Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for August 2018

September 21, 2018
Public

Pacific Gas and Electric Company (“PG&E”) hereby submits this report on Interruptible Load and Demand Response Programs for August 2018. This report is being sent to the Energy Division via EnergyDivisionCentralFiles@cpuc.ca.gov and served on the service list for A.11-03-001

http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/cs/

Table I-1
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Subscription Statistics - Enrolled MW
August 2018

UTILITY NAME: Pacific Gas and Electric Company
Monthly Program Enrollment and Estimated Load Impacts

PROGRAMS	January Service Accounts	January Ex Ante Estimated MW[1]	January Ex Post Estimated MW[1]	February Service Accounts	February Ex Ante Estimated MW[1]	February Ex Post Estimated MW[1]	March Service Accounts	March Ex Ante Estimated MW[1]	March Ex Post Estimated MW[1]	April Service Accounts	April Ex Ante Estimated MW[1]	April Ex Post Estimated MW[1]	May Service Accounts	May Ex Ante Estimated MW[1]	May Ex Post Estimated MW[1]	June Service Accounts	June Ex Ante Estimated MW[1]	June Ex Post Estimated MW[1]	Eligible Accounts as of Jan 1, 2018 [1]
PILOT PROGRAMS [2]																			
SSP II (Load Decrease)																			
Non-Residential	30	N/A	N/A	30	N/A	N/A	30	N/A	N/A	29	N/A	N/A	29	N/A	N/A	30	N/A	N/A	N/A
Residential	0	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	N/A	N/A
XSP (Load Increase)																			
Non-Residential	6	N/A	N/A	6	N/A	N/A	6	N/A	N/A	6	N/A	N/A	6	N/A	N/A	6	N/A	N/A	N/A
Residential	0	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	N/A	N/A
INTERUPTIBLE RELIABILITY PROGRAMS [5]																			
BIP - Day Of	387	193	228	361	187	213	362	196	214	374	217	221	398	238	235	426	266	252	10,935
OBMC	16	0	0	16	0	0	16	0	0	16	0	0	16	0	0	16	0	0	N/A
SLRP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	N/A
SmartAC™ - Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	N/A
SmartAC™ - Residential	114,841	0	58	112,408	0	56	110,717	0	56	108,183	0	54	113,595	27	57	112,627	55	56	N/A
Sub-Total Interruptible	**115,244**	**193**	**286**	**112,785**	**187**	**270**	**111,095**	**196**	**269**	**108,573**	**217**	**275**	**114,009**	**265**	**292**	**113,069**	**321**	**308**	
PRICE-RESPONSIVE PROGRAMS [3,4,6]																			
CBP - Day Ahead	0	0	0	0	0	0	0	0	0	0	0	0	496	14	13	526	25	14	603,881
PDP (200 kW or above)	2,587	10	0	2,583	9	0	2,509	9	0	2,347	18	0	2,233	18	0	2,203	18	0	7,299
PDP (above 20 kW & below 200 kW)	54,596	3	12	53,491	3	12	51,991	3	12	48,009	9	11	45,344	9	10	44,902	10	10	95,833
PDP (20 kW or below)	181,940	0	13	180,502	0	13	174,244	0	12	157,488	1	11	148,964	1	10	147,776	1	10	315,414
SmartRate™ - Residential	122,294	10	24	122,053	10	24	119,202	10	24	120,270	11	24	114,676	14	23	115,755	20	23	N/A
Sub-Total Price Response	476,661	23	50	471,414	22	49	459,041	21	48	436,687	40	46	425,722	57	57	424,231	73	58	
Total All Programs	**476,661**	**216**	**336**	**471,414**	**209**	**319**	**459,041**	**217**	**317**	**436,687**	**257**	**321**	**425,722**	**322**	**349**	**424,231**	**395**	**366**	

Programs	July Service Accounts	July Ex Ante Estimated MW[1]	July Ex Post Estimated MW[1]	August Service Accounts	August Ex Ante Estimated MW[1]	August Ex Post Estimated MW[1]	September Service Accounts	September Ex Ante Estimated MW[1]	September Ex Post Estimated MW[1]	October Service Accounts	October Ex Ante Estimated MW[1]	October Ex Post Estimated MW[1]	November Service Accounts	November Ex Ante Estimated MW[1]	November Ex Post Estimated MW[1]	December Service Accounts	December Ex Ante Estimated MW[1]	December Ex Post Estimated MW[1]	Eligible Accounts as of Jan 1, 2018 [1]
PILOT PROGRAMS [2]																			
SSP II (Load Decrease)																			
Non-Residential	38	N/A	N/A	38	N/A	N/A													N/A
Residential	0	N/A	N/A	0	N/A	N/A													N/A
XSP (Load Increase)																			
Non-Residential	6	N/A	N/A	6	N/A	N/A													N/A
Residential	0	N/A	N/A	0	N/A	N/A													N/A
INTERUPTIBLE RELIABILITY PROGRAMS [5]																			
BIP - Day of	448	274	264	461	281	272													10,935
OBMC	16	0	0	16	0	0													N/A
SLRP	0	0	0	0	0	0													N/A
SmartAC™ - Commercial	0	0	0	0	0	0													N/A
SmartAC™ - Residential	112,424	61	56	111,912	54	56													N/A
Sub-Total Interruptible	**112,888**	**335**	**321**	**112,389**	**335**	**328**													
PRICE-RESPONSIVE PROGRAMS [3,4,6]																			
CBP - Day Ahead	551	34	15	531	34	14													603,881
PDP (200 kW or above)	1,809	14	0	1,705	14	0													7,299
PDP (above 20 kW & below 200 kW)	35,899	8	8	31,841	8	7													95,833
PDP (20 kW or below)	121,309	1	8	110,488	1	8													315,414
SmartRate™ - Residential	115,534	21	23	107,747	19	22													N/A
Sub-Total Price Response	**387,990**	**79**	**55**	**364,701**	**76**	**51**													
Total All Programs	**387,990**	**414**	**375**	**364,701**	**411**	**379**													

NOTES:

Readers should exercise caution in interpreting or using the estimated MW values found in this report in either the Ex Post or Ex Ante columns. Ex post estimates reflect historic event(s) that have taken place during specific time periods and actual weather conditions by a mix of customers that participated on event day(s). Ex Ante forecasts account for variables not included in the Ex Post estimate such as normalized weather conditions, expected customer mix during events, expected time of day which events occur, expected days of the week which events occur, and other lesser effects etc. An Ex Ante forecast reflects forecast impact estimates that would occur between 1 pm and 6pm during a specific DR program's operating season, based on 1-in-2 (normal) weather conditions if all DR programs were called simultaneously on the system peak day. In either case, MW estimates in this report will vary from estimates filed in the PG&E's annual April Compliance Filing pursuant to Decision 08-04-050 and reporting documents that may be supplied to other agencies e.g. CAISO, FERC, NERC, etc. MW estimates found in the Monthly ILP Report are not used by PG&E for operational reporting, resource planning, and cost effectiveness analysis or in developing regulatory filings.

Ex Ante Estimated MW = In compliance with Decision 08-04-050, the values presented herein are based on the April 2, 2018 (R.13-09-011) Load Impact Report for Demand Response. The values reported are calculated by using the monthly Ex Ante average load impact per customer multiplied by the number of currently enrolled service accounts for the reporting month, where the Ex Ante average load impact is the average hourly load impact for an event that would occur from 1 - 6 pm on the system peak day of the month. The Ex Ante Estimated MW value for the aggregator program, e.g., CBP are the monthly nominated MW during the event season May through October and Zero non-event season months November through April.

