PREPARED DIRECT TESTIMONY OF MARCEL HAWIGER

CALIFORNIA PUBLIC UTILITIES COMMISSION

DEMAND RESPONSE RULEMAKING 13-09-011

on behalf of

THE UTILITY REFORM NETWORK

785 Market Street, Suite 1400
San Francisco, CA 94103
Telephone: (415) 929-8876

Email: marcel@turn.org

May 6, 2014

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

PREPARED DIRECT TESTIMONY OF MARCEL HAWIGER

I. INTRODUCTION

I am sponsoring this policy testimony concerning certain of the Phase Three issues identified in the Joint Assigned Commissioner and Administrative Law Judge Ruling of April 2, 2014 ("Joint Ruling"). I have been a staff attorney with the Utility Reform Network ("TURN") since 1998, and have worked on several proceedings related to demand response issues, starting with Rulemaking 02-06-001. My qualifications are included in Attachment 1.

The companion testimony of Kevin Woodruff on behalf of TURN provides more detailed analyses and recommendations concerning the proposed Demand Response Auction Mechanism ("DRAM").

The Joint Ruling asked parties to address "the issues in general" and also to address the specific questions posed in the Testimony Guidance Document. This policy testimony primarily addresses certain high level policy issues, especially as they relate to setting procurement goals, evaluating program characteristics and evaluating the benefits of the proposed Demand Response Auction Mechanism ("DRAM").

While some of the text in this policy testimony might normally be more appropriate for written comments, I submit this sworn testimony partly due to the compressed schedule for addressing certain Phase Two and Three issues.

This policy testimony provides the following analyses and recommendations:

- I provide summary data on existing program enrollment, costs and characteristics as background to explain TURN's support for the proposed DRAM.
- The 5% demand response goal should be an aspirational target, but should not trump the proposed DRAM cost cap or cost effectiveness benchmarks. Procurement goals should generally be more closely associated with market potential and/or system needs.
- The Commission should set a transition schedule so that all Supply Resources participate in the DRAM by January 1, 2019.
- The Commission should require a review of DRAM performance in 2016 and 2017 to determine whether any modifications are needed prior to full participation in 2018 and 2019.

II. Summary of Existing Demand Response Program Characteristics and Costs

In order to discuss program characteristics, the need for goals and the design of the proposed Demand Response Auction Mechanism ("DRAM"), I first provide some summary information concerning the characteristics and costs of existing demand response programs.

A. Amounts of Existing Demand Response Program by IOU and Type

The utility monthly load impact reports provide extensive data on existing programs. The reports provide information on enrollment amounts (both *ex ante* and *ex post*), recorded incentive and administrative costs, as well as data on the performance of different programs during event days. Existing enrollment and cost data are useful as a starting point to consider the impacts of changes to program design and procurement strategies.

While the specifics of program designs may differ between the utilities, on a broad level the utilities all operate or contract for very similar event-based programs. The following summarizes program enrollment in 2013.

Table 1: Demand Response Enrollment by Program and IOU for 2013[1]

Ex ante Sept 2013 Enrolled MW

	SCE	PG&E	SDG&E	Total
Interruptible	630	247	0	877
Agricultural Pumping	52	0	0	52
Air Conditioner Cycling	350	83	20	452
Capacity Bidding Program	20	24	17	61
Demand Bidding Program	82	49	6	137
Aggregator Managed Program	173	244	0	417
Dynamic Pricing	42	87	20	149
All other	49	0	0	49
Total	1,397	733	63	**2,193**

