I)
30.1-35.0	11.1	$2.082	(I)	$0.095	(I)
35.1-40.0	12.8	$2.401	(I)	$0.109	(I)
40.1-45.0	14.5	$2.719	(I)	$0.124	(I)
45.1-50.0	16.2	$3.038	(I)	$0.138	(I)
50.1-55.0	17.9	$3.357	(I)	$0.153	(I)
55.1-60.0	19.6	$3.676	(I)	$0.167	(I)
60.1-65.0	21.4	$4.013	(I)	$0.182	(I)
65.1-70.0	23.1	$4.332	(I)	$0.197	(I)
70.1-75.0	24.8	$4.651	(I)	$0.211	(I)
75.1-80.0	26.5	$4.970	(I)	$0.226	(I)
80.1-85.0	28.2	$5.289	(I)	$0.240	(I)
85.1-90.0	29.9	$5.607	(I)	$0.255	(I)
90.1-95.0	31.6	$5.926	(I)	$0.269	(I)

*** Wattage based on total consumption of lamp and driver.

**** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is:
(high wattage in range-2.5 watts)x(4,100 hours/12 months/1000)

(Continued)

ELECTRIC SCHEDULE LS-1 Sheet 5
PG&E-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT EMITTING DIODE (LED) LAMPS: 120-240 VOLTS (Cont'd.)

Nominal Lamp Ratings					
LAMP WATTS***	kWh per MONTH****	A, C, D, E and F Only Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
95.1-100.0	33.3	$6.245	(I)	$0.284	(I)
100.1-105.1	35.0	$6.564	(I)	$0.298	(I)
105.1-110.0	36.7	$6.883	(I)	$0.313	(I)
110.1-115.0	38.4	$7.202	(I)	$0.327	(I)
115.1-120.0	40.1	$7.520	(I)	$0.342	(I)
120.1-125.0	41.9	$7.858	(I)	$0.357	(I)
125.1-130.0	43.6	$8.177	(I)	$0.372	(I)
130.1-135.0	45.3	$8.496	(I)	$0.386	(I)
135.1-140.0	47.0	$8.814	(I)	$0.401	(I)
140.1-145.0	48.7	$9.133	(I)	$0.415	(I)
145.1-150.0	50.4	$9.452	(I)	$0.430	(I)
150.1-155.0	52.1	$9.771	(I)	$0.444	(I)
155.1-160.0	53.8	$10.090	(I)	$0.459	(I)

*** Wattage based on total consumption of lamp and driver.

**** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is: (high wattage in range-2.5 watts)x(4,100 hours/12 months/1000)

(Continued)

ELECTRIC SCHEDULE LS-1 Sheet 6
PG&E-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT-EMITTING DIODE (LED) LAMPS: 120-240 VOLTS (Cont'd.)

Nominal Lamp Ratings					
LAMP WATTS***	kWh per MONTH****	A, C, D, E and F Only Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
160.1-165.0	55.5	$10.408	(I)	$0.473	(I)
165.1-170.0	57.2	$10.727	(I)	$0.488	(I)
170.1-175.0	58.9	$11.046	(I)	$0.502	(I)
175.1-180.0	60.6	$11.365	(I)	$0.517	(I)
180.1-185.0	62.4	$11.702	(I)	$0.532	(I)
185.1-190.0	64.1	$12.021	(I)	$0.546	(I)
190.1-195.0	65.8	$12.340	(I)	$0.561	(I)
195.1-200.0	67.5	$12.659	(I)	$0.575	(I)
200.1-205.0	69.2	$12.978	(I)	$0.590	(I)
205.1-210.0	70.9	$13.297	(I)	$0.604	(I)
210.1-215.0	72.6	$13.615	(I)	$0.619	(I)
215.1-220.0	74.3	$13.934	(I)	$0.633	(I)
220.1-225.0	76.0	$14.253	(I)	$0.648	(I)
225.1-230.0	77.7	$14.572	(I)	$0.662	(I)
230.1-235.0	79.4	$14.891	(I)	$0.677	(I)
235.1-240.0	81.1	$15.209	(I)	$0.691	(I)
240.1-245.0	82.9	$15.547	(I)	$0.707	(I)
245.1-250.0	84.6	$15.866	(I)	$0.721	(I)

*** Wattage based on total consumption of lamp and driver.
**** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is:
(high wattage in range-2.5 watts)x(4,100 hours/12 months/1000)

(Continued)

ELECTRIC SCHEDULE LS-1 Sheet 7
PG&E-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT-EMITTING DIODE (LED) LAMPS: 120-240 VOLTS (Cont'd.)

Nominal Lamp Ratings					
LAMP WATTS***	kWh per MONTH****	A, C, D, E and F Only Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
250.1-255.0	86.3	$16.185	(I)	$0.736	(I)
255.1-260.0	88.0	$16.504	(I)	$0.750	(I)
260.1-265.0	89.7	$16.822	(I)	$0.765	(I)
265.1-270.0	91.4	$17.141	(I)	$0.779	(I)
270.1-275.0	93.1	$17.460	(I)	$0.794	(I)
275.1-280.0	94.8	$17.779	(I)	$0.808	(I)
280.1-285.0	96.5	$18.098	(I)	$0.823	(I)
285.1-290.0	98.2	$18.416	(I)	$0.837	(I)
290.1-295.0	99.9	$18.735	(I)	$0.852	(I)
295.1-300.0	101.6	$19.054	(I)	$0.866	(I)
300.1-305.0	103.4	$19.392	(I)	$0.881	(I)
305.1-310.0	105.1	$19.710	(I)	$0.896	(I)
310.1-315.0	106.8	$20.029	(I)	$0.910	(I)
315.1-320.0	108.5	$20.348	(I)	$0.925	(I)
320.1-325.0	110.2	$20.667	(I)	$0.939	(I)
325.1-330.0	111.9	$20.986	(I)	$0.954	(I)

*** Wattage based on total consumption of lamp and driver.
**** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is:
(high wattage in range-2.5 watts)x(4,100 hours/12 months/1000)

(Continued)

ELECTRIC SCHEDULE LS-1 Sheet 8
PG&E-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT-EMITTING DIODE (LED) LAMPS: 120-240 VOLTS (Cont'd.)

Nominal Lamp Ratings					
LAMP WATTS***	kWh per MONTH****	A, C, D, E and F Only Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
330.1-335.0	113.6	$21.305	(I)	$0.968	(I)
335.1-340.0	115.3	$21.623	(I)	$0.983	(I)
340.1-345.0	117.0	$21.942	(I)	$0.997	(I)
345.1-350.0	118.7	$22.261	(I)	$1.012	(I)
350.1-355.0	120.4	$22.580	(I)	$1.026	(I)
355.1-360.0	122.1	$22.899	(I)	$1.041	(I)
360.1-365.0	123.9	$23.236	(I)	$1.056	(I)
365.1-370.0	125.6	$23.555	(I)	$1.071	(I)
370.1-375.0	127.3	$23.874	(I)	$1.085	(I)
375.1-380.0	129.0	$24.193	(I)	$1.100	(I)
380.1-385.0	130.7	$24.511	(I)	$1.114	(I)
385.1-390.0	132.4	$24.830	(I)	$1.129	(I)
390.1-395.0	134.1	$25.149	(I)	$1.143	(I)
395.0-400.0	135.8	$25.468	(I)	$1.158	(I)

*** Wattage based on total consumption of lamp and driver.
**** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is: (high wattage in range-2.5 watts)x(4,100 hours/12 months/1000)

(Continued)

RATES: (Cont'd.)

TOTAL ENERGY RATES

Total Energy Charge Rate ($ per kWh)	$0.18754	(I)

UNBUNDLING OF TOTAL ENERGY CHARGES

The total energy charge is unbundled according to the component rates shown below.

Energy Rate by Components ($ per kWh)		
Generation	$0.09091	(I)
Distribution**	$0.05985	(I)
Transmission*	$0.02377	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)
Reliability Services*	$0.00011	
Public Purpose Programs	$0.00532	(I)
Nuclear Decommissioning	$0.00093	
Competition Transition Charge	$0.00003	
Energy Cost Recovery Amount	$0.00032	
Wildfire Fund Charge	$0.00580	
New System Generation Charge	$0.00298	

* 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.

SPECIAL CONDITIONS: (Cont'd.)

17. **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.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.02796	(I)
2010 Vintage	$0.03367	(I)
2011 Vintage	$0.03518	(I)
2012 Vintage	$0.03725	(I)
2013 Vintage	$0.03743	(I)
2014 Vintage	$0.03746	(I)
2015 Vintage	$0.03763	(I)
2016 Vintage	$0.03788	(I)
2017 Vintage	$0.03791	(I)
2018 Vintage	$0.03748	(I)
2019 Vintage	$0.02854	(I)
2020 Vintage	$0.02300	(I)
2021 Vintage	$0.02300	(I)

18. **WILDFIRE FUND CHARGE:** The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

ELECTRIC SCHEDULE LS-2 Sheet 2
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

Facilities Charge Per Lamp Per Month

CLASS:	A	C***
	PG&E supplies energy and service only.	PG&E supplies the energy and maintenance service as described in Special Condition 8
	$0.207	$3.994

Energy Charge Per Lamp Per Month
All Night Rates

Nominal Lamp Rating:

LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS*	Per Lamp Per Month: All Classes		Per Lamp Per Month: Half-Hour Adjustment	
INCANDESCENT LAMPS:						
58	20	600	$3.751	(I)	$0.171	(I)
92	31	1,000	$5.814	(I)	$0.264	(I)
189	65	2,500	$12.190	(I)	$0.554	(I)
295	101	4,000**	$18.942	(I)	$0.861	(I)
405	139	6,000**	$26.068	(I)	$1.185	(I)
620	212	10,000**	$39.758	(I)	$1.807	(I)
860	294	15,000**	$55.137	(I)	$2.506	(I)
MERCURY VAPOR LAMPS:						
40	18	1,300	$3.376	(I)	$0.153	(I)
50	22	1,650	$4.126	(I)	$0.188	(I)
100	40	3,500	$7.502	(I)	$0.341	(I)
175	68	7,500	$12.753	(I)	$0.580	(I)
250	97	11,000	$18.191	(I)	$0.827	(I)
400	152	21,000	$28.506	(I)	$1.296	(I)
700	266	37,000	$49.886	(I)	$2.268	(I)
1,000	377	57,000	$70.703	(I)	$3.214	(I)

* Latest published information should be consulted on best available lumens.

** Service for incandescent lamps over 2,500 lumens will be closed to new installations after September 11, 1978.

*** Closed to new installations and new lamps on existing circuits, see Condition 8A.

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 3
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS	All Classes		Half-Hour Adjustment	
HIGH PRESSURE SODIUM VAPOR LAMPS AT: 120 VOLTS						
35	15	2,150	$2.813	(I)	$0.128	(I)
50	21	3,800	$3.938	(I)	$0.179	(I)
70	29	5,800	$5.439	(I)	$0.247	(I)
100	41	9,500	$7.689	(I)	$0.350	(I)
150	60	16,000	$11.252	(I)	$0.511	(I)
200	80	22,000	$15.003	(I)	$0.682	(I)
250	100	26,000	$18.754	(I)	$0.852	(I)
400	154	46,000	$28.881	(I)	$1.313	(I)
HIGH PRESSURE SODIUM VAPOR LAMPS AT: 240 VOLTS						
50	24	3,800	$4.501	(I)	$0.205	(I)
70	34	5,800	$6.376	(I)	$0.290	(I)
100	47	9,500	$8.814	(I)	$0.401	(I)
150	69	16,000	$12.940	(I)	$0.588	(I)
200	81	22,000	$15.191	(I)	$0.691	(I)
250	100	25,500	$18.754	(I)	$0.852	(I)
310	119	37,000	$22.317	(I)	$1.014	(I)
360	144	45,000	$27.006	(I)	$1.228	(I)
400	154	46,000	$28.881	(I)	$1.313	(I)
LOW PRESSURE SODIUM VAPOR LAMPS:						
35	21	4,800	$3.938	(I)	$0.179	(I)
55	29	8,000	$5.439	(I)	$0.247	(I)
90	45	13,500	$8.439	(I)	$0.384	(I)
135	62	21,500	$11.627	(I)	$0.529	(I)
180	78	33,000	$14.628	(I)	$0.665	(I)

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 4
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LAMP WATTS	kWh per MONTH	AVERAGE INITIAL LUMENS	All Classes		Half-Hour Adjustment	
METAL HALIDE LAMPS:						
70	30	5,500	$5.626	(I)	$0.256	(I)
100	41	8,500	$7.689	(I)	$0.350	(I)
150	63	13,500	$11.815	(I)	$0.537	(I)
175	72	14,000	$13.503	(I)	$0.614	(I)
250	105	20,500	$19.692	(I)	$0.895	(I)
400	162	30,000	$30.381	(I)	$1.381	(I)
1,000	387	90,000	$72.578	(I)	$3.299	(I)
INDUCTION LAMPS:						
23	9	1,840	$1.688	(I)	$0.077	(I)
35	13	2,450	$2.438	(I)	$0.111	(I)
40	14	2,200	$2.626	(I)	$0.119	(I)
50	18	3,500	$3.376	(I)	$0.153	(I)
55	19	3,000	$3.563	(I)	$0.162	(I)
65	24	5,525	$4.501	(I)	$0.205	(I)
70	27	6,500	$5.064	(I)	$0.230	(I)
80	28	4,500	$5.251	(I)	$0.239	(I)
85	30	4,800	$5.626	(I)	$0.256	(I)
100	36	8,000	$6.751	(I)	$0.307	(I)
120	42	8,500	$7.785	(I)	$0.354	(I)
135	48	9,450	$9.002	(I)	$0.409	(I)
150	51	10,900	$9.565	(I)	$0.435	(I)
165	58	12,000	$10.877	(I)	$0.494	(I)
200	72	19,000	$13.503	(I)	$0.614	(I)

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 5
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT EMITTING DIODE (LED) LAMPS OR COMPARABLE LIGHTING TECHNOLOGY (unless otherwise specified in this tariff):

LAMP WATTS****	kWh per MONTH*****	Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
0.00-5.00	0.9	$0.169	(I)	$0.008	
5.01-10.00	2.6	$0.488	(I)	$0.022	
10.01-15.00	4.3	$0.806	(I)	$0.037	(I)
15.01-20.00	6.0	$1.125	(I)	$0.051	(I)
20.01-25.00	7.7	$1.444	(I)	$0.066	(I)
25.01-30.00	9.4	$1.763	(I)	$0.080	(I)
30.01-35.00	11.1	$2.082	(I)	$0.095	(I)
35.01-.40.00	12.8	$2.401	(I)	$0.109	(I)
40.01-45.00	14.5	$2.719	(I)	$0.124	(I)
45.01-50.00	16.2	$3.038	(I)	$0.138	(I)
50.01-55.00	17.9	$3.357	(I)	$0.153	(I)
55.01-60.00	19.6	$3.676	(I)	$0.167	(I)
60.01-65.00	21.4	$4.013	(I)	$0.182	(I)
65.01-70.00	23.1	$4.332	(I)	$0.197	(I)
70.01-75.00	24.8	$4.651	(I)	$0.211	(I)
75.01-80.00	26.5	$4.970	(I)	$0.226	(I)
80.01-85.00	28.2	$5.289	(I)	$0.240	(I)
85.01-90.00	29.9	$5.607	(I)	$0.255	(I)
90.01-95.00	31.6	$5.926	(I)	$0.269	(I)
95.01-100.00	33.3	$6.245	(I)	$0.284	(I)
100.01-105.00	35.0	$6.564	(I)	$0.298	(I)
105.01-110.00	36.7	$6.883	(I)	$0.313	(I)
110.01-115.00	38.4	$7.202	(I)	$0.327	(I)
115.01-120.00	40.1	$7.520	(I)	$0.342	(I)
120.01-125.00	41.9	$7.858	(I)	$0.357	(I)
125.01-130.00	43.6	$8.177	(I)	$0.372	(I)
130.01-135.00	45.3	$8.496	(I)	$0.386	(I)
135.01-140.00	47.0	$8.814	(I)	$0.401	(I)
140.01-145.00	48.7	$9.133	(I)	$0.415	(I)

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 6
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT EMITTING DIODE (LED) LAMPS OR COMPARABLE LIGHTING TECHNOLOGY (unless otherwise specified in this tariff): (Cont'd.)

LAMP WATTS****	kWh per MONTH*****	Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
145.01-150.00	50.4	$9.452	(I)	$0.430	(I)
150.01-155.00	52.1	$9.771	(I)	$0.444	(I)
155.01-160.00	53.8	$10.090	(I)	$0.459	(I)
160.01-165.00	55.5	$10.408	(I)	$0.473	(I)
165.01-170.00	57.2	$10.727	(I)	$0.488	(I)
170.01-175.00	58.9	$11.046	(I)	$0.502	(I)
175.01-180.00	60.6	$11.365	(I)	$0.517	(I)
180.01-185.00	62.4	$11.702	(I)	$0.532	(I)
185.01-190.00	64.1	$12.021	(I)	$0.546	(I)
190.01-195.00	65.8	$12.340	(I)	$0.561	(I)
195.01-200.00	67.5	$12.659	(I)	$0.575	(I)
200.01-205.00	69.2	$12.978	(I)	$0.590	(I)
205.01-210.00	70.9	$13.297	(I)	$0.604	(I)
210.01-215.00	72.6	$13.615	(I)	$0.619	(I)
215.01-220.00	74.3	$13.934	(I)	$0.633	(I)
220.01-225.00	76.0	$14.253	(I)	$0.648	(I)
225.01-230.00	77.7	$14.572	(I)	$0.662	(I)
230.01-235.00	79.4	$14.891	(I)	$0.677	(I)
235.01-240.00	81.1	$15.209	(I)	$0.691	(I)
240.01-245.00	82.9	$15.547	(I)	$0.707	(I)
245.01-250.00	84.6	$15.866	(I)	$0.721	(I)
250.01-255.00	86.3	$16.185	(I)	$0.736	(I)
255.01-260.00	88.0	$16.504	(I)	$0.750	(I)
260.01-265.00	89.7	$16.822	(I)	$0.765	(I)
265.01-270.00	91.4	$17.141	(I)	$0.779	(I)
270.01-275.00	93.1	$17.460	(I)	$0.794	(I)
275.01-280.00	94.8	$17.779	(I)	$0.808	(I)
280.01-285.00	96.5	$18.098	(I)	$0.823	(I)

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 7
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

LIGHT EMITTING DIODE (LED) LAMPS OR COMPARABLE LIGHTING TECHNOLOGY (unless otherwise specified in this tariff): (Cont'd.)

LAMP WATTS****	kWh per MONTH*****	Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
285.01-290.00	98.2	$18.416	(I)	$0.837	(I)
290.01-295.00	99.9	$18.735	(I)	$0.852	(I)
295.01-300.00	101.6	$19.054	(I)	$0.866	(I)
300.01-305.00	103.4	$19.392	(I)	$0.881	(I)
305.01-310.00	105.1	$19.710	(I)	$0.896	(I)
310.01-315.00	106.8	$20.029	(I)	$0.910	(I)
315.01-320.00	108.5	$20.348	(I)	$0.925	(I)
320.01-325.00	110.2	$20.667	(I)	$0.939	(I)
325.01-330.00	111.9	$20.986	(I)	$0.954	(I)
330.01-335.00	113.6	$21.305	(I)	$0.968	(I)
335.01-340.00	115.3	$21.623	(I)	$0.983	(I)
340.01-345.00	117.0	$21.942	(I)	$0.997	(I)
345.01-350.00	118.7	$22.261	(I)	$1.012	(I)
350.01-355.00	120.4	$22.580	(I)	$1.026	(I)
355.01-360.00	122.1	$22.899	(I)	$1.041	(I)
360.01-365.00	123.9	$23.236	(I)	$1.056	(I)
365.01-370.00	125.6	$23.555	(I)	$1.071	(I)
370.01-375.00	127.3	$23.874	(I)	$1.085	(I)
375.01-380.00	129.0	$24.193	(I)	$1.100	(I)
380.01-385.00	130.7	$24.511	(I)	$1.114	(I)
385.01-390.00	132.4	$24.830	(I)	$1.129	(I)
390.01-395.00	134.1	$25.149	(I)	$1.143	(I)
395.01-400.00	135.8	$25.468	(I)	$1.158	(I)

**** Wattage based on total consumption of lamp and driver. Customer may be required to provide verification of total energy consumption of lamp and driver upon request by PG&E.

***** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is:
(high wattage in range-2.5 watts)x(4,100 hours/12 months/1000)

(Continued)

ELECTRIC SCHEDULE LS-2 Sheet 9
CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING

RATES: (Cont'd.)

TOTAL ENERGY RATES

Total Energy Charge Rate ($ per kWh)	$0.18754	(I)

UNBUNDLING OF TOTAL ENERGY CHARGES

The total energy charge is unbundled according to the component rates shown below.

Energy Rate by Components ($ per kWh)		
Generation	$0.09091	(I)
Distribution**	$0.05985	(I)
Transmission*	$0.02377	
Transmission Rate Adjustments*	($0.00248)	(R)
Reliability Services*	$0.00011	
Public Purpose Programs	$0.00532	(I)
Nuclear Decommissioning	$0.00093	
Competition Transition Charge	$0.00003	
Energy Cost Recovery Amount	$0.00032	
Wildfire Fund Charge	$0.00580	
New System Generation Charge**	$0.00298	

* 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)

SPECIAL CONDITIONS: (Cont'd.)

14. **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.

	DA / CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.02796	(I)
2010 Vintage	$0.03367	(I)
2011 Vintage	$0.03518	(I)
2012 Vintage	$0.03725	(I)
2013 Vintage	$0.03743	(I)
2014 Vintage	$0.03746	(I)
2015 Vintage	$0.03763	(I)
2016 Vintage	$0.03788	(I)
2017 Vintage	$0.03791	(I)
2018 Vintage	$0.03748	(I)
2019 Vintage	$0.02854	(I)
2020 Vintage	$0.02300	(I)
2021 Vintage	$0.02300	(I)

15. **WILDFIRE FUND CHARGE:** The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

ELECTRIC SCHEDULE LS-3 Sheet 1

CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE

APPLICABILITY: Applicable to service to electrolier lighting systems, excluding incandescent luminairies, which illuminate streets, highways, and other outdoor ways and places where the Customer owns the lighting fixtures, poles and interconnecting circuits, and PG&E furnishes metered energy. Customers may connect incidental load on a single service account, not to exceed 5% of Customer's total circuit load on the account. Total lighting load must operate in conformance with the 85% off-peak design of this Rate. All lighting must be power factor corrected in accordance with electric Rule 2G. Where loads are found outside these limits PG&E will default the rate to A1 General Service.

TERRITORY: The entire territory served.

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 Charge ($ per meter per day)	$0.24641	
Total Energy Rate ($ per kWh)	$0.18754	(I)

UNBUNDLING OF TOTAL RATES

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

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

Energy Rate by Components ($ per kWh)

Generation	$0.09091	(I)
Distribution**	$0.05985	(I)
Transmission*	$0.02377	
Transmission Rate Adjustments*	($0.00248)	(R)
Reliability Services*	$0.00011	
Public Purpose Programs	$0.00532	(I)
Nuclear Decommissioning	$0.00093	
Competition Transition Charge	$0.00003	
Energy Cost Recovery Amount	$0.00032	
Wildfire Fund Charge	$0.00580	
New System Generation Charge**	$0.00298	

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* 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 LS-3 Sheet 5

CUSTOMER-OWNED STREET AND HIGHWAY LIGHTING ELECTROLIER METER RATE

SPECIAL CONDITIONS: (Cont'd.)

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

Bundled Service Customers receive supply and delivery service 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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.02796	(I)
2010 Vintage	$0.03367	(I)
2011 Vintage	$0.03518	(I)
2012 Vintage	$0.03725	(I)
2013 Vintage	$0.03743	(I)
2014 Vintage	$0.03746	(I)
2015 Vintage	$0.03763	(I)
2016 Vintage	$0.03788	(I)
2017 Vintage	$0.03791	(I)
2018 Vintage	$0.03748	(I)
2019 Vintage	$0.02854	(I)
2020 Vintage	$0.02300	(I)
2021 Vintage	$0.02300	(I)

8. **WILDFIRE FUND CHARGE**: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

ELECTRIC SCHEDULE OL-1
OUTDOOR AREA LIGHTING SERVICE

APPLICABILITY: Applicable to outdoor area lighting service for the illumination of areas where street and highway lighting schedules are not applicable and where PG&E installs, owns, operates and maintains the complete lighting installation on PG&E's existing wood distribution poles or on customer-owned poles acceptable to PG&E installed by the Customer on Customer's private property.

