Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for December 2009 [Amended Version]

Pacific Gas and Electric Company®

April 21, 2010

Pacific Gas and Electric Company ("PG&E") hereby resubmits this report on Interruptible Load and Demand Response Programs for December 2009. This report is submitted to the Energy Division Director and served electronically on the service list for A.08-06-001 pursuant to Decision 09-08-027.[1] A copy of this report may also be accessed on PG&E's website at the following address: http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/cs/

PG&E along with Southern California Edison Company (SCE) and San Diego Gas and Electric Company (SDG&E) (together, the utilities) have worked with the CPUC's Energy Division to develop updated reporting requirements and a format for the monthly DR portfolio report that better incorporates DR load impact estimates supplied to the CPUC pursuant to Commission Decision 08-04-050. The Energy Division and the utilities recently reached agreement on these requirements and format for these reports going forward. Therefore for purposes of consistency, PG&E is reposting previously submitted monthly reports for December 2009 through February 2010.

[1] D.09-08-027, p. 222.

Table I-1
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Subscription Statistics - Enrolled MW
December 2009 Year-End

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**	**Ex Post Estimated MW**	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Eligible Accounts as of Jan 1, 2010**
Interruptible/Reliability																			
BIP - Day of																			
OBMC																			
Pilot OBMC																			
SLRP																			
SmartAC - Commercial																			
SmartAC - Residential																			
Sub-Total Interruptible	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	
Price Response																			
AMP - Day Ahead																			
AMP - Day Of																			
CBP - Day Ahead																			
CBP - Day Of																			
DBP																			
DWR																			
PDP / CPP																			
PeakChoice - Best Effort - Day Ahead																			
PeakChoice - Best Effort - Day Of																			
PeakChoice - Committed - Day Ahead																			
PeakChoice - Committed - Day Of																			
SmartRate - Commercial																			
SmartRate - Residential																			
Sub-Total Price Response	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	
Total All Programs	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	

	July			August			September			October			November			December			
Programs	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Service Accounts**	**Ex Ante Estimated MW**	**Ex Post Estimated MW**	**Eligible Accounts as of Jan 1, 2010**
Interruptible/Reliability																			
BIP - Day of																188	254.4	294.0	N/A
OBMC																28	0.0	0.0	N/A
Pilot OBMC																5	0.0	0.0	N/A
SLRP																0	0.0	0.0	N/A
SmartAC - Commercial																1,131	0.0	0.8	N/A
SmartAC - Residential																102,784	0.0	19.5	N/A
Sub-Total Interruptible	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	104,136	254.4	314.3	
Price Response																			
AMP - Day Ahead																247	0.0	34.8	N/A
AMP - Day Of																624	0.0	78.0	N/A
CBP - Day Ahead																608	0.0	19.5	N/A
CBP - Day Of																224	0.0	17.9	N/A
DBP																1,143	26.2	54.9	N/A
DWR																12	0.0	0.0	N/A
PDP / CPP																622	0.0	8.1	N/A
PeakChoice - Best Effort - Day Ahead																64	0.0	2.9	N/A
PeakChoice - Best Effort - Day Of																36	0.0	0.9	N/A
PeakChoice - Committed - Day Ahead																46	0.0	0.6	N/A
PeakChoice - Committed - Day Of																38	0.0	4.4	N/A
SmartRate - Commercial																172	0.0	0.1	N/A
SmartRate - Residential																25,386	0.0	7.9	N/A
Sub-Total Price Response	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	29,222	26.2	230.0	
Total All Programs	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	133,358	280.5	544.3	

Notes:

1. Ex Ante Estimated MW = The monthly ex ante average load impact per customer reported in the annual April 1st D. 08-04-050 Compliance Filing 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 2 - 6 pm on the system peak day of the month.

2. Ex Post Estimated MW = The annual ex post average load impact per customer reported in the annual April 1st D.08-04-050 Compliance Filing 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 proceeding year when or if events occurred. New programs report "n/a", as there were no prior events.

3. 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 reflects 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 2 pm and 6pm during a specific DR program's operating season, based on 1-in-2 (normal) weather conditions. In either case, MW estimates in this report will vary from estimates filed in the IOUs' annual April 1st Compliance Filings pursuant to Decision D.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.

