**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resources Planning Needs and Operational Requirements.	Rulemaking 13-09-011 (Filed September 19, 2013)

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39E) ON THE PROPOSED DECISION APPROVING DEMAND RESPONSE PROGRAM IMPROVEMENTS AND 2015-2016 BRIDGE FUNDING BUDGET

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TABLE OF CONTENTS

Page

TABLE OF AUTHORITIES

Page(s)

CALIFORNIA PUBLIC UTILITIES COMMISSION DECISIONS AND ORDERS

CPUC RULES OF PRACTICE AND PROCEDURE

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Pacific Gas and Electric Company (PG&E) comments on the proposed decision of Administrative Law Judge (ALJ) Hymes dated April 15, 2014 pursuant to Rule 14.3 of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure.

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

PG&E thanks ALJ Hymes for her efforts in distilling the parties' proposals into a timely Proposed Decision (PD) which would approve a budget for PG&E's 2015-2016 demand response (DR) portfolio. The PD takes positive steps towards retaining the investor-owned utilities' (IOUs') DR programs in 2015-2016 and supports the statewide effort to utilize DR as a preferred resource as set forth in the key actions in the Energy Action Plan II. The PD provides most of PG&E's requested budget and approves some of PG&E's program changes that will improve the performance of existing programs during the bridge years.

The PD reaches the correct conclusions on most issues and PG&E supports it. However, PG&E requests the PD to be revised to address the following requests:

II. SUMMARY OF PG&E'S RECOMMENDATIONS

A. *Transmission and Distribution Deferral Pilot*: PG&E's Transmission and Distribution (T&D) Deferral Pilot should continue in 2015-2016 to allow PG&E to test using demand-side management programs to improve local grid reliability and defer T&D upgrades.

The pilot would also address how demand-side management programs can be included in long-term planning.

B. *Demand Bidding Program (DBP) Improvements*: PG&E's proposed changes to the DBP Rate Schedule should be approved as they would improve PG&E's ability to use the program and provide additional flexibility for customers who elect to participate in program events.

C. *Clarification of Reporting Requirements*: PG&E supports reporting requirements that would provide greater transparency regarding its dispatch and bidding of DR programs. PG&E requests changes in the schedules for the new reporting requirements to allow sufficient time to develop the format for these reports.

D. *Permanent Load Shifting*: The PD appropriately rejects the proposals of the California Energy Storage Alliance (CESA) to increase statewide permanent load shifting (PLS) incentives and to approve a multi-year program budget that exceeds the bridge period.

E. *PG&E's Supply-Side Pilot*: PG&E appreciates that the PD would approve this pilot. PG&E requests a revision to an ordering paragraph that appears to reject the pilot.

These recommendations are discussed in detail below. PG&E's proposed changes to the findings of fact, conclusions of law, and ordering paragraphs as required by Rule 14.3 (b) and (c), are included in Attachment A.

III. DISCUSSION

A. PG&E's Transmission and Distribution Deferral Pilot Should Continue in 2015-2016.

The PD would deny PG&E's request to continue its current T&D pilot as insufficiently supported. (PD, p. 29.) PG&E respectfully requests the PD to be revised to allow it to continue this valuable pilot in 2015-2016, given the Commission's desire to use DR to increase grid reliability, and authorize $1,622,500 to support the T&D pilot. The Rulemaking highlights the importance of evaluating using DR to increase local reliability. One of the issues included in the scope of the proceeding is:

> 4. What mechanisms shall the Commission develop such that local and system reliability needs forecasted by resource planners drive the development and procurement of demand response programs? [1/]

The T&D pilot, if authorized, would provide concrete data to determine whether and to what extent PG&E's demand-side management programs can be used to target specific areas flagged by system planners to defer T&D upgrades. The pilot would also demonstrate the efficacy of integrating demand-side management programs in system planning.