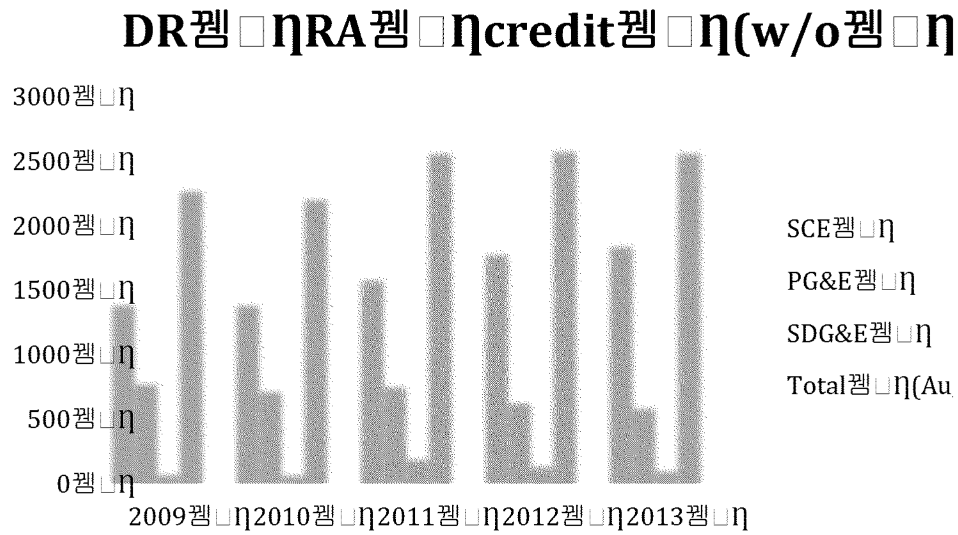
[1] Numbers based on the *ex ante* enrolled MW for September 2013, which represented the highest month in total for 2013. I aggregated certain day-ahead and day-of programs for purposes of this Table.

Table 1 above illustrates two main points. First, the total forecast DR is at approximately 5% of the combined IOU peak demand, with emergency interruptible load supplying about 2% of the peak demand. Second, SCE has a majority (64%) of forecast DR, largely due to the enrollment in its interruptible and air conditioning cycling programs.

Presently, the utilities receive RA credit for all of the expected "price responsive" DR load for August. For 2012, a total of 2,987 MW of DR RA credit, including the 15% planning reserve margin credit, was allocated to benefitting LSEs, representing 5.8% of the total August RA requirement.[2] The following Figure 1 illustrates the demand response RA credit, without the 15% planning reserve margin, that was allocated to LSEs in 2009-2013. These data show that even a higher percentage of DR RA credits originate from SCE.

[2] 2012 RA Report, Table 4, p. 12.

Figure 1: RA credit from Demand Response (2009-2013)



B. Characteristics and Uses of Demand Response Programs

The Testimony Guidance Document requests that parties analyze the characteristics of each demand response program and asks parties to "provide your list of characteristics that the Commission should use in determining how to categorize" each program. Due to time constraints, TURN does not attempt to analyze separately the characteristics of each program. Rather, TURN provides a brief list of key operational program characteristics and an analysis of the potential uses of existing programs. TURN generally agrees with the preliminary categorization as shown in Table 2 of D.14-03-026, with one caveat concerning permanent load shifting resources.

Prior to D.14-03-026, the Commission categorized DR as either "price responsive" or "reliability." The primary difference is that price responsive programs included both Supply Resources and pricing tariffs that are now categorized as Load Modifying Resources.

Supply Resources are characterized by dispatchability based on some trigger which responds to system or market conditions. Key elements include the nature of the trigger, the notice interval necessary to elicit response, the duration of possible load reduction, the number of hours of availability (both for an individual event as well as in total for the month or season), the measurement of actual response in relation to some benchmark, the amount and structure of any compensation and any penalties for non-performance.