Ex Post Estimated MW = In compliance with Decision 08-04-050, the values presented herein are based on the April 2, 2018 (R.13-09-011) Load Impact Report for Demand Response. The values reported are calculated by using the annual Ex Post average load impact per customer multiplied by the number of currently enrolled service accounts for the reporting month, where the Ex Post load impact per customer is the average load impact per customer for those customers that may have participated in an event(s) during all actual event hours in the preceding year when or if events occurred. New programs report "n/a", as there were no prior events.

[1] The 2018 Ex Ante and Ex Post Load Impacts and Eligible Accounts reflect and update the January, February, and March recorded data in the April 2018 ILP Report.

[2] For Pilot Program SSP II (Load Decrease) and XSP Pilot Program (Load Increase), in the absence of a formal load impact evaluation, PG&E estimates SSP 950 kW and XSP 2860 kW.

[3] There are some SmartRate™ Residential customers (<.05%) not reflected in the summary or rate code count as program eligibility is being confirmed.

[4] The CBP - Day Of program is closed and has been eliminated from this table.

[5] BIP customers that dual participate in PDP are not counted towards the 300 MW BIP cap. The BIP program actual capacity is below the 300 MW cap.

[6] May ILP provides restated numbers for PDP for March and April PDP data. Due to a newly discovered temporary data issue, the PDP enrollment (Service Accounts) was understated by approximately 10% in the March and April data.

Program Eligibility and Ex Ante Average Load Impacts [1]

Program	Average Ex Ante Load Impact kW / Customer												Eligible Accounts as of Jan 1, 2018 [1]	Eligibility Criteria (Refer to tariff for specifics)
	January	February	March	April	May	June	July	August	September	October	November	December		
BIP - Day Of	499.47	517.01	542.25	580.65	597.58	624.48	611.84	609.35	609.06	588.82	527.97	525.49	10,935	Bundled, DA and CCA non-residential customer service accounts that have at least an average monthly demand of 100 kW.
OBMC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Not Available	Bundled, DA and CCA non-residential customer accounts with interval meters that must be able to reduce electric load such that the entire load on the PG&E circuit or dedicated substation that provides service to that customer is reduced to or below Maximum Load Levels (MLLs) for the entire duration of each and every RO operation.
SLRP	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Not Available	Bundled-service customers taking service under Schedules A-10, E-19 or E-20 & minimum average monthly demand of 100 kilowatts (kW). Customers must commit to minimum 15% of baseline usage, with a minimum load reduction of 100 kW.
SmartAC™ - Commercial	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Not Available	Small and medium business customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment. Closed to new enrollment.
SmartAC™ - Residential	N/A	N/A	N/A	N/A	0.24	0.49	0.54	0.48	0.46	0.13	N/A	N/A	Not Available	Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
CBP - Day Ahead	N/A	N/A	N/A	N/A	138.07	138.07	138.07	138.07	138.07	138.07	N/A	N/A	603,881	Non-residential customers on commercial, industrial, partial standby, or agricultural rate schedules, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
PDP (200 kW or above)	3.69	3.53	3.39	7.73	7.88	8.00	7.98	8.26	8.61	8.09	3.27	3.10	7,299	Default beginning on: May 1, 2010 for bundled C&I Customers >200kW Maximum Demand; February 1st, 2011 for large bundled Ag customers; November 2014 for bundled C&I Customers with <200 kW Maximum Demand and 12 consecutive months of interval data.
PDP (above 20 kW & below 200 kW)	0.06	0.06	0.05	0.19	0.21	0.23	0.23	0.24	0.23	0.20	0.06	0.06	95,833	
PDP (20 kW or below)	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	315,414	
SmartRate™ - Residential	0.09	0.09	0.08	0.09	0.13	0.17	0.19	0.18	0.18	0.11	0.09	0.09	Not Available	A voluntary rate supplement to residential customers' otherwise applicable schedule. Available to Bundled-Service customers served on a single family residential electric rate schedule.

The average ex ante load impacts per customer are based on the load impacts filing on April 2, 2018 (R.13-09-011). Estimated Average Ex Ante Load Impact kW/Customer = Average kW / Customer, under 1-in-2 weather conditions, of an event that would occur from 1 - 6 pm for April through October, and 4 - 9 pm for November through March, on the PG&E system peak day of the month.

[1] The 2018 Ex Ante Load Impacts and Eligible Accounts reflect and update the January, February, and March recorded data in the April 2018 ILP Report.

Pacific Gas and Electric Company
Average ExPost Load Impact kW / Customer
August 2018

Program Eligibility and Ex Post Average Load Impacts [1]

Program	Average Ex Post Load Impact kW / Customer												Eligible Accounts as of Jan 1, 2018 [1]	Eligibility Criteria (Refer to tariff for specifics)
	January	February	March	April	May	June	July	August	September	October	November	December		
BIP - Day Of	590.40	590.40	590.40	590.40	590.40	590.40	590.40	590.40	590.40	590.40	590.40	590.40	10,907	Bundled, DA and CCA non-residential customer service accounts that have at least an average monthly demand of 100 kW.
OBMC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Not Available	Bundled, DA and CCA non-residential customer accounts with interval meters that must be able to reduce electric load such that the entire load on the PG&E circuit or dedicated substation that provides service to that customer is reduced to or below Maximum Load Levels (MLLs) for the entire duration of each and every RO operation.
SLRP	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Not Available	Bundled-service customers taking service under Schedules A-10, E-19 or E-20 & minimum average monthly demand of 100 kilowatts (kW). Customers must commit to minimum 15% of baseline usage, with a minimum load reduction of 100 kW.
SmartAC^{TM} - Commercial	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Not Available	Small and medium business customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment. Closed.
SmartAC^{TM} - Residential	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	Not Available	Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
CBP - Day Ahead	26.84	26.84	26.84	26.84	26.84	26.84	26.84	26.84	26.84	26.84	26.84	26.84	603,881	Non-residential customers on commercial, industrial, partial standby, or agricultural rate schedules, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
PDP (200 kW or above)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	7,299	Default beginning on: May 1, 2010 for bundled C&I Customers >200kW Maximum Demand; February 1st, 2011 for large bundled Ag customers; November 2014 for bundled C&I Customers with <200 kW Maximum Demand and 12 consecutive months of interval data.
PDP (above 20 kW & below 200 kW)	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	95,833	
PDP (20 kW or below)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	315,414	
SmartRateTM - Residential	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	Not Available	A voluntary rate supplement to residential customers' otherwise applicable schedule. Available to Bundled-Service customers served on a single family residential electric rate schedule.

The average ex post load impacts per customer are based on the load impacts filing on April 2, 2018 (R.13-09-011). Estimated Average Ex Post Load Impact kW / Customer = Average kW / Customer service account from the typical event for the preceeding year if events occurred. Some programs may experience no events or few events while other programs may operate regularly depending on event triggers. For existing programs, the average ex post load impact per customer SA_ID remains constant across all months. The average load impact is "N/A" for programs having no prior events.

[1] The 2018 Ex Post Load Impacts and Eligible Accounts reflect and update the January, February, and March recorded data in the April 2018 ILP Report.