TERRITORY: The entire territory served.

RATES: Total monthly charge per lamp is equal to the sum of the facility charge and the energy charge. The monthly charge per lamp used for billing is calculated using unrounded facility and energy charges.

Monthly facility charges include the costs of owning, operating and maintaining the various lamp types and size, and is assigned to distribution. Monthly energy charges are based on the kWh usage of each lamp. The bundled monthly facility and energy charges are shown below. For customers who elect to participate in PG&E's Optional LED streetlight replacement program, no advance costs will be collected for the replacement of existing lights, but, the customer will pay the LED Program Incremental Facility Charge in addition to the OL-1 monthly facility charge.

Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

Facilities Charge Per Lamp Per Month: $7.126

LED Program Incremental Facility Charge: $2.814

Energy Charge Per Lamp Per Month:

LAMP WATTS	All Night kWh PER MONTH	AVERAGE INITIAL LUMENS		All Night PER LAMP PER MONTH		HALF HOUR ADJUSTMENT	
MERCURY VAPOR LAMPS:*							
175	68	7,500	-------------------	$13.457	(I)	$0.612	(I)
400	152	21,000	------------------	$30.081	(I)	$1.367	(I)
HIGH PRESSURE SODIUM VAPOR LAMPS:							
70	29	5,800	-------------------	$5.739	(I)	$0.261	(I)
100	41	9,500	-------------------	$8.114	(I)	$0.369	(I)
200	81	22,000	-------------------	$16.030	(I)	$0.729	(I)
250	100	25,500	-------------------	$19.790	(I)	$0.900	(I)
400	154	46,000	-------------------	$30.477	(I)	$1.385	(I)

* Closed for new installations as of June 8, 1978.

(Continued)

ELECTRIC SCHEDULE OL-1
OUTDOOR AREA LIGHTING SERVICE

Sheet 2

RATES: (Cont'd.)

LIGHT-EMITTING DIODE (LED) LAMPS: 120-240 VOLTS

Nominal Lamp Ratings

LAMP WATTS**	kWh per MONTH***	Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
0.0-5.0	0.9	$0.178	(I)	$0.008	
5.1-10.0	2.6	$0.515	(I)	$0.023	
10.1-15.0	4.3	$0.851	(I)	$0.039	(I)
15.1-20.0	6.0	$1.187	(I)	$0.054	(I)
20.1-25.0	7.7	$1.524	(I)	$0.069	(I)
25.1-30.0	9.4	$1.860	(I)	$0.085	(I)
30.1-35.0	11.1	$2.197	(I)	$0.100	(I)
35.1-40.0	12.8	$2.533	(I)	$0.115	(I)
40.1-45.0	14.5	$2.870	(I)	$0.130	(I)
45.1-50.0	16.2	$3.206	(I)	$0.146	(I)
50.1-55.0	17.9	$3.542	(I)	$0.161	(I)
55.1-60.0	19.6	$3.879	(I)	$0.176	(I)
60.1-65.0	21.4	$4.235	(I)	$0.193	(I)
65.1-70.0	23.1	$4.571	(I)	$0.208	(I)
70.1-75.0	24.8	$4.908	(I)	$0.223	(I)
75.1-80.0	26.5	$5.244	(I)	$0.238	(I)
80.1-85.0	28.2	$5.581	(I)	$0.254	(I)
85.1-90.0	29.9	$5.917	(I)	$0.269	(I)
90.1-95.0	31.6	$6.254	(I)	$0.284	(I)
95.1-100.0	33.3	$6.590	(I)	$0.300	(I)

** Wattage based on total consumption of lamp and driver.

*** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is: (high wattage in range-2.5 watts)x(4,100 hours/12 months/1000)

(Continued)

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LIGHT-EMITTING DIODE (LED) LAMPS: 120-240 VOLTS (Cont'd.)

Nominal Lamp Ratings

LAMP WATTS**	kWh per MONTH***	Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
100.1-105.1	35.0	$6.927	(I)	$0.315	(I)
105.1-110.0	36.7	$7.263	(I)	$0.330	(I)
110.1-115.0	38.4	$7.599	(I)	$0.345	(I)
115.1-120.0	40.1	$7.936	(I)	$0.361	(I)
120.1-125.0	41.9	$8.292	(I)	$0.377	(I)
125.1-130.0	43.6	$8.628	(I)	$0.392	(I)
130.1-135.0	45.3	$8.965	(I)	$0.408	(I)
135.1-140.0	47.0	$9.301	(I)	$0.423	(I)
140.1-145.0	48.7	$9.638	(I)	$0.438	(I)
145.1-150.0	50.4	$9.974	(I)	$0.453	(I)
150.1-155.0	52.1	$10.311	(I)	$0.469	(I)
155.1-160.0	53.8	$10.647	(I)	$0.484	(I)
160.1-165.0	55.5	$10.983	(I)	$0.499	(I)
165.1-170.0	57.2	$11.320	(I)	$0.515	(I)
170.1-175.0	58.9	$11.656	(I)	$0.530	(I)
175.1-180.0	60.6	$11.993	(I)	$0.545	(I)
180.1-185.0	62.4	$12.349	(I)	$0.561	(I)
185.1-190.0	64.1	$12.685	(I)	$0.577	(I)
190.1-195.0	65.8	$13.022	(I)	$0.592	(I)
195.1-200.0	67.5	$13.358	(I)	$0.607	(I)

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** Wattage based on total consumption of lamp and driver.

*** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is: (high wattage in range-2.5 watts)x(4,100 hours/12 months/1000)

(Continued)

ELECTRIC SCHEDULE OL-1
OUTDOOR AREA LIGHTING SERVICE

RATES: (Cont'd.)

LIGHT-EMITTING DIODE (LED) LAMPS: 120-240 VOLTS (Cont'd.)

Nominal Lamp Ratings

LAMP WATTS**	kWh per MONTH***	Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
200.1-205.0	69.2	$13.695	(I)	$0.623	(I)
205.1-210.0	70.9	$14.031	(I)	$0.638	(I)
210.1-215.0	72.6	$14.368	(I)	$0.653	(I)
215.1-220.0	74.3	$14.704	(I)	$0.668	(I)
220.1-225.0	76.0	$15.040	(I)	$0.684	(I)
225.1-230.0	77.7	$15.377	(I)	$0.699	(I)
230.1-235.0	79.4	$15.713	(I)	$0.714	(I)
235.1-240.0	81.1	$16.050	(I)	$0.730	(I)
240.1-245.0	82.9	$16.406	(I)	$0.746	(I)
245.1-250.0	84.6	$16.742	(I)	$0.761	(I)
250.1-255.0	86.3	$17.079	(I)	$0.776	(I)
255.1-260.0	88.0	$17.415	(I)	$0.792	(I)
260.1-265.0	89.7	$17.752	(I)	$0.807	(I)
265.1-270.0	91.4	$18.088	(I)	$0.822	(I)
270.1-275.0	93.1	$18.424	(I)	$0.837	(I)
275.1-280.0	94.8	$18.761	(I)	$0.853	(I)
280.1-285.0	96.5	$19.097	(I)	$0.868	(I)
285.1-290.0	98.2	$19.434	(I)	$0.883	(I)
290.1-295.0	99.9	$19.770	(I)	$0.899	(I)
295.1-300.0	101.6	$20.107	(I)	$0.914	(I)

** Wattage based on total consumption of lamp and driver.

*** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is: (high wattage in range-2.5 watts)x(4,100 hours/12 months/1000)

(Continued)

ELECTRIC SCHEDULE OL-1
OUTDOOR AREA LIGHTING SERVICE

RATES: (Cont'd.)

LIGHT-EMITTING DIODE (LED) LAMPS: 120-240 VOLTS (Cont'd.)

Nominal Lamp Ratings

LAMP WATTS**	kWh per MONTH***	Energy Rates Per Lamp Per Month		Half-Hour Adjustment	
300.1-305.0	103.4	$20.463	(I)	$0.930	(I)
305.1-310.0	105.1	$20.799	(I)	$0.945	(I)
310.1-315.0	106.8	$21.136	(I)	$0.961	(I)
315.1-320.0	108.5	$21.472	(I)	$0.976	(I)
320.1-325.0	110.2	$21.809	(I)	$0.991	(I)
325.1-330.0	111.9	$22.145	(I)	$1.007	(I)
330.1-335.0	113.6	$22.481	(I)	$1.022	(I)
335.1-340.0	115.3	$22.818	(I)	$1.037	(I)
340.1-345.0	117.0	$23.154	(I)	$1.052	(I)
345.1-350.0	118.7	$23.491	(I)	$1.068	(I)
350.1-355.0	120.4	$23.827	(I)	$1.083	(I)
355.1-360.0	122.1	$24.164	(I)	$1.098	(I)
360.1-365.0	123.9	$24.520	(I)	$1.115	(I)
365.1-370.0	125.6	$24.856	(I)	$1.130	(I)
370.1-375.0	127.3	$25.193	(I)	$1.145	(I)
375.1-380.0	129.0	$25.529	(I)	$1.160	(I)
380.1-385.0	130.7	$25.866	(I)	$1.176	(I)
385.1-390.0	132.4	$26.202	(I)	$1.191	(I)
390.1-395.0	134.1	$26.538	(I)	$1.206	(I)
395.0-400.0	135.8	$26.875	(I)	$1.222	(I)

** Wattage based on total consumption of lamp and driver.

*** Assumptions consistent with tariff, based on 4100 hours of operation for a full year; mid-point in range established by deducting 2.5 watts from highest wattage in range. The energy use calculation is: (high wattage in range-2.5 watts)x(4,100 hours/12 months/1000)

(Continued)

RATES:
(Cont'd.)

TOTAL ENERGY RATES

Total Energy Charge Rate ($ per kWh)	$0.19790	(I)

The total energy charge is unbundled according to the component rates shown below.

UNBUNDLING OF TOTAL ENERGY CHARGES

Energy Rate by Components ($ per kWh)		
Generation	$0.09091	(I)
Distribution**	$0.05985	(I)
Transmission*	$0.02377	
Transmission Rate Adjustments*	($0.00248)	(R)
Reliability Services*	$0.00011	
Public Purpose Programs	$0.01568	(I)
Nuclear Decommissioning	$0.00093	
Competition Transition Charge	$0.00003	
Energy Cost Recovery Amount	$0.00032	
Wildfire Fund Charge	$0.00580	
New System Generation Charge**	$0.00298	

* 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)

SPECIAL CONDITIONS: (Cont'd.)

10. BILLING: (Cont'd.)

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

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

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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.02796	(I)
2010 Vintage	$0.03367	(I)
2011 Vintage	$0.03518	(I)
2012 Vintage	$0.03725	(I)
2013 Vintage	$0.03743	(I)
2014 Vintage	$0.03746	(I)
2015 Vintage	$0.03763	(I)
2016 Vintage	$0.03788	(I)
2017 Vintage	$0.03791	(I)
2018 Vintage	$0.03748	(I)
2019 Vintage	$0.02854	(I)
2020 Vintage	$0.02300	(I)
2020 Vintage	$0.02300	(I)

11. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

ELECTRIC SCHEDULE S
STANDBY SERVICE

RATES: (Cont'd.)

TOTAL RATES

	Secondary Voltage		Primary Voltage		Transmission Voltage	
Total Maximum Reactive Demand Charge ($ per kVAR)	$0.35		$0.35		$0.35	
<u>Total Reservation Charge Rate ($/kW)</u>						
Reservation Charge (per KW per month applied to 85 percent of the Reservation Capacity)	$9.25	(I)	$9.25	(I)	$2.03	(I)
<u>Total Energy Rates ($ per kWh)</u>						
Peak Summer	$0.72109	(I)	$0.72170	(I)	$0.14863	(R)
Part-Peak Summer	$0.32639	(I)	$0.32700	(I)	$0.13338	(R)
Off-Peak Summer	$0.12879	(R)	$0.12940	(R)	$0.11320	(R)
Part-Peak Winter	$0.16284	(R)	$0.16345	(R)	$0.13578	(R)
Off-Peak Winter	$0.13733	(R)	$0.13794	(R)	$0.12028	(R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

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

UNBUNDLING OF TOTAL RATES

	Secondary Voltage		Primary Voltage		Transmission Voltage	
<u>Reservation Charges Rate by Components ($/kW)</u>						
Generation	$0.46		$0.46		$0.37	
Distribution**	$7.61	(I)	$7.61	(I)	$0.48	(I)
Transmission*	$1.17		$1.17		$1.17	
Reliability Services*	$0.01		$0.01		$0.01	
<u>Energy Rate by Components ($ per kWh)</u>						
Generation:						
Peak Summer	$0.11855	(I)	$0.11855	(I)	$0.09721	(I)
Part-Peak Summer	$0.09974	(I)	$0.09974	(I)	$0.08196	(I)
Off-Peak Summer	$0.07513	(I)	$0.07513	(I)	$0.06178	(I)
Part-Peak Winter	$0.10274	(I)	$0.10274	(I)	$0.08436	(I)
Off-Peak Winter	$0.08367	(I)	$0.08367	(I)	$0.06886	(I)
Distribution:**						
Peak Summer	$0.54888	(I)	$0.54888	(I)	$0.00000	
Part-Peak Summer	$0.17299	(I)	$0.17299	(I)	$0.00000	
Off-Peak Summer	$0.00000		$0.00000		$0.00000	
Part-Peak Winter	$0.00644	(I)	$0.00644	(I)	$0.00000	
Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Transmission* (all usage)	$0.02566		$0.02566		$0.02566	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00012		$0.00012		$0.00012	
Public Purpose Programs (all usage)	$0.01713	(I)	$0.01774	(I)	$0.01489	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge(all usage)**	$0.00615		$0.00615		$0.00615	
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.

(Continued)

ELECTRIC SCHEDULE S
STANDBY SERVICE

Sheet 5

RATES
(Cont'd.)

Meter and Customer Charges:*
($/meter/day)

Customer Class	Customer Charge		TOU or Load Profile Meter Charge
Residential	$0.16427		$0.12813
Agricultural	$0.90678		$0.19713
Small Light and Power (Reservation Capacity ≤ 75 kW)			
Single Phase Service	$0.32854		$0.20107
PolyPhase Service	$0.82136		$0.20107
Medium Light and Power (Reservation Capacity > 75 kW and < 500 kW)	$5.47664	(I)	$0.17741
Medium Light and Power (Reservation Capacity ≥ 500 kW and < 1000 kW)			
Transmission	$51.71562	(I)	–
Primary	$42.06396	(I)	–
Secondary	$27.57709	(I)	–
Large Light and Power (Reservation Capacity ≥ 1000 kW)			
Transmission	$48.33253	(I)	–
Primary	$49.95670	(I)	–
Secondary	$50.04986	(I)	–
Supplemental Standby Service Meter Charge	–		$6.11088

* All Meter and Customer charges are assigned to distribution.

(Continued)

ELECTRIC SCHEDULE S
STANDBY SERVICE

SPECIAL CONDITIONS: (Cont'd.)

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

Bundled Service Customers receive supply and delivery service 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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.02541	(I)
2010 Vintage	$0.03059	(I)
2011 Vintage	$0.03196	(I)
2012 Vintage	$0.03385	(I)
2013 Vintage	$0.03401	(I)
2014 Vintage	$0.03403	(I)
2015 Vintage	$0.03419	(I)
2016 Vintage	$0.03442	(I)
2017 Vintage	$0.03444	(I)
2018 Vintage	$0.03405	(I)
2019 Vintage	$0.02593	(I)
2020 Vintage	$0.02090	(I)
2021 Vintage	$0.02090	(I)

13. **WILDFIRE FUND CHARGE:** The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

14. **SCHEDULED MAINTENANCE:** Customers may be allowed to place maintenance load on the distribution system during mutually agreed times (Scheduled Maintenance). Maintenance load is defined as a customer's load that would have otherwise been served by the DG that is down for maintenance. Customers shall provide four (4) days notice prior to PG&E determining whether and when Scheduled Maintenance is available ("Request"). For each Request, customers shall pay PG&E, at the time of such notification, for its expenses related to the scheduling and any necessary rearrangement of its facilities to accommodate Scheduled Maintenance.

(Continued)

ELECTRIC SCHEDULE SB Sheet 3
STANDBY SERVICE

RATES: (Cont'd) **DEFINITION OF SERVICE VOLTAGE:** (Cont'd)

The Standby Reservation Charges for customers who have paid for the total cost of the service transformers as special facilities under electric Rule 2 are determined by the voltage at the high side of the service transformer. All other charges will be billed on the voltage level at the low side of the service transformer.

PG&E retains the right to change its line voltage at any time, after reasonable advance notice to any customer affected by the change. The customer then has the option of changing its system to receive service at the new line voltage or accepting service at the initial voltage level through transformers supplied by PG&E.

DEFINITION OF MAXIMUM DEMAND:

The real (kW) and reactive (kVAR) demands billed under this tariff will be averaged over each 15-minute interval. "Maximum demand" (real and reactive) will be the highest 15-minute interval average 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.

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

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Maximum Reactive Demand Charge ($ per kVAR)	$0.35	$0.35	$0.35
Total Reservation Charge Rate ($/kW)			
Reservation Charge (per KW per month applied to 85 percent of the Reservation Capacity)	$9.55 (I)	$9.55 (I)	$1.84 (I)
Total Energy Rates ($ per kWh)			
Peak Summer	$0.72185 (I)	$0.72246 (I)	$0.15157 (R)
Part-Peak Summer	$0.39566 (I)	$0.39627 (I)	$0.14011 (R)
Off-Peak Summer	$0.14866 (R)	$0.14927 (R)	$0.12735 (R)
Peak Winter	$0.17405 (R)	$0.17466 (R)	$0.14707 (R)
Off-Peak Winter	$0.14978 (R)	$0.15039 (R)	$0.12854 (R)
Super Off-Peak Winter	$0.10732 (R)	$0.10793 (R)	$0.08620 (R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(Continued)

ELECTRIC SCHEDULE SB
STANDBY SERVICE

Sheet 4

RATES: (Cont'd)

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

UNBUNDLING OF TOTAL RATES

	Secondary Voltage		Primary Voltage		Transmission Voltage	
Reservation Charges Rate by Components ($/kW)						
Generation	$0.30		$0.30		$0.17	
Distribution**	$8.07	(I)	$8.07	(I)	$0.49	(I)
Transmission*	$1.17		$1.17		$1.17	
Reliability Services*	$0.01		$0.01		$0.01	
Energy Rate by Components ($ per kWh)						
Generation:						
Peak Summer	$0.11282	(I)	$0.11282	(I)	$0.10015	(I)
Part-Peak Summer	$0.10100	(I)	$0.10100	(I)	$0.08869	(I)
Off-Peak Summer	$0.08785	(I)	$0.08785	(I)	$0.07593	(I)
Peak Winter	$0.10809	(I)	$0.10809	(I)	$0.09565	(I)
Off-Peak Winter	$0.08897	(I)	$0.08897	(I)	$0.07712	(I)
Super Off-Peak Winter	$0.04651	(I)	$0.04651	(I)	$0.03478	(I)
Distribution:**						
Peak Summer	$0.55537	(I)	$0.55537	(I)	$0.00000	
Part-Peak Summer	$0.24100	(I)	$0.24100	(I)	$0.00000	
Off-Peak Summer	$0.00715	(I)	$0.00715	(I)	$0.00000	
Peak Winter	$0.01230	(I)	$0.01230	(I)	$0.00000	
Off-Peak Winter	$0.00715	(I)	$0.00715	(I)	$0.00000	
Super Off-Peak Winter	$0.00715	(I)	$0.00715	(I)	$0.00000	
Transmission* (all usage)	$0.02566		$0.02566		$0.02566	
Transmission Rate Adjustments* (all usage)	($0.00248)	(R)	($0.00248)	(R)	($0.00248)	(R)
Reliability Services* (all usage)	$0.00012		$0.00012		$0.00012	
Public Purpose Programs (all usage)	$0.01713	(I)	$0.01774	(I)	$0.01489	(I)
Nuclear Decommissioning (all usage)	$0.00093		$0.00093		$0.00093	
Competition Transition Charges	$0.00003		$0.00003		$0.00003	
Energy Cost Recovery Amount (all usage)	$0.00032		$0.00032		$0.00032	
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00615		$0.00615		$0.00615	
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.

(Continued)

ELECTRIC SCHEDULE SB
STANDBY SERVICE

RATES: (Cont'd)

Meter and Customer Charges:*
($/meter/day)

Customer Class	Customer Charge		Time-of-Use or Load Profile Meter Charge
Residential	$0.16427		–
Agricultural	$0.90678		–
Small Light and Power (Reservation Capacity ≤ 75 kW)			
Single Phase Service	$0.32854		–
PolyPhase Service	$0.82136		–
Medium Light and Power (Reservation Capacity > 75 kW and < 500 kW)	$5.47664	(I)	–
Medium Light and Power (Reservation Capacity ≥ 500 kW and < 1000 kW)			
Transmission	$51.71562	(I)	–
Primary	$42.06396	(I)	–
Secondary	$27.57709	(I)	–
Large Light and Power (Reservation Capacity ≥ 1000 kW)			
Transmission	$48.33253	(I)	–
Primary	$49.95670	(I)	–
Secondary	$50.04986	(I)	–
Supplemental Standby Service Meter Charge	–		$6.11088

* All Meter and Customer charges are assigned to distribution.

(Continued)

SPECIAL CONDITIONS: (Cont'd.)

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

Bundled Service Customers receive supply and delivery service 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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.02541	(I)
2010 Vintage	$0.03059	(I)
2011 Vintage	$0.03196	(I)
2012 Vintage	$0.03385	(I)
2013 Vintage	$0.03401	(I)
2014 Vintage	$0.03403	(I)
2015 Vintage	$0.03419	(I)
2016 Vintage	$0.03442	(I)
2017 Vintage	$0.03444	(I)
2018 Vintage	$0.03405	(I)
2019 Vintage	$0.02593	(I)
2020 Vintage	$0.02090	(I)
2021 Vintage	$0.02090	(I)

13. **WILDFIRE FUND CHARGE:** The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

(Continued)

ELECTRIC SCHEDULE TC-1 Sheet 1
TRAFFIC CONTROL SERVICE

APPLICABILITY: Applicable to metered service for traffic control-related equipment operating on a 24-hour basis, owned by governmental agencies and located on streets, highways and other publicly-dedicated outdoor ways and places. Streetlights on traffic circuits and other equipment operating on a 24-hour basis in conformity with this rate design may also be connected under this Schedule. Also applicable for service to these installations where service is initially established in the name of a developer who has installed such systems as required by a governmental agency, where ownership of facilities and responsibility for service will ultimately be transferred to the jurisdiction requiring the installation. Non-conforming incidental load such as low voltage sprinkler controls may also be attached where such loads do not exceed 5% of the total connected load served under a TC-1 Service Account. Maximum load per meter is 34,000 kWh per month.

TERRITORY: The entire territory served.

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

Customer Charge Rate ($ per meter per day)	$0.49281	
Energy Rate ($ per kWh)	$0.20413	(I)

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.

Energy Rate by Components ($ per kWh)		
Generation	$0.10150	(I)
Distribution**	$0.06148	(I)
Transmission*	$0.02784	
Transmission Rate Adjustments*	($0.00248)	(R)
Reliability Services*	$0.00013	
Public Purpose Programs	$0.00540	(I)
Nuclear Decommissioning	$0.00093	
Competition Transition Charge	$0.00003	
Energy Cost Recovery Amount	$0.00032	
Wildfire Fund Charge	$0.00580	
New System Generation Charge**	$0.00318	

* 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 TC-1
TRAFFIC CONTROL SERVICE

SPECIAL CONDITIONS: (Cont'd.)

8. **BILLING**: (Cont'd.)