The characteristics of particular Supply Resources are influenced both by customer preferences and the extent of control and communications technology automation. TURN generally agrees with the typology of services outlined by CLECA in their previous comments in this proceeding.[3] Certain programs, such as the Base Interruptible Program ("BIP"), are designed primarily to provide contingency reserves and will participate as a Reliability Demand Response Resource ("RDRR") product in the CAISO markets. Other resources will participate as a Proxy Demand Resource ("PDR") product in the CAISO energy or ancillary services markets. These resources are supposed to provide an economic benefit of wholesale price reduction in addition to potential reliability benefits. Presently, the customer loads comprising these "resources" participate in either tariffed programs such as the Demand Bidding Program ("DBP") and the Capacity Bidding Program ("CBP"), or as part of the aggregated load in the Aggregator Managed Program (AMP). These programs differ in the nature of the trigger, the response time and the payment structure. Most significantly,

[3] See, CLECA Response to Phase Two Foundational Questions, December 13, 2013, p. 5-9.

participants in the CBP receive capacity payments which may be reduced for performance below certain levels, and could lead to penalties for net monthly performance below 50% of committed load reduction. There are neither capacity payments nor penalties for non-performance in the DBP program, which provides energy rate credits at a fixed price.

The air conditioner cycling programs ("ACC") are somewhat unique. While dispatched based on wholesale market or system conditions, they also provide distribution reliability services, with dispatch based on distribution-level emergencies. TURN assumes that as DR evolves to develop better locational and temporal dispatch control, other programs may offer similar distribution-level services. The Commission indicated its intent that the utilities should have control of programs to "address distribution reliability problems."[4] The Commission may need to order workshops to determine how to ensure dual control of such programs.

TURN is concerned about the categorization of Permanent Load Shifting ("PLS") as a load modifying resource. Presently, only thermal energy storage qualifies for PLS funding. But thermal storage is simply a technology to promote load shifting each and every day, without reference to any signal. But PLS only makes sense as a response to a tariff such as TOU. It is not clear why PLS is called out as a separate resource. Other technologies, such as battery storage, can provide either PLS or other service depending on the nature of financial incentives.

---

[4] D.14-03-026, p. 22.

C. Costs of Existing Demand Response Programs

The costs of demand response programs are not readily transparent, partly because program administrative costs and incentive payments are recorded in different accounts and approved in different decisions. Thus, for example, the total of $450 million for 2012-2014 demand response programs and activities approved in D.12-04-045 includes a variety of program and administrative costs, but does not include the incentive payments for the interruptible or aggregator managed programs for all utilities.

The value of DR programs was measured for the first time in 2012-2014 using adopted cost-effectiveness protocols, and many DR programs are either not cost effective or only marginally cost effective.[5] DR costs have become more transparent due to reporting requirements adopted by the Commission for the monthly load impact reports and the cost effectiveness reporting templates.

Tariffed utility programs specify payment amounts. For example, the Capacity Bidding Program provides average capacity incentive payments of approximately $5/kw-month, though prices vary depending on the specific CBP product.[6] The BIP provides rate reductions based on an incentive of $8-9/kW-month (for PG&E). PG&E provides ACC residential customers a one-time enrollment fee of $50, while SCE provides ACC residential customers annual

[5] D.12-04-045, p. 32-33.

[6] The utilities have two different CBP options (Day-Of and Day-Ahead) and pricing based on three different possible daily event durations. SCE's highest priced CBP product (Day-Of, 4-8 hours per day) results in an annual incentive of $76/kW-year.

incentives averaging about $150 per customer, since most customers are signed up on the more lucrative 100% cycling option.

TURN asked PG&E and SCE to provide the "average annual cost ($/kW-year) for each DR program for each year 2012-2013." PG&E calculated the average annual cost by using the cost effectiveness reporting template numbers, while SCE calculated the cost by using actual expenses as reported in the monthly load impact reports. These methods are different, at least in part because the cost effectiveness templates allocate a certain amount of administrative costs to all programs, and also adjust the expected load impacts by the adopted adjustment factors to account for availability and response time. I have not had time to fully compare these two different methods of calculating program costs.

Table 2: PG&E and SCE average annual costs of DR programs[7]

2013 Program	PG&E $/kW-yr	SCE $/kW-yr
Interruptible	$124.06	$123.80
Ag Pumping		$100.67
AC Cycling	$111.66	$200.52
CBP	$95.25	$63.70
DBP	$158.99	$30.90
AMP Contracts	$84.62	$71.66
Weighted Average	$119.82	$131.16

[7] The complete data response is included in Attachment 2. Though TURN has combined PG&E and SCE data in one table, it is important to keep in mind that the two IOUs used different calculation methods. TURN considers these costs to reflect a synthetic "capacity price" analogous to RA capacity prices in contracts for conventional generation.