2018 Detailed Breakdown of MWs To Date in TA/Auto DR/TI Programs

	JANUARY				FEBRUARY				MARCH			
PROGRAM	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs
PILOT PROGRAMS												
SSP II (Load Decrease)												
Non-Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
XSP (Load Increase)												
Non-Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
PRICE-RESPONSIVE PROGRAMS												
CBP - Day Ahead	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
CBP - Day Of	N/A	4.2	0.0	4.2	N/A	4.2	0.0	4.2	N/A	4.2	0.0	4.2
PDP	N/A	0.0	0.0	0.0	N/A	1.2	0.0	1.2	N/A	1.2	0.0	1.2
SmartRate™ - Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
SmartAC™ - Commercial	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
SmartAC™ - Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
DRAM [2]	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
Total	N/A	4.2	0.0	4.2	N/A	5.4	0.0	5.4	N/A	5.4	0.0	5.4
INTERUPTIBLE RELIABILITY PROGRAMS												
BIP - Day of	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
OBMC	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
SLRP	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
Total	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
TOTAL TECHNOLOGY MWs	N/A	4.2	0.0	4.2	N/A	5.4	0.0	5.4	N/A	5.4	0.0	5.4
GENERAL PROGRAM												
TA (may also be enrolled in TI and AutoDR)	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A
Total	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A
TOTAL TA MWs	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A

	APRIL				MAY				JUNE			
PROGRAM	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs
PILOT PROGRAMS												
SSP II (Load Decrease)												
Non-Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
XSP (Load Increase)												
Non-Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
PRICE-RESPONSIVE PROGRAMS												
CBP - Day Ahead	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
CBP - Day Of	N/A	4.2	0.0	4.2	N/A	4.2	0.0	4.2	N/A	4.2	0.0	4.2
PDP	N/A	1.2	0.0	1.2	N/A	1.2	0.0	1.2	N/A	1.2	0.0	1.2
SmartRate™ - Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
SmartAC™ - Commercial	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
SmartAC™ - Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
DRAM [2]	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
Total	N/A	5.4	0.0	5.4	N/A	5.4	0.0	5.4	N/A	5.4	0.0	5.4
INTERUPTIBLE RELIABILITY PROGRAMS												
BIP - Day of	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
OBMC	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
SLRP	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
Total	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0
TOTAL TECHNOLOGY MWs	N/A	5.4	0.0	5.4	N/A	5.4	0.0	5.4	N/A	5.4	0.0	5.4
GENERAL PROGRAM												
TA (may also be enrolled in TI and AutoDR)	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A
Total	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A
TOTAL TA MWs	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A

	JULY				AUGUST				SEPTEMBER			
PROGRAM	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs
PILOT PROGRAMS												
SSP II (Load Decrease)												
Non-Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
XSP (Load Increase)												
Non-Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
PRICE-RESPONSIVE PROGRAMS												
CBP - Day Ahead	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
CBP - Day Of	N/A	4.2	0.0	4.2	N/A	4.2	0.0	4.2				
PDP	N/A	1.2	0.0	1.2	N/A	1.2	0.0	1.2				
SmartRate™ - Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
SmartAC™ - Commercial	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
SmartAC™ - Residential	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
DRAM [2]	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
Total	N/A	5.4	0.0	5.4	N/A	5.4	0.0	5.4				
INTERUPTIBLE RELIABILITY PROGRAMS												
BIP - Day of	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
OBMC	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
SLRP	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
Total	N/A	0.0	0.0	0.0	N/A	0.0	0.0	0.0				
TOTAL TECHNOLOGY MWs	N/A	5.4	0.0	5.4	N/A	5.4	0.0	5.4				
GENERAL PROGRAM												
TA (may also be enrolled in TI and AutoDR)	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A				
Total	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A				
TOTAL TA MWs	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A				

	OCTOBER				NOVEMBER				DECEMBER			
PROGRAM	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs [1]	TI Verified MWs	Total Technology MWs
PILOT PROGRAMS												
SSP II (Load Decrease)												
Non-Residential												
Residential												
XSP (Load Increase)												
Non-Residential												
Residential												
PRICE-RESPONSIVE PROGRAMS												
CBP - Day Ahead												
CBP - Day Of												
PDP												
SmartRate™ - Residential												
SmartAC™ - Commercial												
SmartAC™ - Residential												
DRAM [2]												
Total												
INTERUPTIBLE RELIABILITY PROGRAMS												
BIP - Day of												
OBMC												
SLRP												
Total												
TOTAL TECHNOLOGY MWs												
GENERAL PROGRAM												
TA (may also be enrolled in TI and AutoDR)												
Total												
TOTAL TA MWs												

[1] ADR project payments carry over to the following year. 60% is paid upfront on completion of enrollment and the remaining 40% later on performance during an event season.

[2] As approved in the disposition letter issued September 24, 2015 to advice letter 4618-E-A, customers participating in DRAM are eligible to receive ADR incentives.

Table I-3a
Pacific Gas and Electric Company
Demand Response Programs and Activities
2018-22 Incremental Cost Funding
August 2018