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

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

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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03406	(I)
2010 Vintage	$0.04100	(I)
2011 Vintage	$0.04285	(I)
2012 Vintage	$0.04537	(I)
2013 Vintage	$0.04559	(I)
2014 Vintage	$0.04562	(I)
2015 Vintage	$0.04583	(I)
2016 Vintage	$0.04613	(I)
2017 Vintage	$0.04617	(I)
2018 Vintage	$0.04564	(I)
2019 Vintage	$0.03476	(I)
2020 Vintage	$0.02801	(I)
2021 Vintage	$0.02801	(I)

9. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

BASELINE: A rate structure mandated by the California Legislative and implemented at PG&E in 1984 that insures all residential customers are provided a minimum necessary quantity of electricity at the lowest possible cost.

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD: (T)

A. A transition mitigation measure that allows qualified solar customers to maintain legacy TOU periods for the duration of the transition mitigation period. This transition mitigation measure does not apply to these customers:

(1) For customers on Schedules E-TOU-A, E-TOU-B and E-6, the transition mitigation period that was already adopted by the CPUC in (D.) 15-11-013 continues to apply, as set forth in those rate schedules.

(2) For NEM 2.0 EV customers, the transition mitigation period already adopted by the CPUC in (D.) 16-01-044 continues to apply, as set forth in PG&E's NEM2 rate schedule.

B. Changes to rate design, including allocating marginal costs to TOU periods and setting specific rate levels, will be litigated in utility specific rate proceedings.

C. The new electricity price for legacy peak period hours shall not fall below the new price for legacy off-peak periods and the new electricity price for legacy off peak periods shall not be increased above the price during legacy peak periods.

D. The Legacy TOU Eligibility requirements for behind–the-meter solar are defined in the *Behind-the-Meter Solar Legacy TOU Period Eligibility Requirements*. (T)
|
|

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ELIGIBILITY REQUIREMENTS: (T)

A customer is eligible for behind-the-meter solar legacy TOU period if the following conditions are met: (T)

A. Qualified residential on-site solar customers

(1) EV customers who interconnected on NEM on or before December 16, 2016.

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ELIGIBILITY REQUIREMENTS: (Cont'd) (T)

B. Qualified non-residential solar customers

(1) With a behind-the-meter solar (PV) generating facility with load as well as generation

(2) This includes benefitting accounts (or the generating account where considered a benefitting account), on a rate schedule in (i) above and in an arrangement on the Load Aggregation provisions (NEMA) of Schedules NEM or NEM2, or on Schedule NEMV or NEM2V (Virtual NEM), or Schedule NEMVMASH or NEM2VMSH (Virtual NEM for Multifamily Affordable Housing with Solar Generation), or Schedule RES-BCT (Local Government Renewable Energy Self-Generation Bill Credit Transfer) by the time the PTO is issued, which allow electric accounts, not physically tied behind-the-meter to a solar system, to receive credits from the exported power of an electric meter account that is physically tied to a solar system. Benefitting accounts added to an arrangement after the PTO is issued will not be eligible for legacy TOU periods. (T) Benefiting accounts removed from an arrangement after the PTO is issued lose their eligibility for legacy TOU periods. (T)

C. Customer Eligibility Grace Period End Date

There is no deadline to complete projects to preserve eligibility for legacy TOU time periods. Customers must comply with Rule 21. (T)

D. Transition Mitigation Period

(1) For residential on-site solar customer systems, the transition mitigation period is five years from issuance of a permission to operate. In no event shall the duration continue beyond July 31, 2022.

(2) For non-residential customers, the transition mitigation period is ten years after issuance of a permission to operate. In no event shall the duration continue beyond December 31, 2027, (for public schools) or July 31, 2027, (for all other non-residential customers).

(Continued)

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ELIGIBILITY REQUIREMENTS: (Cont'd) (T)

E. Eligible System

An Eligible System is a solar (PV) generating facility:

(1) That serves customer load behind-the-same meter as the generating facility. Such Generating Facilities may be taking service on Rate schedules NEM, NEM2, NEMV, NEM2V, NEMVMASH, NEM2VMSH, E-REMAT, RES-BCT, the RAM program, or interconnected under Electric Rule 21 as non-export or uncompensated export; and

for which an Initial interconnection application was received by PG&E

(a) No later than January 31, 2017; or

(b) (for Public Agencies), no later than December 31st, 2017. (Public agency is defined here as public schools, colleges and universities; federal, state, county and city government agencies; municipal utilities; public water and/or sanitation agencies;and joint powers authorities).

(2) For which PG&E has received evidence of the customer's final inspection clearance from the governmental authority; and

(3) If the interconnection application was received by PG&E between January 23, 2017 and December 31, 2017, the generating facility must be designed to offset at least 15%[1] of the customer's current load, in a manner with consistent with the Option R requirements in Rate Schedule E19, Special Condition 19. This requirement must be met at the time the Initial Application is filed and PG&E reserves the right to verify this requirement. This requirement will not be retroactively applied to systems where an application to interconnect was received by PG&E prior to January 23, 2017.[2]

For the purposes of legacy TOU period eligibility, Permission to Operate (PTO) refers to the original permission to operate date as issued by PG&E for the Eligible System. Any subsequent requests to modify that previously approved system do not restart the Transition Mitigation Period once the new PTO is issued nor can any changes alter its original legacy TOU eligibility. (T) (T)

[1] For tracking systems, PG&E agrees to use a 21% capacity factor for a single tracker, or 24% for a dual tracker, instead of the 18% in the Option R calculation in E-20 Special Condition 17, Footnote 1.

[2] PG&E will not apply the 15% load requirement to systems with PTO prior to January 23, 2017, the date of (D.) 17-01-006. The intent of the 15% load requirement was to eliminate the potential for applications submitted after the CPUC's decision was issued on January 23, 2017 seeking to "lock in" a legacy TOU period by installing only a token amount of on-site solar generation.

(Continued)

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ELIGIBILITY REQUIREMENTS: (Cont'd) (T)

For the purposes of legacy TOU period eligibility, Permission to Operate (PTO) refers to the original permission to operate date as issued by PG&E for the Eligible System. Any subsequent requests to modify that previously approved system do not restart the Transition Mitigation Period once the new PTO is issued nor can any changes alter its original legacy TOU eligibility, except for subsequent requests received within specific windows of time defined separately for public agencies and for other customers (non-public agencies). [3] (T)

F. Complete Interconnection Application Package

A "Complete Interconnection Application Package" includes all of the following with no deficiencies, or modifications required:

(1) A completed Interconnection Application including all supporting documents and all required payments; AND

(2) A completed signed Interconnection Agreement; AND

(3) Evidence of the customer's final inspection clearance from the governmental authority having jurisdiction over the Electrical Generation Facility.

G. Modifications to Pending Interconnection Request Applying under Fast Track Study

For the purposes of legacy TOU period eligibility, the initial interconnection application that is submitted by the applicable deadline must remain in compliance with Electric Rule 21 for the duration of the application and receive Permission to Operate (PTO). If an Applicant takes any action beyond what is listed below, the Applicant must withdraw the pending application and reapply. If the corrected application is not resubmitted by the timelines prescribed in the Decision, it is no longer eligible for legacy TOU periods. (T)

[3] Any subsequent request submitted between January 23, 2017 and January 31, 2017 (non-Public Agencies), or between January 23, 2017 and December 31, 2017 (Public Agencies), to modify a previously approved generating facility with solar technology, and whose interconnection application remains in compliance with Electric Rule 21 for the duration of the application and receives Permission to Operate (PTO), will commence their Legacy TOU Period as of the issuance date of the PTO for that subsequent request. (T)

(Continued)

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ELIGIBILITY REQUIREMENTS: (Cont'd) (T)

G. Modifications to Pending Interconnection Request Applying under Fast Track Study (Cont'd)

Acceptable Changes

(A) Modifying the generating facility size after the initial application has been submitted but prior to any Engineering Review

(B) Decreasing the generating facility size during[4] or after an Engineering Review has been completed (prior to PTO)

- If mitigations are required at the customer's expense (e.g., Dedicated Transformer Upgrade), the Applicant may downsize but must do so while accepting the upgrade. If the Applicant requests a restudy to determine whether the mitigation is no longer required after downsizing, they must withdraw and reapply.

H. Additional Implementation Details For Ineligible[5] Customers

Customers submitting an interconnection application to PG&E will be eligible to select another legacy rate via the interconnection agreement (where applicable) upon the issuance of a Permission to Operate (PTO) if the following criteria are met:

A. For Commercial and Industrial Customers: Receive PTO prior to the scheduled Default in March 2021 (T)

B. For Agricultural Customers: Receive PTO prior to the scheduled Default in March 2021

However, at the time of the mandatory Defaults, customers ineligible for solar legacy TOU period will be defaulted to a new TOU period rate. (T)

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[4] "During" refers to the time after an Engineering Review has been completed but the result was a failure thereby requiring an Applicant to decide how to proceed.

[5] Customers who either (1) already meet the definition of "behind-the-meter solar legacy TOU period" but are re- (T)
applying to PG&E to modify the existing solar system or (2) will meet the definition of "behind-the-meter solar (T)
legacy TOU period" upon the issuance of the permission to operate (PTO) are not required to receive PTO by the timelines mentioned above. When PTO is issued, the customer will be transitioned to the applicable legacy rate listed on the interconnection agreement. However, if their solar legacy TOU period transition mitigation period has (T)
already expired, the customer will remain on their current defaulted rate upon PTO. After the mandatory default commences, solar legacy TOU period eligible customers will be able to move between legacy rates for the (T)
duration of their solar legacy TOU period, in accordance with Electric Rule 12, subject to remaining on their legacy TOU hours, with no meter changes required, and subject to all other applicable tariff terms and conditions.

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Attachment 3

Redline Tariffs

For convenience of the reader, PG&E has included redline revisions in Attachment 3.

The redlines only represent revisions to the text of the tariff and does not represent changes in rate values within the tariff. Changes to the rate values within the tariffs are noted with the revision marks on the right margin of the final tariffs in Attachment 2.

Revisions in the primary color (red) represents tariff revisions that were submitted with the proforma tariffs that were approved in Advice 5861-E. Revisions in the secondary color (blue) represents new revisions that are being made in this advice letter. In some cases the new revisions may overwrite the language that was included in the proforma tariffs of Advice 5861-E (blue text with red underline).

ELECTRIC SCHEDULE A-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~~legacy customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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~~legacy 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, (T) per Decision 17-01-006, as described in the Electric Rule 1, Definitions: Behind-the-Meter Solar Legacy TOU ~~Grandfathering~~ and Eligibility Requirements. (T)

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

~~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.~~ (D)

~~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.~~

~~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~~

(Continued)

~~rate pursuant to Electric Rule 12, Section C, or in accordance with Electric Rule 1 as referenced above, for solar grandfathered customers~~. (D)

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* 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-1
SMALL GENERAL 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~~. (D)

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 SB—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 SB, in addition to all applicable Schedule A-1 charges. Exemptions to Standby Charges are outlined in the Standby Applicability Section of this rate schedule. (T)

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.~~ (D)

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)

~~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.~~ (D)

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. (T)

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

Sheet 2

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.

(Continued)

ELECTRIC SCHEDULE A-1
SMALL GENERAL SERVICE

APPLICABILITY: (cont'd.)

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.

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 Legacy TOU Period ~~Grandfathering~~" and the terms of "Behind-the-Meter Solar Legacy 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. (T) (T)

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.

(Continued)

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.~~ (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

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	$0.27733
Winter	$0.21679

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	$0.29202		
Part-Peak Summer	$0.26837		
Off-Peak Summer	$0.24101		
Part-Peak Winter	$0.24777		
Off-Peak Winter	$0.22686		
~~PDP Rates (Consecutive Day and Four-Hour Event Option) *~~			
~~PDP Charges ($ per kWh)~~			(D)
~~All Usage During PDP Event~~	~~$0.60~~		
~~PDP Credits~~			
~~Energy ($ per kWh)~~			
~~Peak Summer~~	~~($0.00884)~~	~~(I)~~	
~~Part-Peak Summer~~	~~($0.00884)~~	~~(I)~~	
~~Off-Peak Summer~~	~~($0.00884)~~	~~(I)~~	

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

(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.~~ (D) (D)

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	$0.12677
Winter	$0.08663
Distribution**	
Summer	$0.09492
Winter	$0.07452
Transmission* (all usage)	$0.02784
Transmission Rate Adjustments* (all usage)	$0.00294
Reliability Services* (all usage)	$0.00013
Public Purpose Programs (all usage)	$0.01447
Nuclear Decommissioning (all usage)	$0.00093
Competition Transition Charges (all usage)	$0.00003
Energy Cost Recovery Amount (all usage)	$0.00032
New System Generation Charge (all usage)**	$0.00318
Wildfire Fund Charge (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 A-1
SMALL GENERAL 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-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.~~ (D)

~~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.~~

~~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.~~ (D)

(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.~~ (D)

~~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 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.~~ (D)

(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).~~ (D)

~~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 (ºF), and will be triggered at 105ºF 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.~~ (D)

ELECTRIC SCHEDULE A-10
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~~legacy customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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~~legacy 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 Legacy TOU ~~Grandfathering and~~ Eligibility Requirements. (T)

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

~~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.~~ (D)

~~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.~~ (D)

(Continued)

ELECTRIC SCHEDULE A-10 Sheet 1
MEDIUM GENERAL DEMAND-METERED SERVICE

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

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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.~~ (D)

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 SB—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 SB, 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 SmartMeterTM system, or interval meter, installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates.~~ (D)

~~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~~

(Continued)

~~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.~~ (D)

(Continued)

APPLICABILITY (CONT'D):

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)

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.

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 Legacy TOU Period ~~Grandfathering~~" and the terms of "Behind-the-Meter Solar Legacy 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.

(Continued)

ELECTRIC SCHEDULE A-10
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.~~

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)	$4.92753	(I)	$4.92753	(I)	$4.92753	(I)	
Total Demand Rates ($ per kW)							
Summer	$21.90	(R)	$20.68	(R)	$14.25	(R)	
Winter	$13.41	(I)	$13.67	(I)	$10.47	(I)	
Total Energy Rates ($ per kWh)							
Peak Summer	$0.23577	(R)	$0.22252	(R)	$0.18337	(R)	
Part-Peak Summer	$0.18065	(R)	$0.17196	(R)	$0.13649	(R)	
Off-Peak Summer	$0.15258	(R)	$0.14533	(R)	$0.11119	(R)	
Part-Peak Winter	$0.15125	(R)	$0.14823	(R)	$0.12470	(R)	
Off-Peak Winter	$0.13419	(R)	$0.13235	(R)	$0.11013	(R)	
~~PDP Rates (Consecutive Day and Four-Hour Event Option)*~~							(N)
~~PDP Charges ($ per kWh)~~							|
~~All Usage During PDP Event~~	~~$0.90~~		~~$0.90~~		~~$0.90~~		|
~~PDP Credits~~							|
~~Demand ($ per kW)~~							|
~~Maximum Summer~~	~~($3.68)~~	~~(I)~~	~~($3.19)~~	~~(I)~~	~~($2.52)~~	~~(I)~~	|
~~Energy ($ per kWh)~~							|
~~Peak Summer~~	~~($0.00068)~~	~~(I)~~	~~($0.00384)~~	~~(R)~~	~~($0.01113)~~	~~(R)~~	|
~~Part-Peak Summer~~	~~($0.00068)~~	~~(I)~~	~~($0.00384)~~	~~(R)~~	~~($0.01113)~~	~~(R)~~	|
~~Off-Peak Summer~~	~~($0.00068)~~	~~(I)~~	~~($0.00384)~~	~~(R)~~	~~($0.01113)~~	~~(R)~~	|

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

(Continued)

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

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.~~ (D)

Table B (Cont'd.)

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.

	Secondary Voltage		Primary Voltage		Transmission Voltage	
Demand Rate by Components ($ per kW)						
Generation:						
Summer	$5.51	(R)	$4.79	(R)	$3.78	(R)
Winter	$0.00		$0.00		$0.00	
Distribution:**						
Summer	$7.55	(I)	$7.05	(I)	$1.63	(I)
Winter	$4.57	(I)	$4.83	(I)	$1.63	(I)
Transmission Maximum Demand*	$8.80	(R)	$8.80	(R)	$8.80	(R)
Reliability Services Maximum Demand*	$0.04	(I)	$0.04	(I)	$0.04	(I)
Energy Rate by Components ($ per kWh)						
Generation:						
Peak Summer	$0.17228	(R)	$0.16100	(R)	$0.14808	(R)
Part-Peak Summer	$0.11716	(R)	$0.11044	(R)	$0.10120	(R)
Off-Peak Summer	$0.08909	(R)	$0.08381	(R)	$0.07590	(R)
Part-Peak Winter	$0.10121	(R)	$0.09674	(R)	$0.08941	(R)
Off-Peak Winter	$0.08415	(R)	$0.08086	(R)	$0.07484	(R)
Distribution:**						
Summer	$0.03689	(I)	$0.03503	(I)	$0.00895	(I)
Winter	$0.02344	(I)	$0.02500	(I)	$0.00895	(I)
Transmission Rate Adjustments* (all usage)	$0.00294	(R)	$0.00294	(R)	$0.00294	(R)
Public Purpose Programs (all usage)	$0.01367	(I)	$0.01356	(I)	$0.01341	(I)
Competition Transition Charge (all usage)	$0.00004	(R)	$0.00004	(R)	$0.00004	(R)
Energy Cost Recovery Amount (all usage)	$0.00032	(I)	$0.00032	(I)	$0.00032	(I)
Nuclear Decommissioning (all usage)	$0.00093	(R)	$0.00093	(R)	$0.00093	(R)
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290	(R)	$0.00290	(R)	$0.00290	(R)
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.

(Continued)

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

~~PEAK DAY PRICING DETAILS~~

~~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.~~ (D)

~~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.~~ (N)

(Continued)

ELECTRIC SCHEDULE A-10
MEDIUM GENERAL DEMAND-METERED SERVICE

~~PEAK DAY PRICING DETAILS (continued)~~

~~c. Notification Equipment (Cont'd.)~~ (D)

~~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. Demand Response Operations Website: Customers can go to www.pge.com/peakdaypricing to view the forecast and history of Peak Day Pricing event days. Customers may manage the means by which they are notified by PG&E for Peak Day Pricing events by contacting PG&E.~~

~~The customer's actual energy usage is available on "Your Account". This data may not match billing quality data, and the customer understands and agrees that the data posted to PG&E's "Your Account" 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.~~

~~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).~~ (D)

(Continued)

ELECTRIC SCHEDULE A-10
MEDIUM GENERAL DEMAND-METERED SERVICE

~~PEAK DAY PRICING DETAILS (continued)~~

(D)

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

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

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

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

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

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

(D)

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~~legacy customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 Legacy TOU ~~Grandfathering~~ and Eligibility Requirements. (T) (T)

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

~~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.~~ (D)

~~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~~.

(Continued)

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

~~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.~~ (D)

* 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)

~~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.~~ (D)

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 Legacy TOU Period ~~Grandfathering~~" and the terms of "Behind-the-Meter Solar Legacy 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. (T) (T)

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.

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 SB—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 SB, in addition to all applicable Schedule A 6 charges. Exemptions are outlined in the Standby Applicability Section of this rate schedule.

(Continued)

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

APPLICABILITY: (Cont'd.) 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~~. (D) (D)

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)

~~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.~~ (D)

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

(Continued)

ELECTRIC SCHEDULE A-6 Sheet 4
SMALL GENERAL TIME-OF-USE SERVICE

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	$0.60386
Part-Peak Summer	$0.30704
Off-Peak Summer	$0.23545
Part-Peak Winter	$0.25051
Off-Peak Winter	$0.23226

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

~~PDP Charges ($ per kWh)~~			
~~All Usage During PDP Event~~	~~$1.20~~		
~~PDP Credits~~			
~~Energy ($ per kWh)~~			
~~Peak Summer~~	~~($0.44084)~~	~~(R)~~	
~~Part-Peak Summer~~	~~($0.08817)~~	~~(R)~~	

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

(Continued)

ELECTRIC SCHEDULE A-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. ~~PDP charges and credits are all generation and are not included below.~~ (N)

UNBUNDLING OF TOTAL RATES

Customer/Meter Charge Rates: Customer/Meter 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	$0.39027
Part-Peak Summer	$0.15069
Off-Peak Summer	$0.09239
Part-Peak Winter	$0.11786
Off-Peak Winter	$0.10036
Distribution:**	
Peak Summer	$0.15885
Part-Peak Summer	$0.10161
Off-Peak Summer	$0.08832
Part-Peak Winter	$0.07791
Off-Peak Winter	$0.07716
Transmission* (all usage)	$0.02784
Wildfire Fund Charge (all usage)	$0.00580
Transmission Rate Adjustments* (all usage)	$0.00294
Reliability Services* (all usage)	$0.00013
Public Purpose Programs (all usage)	$0.01357
Nuclear Decommissioning (all usage)	$0.00093
Competition Transition Charges (all usage)	$0.00003
Energy Cost Recovery Amount (all usage)	$0.00032
New System Generation Charge (all usage)**	$0.00318
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~~

~~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.~~ (D)

~~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.~~

~~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.~~ (D)

(Continued)

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

~~PEAK DAY PRICING DETAILS (continued)~~

~~c. Notification Equipment: (Cont'd.).~~ (D)

~~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 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.~~

~~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).~~ (D)

(Continued)

~~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.~~ (D)

~~Beginning May 1 of each summer season, the PDP events on non-holiday weekdays will be triggered at 98 degrees Fahrenheit (ºF), and will be triggered at 105ºF on holidays and weekends. If needed, PG&E will adjust the non-holiday weekday trigger up or down by 2ºF 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 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.~~ (D)

RATES FOR LEGACY RES-BCT CUSTOMERS

Pursuant to D.18-08-013 and the Commission's approval of Advice Letter 5379-E-A, solar customers that are eligible for legacy treatment under D.17-01-006 as defined in Rule 1, may take service under legacy rate schedules that retain Time-Of-Use (TOU) periods that include a peak period of noon to 6 pm. Starting on March 1, 2021, the rates shown in the table below will be used to calculate the generation credit for eligible A-6 RES BCT customers. These rates apply only to the calculation of the generation credit for eligible A-6 RES-BCT customers. The rate for load served under Schedule A-6, including for legacy customers, will be charged the applicable rates as shown in the earlier section of this tariff. The generation credit rate will change annually using the rates shown in the table below on the effective date of the Annual Electric True Up Advice (N)

Letter.

	2021	2022	2023
	($/kWh)	($/kWh)	($/kWh)
TOU Period			
Summer Peak	0.34978	0.34601	0.34224
Summer Partial Peak	0.12010	0.11881	0.11751
Summer Off Peak	0.06422	0.06352	0.06283
Winter Partial Peak	0.08863	0.08768	0.08672
Winter Off Peak	0.07186	0.07108	0.07031

Time of Use Periods: The rates provided in the table above will be applied to energy delivered to PG&E in the TOU periods established for Schedule A-6 to determine the applicable generation credit.

(N)

ELECTRIC SCHEDULE AG Sheet 2
TIME-OF-USE AGRICULTURAL POWER

1.APPLICABILITY: (Cont'd.)

The customer will be served under one of the following default rate plans AG-A1, AG-A2, AG-B, or AG-C, under Schedule AG but may elect any rate for which they are eligible, including rate plans under optional Schedule AG-F with flexible off-peak period days, as set forth in the separate tariff for rate Schedule AG-F.

Rates AG-A1 and AG-A2:
Applies to single-motor installations rated less than 35 kilowatts (kW) and to all multi-load installations aggregating less than 35 kW.

Rates AG-B and AG-C:
Applies to single-motor installations rated 35 kW or more, to multi-load installations aggregating 35 kW or more.

Generally, AG-A1 and AG-B are designed for lower load factor customers with fewer operating hours and contains lower demand charges and higher energy charges than AG-A2 and AG-C respectively. By contrast, AG-A2 and AG-C are generally designed for higher load factor customers with more operating hours, and have higher demand charges and lower energy charges than AG-A1 and AG-B respectively.