The data illustrate that, for PG&E, the AMP, CBP and ACC programs were on average less costly than the BIP and the DBP programs in 2013. The price trends are different for SCE. The DBP is much less expensive than other programs, likely reflecting a different allocation of administrative costs. The ACC is much more expensive, likely reflecting SCE's relatively high annual incentives.

For certain programs, such as BIP, CBP and AMP, the majority of the costs reflect capacity and energy incentives. For other programs, such as ACC for PG&E, the majority of the costs may be for program infrastructure and administration.

These numbers reflect some allocated administrative costs, but (especially for SCE) may not include costs for other categories of demand response authorized in budgets, including emerging technologies, technology incentives, marketing, education and outreach, various pilot and supporting projects, as well as evaluation, measurement and verification. Of the $450 million budget authorized for demand response in 2012-2014, only 35% was for programs in categories 1, 2, 3 and 10, which cover all of the reliability and price responsive programs.[8]

The average cost of demand response is significantly higher than Resource Adequacy capacity contract prices for 2012-2016, which averaged almost $40/kW-year.[9] It is useful to keep in mind that DR capacity costs paid to a participating customer do not necessarily reflect fixed or variable costs; rather,

[8] The $450 million does not, however, include incentives which are recovered in other accounts.

[9] 2012 Resource Adequacy Report, April 2014, p. 24. The weighted average of all contracts was $3.28/kW-month. The reported RA prices likely include a combination of both short term (year-ahead), intermediate and long-term RA-only capacity contracts.

they reflect a mix of costs to the customer and the perceived opportunity cost of reducing electricity use.

TURN understands that some customers must make infrastructure investments in control technologies and supporting IT and communications in order to provide demand response. As an example, the LBNL Demand Response Resource Center documented that the one-time implementation cost of AutoDR control technologies ranged from $51-76/kW.[10] DRRC concluded that OpenADR implementation should be a low-cost option for building DR capability.

The existing mix of DR programs have been in place since about 2005, suggesting that for continuing customers the one-time implementation costs should have been amortized already.[11] TURN is concerned that we have not seen evidence of declining costs for DR despite almost ten years of program funding.

Under the present procurement construct, it is difficult to tell if the adopted tariff and contract prices for DR reflect actual supply, or reflect the use of the cost effectiveness protocols to set prices. The potential for DRAM to more accurately measure market supply is one of the reasons TURN supports the mechanism.

III. Goals for Demand Response

The ACR proposes that the Commission establish a goal of 5% of peak load to be met by all Supply Resources, separate from the 2% goal for emergency supply

---

[10] R.08-12-009, Reply Comments of the LBNL DRRC, March 26, 2010, p. 6 and Tables 1-3. DRRC provided data from 28 facilities. The range would have actually been significantly lower absent three outliers with costs above $100/kW.

[11] D.05-01-056.

resources. The DRAM proposes that the IOUs procure an incremental 0.5% of third-party Supply Resources each year starting in 2016, so as to achieve the 5% goal by approximately 2020. While there are no specific penalties associated with a failure to meet the goal, the DRAM procurement is structured so as to require the IOUs to purchase any eligible DR bids up to the procurement goals, unless the cost cap is exceeded first.

TURN does not oppose an aspirational goal, especially if there is an exogenous cost cap. However, TURN is strongly concerned that an arbitrary goal linked to procurement requirements could significantly increase costs due to a lack of technical potential or supplier market power if there is insufficient market competition. In such a situation, any procurement obligation should be tempered by a showing of sufficient market competition and reasonable prices. Possible indicators of market competition include a minimum number of bids and bidders, the shape of the supply curve, and/or an exogenous price benchmark. As detailed in the testimony of Mr. Woodruff, TURN recommends that the Commission use the proposed price cap (based on a weighted average of bid prices) in conjunction with an exogenous benchmark based on a measure of cost-effectiveness.