2018 Program Expenditures [1]

Cost Item	2017 Expenditures	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-Date 2018 Expenditures	Program-to-Date 2018 Expenditures	2018 Funding	Fund shift Adjustments	Percent Funding
Category 1: Supply-Side DR Programs																		
AC Cycling: Smart AC	$0	$317,849	$448,616	$457,297	$435,865	$611,706	$562,094	$736,892	$441,944					$4,012,263	$4,012,263	$6,396,000		62.7%
Base Interruptible Program (BIP)	$0	$23,290	$24,370	$28,168	$36,219	$24,125	$30,226	$28,630	$31,253					$226,280	$226,280	$32,354,000		
Capacity Bidding Program (CBP)	$0	$23,314	$28,701	$31,345	$41,055	$28,815	$34,199	$39,205	$40,083					$266,718	$266,718	$4,103,000		6.5%
Budget Category 1 Total	$0	$364,454	$501,687	$516,811	$513,140	$664,646	$626,518	$804,727	$513,279	$0	$0	$0	$0	$4,505,261	$4,505,261	$42,853,000	$0	10.5%
Category 2: Load Modifying DR Programs																		
OMBC/SLRP	$0	$592	$319	$991	$403	$422	$502	$349	$25					$3,603	$3,603	$12,000		30.0%
Permanent Load Shifting (PLS)	$0	$0	$0	$0	$0	$0	$0	$0	$0					$0	$0	$0		0.0%
Budget Category 2 Total	$0	$592	$319	$991	$403	$422	$502	$349	$25	$0	$0	$0	$0	$3,603	$3,603	$12,000	$0	30.0%
Category 3: DRAM and Rule 24/32																		
DRAM Phase 4	$6,548	$16,035	$18,086	$26,477	$23,354	$641	$946	$2,980	$4,509					$93,028	$99,576	$6,000,000		1.7%
Rule 24 O&M	$0	$51,505	$77,904	$127,242	$76,085	$78,443	$85,747	$77,785	$91,583					$666,293	$666,293	$2,439,000		27.3%
Budget Category 3 Total	$6,548	$67,540	$95,990	$153,719	$99,439	$79,084	$86,694	$80,765	$96,092	$0	$0	$0	$0	$759,321	$765,869	$8,439,000	$0	9.1%
Category 4: Emerging & Enabling Programs																		
Auto DR	$0	$29,127	$217,189	$150,494	$183,428	$89,535	$399,033	$91,022	$224,740					$1,384,569	$1,384,569	$4,006,000		34.6%
DR Emerging Technology	$0	$22,487	$38,716	$43,391	$34,489	$26,247	$85,925	$46,788	$23,542					$321,586	$321,586	$1,380,000		23.3%
Budget Category 4 Total	$0	$51,614	$255,905	$193,885	$217,917	$115,782	$484,958	$137,810	$248,282	$0	$0	$0	$0	$1,706,154	$1,706,154	$5,386,000	$0	31.7%
Category 5: Pilots																		
Supply Side Pilot	$0	$31,884	$40,429	$55,796	$20,358	$36,020	$71,214	$37,807	$47,791					$341,299	$341,299	$2,083,000		16.4%
Excess Supply	$0	$17,738	$23,677	$40,291	$15,448	$28,052	$104,830	$28,439	$29,783					$288,258	$288,258	$596,000		48.4%
Local Capacity Planning Areas andDisadvantaged Communities Pilot	$0	$0	$0	$0	$0	$0	$0	$0	$0					$0	$0	$0		0.0%
Budget Category 5 Total	$0	$49,621	$64,106	$96,087	$35,806	$64,072	$176,044	$66,245	$77,575	$0	$0	$0	$0	$629,557	$629,557	$2,679,000	$0	23.5%
Category 6: Marketing, Education, and Outreach (ME&O)																		
DR Core Marketing & Outreach	$0	$74,778	$38,350	$150,418	$139,668	$312,045	$277,565	$442,793	$271,039					$1,706,655	$1,706,655	$2,325,000		73.4%
Education and Training	$0	$2,839	$3,043	$6,720	$2,141	$1,099	$3,543	$1,764	($488)					$20,661	$20,661	$252,000		8.2%
Budget Category 6 Total	$0	$77,616	$41,393	$157,137	$141,810	$313,144	$281,108	$444,556	$270,551	$0	$0	$0	$0	$1,727,316	$1,727,316	$2,577,000	$0	67.0%
Category 7: Portfolio Support (includes EM&V, Systems Support, and Notifications)																		
DR Measurement and Evaluation (DRMEC)	$0	$6,785	$6,414	$82,284	$24,577	$39,782	$110,649	$46,878	$118,595					$435,965	$435,965	$3,007,000		14.5%
DR Integration Policy & Planning	$0	$97,888	$163,959	$222,848	$774	$129,964	$180,573	$142,060	$144,900					$1,082,966	$1,082,966	$1,576,000		68.7%
Support for Market Activities	$0	$60,947	$110,705	$155,332	$120,972	$102,107	$248,561	$248,779	$311,896					$1,359,299	$1,359,299	$3,791,000		35.9%
Support for Retail & Customer Facing Activities	$0	$221,454	$194,161	$1,024,449	$369,338	$282,926	$273,609	$391,932	$553,371					$3,311,240	$3,311,240	$4,235,000		78.2%
DR Potential Study	$0	$0	$0	$0	$0	$0	$0	$0	$0					$0	$0	$400,000		0.0%
Budget Category 7 Total	$0	$387,074	$475,239	$1,484,913	$515,661	$554,780	$813,391	$829,650	$1,128,763	$0	$0	$0	$0	$6,189,470	$6,189,470	$13,009,000	$0	47.6%
Category 8: Integrated Programs and Activities (Including Technical Assistance) [2]																		
Technology Incentives - IDSM	$0	$0	$0	$0	$0	$0	$0	$0	$0					$0	$0	$0		0.0%
Integrated Energy Audits	$0	$0	$0	$0	$3,349	$0	$18,885	$0	$0					$22,234	$22,234	$22,234		100.0%
Residential IDSM	$0	$0	$0	$0	$0	$0	$0	$0	$0					$0	$0	$1,000,000		0.0%
Non Residential IDSM	$0	$0	$0	$0	$0	$0	$0	$0	$0					$0	$0	$7,977,766		0.0%
Budget Category 8 Total	$0	$0	$0	$0	$3,349	$0	$18,885	$0	$0	$0	$0	$0	$0	$22,234	$22,234	$9,000,000	$0	0.2%
Recovery of DR-related capital costs prior to 2009 (for interval metering as authorized in D.06-03-024/D.06-11-049); and, additionally, for the HAN Integration project (as authorized in D.12-04-045).	$0	$195,972	$173,771	$137,480	$168,249	$167,665	$166,053	$166,190	$165,103					$1,340,484	$1,340,484	$0	$0	0.0%
Total Incremental Cost [3]	$6,548	$1,194,484	$1,608,410	$2,741,024	$1,695,772	$1,959,594	$2,654,154	$2,530,293	$2,499,670	$0	$0	$0	$0	$16,883,401	$16,889,949	$83,955,000	$0	20.1%

Technical Assistance & Technology Incentives (TA&TI) Identified as of August 2018	$0

[1] The expenditures listed are in support of PG&E's DR programs for large commercial, industrial and agricultural customers.
[2] Additional funding for Technology Incentives and Integrated Energy Audits was approved in Energy Efficiency Decision 14-10-046. This funding was to continue through 2025 unless the Commission issues a superseding funding decision. On May 31 2018, the Commission issued a superseding decision via the EE Business Plan which allocated $9m to PG&E for IDSM projects ($1m to Residential and $8m to non-Residential). Since the funding was approved after the cycle had started, PG&E incurred some costs for Integrated Enegy Audits prior to the decision being issued - those funds have now been redirected as per the EE Business Plan decision.

[3] Total Incremental Cost excludes incentives. Incentives are reported on Table I-5.

Table I-3b
Pacific Gas and Electric Company
Demand Response Programs and Activities
Carry-Over Expenditures and Funding
August 2018