Decision 18-08-013 adopted new TOU periods and seasonal definitions for all non-residential customer classes. Agricultural rate 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 new TOU periods, 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 of certain qualifying agricultural customers until March 2022. Certain qualifying customers with solar systems will be permitted to maintain 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 Legacy TOU ~~Grandfathering~~ Eligibility Requirements. (T)

The rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010, including AG-A1, AG-A2, AG-B, and AG-C under Schedule AG~~, will be~~ were available to qualifying customers on a voluntary opt-in basis ~~beginning~~ from March ~~1,~~ 2020 through February 2021. Customers eligible for this rate schedule must have an interval data meter that can be read remotely by PG&E. (T) | (T)

Beginning on March 1, 2021 customers still served on legacy rate Schedules AG-1, AG-4, AG-5, AG-R or AG-V, with the exception of customers referenced above, will be transitioned to AG-A1, AG-A2, AG-B, or AG-C under Schedule AG with revised TOU periods. Customers may elect any rate for which they are eligible, including rates under 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.

(Continued)

ELECTRIC SCHEDULE AG Sheet 3
TIME-OF-USE AGRICULTURAL POWER

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)

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.

A customer exceeding 200 kW as described above is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

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

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

(L)

(Continued)

|
|
(L)

(Continued)

ELECTRIC SCHEDULE AG
TIME-OF-USE AGRICULTURAL POWER

Sheet 4

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)

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	—	—	—	$17.69
Maximum Demand Summer	$5.73	$10.36	$5.97	$10.73
Maximum Demand Winter	$5.73	$10.36	$5.97	$10.73
Primary Voltage				
Maximum Peak Demand Summer	—	—	—	$17.69
Maximum Demand Summer	—	—	$5.16	$9.61
Maximum Demand Winter	—	—	$5.16	$9.61
Transmission Voltage				
Maximum Peak Demand Summer	—	—	—	$17.69
Maximum Demand Summer	—	—	$2.00	$2.77
Maximum Demand Winter	—	—	$2.00	$2.77
Total Energy Rates ($ per kWh)				
Peak Summer	$0.39793	$0.33970	$0.39365	$0.17992
Off-Peak Summer	$0.23199	$0.17377	$0.22080	$0.14048
Peak Winter	$0.22162	$0.18066	$0.21673	$0.15213
Off-Peak Winter	$0.19233	$0.15137	$0.18747	$0.12644
Demand Charge Rate Limiter ($/kWh in all months, see Demand Charge Rate Limiter section)	—	—	—	$0.50

(L)

PDP Rates (Consecutive Day and Three-Hour Event Option)*				
PDP Charges ($ per kWh)				
All Usage During PDP Event	$1.00 (N)	$1.00 (N)	$1.00 (N)	$1.00 (N)
PDP Credits				
Demand ($ per kW)				
Peak Summer	—	—	—	$3.99 (N)
Energy ($ per kWh)				
Peak Summer	$0.09209 (N)	0.09997 (N)	0.10572 (N)	—

(N)

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

(Continued)

ELECTRIC SCHEDULE AG
TIME-OF-USE AGRICULTURAL 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	—	—	—	$11.79
Distribution:**				
Secondary Voltage				
Maximum Peak Demand Summer	—	—	—	$5.90
Maximum Demand Summer	$5.73	$10.36	$5.97	$10.73
Maximum Demand Winter	$5.73	$10.36	$5.97	$10.73
Primary				
Maximum Peak Demand Summer	—	—	—	$5.90
Maximum Demand Summer	—	—	$5.16	$9.61
Maximum Demand Winter	—	—	$5.16	$9.61
Transmission				
Maximum Peak Demand Summer	—	—	—	$5.90
Maximum Demand Summer	—	—	$2.00	$2.77
Maximum Demand Winter	—	—	$2.00	$2.77

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

(Continued)

ELECTRIC SCHEDULE AG
TIME-OF-USE AGRICULTURAL POWER

3. RATES:
(Cont'd.)

(L)

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	$0.22214	$0.22214	$0.23730	$0.11111
Off-Peak Summer	$0.10246	$0.10246	$0.11423	$0.08163
Peak Winter	$0.09914	$0.09914	$0.10889	$0.09647
Off-Peak Winter	$0.07269	$0.07269	$0.08269	$0.07095
Distribution*:				
Peak Summer	$0.12494	$0.06671	$0.10596	$0.01974
Off-Peak Summer	$0.07868	$0.02046	$0.05618	$0.00978
Peak Winter	$0.07163	$0.03067	$0.05745	$0.00659
Off-Peak Winter	$0.06879	$0.02783	$0.05439	$0.00642
Transmission* (all usage)	$0.02302	$0.02302	$0.02302	$0.02302
Transmission Rate Adjustments* (all usage)	$0.00294	$0.00294	$0.00294	$0.00294
Reliability Services* (all usage)	$0.00011	$0.00011	$0.00011	$0.00011
Public Purpose Programs (all usage)	$0.01477	$0.01477	$0.01431	$0.01299
Nuclear Decommissioning (all usage)	$0.00093	$0.00093	$0.00093	$0.00093
Competition Transition Charges (all usage)	$0.00003	$0.00003	$0.00003	$0.00003
Energy Cost Recovery Amount (all usage)	$0.00032	$0.00032	$0.00032	$0.00032
Wildfire Fund Charge (all usage)	$0.00580	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00293	$0.00293	$0.00293	$0.00293
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)

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)

ELECTRIC SCHEDULE AG
TIME-OF-USE AGRICULTURAL POWER

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)	$0.00032
Wildfire Fund Charge (per kWh)	$0.00580
CTC Charge (per kWh)	$0.00003
Power Charge Indifference Adjustment (per kWh)	
2009 Vintage	$0.02818
2010 Vintage	$0.03482
2011 Vintage	$0.03662
2012 Vintage	$0.03902
2013 Vintage	$0.03923
2014 Vintage	$0.03926
2015 Vintage	$0.03946
2016 Vintage	$0.03974
2017 Vintage	$0.03978
2018 Vintage	$0.03929
2019 Vintage	$0.02916
2020 Vintage	$0.02287
2021 Vintage	$0.02287

(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. WILDFIRE FUND CHARGE The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

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
TIME-OF-USE AGRICULTURAL POWER

17. PEAK DAY PRICING

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

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours~~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 default to PDP and to opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **Capacity Reservation Level**: Customers 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.

~~b.~~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

(Continued)

than it would have had it opted-out to the applicable TOU rate.

(Continued)

17. PEAK DAY PRICING (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 voice, text, or email notification messages of a PDP event from PG&E.

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

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

e. **PG&E website:** 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, phone call, email and/or text) for PDP customers. (N)

(Continued)

17. PEAK DAY PRICING (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. **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).

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.

~~c.~~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 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 that can be read remotely by PG&E, and to highly impacted agricultural customers, as specified in greater detail below. Schedule AG-1 is not available for solar ~~grandfathering~~legacy 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: (T)

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) (T)

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.

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.

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.

(Continued)

ELECTRIC SCHEDULE AG-1
AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

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.. (T) (T)

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 Legacy TOU ~~Grandfathering and~~ Eligibility Requirements. (T) (T)

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

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.~~ (D)

~~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.~~ (D)

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-1 Sheet 3
AGRICULTURAL POWER

1.APPLICABILITY: (Cont'd.)

The provisions of Schedule SB—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 SB, in addition to all applicable Schedule AG-1 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule. (T) (T)

Time-of-Use Rates: Decision 10-02-032, as modified by Decision 11-11-008, makes TOU rates mandatory beginning March 1, 2013, for Agricultural customers that have at least twelve (12) billing months of hourly usage data available.

Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. The Decision also suspends the transition of eligible AG-1 customers to mandatory TOU rates beginning March 1, 2019 until the 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 customer transitions to mandatory TOU rates.

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

Beginning March 2021, customers served under Schedule AG-1 will transition to the rate plans under Schedule AG with revised TOU periods on a mandatory basis or may elect service under optional Schedule AG-F or any other rate plan for which they are eligible.

Customers on AG-1A with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand less than 35 kW, will transition to AG-A1 under Schedule AG, or may elect to enroll in AG-A2 or AG-FA under Schedule AG-F.

Customers on AG-1A with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand of 35 kW or greater, for three consecutive months in the most recent twelve months, will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Customers on AG-1B, with an interval meter that have at least twelve (12) billing months hourly usage data available, will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

(Continued)

ELECTRIC SCHEDULE AG-1
AGRICULTURAL POWER

Sheet 4

1.APPLICABILITY: (Cont'd.)

Summarized below:

Legacy Rate	Defaults to service under Schedule AG:	Or May Opt-In to
AG-1A < 35 kW	AG-A1	AG-A2, AG-FA
AG-1A >= 35 kW, AG-1B	AG-B	AG-C, AG-FB, AG-FC

The transition of customers no longer eligible for AG-1 to Schedule AG with revised TOU periods will occur on the start of the customer's March 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 rate plan with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule AG.

Customers on Schedule AG-1 transitioning to the new rates with later TOU periods in March 2021 or each March thereafter will also be subject to default Peak Day Pricing (PDP) if over 200 kW, and opt-in PDP if below 200 kW. See Schedules AG and AG-F for the terms applicable to the PDP program. (T) (T)

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 Legacy TOU Period ~~Grandfathering~~" and the terms of "Behind-the-Meter Solar Legacy 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. (T) (T)

"Highly impacted" customers, defined as those agricultural customers with potential bill increases greater than 7 percent and $100 annually due to the transition, may remain on their legacy rate schedule for an additional year but must transition to the new rates with revised TOU periods in March 2022. Decision 19-05-010 delays the mandatory transition to rates with revised TOU periods for these "highly impacted" customers and clarifies that net energy metering (NEM) customers, direct access customers, and community choice aggregation customers and accounts beginning service on or after August 9, 2018 are not eligible for "highly impacted" subgroup exemptions from the mandatory TOU transition in March 2021. However, direct access and community choice aggregation customers are also allowed to qualify as highly impacted customers pursuant to a modification granted by the CPUC Executive Director by letter dated November 16, 2020. Schedule AG-1 customers are evaluated on AG-4 to assess highly impacted determinations. (N) (N)

Customers that do not have a meter that is capable of billing on the new Schedule AG on or after March 2021, 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 occur each March to transition all applicable remaining AG-1 customers to the rates with revised TOU periods as described above.

All AG-1A customers will remain on a connected load basis and will not covert to metered demand.

(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~~legacy customers, highly impacted agricultural customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 SB—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 SB, in addition to all applicable Schedule AG-4 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule. (T)

(Continued)

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

1. APPLICABILITY: (Cont'd.)

Depending upon the end-use of electricity and 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 the rates under Schedule AG-4: Rate A, B, C, D, E or F.

Rates A and D: 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. Rate D applies to customers who were on Rate D as of May 1, 2006 and are not billed via SmartMeter™. Rate A applies to all other customers.

Rates B, C, E, and F: 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. Rates E and F apply to customers who were on Rates E and F as of May 1, 2006 and are not billed via SmartMeter™. Rates B and C apply to all other customers.

Rates B and C will apply to those customers whose maximum demand is 200 kW or greater for three consecutive months and select this schedule upon the initial installation of the interval data meter, unless the customer was on Rate E or F as of May 1, 2006 and is not billed via SmartMeter™.

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 Legacy TOU ~~Grandfathering and~~ Eligibility Requirements. (T)

(Continued)

ELECTRIC SCHEDULE AG-4 Sheet 3
TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

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

~~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.~~ (D)

~~Legacy rate schedules, including Schedule AG-4, will be closed to all new enrollment. Customers requesting to establish service on Schedule AG-4, 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-4 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-4 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.~~ (D)

Beginning March 2021, customers served under Schedule AG-4 will transition to the rate plans under Schedule AG with revised TOU periods on a mandatory basis or may elect service under optional Schedule AG-F or any other rate plan for which they are eligible.

Customers on AG-4A or AG-4D, with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand less than 35 kW, will transition to rate AG-A1 under Schedule AG, or may elect to enroll in AG-A2 or AG-FA under Schedule AG-F.

Customers on AG-4A or AG-4D, with a maximum demand of 35 kW or greater, for three consecutive months in the most recent twelve months, or on AG-4B, AG-4C, AG-4E or AG-4F will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Summarized below:

Legacy Rate	Defaults to service under Schedule AG:	Or May Opt-In to
AG-4A/D < 35 kW	AG-A1	AG-A2, AG-FA
AG-4A/D >= 35 kW	AG-B	AG-C, AG-FB, AG-FC
AG-4B/E, AG-4C/F	AG-B	AG-C, AG-FB, AG-FC

(Continued)

1. APPLICABILITY: (Cont'd.)

The transition of customers no longer eligible for AG-4 to Schedule AG with revised TOU periods will occur on the start of the customer's March 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 rate plan with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule AG.

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.

"Highly impacted" customers, defined as those agricultural customers with potential bill increases greater than 7 percent and $100 annually due to the transition, may remain on their legacy rate schedule for an additional year but must transition to the new rates with revised TOU periods in March 2022. Decision 19-05-010 delays the mandatory transition to rates with revised TOU periods for these "highly impacted" customers and clarifies that net energy metering (NEM) customers, direct access customers, and community choice aggregation customers and accounts beginning service on or after August 9, 2018 are not eligible for "highly impacted" subgroup exemptions from the mandatory TOU transition in March 2021. However, direct access and community choice aggregation customers are also allowed to qualify as highly impacted customers pursuant to a modification granted by the CPUC Executive Director by letter dated November 16, 2020. (N)

Customers that do not have a meter that is capable of billing on the new Schedule AG on or after March 2021, 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 occur each March to transition all applicable remaining AG-4 customers to the rates with revised TOU periods as described above.

All AG-4Aand AG-4D customers will convert from connected load demand to metered demand in March 2022 for customers with meters having that capability.

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.

(Continued)

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.~~ (D)

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~~. (D)

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

(Continued)

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

Sheet 6

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.~~ (D)
|
(D)

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	$9.74	–	–
Connected Load Winter	$1.49	–	–
Maximum Demand Summer	–	$11.71	$6.22
Maximum Demand Winter	–	$2.78	$3.00
Maximum Peak Demand Summer	–	$6.04	$14.37
Maximum Part-Peak Demand Summer	–	–	$2.76
Maximum Part-Peak Demand Winter	–	–	$0.68
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–	$1.19	$1.53
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–	$0.43	$0.38
Transmission Voltage Discount			
Maximum Peak Demand Summer	–	–	$7.68
Maximum Part-Peak Demand Summer	–	–	$1.62
Maximum Demand Summer	–	–	$0.30
Maximum Part-Peak Demand Winter	–	–	$0.68
Maximum Demand Winter	–	–	$2.08

Total Energy Rates ($ per kWh)	Rate A,D	Rate B,E	Rate C,F
Peak Summer	$0.50063	$0.32818	$0.30069
Part-Peak Summer	–	–	$0.17800
Off-Peak Summer	$0.22618	$0.17955	$0.13511
Part-Peak Winter	$0.23366	$0.17997	$0.14923
Off-Peak Winter	$0.19172	$0.15250	$0.13013

(Continued)

~~3. RATES:~~ (D)
~~(Cont'd.)~~

~~TOTAL RATES (Cont'd.)~~

~~PDP Rates (Rate A and C Options Only)~~

	~~RATE A~~		~~RATE C~~		
~~PDP Charges ($ per kWh)~~					
~~All Usage During PDP Event~~	~~$1.00~~		~~$1.00~~		
~~PDP Credits~~					
~~Demand ($ per kW)~~					
~~Peak Summer~~	-		~~($1.27)~~	~~(R)~~	
~~Part-Peak Summer~~	-		~~($0.22)~~	~~(R)~~	
~~Connected Load~~	~~($1.00)~~	~~(I)~~	-		
~~Energy ($ per kWh)~~					
~~Peak Summer~~	~~($0.02400)~~	~~(I)~~	~~$0.00000~~		(D)

(Continued)

ELECTRIC SCHEDULE AG-4 Sheet 8
TIME-OF-USE AGRICULTURAL 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~~ (D) (D)

UNBUNDLING OF TOTAL RATES

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

Demand Rates by Component ($ per kW)	Rate A,D	Rate B,E	Rate C,F
Generation:			
Connected Load Summer	$1.50	–	–
Connected Load Winter	$0.00	–	–
Maximum Demand Summer	–	$2.64	$0.00
Maximum Demand Winter	–	$0.00	$0.00
Maximum Peak Demand Summer		$2.81	$6.54
Maximum Part-Peak Demand Summer		–	$1.12
Maximum Part-Peak Demand Winter	–	–	$0.00
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–	$0.65	$1.13
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–	$0.00	$0.00
Transmission Voltage Discount			
Maximum Peak Demand Summer	–	–	$2.09
Maximum Part-Peak Demand Summer	–	–	($0.02)
Maximum Demand Summer	–	–	$0.00
Maximum Part-Peak Demand Winter	–	–	$0.00
Maximum Demand Winter	–	–	$0.00
Distribution:**			
Connected Load Summer	$8.24	–	–
Connected Load Winter	$1.49	–	–
Maximum Demand Summer	–	$9.07	$6.22
Maximum Demand Winter	–	$2.78	$3.00
Maximum Peak Demand Summer	–	$3.23	$7.83
Maximum Part-Peak Demand Summer	–	–	$1.64
Maximum Part-Peak Demand Winter	–	–	$0.68
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–	$0.54	$0.40
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–	$0.43	$0.38
Transmission Voltage Discount			
Maximum Peak Demand Summer	–	–	$5.59
Maximum Part-Peak Demand Summer	–	–	$1.64
Maximum Demand Summer	–	–	$0.30
Maximum Part-Peak Demand Winter	–	–	$0.68
Maximum Demand Winter	–	–	$2.08

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

(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.~~ (D)

~~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.~~ (D)

(Continued)

~~16. PEAK DAY PRICING DETAILS (CONT'D):~~ (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.~~

~~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. Demand Response Operations Website: Customers can go to www.pge.com/peakdaypricing to view the forecast and history of Peak Day Pricing event days. Customers may manage the means by which they are notified by PG&E for Peak Day Pricing events by contacting PG&E.~~

~~The customer's actual energy usage is available on "Your Account". This data may not match billing quality data, and the customer understands and agrees that the data posted to PG&E's "Your Account" 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.~~ (D)

(Continued)

~~16. 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).~~ (D)

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

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

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

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

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

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

ELECTRIC SCHEDULE AG-5
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~~legacy customers, highly impacted agricultural customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 Time-of-Use (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 SB—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 SB, 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.)

Depending upon the end-use of electricity and 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 the rates under Schedule AG-5: Rate A, B, C, D, E or F.

Rates A and D: 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. Rate D applies to customers who were on Rate D as of May 1, 2006 and are not billed via SmartMeter™. Rate A applies to all other customers.

Rates B, C, E, and F: 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. Rates E and F apply to customers who were on Rates E and F as of May 1, 2006 and are not billed via SmartMeter™. Rates B and C apply to all other customers.

Rates B and C will apply to customers whose maximum demand is 200 kW or greater for three consecutive months and select this schedule upon the initial installation of the interval data meter, unless the customer was on Rate E or F as of May 1, 2006 and is not billed via SmartMeter™.

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 Legacy TOU ~~Grandfathering and~~ Eligibility Requirements.

(T)

(Continued)

ELECTRIC SCHEDULE AG-5 Sheet 3
LARGE TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

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

~~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.~~ (D)

~~Legacy rate schedules, including Schedule AG-5, will be closed to all new enrollment. Customers requesting to establish service on Schedule AG-5, 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-5 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-5 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.~~ (D)

Beginning March 2021, customers served under Schedule AG-5 will transition to the rate plans under Schedule AG with revised TOU periods on a mandatory basis or may elect service under optional Schedule AG-F or any other rate plan for which they are eligible.

Customers on AG-5A or AG-5D, with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand less than 35 kW, will transition to rate AG-A2 under Schedule AG, or may elect to enroll in AG-A1 or AG-FA under Schedule AG-F.

Customers on AG-5A or AG-5D, with a maximum demand of 35 kW or greater, for three consecutive months in the most recent twelve months, will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Customers on AG-5B, AG-5C, AG-5E or AG-5F will transition to AG-C under Schedule AG, or may elect to enroll in AG-B, or AG-FB or AG-FC under Schedule AG-F.

Summarized below:

Legacy Rate	Defaults to service under Schedule AG:	Or May Opt-In to
AG-5A/D < 35 kW	AG-A2	AG-A1, AG-FA
AG-5A/D >= 35 kW	AG-B	AG-C, AG-FB, AG-FC
AG-5B/E, AG-5C/F	AG-C	AG-B, AG-FB, AG-FC

(Continued)

ELECTRIC SCHEDULE AG-5 Sheet 4
LARGE TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

The mandatory transition of customers no longer eligible for AG-5 to Schedule AG with revised TOU periods will occur on the start of the customer's March 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 rate plan with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule AG. (T)

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 Legacy TOU Period ~~Grandfathering~~" and the terms of "Behind-the-Meter Solar Legacy 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. (T) (T)

"Highly impacted" customers, defined as those agricultural customers with potential bill increases greater than 7 percent and $100 annually due to the transition, may remain on their legacy rate schedule for an additional year but must transition to the new rates with revised TOU periods in March 2022. Decision 19-05-010 delays the mandatory transition to rates with revised TOU periods for these "highly impacted" customers and clarifies that net energy metering (NEM) customers, direct access customers, and community choice aggregation customers and accounts beginning service on or after August 9, 2018 are not eligible for "highly impacted" subgroup exemptions from the mandatory TOU transition in March 2021. However, direct access and community choice aggregation customers are also allowed to qualify as highly impacted customers pursuant to a modification granted by the CPUC Executive Director by letter dated November 16, 2020. (N)

Customers that do not have a meter that is capable of billing on the new Schedule AG on or after March 2021, 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 occur each March to transition all applicable remaining AG-5 customers to the rates with revised TOU periods as described above.

All AG-5A and AG-5D customers will convert from connected load demand to metered demand in March 2022 for customers with meters having that capability.

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.

Transfers Off of Schedule AG-5: 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.

(Continued)

ELECTRIC SCHEDULE AG-5 Sheet 5
LARGE 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 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.~~ (D)

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~~. (D)

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

(Continued)

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.~~ (D)

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	$14.05	–	–
Connected Load Winter	$2.71	–	–
Maximum Demand Summer	–	$18.41	$7.51
Maximum Demand Winter	–	$7.33	$4.69
Maximum Peak Demand Summer	–	$11.48	$19.59
Maximum Part-Peak Demand Summer	–	–	$4.09
Maximum Part-Peak Demand Winter	–	–	$1.12
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–	$1.94	$2.85
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–	$0.22	$0.32
Transmission Voltage Discount			
Maximum Peak Demand Summer	–	–	$12.47
Maximum Part-Peak Demand Summer	–	–	$1.91
Maximum Demand Summer	–	$13.87	$4.27
Maximum Part-Peak Demand Winter	–	–	$1.12
Maximum Demand Winter	–	$6.31	$3.07

(Continued)

3. RATES:
(Cont'd.)

TOTAL RATES (Cont'd.)