PG&E proposed to continue the pilot in its March 3, 2014 Demand Response Program Proposals for 2015 and 2016 (PG&E Proposal), and attached a detailed five-page pilot proposal to its filing. (PG&E Proposal, Attachment D.) The PD includes a cursory denial of the pilot, as unreasonable and insufficiently explained. (PD, p. 29.) The PD does not explain or discuss the details in PG&E's Proposal and in Attachment D or state why PG&E's request is unreasonable. PG&E also provided the Commission information about this pilot, and how it could be supplemented and improved with other demand-side management programs' participation, in the Energy Efficiency Rulemaking, R.13-11-005. PG&E requests this Commission to consider the information provided in the Energy Efficiency Rulemaking in this proceeding.[2/]

PG&E will complete Phase One of the approved T&D pilot this month. The T&D pilot, as originally proposed in PG&E's 2012-2014 application, was planned to be conducted in two phases throughout 2012 to 2014. The DR portfolio decision, which was delayed until April 2012, required PG&E to file an advice letter for its proposed pilots with detailed pilot plans. (D.12-04-045, OP 80.) PG&E filed Advice Letter 4077-E on June 29, 2012, but the Advice

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1/ *Order Instituting Rulemaking To Enhance The Role Of Demand Response In Meeting The State's Resource Planning Needs And Operational Requirements,* R.13-09-011 (Sept. 25, 2013), p. 18 (OIR). The OIR also recognizes that DR "has potential value . . . as an alternative to transmission upgrades" and indicates a need to determine how to correctly match DR resources with the needs of the grid. (OIR, pp. 8-9.)

2/ *Pacific Gas and Electric Company's (U 39-M) Energy Efficiency 2015 Funding Proposal,* R.13-11-005 (Mar. 26, 2014), pp. 23-24; Attachment 3, pp. 46-47. PG&E's filing is available at the following link: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M089/K641/89641253.PDF

Letter was required to be refiled. It was then approved April 2, 2013.[3/] Due to these regulatory processes, PG&E was not authorized to start the pilot until 15 months after the three-year portfolio period began. Because of the delay in obtaining approval of its pilot plan, PG&E has only had sufficient time to complete the first phase of its pilot, rather than both phases. PG&E requests additional time to conduct Phase Two of the pilot, which it has recently proposed to expand to incorporate other demand-side management programs.

PG&E's objectives with respect to T&D planning integration which would be tested during this pilot include: (1) developing the experience and tools needed to create and utilize customer- and location-specific integrated demand side management (IDSM) resources to assist with distribution capacity constraints; and (2) integrating PG&E's Customer Energy Solutions (CES) planning and operations activities with T&D planning and operations activities to increase the probability of asset deferral and capture additional value from energy efficiency (EE) and DR program funds.

PG&E identified four substation capacity projects to target load reductions in 2014 and 2015. PG&E will evaluate additional substations for potential inclusion in the T&D locational targeting effort on an ongoing basis. The substation capacity projects were selected based on the following criteria: (1) the substations' projected capacity overload was less than 2 MW; (2) the substation capacity expansion projects were not scheduled to begin construction until 2016, allowing two-years lead time to develop the IDSM projects to mitigate the projected overloading condition; (3) the substations identified have a reasonable probability of achieving the targeted load reductions during 2014-2015 based on an analysis of connected customer's loads; and (4) the substations represent a diverse population of customers including large commercial and industrial, small and medium business and residential; the residential areas selected also include areas with hard-to-reach segments including low income and non-English speaking customers.

3/ Advice Letter 4077-E A dated December 21, 2102 superseded Advice Letter 4077-E and is available at the following link: http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4077-E-A.pdf

In 2013, PG&E completed a series of foundational activities for the first phase of the pilot including: (1) identifying initial candidate substations; (2) streamlining the process of deploying localized DR; and (3) adding new targeted capabilities to marketing efforts. For example, using analytical tools, the marketing team can now analyze customers served by a specific feeder or substation and find those with energy usage patterns suggesting the best opportunity for EE savings. Using this information and data regarding the customers' industry group, PG&E can identify the partners and channels best positioned to target these customers, and prioritize relevant products and technologies in marketing campaigns.

In 2014, PG&E is taking the following actions to improve T&D integration: (1) increasing marketing and outreach for SmartAC™ by targeting customers with energy usage profiles showing significant air conditioning usage; (2) focusing energy savings assistance (ESA) and EE programs for customers connected to the targeted substations; (3) increasing localized marketing outreach to increase the participation of residential customers in EE programs by targeting the highest energy users; (4) increasing incentives in the targeted areas for peak load reductions; and (5) focusing engineering support to develop IDSM (EE, DR, distributed generation, and energy storage) solutions for the largest customers on each of the targeted substations.