Cost Item [1]	January	February	March	April	May	June	July	August	September	October	November	December	Carry-Over Expenditures incurred in 2018
Category 1: Reliability Programs													
Base Interruptible Program (BIP)	$3,174	($3,106)	($86)	($32)	$216	$22	$539	$106					$832
Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)	$280	$364	($886)	($16)	$104	$11	$259	$51					$166
Budget Category 1 Total	**$3,453**	**($2,742)**	**($973)**	**($48)**	**$320**	**$33**	**$799**	**$157**	**$0**	**$0**	**$0**	**$0**	**$998**
Category 2: Price-Responsive Programs													
Capacity Bidding Program (CBP)	$3,801	($2,767)	($1,421)	($55)	$369	$38	$923	$181					$1,069
SmartAC[TM]	$23,723	($52,579)	($10,794)	($199)	$1,324	$136	$3,309	$649					($34,432)
Budget Category 2 Total	**$27,524**	**($55,346)**	**($12,216)**	**($254)**	**$1,693**	**$173**	**$4,232**	**$830**	**$0**	**$0**	**$0**	**$0**	**($33,364)**
Category 3: DR Provider/Aggregator Managed Programs													
Aggregator Managed Portfolio (AMP)	$0	$0	$0	$0	$0	$0	$0	$0					$0
Budget Category 3 Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Category 4: Emerging & Enabling Programs													
Auto DR	$4,839	$54,689	$4,389	($85)	$10,955	$9,562	$15,367	$20,048					$119,764
DR Emerging Technology	$5,871	$600	($6,123)	($4,308)	$717	$3,886	$1,792	$352					$2,785
Budget Category 4 Total	**$10,710**	**$55,289**	**($1,735)**	**($4,393)**	**$11,671**	**$13,448**	**$17,159**	**$20,400**	**$0**	**$0**	**$0**	**$0**	**$122,549**
Category 5: Pilots													
Supply Side Pilot	$5,687	$1,705	($4,457)	($78)	$32	$53	$1,304	$256					$4,501
Excess Supply	$5,130	$1,266	($3,084)	($544)	$361	$37	$902	$177					$4,245
Budget Category 5 Total	**$10,817**	**$2,970**	**($7,541)**	**($623)**	**$393**	**$90**	**$2,207**	**$433**	**$0**	**$0**	**$0**	**$0**	**$8,747**
Category 6: Evaluation, Measurement and Verification													
DRMEC	$133,076	$344,543	($53,213)	$171,213	$140,293	$69,929	($102,083)	$25,423					$729,180
DR Research Studies	$10,000	$8,000	$0	$0	$10,000	$46,845	($19,160)	$10,000					$65,685
Budget Category 6 Total	**$143,076**	**$352,543**	**($53,213)**	**$171,213**	**$150,293**	**$116,774**	**($121,243)**	**$35,423**	**$0**	**$0**	**$0**	**$0**	**$794,865**
Category 7: Marketing, Education and Outreach													
DR Core Marketing and Outreach	$4,175	($2,529)	$1,805	$1,369	($143)	($1,243)	$1,252	($1)					$4,685
SmartAC[TM] ME&O	$12,048	$4,559	($9,624)	$315	$4,280	($429)	$3,339	$0					$14,488
Education and Training	$946	($1,388)	$608	$0	$0	$0	$0	$0					$166
Budget Category 7 Total	**$17,169**	**$642**	**($7,211)**	**$1,684**	**$4,136**	**($1,672)**	**$4,590**	**($1)**	**$0**	**$0**	**$0**	**$0**	**$19,338**
Category 8: DR System Support Activities													
InterAct / DR Forecasting Tool	$123,472	$137,825	$84,240	$52,760	$154,074	$13,161	$30,797	$23,154					$619,484
DR Enrollment & Support [2]	($513,756)	$107,793	$80,730	$56,399	$160,577	($2,767)	$26,237	$23,062					($61,724)
Notifications	$59,445	$68,445	$153,138	$52,777	$153,962	$17,213	$26,453	$26,034					$557,468
DR Integration Policy & Planning	$25,928	($13,276)	($2,826)	$3,935	$10,222	($25,055)	$4,520	$887					$4,334
Budget Category 8 Total	**($304,911)**	**$300,787**	**$315,283**	**$165,872**	**$478,835**	**$2,553**	**$88,007**	**$73,137**	**$0**	**$0**	**$0**	**$0**	**$1,119,561**
Category 9: Integrated Programs and Activities (Including Technical Assistance)													
Technology Incentives - IDSM	$0	$0	$0	$0	$0	$0	$0	$0					$0
Integrated Energy Audits	$8,539	($889)	$9,826	$6,315	$9,365	($19,384)	$2,441	$191					$16,403
Budget Category 9 Total	**$8,539**	**($889)**	**$9,826**	**$6,315**	**$9,365**	**($19,384)**	**$2,441**	**$191**	**$0**	**$0**	**$0**	**$0**	**$16,403**
Category 10: Special Projects													
Demand Response Auction Mechanism Pilot Phase 1	$0	$0	$0	$0	$0	$0	$0	$0					$0
Demand Response Auction Mechanism Pilot Phase 2	$9,853	$1,410	$1,746	($938)	$401	$308	$953	($777)					$12,955
Demand Response Auction Mechanism Pilot Phase 3	$11,954	$6,758	$15,242	$18,919	$19,793	$13,014	$17,129	$19,734					$122,542
Rule 24 O&M	$410	$0	($6,415)	$0	$0	$0	$0	$0					($6,005)
Permanent Load Shifting	$6,927	$145	$21,466	($2,683)	$6,614	$19,656	$6,468	$8,903					$67,497
Budget Category 10 Total	**$29,143**	**$8,313**	**$32,039**	**$15,298**	**$26,808**	**$32,979**	**$24,550**	**$27,860**	**$0**	**$0**	**$0**	**$0**	**$196,989**
Total Incremental Cost	**($54,481)**	**$661,566**	**$274,260**	**$355,064**	**$683,515**	**$144,994**	**$22,741**	**$158,429**	**$0**	**$0**	**$0**	**$0**	**$2,246,087**

[1] Expenditures on this page reflect expenses incurred in 2018 from all prior funding cycles

[2] January credit for DR Enrollment & Support is due to the reversal of an accrual and reversal of a prior month incorrect charge.