Program Eligibility and Average Load Impacts

	Average Ex Ante Load Impact kW / Customer													
Program	January	February	March	April	May	June	July	August	September	October	November	December	Eligible Accounts as of Jan 1, 2010	Eligibility Criteria (Refer to tariff for specifics)
BIP - Day Of												1,353		Bundled, DA and CCA non-residential customer service accounts that have at least an *average monthly* demand of 100 kW
OBMC												0		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 MLLs for the entire duration of each and every RO operation.
Pilot OBMC												0		In addition to the OBMC requirments, POBMC is limited to a maximum total of ten (10) PG&E customers located in Alameda, San Mateo, or Santa Clara counties who can meet the eligibility requirements. Customers are being migrated to OBMC.
SLRP												0		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		SMB customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment
SmartAC - Residential												0		Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment
AMP - Day Ahead												0		Non-residential customers on a C&I, partial standby, or Ag 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												0		Non-residential customers on a 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												0		Non-residential customers on a C&I, partial standby, or Ag rate schedule, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
CBP - Day Of												0		Non-residential customers on a C&I, partial standby, or Ag rate schedule, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
DBP												23		Non-residential Customers > 200 kW on a demand TOU rate schedule. Non-residential Customers' accounts < 200 kW may participate as aggregated group for service accounts with same Federal Taxpayer ID Number.
DWR												0		Bilateral contract for wholesale DR resources supplied by the California Department of Water Resources pumps at multiple locations
PDP / CPP												0		Default beginning May 1, 2010 for bundled C&I Customers > 200kW Maximum Demand; default begins February 1st, 2011 for large bundled Ag customers and default beginning November 1, 2011: bundled C&I Customers with < 200 kW Maximum Demand and 12 months on Interval Meter
PeakChoice - Best Effort - Day Ahead												0		Bundled-Service Customers on a demand time-of-use (TOU) rate schedule, except those who are on net metering, standby, AG-R or AG-V rate schedules. Must be able to reduce at least 10 kW.
PeakChoice - Best Effort - Day Of												0		Bundled-Service Customers on a demand time-of-use (TOU) rate schedule, except those who are on net metering, standby, AG-R or AG-V rate schedules. Must be able to reduce at least 10 kW.
PeakChoice - Committed - Day Ahead												0		Bundled-Service Customers on a demand time-of-use (TOU) rate schedule, except those who are on net metering, standby, AG-R or AG-V rate schedules. Must be able to reduce at least 10 kW.
PeakChoice - Committed - Day Of												0		Bundled-Service Customers on a demand time-of-use (TOU) rate schedule, except those who are on net metering, standby, AG-R or AG-V rate schedules. Must be able to reduce at least 10 kW.
SmartRate - Commercial												0		No longer available to Business Customers beginning January 2010 as Business customers transition to voluntary PDP
SmartRate - Residential												0		A voluntary rate supplement to residential customers' OAS. Available to Bundled-Service customers served on a single family residential electric rate schedule. No longer available to Business Customers beginning January 2010

Estimated Average Ex Ante Load Impact kW/Customer = Average kW / Customer, under 1-in-2 weather conditions, of an event that would occur from 2 - 6 pm on the system peak day of the month, as reported in the load impact reports filed in May 2009.