The Commission has a sufficient record regarding this pilot and the activities that PG&E would conduct during the second phase in PG&E's Advice Letter 4077-E, as amended by supplemental Advice Letter 4077 E-A, as well as the information provided with PG&E's Proposal (Attachment D). In addition, the Commission has a record of how this pilot would be supplemented and improved with other demand-side management programs as part of PG&E's companion proposal for a T&D pilot in the Energy Efficiency Rulemaking. PG&E respectfully requests the PD to be amended to allow PG&E to complete this pilot as it should provide valuable information to PG&E's demand-side management and T&D planners regarding whether and how distribution system investments can be deployed to defer or reduce planned T&D

investments.[4/] The PD should be revised to approve PG&E's budget request for the pilot or, in the alternative, allow PG&E to conduct Phase II of the pilot with the budget previously approved and collected in 2012-2014 rates.

B. PG&E's Proposed Changes to the E-DBP Rate Schedule Should Be Approved.

Two of PG&E's proposed revisions to the DBP - to dispatch a DBP event at its discretion and to expand the dispatch window from 6 a.m.-10 p.m. - were denied and should be reconsidered. (PD, p. 26.)

PG&E's Proposal included revisions to its DBP event triggers. The PD disapproved two of PG&E's proposed changes to DBP which would: (1) add language that would allow PG&E to dispatch the program at its discretion; and (2) expand the event window to 6 a.m.-10 p.m.[5/] The PD proposes to reject the first program improvement on the grounds that it is "*outside of the four criteria currently approved*" for program revisions. (PD, p. 27.) It also rejects the second proposed change due a lack of evidence that benefits would outweigh the burden to participants. (*Id.*) The proposed changes, however, would improve the program for participants and create more value for both customers and ratepayers, and should be approved.

1. PG&E Should Be Authorized to Dispatch a DBP Event at its Discretion.

Due to the voluntary nature of DBP, DBP events do not burden participants. A customer who is unable or unwilling to participate does not need to take any action. Customers voluntarily choose to enroll in the program and then choose whether to participate in any DBP event.[6/]

4/ The CAISO has repeatedly called for the utilities to develop better evidence to demonstrate that their DR programs are incorporated in their planning to avoid building new T&D facilities. See e.g., D.09-08-027, p. 25. This pilot would help support such a showing and would be useful as an input to the cost-effectiveness analysis. If the utilities can show a T&D benefit through avoided T&D costs, this would improve program cost-effectiveness results.

5/ PG&E Proposal, pp. 3-4.

6/ The rate schedule states that "The selected SAs **may** elect to submit bids to the Program's website between 12:00 noon and 3:00 p.m. the day the E-DBP event notice was issued." (Emphasis added.) http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-DBP.pdf, Sheet 4, first par.

Customers choose to participate by placing a bid; there is no penalty for not placing a bid or not participating.

Southern California Edison Company (SCE)'s DBP rate schedule allows it to call a DBP event "[a]t [its] discretion when needed," and contains exemplary factors that may be considered when SCE makes a decision whether to dispatch an event.[7/] The addition of this "soft trigger" to DBP was approved by the Commission in 2006.[8/] Since DBP is a statewide program, PG&E should have the same ability to trigger DBP events as the Commission authorized for SCE.

The discretionary event trigger would benefit customers because it would give them increased opportunities to earn incentives if they choose to participate in a DBP event. Different customers have different time-varying capabilities to shed load. Since customer decisions about participating (or not) occurs for each individual event, whenever PG&E dispatches DBP, it provides opportunities for customers to participate but does not force any customer to participate. The additional discretion to call would increase grid reliability as it would allow PG&E to address an immediate need, particularly during the winter months when some of PG&E's DR programs are unavailable.