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
August 2018

Program Name	Month	Zones [1]		Event No. (by Program / Type)	Event Date	Program Type	Trigger	# of Accounts	Event Start Time (PDT)	Event End Time (PDT)	Program Tolled Hours	Load Reduction MW (Max Hourly) [2,3]
Base Interruptible Program [3]	JULY	N/A	SubLap/Zones (1) : Humboldt PGHB	1	7/18/18	Day Of	Transmission Emergency	8	10:05 PM	11:59 PM	2	1.6
Base Interruptible Program [3]	JULY	N/A	SubLap/Zones (1) : North Coast PGNC	2	7/27/18	Day Of	Transmission Emergency	7	7:45 PM	11:59 PM	4	0.5
Category 2: Price-Responsive Programs												
Capacity Bidding Program [3]	JUNE	2 Market Resources	SubLap/Zones (1) : Peninsula (Bay Area) PGP2	1	6/13/18	Day Ahead	Received CAISO Market Award	55	7:00 PM	8:00 PM	1	1.6
Capacity Bidding Program [3]	JUNE	4 Market Resources	SubLap/Zones (2) : Peninsula (Bay Area) PGP2 ; South Bay (Bay Area) PGSB	2	6/22/18	Day Ahead	Received CAISO Market Award	18	5:00 PM	6:00 PM	1	0.5
Capacity Bidding Program [3]	JULY	2 Market Resources	SubLap/Zones (1) : Peninsula (Bay Area) PGP2	3	7/3/18	Day Ahead	Received CAISO Market Award	5	3:00 PM	6:00 PM	2	9.1
Capacity Bidding Program [3]	JULY	Market Resources	SubLap/Zones (2) : Peninsula (Bay Area) PGP2 ; South Bay (Bay Area) PGSB	4	7/10/18	Day Ahead	Received CAISO Market Award	61	3:00 PM	8:00 PM	5	6.9
Capacity Bidding Program [3]	JULY	Market Resources	SubLap/Zones (5) : Central Coast PGCC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; South Bay (Bay Area) PGSB ; Stockton PGST	5	7/11/18	Day Ahead	Received CAISO Market Award	72	6:00 PM	8:00 PM	2	9.9
Capacity Bidding Program [3]	JULY	Market Resources	SubLap/Zones (5) : Central Coast PGCC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; South Bay (Bay Area) PGSB ; Stockton PGST	6	7/12/18	Day Ahead	Received CAISO Market Award	72	4:00 PM	8:00 PM	4	10.7
Capacity Bidding Program [3]	JULY	Market Resources	SubLap/Zones (1) : Peninsula (Bay Area) PGP2	7	7/17/18	Day Ahead	Received CAISO Market Award	5	4:00 PM	5:00 PM	1	5.6
Capacity Bidding Program [3]	JULY	Market Resources	SubLap/Zones (1) : South Bay (Bay Area) PGSB	8	7/18/18	Day Ahead	Received CAISO Market Award	56	7:00 PM	8:00 PM	1	2.4
Capacity Bidding Program [3]	JULY	Market Resources	SubLap/Zones (1) : South Bay (Bay Area) PGSB	9	7/19/18	Day Ahead	Received CAISO Market Award	56	7:00 PM	8:00 PM	1	2.8
Capacity Bidding Program [3]	JULY	Market Resources	SubLap/Zones (1) : North Bay PGNB	10	7/20/18	Day Ahead	Received CAISO Market Award	16	3:00 PM	4:00 PM	1	0.3
Capacity Bidding Program	JULY	Market Resources	SubLap/Zones (13) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Kern PGKN ; North Bay PGNB ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	11	7/23/18	Day Ahead	Received CAISO Market Award	446	3:00 PM	8:00 PM	5	17.7
Capacity Bidding Program	JULY	Market Resources	SubLap/Zones (13) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Kern PGKN ; North Bay PGNB ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	12	7/24/18	Day Ahead	Received CAISO Market Award	490	3:00 PM	9:00 PM	6	18.8
Capacity Bidding Program	JULY	Market Resources	SubLap/Zones (13) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Kern PGKN ; North Bay PGNB ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	13	7/25/18	Day Ahead	Received CAISO Market Award	512	4:00 PM	7:00 PM	3	22.3
Capacity Bidding Program	JULY	Market Resources	SubLap/Zones (2) : South Bay (Bay Area) PGSB ; Stockton PGST	14	7/26/18	Day Ahead	Received CAISO Market Award	66	5:00 PM	9:00 PM	4	2.4
Capacity Bidding Program	JULY	Market Resources	SubLap/Zones (2) : Fresno PGF1 ; South Bay (Bay Area) PGSB	15	7/27/18	Day Ahead	Received CAISO Market Award	58	3:00 PM	9:00 PM	6	3.1
Capacity Bidding Program	JULY	Market Resources	SubLap/Zones (2) : Fresno PGF1 ; South Bay (Bay Area) PGSB	16	7/30/18	Day Ahead	Received CAISO Market Award	58	4:00 PM	8:00 PM	4	2.7
Capacity Bidding Program	JULY	Market Resources	SubLap/Zones (1) : South Bay (Bay Area) PGSB	17	7/31/18	Day Ahead	Received CAISO Market Award	56	5:00 PM	8:00 PM	3	2.4
Capacity Bidding Program [3]	AUGUST	Market Resources	SubLap/Zones (6) : Central Coast PGCC ; Fresno PGF1; North of Path 15 PGNP; Peninsula (Bay Area) PGP2; South Bay (Bay Area) PGSB ; Stockton PGST	18	8/1/18	Day Ahead	Received CAISO Market Award	71	3:00 PM	7:00 PM	4	REDACTED
Capacity Bidding Program	AUGUST	Market Resources	SubLap/Zones (1) : South Bay (Bay Area) PGSB	19	8/2/18	Day Ahead	Received CAISO Market Award	49	3:00 PM	7:00 PM	4	2.6
Capacity Bidding Program [3]	AUGUST	Market Resources	SublLap/Zones (6) : (Central Coast PGCC ; Fresno PGF1; Peninsula (Bay Area) PGP2; South Bay (Bay Area) PGSB ; Stockton PGST; South Bay (Bay Area) PGSB	20	8/6/18	Day Ahead	Received CAISO Market Award	61	3:00 PM	7:00 PM	4	REDACTED
Capacity Bidding Program [3]	AUGUST	Market Resources	SubLap/Zones (13) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Kern PGKN ; North Bay PGNB ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	21	8/7/18	Day Ahead	Received CAISO Market Award	486	3:00 PM	8:00 PM	5	REDACTED
Capacity Bidding Program [3]	AUGUST	Market Resources	SubLap/Zones (12) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Kern PGKN ; North Bay PGNB ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	22	8/8/18	Day Ahead	Received CAISO Market Award	449	3:00 PM	8:00 PM	5	REDACTED
Capacity Bidding Program	AUGUST	Market Resources	SubLap/Zones (12) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Kern PGKN ; North Bay PGNB ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	23	8/9/18	Day Ahead	Received CAISO Market Award	388	6:00 PM	8:00 PM	2	15.2
Capacity Bidding Program	AUGUST	Market Resources	SublLap/Zones (6) : Central Coast PGCC; Fresno PGF1 ; Peninsula (Bay Area) PGP2 ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	24	8/10/18	Day Ahead	Received CAISO Market Award	12	4:00 PM	7:00 PM	5	9.7
Capacity Bidding Program [3]	AUGUST	Market Resources	SubLap/Zones (1) : ZP26 PGZP	25	8/13/18	Day Ahead	Received CAISO Market Award	1	6:00 PM	7:00 PM	6	REDACTED

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[2] Load reduction amount is based on available meter data and may vary by month pending the collection of all data.

[3] Pursuant to Commission guidance in D.14-05-016, p.118 and Finding of Fact 17, PG&E will redact the load reduction MW (Max Hourly) in the Public Version (identified with shaded cells) according to the 15/15 rule where there are fewer than 15 customers involved or where a single customer in the group accounts for more than 15 percent of the aggregated total.