Program Eligibility and Average Load Impacts

	Average Ex Post Load Impact kW / Customer													
Program	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Eligible Accounts as of Jan 1, 2010**	**Eligibility Criteria (Refer to tariff for specifics)**
BIP - Day Of	1564	1564	1564	1564	1564	1564	1564	1564	1564	1564	1564	1564		Bundled, DA and CCA non-residential customer service accounts that have at least an *average monthly* demand of 100 kW
OBMC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		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 MLLs for the entire duration of each and every RO operation
Pilot OBMC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		In addition to the OBMC requirments, POBMC is limited to a maximum total of ten (10) PG&E customers located in Alameda, San Mateo, or Santa Clara counties who can meet the eligibility requirements. Customers are being migrated to OBMC
SLRP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		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	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71		SMB customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment
SmartAC - Residential	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19		Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment
AMP - Day Ahead	141	141	141	141	141	141	141	141	141	141	141	141		Non-residential customers on a C&I, partial standby, or Ag 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	125	125	125	125	125	125	125	125	125	125	125	125		Non-residential customers on a 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	32	32	32	32	32	32	32	32	32	32	32	32		Non-residential customers on a C&I, partial standby, or Ag rate schedule, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
CBP - Day Of	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00		Non-residential customers on a C&I, partial standby, or Ag rate schedule, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
DBP	48	48	48	48	48	48	48	48	48	48	48	48		Non-residential Customers > 200 kW on a demand TOU rate schedule. Non-residential Customers' accounts < 200 kW may participate as aggregated group for service accounts with same Federal Taxpayer ID Number.
DWR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		Bilateral contract for wholesale DR resources supplied by the California Department of Water Resources pumps at multiple locations
PDP / CPP	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00		Default beginning May 1, 2010 for bundled C&I Customers > 200kW Maximum Demand; default begins February 1st, 2011 for large bundled Ag customers and default beginning November 1, 2011: bundled C&I Customers with < 200 kW Maximum Demand and 12 months on Interval Meter
PeakChoice - Best Effort - Day Ahead	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00		Bundled-Service Customers on a demand time-of-use (TOU) rate schedule, except those who are on net metering, standby, AG-R or AG-V rate schedules. Must be able to reduce at least 10 kW.
PeakChoice - Best Effort - Day Of	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00		Bundled-Service Customers on a demand time-of-use (TOU) rate schedule, except those who are on net metering, standby, AG-R or AG-V rate schedules. Must be able to reduce at least 10 kW.
PeakChoice - Committed - Day Ahead	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00		Bundled-Service Customers on a demand time-of-use (TOU) rate schedule, except those who are on net metering, standby, AG-R or AG-V rate schedules. Must be able to reduce at least 10 kW.
PeakChoice - Committed - Day Of	116.00	116.00	116.00	116.00	116.00	116.00	116.00	116.00	116.00	116.00	116.00	116.00		Bundled-Service Customers on a demand time-of-use (TOU) rate schedule, except those who are on net metering, standby, AG-R or AG-V rate schedules. Must be able to reduce at least 10 kW.
SmartRate - Commercial	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44		No longer available to Business Customers beginning January 2010 as Business customers transition to voluntary PDP
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		A voluntary rate supplement to residential customers' OAS. Available to Bundled-Service customers served on a single family residential electric rate schedule. No longer available to Business Customers beginning January 2010

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 SAID remains constant across all months. For new programs, the average load impact is "n/a", as there were no prior events.

Table I-2
Pacific Gas and Electric Company
Program Subscription Statistics
December 2009 Year-End

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

2009	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
AMP - Day Of				0.0				0.0				0.0				0.0				0.0				0.0
CBP - Day Ahead				0.0				0.0				0.0				0.0				0.0				0.0
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
DWR				0.0				0.0				0.0				0.0				0.0				0.0
PDP / CPP				0.0				0.0				0.0				0.0				0.0				0.0
PeakChoice - Best Effort - Day Ahead				0.0				0.0				0.0				0.0				0.0				0.0
PeakChoice - Best Effort - Day Of				0.0				0.0				0.0				0.0				0.0				0.0
PeakChoice - Committed - Day Ahead				0.0				0.0				0.0				0.0				0.0				0.0
PeakChoice - Committed - Day Of				0.0				0.0				0.0				0.0				0.0				0.0
SmartRate - Commercial				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
Total		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
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
Pilot 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
SmartAC - Residential				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		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		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
General Program																								
TA (may also be enrolled in TI and AutoDR)																								
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A

	July				August				September				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				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	0.0	0.0
CBP - Day Ahead				0.0				0.0				0.0				0.0				0.0		0.0	0.0	0.0
CBP - Day Of				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
DWR				0.0				0.0				0.0				0.0				0.0		0.0	0.0	0.0
PDP / CPP				0.0				0.0				0.0				0.0				0.0		0.0	0.0	0.0
PeakChoice - Best Effort - Day Ahead				0.0				0.0				0.0				0.0				0.0		0.0	0.0	0.0
PeakChoice - Best Effort - Day Of				0.0				0.0				0.0				0.0				0.0		0.0	0.0	0.0
PeakChoice - Committed - Day Ahead				0.0				0.0				0.0				0.0				0.0		0.0	0.0	0.0
PeakChoice - Committed - Day Of				0.0				0.0				0.0				0.0				0.0		0.0	0.0	0.0
SmartRate - Commercial				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
Total		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
Interruptible/Reliability																								
BIP - Day of				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
Pilot OBMC				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
SmartAC - Commercial				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
Total		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		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		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
General Program																								
TA (may also be enrolled in TI and AutoDR)																					1.2			
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	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	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	1.2	N/A	N/A	N/A

Notes:

2009-2011 Portfolio to date results
MW Impacts reported on the TA-TI Distribution worksheet are not calculated using the DR Load Impact Protocols i.e. either ex post or ex ante data. Customer counts reported on this worksheet are included in the Program MW worksheet.