From a policy perspective, TURN also suggests that adopted goals should be based on some technical analysis of a) technical potential, b) cost effectiveness, and c) electric system needs. In the energy efficiency sector, the Commission sets goals and budgets based on detailed market evaluations and analyses of both technical and economic potential for energy efficiency programs. As early as

September 2002, the Commission identified a process for setting quantitative goals for DR based on data concerning "historic price elasticities, estimates of projected customer participation for a given tariff and the expected price change seen by customers."[12] However, the Commission adopted a target of 5% in its initial "Vision Statement,"[13] and that target was adopted without modification in D.03-06-032.

TURN is not aware of studies or data which support this target as an actual reflection of demand response potential, though we do not question that it reflects some heuristic notion of DR potential. The original 5% goal reflected the impacts of what are now termed both Supply Resources and Load Modifying Resources. Presently, the impact of load modifying dynamic pricing tariffs is accounted for in CEC demand forecasts, and the CEC forecasts a total reduction of about 0.5% of peak demand by 2017.[14] It is not clear that the 5% target is necessarily appropriate for Supply Resources only, especially if those resources must meet the eligibility criteria of the CAISO's proxy demand resource or reliability demand response resource tariffs.

IV. Demand Response Auction Mechanism

The Joint Ruling proposes a Demand Response Auction Mechanism ("DRAM") to start in 2015, with the first auction to procure demand response resources for delivery in 2016. The DRAM would result in IOUs accepting bids from demand

[12] R.02-06-001, ALJ Ruling, September 5, 2002, p. 7.

[13] R.02-06-001, ALJ Ruling, October 29, 2002, Attachment Item 2.

[14] CEC, California Energy Demand, 2013, Tables 8 and 9.

response providers based on annual or seasonal capacity prices; and the winning bidders would then have a contractual obligation to participate in the CAISO PDR or RDRR market subject to applicable CAISO tariff regulations. The staff proposal provides details regarding the auction mechanism, the price selection and the contracting process.

TURN supports the DRAM mechanism as a method to procure cost-effective DR based on capacity prices so as to achieve state energy goals, and then require the DR resources to participate in CAISO energy markets.

The companion testimony of Kevin Woodruff provides specific recommendations concerning the DRAM. I offer certain high-level policy suggestions and comments concerning this mechanism. Specifically, I recommend that the Commission:

- Require all supply resource demand response to participate in the DRAM starting in 2017 and 2018;
- Provide for a specific review and reauthorization of the DRAM after piloting the program for 2016 and 2017.

A. Require all supply resource programs to participate in the DRAM after a three year transition period 2018 in 2016

Staff explained that the DRAM would apply only to incremental procurement in 2016, meaning the IOUs would seek to procure 0.5% of peak load through the DRAM in 2016 in addition to existing programs authorized for 2015-2016. It is unclear whether the intent would be to terminate existing tariff programs in 2017 and allow all customers to participate in third party aggregation that would bid load reduction into the DRAM, or to continue some or all of the programs for some period of time.

TURN's primary concern is that if customers presently enrolled in a DR program continue on that program, so that the DRAM only procures new customers (incremental load), the available supply of DR could be limited, thus resulting in higher bid prices and/or fewer bids. Furthermore, if customers can choose whether to participate in existing programs or sign up with a third party who has one a DRAM contract, customers would simply choose the higher cost alternative.

For these reasons, TURN would prefer all existing programs terminate in 2017. However, such a rapid transition may prove difficult given the number of unresolved issues. Thus, as an alternative TURN recommends a three-year transition period. All AMP contracts should terminate in by end of 2016. Aggregators have already acquired the customers participating in AMP, and the transition to bidding load into a DRAM in 2016 and participating in PDR or RDRR should be less drastic. Tariffed programs such as CBP, DBP and BIP should continue for one additional year, and terminate at the end of 2017.

