Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for August 2014

Public
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Pacific Gas and Electric Company ("PG&E") hereby submits this report on Interruptible Load and Demand Response Programs for August 2014. This report is being served on the Energy Division Director and 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 2014

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

	January			February			March			April			May			June			
Programs	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Eligible Accounts as of Jan 1, 2014**
Interruptible/Reliability																			
BIP - Day Of	249	209	192	218	195	168	218	197	168	220	229	170	221	222	171	219	229	169	10,813
OBMC	25	0	0	25	0	0	25	0	0	25	0	0	24	0	0	24	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	5,762	0	2	5,760	0	2	5,760	0	2	5,792	0	2	5,780	2	2	5,746	3	2	N/A
SmartAC™ - Residential	154,398	0	63	154,529	0	63	154,335	0	63	154,597	0	63	154,001	49	63	153,042	61	63	N/A
Sub-Total Interruptible	160,434	209	257	160,532	195	233	160,338	197	233	160,634	229	235	160,026	274	235	159,031	293	233	
Price Response																			
AMP - Day Ahead	680	0	60	675	0	60	698	0	62	703	0	62	750	68	67	765	68	68	594,510
AMP - Day Of	1952	0	184	1,941	0	183	1,983	0	187	1985	0	187	2,076	167	196	2,108	168	199	
CBP - Day Ahead	0	0	0	0	0	0	0	0	0	0	0	0	31	7	10	33	7	11	594,510
CBP - Day Of	0	0	0	0	0	0	0	0	0	0	0	0	545	14	8	554	14	8	
DBP	940	35	35	930	38	35	926	35	35	914	42	34	907	41	34	897	37	34	10,813
PDP (200 kW or above)	1,814	14	69	1,796	14	68	1,808	14	69	1,874	41	71	1,857	44	70	1,845	36	70	7,146
PDP (<200 kW)	4,490	2	11	4,559	2	11	5,541	3	14	7,428	21	19	8,634	28	22	9,289	39	23	399,593
SmartRate™ - Residential	118,053	0	44	118,441	0	44	119,047	0	44	118,534	0	44	119,243	26	44	125,882	35	47	N/A
Sub-Total Price Response	127,929	51	404	128,342	55	401	130,003	53	410	131,438	104	418	134,043	395	451	141,373	404	459	
Total All Programs	288,363	260	661	288,874	250	635	290,341	250	644	292,072	333	652	294,069	669	686	300,404	698	693	

	July			August			September			October			November			December			
Programs	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Eligible Accounts as of Jan 1, 2014**
Interruptible/Reliability																			
BIP - Day of	215	230	166	215	240	166													10,813
OBMC	24	0	0	24	0	0													N/A
SLRP	0	0	0	0	0	0													N/A
SmartAC™ - Commercial	5,062	4	1	5,047	3	1													N/A
SmartAC™ - Residential	151,757	91	62	151,120	70	62													N/A
Sub-Total Interruptible	157,058	324	230	156,406	313	229													
Price Response																			
AMP - Day Ahead	800	68	71	832	68	74													594,510
AMP - Day Of	2152	168	203	2,273	163	215													
CBP - Day Ahead	40	8	13	41	10	13													594,510
CBP - Day Of	536	14	8	539	14	8													
DBP	880	40	33	875	40	33													10,813
PDP (200 kW or above)	1,809	38	69	1,798	39	68													7,146
PDP (<200 kW)	9,769	44	24	9,758	44	24													399,593
SmartRate™ - Residential	130,372	48	48	129,841	40	48													N/A
Sub-Total Price Response	146,358	430	470	145,957	418	483													
Total All Programs	303,416	754	699	302,363	731	713													

[1] Ex Ante Estimated MW = In compliance with Decision 08-04-050, the values presented herein are based on the April 1, 2014 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 programs, e.g., AMP and CBP are the monthly nominated MW.

[2] Ex Post Estimated MW = In compliance with Decision 08-04-050, the values presented herein are based on the April 1, 2014 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.

[3] There is also another group of customers on the Critical Peak Pricing (CPP also known as PDP) rate, e.g., small business and medium C&I customers, who are enrolled on CPP on a purely voluntary basis. This group of customers is referred to as the voluntary CPP customers. The great majority of these service accounts are associated with a single business entity and do not respond on event days. These voluntary CPP participants inflate the enrollment number because they are not representative of the small business or medium C&I populations that will default onto CPP in coming years. Load impacts for these customers are presented in the PG&E electronic ex post load impact table generator; but it is important to remember that their load impacts do not reflect what would be expected from the small business and medium C&I customer classes in the future under default CPP.

NOTE: 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 1st 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.

NOTE: AUG ILP corrected inaccurate data reported in July for AMP and CBP Service Accounts and ExAnte MW.