TA Identified MWs	**Represents "Identified MW" from TA Program participants' service accounts from completed TA audits**
AutoDR Verified MWs	**Represents verified i.e.tested MW for service accounts that participate in Auto DR.**
TI Verified MWs	**Represents verified MW for service accounts that participated in Technology Incentives (TI). Customer service accounts must be enrolled in a DR program however not in AutoDR. MW reported in this column are not necessarily the amount enrolled in a DR Program.**
Total Technology MWs	**Represents the sum of verified MWs associated with the service accounts that participated in TI plus Auto DR programs.**
General Program category	**Represents MW of participants in the TA stage i.e."Identified MW".**

Table I-3
Pacific Gas and Electric Company
Demand Response Programs and Activities
Incremental Cost
December 2009 Year-End (1)

Year-to-Date Program Expenditures

Cost Item	2009 Expenditures	2009 Expenditures: January	February	March	April	May	June	July	August	September	October	November	December	Year-to Date 2009 Expenditures	Program-to-Date Total Expenditures 2009	3-Year Funding	Fundshift Adjustments (a)	Percent Funding
Category 1: Emergency Programs																		
Base Interruptible Program (BIP)	N/A												$28,596	$302,314	$302,314	$800,000		37.8%
Optional Bidding Mandatory Curtailment / Scheduled Load Reduction Program (OBMC / SLRP)	N/A												$0	$3,770	$3,770	$138,000		2.7%
Budget Category 1 Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,596	$306,084	$306,084	$938,000		32.6%
Category 2: Price Responsive Programs																		
Capacity Bidding Program (CBP)	N/A												$46,058	$908,567	$908,567	$3,615,076	$1,756,000	25.1%
Critical Peak Pricing (CPP)	N/A												$36,760	$575,169	$575,169	$3,514,000	($1,756,000)	16.4%
Demand Bidding Program (DBP)	N/A												$32,435	$539,591	$539,591	$3,216,000		16.8%
Peak Choice	N/A												$119,833	$713,571	$713,571	$9,000,000		7.9%
Budget Category 2 Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$235,086	$2,736,898	$2,736,898	$19,345,076		14.1%
Category 3: DR Aggregator Managed Programs																		
Aggregator Managed Portfolio (AMP)	N/A												$80,352	$693,357	$693,357	$2,772,000	$2,311,998	25.0%
Business Energy Coalition (BEC)	N/A												$40,366	$929,925	$929,925	$4,623,996	($2,311,998)	20.1%
Budget Category 3 Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$120,718	$1,623,282	$1,623,282	$7,395,996		21.9%
Category 4: DR Enabled Programs																		
Automatic Demand Response (AutoDR)	N/A												$37,181	$1,122,900	$1,122,900	$16,117,000		7.0%
DR Emerging Technology	N/A												$12,208	$198,275	$198,275	$2,421,000		8.2%
Integrated Energy Audits	N/A												$8,025	$202,114	$202,114	$2,942,000		6.9%
Permanent Load Shift (PLS)	N/A												$7,394	$39,700	$39,700	$138,000		28.8%
Technology Incentive (TI)	N/A												$17,640	$218,388	$218,388	$10,310,000		2.1%
Budget Category 4 Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$82,448	$1,781,377	$1,781,377	$31,928,000		5.6%
Category 5: Pilots & SmartConnect Enabled Programs																		
C&I Ancillary Service Pilot (CIAS)	N/A												$71,864	$1,140,761	$1,140,761	$3,494,000		32.6%
C&I Intermittent Resources Pilot (CIIR)	N/A												($6,022)	$0	$0	$1,764,000		0.0%