Total Energy Rates ($ per kWh)	Rate A, D	Rate B, E	Rate C, F
Peak Summer	$0.34494	$0.23730	$0.18496
Part-Peak Summer	–	–	$0.12816
Off-Peak Summer	$0.17900	$0.10565	$0.10703
Part-Peak Winter	$0.18820	$0.12809	$0.11336
Off-Peak Winter	$0.16008	$0.09637	$0.10375

~~PDP Rates (Rate C Option Only)~~	~~RATE C~~		(D)
~~PDP Charges ($ per kWh)~~			|
~~All Usage During PDP Event~~	~~$1.00~~		|
~~PDP Credits - Demand ($ per kW)~~			|
~~Peak Summer~~	~~($3.30)~~	~~(R)~~	|
~~Part-Peak Summer~~	~~($0.62)~~	~~(R)~~	(D)

(Continued)

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.~~ (D) (D)

UNBUNDLING OF TOTAL RATES

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

Demand Rates by Component ($ per kW)	Rate A,D	Rate B,E	Rate C,F
Generation:			
Connected Load Summer	$4.07	–	–
Connected Load Winter	$0.00	–	–
Maximum Demand Summer	–	$4.96	$0.00
Maximum Demand Winter	–	$0.00	$0.00
Maximum Peak Demand Summer	–	$6.21	$11.57
Maximum Part-Peak Demand Summer	–	–	$2.18
Maximum Part-Peak Demand Winter	–	–	$0.00
Primary Voltage Discount Summer (B, E per Maximum Demand; C, F per Maximum Peak Demand)	–	$1.55	$2.38
Primary Voltage Discount Winter (B, E, C, F per Maximum Demand)	–	$0.00	$0.00
Transmission Voltage Discount			
Maximum Peak Demand Summer	–	–	$4.45
Maximum Part-Peak Demand Summer	–	–	$0.00
Maximum Demand Summer	–	$2.71	$0.00
Maximum Part-Peak Demand Winter	–	–	$0.00
Maximum Demand Winter	–	$0.00	$0.00

(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.~~ (D)

~~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.~~

~~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.~~ (D)

(Continued)

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

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

~~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.~~ (D)

(Continued)

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

~~e. Demand Response Operations Website: Customers can go to www.pge.com/peakdaypricing to view the forecast and history of Peak Day Pricing event days. Customers may manage the means by which they are notified by PG&E for Peak Day Pricing events by contacting PG&E.~~

~~The customer's actual energy usage is available on "Your Account". This data may not match billing quality data, and the customer understands and agrees that the data posted to PG&E's "Your Account" may be different from the actual bill.~~

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

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

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

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

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

(Continued)

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

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

~~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.~~ (D)

~~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.~~ (D)

ELECTRIC SCHEDULE AG-F Sheet 2
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

1.APPLICABILITY: (Cont'd)

The provisions of Schedule SB—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 SB, in addition to all applicable Schedule AG-F charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Agricultural customers applying for service under the optional rate Schedule AG-F will be served under one of the rate plans as set forth below:

Rate FA: Applies to single-motor installations rated less than 35 kilowatts (kW)and to all multi-load installations aggregating less than 35 kW.

Rates FB and FC: Applies to single-motor installations rated 35 kW or more, to multi-load installations aggregating 35 kW or more.

Generally, AG-FB is designed for lower load factor customers with fewer operating hours and contains lower demand charges and higher energy charges than AG-FC. By contrast, AG-FC is generally designed for higher load factor customers with more operating hours and has higher demand charges and lower energy charges than AG-FB.

Decision 18-08-013 adopted new TOU periods and seasonal definitions for all non-residential customer classes. Agricultural rate 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 rate options with new TOU periods, 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 of certain qualifying agricultural customers until March 2022. 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 Legacy TOU ~~Grandfathering~~ and Eligibility Requirements. (T)

The rates with revised TOU periods adopted in D.18-08-013 and modified in D.19-05-010, including rates FA, FB, and FC under this Schedule AG-F ~~will be~~were available to qualifying customers on a voluntary opt-in basis ~~beginning~~ from March ~~1,~~ 2020 through February 2021. Customers eligible for this rate schedule must have an interval data meter that can be read remotely by PG&E. (T) | (T)

Any agricultural customers establishing service on or after March 1, 2020 with an interval meter that can be read remotely by PG&E already in place will be charged the Schedule AG or Schedule AG-F rates with revised TOU periods and are not eligible for legacy agricultural rates.

(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).

(L)

(Continued)

ELECTRIC SCHEDULE AG-F Sheet 4
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

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 SmartMeterTM system installed that can be remotely read by PG&E may voluntarily elect to enroll on PDP rates.~~ (N)

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.

A customer exceeding 200 kW as described above is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

PDP rate options are not available to customers under this Schedule. However, all PDP default eligibility criteria also apply to Schedule AG-F. Customers taking service on Schedule AG-F who are eligible for default to PDP or 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 default or voluntarily opt-in and enroll in the PDP program

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

(Continued)

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

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)

TOTAL RATES

Total Customer/Meter Charge Rates	**Rate A**		**Rate B**		**Rate C**		
Customer Charge ($ per meter per day)	$0.68895		$0.91565		$1.43343		
Total Demand Rates ($ per kW)							
Secondary Voltage							
Maximum Peak Demand Summer	—		—		$17.69	(R)	
Maximum Demand Summer	$5.73	(I)	$5.97	(R)	$10.73	(R)	
Maximum Demand Winter	$5.73	(I)	$5.97	(R)	$10.73	(R)	
Primary Voltage							
Maximum Peak Demand Summer	—		—		$17.69	(R)	
Maximum Demand Summer	—		$5.16	(R)	$9.61	(R)	
Maximum Demand Winter	—		$5.16	(R)	$9.61	(R)	
Transmission Voltage							
Maximum Peak Demand Summer	—		—		$17.69	(R)	
Maximum Demand Summer	—		$2.00	(R)	$2.77	(R)	
Maximum Demand Winter	—		$2.00	(R)	$2.77	(R)	
Total Energy Rates ($ per kWh)							
Peak Summer	$0.43816	(I)	$0.41611	(R)	$0.20329	(I)	
Off-Peak Summer	$0.23455	(I)	$0.22528	(R)	$0.15856	(I)	
Peak Winter	$0.26906	(I)	$0.25317	(R)	$0.17226	(I)	
Off-Peak Winter	$0.18864	(I)	$0.18484	(R)	$0.14431	(I)	(L)

—

(Continued)

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

UNBUNDLING OF TOTAL RATES

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

Demand Charge by Component ($/kW)	Rate A		Rate B		Rate C	
Generation:						
Maximum Peak Demand Summer	—		—		$11.79	(R)
Distribution**:						
Secondary Voltage						
Maximum Peak Demand Summer	—		—		$5.90	(R)
Maximum Demand Summer	$5.73	(I)	$5.97	(R)	$10.73	(R)
Maximum Demand Winter	$5.73	(I)	$5.97	(R)	$10.73	(R)
Primary Voltage						
Maximum Peak Demand Summer	—		—		$5.90	(R)
Maximum Demand Summer	—		$5.16	(R)	$9.61	(R)
Maximum Demand Winter	—		$5.16	(R)	$9.61	(R)
Transmission Voltage						
Maximum Peak Demand Summer	—		—		$5.90	(R)
Maximum Demand Summer	—		$2.00	(R)	$2.77	(R)
Maximum Demand Winter	—		$2.00	(R)	$2.77	(R)

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

(Continued)

ELECTRIC SCHEDULE AG-F Sheet 7
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL POWER

3. RATES: (Cont'd.) **UNBUNDLING OF TOTAL RATES** (Cont'd) (L)

Energy Rate by Components ($ per kWh)	**Rate A**		**Rate B**		**Rate C**	
Generation:						
Peak Summer	$0.18766	(R)	$0.20440	(R)	$0.12548	(I)
Off-Peak Summer	$0.11052	(R)	$0.12309	(R)	$0.09547	(I)
Peak Winter	$0.10032	(R)	$0.11103	(R)	$0.11106	(I)
Off-Peak Winter	$0.07387	(R)	$0.08458	(R)	$0.08461	(I)
Distribution**:						
Peak Summer	$0.19965	(I)	$0.16132	(R)	$0.02874	(I)
Off-Peak Summer	$0.07318	(I)	$0.05180	(R)	$0.01402	(I)
Peak Winter	$0.11789	(I)	$0.09175	(R)	$0.01213	(I)
Off-Peak Winter	$0.06392	(I)	$0.04987	(R)	$0.01063	(I)
Transmission* (all usage)	$0.02302	(I)	$0.02302	(I)	$0.02302	(I)
Reliability Services* (all usage)	$0.00011	(I)	$0.00011	(I)	$0.00011	(I)
Transmission Rate Adjustments* (all usage)	$0.00294	(R)	$0.00294	(R)	$0.00294	(R)
Public Purpose Programs (all usage)	$0.01477	(I)	$0.01431	(I)	$0.01299	(I)
Nuclear Decommissioning (all usage)	$0.00093	(R)	$0.00093	(R)	$0.00093	(R)
Competition Transition Charges (all usage)	$0.00003	(R)	$0.00003	(R)	$0.00003	(R)
Energy Cost Recovery Amount (all usage)	$0.00032	(I)	$0.00032	(I)	$0.00032	(I)
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00293	(R)	$0.00293	(R)	$0.00293	(R)
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)

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)

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 A, B, and C on Schedule AG-F:

Peak:

Option I	5:00 p.m. to 8:00 p.m.
Option II	5:00 p.m. to 8:00 p.m.
Option III	5:00 p.m. to 8:00 p.m.

The above peak hours apply every day of the year, including weekends and holidays, except for the special off-peak days by Group as follows:

Off-Peak * All other hours All 365 days of the year

Option I *	Wednesday and Thursday,
Option II *	Saturday and Sunday,
Option III *	Monday and Friday.

The above off-peak hours by Group shall begin at midnight on the designated day and shall continue until midnight 24 hours later. However, peak hours do not begin until 5:00 p.m. on the five days of the week on which the peak hours apply.

WINTER: Service from October 1 through May 31.

Peak: Same as shown above for the summer period

Off-Peak: Same as shown above for the summer period

* Providing space is available, you may have the option of choosing the applicable Group and days for off-peak hours as set forth above and under the terms provided in the Applicability clause. (L)

(Continued)

ELECTRIC SCHEDULE AG-F Sheet 9
FLEXIBLE OFF-PEAK TIME-OF-USE AGRICULTURAL 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-F is provided for a minimum of 12 months beginning with the date your service commences. You may be required to sign a service contract with a minimum term of one year. After your initial one-year term has expired, your contract will continue in effect until it is cancelled by you or PG&E.

9. 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 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), the customer's 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 the customer's demand charge for each season of the billing period will be: (1) the maximum demand created in each season's portion of the billing month as measured by a meter with such capability; or (2) the maximum demand for the billing month where the installed meter is incapable of measuring time-varying demands.

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 (Rates B and E Only): 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. DEFINITION OF SERVICE VOLTAGE: The following defines the three voltage classes of Schedule AG-F 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. (L)

(Continued)

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

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

Transitional Bundled Service Customers take transitional bundled service as prescribed in Rules 22.1 and 23.1, or take bundled service prior to the end of the six (6) month advance notice period required to elect bundled portfolio service as prescribed in Rules 22.1 and 23.1. These customers shall pay charges for transmission, transmission rate adjustments, reliability services, distribution, nuclear decommissioning, public purpose programs, New System Generation Charges, 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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	(I)
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	(R)
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.02818	(I)
2010 Vintage	$0.03482	(I)
2011 Vintage	$0.03662	(I)
2012 Vintage	$0.03902	(I)
2013 Vintage	$0.03923	(I)
2014 Vintage	$0.03926	(I)
2015 Vintage	$0.03946	(I)
2016 Vintage	$0.03974	(I)
2017 Vintage	$0.03978	(I)
2018 Vintage	$0.03929	(I)
2019 Vintage	$0.02916	(R)
2020 Vintage	$0.02287	(R)
2021 Vintage	$0.02287	(N)

(L)

(Continued)

13. 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.

14. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082. (L)

ELECTRIC SCHEDULE AG-R

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~~legacy customers, highly impacted agricultural customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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: (T)

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 SB—Standby Service Special Conditions 1 through 6 shall (T) 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 SB, in addition (T) 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 2
SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

Depending upon the end-use of electricity and 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 the rates under Schedule AG-R: Rate A, B, D or E.

Rates A and D: 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. Rate D applies to customers who were on Rate D as of May 1, 2006 and are not billed via SmartMeter™. Rate A applies to all other customers.

Rates B and E: 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. Rate E applies to customers who were on Rate E as of May 1, 2006 and are not billed via SmartMeter™. Rate B applies to all other customers.

Rate B will apply to those customers whose maximum demand is 200 kW or greater for three consecutive months and select this schedule upon the initial installation of the interval data meter, unless the customer was on Rate E as of May 1, 2006 and is not billed via SmartMeter™.

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 Legacy TOU ~~Grandfathering and~~ Eligibility Requirements. (T)

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

(Continued)

ELECTRIC SCHEDULE AG-R Sheet 3

SPLIT-WEEK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

~~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.~~ (D)

~~Customers taking service under Schedule AG-R 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.~~ (D)

Beginning March 2021, customers served under Schedule AG-R will transition to the rate plans under Schedule AG with revised TOU periods on a mandatory basis or may elect service under optional Schedule AG-F or any other rate plan for which they are eligible.

Customers on AG-RA or AG-RD, with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand less than 35 kW, will transition to rate AG-A1 under Schedule AG, or may elect to enroll in AG-A2 or AG-FA under Schedule AG-F.

Customers on AG-RA or AG-RD, with a maximum demand of 35 kW or greater, for three consecutive months in the most recent twelve months, or on AG-RB or AG-RE will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Summarized below:

Legacy Rate	Defaults to service under Schedule AG:	Or May Opt-In to
AG-RA/D < 35 kW	AG-A1	AG-A2, AG-FA
AG-RA/D >= 35 kW	AG-B	AG-C, AG-FB, AG-FC
AG-RB/E	AG-B	AG-C, AG-FB, AG-FC

The transition of customers no longer eligible for AG-R to Schedule AG with revised TOU periods will occur on the start of the customer's March 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 rate plan with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule AG.

(Continued)

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

1. APPLICABILITY: (Cont'd.)

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 Legacy TOU Period ~~Grandfathering~~" and the terms of "Behind-the-Meter Solar Legacy 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. (T) (T)

"Highly impacted" customers, defined as those agricultural customers with potential bill increases greater than 7 percent and $100 annually due to the transition, may remain on their legacy rate schedule for an additional year but must transition to the new rates with revised TOU periods in March 2022. Decision 19-05-010 delays the mandatory transition to rates with revised TOU periods for these "highly impacted" customers and clarifies that net energy metering (NEM) customers, direct access customers, and community choice aggregation customers and accounts beginning service on or after August 9, 2018 are not eligible for "highly impacted" subgroup exemptions from the mandatory TOU transition in March 2021. However, direct access and community choice aggregation customers are also allowed to qualify as highly impacted customers pursuant to a modification granted by the CPUC Executive Director by letter dated November 16, 2020. (N)

Customers that do not have a meter that is capable of billing on the new Schedule AG on or after March 2021, 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 occur each March to transition all applicable remaining AG-R customers to the rates with revised TOU periods as described above.

All AG-RA and AG-RD customers will convert from connected load demand to metered demand in March 2022 for customers with meters having that capability.

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.

Transfers Off of Schedule AG-R: 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.

(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.~~ (D)

~~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.~~ (D)

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.~~ (D)

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 ~~grandfathered~~legacy customers, highly impacted agricultural customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 SB—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 SB, in addition to all applicable Schedule AG-V charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule. (T)

(Continued)

ELECTRIC SCHEDULE AG-V Sheet 2
SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

Depending upon the end-use of electricity and 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 the rates under Schedule AG-V: Rate A, B, D or E.

Rates A and D: 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. Rate D applies to customers who were on Rate D as of May 1, 2006 and are not billed via SmartMeter™. Rate A applies to all other customers.

Rates B and E: 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. Rate E applies to customers who were on Rate E as of May 1, 2006 and are not billed via SmartMeter™. Rate B applies to all other customers.

Rate B will apply to those customers whose maximum demand is 200 kW or greater for three consecutive months and select this schedule upon the initial installation of the interval data meter, unless the customer was on Rate E as of May 1, 2006 and is not billed via SmartMeter™.

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 Legacy TOU ~~Grandfathering and~~ Eligibility Requirements. (T)

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

(Continued)

ELECTRIC SCHEDULE AG-V Sheet 3
SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

~~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.~~ (D)

~~Customers taking service under Schedule AG-V 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.~~ (D)

Beginning March 2021, customers served under Schedule AG-V will transition to the rate plans under Schedule AG with revised TOU periods on a mandatory basis or may elect service under optional Schedule AG-F or any other rate plan for which they are eligible.

Customers on AG-VA or AG-VD, with an interval meter that have at least twelve (12) billing months hourly usage data available, and a maximum demand less than 35 kW, will transition to rate AG-A1 under Schedule AG, or may elect to enroll in AG-A2 or AG-FA under Schedule AG-F.

Customers on AG-VA or AG-VD, with a maximum demand of 35 kW or greater, for three consecutive months in the most recent twelve months, or on AG-VB or AG-VE will transition to AG-B under Schedule AG, or may elect to enroll in AG-C, or AG-FB or AG-FC under Schedule AG-F.

Summarized below:

Legacy Rate	Defaults to service under Schedule AG:	Or May Opt-In to
AG-VA/D < 35 kW	AG-A1	AG-A2, AG-FA
AG-VA/D >= 35 kW	AG-B	AG-C, AG-FB, AG-FC
AG-VB/E	AG-B	AG-C, AG-FB, AG-FC

The transition of customers no longer eligible for AG-V to Schedule AG with revised TOU periods will occur on the start of the customer's March 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 rate plan with revised TOU periods, based on their eligibility, up to five (5) days prior to the planned transition date to the new Schedule AG.

(Continued)

ELECTRIC SCHEDULE AG-V Sheet 4
SHORT-PEAK TIME-OF-USE AGRICULTURAL POWER

1. APPLICABILITY: (Cont'd.)

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 Legacy TOU Period ~~Grandfathering~~" and the terms of "Behind-the-Meter Solar Legacy 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. (T) (T)

"Highly impacted" customers, defined as those agricultural customers with potential bill increases greater than 7 percent and $100 annually due to the transition, may remain on their legacy rate schedule for an additional year but must transition to the new rates with revised TOU periods in March 2022. Decision 19-05-010 delays the mandatory transition to rates with revised TOU periods for these "highly impacted" customers and clarifies that net energy metering (NEM) customers, direct access customers, and community choice aggregation customers and accounts beginning service on or after August 9, 2018 are not eligible for "highly impacted" subgroup exemptions from the mandatory TOU transition in March 2021. However, direct access and community choice aggregation customers are also allowed to qualify as highly impacted customers pursuant to a modification granted by the CPUC Executive Director by letter dated November 16, 2020. (N)

Customers that do not have a meter that is capable of billing on the new Schedule AG on or after March 2021, 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 occur each March to transition all applicable remaining AG-V customers to the rates with revised TOU periods as described above.

All AG-VA and AG-VD customers will convert from connected load demand to metered demand in March 2022 for customers with meters having that capability.

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.

Transfers Off of Schedule AG-V: 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.

(Continued)

ELECTRIC SCHEDULE AG-V Sheet 5
SHORT-PEAK 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-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.~~ (D)

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.~~ (D)

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

(Continued)

ELECTRIC SCHEDULE B-1
SMALL GENERAL SERVICE

Sheet 1

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 Legacy TOU ~~Grandfathering~~ and Eligibility Requirements. (T) (T)

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

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 legacy ~~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. (T)

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. (T)

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.

* 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-1
SMALL GENERAL SERVICE

APPLICABILITY: (Cont'd)

B1-ST for Storage: The B1-ST rate for storage is an optional rate available to qualifying customers taking Bundled, DA or CCA service under Schedule B-1.

The B1-ST rate is a pilot program that will be offered with a cap on the number of participants of 15,000. The B1-ST rate for storage is available to customers who are subject to the maximum demand eligibility requirements for the class of 75 kW or usage in excess of 150,000 kWh per year (as defined in each rate schedule) and have a minimum energy storage capacity equal to the greater of either 4.8 kWh or at least 0.05 percent of the customer's annual usage (in kWh) for the previous 12 months. Customer under 75 kW that are eligible to take service on Schedule B-1 may elect to take service on B1-ST for Storage. For additional B1-ST details and program specifics see the Special Condition "B1-ST FOR STORAGE" provided further below in this tariff.

~~**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)

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

Decision10-02-032, as modified by Decision 11-11-008, ordered that beginning November 1, 2014, eligible small and medium C&I customers (those with demands that are not equal to or greater than 200 kW for three consecutive months) default to PDP rates. A customer is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeterTM system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

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

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

(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	B-1 Rates		B1-ST Rates		
Total Customer Charge Rates					
Customer Charge Single-phase ($ per meter per day)	$0.32854		$0.32854		
Customer Charge Poly-phase ($ per meter per day)	$0.82136		$0.82136		
Demand Charge (for B1-ST only)					
Total Demand Rate (per metered kW/month assessed from 2:00 p.m. to 11:00 p.m. only)					
Summer	---		$3.74	(I)	
Winter	---		$3.74	(I)	
Total TOU Energy Rates ($ per kWh)					
Peak Summer	$0.32443	(R)	$0.39060	(R)	
Part-Peak Summer	$0.27520	(R)	$0.24930	(R)	
Off-Peak Summer	$0.25439	(R)	$0.20197	(R)	
Peak Winter	$0.24901	(R)	$0.29265	(R)	
Partial-Peak Winter (for B1-ST only)	---		$0.26315	(R)	
Off-Peak Winter	$0.23289	(R)	$0.17410	(R)	
Super Off-Peak Winter	$0.21647	(R)	$0.15768	(R)	
PDP Rates (Consecutive Day and Three-Hour Event Option)*					(N)
PDP Charges ($ per kWh)					|
All Usage During PDP Event	$0.60	(N)			|
PDP Credits					|
Energy ($ per kWh)					|
Peak Summer	($0.03468)	(N)			|
Part-Peak Summer	($0.01030)	(N)			|

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

(Continued)

ELECTRIC SCHEDULE B-1
SMALL GENERAL SERVICE

Sheet 4

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	B-1 Rate		B1-ST Rate	
Customer and Demand Charge Rates: Customer and demand 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	$0.17054	(R)	$0.17530	(R)
Part-Peak Summer	$0.12131	(R)	$0.13284	(R)
Off-Peak Summer	$0.10050	(R)	$0.09709	(R)
Peak Winter	$0.11529	(R)	$0.12472	(R)
Partial-Peak Winter (For B1-ST Only)	---		$0.11238	(R)
Off-Peak Winter	$0.09917	(R)	$0.09038	(R)
Super Off-Peak Winter	$0.08275	(R)	$0.07396	(R)
Distribution:**				
Peak Summer	$0.09825	(I)	$0.15966	(I)
Part-Peak Summer	$0.09825	(I)	$0.06082	(I)
Off-Peak Summer	$0.09825	(I)	$0.04924	(I)
Peak Winter	$0.07808	(I)	$0.11229	(I)
Partial-Peak Winter (For B1-ST Only)	---		$0.09513	(I)
Off-Peak Winter	$0.07808	(I)	$0.02808	(I)
Super Off-Peak Winter	$0.07808	(I)	$0.02808	(I)
Transmission* (all usage)	$0.02784	(I)	$0.02784	(I)
Transmission Rate Adjustments* (all usage)	$0.00294	(R)	$0.00294	(R)
Reliability Services* (all usage)	$0.00013	(I)	$0.00013	(I)
Public Purpose Programs (all usage)	$0.01447	(I)	$0.01447	(I)
Nuclear Decommissioning (all usage)	$0.00093	(R)	$0.00093	(R)
Competition Transition Charges (all usage)	$0.00003	(R)	$0.00003	(R)
Energy Cost Recovery Amount (all usage)	$0.00032	(I)	$0.00032	(I)
New System Generation Charge (all usage)**	$0.00318	(R)	$0.00318	(R)
Wildfire Fund Charge (all usage)	$0.00580		$0.00580	
California Climate Credit (all usage)***	$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)

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

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours~~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 default to PDP and to opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **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 (N)
until 12-months have elapsed since their initial enrollment in Legacy PDP, or

(Continued)

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.

(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 voice, text, or email 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, phone call, 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.

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)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd.).

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. (N)

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)

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 (T)
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 Legacy TOU (T)
~~Grandfathering~~ and Eligibility Requirements.