TURN anticipates that a longer time may be necessary to acquire residential customers currently participating on ACC programs due to greater difficult in customer acquisition. For this reason, TURN recommends the ACC programs terminate by end of 2018.

B. Review Auction Results in 2016 and 2017 in Order to Make Modifications for 2018

TURN cautions that several issues concerning both the DRAM and subsequent participation in CAISO markets (including the must offer obligation) are not fully developed, and may also create unintended or unknown consequences. Two major issues raised during workshops were the requirement for dispatch at the sub-LAP level, and the issue of the potential for DRP scheduling coordinators to submit very high bid prices so as to avoid dispatch.

TURN thus recommends that, as part of any decision authorizing the DRAM, the Commission explicitly require staff to monitor relevant auction and bidding data in 2016 and 2017, assess the results with respect to program participation, dispatch, performance and cost, publish the results and allow for comments proposing any significant modifications.

This completes my written testimony.

ATTACHMENT 1

Statement of Qualifications: Marcel Hawiger

My current position is Staff Attorney at TURN. I have held this position since August of 1998. I have represented TURN as the attorney of record in numerous energy proceedings since 1998, including several proceedings related to demand-side management programs and budgets. I am a member of the Procurement Review Groups for all three IOUs. I have testified previously before this Commission.

Prior to my employment with TURN I was the Director of MidPeninsula Citizens for Fair Housing (1996-1998). I have also been employed by Evergreen Legal Services (1994-1996), the Massachusetts Department of Environmental Protection (1988-1990) and GHR Engineering, Inc. (1986-1988).

My education includes a Bachelor of Science degree in Geology from Yale University (1982), a Master of Science degree in Civil and Environmental Engineering from Cornell University (1988), and a law degree from New York University (1993).

ATTACHMENT 2

PGE Response to TURN DR 001-01

PACIFIC GAS AND ELECTRIC COMPANY
Demand Response OIR 2013
Rulemaking 13-09-011
Data Response

PG&E Data Request No.:	TURN_001-01		
PG&E File Name:	DemandResponseOIR-2013_DR_TURN_001-Q01		
Request Date:	April 25, 2014	Requester DR No.:	TURN-PG&E-001R (Revised)
Date Sent:	April 28, 2014	Requesting Party:	The Utility Reform Network
PG&E Witness:	Bill Gavelis	Requester:	Marcel Hawiger

QUESTION 1

Please provide the average annual cost ($/kw-yr) for each DR program for each year 2012-2013, calculated in whatever way best reflects the total costs of the program per kW of enrolled August load. Please explain method used.

ANSWER 1

The forecast average annual cost ($/kW-year) for each DR program for 2012 and 2013 as calculated in PG&E's most recently submitted DR Reporting Template is as follows.

		2012	2013
AMP	TRC costs 1/ (NPV $)	$ 14,951,988	$ 19,529,798
	MW 2/ (NPV MW wt. by mo. cap. alloc. %)	191	231
	dividing TRC costs by MW ($/kW-year)	**$ 78.26**	**$ 84.62**
BIP	TRC costs 1/ (NPV $)	$ 22,233,850	$ 23,276,412
	MW 2/ (NPV MW wt. by mo. cap. alloc. %)	187	188
	dividing TRC costs by MW ($/kW-year)	**$ 118.59**	**$ 124.06**
CBP day-ahead	TRC costs 1/ (NPV $)	$ 1,113,963	$ 1,251,245
	MW 2/ (NPV MW wt. by mo. cap. alloc. %)	12	13
	dividing TRC costs by MW ($/kW-year)	**$ 92.42**	**$ 95.25**
CBP day-of	TRC costs 1/ (NPV $)	$ 1,762,062	$ 1,969,553
	MW 2/ (NPV MW wt. by mo. cap. alloc. %)	17	19
	dividing TRC costs by MW ($/kW-year)	**$ 100.76**	**$ 105.01**
DBP	TRC costs 1/ (NPV $)	$ 1,663,054	$ 2,029,789
	MW 2/ (NPV MW wt. by mo. cap. alloc. %)	12	13
	dividing TRC costs by MW ($/kW-year)	**$ 134.25**	**$ 158.99**
SmartAC residential	TRC costs 1/ (NPV $)	$ 7,638,016	$ 8,168,042
	MW 2/ (NPV MW wt. by mo. cap. alloc. %)	82	73
	dividing TRC costs by MW ($/kW-year)	**$ 93.60**	**$ 111.66**