Plug-in Hybrid Electric Vehicle / Electric Vehicle Pilot (PHEV / EV)	N/A												$0	$0	$0	$1,010,000		0.0%
SF Power Small Load Aggregation Pilot	N/A												$140	$101,277	$101,277	$109,000		92.9%
Smart AC Ancillary Service Pilot	N/A												$310,479	$1,277,103	$1,277,103			
Budget Category 5 Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$376,461	$2,519,141	$2,519,141	$6,377,000		39.5%
Category 6: Statewide Marketing Program																		
Statewide DR Awareness Campaign (SDRAC)	N/A												($128,283)	$144,183	$144,183	$6,405,000		2.3%
Budget Category 6 Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($128,283)	$144,183	$144,183	$6,405,000		2.3%
Category 7: Measurement & Evaluation																		
Evaluation, Measurement, and Verification (EM&V)	N/A												$178,610	$217,467	$217,467	$9,062,000		2.4%
Budget Category 7 Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$178,610	$217,467	$217,467	$9,062,000		2.4%
Category 8: System Support Activities																		
DR On-Line Enrollment (DRE)	N/A												$71,050	$1,971,056	$1,971,056	$6,489,000		30.4%
InterAct / DR Forecasting Tool	N/A												$229,436	$2,660,004	$2,660,004	$10,413,000		25.5%
Budget Category 8 Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$300,486	$4,631,060	$4,631,060	$16,902,000		27.4%
Category 9: Marketing Education & Outreach																		
DR Core Education and Training	N/A												$2,946	$146,387	$146,387	$1,368,000		10.7%
DR Core Marketing and Outreach	N/A												$430,778	$1,628,637	$1,628,637	$9,339,000		17.4%
Budget Category 9 Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$433,724	$1,775,024	$1,775,024	$10,707,000		16.6%
Category 10: Integrated Programs																		
Integrated Education and Training	N/A												$23,962	$50,082	$50,082	$200,000		25.0%
Integrated Marketing and Training	N/A												$11,049	$63,747	$63,747	$1,000,000		6.4%
Integrated Sales Training	N/A												$0	$0	$0	$250,000		0.0%
Integrated Demand Side Management Clearinghouse (IDSM)	N/A												$0	$0	$0	$500,000		0.0%
PEAK	N/A												$40,312	$412,678	$412,678	$1,639,000		25.2%
Budget Category 10 Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$75,323	$526,507	$526,507	$3,589,000		14.7%
Programs Support costs (Std Cost Variance)	N/A												$113,744	$259,012	$259,012	$0		N/A
Meters >200kW INTG	N/A												$0	$846,513	$846,513	$0		N/A
Allocation (Ralph Tobia)	N/A												$25,698	$399,987	$399,987	$0		N/A
Total Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,842,611	$17,766,535	$17,766,535	$112,649,072		15.8%
Technical Assistance & Technology Incentives (TA&TI) commitments ~~as of 9/30/09,~~ as of December 2009.		$69,627																

(a) See "Fund Shift Log" for explanations.
(1) Costs reported here are recorded in SCE's Demand Response Program Balancing Account (DRPBA), unless otherwise noted. **This does not apply to PG&E**.
(2) Funding and expenses for DR Contracts reflect the administrative portion of costs tracked in the Purchase Agreement Administrative Costs Balancing Account (PAACBA). Incentive payments are recorded separately in Table I-5.
(3) 2009 Funding authorized in D09-08-027 and D.08-03-017.
(4) TA&TI expenses include Auto DR incentives

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
December 2009 Year-End
Event Summary