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

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~~ legacy customers (T)
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)

* 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
MEDIUM GENERAL DEMAND-METERED 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)

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

Decision10-02-032, as modified by Decision 11-11-008, ordered that beginning November 1, 2014, eligible small and medium C&I customers (those with demands that are not equal to or greater than 200 kW for three consecutive months) default to PDP rates. A customer is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

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

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

(Continued)

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)	$4.92753	(I)	$4.92753	(I)	$4.92753	(I)	
Total Demand Rates ($ per kW)							
Summer	$13.76	(I)	$13.51	(I)	$10.59	(I)	
Winter	$13.76	(I)	$13.51	(I)	$10.59	(I)	
Total Energy Rates ($ per kWh)							
Peak Summer	$0.26951	(R)	$0.25438	(R)	$0.19934	(R)	
Part-Peak Summer	$0.20782	(R)	$0.19607	(R)	$0.14259	(R)	
Off-Peak Summer	$0.17526	(R)	$0.16524	(R)	$0.11253	(R)	
Peak Winter	$0.19325	(R)	$0.18151	(R)	$0.14629	(R)	
Off-Peak Winter	$0.15777	(R)	$0.14788	(R)	$0.11345	(R)	
Super Off-Peak Winter	$0.12143	(R)	$0.11154	(R)	$0.07711	(R)	(L)
PDP Rates (Consecutive Day and Three-Hour Event Option							(N)
PDP Charges ($ per kWh)							
All Usage During PDP Event	$0.90	(N)	$0.90	(N)	$0.90	(N)	
PDP Credits							
Energy ($ per kWh)							
Peak Summer	$0.04900	(N)	$0.04900	(N)	$0.04900	(N)	
Part-Peak Summer	$0.01697	(N)	$0.01697	(N)	$0.01697	(N)	

* 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	$4.92	(I)	$4.67	(I)	$1.75	(I)
Winter	$4.92	(I)	$4.67	(I)	$1.75	(I)
Transmission Maximum Demand*	$8.80	(R)	$8.80	(R)	$8.80	(R)
Reliability Services Maximum Demand*	$0.04	(I)	$0.04	(I)	$0.04	(I)
Energy Rate by Components ($ per kWh)						
Generation:						
Peak Summer	$0.19636	(R)	$0.18136	(R)	$0.16445	(R)
Part-Peak Summer	$0.13467	(R)	$0.12305	(R)	$0.10770	(R)
Off-Peak Summer	$0.10211	(R)	$0.09222	(R)	$0.07764	(R)
Peak Winter	$0.13832	(R)	$0.12672	(R)	$0.11140	(R)
Off-Peak Winter	$0.10284	(R)	$0.09309	(R)	$0.07856	(R)
Super Off-Peak Winter	$0.06650	(R)	$0.05675	(R)	$0.04222	(R)
Distribution:**						
Summer	$0.04655	(I)	$0.04653	(I)	$0.00855	(I)
Winter	$0.02833	(I)	$0.02830	(I)	$0.00855	(I)
Transmission Rate Adjustments* (all usage)	$0.00294	(R)	$0.00294	(R)	$0.00294	(R)
Public Purpose Programs (all usage)	$0.01367	(I)	$0.01356	(I)	$0.01341	(I)
Competition Transition Charge (all usage)	$0.00004	(R)	$0.00004	(R)	$0.00004	(R)
Energy Cost Recovery Amount (all usage)	$0.00032	(I)	$0.00032	(I)	$0.00032	(I)
Nuclear Decommissioning (all usage)	$0.00093	(R)	$0.00093	(R)	$0.00093	(R)
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290	(R)	$0.00290	(R)	$0.00290	(R)
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)

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)	$0.00032	(I)
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00004	(R)
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03248	(I)
2010 Vintage	$0.04013	(I)
2011 Vintage	$0.04221	(I)
2012 Vintage	$0.04497	(I)
2013 Vintage	$0.04521	(I)
2014 Vintage	$0.04525	(I)
2015 Vintage	$0.04547	(I)
2016 Vintage	$0.04580	(I)
2017 Vintage	$0.04584	(I)
2018 Vintage	$0.04528	(I)
2019 Vintage	$0.03360	(R)
2020 Vintage	$0.02636	(R)
2021 Vintage	$0.02636	(N)

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 Wildfire Fund 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.

WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082. (L)

ELECTRIC SCHEDULE B-10 Sheet 10
MEDIUM GENERAL DEMAND-METERED 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-10 TOU customers to PDP beginning November 1, 2018 until rates with new TOU periods, as adopted in the same Decision, become mandatory.~~ **Default Provision**: The default of eligible customers to PDP will occur once per year with the start of their billing cycle after November 1. Eligible customers will have at least 45-days notice prior to their planned default date when they may opt-out of PDP rates to take service on TOU rates. During the 45-day period, customers will continue to take service on their non-PDP rate. Customers may elect any applicable PDP rate. However, if the customers taking service on this schedule have not made that choice or elected to opt-out to a TOU rate at least five (5) days before their proposed default date, their service will be defaulted to the PDP version of this rate schedule on their default date. (N)

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours.~~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 default PDP and to opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **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 (N)
until 12-months have elapsed since their initial enrollment in Legacy PDP, or

(Continued)

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.

ELECTRIC SCHEDULE B-10
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 voice, text, or email 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, phone call, 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)

ELECTRIC SCHEDULE B-19 Sheet 1
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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

Decision 18-08-013 adopted new TOU periods for all non-residential customer classes. Schedules A-1, A-6, A-10, E-19 and E-20 will be retained as legacy rate schedules with their 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 Legacy TOU ~~Grandfathering~~ and Eligibility Requirements. (T) (T)

These new rates with revised TOU periods adopted in D.18-08-013~~, including Schedule B-19, will be~~ were available to qualifying customers on a voluntary opt-in basis ~~beginning in~~from November 2019 through February 2021. ~~During that period, eligible customers have a one time opportunity to opt in.~~ (T)

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

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

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

Eligibility for Schedule B-19: This schedule is available on a voluntary basis for customers with maximum billing demands less than 500 kW. Customers voluntarily taking service on this schedule are subject to all the terms and conditions below, unless otherwise specified in Section 13. If a customer's maximum demand has failed to exceed 499 kilowatts for 12 consecutive months, PG&E will transfer that customer's account to voluntary B-19 service or to a different applicable rate schedule..

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

(Continued)

ELECTRIC SCHEDULE B-19 Sheet 2
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

1. APPLICABILITY: (Cont'd.)

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

Definition of Maximum Demand: Demand will be averaged over 15-minute intervals for customers whose maximum demand exceeds 499 kW. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month. (See Section 6 for a definition of "Peak-Period.") See Section 13 for the definition of maximum demand for customers voluntarily selecting B-19.

Option R for 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).

(L)

(Continued)

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

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)

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

Decision10-02-032, as modified by Decision 11-11-008, ordered that beginning November 1, 2014, eligible small and medium C&I customers (those with demands that are not equal to or greater than 200 kW for three consecutive months) default to PDP rates. A customer is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

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

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

(Continued)

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

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

BUNDLED TOTAL RATES

	Secondary Voltage		Primary Voltage		Transmission Voltage		
Total Customer Charge Rates							
Customer Charge Mandatory B-19 ($ per meter per day)	$24.86564	(R)	$37.95479	(R)	$47.04972	(R)	
Customer Charge with SmartMeter™ ($ per meter per day)	$4.92753	(I)	$4.92753	(I)	$4.92753	(I)	
Total Demand Rates ($ per kW**)**							
Maximum Peak Demand Summer	$25.12	(R)	$22.09	(R)	$9.50	(R)	
Maximum Part-Peak Demand Summer	$5.21	(R)	$4.64	(R)	$2.38	(R)	
Maximum Demand Summer	$21.40	(R)	$17.51	(R)	$11.98	(R)	
Maximum Peak Demand Winter	$1.69	(R)	$1.23	(R)	$0.91	(R)	
Maximum Demand Winter	$21.40	(R)	$17.51	(R)	$11.98	(R)	
Total Energy Rates ($ per kWh)							
Peak Summer	$0.15871	(R)	$0.14140	(R)	$0.13292	(R)	
Part-Peak Summer	$0.13029	(R)	$0.12018	(R)	$0.12393	(R)	
Off-Peak Summer	$0.11020	(R)	$0.10172	(R)	$0.10478	(R)	
Peak Winter	$0.14066	(R)	$0.12990	(R)	$0.13412	(R)	
Off-Peak Winter	$0.11012	(R)	$0.10184	(R)	$0.10503	(R)	
Super Off-Peak Winter	$0.06914	(R)	$0.06191	(R)	$0.06225	(R)	
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005		(L)
PDP Rates							(N)
PDP Charges ($ per kWh)							
All Usage During PDP Event	$1.20	(N)	$1.20	(N)	$1.20	(N)	
PDP Credits							
Demand ($ per kW)							
Peak Summer	($6.34)	(N)	($6.01)	(N)	($4.91)	(N)	
Part-Peak Summer	($0.92)	(N)	($0.88)	(N)	($1.23)	(N)	
Energy ($ per kWh)							
Peak Summer	$0.00000	(N)	$0.00000	(N)	$0.00000	(N)	
Part-Peak Summer	$0.00000	(N)	$0.00000	(N)	$0.00000	(N)	(N)

(Continued)

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)

UNBUNDLING OF TOTAL RATES (L)

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	$14.23	(R)	$11.97	(R)	$9.50	(R)
Maximum Part-Peak Demand Summer	$2.07	(R)	$1.75	(R)	$2.38	(R)
Maximum Peak-Demand Winter	$1.69	(R)	$1.23	(R)	$0.91	(R)
Distribution:**						
Maximum Peak Demand Summer	$10.89	(R)	$10.12	(R)	$0.00	
Maximum Part-Peak Demand Summer	$3.14	(R)	$2.89	(R)	$0.00	
Maximum Demand Summer	$12.56	(R)	$8.67	(R)	$3.14	(R)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$12.56	(R)	$8.67	(R)	$3.14	(R)
Transmission Maximum Demand*	$8.80	(R)	$8.80	(R)	$8.80	(R)
Reliability Services Maximum Demand*	$0.04	(I)	$0.04	(I)	$0.04	(I)

* 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-19 Sheet 6
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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 (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	$0.13238	(R)	$0.11541	(R)	$0.10693	(R)
Part-Peak Summer	$0.10396	(R)	$0.09419	(R)	$0.09794	(R)
Off-Peak Summer	$0.08387	(R)	$0.07573	(R)	$0.07879	(R)
Peak Winter	$0.11433	(R)	$0.10391	(R)	$0.10813	(R)
Off-Peak Winter	$0.08379	(R)	$0.07585	(R)	$0.07904	(R)
Super Off-Peak Winter	$0.04281	(R)	$0.03592	(R)	$0.03626	(R)
Transmission Rate Adjustments* (all usage)	$0.00294	(R)	$0.00294	(R)	$0.00294	(R)
Public Purpose Programs (all usage)	$0.01341	(I)	$0.01307	(I)	$0.01307	(I)
Nuclear Decommissioning (all usage)	$0.00093	(R)	$0.00093	(R)	$0.00093	(R)
Competition Transition Charge (all usage)	$0.00003	(R)	$0.00003	(R)	$0.00003	(R)
Energy Cost Recovery Amount (all usage)	$0.00032	(I)	$0.00032	(I)	$0.00032	(I)
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00290	(R)	$0.00290	(R)	$0.00290	(R)
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. (L)

(Continued)

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 18)

Total Customer Charge Rates	Secondary Voltage		Primary Voltage		Transmission Voltage	
Customer Charge Mandatory B-19 ($ per meter per day)	$24.86564	(R)	$37.95479	(R)	$47.04972	(R)
Customer Charge Voluntary B-19:	$4.92753	(I)	$4.92753	(I)	$4.92753	(I)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$2.72	(R)	$2.53	(R)	$0.00	
Maximum Part-Peak Demand Summer	$0.79	(R)	$0.72	(R)	$0.00	
Maximum Demand Summer	$21.40	(R)	$17.51	(R)	$11.98	(R)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$21.40	(R)	$17.51	(R)	$11.98	(R)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.36396	(R)	$0.34168	(R)	$0.23252	(R)
Part-Peak Summer	$0.18011	(R)	$0.16694	(R)	$0.15102	(R)
Off-Peak Summer	$0.11965	(R)	$0.10988	(R)	$0.10887	(R)
Peak Winter	$0.15613	(R)	$0.14193	(R)	$0.14276	(R)
Off-Peak Winter	$0.11381	(R)	$0.10427	(R)	$0.10908	(R)
Super Off-Peak Winter	$0.07799	(R)	$0.06845	(R)	$0.07326	(R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

(L)

(Continued)

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

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

Demand Rates by Components ($ per kW)	Secondary Voltage	Primary Voltage	Transmission Voltage
Distribution:**			
Maximum Peak Demand Summer	$2.72 (R)	$2.53 (R)	$0.00
Maximum Part-Peak Demand Summer	$0.79 (R)	$0.72 (R)	$0.00
Maximum Demand Summer	$12.56 (R)	$8.67 (R)	$3.14 (R)
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$12.56 (R)	$8.67 (R)	$3.14 (R)
Transmission Maximum Demand*	$8.80 (R)	$8.80 (R)	$8.80 (R)
Reliability Services Maximum Demand*	$0.04 (I)	$0.04 (I)	$0.04 (I)

* 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-19 Sheet 9
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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

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

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

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

Energy Charges by Components ($ per kWh)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Peak Summer	$0.26163 (R)	$0.23711 (R)	$0.20653 (R)
Part-Peak Summer	$0.12606 (R)	$0.11357 (R)	$0.12503 (R)
Off-Peak Summer	$0.08755 (R)	$0.07817 (R)	$0.08288 (R)
Peak Winter	$0.12980 (R)	$0.11594 (R)	$0.11677 (R)
Off-Peak Winter	$0.08748 (R)	$0.07828 (R)	$0.08309 (R)
Super Off-Peak Winter	$0.05166 (R)	$0.04246 (R)	$0.04727 (R)
Distribution:**			
Peak Summer	$0.07600 (I)	$0.07858 (I)	$0.00000
Part-Peak Summer	$0.02772 (I)	$0.02738 (I)	$0.00000
Off-Peak Summer	$0.00577 (I)	$0.00572 (I)	$0.00000
Peak Winter	$0.00000	$0.00000	$0.00000
Off-Peak Winter	$0.00000	$0.00000	$0.00000
Super Off-Peak Winter	$0.00000	$0.00000	$0.00000
Transmission Rate Adjustments* (all usage)	$0.00294 (R)	$0.00294 (R)	$0.00294 (R)
Public Purpose Programs (all usage)	$0.01341 (I)	$0.01307 (I)	$0.01307 (I)
Nuclear Decommissioning (all usage)	$0.00093 (R)	$0.00093 (R)	$0.00093 (R)
Competition Transition Charge (all usage)	$0.00003 (R)	$0.00003 (R)	$0.00003 (R)
Energy Cost Recovery Amount (all usage)	$0.00032 (I)	$0.00032 (I)	$0.00032 (I)
Wildfire Fund Charge (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00290 (R)	$0.00290 (R)	$0.00290 (R)
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. (L)

(Continued)

ELECTRIC SCHEDULE B-19 Sheet 10
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

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 20)

Total Customer Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory B-19 ($ per meter per day)	$24.86564 (R)	$37.95479 (R)	$47.04972 (R)
Customer Charge Voluntary B-19:	$4.92753 (I)	$4.92753 (I)	$4.92753 (I)
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer (per day)	$0.54 (R)	$0.45 (R)	$0.14 (R)
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)	$2.54 (R)	$1.75 (R)	$0.63 (R)
Maximum Demand Summer (per monthly billing)	$8.84 (R)	$8.84 (R)	$8.84 (R)
Maximum Peak Demand Winter (per day)	$0.46 (R)	$0.35 (R)	$0.14 (R)
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.54 (R)	$1.76 (R)	$0.64 (R)
Maximum Demand Winter (per monthly billing)	$8.84 (R)	$8.84 (R)	$8.84 (R)
Total Energy Rates ($ per kWh)			
Peak Summer	$0.36396 (R)	$0.34168 (R)	$0.23252 (R)
Part-Peak Summer	$0.18011 (R)	$0.16694 (R)	$0.15102 (R)
Off-Peak Summer	$0.11965 (R)	$0.10988 (R)	$0.10887 (R)
Peak Winter	$0.15613 (R)	$0.14193 (R)	$0.14276 (R)
Off-Peak Winter	$0.11381 (R)	$0.10427 (R)	$0.10908 (R)
Super Off-Peak Winter	$0.07799 (R)	$0.06845 (R)	$0.07326 (R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(L)

(Continued)

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

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

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

Demand Rates by Components ($ per kW)	Secondary Voltage	Primary Voltage	Transmission Voltage
Distribution:**			
Maximum Peak Demand Summer (per day)	$0.54 (R)	$0.45 (R)	$0.14 (R)
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)	$2.54 (R)	$1.75 (R)	$0.63 (R)
Maximum Demand Summer (per monthly billing)	$0.00	$0.00	$0.00
Maximum Peak Demand Winter (per day)	$0.46 (R)	$0.35 (R)	$0.14 (R)
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.54 (R)	$1.76 (R)	$0.64 (R)
Maximum Demand Winter (per monthly billing)	$0.00	$0.00	$0.00
Transmission Maximum Demand*	8.80 (R)	$8.80 (R)	$8.80 (R)
Reliability Services Maximum Demand*	0.04 (I)	0.04 (I)	$0.04 (I)

(L)

(Continued)

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 20)

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

Energy Charges by Components ($ per kWh)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Peak Summer	$0.26163 (R)	$0.23711 (R)	$0.20653 (R)
Part-Peak Summer	$0.12606 (R)	$0.11357 (R)	$0.12503 (R)
Off-Peak Summer	$0.08755 (R)	$0.07817 (R)	$0.08288 (R)
Peak Winter	$0.12980 (R)	$0.11594 (R)	$0.11677 (R)
Off-Peak Winter	$0.08748 (R)	$0.07828 (R)	$0.08309 (R)
Super Off-Peak Winter	$0.05166 (R)	$0.04246 (R)	$0.04727 (R)
Distribution:**			
Peak Summer	$0.07600 (I)	$0.07858 (I)	$0.00000
Part-Peak Summer	$0.02772 (I)	$0.02738 (I)	$0.00000
Off-Peak Summer	$0.00577 (I)	$0.00572 (I)	$0.00000
Peak Winter	$0.00000	$0.00000	$0.00000
Off-Peak Winter	$0.00000	$0.00000	$0.00000
Super Off-Peak Winter	$0.00000	$0.00000	$0.00000
Transmission Rate Adjustments* (all usage)	$0.00294 (R)	$0.00294 (R)	$0.00294 (R)
Public Purpose Programs (all usage)	$0.01341 (I)	$0.01307 (I)	$0.01307 (I)
Nuclear Decommissioning (all usage)	$0.00093 (R)	$0.00093 (R)	$0.00093 (R)
Competition Transition Charge (all usage)	$0.00003 (R)	$0.00003 (R)	$0.00003 (R)
Energy Cost Recovery Amount (all usage)	$0.00032 (I)	$0.00032 (I)	$0.00032 (I)
Wildfire Fund Charge (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00290 (R)	$0.00290 (R)	$0.00290 (R)
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. (L)

(Continued)

3. Rates: (Cont'd.)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule B-19 is the sum of a customer charge, demand charges, and energy charges: (L)

- The **customer charge** is a flat monthly fee.
- This schedule has three **demand charges,** a maximum-peak-period-demand charge, a maximum part-peak-period and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum part-peak-period demand charge per kilowatt applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include 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 level of the customers maximum demand and the voltage at which service is taken. Service voltages are defined in Section 5 below.

4. METERING REQUIRE-MENTS:

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

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

(Continued)

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

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

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

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

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

SUMMER (Service from June 1 through September 30):

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

WINTER (Service from October 1 through May 31):

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

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

(Continued)

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

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

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

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

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

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

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

(Continued)

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

11. COMMON-AREA ACCOUNTS: Common-area accounts are those accounts that provide electric service to Common Use Areas as defined in Rule 1. Common-area accounts that are separately metered by PG&E and which took electric service from PG&E on or prior to January 16, 2003, had a one-time opportunity to return to a residential rate schedule from April 1, 2004 to May 31, 2004, by notifying PG&E in writing. These accounts remain eligible for service under this rate schedule if the customer did not invoke this first right of return. (L)

In the event that the CPUC substantially amends any or all of PG&E's commercial or residential rate schedules, the Executive Council of Homeowners (ECHO) can direct PG&E to begin an optional second right-of-return period lasting 105 days.

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

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

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

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

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

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

(Continued)

13. BILLING: A customer's bill is calculated based on the option applicable to the customer. (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	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	(I)
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	(R)
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.02977	(I)
2010 Vintage	$0.03678	(I)
2011 Vintage	$0.03868	(I)
2012 Vintage	$0.04122	(I)
2013 Vintage	$0.04143	(I)
2014 Vintage	$0.04147	(I)
2015 Vintage	$0.04167	(I)
2016 Vintage	$0.04197	(I)
2017 Vintage	$0.04201	(I)
2018 Vintage	$0.04150	(I)
2019 Vintage	$0.03080	(R)
2020 Vintage	$0.02416	(R)
2021 Vintage	$0.02416	(N)

14. CARE DISCOUNT FOR NONPROFIT GROUP-LIVING AND SPECIAL EMPLOYEE HOUSING FACILITIES: Facilities which meet the eligibility criteria in Rule 19.2 or 19.3 are eligible for a California Alternate Rates for Energy discount under Schedule E-CARE. CARE customers are exempt from paying the Wildfire Fund Charge rate component. For CARE customers, no portion of the rates shall be used to pay the Wildfire Fund Charge. (L)

(Continued)

15. ELECTRIC EMERGENCY PLAN ROTATING BLOCK OUTAGES See Electric Rule 14. (L)

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

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

17. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082. (L)

(Continued)

18. Option R The Option R rate is available to qualifying customers with 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:
https://www.energy.ca.gov/programs-and-topics/topics/renewable-energy/solar-equipment-lists

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)

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

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

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

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

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

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

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

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

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

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

(Continued)

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

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

A. No Retroactive Application

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

B. Customer Notification to PG&E

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

ELECTRIC SCHEDULE B-19 Sheet 22
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

20. OPTION S

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

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

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

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

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

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

The following are not eligible for Option S:

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

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

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

(Continued)

21. PEAK DAY PRICING DETAILS:

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

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rate with later TOU hours~~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 default to PDP and opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **Capacity Reservation Level**: Customers may elect a capacity reservation level (CRL) and pay for a fixed level of capacity, specified in kW. While the CRL is applicable year round, customers electing a CRL will be billed on a take-or-pay basis up to the specified CRL under the non-PDP rate of this schedule during the summer period (June 1 through September 30). This means that customers will be billed for summer peak generation demand charges up to the level of their CRL, even in summer months when the actual demand might be less than their CRL. Customers will receive PDP credits on summer usage above the CRL on all summer-period days. All usage during a PDP event protected under the CRL will be billed at the non-PDP rate. All usage above the CRL (as measured in 15-minute intervals), and not protected during a PDP event, will be billed at the PDP rate. If a customer fails to elect an initial CRL, the customer's initial CRL will be set at 50% of its most recent full summer season average peak-period maximum demand and (N) 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)

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

c. **Bill Stabilization**: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate. (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 voice, text/SMS, or email notification messages of a PDP event from PG&E.

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

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

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

(Continued)

ELECTRIC SCHEDULE B-19
MEDIUM GENERAL DEMAND-METERED TOU SERVICE
Sheet 25

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

f. **Program Operations**: A maximum of fifteen (15) PDP events and a minimum of nine (9) PDP events may be called in any calendar year. PG&E will notify customers by 4:00 p.m. on a day-ahead basis when a PDP event will occur the next day. The PDP program will operate year-round and PDP events may be called for any day of the week. (N)

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

g. **Event Cancellation or Reduction**: PG&E may initiate the cancellation of a PDP event before 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.

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.

~~f.~~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 1
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

1. APPLICABILITY: **Initial Assignment:** A customer is eligible for service under Schedule B-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.

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 Legacy TOU ~~Grandfathering~~ and Eligibility Requirements. (T) (T) (T)

These new rates with revised TOU periods~~, including Schedule B-20, will be~~ were available to qualifying customers on a voluntary opt-in basis ~~beginning in~~from November 2019 through February 2021. ~~During that period, eligible customers have a one-time opportunity to opt-in.~~ (T) (T)

Customers eligible for this rate schedule must have an interval data meter that can be read remotely by PG&E. Beginning on March 2021, customers still served on Schedule E-20, with the exception of solar ~~grandfathered~~ legacy customers referenced above, will be transitioned to Schedule B-20. The transition notification and default process are further described in the legacy rate Schedule E-20. (T)

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 S, in addition to all applicable Schedule B-20 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Transfers Off of Schedule B-20: PG&E will review its Schedule E-20 accounts annually. A customer will be eligible for continued service on Schedule B-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.

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 B-20.