PLS	TRC costs **1/** (NPV $)	$	-	$	15,187,683
	MW **2/** (NPV MW wt. by mo. cap. alloc. %)		-		59
	dividing TRC costs by MW ($/kW-year)	**$**	**-**	**$**	**255.76**

1/ row 102, columns D:F, in each program tab
2/ row 56, cols L:AI, in each program tab; multiplied by monthly capacity allocation percentages in the Inputs tab, row 32, cols I:T; multiplied by the discount factors in the Inputs tab, row 56, cols I:K.

The data is available in PG&E's most recent DR Reporting Template:

Disclaimer: Please be advised that Per D.12-04-045 (OP 7), there are deficiencies in the cost-effectiveness protocol, which have yet to be resolved. Therefore, please exercise caution when conducting cost-effectiveness calculations.

PG&E's most recent DR Reporting Template was submitted in its Advice Letter 4164-E, "Resubmitted Cost Effectiveness Analyses of Pacific Gas and Electric Company's Capacity Bidding Program and Demand Bidding Program in Compliance With Decision 12-04-045." PG&E's DR Reporting Template was prepared per Energy Division's May 11, 2012, guidance in accordance with Ordering Paragraph 83 of D.12-04-045.

This advice letter was approved by Energy Division on April 25, 2013. That approval letter stated, "Based on its analysis, Energy Division has determined that AL 4164-E is in compliance with D.12-04-045."

PG&E's DR Reporting Template is available on PG&E's public website. To access the spreadsheet, please:

1) Go to: http://apps.pge.com/regulation/

2) Click on "Search for Public Case Documents"

3) Select "Demand Response 2012-2014 Projects" from the dropdown menu.

4) Select "01/10/13 and PG&E" as the party to narrow the search criteria

5) Click Search

The Description of the DR Reporting Template is: "PG&E's Demand Response Reporting Template for Advice Letter 4164-E including all DR programs using 2012 load impacts." The spreadsheet filename is: "DemandResponse2012-2014-Projects_Other-Doc_PGE_20130110_259097.xls"

This DR Reporting Template was submitted with PG&E's January 10, 2013, Reply to Division of Ratepayer Advocates' Protest to Advice Letter 4164-E on the Resubmitted Cost Effectiveness Analyses of the Capacity Bidding Program and Demand Bidding Program in Compliance With Decision 12-04-045.

ATTACHMENT 2

SCE Response to TURN DR 001-01

Demand Response Program	Program Costs[1]		Aggregate Load Impact kW[2]		$/kW-Year[3] [4]	
	2012	2013	2012	2013	2012	2013
Agricultural Pumping Interruptible (API)	5,901,416	5,728,927	45,252	56,909	$ 130.41	$ 100.67
Base Interruptible Program (BIP)	75,576,753	75,576,588	596,576	610,462	$ 126.68	$ 123.80
AC Cycling : Summer Discount Plan (SDP)	74,505,618	72,924,194	534,638	363,683	$ 139.36	$ 200.52
Capacity Bidding Program (CBP)	1,008,566	1,321,505	16,704	20,747	$ 60.38	$ 63.70
Demand Bidding Program (DBP)	3,618,591	2,086,699	69,809	67,535	$ 51.84	$ 30.90
Save Power Day (SPD/PTR)	24,107,038	25,500,230	107,295	21,693	$ 224.68	$ 1,175.52
AMP Contracts/DR Contracts (AMP)	17,327,572	13,040,246	254,193	181,981	$ 68.17	$ 71.66

Footnote 1: 2012 and 2013 program costs are based on total annual actuals filed in SCE's Monthly ILP and DRP Report for December 2013. Program costs include direct program costs (e.g. program management, equipment, & incentives). Program costs do not include allocations of portfolio costs (e.g. AutoDR, Systems & Technology, etc.).