The PD would reject this change, in part, because it is outside of the approved criteria for this phase of the proceeding in the *Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for Submitting Demand Response Program Proposals*, dated January 31, 2014 (Guidance Ruling). (PD, p. 27.) However, this is inaccurate because, as noted above, PG&E's proposed improvements to DBP would "improve program performance or increase the availability or flexibility of a demand response program" and would not require a budget

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7/ SCE's DBP rate schedule provides: "A Day-Ahead DBP Event, may be called at SCE's discretion, when it is needed based on CAISO emergencies, day-ahead load and/or price forecasts, extreme or unusual temperature conditions impacting system demand and/or SCE's procurement needs" https://www.sce.com/NR/sc3/tm2/pdf/ce185.pdf, Sheet 2, Special Conditions, Item No. 2.

8/ D.06-11-049, pp. 36-37.

increase. (Guidance Ruling, pp. 2-3; PD, p. 3.) PG&E's proposed DBP improvements are consistent with the Guidance Ruling criteria and should be approved.

2. PG&E Should Be Authorized to Expand the DBP Dispatch Window to 6:00 a.m.–10:00 p.m.

An extension of the DBP dispatch window increases DR participation opportunities but does not increase the total hours a customer is required to participate in an event since, as discussed above, participation is voluntary. Accordingly, the PD errs in concluding that this proposed change would burden customers. (PD, p. 27.) The proposal to expand the hours an event may be called would "increase the availability and/or flexibility" of the program, as specified in the Guidance Ruling (p. 2).

The existing dispatch window is from noon to 8:00 p.m. Extending this window to allow PG&E to dispatch an event during the hours of 6 a.m. to 10 p.m. expands the hours a customer would have the option to bid in and participate. It would not extend the dispatch duration, which remains a minimum of two (2) consecutive hours and a maximum of eight (8) hours. This modification would increase the flexibility of DBP by providing customers more options to voluntarily participate. Since customers' peak loads may not coincide with the evening system peak, this expansion could provide more opportunities for customers to participate and also help PG&E manage loads during the morning peak. There is no financial penalty for non-performance or under performance; this change would not disadvantage participating customers.[9/] The expanded hours will also increase the value of DBP since it can be used to address issues that may arise in these expanded hours.

The PD's suggestion that customers would be burdened by an expansion of the dispatch window is incorrect. (PD, p. 27.) DBP customers would benefit from being offered a wider event window in which they could opt to participate and receive incentives.

9/ http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-DBP.pdf, Sheet 9, second par.

C. New Reporting Requirements

The PD contains two new reporting requirements for the IOUs: (1) a weekly report to Energy Division and the Office of Ratepayer Advocates (ORA) if the utility does not call a DR program when it is economic to do so (PD, pp. 15-16, OPs 1, 2); and (2) a reporting template and timeline for feedback on the IOUs' experience with bidding into the California Independent System Operator (CAISO) markets during 2015-2016. (PD, pp. 20-21, OP 3.)

1. Weekly Report regarding Program Non-Events

The PD would require the IOUs, as suggested by ORA, to indicate on a weekly report "occurrence[s] when a demand response program was economic to dispatch but the utility decided to utilize a non-demand response resource instead." (PD, p. 15.) PG&E supports reporting requirements to the extent they are reasonable and would provide greater transparency regarding its dispatch of its DR programs. However, PG&E is concerned about the scope of the proposed reporting requirement and the short 30-day time frame that the PD would allow for negotiating the reporting format. (PD, p. 16.) As PG&E noted in its *Reply Comments on Assigned Commissioner and Administrative Law Judge's Ruling*, dated March 13, 2014 (PG&E Reply Comments), ORA's proposal is very broad and certain of the information that ORA proposes is either not available or may not be available for reporting within the timeframe proposed. (PG&E Reply Comments, p. 10; PD, p. 15-16.) In addition, while ORA is requesting the "highest cost resources [] dispatched" instead of DR, the IOUs do not have this information as "the dispatch of generation resources is a result of the CAISO market optimization algorithm." (PG&E Reply Comments, p. 10.)

Multi-party agreements, as required by the PD, tend to require more time for coordination and collaboration with external stakeholders. Developing the report format requested may be very complicated. Thus it is very likely that more than thirty days will be required to reach agreement on the new reporting requirement. The 30-day deadline to reach agreement on the report is also problematic given the regulatory schedule for the DR OIR Phase III. The PD should be revised to include a more realistic timeframe.