(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)

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

Decision10-02-032, as modified by Decision 11-11-008, ordered that beginning November 1, 2014, eligible small and medium C&I customers (those with demands that are not equal to or greater than 200 kW for three consecutive months) default to PDP rates. A customer is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

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

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

(Continued)

ELECTRIC SCHEDULE B-20
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)	$45.17016	(R)	$45.12903	(R)	$47.63491	(R)	
Total Demand Rates ($ per kW)							
Maximum Peak Demand Summer	$24.94	(R)	$25.32	(R)	$17.02	(R)	
Maximum Part-Peak Demand Summer	$5.19	(R)	$4.95	(R)	$4.06	(R)	
Maximum Demand Summer	$21.56	(R)	$19.48	(R)	$10.81	(R)	
Maximum Peak Demand Winter	$1.77	(R)	$1.75	(R)	$2.27	(R)	
Maximum Demand Winter	$21.56	(R)	$19.48	(R)	$10.81	(R)	
Total Energy Rates ($ per kWh)							
Peak Summer	$0.15111	(R)	$0.14724	(R)	$0.12769	(R)	
Part-Peak Summer	$0.12561	(R)	$0.12022	(R)	$0.11121	(R)	
Off-Peak Summer	$0.10547	(R)	$0.10137	(R)	$0.09281	(R)	
Peak Winter	$0.13592	(R)	$0.13005	(R)	$0.12689	(R)	
Off-Peak Winter	$0.10531	(R)	$0.10143	(R)	$0.08948	(R)	
Super Off-Peak Winter	$0.06431	(R)	$0.06082	(R)	$0.05212	(R)	
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005		(L)
PDP Rates							(N)
PDP Charges ($ per kWh)							
All Usage During PDP Event	$1.20	(N)	$1.20	(N)	$1.20	(N)	
PDP Credits							
Demand ($ per kW)							
Peak Summer	($6.31)	(N)	($6.93)	(N)	($6.43)	(N)	
Part-Peak Summer	($0.91)	(N)	($0.95)	(N)	($1.53)	(N)	
Energy ($ per kWh)							
Peak Summer	$0.00000	(N)	$0.00000	(N)	$0.00000	(N)	
Part-Peak Summer	$0.00000	(N)	$0.00000	(N)	$0.00000	(N)	(N)

(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)/(N)

UNBUNDLING OF TOTAL RATES (L)

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	$13.85	(R)	$15.21	(R)	$17.02	(R)
Maximum Part-Peak Demand Summer	$2.01	(R)	$2.09	(R)	$4.06	(R)
Maximum Demand Summer	$0.00		$0.00		$0.00	
Maximum Peak Demand Winter	$1.77	(R)	$1.75	(R)	$2.27	(R)
Maximum Demand Winter						
Distribution:**						
Maximum Peak Demand Summer	$11.09	(R)	$10.11	(R)	$0.00	
Maximum Part-Peak Demand Summer	$3.18	(R)	$2.86	(R)	$0.00	
Maximum Demand Summer	$11.62	(R)	$9.54	(R)	$0.87	(R)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$11.62	(R)	$9.54	(R)	$0.87	(R)
Transmission Maximum Demand*	$9.89	(I)	$9.89	(I)	$9.89	(I)
Reliability Services Maximum Demand*	$0.05	(I)	$0.05	(I)	$0.05	(I)

* 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)

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	$0.12540 (R)	$0.12191 (R)	$0.10295 (R)
Part-Peak Summer	$0.09990 (R)	$0.09489 (R)	$0.08647 (R)
Off-Peak Summer	$0.07976 (R)	$0.07604 (R)	$0.06807 (R)
Peak Winter	$0.11021 (R)	$0.10472 (R)	$0.10215 (R)
Off-Peak Winter	$0.07960 (R)	$0.07610 (R)	$0.06474 (R)
Super Off-Peak Winter	$0.03860 (R)	$0.03549 (R)	$0.02738 (R)
Distribution:**			
Peak Summer	—	—	—
Part-Peak Summer	—	—	—
Off-Peak Summer	—	—	—
Peak Winter	—	—	—
Off-Peak Winter	—	—	—
Super Off-Peak Winter	—	—	—
Transmission Rate Adjustments* (all usage)	$0.00294 (R)	$0.00294 (R)	$0.00294 (R)
Public Purpose Programs (all usage)	$0.01316 (I)	$0.01278 (I)	$0.01219 (I)
Nuclear Decommissioning (all usage)	$0.00093 (R)	$0.00093 (R)	$0.00093 (R)
Competition Transition Charge (all usage)	$0.00003 (R)	$0.00003 (R)	$0.00003 (R)
Energy Cost Recovery Amount (all usage)	$0.00032 (I)	$0.00032 (I)	$0.00032 (I)
Wildfire Fund Charge (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00253 (R)	$0.00253 (R)	$0.00253 (R)

* 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)	$45.17016	(R)	$45.12903	(R)	$47.63491	(R)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$2.77	(R)	$2.53	(R)	$0.00	
Maximum Part-Peak Demand Summer	$0.80	(R)	$0.71	(R)	$0.00	
Maximum Demand Summer	$21.56	(R)	$19.48	(R)	$10.81	(R)
Maximum Peak Demand Winter	$0.00		$0.00		$0.00	
Maximum Demand Winter	$21.56	(R)	$19.48	(R)	$10.81	(R)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.35581	(R)	$0.33403	(R)	$0.26537	(R)
Part-Peak Summer	$0.17298	(R)	$0.16287	(R)	$0.14675	(R)
Off-Peak Summer	$0.11395	(R)	$0.11030	(R)	$0.09650	(R)
Peak Winter	$0.15254	(R)	$0.14521	(R)	$0.14659	(R)
Off-Peak Winter	$0.10881	(R)	$0.10514	(R)	$0.09358	(R)
Super Off-Peak Winter	$0.07306	(R)	$0.06939	(R)	$0.06078	(R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

(L)

(Continued)

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

Sheet 8

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	$2.77 (R)	$2.53 (R)	$0.00
Maximum Part-Peak Demand Summer	$0.80 (R)	$0.71 (R)	$0.00
Maximum Demand Summer	$11.62 (R)	$9.54 (R)	$0.87 (R)
Maximum Peak Demand Winter	$0.00	$0.00	$0.00
Maximum Demand Winter	$11.62 (R)	$9.54 (R)	$0.87 (R)
Transmission Maximum Demand*	$9.89 (I)	$9.89 (I)	$9.89 (I)
Reliability Services Maximum Demand*	$0.05 (I)	$0.05 (I)	$0.05 (I)

* 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	$0.25344	(R)	$0.24336	(R)	$0.24063	(R)
Part-Peak Summer	$0.12069	(R)	$0.11447	(R)	$0.12201	(R)
Off-Peak Summer	$0.08323	(R)	$0.07976	(R)	$0.07176	(R)
Peak Winter	$0.12683	(R)	$0.11988	(R)	$0.12185	(R)
Off-Peak Winter	$0.08310	(R)	$0.07981	(R)	$0.06884	(R)
Super Off-Peak Winter	$0.04735	(R)	$0.04406	(R)	$0.03604	(R)
Distribution:**						
Peak Summer	$0.07666	(I)	$0.06534	(I)	$0.00000	
Part-Peak Summer	$0.02658	(I)	$0.02307	(I)	$0.00000	
Off-Peak Summer	$0.00501	(I)	$0.00521	(I)	$0.00000	
Peak Winter	$0.00000		$0.00000		$0.00000	
Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Super Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Transmission Rate Adjustments* (all usage)	$0.00294	(R)	$0.00294	(R)	$0.00294	(R)
Public Purpose Programs (all usage)	$0.01316	(I)	$0.01278	(I)	$0.01219	(I)
Nuclear Decommissioning (all usage)	$0.00093	(R)	$0.00093	(R)	$0.00093	(R)
Competition Transition Charge (all usage)	$0.00003	(R)	$0.00003	(R)	$0.00003	(R)
Energy Cost Recovery Amount (all usage)	$0.00032	(I)	$0.00032	(I)	$0.00032	(I)
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00253	(R)	$0.00253	(R)	$0.00253	(R)

* 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)	$45.17016	(R)	$45.12903	(R)	$47.63491	(R)
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer (per day)	$0.54	(R)	$0.43	(R)	$0.03	(R)
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)	$2.35	(R)	$1.93	(R)	$0.18	(R)
Maximum Demand Summer (per monthly billing)	$9.94	(I)	$9.94	(I)	$9.94	(I)
Maximum Peak Demand Winter (per day)	$0.44	(R)	$0.35	(R)	$0.03	(R)
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.35	(R)	$1.93	(R)	$0.18	(R)
Maximum Demand Winter (per billing month)	$9.94	(I)	$9.94	(I)	$9.94	(I)
Total Energy Rates ($ per kWh)						
Peak Summer	$0.35581	(R)	$0.33403	(R)	$0.26537	(R)
Part-Peak Summer	$0.17298	(R)	$0.16287	(R)	$0.14675	(R)
Off-Peak Summer	$0.11395	(R)	$0.11030	(R)	$0.09650	(R)
Peak Winter	$0.15254	(R)	$0.14521	(R)	$0.14659	(R)
Off-Peak Winter	$0.10881	(R)	$0.10514	(R)	$0.09358	(R)
Super Off-Peak Winter	$0.07306	(R)	$0.06939	(R)	$0.06078	(R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005	

(L)

(Continued)

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	(R)	$0.43	(R)	$0.03	(R)
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)	$2.35	(R)	$1.93	(R)	$0.18	(R)
Maximum Demand Summer (per monthly billing)	$0.00		$0.00		$0.00	
Maximum Peak Demand Winter (per day)	$0.44	(R)	$0.35	(R)	$0.03	(R)
Maximum Demand Winter (per monthly billing, all hours except 9 am to 2 pm)	$2.35	(R)	$1.93	(R)	$0.18	(R)
Maximum Demand Winter (per billing month)	$0.00		$0.00		$0.00	
Transmission Maximum Demand*	$9.89	(I)	$9.89	(I)	$9.89	(I)
Reliability Services Maximum Demand*	$0.05	(I)	$0.05	(I)	$0.05	(I)

* 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	$0.25344	(R)	$0.24336	(R)	$0.24063	(R)
Part-Peak Summer	$0.12069	(R)	$0.11447	(R)	$0.12201	(R)
Off-Peak Summer	$0.08323	(R)	$0.07976	(R)	$0.07176	(R)
Peak Winter	$0.12683	(R)	$0.11988	(R)	$0.12185	(R)
Off-Peak Winter	$0.08310	(R)	$0.07981	(R)	$0.06884	(R)
Super Off-Peak Winter	$0.04735	(R)	$0.04406	(R)	$0.03604	(R)
Distribution:**						
Peak Summer	$0.07666	(I)	$0.06534	(I)	$0.00000	
Part-Peak Summer	$0.02658	(I)	$0.02307	(I)	$0.00000	
Off-Peak Summer	$0.00501	(I)	$0.00521	(I)	$0.00000	
Peak Winter	$0.00000		$0.00000		$0.00000	
Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Super Off-Peak Winter	$0.00000		$0.00000		$0.00000	
Transmission Rate Adjustments* (all usage)	$0.00294	(R)	$0.00294	(R)	$0.00294	(R)
Public Purpose Programs (all usage)	$0.01316	(I)	$0.01278	(I)	$0.01219	(I)
Nuclear Decommissioning (all usage)	$0.00093	(R)	$0.00093	(R)	$0.00093	(R)
Competition Transition Charge (all usage)	$0.00003	(R)	$0.00003	(R)	$0.00003	(R)
Energy Cost Recovery Amount (all usage)	$0.00032	(I)	$0.00032	(I)	$0.00032	(I)
Wildfire Fund Charge (all usage)	$0.00580		$0.00580		$0.00580	
New System Generation Charge (all usage)**	$0.00253	(R)	$0.00253	(R)	$0.00253	(R)

* 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)

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)

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 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. (L)

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

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

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

9. STANDARD SERVICE FACILITIES: If PG&E must install any new or additional facilities to provide the customer with service under 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 Sheet 16
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)	$0.00032	(I)	$0.00032	(I)	$0.00032	(I)
Wildfire Fund Charge (per kWh)	$0.00580		$0.00580		$0.00580	
CTC Rate (per kWh)	$0.00003	(R)	$0.00003	(R)	$0.00003	(R)
Power Charge Indifference Adjustment (per kWh)						
2009 Vintage	$0.02853	(I)	$0.02730	(I)	$0.02547	(I)
2010 Vintage	$0.03525	(I)	$0.03374	(I)	$0.03148	(I)
2011 Vintage	$0.03707	(I)	$0.03548	(I)	$0.03310	(I)
2012 Vintage	$0.03950	(I)	$0.03781	(I)	$0.03527	(I)
2013 Vintage	$0.03971	(I)	$0.03800	(I)	$0.03546	(I)
2014 Vintage	$0.03974	(I)	$0.03804	(I)	$0.03549	(I)
2015 Vintage	$0.03994	(I)	$0.03823	(I)	$0.03566	(I)
2016 Vintage	$0.04023	(I)	$0.03850	(I)	$0.03592	(I)
2017 Vintage	$0.04027	(I)	$0.03854	(I)	$0.03595	(I)
2018 Vintage	$0.03977	(I)	$0.03806	(I)	$0.03551	(I)
2019 Vintage	$0.02952	(R)	$0.02825	(R)	$0.02636	(R)
2020 Vintage	$0.02316	(R)	$0.02216	(R)	$0.02068	(R)
2021 Vintage	$0.02316	(N)	$0.02216	(N)	$0.02068	(N)

(L)

(Continued)

ELECTRIC SCHEDULE B-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 Wildfire Fund Charge. (L)

13. ELECTRIC EMERGENCY PLAN ROTATING BLOCK OUTAGES: See Electric Rule 14.

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.

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. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082. (L)

(Continued)

ELECTRIC SCHEDULE B-20 Sheet 18
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:

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

Where the PTC and CEC inverter Efficiency Rating can be found at:
https://www.energy.ca.gov/programs-and-topics/topics/renewable-energy/solar-equipment-lists

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)

ELECTRIC SCHEDULE B-20 Sheet 21
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-20 or voluntary B-20. 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 B-20 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)

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

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours~~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 default to PDP and opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **Capacity Reservation Level**: Customers may elect a capacity reservation level (CRL) and pay for a fixed level of capacity, specified in kW. While the CRL is applicable year round, customers electing a CRL will be billed on a take-or-pay basis up to the specified CRL under the non-PDP rate of this schedule during the summer period (June 1 through September 30). This means that customers will be billed for summer peak generation demand charges up to the level of their CRL, even in summer months when the actual demand might be less than their CRL. Customers will receive PDP credits on summer usage above the CRL on all summer-period days. All usage during a PDP event protected under the CRL will be billed at the non-PDP rate. All usage above the CRL (as measured in 15-minute intervals), and not protected during a PDP event, will be billed at the PDP rate. If a customer fails to elect an initial CRL, the customer's initial CRL will be set at 50% of its most recent full summer season average peak-period maximum demand and may go back to the previous year to make a full summer season (if available). If the customer has not established any historic summer billing demand, the CRL will be set at zero (0). The CRL for all customers, including NEM customers, must be greater than or equal to zero (0). A customer may only elect to change their CRL once every 12-months. (N)

(Continued)

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

c. **Bill Stabilization**: PDP customers will be offered bill stabilization for the initial twelve (12) months unless they opt-out during their initial 45-day period. Bill stabilization ensures that during the initial 12-months under PDP, the customer will not pay more than it would have had it opted-out to the applicable TOU rate. (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 voice, text, or email notification messages of a PDP event from PG&E.

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

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

~~c.~~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. (N)

19. PEAK DAY PRICING DETAILS (Cont'd.): (N)

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, phone call, email and/or text) for PDP customers.

g. **Event Cancellation or Reduction**: PG&E may initiate the cancellation of a PDP event before 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.

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)

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 Legacy TOU ~~Grandfathering~~ and Eligibility Requirements. (T) (T)

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

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~~ legacy 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. (T)

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)

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

Decision10-02-032, as modified by Decision 11-11-008, ordered that beginning November 1, 2014, eligible small and medium C&I customers (those with demands that are not equal to or greater than 200 kW for three consecutive months) default to PDP rates. A customer is eligible for default when it has at least twelve (12) billing months of hourly usage data available and two years of experience on TOU rates. All eligible customers will be placed on PDP rates unless they opt-out to a TOU rate. Customers with a SmartMeter™ system, or interval meter, installed that can be remotely read by PG&E may also voluntarily elect to enroll on PDP rates.

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

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

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

(Continued)

ELECTRIC SCHEDULE B-6
SMALL GENERAL TIME-OF-USE 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. (L)

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	$0.35490	(R)
Off-Peak Summer	$0.23696	(R)
Peak Winter	$0.24729	(R)
Off-Peak Winter	$0.22755	(R)
Super Off-Peak Winter	$0.21113	(R) (L)

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

PDP Charges ($ per kWh)		
All Usage During PDP Event	$0.60	(N)
PDP Credits		
Energy ($ per kWh)		
Peak Summer	$0.04291	(N)
	$0.60	(N)

* See PDP Details, 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. (L) (L)/(N) (N)

UNBUNDLING OF TOTAL RATES (L)

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)	Rates	
Generation:		
Peak Summer	$0.17358	(R)
Off-Peak Summer	$0.10242	(R)
Peak Winter	$0.11006	(R)
Off Peak Winter	$0.09301	(R)
Super Off-Peak Winter	$0.07659	(R)
Distribution:**		
Peak Summer	$0.12658	(I)
Off-Peak Summer	$0.07980	(I)
Peak Winter	$0.08249	(I)
Off Peak Winter	$0.07980	(I)
Super Off-Peak Winter	$0.07980	(I)
Transmission* (all usage)	$0.02784	(I)
Wildfire Fund Charge (all usage)	$0.00580	
Transmission Rate Adjustments* (all usage)	$0.00294	(R)
Reliability Services* (all usage)	$0.00013	(I)
Public Purpose Programs (all usage)	$0.01357	(I)
Nuclear Decommissioning (all usage)	$0.00093	(R)
Competition Transition Charges (all usage)	$0.00003	(R)
Energy Cost Recovery Amount (all usage)	$0.00032	(I)
New System Generation Charge (all usage)**	$0.00318	(R)
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. (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
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.	

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.

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

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. (L)

(Continued)

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

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

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

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

	DA /CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00032	(I)
Wildfire Fund Charge (per kWh)	$0.00580	
CTC Charge (per kWh)	$0.00003	(R)
Power Charge Indifference Adjustment (per kWh)		
2009 Vintage	$0.03029	(I)
2010 Vintage	$0.03743	(I)
2011 Vintage	$0.03936	(I)
2012 Vintage	$0.04194	(I)
2013 Vintage	$0.04216	(I)
2014 Vintage	$0.04219	(I)
2015 Vintage	$0.04240	(I)
2016 Vintage	$0.04271	(I)
2017 Vintage	$0.04275	(I)
2018 Vintage	$0.04222	(I)
2019 Vintage	$0.03134	(R)
2020 Vintage	$0.02458	(R)
2021 Vintage	$0.02458	(N) (L)

(Continued)

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 Wildfire Fund Charge. (L)

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

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

WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082. (L)

(Continued)

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

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.

Starting in March 2021, Legacy PDP will be discontinued, and New PDP will be available only on the new rates with later TOU hours~~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 default to PDP and to opt-in to PDP. NEM customers on NEMBIO, NEMFC, NEMCCSF, and NEMA are not eligible for PDP. The NEM Annual True-Up billing date, and the first year PDP Bill Stabilization date in section b below, may be independent 12-month periods. After the first year on PDP, NEM credits can offset PDP charges. PDP credits and charges will be provided for exported generation. All PDP billing for NEM customers will be based on net usage during each 15-minute interval.

b. **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 (N)
until 12-months have elapsed since their initial enrollment in Legacy PDP, or

(Continued)

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.

(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 voice, text, or email 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, phone call, 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.

~~e.~~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)

(Continued)

PEAK DAY PRICING DETAILS (Cont'd.):

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. (N)

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.

~~d.~~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 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~~legacy customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 Legacy TOU ~~Grandfathering and~~ Eligibility Requirements. (T)

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

~~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.~~ (D)

~~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~~. (D)

(Continued)

* 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.~~ (D)

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 Legacy TOU Period ~~Grandfathering~~" and (T)
the terms of "Behind-the-Meter Solar Legacy TOU Period ~~Grandfathering~~ (T)
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 SB—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 SB, 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.~~ (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), or on net-energy metering Schedules NEMFC, NEMBIO, NEMCCSF, or~~

(Continued)

~~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~~. (D)

(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~~

TOTAL RATES

Total Customer/Meter Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage	
Customer Charge Mandatory E-19 ($ per meter per day)	$24.86564	$37.95479	$47.04972	
Customer Charge Voluntary E-19:				
Customer Charge with SmartMeter™ ($ per meter per day)	$4.92753	$4.92753	$4.92753	
Customer Charge without SmartMeter™				
Customer Charge Rate V ($ per meter per day)	$5.10494	$5.10494	$5.10494	
Customer Charge Rate W ($ per meter per day)	$4.96301	$4.96301	$4.96301	
Customer Charge Rate X ($ per meter per day)	$5.10494	$5.10494	$5.10494	
Total Demand Rates ($ per kW)				
Maximum Peak Demand Summer	$21.28	$18.95	$13.89	
Maximum Part-Peak Demand Summer	$5.94	$5.20	$3.48	
Maximum Demand Summer	$21.08	$17.43	$11.98	
Maximum Part-Peak Demand Winter	$0.14	$0.17	$0.00	
Maximum Demand Winter	$21.08	$17.43	$11.98	
Total Energy Rates ($ per kWh)				
Peak Summer	$0.16733	$0.15617	$0.11585	
Part-Peak Summer	$0.12183	$0.11324	$0.10175	
Off-Peak Summer	$0.09170	$0.08564	$0.08309	
Part-Peak Winter	$0.11560	$0.10744	$0.10397	
Off-Peak Winter	$0.09918	$0.09246	$0.08964	
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005	
~~PDP Rates~~				(D)
~~PDP Charges ($ per kWh)~~				|
~~All Usage During PDP Event~~	~~$1.20~~	~~$1.20~~	~~$1.20~~	|
~~PDP Credits~~				|
~~Demand ($ per kW)~~				|
~~Peak Summer~~	~~($5.00)~~ ~~(I)~~	~~($4.85)~~ ~~(I)~~	~~($4.84)~~	|
~~Part-Peak Summer~~	~~($1.24)~~ ~~(I)~~	~~($1.18)~~ ~~(I)~~	~~($1.21)~~	|
~~Energy ($ per kWh)~~				|
~~Peak Summer~~	~~$0.00000~~	~~$0.00000~~	~~$0.00000~~	|
~~Part-Peak Summer~~	~~$0.00000~~	~~$0.00000~~	~~$0.00000~~	(D)

(Continued)

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~~. (D)

UNBUNDLING OF TOTAL RATES

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

Demand Rates by Components ($ per kW)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Maximum Peak Demand Summer	$14.19	$12.63	$13.89
Maximum Part-Peak Demand Summer	$3.51	$3.08	$3.48
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	$7.09	$6.32	$0.00
Maximum Part-Peak Demand Summer	$2.43	$2.12	$0.00
Maximum Demand Summer	$12.24	$8.59	$3.14
Maximum Part-Peak Demand Winter	$0.14	$0.17	$0.00
Maximum Demand Winter	$12.24	$8.59	$3.14
Transmission Maximum Demand*	$8.80	$8.80	$8.80
Reliability Services Maximum Demand*	$0.04	$0.04	$0.04

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

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

(Continued)

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

3. Rates: (Cont'd.)

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.~~ (D)

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Charges by Components ($ per kWh)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Peak Summer	$0.14100	$0.13018	$0.08986
Part-Peak Summer	$0.09550	$0.08725	$0.07576
Off-Peak Summer	$0.06537	$0.05965	$0.05710
Part-Peak Winter	$0.08927	$0.08145	$0.07798
Off-Peak Winter	$0.07285	$0.06647	$0.06365
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)	$0.00294	$0.00294	$0.00294
Public Purpose Programs (all usage)	$0.01341	$0.01307	$0.01307
Nuclear Decommissioning (all usage)	$0.00093	$0.00093	$0.00093
Competition Transition Charge (all usage)	$0.00003	$0.00003	$0.00003
Energy Cost Recovery Amount (all usage)	$0.00032	$0.00032	$0.00032
Wildfire Fund Charge (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00290	$0.00290	$0.00290
California Climate Credit (all usage – E-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)

a3. Rates: (Cont'd.)