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
August 2018

Program Name	Month	Zones [1]		Event No. (by Program / Type)	Event Date	Program Type	Trigger	# of Accounts	Event Start Time (PDT)	Event End Time (PDT)	Program Tolled Hours	Load Reduction MW (Max Hourly) [2,3]
Category 2: Price-Responsive Programs (Cont'd)												
Peak Day Pricing	JUNE	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	1	6/12/18	Day Ahead	Temperature	2,203	2:00 PM	6:00 PM	4	15.9
Peak Day Pricing	JUNE	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	2	6/13/18	Day Ahead	Temperature	2,203	2:00 PM	6:00 PM	4	13.0
Peak Day Pricing	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	3	7/10/18	Day Ahead	Temperature	1,809	2:00 PM	6:00 PM	4	9.3
Peak Day Pricing	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	4	7/16/18	Day Ahead	Temperature	1,809	2:00 PM	6:00 PM	4	11.5
Peak Day Pricing	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	5	7/17/18	Day Ahead	Temperature	1,809	2:00 PM	6:00 PM	4	11.9
Peak Day Pricing	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	7	7/24/18	Day Ahead	Temperature	1,809	2:00 PM	6:00 PM	4	16.6
Peak Day Pricing	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	8	7/25/18	Day Ahead	Temperature	1,809	2:00 PM	6:00 PM	4	11.6
Peak Day Pricing	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	9	7/27/18	Day Ahead	Temperature	1,809	2:00 PM	6:00 PM	4	24.1
SmartAC	JULY	Market Award	SubLap/Zones (4) : Fresno PGF1 ; Kern PGKN ; North of Path 15 PGNP ; Sierra PGSI	1	7/23/18	Day Ahead	Market Award	56,738	4:00 PM	8:00 PM	4	20.7
SmartAC	JULY	Market Award	SubLap/Zones (6) : Fresno PGF1 ; Kern PGKN ; North of Path 15 PGNP ; Sierra PGSI ; North Coast PGNC ; ZP26 PGZP	2	7/24/18	Day Ahead	Market Award	59,065	3:00 PM	8:00 PM	5	22.9
SmartAC	JULY	Market Award	SubLap/Zones (2) : Stockton PGST ; Sierra PGSI	3	7/25/18	Day Ahead	Market Award	25,256	3:00 PM	9:00 PM	6	14.0
SmartAC	JULY	Market Award	SubLap/Zones (5) : East Bay (Bay Area) PGEB ; Geysers PGFG ; North Coast PGNC ; Stockton PGST ; ZP26 PGZP	4	7/26/18	Day Ahead	Market Award	35,096	4:00 PM	7:00 PM	3	8.8
SmartAC	JULY	Transmission Emergency	SubLap/Zones (1) : North Coast PGNC	5	7/27/18	Day Of	Transmission Emergency	753	7:00 PM	11:59 PM	4	0.0
SmartAC	AUGUST	Market Resources	SubLap/Zones (5) : East Bay (Bay Area) PGEB ; Fresno PGF1 ; Kern PGKN ; Stockton PGST ; ZP26 PGZP	6	8/8/18	Day Ahead	Received CAISO Market Award	58,678	4:00 PM	7:00 PM	3	17.4
SmartAC	AUGUST	Market Resources	SubLap/Zones (6) : East Bay (Bay Area) PGEB ; Fresno PGF1 ; Kern PGKN ; Stockton PGST ; ZP26 PGZP ; Sierra PGSI	7	8/9/18	Day Ahead	Received CAISO Market Award	76,358	4:00 PM	7:00 PM	3	30.6
SmartAC	AUGUST	Market Resources	SubLap/Zones (3) : Fresno PGF1 ; Kern PGKN ; ZP26 PGZP	8	8/10/18	Day Ahead	Received CAISO Market Award	28,187	4:00 PM	7:00 PM	3	10.7

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[2] Load reduction amount is based on available meter data and may vary by month pending the collection of all data.

[3] Pursuant to Commission guidance in D.14-05-016, p.118 and Finding of Fact 17, PG&E will redact the load reduction MW (Max Hourly) in the Public Version (identified with shaded cells) according to the 15/15 rule where there are fewer than 15 customers involved or where a single customer in the group accounts for more than 15 percent of the aggregated total.

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Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
August 2018

Program Name	Month	Zones [1]		Event No. (by Program / Type)	Event Date	Program Type	Trigger	# of Accounts	Event Start Time (PDT)	Event End Time (PDT)	Program Tolled Hours	Load Reduction MW (Max Hourly) [2,3]
Category 2: Price-Responsive Programs (Cont'd)												
SmartRate	JUNE	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	1	6/12/18	Day Ahead	Temperature	115,755	2:00 PM	7:00 PM	5	27.0
SmartRate	JUNE	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	2	6/13/18	Day Ahead	Temperature	115,755	2:00 PM	7:00 PM	5	25.9
SmartRate	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	3	7/9/18	Day Ahead	Temperature	113,291	2:00 PM	6:00 PM	4	27.1
SmartRate	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	4	7/10/18	Day Ahead	Temperature	113,291	2:00 PM	7:00 PM	5	27.3
SmartRate	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	5	7/12/18	Day Ahead	Temperature	113,291	2:00 PM	7:00 PM	5	23.2
SmartRate	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	6	7/17/18	Day Ahead	Temperature	113,291	2:00 PM	7:00 PM	5	26.9
SmartRate	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	7	7/18/18	Day Ahead	Temperature	113,291	2:00 PM	7:00 PM	5	27.2
SmartRate	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	8	7/25/18	Day Ahead	Temperature	113,291	2:00 PM	7:00 PM	5	28.6
SmartRate	JULY	System	SubLap/Zones (15) : Central Coast PGCC ; East Bay (Bay Area) PGEB ; Fresno PGF1 ; Geysers PGFG ; Humboldt PGHB ; Kern PGKN ; North Bay PGNB ; North Coast PGNC ; North of Path 15 PGNP ; Peninsula (Bay Area) PGP2 ; San Francisco (Bay Area) PGSF ; Sierra PGSI ; South Bay (Bay Area) PGSB ; Stockton PGST ; ZP26 PGZP	9	7/26/18	Day Ahead	Temperature	113,291	2:00 PM	7:00 PM	5	20.4

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[3] Pursuant to Commission guidance in D.14-05-016, p.118 and Finding of Fact 17, PG&E will redact the load reduction MW (Max Hourly) in the Public Version (identified with shaded cells) according to the 15/15 rule where there are fewer than 15 customers involved or where a single customer in the group accounts for more than 15 percent of the aggregated total.

Table I-5a
Pacific Gas and Electric Company
2018-22 Demand Response Programs Incentives
August 2018

Annual Total Cost													
Cost Item	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Year-to-Date Total Cost**
Program Incentives													
Automatic Demand Response (AutoDR)	$0	$0	$0	$0	$0	$0	$0	$0					$0
Base Interruptible Program (BIP)	$1,661,645	$1,967,373	1,993,536	$2,157,174	2,485,731	$2,498,270	$2,458,773	$2,538,704					$17,761,207
Capacity Bidding Program (CBP) [1]	$0	$0	$0	$0	$45,970	$91,110	$536,812	$733,381					$1,407,273
Excess Supply Pilot	$18,600	21,425	18,600	$24,547	$20,983	$14,810	$17,900	$13,950					$150,815
SmartAC^{TM}	$0	$0	$0	$150	$35,200	$36,900	$1,300	$84,100					$157,650
Supply Side Pilot	$9,440	$7,961	8,700	$6,855	$8,700	$6,624	$8,700	$3,986					$60,966
Total Cost of Incentives	$1,689,685	$1,996,758	$2,020,836	$2,188,727	$2,596,584	$2,647,715	$3,023,485	$3,374,122	$0	$0	$0	$0	$19,537,910
Revenues from Penalties [2]	$0	$0	$0	$0	$0	$0	$0	$0					$0

[1] Incentives reported are net of penalties paid by the aggregators.

[2] Revenues from Penalties denote penalty/default payments made by aggregators and charges to direct enrolled customers enrolled in BIP programs.

Table I-5b
Pacific Gas and Electric Company
Demand Response Programs and Activities
Carryover and Incentive Funding
August 2018

Annual Total Cost													
Cost Item [1]	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Carry-Over Incentives incurred in 2018**
Program Incentives													
Automatic Demand Response (AutoDR)	$53,246	$136,986	$0	$0	$0	$70,560	$1,227	$0	$0	$0	$0	$0	$262,019
Base Interruptible Program (BIP)	($15,302)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($15,302)
Capacity Bidding Program (CBP)	($16,824)	($330)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($17,154)
DRAM Phase 1 [2]	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
DRAM Phase 2 [2]	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
DRAM Phase 3 [2]	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Excess Supply Pilot	$0	$6,894	$0	($2,741)	$0	$0	$0	$0	$0	$0	$0	$0	$4,152
Permanent Load Shift	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Supply Side Pilot	$0	$0	$0	($1,365)	$0	($1)	$0	$0	$0	$0	$0	$0	($1,366)
SmartAC™	$187	$4,750	$10,621	$409	$901	$163	($1,698)	($1,199)	$0	$0	$0	$0	$14,133
Total Cost of Incentives	**$21,307**	**$148,300**	**$10,621**	**($3,698)**	**$901**	**$70,722**	**($471)**	**($1,199)**	**$0**	**$0**	**$0**	**$0**	**$246,483**
Revenues from Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

[1] Incentives on this page reflect incentives paid in 2018 from all prior funding cycles.