Therefore, PG&E requests that the negotiation period for the new reporting requirement be extended from **30** days to **90** days, which would provide sufficient time for the parties to reach agreement. The advice letter would then be filed within 30 days after the end of the negotiation period. Specific language to incorporate this request is included in Attachment A.

2. Report regarding Bidding into the CAISO Market.

The PD requires the IOUs to meet with Commission staff "to discuss and develop a reporting template and timeline to provide feedback on its experience with bidding into the CAISO energy markets." (PD, pp. 20-21; OP 3.) Currently, only a few DR customers are bidding in the CAISO market. The IOUs will need additional experience with customers bidding into the markets in order to develop the required templates and timelines. PG&E proposes that the development of this template be deferred until after the conclusion of the summer 2014 event season, when there will be additional data available on bidding into the market. This information would better inform the reporting requirements. Therefore PG&E requests that the deadline to meet regarding the draft template be moved from 30 days after the decision to November 30, 2014 — a date which is 30 days after the close of the event season for many DR programs. Proposed language for this change is included in Appendix A, below. This delay would allow a better reporting template to be prepared and ultimately would lead to better information for the Commission.

D. Permanent Load Shifting Program

The PD appropriately rejects the unsupported proposals of the CESA to increase statewide PLS incentives, lock in an increased budget through 2020, and modify the conversion factors. (PD, pp. 7-8.) As the PD notes, the CESA proposals were not supported by adequate analytics and disregarded the previous Guidance Ruling, which provided specific rules for 2015-2016 funding.

E. Marin Clean Energy's Participation In DR Programs.

As noted in the PD, Marin Clean Energy (MCE), as a community choice aggregator (CCA), proposed to participate in the IRM2 Enhancement pilot that was proposed by Energy Division. (PD, pp. 22-23.) The PD states "barriers make it difficult" for MCE to participate in the Northern California IRM2 Enhancement pilot. (PD, p. 23; FOF 37.) The Northern California IRM2 Enhancement pilot was not approved in PD.

On the broader issue of whether MCE and its CCA customers can participate in DR programs, the PD mentions MCE's unsupported allegations that the DR programs rules are "biased," "anti-competitive," and "[do] not facilitate CCA participation." (PD, p. 22.) PG&E addressed these allegations in its Reply Comments dated March 13, 2014, which explained that MCE's assertions that structural constraints hinder CCA customer participation are without merit. (PG&E Reply Comments, p. 11.)

CCA customers are eligible to participate in most PG&E DR programs. If MCE is interested in participating as an aggregator, MCE could choose to aggregate non-residential customer load in any of PG&E's aggregated DR programs, including the Capacity Bidding Program, the Aggregator Managed Portfolio Program (when open to new aggregators) and the Base Interruptible Program (BIP), which are for non-residential customers. PG&E encourages MCE to participate as an aggregator in one of these existing programs if it is interested in aggregating its non-residential customers' load in a DR program.

F. PG&E's Supply-Side Pilot

PG&E's proposed Supply-Side Pilot was approved in the PD. (PD, pp. 23, 26-27; OP 5(e).) However, the pilot is inadvertently listed as disapproved in OP 6(e). PG&E believes this to be an error as it is inconsistent with the PD, and requests OP 6(e) to be corrected, as indicated in Attachment A below.

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IV. CONCLUSION

PG&E respectfully requests ALJ Hymes to modify the PD as discussed herein and in Attachment A (Proposed Revisions to Findings of Fact and Conclusions of Law).

Respectfully Submitted,

By: */s/ Mary A. Gandesbery*
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Dated: May 5, 2014

ATTACHMENT A

Attachment A: Proposed Revisions To Findings of Fact and Conclusions of Law[10]

Proposed modifications to Findings of Fact:

~~39. The request by PG&E to dispatch a DBP event at its discretion is more than a clarification, as claimed by PG&E, because allowing PG&E to call an event at its own discretion is outside of the four criteria currently approved.~~ **<u>PG&E's proposed changes to its DBP to call a program event as needed at its discretion and to expand the hours a program event can occur would provide further opportunities for customers voluntarily to participate in a demand response program and should be approved</u>. <u>Since customers are not required to submit a bid, these program revisions would add flexibility to the program without burdening customers</u>**.