Year-to-Date Event Summary

Program Category	Event No.	Date	Event Trigger	Load Reduction kW	Event Beginning:End	Program Tolled Hours (Annual)
Category 1: Emergency Programs						
Base Interruptible Program (BIP)	1	08/28/09	Day-Of (Test)	173.2	HE 15 to HE 16	2
SmartAC	1	09/10/09	N/A (Test)	126.4	HE 15 to HE 18	4
SmartRate						
Commercial	1	06/29/09	Day-Ahead	0.11	HE 15 to HE 18	4
	2	06/30/09	Day-Ahead	0.08	HE 15 to HE 18	8
	3	07/13/09	Day-Ahead	0.05	HE 15 to HE 18	12
	4	07/14/09	Day-Ahead	0.04	HE 15 to HE 18	16
	5	07/16/09	Day-Ahead	0.03	HE 15 to HE 18	20
	6	07/21/09	Day-Ahead	0.05	HE 15 to HE 18	24
	7	07/27/09	Day-Ahead	0.06	HE 15 to HE 18	28
	8	08/10/09	Day-Ahead	0.04	HE 15 to HE 18	32
	9	08/11/09	Day-Ahead	0.01	HE 15 to HE 18	36
	10	08/18/09	Day-Ahead	0.06	HE 15 to HE 18	40
	11	08/27/09	Day-Ahead	0.02	HE 15 to HE 18	44
	12	08/28/09	Day-Ahead	0.06	HE 15 to HE 18	48
	13	09/02/09	Day-Ahead	0.06	HE 15 to HE 18	52
	14	09/10/09	Day-Ahead	0.00	HE 15 to HE 18	56
	15	09/11/09	Day-Ahead	0.06	HE 15 to HE 18	60
Residential	1	06/29/09	Day-Ahead	4.1	HE 15 to HE 19	5
	2	06/30/09	Day-Ahead	4.8	HE 15 to HE 19	10
	3	07/13/09	Day-Ahead	3.0	HE 15 to HE 19	15
	4	07/14/09	Day-Ahead	2.6	HE 15 to HE 19	20
	5	07/16/09	Day-Ahead	5.0	HE 15 to HE 19	25
	6	07/21/09	Day-Ahead	3.4	HE 15 to HE 19	30
	7	07/27/09	Day-Ahead	2.7	HE 15 to HE 19	35
	8	08/10/09	Day-Ahead	3.9	HE 15 to HE 19	40
	9	08/11/09	Day-Ahead	5.3	HE 15 to HE 19	45
	10	08/18/09	Day-Ahead	3.4	HE 15 to HE 19	50
	11	08/27/09	Day-Ahead	2.9	HE 15 to HE 19	55
	12	08/28/09	Day-Ahead	6.6	HE 15 to HE 19	60
	13	09/02/09	Day-Ahead	6.1	HE 15 to HE 19	65
	14	09/10/09	Day-Ahead	4.4	HE 15 to HE 19	70
	15	09/11/09	Day-Ahead	8.1	HE 15 to HE 19	75
Category 2: Price Responsive Programs						
Capacity Bidding Program (CBP)	1	07/27/09	Day-Ahead (Test)	24.7	HE 14 to HE 15	2
Capacity Bidding Program (CBP)	1	07/27/09	Day-Of (Test)	29.4	HE 16 to HE 18	5
Critical Peak Pricing (CPP)	1	06/29/09	Day-Ahead	14.8	HE 13 to HE 18	6
Critical Peak Pricing (CPP)	2	06/30/09	Day-Ahead	10.3	HE 13 to HE 18	12
Critical Peak Pricing (CPP)	3	07/13/09	Day-Ahead	2.5	HE 13 to HE 18	18
Critical Peak Pricing (CPP)	4	07/14/09	Day-Ahead	8.5	HE 13 to HE 18	24
Critical Peak Pricing (CPP)	5	07/16/09	Day-Ahead	9.1	HE 13 to HE 18	30
Critical Peak Pricing (CPP)	6	07/21/09	Day-Ahead	9.6	HE 13 to HE 18	36
Critical Peak Pricing (CPP)	7	07/27/09	Day-Ahead	2.2	HE 13 to HE 18	42
Critical Peak Pricing (CPP)	8	08/10/09	Day-Ahead	12.4	HE 13 to HE 18	48
Critical Peak Pricing (CPP)	9	08/11/09	Day-Ahead	15.2	HE 13 to HE 18	54
Critical Peak Pricing (CPP)	10	08/18/09	Day-Ahead	13.1	HE 13 to HE 18	60
Critical Peak Pricing (CPP)	11	08/27/09	Day-Ahead	12.3	HE 13 to HE 18	66
Critical Peak Pricing (CPP)	12	08/28/09	Day-Ahead	23.1	HE 13 to HE 18	72
Demand Bidding Program (DBP)	1	08/28/09	Day-Ahead (Test)	104.4	HE 15 to HE 18	4
Peak Choice	1	09/23/09	Day-Ahead (Test)	6.8	HE 14 to HE 17	4
Peak Choice	1	09/23/09	Day-Of (Test)	7.7	HE 14 to HE 17	4
Category 3: DR Aggregator Managed Programs						
Aggregator Managed Portfolio (AMP)	1	07/16/09	Day-Ahead (Test)	29.2	HE 16 to HE 17	2
Aggregator Managed Portfolio (AMP)	1	07/16/09	Day-Of (Test)	80.9	HE 16 to HE 17	2
Aggregator Managed Portfolio (AMP)	2	07/27/09	Day-Of (Test)	1.4	HE 16 to HE 17	4
Aggregator Managed Portfolio (AMP)	3	08/28/09	Day-Ahead (Test)	40.5	HE 16 to HE 17	6
Aggregator Managed Portfolio (AMP)	3	08/28/09	Day-Of (Test)	86.8	HE 16 to HE 17	6