Footnote 2: Using SCE's Monthly ILP and DRP Report for December 2012 and 2013, calculate the "Aggregate Load Impact kW" by multiplying the August average ex ante load impact kW per customer for each program (tab "Load Impacts (ExPost & ExAnte)", column J, rows 30-44); multiplied by the August enrolled service accounts (tab "Program MW ExPost & ExAnte", column F, rows 32-47).

Footnote 3: $/kW-Year is calculated dividing annual program costs by annual average load impact kW.

Footnote 4: Based upon total number of eligible customers (incentive costs were paid to all eligible residential customers), the 2012 & 2013 $/kW-Year for the Save Power Day program would have been $5.74/kW-Year and $6.07/kW-Year, respectively. Amounts reflected in table is based upon number customers enrolled in notifications (opt-in & default).

Program	Total Program Costs		Total Incentives [1]		Total Program Costs Including Incentives	
	2012	2013	2012	2013	2012	2013
Agricultural Pumping Interruptible (API)	373,766	283,014	5,527,650	5,445,913	5,901,416	5,728,927
Base Interruptible Program (BIP)	999,326	397,028	74,577,427	75,179,560	75,576,753	75,576,588
AC Cycling : Summer Discount Plan (SDP)	9,897,809	6,645,480	64,607,809	66,278,714	74,505,618	72,924,194
Capacity Bidding Program (CBP)	230,537	142,107	778,029	1,179,398	1,008,566	1,321,505
Demand Bidding Program (DBP)	346,612	196,916	3,271,979	1,889,783	3,618,591	2,086,699
Save Power Day (SPD/PTR)		645,978	24,107,038	24,854,252	24,107,038	25,500,230
AMP Contracts/DR Contracts (AMP)	509,375	353,808	16,818,197	12,686,438	17,327,572	13,040,246

Footnote 1: 2012 and 2013 incentives for the Save Power Day program are total incentives that were issued to the approximately 4.2 million eligible residential customers.

Program	August Average Ex Ante Load Impact kW per Customer		August Program Enrollment [1]		Aggregate Load Impact kW	
	2012	2013	2012	2013	2012	2013
Agricultural Pumping Interruptible (API)	40.73	50.54	1,111	1,126	45,252	56,909
AMP Contracts/DR Contracts (AMP) - Day Ahead	63.17	129.30	0	0	0	0
AMP Contracts/DR Contracts (AMP) - Day Of	91.94	87.98	2,840	1,944	254,193	181,981
Base Interruptible Program (BIP) 15 Minute Option	897.11	1,848.10	67	74	60,106	136,759
Base Interruptible Program (BIP) 30 Minute Option	897.11	822.40	598	576	536,470	473,702
Capacity Bidding Program (CBP) Day Ahead	46.45	0.04	50	15	2,323	1
Capacity Bidding Program (CBP) Day Of	46.54	42.60	309	487	14,381	20,746
Demand Bidding Program (DBP)	50.77	51.09	1,375	1,322	69,809	67,535
Optional Binding Mandatory Curtailment (OBMC)	1,532.09	1,532.09	11	11	16,853	16,853
Real Time Pricing (RTP)	113.89	130.94	131	127	14,920	16,630
Save Power Day (SPD/PTR)	0.23	0.03	468,537	794,390	107,295	21,693
Summer Advantage Incentive (SAI/CPP)	10.35	10.18	3,136	3,294	32,472	33,522
Summer Discount Plan (SDP) - Commercial	6.44	6.40	10,589	10,638	68,193	68,083
Summer Discount Plan (SDP) - Residential	1.51	0.96	308,539	307,641	466,444	295,600

Footnote 1: The 2012 and 2013 August program enrollment numbers for the Save Power Day program represents customers enrolled in event notifications (opt-in & default).