~~40. The request by PG&E to expand the DBP dispatch window could place an unfair burden on participants.~~

~~41. PG&E did not present evidence that the benefits of expanding the DBP dispatch window would counterbalance the participant burden.~~

47. ~~The information provided by PG&E did not adequately explain how its T&D Pilot differs from the first pilot~~.

48. PG&E ~~did not~~ adequately ~~justify~~ **<u>adequately justified</u>** the need to continue the T&D pilot for two additional years.

Proposed Revisions to Conclusions of Law

14. It is ~~not~~ reasonable for PG&E to be allowed to call a DBP event at its own discretion.

15. It is reasonable to ~~deny~~ **<u>approve</u>** the PG&E request to expand the DBP dispatch window.

Proposed Revisions to Ordering Paragraphs

2. Within ~~30~~ **<u>90</u>** days from the issuance of this decision Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company (jointly, the Utilities) shall organize and meet with the appropriate Commission Staff, the Office of Ratepayer Advocates, and any other interested stakeholders to develop an agreed-upon reporting template for providing weekly exception reporting, using the draft reporting template in Attachment A as a starting point. All stakeholders should take into consideration other utility reporting requirements to ensure no unnecessary duplication.

[10] Pursuant to Rule 14.3 (b), this appendix does not count toward the page limit for opening comments.

Within 30 days following the initial meeting, the Utilities shall file a Tier Two Advice Letter requesting approval by the Commission of the final reporting template.

3. ~~Within 30 days of the issuance of this decision,~~ **Once sufficient data is available on bidding DR programs into the CAISO market, but no later than November 30, 2014**, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) shall meet with the appropriate Commission Staff to discuss and develop a reporting template and timeline to provide feedback on the utilities' experience with bidding into the CAISO energy markets during the 2015-2016 demand response program cycle. Within ~~30~~ 60 days of this initial meeting, PG&E, SDG&E and SCE shall each file a finalized reporting template and timeline for approval via a Tier One Advice Letter.

4. We authorize a budget of $2.45 million for Pacific Gas and Electric Company to **conduct** the Supply Side pilot.

5. We approve the following requests by Pacific Gas and Electric Company for its 2014-2015 Demand Response Programs and Activities:

a. the continued operation of all 2012-2014 demand response programs during the 2015-2016 bridge years, except as otherwise denied in this decision;

b. the improvements to its Base Interruptible Program, the Demand Bidding Program, and the Auto Demand Response program~~, except as otherwise denied in this decision~~;

c. the revisions to the Capacity Bidding Program approved in Advice Letter 4332-E;

d. the revisions to the Aggregated Managed Portfolio program agreements approved in D.14-02-033; and

e. the implementation of its proposed Supply Side and Excess Supply Pilots.

f. **the continuation of the transmission and distribution pilot originally approved in D.12-04-045**.

6. The following requested changes to Pacific Gas and Electric Company (PG&E) 2015-2016 Demand Response Programs are denied:

~~a. to specifically state that PG&E can dispatch a Demand Bidding Program (DBP) event at its discretion;~~

~~b. to expand the DBP dispatch window to be 6:00 am to 10:00 p.m.~~;

c. all changes to the Air Conditioning Cycling program;

d. to carry over the **unspent and uncommitted portion of the** 2012-2014 Permanent Load Shifting budget;[11/]

e. ~~to extend the Transmission & Distribution Pilot and to perform a Supply Side Demand Response Pilot~~; and

f. the request by the Office of Ratepayer Advocates to target the marketing of the SmartRate program.

8. We authorize a budget of $~~99,050,633~~ **100,673,133.00** for Pacific Gas and Electric Company for its 2015-2016 demand response programs to be allocated in the previously approved demand response categories as indicated in Attachment 2.

11/ The Commission's rules as articulated in EE proceedings allow the IOUs to carry-over funds committed to customer projects from one portfolio cycle to the next to allow customers to complete projects started in once cycle but completed in the next. See e.g., D.12-11-015, pp. 94-95. Thus this Ordering Paragraph requirement should be limited to unspent and uncommitted funds.