Program Eligibility and Ex Ante Average Load Impacts

Program	Average Ex Ante Load Impact kW / Customer												Eligible Accounts as of Jan 1, 2014	Eligibility Criteria (Refer to tariff for specifics)
	January	February	March	April	May	June	July	August	September	October	November	December		
BIP - Day Of	840.90	894.70	903.60	1040.60	1006.00	1047.70	1068.10	1117.60	1055.30	968.50	927.10	854.60	10,813	This schedule is available to bundled-service, Community Choice Aggregation (CCA) Service, and Direct Access (DA) commercial, industrial, and agricultural customers. Each customer, both directly enrolled and those enrolled in an aggregator's portfolio, must take service under the provisions of a demand time-of-use rate schedule to participate in the Program and have at least an average monthly demand of 100 kilowatt (kW). Customers being served under Schedules AG-R or AG-V are not eligible for this program. Customers taking service under DA must meet the metering requirements prescribed in the Metering Equipment section of this rate schedule.
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	N/A	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	N/A	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	0.37	0.47	0.69	0.55	0.51	0.32	N/A	N/A	N/A	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	0.32	0.40	0.60	0.46	0.47	0.24	N/A	N/A	N/A	Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
AMP - Day Ahead	N/A	N/A	N/A	N/A	68.00	68.00	68.00	68.00	68.00	68.00	N/A	N/A	594,510	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.
AMP - Day Of	N/A	N/A	N/A	N/A	162.50	162.50	162.50	162.50	162.50	162.50	N/A	N/A		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.
CBP - Day Ahead	N/A	N/A	N/A	N/A	172.30	179.20	185.00	168.50	157.20	158.90	N/A	N/A	594,510	A customer may participate in either the Day-Ahead or Day-Of option. A customer with multiple service agreements (SA) may nominate demand reductions from a single SA to either the Day-of option or Day-ahead option. A SA may not be nominated to both the Day-of and Day-ahead option during a single program month. Customers that receive electric power from third parties (other than through direct access and Community Choice Aggregation) and customers billed for standby service are not eligible for Schedule E-CBP. Eligible customers include those receiving partial standby service or services pursuant to one or more of the Net Energy Metering Service schedules except NEMCCSF.
CBP - Day Of	N/A	N/A	N/A	N/A	31.40	33.50	30.10	30.20	29.20	22.20	N/A	N/A		A customer may participate in either the Day-Ahead or Day-Of option. A customer with multiple service agreements (SA) may nominate demand reductions from a single SA to either the Day-of option or Day-ahead option. A SA may not be nominated to both the Day-of and Day-ahead option during a single program month. Customers that receive electric power from third parties (other than through direct access and Community Choice Aggregation) and customers billed for standby service are not eligible for Schedule E-CBP. Eligible customers include those receiving partial standby service or services pursuant to one or more of the Net Energy Metering Service schedules except NEMCCSF.
DBP	37.10	41.30	38.30	46.10	44.80	41.00	45.90	46.00	45.20	42.00	40.10	41.50	10,813	This schedule is available to individual PG&E bundled-service customers, Community Choice Aggregation Service (CCA Service) customers, and Direct Access (DA) customers. Each customer must take service under the provisions of their otherwiseapplicable rate schedule. Customers participating in the Program must be on an eligible rate schedule and able to reduce load by at least 10 kW during an E-DBP event. Prior to May 1, 2013, customers with SAs throughout PG&E's electric service territory with individual meters with demands less than 200 kW (as described in the Applicability Section) had the option to participate in this Program under the provisions stated in the Aggregated Group Section of this rate schedule. Those SAs participating as an Aggregated Group as of May 1, 2013, may continue to participate as an Aggregated Group.
PDP (200 kW or above)	7.66	7.77	7.90	21.84	23.79	19.75	21.13	21.70	23.06	20.63	7.91	7.16	7,146	Default beginning on: May 1, 2010 for bundled C&I Customers >200kW Maximum Demand; February 1st, 2011 for large bundled Ag customers;
PDP (<200 kW)	0.52	0.51	0.55	2.87	3.22	4.20	4.55	4.49	4.12	3.04	0.27	0.25	399,593	November 2014 for bundled C&I Customers with <200 kW Maximum Demand and 12 consecutive months of interval data.
SmartRate™ - Residential	N/A	N/A	N/A	N/A	0.22	0.28	0.37	0.31	0.30	0.20	N/A	N/A	N/A	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 1, 2014 (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 system peak day of the month.

Program Eligibility and Average Load Impacts

Program	Average Ex Post Load Impact kW / Customer: January	February	March	April	May	June	July	August	September	October	November	December	Eligible Accounts as of Jan 1, 2014	Eligibility Criteria (Refer to tariff for specifics)
BIP - Day Of	771.6	771.6	771.6	771.6	771.6	771.6	771.6	771.6	771.6	771.6	771.6	771.6	10,813	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	N/A	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	N/A	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	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	N/A	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[TM] - Residential	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	N/A	Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
AMP - Day Ahead	88.8	88.8	88.8	88.8	88.8	88.8	88.8	88.8	88.8	88.8	88.8	88.8	594,510	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.
AMP - Day Of	94.4	94.4	94.4	94.4	94.4	94.4	94.4	94.4	94.4	94.4	94.4	94.4		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.
CBP - Day Ahead	322.9	322.9	322.9	322.9	322.9	322.9	322.9	322.9	322.9	322.9	322.9	322.9	594,510	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.
CBP - Day Of	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1		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.
DBP	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	10,813	Non-residential Customers 200 kW or above on a demand TOU rate schedule, not on rate schedule AG-R, AG-V or S. Eligible customers include PG&E Bundled, Direct Access (DA; ESP), and Community Choice Aggregation Service. Non-residential Customers' accounts < 200 kW may participate as aggregated group for service accounts with same Federal Taxpayer ID Number.
PDP (200 kW or above)	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	7,146	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 (<200 kW)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	399,593	
SmartRate[TM] - Residential	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	N/A	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 1, 2014 (R.13-09-011). Estimated Average Ex Post Load Impact kW / Customer = Average kW / Customer service account over all actual event hours for the preceeding year when or 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. Commercial SmartAC was not called in 2013; its average-customer impact reported here is from the April 2, 2012 filing.

Table I-2
Pacific Gas and Electtric Company
Program Subscription Statistics
August 2014

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

2014	January				February				March			
Price Responsive	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs
AMP - Day Ahead		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
AMP - Day Of		0.0	0.0	**0.0**		0.0	0.0	**0.0**		**0.4**	0.0	**0.4**
CBP - Day Ahead		0.0	0.0	**0.0**		0.0	0.0	**0.0**		**0.4**	0.0	**0.4**
CBP - Day Of		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
DBP		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
PDP		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	**0.2**	**0.2**
SmartRate™ - Residential		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
SmartAC™ - Commercial		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
SmartAC™ - Residential		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
Total		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**		**0.8**	**0.2**	**1.0**
Interruptible/Reliability												
BIP - Day of		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
OBMC		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
SLRP		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
Total		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**
Total Technology MWs		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**		**0.8**	**0.2**	**1.0**
General Program												
TA (may also be enrolled in TI and AutoDR)	0.4				0.4				1.3			
Total	**0.4**				**0.4**				**1.3**			
Total TA MWs	**0.4**	N/A	N/A	N/A	**0.4**	N/A	N/A	N/A	**1.3**	N/A	N/A	N/A

2014	April				May				June			
Price Responsive	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs
AMP - Day Ahead		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
AMP - Day Of		**0.4**	0.0	**0.4**		**0.4**	0.0	**0.4**		**0.5**	0.0	**0.5**
CBP - Day Ahead		**0.5**	0.0	**0.5**		**0.5**	0.0	**0.5**		**0.5**	**0.1**	**0.5**
CBP - Day Of		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
DBP		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
PDP		0.0	**0.2**	**0.2**		0.0	**0.2**	**0.2**		0.0	**0.2**	**0.2**
SmartRate™ - Residential		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
SmartAC™ - Commercial		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
SmartAC™ - Residential		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
Total		**0.8**	**0.2**	**1.1**		**0.8**	**0.2**	**1.1**		**1.0**	**0.3**	**1.3**
Interruptible/Reliability												
BIP - Day of		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
OBMC		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
SLRP		0.0	0.0	**0.0**		0.0	0.0	**0.0**		0.0	0.0	**0.0**
Total		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**
Total Technology MWs		**0.8**	**0.2**	**1.1**		**0.8**	**0.2**	**1.1**		**1.0**	**0.3**	**1.3**
General Program												
TA (may also be enrolled in TI and AutoDR)	1.3				2.3				2.5			
Total	**1.3**				**2.3**				**2.5**			
Total TA MWs	**1.3**	N/A	N/A	N/A	**2.3**	N/A	N/A	N/A	**2.5**	N/A	N/A	N/A

2014	July				August				September			
Price Responsive	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs
AMP - Day Ahead		**0.3**	0.0	**0.3**		**0.3**	0.0	**0.3**				
AMP - Day Of		**1.1**	0.0	**1.1**		**10.4**	0.0	**10.4**				
CBP - Day Ahead		**0.1**	**0.1**	**0.1**		**0.1**	**0.1**	**0.2**				
CBP - Day Of		0.0	0.0	**0.0**		0.0	0.0	**0.0**				
DBP		0.0	0.0	**0.0**		0.0	0.0	**0.0**				
PDP		**0.2**	**0.2**	**0.5**		**0.2**	**0.2**	**0.5**				
SmartRate™ - Residential		0.0	0.0	**0.0**		0.0	0.0	**0.0**				
SmartAC™ - Commercial		0.0	0.0	**0.0**		0.0	0.0	**0.0**				
SmartAC™ - Residential		0.0	0.0	**0.0**		0.0	0.0	**0.0**				
Total		**1.7**	**0.3**	**2.0**		**11.1**	**0.3**	**11.3**				
Interruptible/Reliability												
BIP - Day of		0.0	0.0	**0.0**		0.0	0.0	**0.0**				
OBMC		0.0	0.0	**0.0**		0.0	0.0	**0.0**				
SLRP		0.0	0.0	**0.0**		0.0	0.0	**0.0**				
SmartAC™ - Commercial		0.0	0.0	**0.0**		0.0	0.0	**0.0**				
Total		**0.0**	**0.0**	**0.0**		0.0	0.0	**0.0**				
Total Technology MWs		**1.7**	**0.3**	**2.0**		**11.1**	**0.3**	**11.3**				
General Program												
TA (may also be enrolled in TI and AutoDR)	**2.5**				**2.6**							
Total	**2.5**				**2.6**							
Total TA MWs	**2.5**	N/A	N/A	N/A	**2.6**	N/A	N/A	N/A		N/A	N/A	N/A

2014	October				November				December			
Price Responsive	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs
AMP - Day Ahead												
AMP - Day Of												
CBP - Day Ahead												
CBP - Day Of												
DBP												
PDP												
SmartRate™ - Residential												
SmartAC™ - Commercial												
SmartAC™ - Residential												
Total												
Interruptible/Reliability												
BIP - Day of												
OBMC												
SLRP												
SmartAC™ - Commercial												
Total												
Total Technology MWs												
General Program												
TA (may also be enrolled in TI and AutoDR)												
Total												
Total TA MWs		N/A	N/A	N/A		**N/A**	**N/A**	**N/A**		**N/A**	**N/A**	**N/A**

Table I-3
Pacific Gas and Electric Company
Demand Response Programs and Activities
2012-2014 Incremental Cost Funding
August 2014

2012-2014 Program Expenditures

Cost Item	2012 and 2013 Expenditures	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-Date 2014 Expenditures	Program-to-Date Total Expenditures 2012-2014	3-Year Funding[10]	Fundshift Adjustments[4]	Percent Funding
Category 1: Reliability Programs																		
Base Interruptible Program (BIP)	$451,829	$9,630	$14,854	$13,186	$14,011	$9,616	$10,690	$5,505	$26,668					$104,160	$555,989	$702,538		79.1%
Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)	$159,363	$1,121	$1,854	$2,603	$1,573	$2,025	$1,882	$2,156	$5,333					$18,546	$177,910	$419,468		42.4%
Budget Category 1 Total	$611,192	$10,750	$16,708	$15,789	$15,584	$11,641	$12,573	$7,661	$32,001	$0	$0	$0	$0	$122,706	$733,899	$1,122,006	$0	65.4%
Category 2: Price-Responsive Programs																		
Demand Bidding Program (DBP)	$498,460	$13,416	$16,415	$14,812	$14,319	$13,544	$16,288	$10,644	$41,395					$140,834	$639,294	$3,261,949		19.6%
Capacity Bidding Program (CBP)	$662,889	$23,045	$30,178	$22,203	$22,758	$24,092	$19,940	$22,680	$70,196					$235,091	$897,980	$11,639,186		7.7%
Peak Choice[1]	$843,326	$156	$119	$0	$0	$0	$0	$0	$62					$338	$843,663	$1,750,000		48.2%
SmartAC™	$6,929,374	$161,983	$276,486	$372,676	$544,699	$173,565	$612,674	$573,946	$843,992					$3,560,021	$10,489,395	$19,543,921		53.7%
Budget Category 2 Total	$8,934,048	$198,600	$323,198	$409,691	$581,776	$211,201	$648,903	$607,270	$955,646	$0	$0	$0	$0	$3,936,284	$12,870,332	$36,195,056	$0	35.6%
Category 3: DR Provider/Aggregator Managed Programs																		
Aggregator Managed Portfolio (AMP)	$620,347	$23,348	$21,629	$19,821	$18,411	$19,301	$18,572	$17,242	$53,031					$191,357	$811,703	$1,251,453		64.9%
Budget Category 3 Total	$620,347	$23,348	$21,629	$19,821	$18,411	$19,301	$18,572	$17,242	$53,031	$0	$0	$0	$0	$191,357	$811,703	$1,251,453	$0	64.9%
Category 4: Emerging & Enabling Programs																		
Auto DR	$3,429,791	$47,920	$157,568	$158,555	$185,676	$240,620	$247,981	$173,253	$349,444					$1,561,019	$4,990,809	$26,435,125		18.9%
DR Emerging Technology	$638,142	$89,921	$100,104	$152,591	$136,553	$138,161	$147,649	$131,390	$204,351					$1,100,721	$1,738,862	$3,879,133		44.8%
Budget Category 4 Total	$4,067,932	$137,842	$257,673	$311,146	$322,230	$378,782	$395,631	$304,643	$553,794	$0	$0	$0	$0	$2,661,739	$6,729,671	$30,314,258	$0	22.2%
Category 5: Pilots																		
IRR Phase 2	$489,707	$81,891	$47,199	$39,674	$40,633	$128,799	$18,102	$33,210	$54,913					$444,419	$934,126	$2,497,952		37.4%
T&D DR	$156,168	$13,466	$14,544	$17,171	$11,143	$16,166	$19,438	$8,819	$49,560					$150,307	$306,476	$2,494,190		12.3%
Plug-in Hybrid EV/EV (incl. HAN-EV)	$110,937	$4,631	$2,507	$4,297	$218	$1,337	-	$15,285	$9,802					$38,077	$149,014	$3,008,402		5.0%
Budget Category 5 Total	$756,812	$99,988	$64,249	$61,142	$51,994	$146,302	$37,540	$57,314	$114,275	$0	$0	$0	$0	$632,804	$1,389,616	$8,000,544	$0	17.4%
Category 6: Evaluation, Measurement and Verification																		
DRMEC	$3,690,348	$329,776	$214,082	$876,175	$373,241	$263,157	$87,915	$183,942	$299,354					$2,627,643	$6,317,991	$14,852,945		42.5%
DR Research Studies	-	-	-	-	-	-	-	-	-					-	-	$1,200,000		0.0%
Budget Category 6 Total	$3,690,348	$329,776	$214,082	$876,175	$373,241	$263,157	$87,915	$183,942	$299,354	$0	$0	$0	$0	$2,627,643	$6,317,991	$16,052,945	$0	39.4%
Category 7: Marketing, Education and Outreach																		
Statewide Marketing[1]	$3,360,000	-	-	-	-	-	-	-	-					-	$3,360,000	$3,500,000		96.0%
DR Core Marketing and Outreach[2]	$1,819,726	$29,920	$43,609	$65,181	$67,218	$51,276	$62,707	$121,664	$191,449					$633,024	$2,452,750	$13,228,509		61.5%
SmartAC™ ME&O[3]	$4,021,452	$51,154	$132,493	$390,089	$276,424	$93,646	$124,247	$456,792	$138,499					$1,663,343	$5,684,795	$0		
Education and Training	$146,896	$2,461	$4,398	$2,796	$3,088	$2,126	$3,957	$2,760	$6,240					$27,825	$174,721	$781,910		22.3%
Budget Category 7 Total	$9,348,074	$83,536	$180,499	$458,065	$346,730	$147,048	$190,911	$581,216	$336,187	$0	$0	$0	$0	$2,324,192	$11,672,266	$17,510,419	$0	66.7%
Category 8: DR System Support Activities																		
InterAct / DR Forecasting Tool	$6,777,573	$892,009	$249,639	$270,119	$226,617	$212,009	$264,697	$222,448	$400,875					$2,738,414	$9,515,987	$14,731,256		64.6%
DR Enrollment & Support	$6,744,848	($450,046)	$722,043	($227,847)	$1,420,370	$286,390	$1,188,021	$308,200	$531,664					$3,778,795	$10,523,643	$16,040,057		65.6%
Notifications	$562,647	$1,875	$5,268	$46,493	$20,248	$38,385	$18,876	$396,573	$7,344					$535,063	$1,097,710	$7,484,401		14.7%
DR Integration Policy & Planning	$1,340,078	$83,299	$138,984	$152,092	$161,209	$267,255	$204,361	$209,157	$271,935					$1,488,292	$2,828,370	$4,177,319		67.7%
Budget Category 8 Total	$15,425,146	$527,138	$1,115,935	$240,856	$1,828,445	$804,038	$1,675,956	$1,136,378	$1,211,818	$0	$0	$0	$0	$8,540,564	$23,965,710	$42,433,033	$0	56.5%
Category 9: Integrated Programs and Activities (Including Technical Assistance)																		
Technology Incentives - IDSM[5]	$1,000,994	($115,661)	$231,348	$83,352	$87,565	$105,190	$76,935	$116,569	$137,836					$723,134	$1,724,129	$7,561,166		22.8%
PEAK[1]	$541,609	-	-	-	-	-	-		-					-	$541,609	$560,000		96.7%
Integrated Marketing & Outreach[1]	$359,406	-	$0	-	-	-	-	-	$0					$0	$359,406	$304,500	$73,000	118.0%
Integrated Education & Training[1]	$15,181	$39	$30	-	-	-	-	-	$16					$84	$15,265	$61,000		25.0%
Integrated Sales Training[1]	$14,507	-	-	-	-	-	-		-					-	$14,507	$76,000		19.1%
Integrated Energy Audits[5]	$1,028,451	$10,470	$20,768	$27,967	$37,269	$60,500	$49,963	$30,834	$55,287					$293,058	$1,321,509	$3,801,338	($73,000)	34.8%
Integrated Emerging Technology[1]	$427,248	($158)	-	-	$19	-	-	-	-					($139)	$427,109	$440,000		97.1%
Budget Category 9 Total	$3,387,396	($105,310)	$252,146	$111,319	$124,853	$165,690	$126,898	$147,402	$193,139	$0	$0	$0	$0	$1,016,137	$4,403,532	$12,804,004	$0	34.4%
Category 10: Special Projects																		
DR-HAN Integration (excl. HAN-EV)[6]																$12,022,474		64.2%
HAN Integration Expense	$39,915	$47,631	$22,697	($9,456)	$131,338	$70,067	$317,637	$135,358	241,676.12					$956,948	$996,863			
HAN Integration Capital[8]	$2,935,105	$591,328	$608,016	$556,311	$632,384	$455,788	$280,007	$364,763	$294,357					$3,782,954	$6,718,059			
Permanent Load Shifting	$608,747	$45,277	$62,162	$63,262	$48,753	$71,388	$55,269	$38,541	$82,242					$466,893	$1,075,641	$15,067,395		7.1%
Budget Category 10 Total	$3,583,767	$684,236	$692,875	$610,117	$812,475	$597,243	$652,913	$538,661	$618,274	$0	$0	$0	$0	$5,206,795	$8,790,562	$27,089,869	$0	32.4%
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). [9]	$1,675,359	$64,449	$64,449	$64,591	$64,059	$63,841	$63,623	$63,174	($1,493,138)					($1,044,951)	$630,408	$0	$0	N/A
Total Incremental Cost[7]	$52,100,423	$2,054,352	$3,203,443	$3,178,714	$4,539,797	$2,808,243	$3,911,433	$3,644,905	$2,874,382	$0	$0	$0	$0	$26,215,269	$78,315,691	$192,773,588	$0	40.6%

Technical Assistance & Technology Incentives (TA&TI) Identified as of AUGUST 2014.	$4,006

[1] Authorized funding for 2012 only.
[2] The expenditures listed are in support of PG&E's DR programs for large commercial, industrial and agricultural customers, excluding the aggregator-managed programs. Disclosure complies with OP 24 of D.12-04-045. The 2012-14 approved budget for DR Core Marketing and Outreach includes funding for SmartAC marketing, education and outreach
[3] The budget for SmartAC marketing, education, and outreach costs are included in the 2012-14 approved budget for DR Core Marketing and Outreach; however, the expenses are separated to differentiate the ME&O efforts targeting residential and small commercial customers. SmartAC is now closed to non-residential customers. The "percent funding" calculation shown on the DR Core Marketing and Outreach line includes SmartAC marketing expenditures.
[4] See the Fund Shift Log 2012-14 for explanations.
[5] Additional funding for Technology Incentives and Integrated Energy Audits was approved in Energy Efficiency Decision 12-11-015 for 2013 and 2014.
[6] The CPUC authorized the HAN Integration Project in the amount of $11,941,000 on April 8, 2013 per Advice Letter 4119-E/E-A.
[7] Total Incremental Cost excludes incentives. Incentives are reported on Table I-5.
[8] The HAN Integration capital expenditures are for informational purpose only, that is, the capital revenue requirement will not be recorded in DREBA until the assets are operational.
[9]The capital RRQ for August 2014 is negative due to tax benefits received by PG&E for software expenditures related to the HAN Integration Project.
[10] Program budgets have been updated to include employee benefits costs approved in the GRC (D.14-08-032) – Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2014-2016, approved on August 14, 2014."

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
August 2014

Program Category	Program Name	Month	Zones[1]	Event Date	Event No. (by Program Type)	Program Type	Trigger	# of Accounts	Event Start Time (PDT)	Event End Time (PDT)	Program Tolled Hours	Load Reduction MW (Max Hourly)[2]
(Page 1 of 2)												
Category 1: Reliability Programs												
	Base Interruptible Program (BIP)	FEBRUARY	System, All SubLaps	2/6/2014	1	Day Of	Ordered by ISO	220	3:15 PM	7:15 PM	4	189.3
	Base Interruptible Program (BIP)[3]	APRIL	Re-test	4/17/2014	2	Day Of	Re-test	47	2:00 PM	6:00 PM	4	12.3
	Base Interruptible Program (BIP)[3,4]	MAY	Re-test	5/15/2014	3	Day Of	Re-test	**<15**	2:00 PM	6:00 PM	4	Redacted
	Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)											
Category 2: Price-Responsive Programs												
	Capacity Bidding Program (CBP)[4]	MAY	4 SubLaps: San Francisco (Bay Area), Peninsula (Bay Area), Central Coast, South Bay (Bay Area)	5/14/2014	1	Day Ahead	Temperature	**<15**	4:00 PM	7:00 PM	3	Redacted
	Capacity Bidding Program (CBP)	MAY	4 SubLaps: San Francisco (Bay Area), Peninsula (Bay Area), Central Coast, South Bay (Bay Area)	5/14/2014	1	Day Of	Temperature	186	3:00 PM	7:00 PM	4	3.6
	Capacity Bidding Program (CBP)[4]	MAY	System	5/15/2014	2	Day Ahead	Temperature	31	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	MAY	System	5/15/2014	2	Day Of	Temperature	545	3:00 PM	7:00 PM	4	12.3
	Capacity Bidding Program (CBP)	JUNE	System	6/9/2014	3	Day Of	Heat Rate	554	3:00 PM	7:00 PM	4	13.2
	Capacity Bidding Program (CBP)	JUNE	System	6/30/2014	4	Day Of	Heat Rate	1,448	3:00 PM	7:00 PM	4	13.8
	Capacity Bidding Program (CBP)[4]	JULY	System	7/7/2014	5	Day Ahead	Heat Rate	40	4:00 PM	7:00 PM	3	Redacted
	Capacity Bidding Program (CBP)[4]	JULY	2 SubLaps: Central Coast, Fresno	7/7/2014	5	Day Of	Heat Rate	120	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[4]	JULY	3 SubLaps: Fresno, Los Padres, Stockton	7/14/2014	6	Day Ahead	Heat Rate	29	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[4]	JULY	7 SubLaps: Humboldt, North Coast, North Valley, Sacramento Valley, Sierra, San Joaquin, Stockton	7/14/2014	6	Day Of	Heat Rate	107	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[4]	JULY	3 SubLaps: Stockton, Fresno, San Francisco (Bay Area)	7/25/2014	7	Day Ahead	Market Award, Heat Rate	26	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[4]	JULY	2 SubLaps: San Francisco (Bay Area), Fresno	7/25/2014	7	Day Of	Heat Rate	104	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[4]	JULY	System	7/28/2014	8	Day Ahead	Heat Rate	40	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[4]	JULY	System	7/28/2014	8	Day Of	Heat Rate	536	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[4]	JULY	System	7/29/2014	9	Day Ahead	Heat Rate	40	4:00 PM	7:00 PM	3	Redacted
	Capacity Bidding Program (CBP)[4]	JULY	System	7/29/2014	9	Day Of	Heat Rate	536	4:00 PM	7:00 PM	3	Redacted
	Capacity Bidding Program (CBP)[4]	AUGUST	12 SubLaps: East Bay (Bay Area), Fresno, Geysers, Los Padres, North Bay, North Coast, North Valley, Peninsula (Bay Area), Sacramento Valley, San Francisco (Bay Area), Sierra, South Bay (Bay Area)	8/1/2014	10	Day Ahead	Heat Rate	37	3:00 p.m.	7:00 p.m.	4	Redacted
	Capacity Bidding Program (CBP)	AUGUST	12 SubLaps: East Bay (Bay Area), Fresno, Geysers, Los Padres, North Bay, North Coast, North Valley, Peninsula (Bay Area), Sacramento Valley, San Francisco (Bay Area), Sierra, South Bay (Bay Area)	8/1/2014	10	Day Of	Heat Rate	503	3:00 p.m.	7:00 p.m.	4	16.3
	Demand Bidding Program (DBP)[4]	MAY	3 SubLaps: San Francisco (Bay Area), Central Coast, South Bay (Bay Area)	5/14/2014	1	Day Ahead	Temperature	**<15**	12:00 PM	8:00 PM	8	Redacted
	Demand Bidding Program (DBP)[4]	JUNE	System	6/30/2014	2	Day Ahead	Temperature	61	12:00 PM	8:00 PM	8	56.2
	Demand Bidding Program (DBP)[4]	JULY	System	7/7/2014	3	Day Ahead	Temperature	55	12:00 PM	8:00 PM	8	Redacted
	Demand Bidding Program (DBP)[4]	JULY	3 SubLaps: Fresno, Los Padres Sierra	7/14/2014	4	Day Ahead	Temperature	**<15**	12:00 PM	8:00 PM	8	Redacted
	Demand Bidding Program (DBP)[4]	JULY	System	7/28/2014	5	Day Ahead	System Load	59	12:00 PM	8:00 PM	8	Redacted
	Demand Bidding Program (DBP)[4]	JULY	System	7/29/2014	6	Day Ahead	System Load	58	12:00 PM	8:00 PM	8	Redacted
	Demand Bidding Program (DBP)[4]	JULY	System	7/30/2014	7	Day Ahead	System Load	56	12:00 PM	8:00 PM	8	Redacted
	Demand Bidding Program (DBP)[4]	JULY	System	7/31/2014	8	Day Ahead	System Load	51	12:00 PM	8:00 PM	8	Redacted
	Demand Bidding Program (DBP)[4]	AUGUST	System	8/1/2014	9	Day Ahead	System Load	50	12:00 PM	8:00 PM	8	Redacted

[1] Identifies location of event (SubLAP) for locally-dispatchable programs. Non-locally-dispatchable programs are listed as System.
[2] Load reduction amount is based on available meter data and may vary by month pending the collection of all data.
[3] The BIP re-test includes only a subset of the program's enrollment.
[4] Pursuant to Commission guidance in D.14-05-016, p.118 and Finding of Fact 17, PG&E redacted the load reduction MW (Max Hourly) in the Public Version because there were fewer than 15 customers involved or a single customer in the group account 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 2014

Program Category	Program Name	Month	Zones[1]	Event Date	Event No. (by Program Type)	Program Type	Trigger	# of Accounts	Event Start Time (PDT)	Event End Time (PDT)	Program Tolled Hours	Load Reduction MW (Max Hourly)[2]
(Page 2 of 2)												
Category 2: Price-Responsive Programs (Cont'd)												
	Peak Day Pricing (PDP)	JUNE	System	6/9/2014	1	Day Ahead	Temperature	11,178	2:00 PM	6:00 PM	4	34.7
	Peak Day Pricing (PDP)	JUNE	System	6/30/2014	2	Day Ahead	Temperature	11,544	2:00 PM	6:00 PM	4	56.2
	Peak Day Pricing (PDP)	JULY	System	7/1/2014	3	Day Ahead	Temperature	11,547	2:00 PM	6:00 PM	4	42.3
	Peak Day Pricing (PDP)	JULY	System	7/7/2014	4	Day Ahead	Temperature	11,570	2:00 PM	6:00 PM	4	45.7
	Peak Day Pricing (PDP)	JULY	System	7/14/2014	5	Day Ahead	Temperature	11,562	2:00 PM	6:00 PM	4	54.8
	Peak Day Pricing (PDP)	JULY	System	7/25/2014	6	Day Ahead	Temperature	11,561	2:00 PM	6:00 PM	4	39.7
	Peak Day Pricing (PDP)	JULY	System	7/28/2014	7	Day Ahead	Temperature	11,578	2:00 PM	6:00 PM	4	45.0
	Peak Day Pricing (PDP)	JULY	System	7/29/2014	8	Day Ahead	Temperature	11,565	2:00 PM	6:00 PM	4	41.7
	Peak Day Pricing (PDP)	JULY	System	7/31/2014	9	Day Ahead	Temperature	11,546	2:00 PM	6:00 PM	4	29.5
	SmartAC™[5]	JUNE	Two Group Test	6/30/2014	1	Day Ahead	Test	28,000	3:00 PM	6:00 PM	2	12.7
	SmartAC™[5]	JULY	System Wide Test	7/30/2014	2	Day Ahead	Test	136,000	9:30 AM	8:00 PM	11	18.0
	SmartRate™	MAY	System	5/14/2014	1	Day Ahead	Temperature	122,000	2:00 PM	7:00 PM	5	43.9
	SmartRate™	JUNE	System	6/9/2014	2	Day Ahead	Temperature	128,677	2:00 PM	7:00 PM	5	67.4
	SmartRate™	JUNE	System	6/30/2014	3	Day Ahead	Temperature	129,894	2:00 PM	7:00 PM	5	63.9
	SmartRate™	JULY	System	7/1/2014	4	Day Ahead	Temperature	129,995	2:00 PM	7:00 PM	5	45.0
	SmartRate™	JULY	System	7/7/2014	5	Day Ahead	Temperature	130,120	2:00 PM	7:00 PM	5	33.9
	SmartRate™	JULY	System	7/14/2014	6	Day Ahead	Temperature	130,120	2:00 PM	7:00 PM	5	52.8
	SmartRate™	JULY	System	7/25/2014	7	Day Ahead	Temperature	130,225	2:00 PM	7:00 PM	5	57.5
	SmartRate™	JULY	System	7/28/2014	8	Day Ahead	Temperature	130,170	2:00 PM	7:00 PM	5	44.2
	SmartRate™	JULY	System	7/29/2014	9	Day Ahead	Temperature	130,283	2:00 PM	7:00 PM	5	52.2
	SmartRate™	JULY	System	7/31/2014	10	Day Ahead	Temperature	130,287	2:00 PM	7:00 PM	5	52.9
Category 3: DR Provider/Aggregator Managed Programs												
	Aggregator Managed Portfolio (AMP)[4]	MAY	4 SubLaps: San Francisco (Bay Area), Peninsula (Bay Area), Central Coast, South Bay (Bay Area)	5/14/2014	1	Day Ahead	Heat Rate	137	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)[4]	MAY	4 SubLaps: San Francisco (Bay Area), Peninsula (Bay Area), Central Coast, South Bay (Bay Area)	5/14/2014	1	Day Of	Heat Rate	181	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)[4]	MAY	All Sublaps	5/15/2014	2	Day Ahead	Heat Rate	507	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)	MAY	System, All Sublaps	5/15/2014	2	Day Of	Heat Rate	1,400	3:00 PM	7:00 PM	4	121.8
	Aggregator Managed Portfolio (AMP)	JUNE	System	6/9/2014	3	Day Of	Heat Rate	1,448	3:00 PM	7:00 PM	4	140.4
	Aggregator Managed Portfolio (AMP)	JUNE	System	6/30/2014	4	Day Of	Heat Rate	554	3:00 PM	7:00 PM	4	142.0
	Aggregator Managed Portfolio (AMP)[4]	JUNE	System	6/30/2014	3	Day Ahead	Test	501	3:00 PM	5:00 PM	2	Redacted
	Aggregator Managed Portfolio (AMP)[4]	JULY	System	7/7/2014	4	Day Ahead	Heat Rate	516	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)[4]	JULY	2 SubLaps: Central Coast PGCC, Fresno	7/7/2014	5	Day Of	Heat Rate	225	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)	JULY	8 SubLaps: Fresno, Humboldt, Los Padres, North Coast, North Valley, Sierra, San Joaquin, Stockton	7/14/2014	5	Day Ahead	Heat Rate	209	3:00 PM	7:00 PM	4	15.8
	Aggregator Managed Portfolio (AMP)[4]	JULY	7 SubLaps: Humboldt, North Coast, North Valley, Sacramento Valley, Sierra, San Joaquin, Stockton	7/14/2014	6	Day Of	Heat Rate	58	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)[4]	JULY	2 SubLaps: Fresno, San Francisco (Bay Area)	7/25/2014	6	Day Ahead	Heat Rate	102	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)[4]	JULY	2 SubLaps: Fresno, San Francisco (Bay Area)	7/25/2014	7	Day Of	Heat Rate	226	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)[4]	JULY	System	7/28/2014	7	Day Ahead	Heat Rate	516	2:00 PM	7:00 PM	5	Redacted
	Aggregator Managed Portfolio (AMP)[4]	JULY	System	7/28/2014	8	Day Of	Heat Rate	1,404	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)[4]	JULY	System	7/29/2014	8	Day Ahead	Heat Rate	516	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)[4]	JULY	System	7/29/2014	9	Day Of	Heat Rate	1,404	3:00 PM	7:00 PM	4	Redacted
	Aggregator Managed Portfolio (AMP)[4]	AUGUST	12 SubLaps: East Bay (Bay Area), Fresno, Geysers, Los Padres, North Bay, North Coast, North Valley, Peninsula (Bay Area), Sacramento Valley, San Francisco (Bay Area), Sierra, South Bay (Bay Area)	8/1/2014	9	Day Ahead	Heat Rate	477	3:00 p.m.	7:00 p.m.	4	Redacted
	Aggregator Managed Portfolio (AMP)	AUGUST	12 SubLaps: East Bay (Bay Area), Fresno, Geysers, Los Padres, North Bay, North Coast, North Valley, Peninsula (Bay Area), Sacramento Valley, San Francisco (Bay Area), Sierra, South Bay (Bay Area)	8/1/2014	10	Day Of	Heat Rate	1,421	3:00 p.m.	7:00 p.m.	4	153.8

[1] Identifies location of event (SubLAP) for locally-dispatchable programs. Non-locally-dispatchable programs are listed as System.

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

[3] The BIP re-test includes only a subset of the program's enrollment.

[4] Pursuant to Commission guidance in D.14-05-016, p.118 and Finding of Fact 17, PG&E redacted the load reduction MW (Max Hourly) in the Public Version because there were fewer than 15 customers involved or a single customer in the group account for more than 15 percent of the aggregated total.

[5] SmartAC operational testing is conducted in rotating groups throughout the reported event hours. Customers are divided into ten groups and each group consists of ~14k customers. Each group is cycled in 1 ½ - 3 ½ increments with half an hour overlaps. In the case of 6/30, two groups were cycled simultaneously for 3 ½ hours. On 7/30, ~136k customers were cycled in 1 ½ - 3 ½ hour increments with two groups overlapping in the 2:30-6 timeframe.

Table I-5
Pacific Gas and Electric Company
2012-2014 Demand Response Programs
Total Embedded Cost and Revenues
August 2014

Cost Item	2012 and 2013 Cost of Incentives	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-Date 2014 Total Cost	Program-to-Date Total Cost
Annual Total Cost															
Program Incentives															
Automatic Demand Response (AutoDR)	$94,906	$0	$0	$152,200	$15,200	$0	$16,320	$141,900	$1,855,760					$2,181,380	$2,276,286
Aggregator Managed Portfolio (AMP)[1,3]	$27,419,047	$0	$0	$0	$0	$0	$0	$0	$557,798					$557,798	$27,976,845
Base Interruptible Program (BIP)[1]	$47,541,369	$1,843,389	$1,943,367	$1,921,351	$2,133,360	$2,034,300	$2,129,143	$2,212,328	$2,293,893					$16,511,130	$64,052,499
Capacity Bidding Program (CBP)	$3,201,084	($15)	($4)	$0	$0	$33,144	$70,888	$354,118	$92,846					$550,976	$3,752,060
Demand Bidding Program (DBP)	$975,678	$0	$0	$0	$0	$0	$0	$0	$0					$0	$975,678
Optional Binding Mandatory Curtailment / Scheduled Load Reduction Program (OBMC / SLRP)[1]	$0	$0	$0	$0	$0	$0	$0	$0	$0					$0	$0
Technology Incentive (TI)	$567,000	$0	$0	$46,200	$0	$0	$0	$100,330	$26,250					$172,780	$739,780
PeakChoice	$139,230	$0	$0	$0	$0	$0	$0	$0	$0					$0	$139,230
Commercial and Industrial Based Intermittent Resource Management Pilot 2	$100,000	$0	$0	$0	$100,000	$0	$100,000	$0	$0					$200,000	$300,000
SmartAC™	$1,223,030	$27,099	$72,159	$22,424	$169	$40,556	$948	$53,545	$51,830					$268,730	$1,491,760
Total Cost of Incentives	$81,261,343	$1,870,473	$2,015,522	$2,142,174	$2,248,730	$2,108,000	$2,317,299	$2,862,220	$4,878,377	$0	$0	$0	$0	$20,442,795	$101,704,137
Revenues from Penalties[2]	$71,863	$0	$0	$0	$0	$0	$0	$0	$0					$0	$71,863

[1]Amounts reported are for incentive costs that are not recorded in the Demand Response Expenditures Balancing Account. Incentives are recorded at the time of payment.

[2] The amount reported for November 2013 represents the termination fee received from an AMP aggregator who defaulted on Product B (Day-Ahead with Local Dispatch). As per D.13-01-024, which authorized the cost recovery of agreement costs for the AMP program in the Energy Resource Recovery Account (ERRA), the termination fee received was posted in ERRA.

[3] The AMP expenditures for the months of May, June, and July have been restated.

Table I-7
Pacific Gas and Electric Company
2012-2014 Marketing, Education and Outreach
Actual Expenditures
August 2014

PG&E's ME&O Actual Expenditures	2012- 2014 Funding Cycle Customer Communication, Marketing, and Outreach													Year-to-Date 2014 Expenditures	2012-2014 Total Expenditures	Authorized Budget (if Applicable)
	2012 and 2013 Expenditures	January	February	March	April	May	June	July[6]	August	September	October	November	December			
I. STATEWIDE MARKETING[1]																
IOU Administrative Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Statewide ME&O contract	$ 3,360,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,360,000	
I. TOTAL STATEWIDE MARKETING		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,360,000	$ 3,500,000
II. UTILITY MARKETING BY ACTIVITY[2,3,4]																
TOTAL AUTHORIZED UTILITY MARKETING BUDGET FOR 2012-2014	[redacted]															
PROGRAMS, RATES & ACTIVITES WHICH DO NOT REQUIRE ITEMIZED ACCOUNTING																
Integrated Demand Side Marketing[5]	$ 374,586	$ 39	$ 30	$ -	$ -	$ -	$ -	$ -	$ 16					$ 84	$ 374,670	$ 438,500
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	N/A	N/A	
Demand Bidding Program	$ 633,948	$ 16,191	$ 24,003	$ 33,988	$ 35,153	$ 26,701	$ 33,332	$ 62,212	$ 98,844					$ 330,424	$ 964,373	
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	N/A	N/A	
Permanent Load Shifting	$ 276,870	$ 6,476	$ 9,601	$ 13,595	$ 14,061	$ 10,680	$ 13,333	$ 24,885	$ 39,538					$ 132,170	$ 409,040	
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	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	N/A	N/A	
Enabling Technologies (e.g., AutoDR, TI)	$ 589,987	$ 9,714	$ 14,402	$ 20,393	$ 21,092	$ 16,021	$ 19,999	$ 37,327	$ 59,307					$ 198,255	$ 788,241	
PeakChoice	$ 465,817	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					$ -	$ 465,817	
Customer Awareness, Education and Outreach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					$ -	$ -	
PROGRAMS & RATES WHICH REQUIRE ITEMIZED ACCOUNTING																
SmartAC	$ 4,021,452	$ 51,154	$ 132,493	$ 390,089	$ 276,424	$ 93,646	$ 124,247	$ 456,792	$ 138,499	$ -	$ -	$ -	$ -	$ 1,663,343	$ 5,684,795	
Customer Research	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					$ -	$ -	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ 3,438,383	$ 39,469	$ 89,746	$ 353,045	$ 240,829	$ 79,719	$ 83,947	$ 416,692	$ 61,072					$ 1,364,519	$ 4,802,902	
Labor	$ 516,395	$ 11,686	$ 32,422	$ 26,993	$ 35,595	$ 13,927	$ 19,500	$ 33,408	$ 75,872					$ 249,402	$ 765,797	
Paid Media	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -					$ -	$ -	
Other Costs	$ 66,674	$ -	$ 10,325	$ 10,050	$ -	$ -	$ 20,800	$ 6,692	$ 1,554					$ 49,422	$ 116,096	
II. TOTAL UTILITY MARKETING BY ACTIVITY	$ 6,362,661	$ 83,575	$ 180,529	$ 458,065	$ 346,730	$ 147,048	$ 190,911	$ 581,216	$ 336,203	$ -	$ -	$ -	$ -	$ 2,324,276	$ 8,686,936	$ 14,448,919
III. UTILITY MARKETING BY ITEMIZED COST																
Customer Research	$ 37,290	$ -	$ -	$ -	$ -	$ -	$ -	$ -						$ -	$ 37,290	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ 3,986,335	$ 39,093	$ 89,746	$ 389,071	$ 259,541	$ 29,226	$ 84,882	$ 431,389	$ 83,088					$ 1,406,036	$ 5,392,371	
Labor	$ 2,229,975	$ 44,482	$ 80,458	$ 57,766	$ 86,435	$ 117,822	$ 85,228	$ 143,134	$ 251,561					$ 866,885	$ 3,096,860	
Paid Media	$ -	$ -	$ -											$ -	$ -	
Other Costs	$ 109,061	$ -	$ 10,325	$ 11,228	$ 754	$ -	$ 20,800	$ 6,692	$ 1,554					$ 51,354	$ 160,415	
III. TOTAL UTILITY MARKETING BY ITEMIZED COST	$ 6,362,661	$ 83,575	$ 180,529	$ 458,065	$ 346,730	$ 147,048	$ 190,911	$ 581,216	$ 336,203	$ -	$ -	$ -	$ -	$ 2,324,276	$ 8,686,936	
IV. UTILITY MARKETING BY CUSTOMER SEGMENT																
Agricultural	$ 351,181	$ 4,863	$ 7,205	$ 10,196	$ 10,546	$ 8,010	$ 10,000	$ 18,664	$ 29,656					$ 99,140	$ 450,321	
Large Commercial and Industrial	$ 1,990,027	$ 27,557	$ 40,831	$ 57,780	$ 59,760	$ 45,392	$ 56,665	$ 105,760	$ 168,049					$ 561,793	$ 2,551,820	
Small and Medium Commercial	$ 201,073	$ 2,558	$ 6,625	$ 19,504	$ 13,821	$ 4,682	$ 6,212	$ 22,840	$ 6,925					$ 83,167	$ 284,240	
Residential	$ 3,820,380	$ 48,597	$ 125,868	$ 370,584	$ 262,602	$ 88,964	$ 118,034	$ 433,953	$ 131,574					$ 1,580,176	$ 5,400,555	
IV. TOTAL UTILITY MARKETING BY CUSTOMER SEGMENT	$ 6,362,661	$ 83,575	$ 180,529	$ 458,065	$ 346,730	$ 147,048	$ 190,911	$ 581,216	$ 336,203	$ -	$ -	$ -	$ -	$ 2,324,276	$ 8,686,936	

Notes:

[1]Statewide Marketing refers to the one year of funding, which is equal to $3.5 million, to be used for an emergency alert campaign as per Decision 12-04-045 Ordering Paragraph 19.

[2]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 12-04-045, 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 such as Peak Choice 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.

[3]The 2012 Authorized Budget for Integrated Demand Side Marketing includes the budget for Integrated Marketing & Outreach ($304,500) and Integrated Education & Training ($61,000).

[4]The Total Authorized Budget for Utility Marketing includes the Integrated Demand Side Marketing budget for 2012 and the local ME&O (DR Core Marketing & Outreach and Education & Training) budget for 2012-14.

[5]See the Fund Shift Log 2012-14 for explanations.

[6]Expenditures for the month of July 2014 have been restated.

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: Reliability Programs	$0.00			
Category 2: Price-Responsive Programs	$0.00			
Category 3: DR Provider/Aggregator Managed Programs	$0.00			
Category 4: Emerging & Enabling Programs	$0.00			
Category 5: Pilots	$0.00			
Category 6: Evaluation, Measurement and Verification	$0.00			
Category 7: Marketing, Education and Outreach	$0.00			
Category 8: DR System Support Activities	$0.00			
Category 9: Integrated Programs and Activities	$73,000	Integrated Energy Audits to Integrated Marketing & Outreach	12/1/2012	The transferred funds support the expanded effort to increase adoption of energy management solutions, which integrate DR with other PG&E programs.
Category 10: Special Projects	$0.00			
Total	**$73,000**			