Direction for Load Reduction	**With the exception of AMP which uses a contractual 3 in 10 caluclated baseline, all DR programs use a calculated 10 in 10 baseline with an optional day of adjustment.**
Methodology used to calculate 2009 Event Load Reduction	**Methodology used is the Hot Day Proxy, in which the Hot Day is the day that had the highest load during the event window within the past ten (10) like days.**

Table I-5
Pacific Gas and Electric Company
Demand Response Programs
Total Embedded Cost and Revenues [1]
December 2009 Year-End

Annual Total Cost													
Cost Item	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Year-to-Date Total Cost**
Program Incentives [2]													
Automatic Demand Response (AutoDR)												$0	$0
Base Interruptible Program (BIP)[1]												$1,485,266	$18,804,562
Business Energy Coalition (BEC)												$0	$631,850
C&I Ancilliary Services Pilot (CIAS)												$0	$30,539
Capacity Bidding Program (CBP)												$63,645	$2,777,075
Demand Bidding Program (DBP)												$53,819	$99,774
Optional Bidding Mandatory Curtailment / Scheduled Load Reduction Program (OBMC / SLRP)[1,4]												$0	$0
Peak Choice												$0	$272,810
Smart AC Ancillary Service Pilot												$0	$31,615
Total Cost of Incentives	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,602,730	$22,648,225
Revenues from Penalties [3]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

(1) Amounts reported are for incentives costs that are not recovered in the Demand Response Program Balancing Account.
(2) Incentive data is preliminary and subject to change based on billing records.
(3) Penalties assessed BIP participants for failure to reduce load when requested during curtailment events.
(4) OBMC customers can be charged a penalty; there are no incentives paid.

Table I-6
Pacific Gas and Electric Company
Interruptible, Curtailment and Demand Response
ACEBA Account Balance Year-to-Date
December 2009 Year-End

Operations and Maintenance Expense	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-Date Cost
Smart AC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$673,791	$18,536,334

Program Incentives	January	February	March	April	May	June	July	August	September	October	November	December	Total Incentives
Smart AC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$103,170	$967,015
Total Cost of Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$776,961	$19,503,349

FUND SHIFTING DOCUMENTATION PER DECISION 09-08-027 ORDERING PARAGRAPH 35

OP 35: **The utilities may shift up to 50% of a program funds to another program's funds to another program within the same budget category.**
The utilities shall document the amount of and reason for each shift in their monthly demand response reports.

Program Category	Fund Shift	Programs Impacted	Date	Rationale for Fundshift
Category 2	$1,756,000	Critical Peak Pricing (CPP) to Capacity Bidding Program (CBP)	10/21/2009	The decision allowed PG&E $1,807,538 to administer CBP for three years. PG&E incurred $818,973 in administrative expenses in 2008, the only year in which CBP was fully operational. These amounts include PG&E's internal costs and third-party scheduling coordinator services.
Total	**$1,756,000**			
Category 3	$2,311,998	Business Energy Coalition (BEC) to Aggregator Managed Portfolio Program (AMP)	12/9/2009	The decision approved a BEC budget of $4,623,996. Pursuant to Ordering Paragraph 7, the BEC Program is terminated as of November 18, 2009. The transferred funds will pay for AMP program costs, as needed. The amount transferred is 50% of the total BEC program budget, as authorized by the decision.
Total	**$2,311,998**			

Notes: Provide concise rationale for the fund shift in column "Rationale for Fund Shift"