[2] DRAM incentives are confidential and redacted for the public version. The MWs under contract are known, and the costs are being paid under the contracts that won in the RFO.

Table I-7
Pacific Gas and Electric Company
2018-22 Marketing, Education and Outreach
Actual Expenditures
August 2018

PG&E's ME&O Actual Expenditures	2018-22 Funding Cycle Customer Communication, Marketing, and Outreach												Year-to-Date 2018 Expenditures	2018 Authorized Budget (if Applicable)	2018-22 Authorized Budget (if Applicable)
	January	February	March	April	May	June	July	August	September	October	November	December			
I. STATEWIDE MARKETING															
IOU Administrative Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Statewide ME&O contract	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
I. TOTAL STATEWIDE MARKETING	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
II. UTILITY MARKETING BY ACTIVITY[1]															
TOTAL AUTHORIZED UTILITY MARKETING BUDGET	[redacted]													$2,577,000	$13,570,000
PROGRAMS, RATES & ACTIVITES WHICH DO NOT REQUIRE ITEMIZED ACCOUNTING															
Integrated Demand Side Marketing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Marketing My Account/Energy and Integrated Online Audit Tools													$ -		
Critical Peak Pricing > 200 kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Demand Bidding Program													$ -		
Real Time Pricing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Permanent Load Shifting													$ -		
Circuit Savers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Small Commercial Technology Deployment	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Enabling Technologies (e.g., AutoDR, TI)	$ 7,958	$ 9,640	$ 14,869	$ 9,413	$ 4,252	$ 9,463	$ 44,271	$ 6,211					$ 106,077		
PeakChoice	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Customer Awareness, Education and Outreach	$ 11,937	$ 14,460	$ 22,303	$ 14,119	$ 6,378	$ 14,195	$ 66,407	$ 9,316					$ 159,116		
PROGRAMS & RATES WHICH REQUIRE ITEMIZED ACCOUNTING															
SmartAC	$ 57,722	$ 17,294	$ 119,965	$ 118,277	$ 302,514	$ 257,449	$ 333,878	$ 255,024	$ -	$ -	$ -	$ -	$ 1,462,123		
Customer Research													$ -		
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ 51,699	$ 1,864	$ 93,757	$ 103,099	$ 287,410	$ 239,931	$ 321,938	$ 238,617					$ 1,338,316		
Labor	$ 6,023	$ 15,430	$ 17,053	$ 15,178	$ 15,104	$ 11,518	$ 11,940	$ 16,407					$ 108,653		
Paid Media	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					$ -		
Other Costs	$ -	$ -	$ 9,154	$ -	$ -	$ 6,000	$ -	$ -					$ 15,154		
II. TOTAL UTILITY MARKETING BY ACTIVITY	$ 77,616	$ 41,393	$ 157,137	$ 141,810	$ 313,144	$ 281,108	$ 444,556	$ 270,551	$ -	$ -	$ -	$ -	$ 1,727,316	$ 2,577,000	$ 13,570,000
III. UTILITY MARKETING BY ITEMIZED COST															
Customer Research													$ -		
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ 51,699	$ 1,864	$ 93,757	$ 106,779	$ 287,410	$ 240,263	$ 418,238	$ 242,791					$ 1,442,802		
Labor	$ 25,918	$ 39,530	$ 53,256	$ 33,540	$ 25,435	$ 30,845	$ 24,976	$ 26,269					$ 259,769		
Paid Media	$ -	$ -	$ -	$ -	$-	$ -	$ -	$ -					$ -		
Other Costs	$ -	$ -	$ 10,123	$ 1,491	$ 298	$ 10,000	$ 1,342	$ 1,491					$ 24,746		
III. TOTAL UTILITY MARKETING BY ITEMIZED COST	$ 77,616	$ 41,393	$ 157,137	$ 141,810	$ 313,144	$ 281,108	$ 444,556	$ 270,551	$ -	$ -	$ -	$ -	$ 1,727,316	$ 2,577,000	$ 13,570,000
IV. UTILITY MARKETING BY CUSTOMER SEGMENT															
Agricultural	$ 2,984	$ 3,615	$ 5,576	$ 3,530	$ 1,595	$ 3,549	$ 16,602	$ 2,329					$ 39,779		
Large Commercial and Industrial	$ 16,911	$ 20,485	$ 31,597	$ 20,002	$ 9,036	$ 20,110	$ 94,076	$ 13,198					$ 225,414		
Small and Medium Commercial	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					$ -		
Residential	$ 57,722	$ 17,294	$ 119,965	$ 118,277	$ 302,514	$ 257,449	$ 333,878	$ 255,024					$ 1,462,123		
IV. TOTAL UTILITY MARKETING BY CUSTOMER SEGMENT	$ 77,616	$ 41,393	$ 157,137	$ 141,810	$ 313,144	$ 281,108	$ 444,556	$ 270,551	$ -	$ -	$ -	$ -	$ 1,727,316	$ 2,577,000	$ 13,570,000

[1]Utility Marketing includes all activities to market individual utility programs or rates, demand response concepts, and customer tools, that were approved or directed by Decision 14-05-025, whether or not the marketing budget was approved as a line item in the Decision. For example, PG&E should not include marketing for TOU and PDP because funding was authorized in another proceeding. However, PG&E must document all amounts spent on marketing individual demand response programs even though a specific marketing budget was not approved for the program. This example applies to all of the utilities. The programs and activities listed in item II of the template are meant as examples, and may not be exhaustive. However, the utilities must include all programs or rates that meet this description. The totals for Items II, III and IV should be equal.

Pacific Gas and Electric Company
2018 Fund Shifting Documentation
August 2018

FUND SHIFTING DOCUMENTATION PER DECISION 12-04-045 ORDERING PARAGRAPH 4

OP 4:

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company:
May not shift funds between categories with two exceptions as stated in Ordering Paragraphs 4 and 5;
May continue to shift up to 50 percent of a Demand Response program's funds to another program within the same budget category, with proper monthly reporting;
Shall not shift funds within the "Pilots" or "Special Projects" categories without submitting a Tier 2 Advice Letter filing;
May shift funds for pilots in the Enabling or Emerging Technologies category;
Shall continue to submit a Tier 2 Advice Letter to eliminate a Demand Response program;
Shall not eliminate a program through multiple fund shifting events or for any other reason without prior authorization from the Commission; and
Shall submit a Tier 2 Advice Letter before shifting more than 50 percent of a program's funds to a different program within the same budget category.

Program Category	Fund Shift Amount	Programs Impacted	Date	Rationale for Fundshift
Category 1: Supply-Side DR Programs				
Category 2: Load Modifying DR Programs				
Category 3: DRAM and Rule 24/32				
Category 4: Emerging and Enabling Technology				
Category 5: Pilots				
Category 6: Marketing, Education, and Outreach (ME&O)				
Category 7: Portfolio Support (includes EM&V, Systems Support, and Notifications)				
Category 8: Integrated Programs and Activities				
Total	**$0**			