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

TOTAL RATES FOR OPTION R
(for qualifying solar customers as set forth in Section ~~20~~18) (T)

Total Customer/Meter Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory E-19 ($ per meter per day)	$24.86564	$37.95479 (R)	$47.04972 (R)
Customer Charge Voluntary E-19:			
Customer Charge with SmartMeter™ ($ per meter per day)	$4.92753	$4.92753	$4.92753
Customer Charge without SmartMeter™			
Customer Charge Rate V ($ per meter per day)	$5.10494	$5.10494	$5.10494
Customer Charge Rate W ($ per meter per day)	$4.96301	$4.96301	$4.96301
Customer Charge Rate X ($ per meter per day)	$5.10494	$5.10494	$5.10494
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$1.77	$1.58	$0.00
Maximum Part-Peak Demand Summer	$0.61	$0.53	$0.00
Maximum Demand Summer	$21.08	$17.43	$11.98
Maximum Part-Peak Demand Winter	$0.04	$0.04	$0.00
Maximum Demand Winter	$21.08	$17.43	$11.98
Total Energy Rates ($ per kWh)			
Peak Summer	$0.38642	$0.37343	$0.30728
Part-Peak Summer	$0.18183	$0.17244	$0.15118
Off-Peak Summer	$0.09729	$0.09210	$0.08853
Part-Peak Winter	$0.12199	$0.11489	$0.10963
Off-Peak Winter	$0.10485	$0.09900	$0.09515
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(Continued)

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

3. Rates: (Cont'd.)

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

UNBUNDLING OF TOTAL RATES FOR OPTION R
(for qualifying solar customers as set forth in Section ~~20~~18) (T)

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	$1.77	$1.58	$0.00
Maximum Part-Peak Demand Summer	$0.61	$0.53	$0.00
Maximum Demand Summer	$12.24	$8.59	$3.14
Maximum Part-Peak Demand Winter	$0.04	$0.04	$0.00
Maximum Demand Winter	$12.24	$8.59	$3.14
Transmission Maximum Demand*	$8.80	$8.80	$8.80
Reliability Services Maximum Demand*	$0.04	$0.04	$0.04

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

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

(Continued)

ELECTRIC SCHEDULE E-19 Sheet 10
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~~. (D)

UNBUNDLING OF TOTAL RATES FOR OPTION R (Cont'd.)
(for qualifying solar customers as set forth in Section ~~20~~18) (T)

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

Energy Charges by Components ($ per kWh)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Peak Summer	$0.30443	$0.29106	$0.28129
Part-Peak Summer	$0.13659	$0.12785	$0.12519
Off-Peak Summer	$0.06918	$0.06434	$0.06254
Part-Peak Winter	$0.09334	$0.08639	$0.08364
Off-Peak Winter	$0.07674	$0.07124	$0.06916
Distribution:**			
Peak Summer	$0.05566	$0.05638	$0.00000
Part-Peak Summer	$0.01891	$0.01860	$0.00000
Off-Peak Summer	$0.00178	$0.00177	$0.00000
Part-Peak Winter	$0.00232	$0.00251	$0.00000
Off-Peak Winter	$0.00178	$0.00177	$0.00000
Transmission Rate Adjustments* (all usage)	$0.00294	$0.00294	$0.00294
Public Purpose Programs (all usage)	$0.01341	$0.01307	$0.01307
Nuclear Decommissioning (all usage)	$0.00093	$0.00093	$0.00093
Competition Transition Charge (all usage)	$0.00003	$0.00003	$0.00003
Energy Cost Recovery Amount (all usage)	$0.00032	$0.00032	$0.00032
Wildfire Fund Charge (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00290	$0.00290	$0.00290
California Climate Credit (all usage – E-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)

~~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.~~ (D)

~~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.~~

~~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.~~ (D)

(Continued)

~~18. PEAK DAY PRICING DETAILS: (cont.)~~

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

~~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.~~

~~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 go to www.pge.com/peakdaypricing to view the forecast and history of Peak Day Pricing event days. Customers may manage the means by which they are notified by PG&E for Peak Day Pricing events by contacting PG&E.~~

~~The customer's actual energy usage is available on "Your Account". This data may not match billing quality data, and the customer understands and agrees that the data posted to PG&E "Your Account" may be different from the actual bill.~~

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

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

(Continued)

~~18. PEAK DAY PRICING DETAILS: (cont.)~~

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

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

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

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

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

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

~~19~~18. 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. (T)

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:

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

Where the PTC and CEC inverter Efficiency Rating can be found at:
https://www.energy.ca.gov/programs-and-topics/topics/renewable-energy/solar-equipment-lists

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%

(Continued)

~~20~~19. OPTIMAL BILLING PERIOD SERVICE: The Optimal Billing Period (OBP) service is a voluntary program available to bundled, direct access and community choice aggregation customers taking service on Schedule 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. (T)

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.

(Continued)

~~20~~19. OPTIMAL BILLING PERIOD SERVICE: (Cont'd.)

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

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.

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~~legacy customers, or to qualifying customers without interval meters that can be read remotely by PG&E, 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 Legacy TOU ~~Grandfathering and~~ Eligibility Requirements. (T) (T)

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

(D)

~~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.~~

~~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~~

(Continued)

~~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.~~ (D)

* 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.)

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 Legacy TOU Period ~~Grandfathering~~" and the terms of "Behind-the-Meter Solar Legacy 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. (T) (T)

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 SB—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 SB, in addition to all applicable Schedule E-20 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

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.

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~~. (T)

(Continued)

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

1. APPLICABILITY: (Cont'd.)

Peak Day Pricing Default Rates (Cont'd):

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.~~ (D)

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

(Continued)

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

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.

(Continued)

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

1. APPLICABILITY: (Cont'd.)

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.

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.~~

TOTAL RATES

	Secondary Voltage		Primary Voltage		Transmission Voltage		
Total Customer/Meter Charge Rates							
Customer Charge Mandatory E-20 ($ per meter per day)	$45.17016		$45.12903		$47.63491		
Total Demand Rates ($ per kW)							
Maximum Peak Demand Summer	$20.54		$22.04		$17.93		
Maximum Part-Peak Demand Summer	$5.71		$5.90		$4.27		
Maximum Demand Summer	$21.51		$19.00		$10.81		
Maximum Part-Peak Demand Winter	$0.06		$0.15		$0.00		
Maximum Demand Winter	$21.51		$19.00		$10.81		
Total Energy Rates ($ per kWh)							
Peak Summer	$0.15676		$0.15899		$0.11273		
Part-Peak Summer	$0.11538		$0.11349		$0.09892		
Off-Peak Summer	$0.08697		$0.08550		$0.08066		
Part-Peak Winter	$0.10937		$0.10749		$0.10110		
Off-Peak Winter	$0.09398		$0.09238		$0.08706		
Power Factor Adjustment Rate ($/kWh/%)	$0.00005		$0.00005		$0.00005		
~~PDP Rates~~							
~~PDP Charges ($ per kWh)~~							(D)
~~All Usage During PDP Event~~	~~$1.20~~		~~$1.20~~		~~$1.20~~		|
~~PDP Credits~~							|
~~Demand ($ per kW)~~							|
~~Peak Summer~~	~~($4.94)~~	~~(I)~~	~~($5.35)~~	~~(I)~~	~~($5.90)~~	~~(I)~~	|
~~Part-Peak Summer~~	~~($1.22)~~	~~(I)~~	~~($1.26)~~	~~(I)~~	~~($1.41)~~	~~(I)~~	|
~~Energy ($ per kWh)~~							|
~~Peak Summer~~	~~$0.00000~~		~~$0.00000~~		~~$0.00000~~		|
~~Part-Peak Summer~~	~~$0.00000~~		~~$0.00000~~		~~$0.00000~~		(D)

(Continued)

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

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.~~ (D)

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	$13.75	$15.05	$17.93
Maximum Part-Peak Demand Summer	$3.39	$3.56	$4.27
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	$6.79	$6.99	$0.00
Maximum Part-Peak Demand Summer	$2.32	$2.34	$0.00
Maximum Demand Summer	$11.57	$9.06	$0.87
Maximum Part-Peak Demand Winter	$0.06	$0.15	$0.00
Maximum Demand Winter	$11.57	$9.06	$0.87
Transmission Maximum Demand*	$9.89	$9.89	$9.89
Reliability Services Maximum Demand*	$0.05	$0.05	$0.05
Energy Rates by Component ($ per kWh)			
Generation:			
Peak Summer	$0.13105	$0.13366	$0.08799
Part-Peak Summer	$0.08967	$0.08816	$0.07418
Off-Peak Summer	$0.06126	$0.06017	$0.05592
Part-Peak Winter	$0.08366	$0.08216	$0.07636
Off-Peak Winter	$0.06827	$0.06705	$0.06232
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**)**	$0.00294	$0.00294	$0.00294
Public Purpose Programs (all usage)	$0.01316	$0.01278	$0.01219
Nuclear Decommissioning (all usage)	$0.00093	$0.00093	$0.00093
Competition Transition Charge (all usage)	$0.00003	$0.00003	$0.00003
Energy Cost Recovery Amount (all usage)	$0.00032	$0.00032	$0.00032
Wildfire Fund Charge (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00253	$0.00253	$0.00253

* 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 6
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

3. RATES: (Cont'd.)

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

TOTAL RATES FOR OPTION R
(for qualifying solar customers as set forth in Section ~~18~~16) (T)

Total Customer/Meter Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory E-20 ($ per meter per day)	$45.17016	$45.12903	$47.63491
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$1.70	$1.75	$0.00
Maximum Part-Peak Demand Summer	$0.58	$0.58	$0.00
Maximum Demand Summer	$21.51	$19.00	$10.81
Maximum Part-Peak Demand Winter	$0.01	$0.04	$0.00
Maximum Demand Winter	$21.51	$19.00	$10.81
Total Energy Rates ($ per kWh)			
Peak Summer	$0.35210	$0.36989	$0.31055
Part-Peak Summer	$0.16970	$0.16738	$0.14192
Off-Peak Summer	$0.09071	$0.08956	$0.08185
Part-Peak Winter	$0.11359	$0.11235	$0.10256
Off-Peak Winter	$0.09780	$0.09652	$0.08834
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

(Continued)

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

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.~~ (D)

UNBUNDLING OF TOTAL RATES FOR OPTION R
(for qualifying solar customers as set forth in Section ~~18~~16) (T)

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	$1.70	$1.75	$0.00
Maximum Part-Peak Demand Summer	$0.58	$0.58	$0.00
Maximum Demand Summer	$11.57	$9.06	$0.87
Maximum Part-Peak Demand Winter	$0.01	$0.04	$0.00
Maximum Demand Winter	$11.57	$9.06	$0.87
Transmission Maximum Demand*	$9.89	$9.89	$9.89
Reliability Services Maximum Demand*	$0.05	$0.05	$0.05
Energy Rates by Component ($ per kWh)			
Generation:			
Peak Summer	$0.27676	$0.29405	$0.28581
Part-Peak Summer	$0.12684	$0.12550	$0.11718
Off-Peak Summer	$0.06363	$0.06263	$0.05711
Part-Peak Winter	$0.08630	$0.08490	$0.07782
Off-Peak Winter	$0.07072	$0.06959	$0.06360
Distribution:**			
Peak Summer	$0.04963	$0.05051	$0.00000
Part-Peak Summer	$0.01715	$0.01655	$0.00000
Off-Peak Summer	$0.00137	$0.00160	$0.00000
Part-Peak Winter	$0.00158	$0.00212	$0.00000
Off-Peak Winter	$0.00137	$0.00160	$0.00000
Transmission Rate Adjustments* (all usage)	$0.00294	$0.00294	$0.00294
Public Purpose Programs (all usage)	$0.01316	$0.01278	$0.01219
Nuclear Decommissioning (all usage)	$0.00093	$0.00093	$0.00093
Competition Transition Charge (all usage)	$0.00003	$0.00003	$0.00003
Energy Cost Recovery Amount (all usage)	$0.00032	$0.00032	$0.00032
Wildfire Fund Charge (all usage)	$0.00580	$0.00580	$0.00580
New System Generation Charge (all usage)**	$0.00253	$0.00253	$0.00253

* 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 13
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

15. WILDFIRE FUND CHARGE: The Wildfire Fund Charge was imposed by California Public Utilities Commission Decisions 19-10-056, 20-07-014, 20-09-005, and 20-09-023 and is property of Department of Water Resources (DWR) for all purposes under California law. The Charge became effective October 1, 2020, and applies to all retail sales, excluding CARE and Medical Baseline sales. The Wildfire Fund Charge (where applicable) is included in customers' total billed amounts. The Wildfire Fund Charge replaces the DWR Bond Charge imposed by California Public Utilities Commission Decisions 02-10-063 and 02-12-082.

~~16. PEAK DAY PRICING DETAILS:~~

~~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 C&I customers in March 2021, concurrent with the resumption of the default of eligible customers to PDP.~~ (D)

~~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.~~ (D)

(Continued)

ELECTRIC SCHEDULE E-20 Sheet 14
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.~~ (D)

~~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 go to www.pge.com/peakdaypricing to view the forecast and history of Peak Day Pricing event days. Customers may manage the means by which they are notified by PG&E for Peak Day Pricing events by contacting PG&E..~~

~~The customer's actual energy usage is available on "Your Account". This data may not match billing quality data, and the customer understands and agrees that the data posted to PG&E's "Your Account" may be different from the actual bill.~~

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

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

(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.~~ (D)

~~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.~~ (D)

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

~~17~~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) * 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:
https://www.energy.ca.gov/programs-and-topics/topics/renewable-energy/solar-equipment-lists

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 17
SERVICE TO CUSTOMERS WITH MAXIMUM
DEMANDS of 1000 KILOWATTS or MORE

~~18~~17. OPTIMAL BILLING PERIOD SERVICE: (L)

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.

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)

~~18~~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)

BASELINE: A rate structure mandated by the California Legislative and implemented at PG&E in 1984 that insures all residential customers are provided a minimum necessary quantity of electricity at the lowest possible cost.

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ~~GRANDFATHERING~~:

A. A transition mitigation measure that allows qualified solar customers to maintain legacy TOU periods for the duration of the transition mitigation period. This transition mitigation measure does not apply to these customers:

(1) For customers on Schedules E-TOU-A, E-TOU-B and E-6, the transition mitigation period that was already adopted by the CPUC in (D.) 15-11-013 continues to apply, as set forth in those rate schedules.

(2) For NEM 2.0 EV customers, the transition mitigation period already adopted by the CPUC in (D.) 16-01-044 continues to apply, as set forth in PG&E's NEM2 rate schedule.

B. Changes to rate design, including allocating marginal costs to TOU periods and setting specific rate levels, will be litigated in utility specific rate proceedings.

C. The new electricity price for legacy peak period hours shall not fall below the new price for legacy off-peak periods and the new electricity price for legacy off peak periods shall not be increased above the price during legacy peak periods.

D. The Legacy TOU ~~Grandfathering~~ Eligibility requirements for behind–the-meter solar are defined in the *Behind-the-Meter Solar Legacy TOU Period ~~Grandfathering~~ Eligibility Requirements*.

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ~~GRANDFATHERING~~ ELIGIBILITY REQUIREMENTS:

A customer is eligible for behind-the-meter solar legacy TOU period ~~grandfathering~~ if the following conditions are met:

A. Qualified residential on-site solar customers

(1) EV customers who interconnected on NEM on or before December 16, 2016.

(Continued)

ELECTRIC RULE NO. 1
DEFINITIONS

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ~~GRANDFATHERING~~ ELIGIBILITY REQUIREMENTS: (Cont'd)

B. Qualified non-residential solar customers

(1) With a behind-the-meter solar (PV) generating facility with load as well as generation

(2) This includes benefitting accounts (or the generating account where considered a benefitting account), on a rate schedule in (i) above and in an arrangement on the Load Aggregation provisions (NEMA) of Schedules NEM or NEM2, or on Schedule NEMV or NEM2V (Virtual NEM), or Schedule NEMVMASH or NEM2VMSH (Virtual NEM for Multifamily Affordable Housing with Solar Generation), or Schedule RES-BCT (Local Government Renewable Energy Self-Generation Bill Credit Transfer) by the time the PTO is issued, which allow electric accounts, not physically tied behind-the-meter to a solar system, to receive credits from the exported power of an electric meter account that is physically tied to a solar system. Benefitting accounts added to an arrangement after the PTO is issued will not be eligible for ~~receive~~ legacy TOU p~~P~~eriods ~~Grandfathering~~. Benefiting accounts removed from an arrangement after the PTO is issued lose their eligibility for legacy TOU p~~P~~eriods ~~Grandfathering~~.

C. Customer Eligibility Grace Period End Date

There is no deadline to complete projects to preserve ~~ability to grandfather~~eligibility for legacy TOU time periods. Customers must comply with Rule 21.

D. Transition Mitigation Period

(1) For residential on-site solar customer systems, the transition mitigation period is five years from issuance of a permission to operate. In no event shall the duration continue beyond July 31, 2022.

(2) For non-residential customers, the transition mitigation period is ten years after issuance of a permission to operate. In no event shall the duration continue beyond December 31, 2027, (for public schools) or July 31, 2027, (for all other non-residential customers).

(Continued)

ELECTRIC RULE NO. 1
DEFINITIONS

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ~~GRANDFATHERING~~ ELIGIBILITY REQUIREMENTS: (Cont'd)

E. Eligible System

An Eligible System is a solar (PV) generating facility:

(1) That serves customer load behind-the-same meter as the generating facility. Such Generating Facilities may be taking service on Rate schedules NEM, NEM2, NEMV, NEM2V, NEMVMASH, NEM2VMSH, E-REMAT, RES-BCT, the RAM program, or interconnected under Electric Rule 21 as non-export or uncompensated export; and

for which an Initial interconnection application was received by PG&E

(a) No later than January 31, 2017; or

(b) (for Public Agencies), no later than December 31st, 2017. (Public agency is defined here as public schools, colleges and universities; federal, state, county and city government agencies; municipal utilities; public water and/or sanitation agencies; and joint powers authorities).

(2) For which PG&E has received evidence of the customer's final inspection clearance from the governmental authority; and

(3) If the interconnection application was received by PG&E between January 23, 2017 and December 31, 2017, the generating facility must be designed to offset at least 15%[1] of the customer's current load, in a manner with consistent with the Option R requirements in Rate Schedule E19, Special Condition 19. This requirement must be met at the time the Initial Application is filed and PG&E reserves the right to verify this requirement. This requirement will not be retroactively applied to systems where an application to interconnect was received by PG&E prior to January 23, 2017.[2]

For the purposes of legacy TOU p~~P~~eriod eligibility ~~Grandfathering~~, Permission to Operate (PTO) refers to the original permission to operate date as issued by PG&E for the Eligible System. Any subsequent requests to modify that previously approved system do not restart the Transition Mitigation Period once the new PTO is issued nor can any changes alter its original legacy TOU ~~grandfathering~~ eligibility.

[1] For tracking systems, PG&E agrees to use a 21% capacity factor for a single tracker, or 24% for a dual tracker, instead of the 18% in the Option R calculation in E-20 Special Condition 17, Footnote 1.

[2] PG&E will not apply the 15% load requirement to systems with PTO prior to January 23, 2017, the date of (D.) 17-01-006. The intent of the 15% load requirement was to eliminate the potential for applications submitted after the CPUC's decision was issued on January 23, 2017 seeking to "lock in" a legacy TOU period by installing only a token amount of on-site solar generation.

(Continued)

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ~~GRANDFATHERING~~ ELIGIBILITY REQUIREMENTS: (Cont'd)

For the purposes of legacy TOU p~~P~~eriod eligibility ~~Grandfathering~~, Permission to Operate (PTO) refers to the original permission to operate date as issued by PG&E for the Eligible System. Any subsequent requests to modify that previously approved system do not restart the Transition Mitigation Period once the new PTO is issued nor can any changes alter its original legacy TOU ~~grandfathering~~ eligibility, except for subsequent requests received within specific windows of time defined separately for public agencies and for other customers (non-public agencies). [3]

F. Complete Interconnection Application Package

A "Complete Interconnection Application Package" includes all of the following with no deficiencies, or modifications required:

(1) A completed Interconnection Application including all supporting documents and all required payments; AND

(2) A completed signed Interconnection Agreement; AND

(3) Evidence of the customer's final inspection clearance from the governmental authority having jurisdiction over the Electrical Generation Facility.

G. Modifications to Pending Interconnection Request Applying under Fast Track Study

For the purposes of legacy TOU p~~P~~eriod eligibility ~~Grandfathering~~, the initial interconnection application that is submitted by the applicable deadline must remain in compliance with Electric Rule 21 for the duration of the application and receive Permission to Operate (PTO). If an Applicant takes any action beyond what is listed below, the Applicant must withdraw the pending application and reapply. If the corrected application is not resubmitted by the timelines prescribed in the Decision, it is no longer eligible for legacy TOU p~~P~~eriods. ~~Grandfathering~~

[3] Any subsequent request submitted between January 23, 2017 and January 31, 2017 (non-Public Agencies), or between January 23, 2017 and December 31, 2017 (Public Agencies), to modify a previously approved generating facility with solar technology, and whose interconnection application remains in compliance with Electric Rule 21 for the duration of the application and receives Permission to Operate (PTO), will commence their Legacy TOU Period ~~Grandfathering~~ as of the issuance date of the PTO for that subsequent request.

(Continued)

ELECTRIC RULE NO. 1
DEFINITIONS

BEHIND-THE-METER SOLAR LEGACY TOU PERIOD ~~GRANDFATHERING~~ ELIGIBILITY REQUIREMENTS: (Cont'd)

G. Modifications to Pending Interconnection Request Applying under Fast Track Study (Cont'd)

Acceptable Changes

(A) Modifying the generating facility size after the initial application has been submitted but prior to any Engineering Review

(B) Decreasing the generating facility size during[4] or after an Engineering Review has been completed (prior to PTO)

- If mitigations are required at the customer's expense (e.g., Dedicated Transformer Upgrade), the Applicant may downsize but must do so while accepting the upgrade. If the Applicant requests a restudy to determine whether the mitigation is no longer required after downsizing, they must withdraw and reapply.

H. Additional Implementation Details For Ineligible[5] Customers

Customers submitting an interconnection application to PG&E will be eligible to select another legacy rate via the interconnection agreement (where applicable) upon the issuance of a Permission to Operate (PTO) if the following criteria are met:

A. For Commercial and Industrial Customers: Receive PTO prior to the scheduled Default in March 2021~~November 2020~~

B. For Agricultural Customers: Receive PTO prior to the scheduled Default in March 2021

However, at the time of the mandatory Defaults, customers ineligible for solar legacy TOU period ~~grandfathering~~ will be defaulted to a new TOU period rate.

[4] "During" refers to the time after an Engineering Review has been completed but the result was a failure thereby requiring an Applicant to decide how to proceed.

[5] Customers who either (1) already meet the definition of "behind-the-meter solar legacy TOU period ~~grandfathering~~" but are re-applying to PG&E to modify the existing solar system or (2) will meet the definition of "behind-the-meter solar legacy TOU period ~~grandfathering~~" upon the issuance of the permission to operate (PTO) are not required to receive PTO by the timelines mentioned above. When PTO is issued, the customer will be transitioned to the applicable legacy rate listed on the interconnection agreement. However, if their solar legacy TOU period transition mitigation period~~grandfathering~~ has already expired, the customer will remain on their current defaulted rate upon PTO. After the mandatory default commences, s~~S~~olar legacy TOU p~~P~~eriod eligible ~~Grandfathering~~ customers will be able~~eligible~~ to move between legacy rates for the duration of their solar legacy TOU period ~~grandfathering~~, in accordance with Electric Rule 12, subject to remaining on their legacy TOU hours, with no meter changes required, and subject to all other applicable tariff terms and conditions.

(Continued)

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
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

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
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
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
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy