Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for March 2016

Pacific Gas and Electric Company®

April 21, 2016

Pacific Gas and Electric Company (“PG&E”) hereby submits this report on Interruptible Load and Demand Response Programs for March. 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
March 2016

UTILITY NAME: Pacific Gas and Electric Company

Monthly Program Enrollment and Estimated Load Impacts

	January			February			March			April			May			June			
Programs	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**[3] Eligible Accounts as of Jan 1, 2016**
Interruptible/Reliability																			
BIP - Day Of	218	235	263	208	233	251	210	236	253										10,795
OBMC	22	0	0	22	0	0	22	0	0										N/A
SLRP	0	0	0	0	0	0	0	0	0										N/A
SmartAC™ - Commercial	4,337	0	1	4,295	0	1	4,265	0	44										N/A
SmartAC™ - Residential	153,363	0	71	153,147	0	70	152,765	0	2										N/A
Sub-Total Interruptible	157,940	235	335	157,672	233	323	157,262	236	300										
Price Response																			
AMP - Day Of	2,661	0	179	2,672	0	180	2,676	0	180										599,649
CBP - Day Ahead	0	0	0	0	0	0	0	0	0										599,649
CBP - Day Of	0	0	0	0	0	0	0	0	0										
DBP	494	23	19	493	23	19	485	22	18										10,795
PDP (200 kW or above)	2,099	12	30	2,120	12	30	2111	14	30										5,890
PDP (above 20 kW & below 200 kW)	34,045	2	8	33,594	2	8	33,266	2	8										81,268
PDP (20 kW or below)	190,682	0	2	189,048	0	2	187,469	0	2										323,351
SmartRate™ - Residential	144,524	13	45	144,729	13	45	145,535	13	45										Not Available
Sub-Total Price Response	374,505	50	282	372,656	51	283	371,542	51	283										
Total All Programs	532,445	285	617	530,328	283	606	528,804	287	583										

	July			August			September			October			November			December			
Programs	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3]**	**Ex Ante Estimate MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**[3] Eligible Accounts as of Jan 1, 2016**
Interruptible/Reliability																			
BIP - Day of																			10,795
OBMC																			N/A
SLRP																			N/A
SmartAC™ - Commercial																			N/A
SmartAC™ - Residential																			N/A
Sub-Total Interruptible																			
Price Response																			
AMP - Day Of																			599,649
CBP - Day Ahead																			599,649
CBP - Day Of																			
DBP																			10,795
PDP (200 kW or above)																			5,890
PDP (above 20 kW & below 200 kW)																			81,268
PDP (20 kW or below)																			323,351
SmartRate™ - Residential																			Not Available
Sub-Total Price Response																			
Total All Programs																			

[1] Ex Ante Estimated MW = In compliance with Decision 08-04-050, the values presented herein are based on the April 1, 2015 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 during the event season May through October.

[2] Ex Post Estimated MW = In compliance with Decision 08-04-050, the values presented herein are based on the April 1, 2015 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] The March 2016 ILP provides the available 2015-2016 data for Eligible Accounts and Program Eligibility for Ex Ante and Expost Average Load Impacts.

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: 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 continue to 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.

Pacific Gas and Electric Company
Average Ex Post Load Impact kW / Customer
March 2016

Program Eligibility and Ex Ante Average Load Impacts

Program	Average Ex Ante Load Impact kW / Customer												Eligible Accounts as of Jan 1, 2016 [1]	Eligibility Criteria (Refer to tariff for specifics)
	January	February	March	April	May	June	July	August	September	October	November	December		
BIP - Day Of	1077.6	1118.2	1124.2	1159.9	1151.0	1211.6	1206.9	1226.3	1207.7	1225.4	1107.0	1081.6	10,795	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 toparticipate 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	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	0.39	0.62	0.62	0.61	0.53	0.30	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	0.29	0.49	0.52	0.48	0.45	0.18	N/A	N/A	Not Available	Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
AMP - Day Of	N/A	N/A	N/A	N/A	55.1	55.1	55.1	55.1	55.1	55.1	N/A	N/A	599,649	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	120.9	120.9	120.9	120.9	120.9	120.9	N/A	N/A	599,649	A customer may participate in either the Day-Ahead or Day-Of option. A customer with multipleservice agreements (SA) may nominate demand reductions from a single SA to either the Day-ofoption or Day-ahead option. A SA may not be nominated to both the Day-of and Day-aheadoption during a single program month.Customers that receive electric power from third parties (other than through direct access andCommunity Choice Aggregation) and customers billed for standby service are not eligible forSchedule E-CBP. Eligible customers include those receiving partial standby service or servicespursuant to one or more of the Net Energy Metering Service schedules except NEMCCSF.
CBP - Day Of	N/A	N/A	N/A	N/A	28.1	28.1	28.1	28.1	28.1	28.1	N/A	N/A		A customer may participate in either the Day-Ahead or Day-Of option. A customer with multipleservice agreements (SA) may nominate demand reductions from a single SA to either the Day-ofoption or Day-ahead option. A SA may not be nominated to both the Day-of and Day-aheadoption during a single program month.Customers that receive electric power from third parties (other than through direct access andCommunity Choice Aggregation) and customers billed for standby service are not eligible forSchedule E-CBP. Eligible customers include those receiving partial standby service or servicespursuant to one or more of the Net Energy Metering Service schedules except NEMCCSF.
DBP	47.4	47.5	46.0	53.0	49.4	51.8	52.0	54.2	52.6	50.9	43.4	51.0	10,795	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)	5.8	5.9	6.7	13.0	13.6	14.2	13.7	14.4	14.5	13.4	7.0	5.8	5,890	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)	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	81,268	
PDP (20 kW or below)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	323,351	
SmartRate™ - Residential	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	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 1, 2016 (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 March 2016 ILP provides the available 2015-2016 data for Eligible Accounts and Program Eligibility for Ex Ante and Expost Average Load Impacts .

Pacific Gas and Electric Company
Average Ex Ante Load Impact kW / Customer
March 2016

Program Eligibility and Ex Post Average Load Impacts

Program	Average Ex Post Load Impact kW / Customer												Eligible Accounts as of Jan 1, 2016 [1]	Eligibility Criteria (Refer to tariff for specifics)
	January	February	March	April	May	June	July	August	September	October	November	December		
BIP - Day Of	1206.90	1206.90	1206.90	1206.90	1206.90	1206.90	1206.90	1206.90	1206.90	1206.90	1206.90	1206.90	10,795	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	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	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	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	Not Available	Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
AMP - Day Of	67.30	67.30	67.30	67.30	67.30	67.30	67.30	67.30	67.30	67.30	67.30	67.30	599,649	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	79.70	79.70	79.70	79.70	79.70	79.70	79.70	79.70	79.70	79.70	79.70	79.70	599,649	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	34.70	34.70	34.70	34.70	34.70	34.70	34.70	34.70	34.70	34.70	34.70	34.70		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	37.90	37.90	37.90	37.90	37.90	37.90	37.90	37.90	37.90	37.90	37.90	37.90	10,795	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)	14.20	14.20	14.20	14.20	14.20	14.20	14.20	14.20	14.20	14.20	14.20	14.20	5,890	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	81,268	
PDP (20 kW or below)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	323,351	
SmartRate™ - Residential	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	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 1, 2016 (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 2015; its average-customer impact reported here is from the April 2, 2012 filing.

[1] The March 2016 ILP provides the available 2015-2016 data for Eligible Accounts and Program Eligibility for Ex Ante and Expost Average Load Impacts.

Table I-2
Pacific Gas and Electtric Company
Program Subscription Statistics
March 2016

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

2016	January				February				March				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	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		0.3	0.0	0.3		0.4	0.0	0.4		0.0	0.0	0.0												
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	0.0	0.0												
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		0.3	0.0	0.3		0.4	0.0	0.4		0.4	0.0	0.4												
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	0.3		0.4	0.0	0.4		0.4	0.0	0.4												
General Program																								
TA (may also be enrolled in TI and AutoDR)	0.0				0.0				0.0															
Total	0.0				0.0				0.0															
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												

2016	July				August				September				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	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																								
Total																								
Total Technology MWs																								
General Program																								
TA (may also be enrolled in TI and AutoDR)																								
Total																								
Total TA MWs																								

NOTE: Projects for which applications were approved in the previous funding cycle are charged to that funding cycle; however, installed megawatts are at the time of installation regardless of funding cycle.

Table I-3
Pacific Gas and Electric Company
Demand Response Programs and Activities
2015-2016 Incremental Cost Funding
March 2016

2015-2016 Program Expenditures

Cost Item	2015 Expenditures	January [6]	February	March	April	May	June	July	August	September	October	November	December	Year-to-Date 2016 Expenditures	Program-to-Date Expenditures	2-Year Funding [7]	Fundshift Adjustments [8]	Percent Funding
Category 1: Reliability Programs																		
Base Interruptible Program (BIP)	$139,467	$14,183	$13,681	$13,592										$41,456	$180,923	$537,137		33.7%
Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)	$15,522	$1,115	$1,263	$1,012										$3,390	$18,912	$304,304		6.2%
Budget Category 1 Total	$154,989	$15,298	$14,944	$14,604	$0	$0	$0	$0	$0	$0	$0	$0	$0	$44,845	$199,835	$841,441	$0	23.7%
Category 2: Price-Responsive Programs																		
Demand Bidding Program (DBP)	$206,215	$11,330	$13,505	$10,935										$35,770	$241,985	$1,161,150		20.8%
Capacity Bidding Program (CBP)	$249,657	$19,349	$18,956	$19,046										$57,351	$307,008	$4,887,754		6.3%
SmartAC™	$3,893,694	$491,228	$462,807	$128,704										$1,082,738	$4,976,432	$13,336,338		37.3%
Budget Category 2 Total	$4,349,566	$521,907	$495,268	$158,685	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,175,860	$5,525,425	$19,385,242	$0	28.5%
Category 3: DR Provider/Aggregator Managed Programs																		
Aggregator Managed Portfolio (AMP)	$283,875	$21,443	$21,281	$21,919										$64,643	$348,518	$944,506		36.9%
Budget Category 3 Total	$283,875	$21,443	$21,281	$21,919	$0	$0	$0	$0	$0	$0	$0	$0	$0	$64,643	$348,518	$944,506	$0	36.9%
Category 4: Emerging & Enabling Programs																		
Auto DR	$1,989,906	$75,318	$410,341	$303,022										$788,681	$2,778,587	$17,870,739		15.5%
DR Emerging Technology	$911,820	$35,166	$95,340	$84,687										$215,193	$1,127,014	$2,809,056		40.1%
Budget Category 4 Total	$2,901,727	$110,483	$505,681	$387,709	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,003,874	$3,905,601	$20,679,795	$0	18.9%
Category 5: Pilots																		
Supply Side Pilot	$756,309	($473)	$35,755	$78,515										$113,797	$870,106	$2,511,198		34.6%
T&D DR	$493,857	$64,669	$8,108	$7,226										$80,003	$573,861	$1,698,036		33.8%
Excess Supply	$385,279	$30,991	$26,721	$83,941										$141,653	$526,932	$1,199,842		43.9%
Budget Category 5 Total	$1,635,446	$95,187	$70,583	$169,682	$0	$0	$0	$0	$0	$0	$0	$0	$0	$335,453	$1,970,899	$5,409,076	$0	36.4%
Category 6: Evaluation, Measurement and Verification																		
DRMEC	$1,345,427	$274,702	$396,981	$207,875										$879,557	$2,224,984	$8,885,397		25.0%
Budget Category 6 Total	$1,345,427	$274,702	$396,981	$207,875	$0	$0	$0	$0	$0	$0	$0	$0	$0	$879,557	$2,224,984	$8,885,397	$0	25.0%
Category 7: Marketing, Education and Outreach																		
DR Core Marketing and Outreach [1]	$1,057,377	$48,974	$45,688	$48,076										$142,739	$1,200,116	$9,142,336		52.7%
SmartAC™ ME&O [2]	$3,109,604	$365,934	($213,291)	$353,515										$506,159	$3,615,763			
Education and Training	$131,663	$8,816	$6,526	$25,781										$41,123	$172,787	$529,889		32.6%
Budget Category 7 Total	$4,298,644	$423,724	($161,076)	$427,373	$0	$0	$0	$0	$0	$0	$0	$0	$0	$690,020	$4,988,665	$9,672,225	$0	51.6%
Category 8: DR System Support Activities																		
InterAct / DR Forecasting Tool	$2,922,482	$142,383	$145,603	$333,785										$621,772	$3,544,254	$9,974,090		35.5%
DR Enrollment & Support	$3,457,527	$249,617	$413,818	$378,489										$1,041,923	$4,499,450	$10,874,287		41.4%
Notifications	$2,491,204	$42,107	$170,163	$70,662										$282,932	$2,774,136	$5,473,744		50.7%
DR Integration Policy & Planning	$1,366,095	$84,480	$125,226	$117,049										$326,755	$1,692,850	$3,207,039		52.8%
Budget Category 8 Total	$10,237,307	$518,587	$854,811	$899,984	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,273,383	$12,510,690	$29,529,161	$0	42.4%
Category 9: Integrated Programs and Activities (Including Technical Assistance)																		
Technology Incentives - IDSM [3]	$521,715	$3,359	$58,987	$56,606										$118,953	$640,668	$4,051,540		15.8%
Integrated Energy Audits [3]	$892,506	($1,148)	$4,038	$2,604										$5,494	$898,000	$2,550,462		35.2%
Budget Category 9 Total	$1,414,221	$2,211	$63,026	$59,210	$0	$0	$0	$0	$0	$0	$0	$0	$0	$124,446	$1,538,667	$6,602,002	$0	23.3%
Category 10: Special Projects																		
Permanent Load Shifting	$431,129	$38,902	$45,620	$40,307										$124,829	$555,958	$10,128,288	($2,000,000)	5.5%
Demand Response Auction Mechanism Pilot [4]	$104,556	$24,516	$32,207	$26,785										$83,507	$188,063	$0	$2,000,000	
Budget Category 10 Total	$535,685	$63,418	$77,826	$67,092	$0	$0	$0	$0	$0	$0	$0	$0	$0	$208,336	$744,021	$10,128,288	$0	7.3%
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).	$3,272,979	$271,946	$208,555	$140,974										$621,475	$3,894,454		$0	N/A
Total Incremental Cost [5]	$30,429,866	$2,318,906	$2,547,881	$2,555,106	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,421,893	$37,851,759	$112,077,133	$0	33.8%

Technical Assistance & Technology Incentives (TA&TI) Identified as of March 2016.	$0

[1] 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 2015-16 approved budget for DR Core Marketing and Outreach includes funding for SmartAC marketing, education and outreach activities.

[2] The budget for SmartAC marketing, education, and outreach costs are included in the 2015-16 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. February credit is attributable to adjustment of prior month's financials.

[3] Additional funding for Technology Incentives and Integrated Energy Audits was approved in Energy Efficiency Decision 14-10-046. This funding will continue through 2025 unless the Commission issues a superseding funding decision.

[4] $4 Million DRAM pilot funding for 2016 was approved in Resolution E-4728 and an additional $6 Million was approved to expend in 2017 in Resolution E-4754 . IOUs are directed to reserve these funds within the existing authorized 2015-2016 program year budgets and fund shift from existing DR programs. $10M authorized budget for DRAM is not reflected in the 2-Year Funding field due to no change in overall DREBA funding.

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

[6] Credits are attributable to prior months' adjustments; adjustments are normal course of business and may result in a positive or negative number. reserve those funds within their existing authorized 2015-2016 program year budgets

[7] Program budgets 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, issued on August 20, 2014.

[8] Fundshift Adjustments reflect funds shifted between programs since start of the funding cycle.

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
March 2016

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)
Page 1 of 1												
Category 1: Reliability Programs												
	Base Interruptible Program (BIP)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Category 2: Price-Responsive Programs												
	Capacity Bidding Program (CBP)	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 (DBP)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Category 2: Price-Responsive Programs **(Cont'd)**												
	Peak Day Pricing (PDP)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	SmartAC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	SmartRate (SR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Category 3: DR Provider/Aggregator Managed Programs												
	Aggregator Managed Portfolio (AMP)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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

Table I-5
Pacific Gas and Electric Company
2015-2016 Demand Response Programs
Total Embedded Cost and Revenues
March 2016

Annual Total Cost															
Cost Item	**Year-to-Date 2015 Total Cost**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Year-to-Date 2016 Total Cost**	**Program-to-Date**
Program Incentives															
Aggregator Managed Portfolio (AMP)[1]	$8,046,840	$0	$0	$0										$0	$8,046,840
Automatic Demand Response (AutoDR)	$46,470	$48,891	$77,490	$0										$126,381	$172,851
Base Interruptible Program (BIP) [2]	$26,084,254	$2,076,251	$2,095,754	$2,097,493										$6,269,497	$32,353,752
Capacity Bidding Program (CBP) [3]	$1,742,221	$0	$0	$0										$0	$1,742,221
Demand Bidding Program (DBP)	$1,022,581	$0	$0	$0										$0	$1,022,581
Excess Supply Pilot	$0	$0	$0	$500										$500	$500
Optional Binding Mandatory Curtailment / Scheduled Load Reduction Program (OBMC / SLRP)[1]	$0	$0	$0	$0										$0	$0
SmartAC™	$700,649	$22,781	$67,648	$41,823										$132,252	$832,901
Supply Side Pilot	$45,687	$11,000	$14,312	$11,000										$36,312	$81,999
Technology Incentive (TI)	$88,020	$0	$0	$0										$0	$88,020
Transmission and Distribution Pilot (T&D DR	$5,150	$0	$0	$0										$0	$5,150
Total Cost of Incentives	$37,781,872	$2,158,924	$2,255,203	$2,150,816	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,564,943	$44,346,815
Revenues from Penalties[4]	($1,915,464)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,915,464)

[1]Amounts reported are for incentive costs that are not recorded in the Demand Response Expenditures Balancing Account. Starting in 2016, incentives are reported on an accrual basis. Year-to-Date 2015 Total Cost has been adjusted to reflect accrual accounting.

[2]Amounts reported are for incentive costs that are not recorded in the Demand Response Expenditures Balancing Account. Starting in 2016, incentives are reported on an accrual basis. Year-to-Date 2015 Total Cost has been adjusted to reflect accrual accounting. In the March 2016 ILP report, Year-to-Date 2015 Total Cost, January 2016 and March 2016 have been adjusted to reflect actual BIP incentive costs.

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

[4] Revenues from Penalties denote penalty/default payments made by aggregators and charges to direct enrolled customers enrolled in AMP and BIP programs. In the March 2016 ILP report, Year-to-Date 2015 Total Cost has been adjusted to reflect actual penalties.

Table I-7
Pacific Gas and Electric Company
2015-2016 Marketing, Education and Outreach
Actual Expenditures
March 2016

PG&E's ME&O Actual Expenditures	2015-2016 Funding Cycle Customer Communication, Marketing, and Outreach													Year-to-Date 2016 Expenditures	2015-2016 Inception-to-Date Expenditures	2015-2016 Authorized Budget (if Applicable)
	2015 Total Costs	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 FOR 2015-2016	[redacted]															
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	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	N/A	N/A	
Demand Bidding Program	$ 594,520	$ 28,895	$ 26,107	$ 36,929	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 91,931	$ 686,451	
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	$ 237,808	$ 11,558	$ 10,443	$ 14,771	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,772	$ 274,580	
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)	$ 356,712	$ 17,337	$ 15,664	$ 22,157	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 55,159	$ 411,871	
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	N/A	N/A	
Customer Awareness, Education and Outreach	$ -													$ -	$ -	
PROGRAMS & RATES WHICH REQUIRE ITEMIZED ACCOUNTING																
SmartAC	$ 3,109,604	$ 365,934	($213,291)	$ 353,515	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 506,159	$ 3,615,763	
Customer Research	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ 2,492,934	$ 48,555	$ 66,722	$ 334,914	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 450,191	$ 2,943,126	
Labor	$ 445,276	$ 317,379	$ (280,013)	$ 18,457	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 55,823	$ 501,099	
Paid Media	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other Costs	$ 171,393	$ -	$ -	$ 144	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 144	$ 171,538	
II. TOTAL UTILITY MARKETING BY ACTIVITY	$ 4,298,644	$ 423,724	$ (161,076)	$ 427,373	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 690,020	$ 4,988,665	
III. UTILITY MARKETING BY ITEMIZED COST																
Customer Research	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ 2,942,619	$ 62,143	$ 66,745	$ 336,119	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 465,007	$ 3,407,626	
Labor	$ 1,184,486	$ 360,703	$ (227,822)	$ 90,118	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 223,000	$ 1,407,485	
Paid Media	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other Costs	$ 171,539	$ 878	$ -	$ 1,136	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,014	$ 173,553	
III. TOTAL UTILITY MARKETING BY ITEMIZED COST	$ 4,298,644	$ 423,724	$ (161,076)	$ 427,373	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 690,020	$ 4,988,665	
IV. UTILITY MARKETING BY CUSTOMER SEGMENT																
Agricultural	$ 178,356	$ 8,669	$ 7,832	$ 11,079	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,579	$ 205,935	
Large Commercial and Industrial	$ 1,010,684	$ 49,122	$ 44,382	$ 62,779	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,283	$ 1,166,967	
Small and Medium Commercial	$ 155,480	$ 18,297	$ (10,665)	$ 17,676	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,308	$ 180,788	
Residential	$ 2,954,124	$ 347,638	$ (202,626)	$ 335,839	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 480,851	$ 3,434,974	
IV. TOTAL UTILITY MARKETING BY CUSTOMER SEGMENT	$ 4,298,644	$ 423,724	(161,076)	$ 427,373	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 690,020	$ 4,988,665	

Notes:

[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.

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	$0.00			
Category 10: Special Projects	$100,000	Permanent Load Shifting to Demand Response Auction Mechanism Pilot	8/14/2015	The transferred funds support Demand Response Auction Mechanism pilot pursuant to Ordering Paragraph 5 of Decision 14-12-014.
	$200,000	Permanent Load Shifting to Demand Response Auction Mechanism Pilot	12/16/2015	The transferred funds support Demand Response Auction Mechanism pilot pursuant to Ordering Paragraph 5 of Decision 14-12-014.
	$1,700,000	Permanent Load Shifting to Demand Response Auction Mechanism Pilot	1/31/2016	The transferred funds support Demand Response Auction Mechanism pilot pursuant to Ordering Paragraph 5 of Decision 14-12-014.
Total	**$2,000,000**			