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APPENDIX

Demand Response Baseline Related Data

Southern California Edison
2012-2014 Demand Response Application A.11-03-003

DATA REQUEST SET A1103003 ED-SCE-008

To: ENERGY DIVISION
Prepared by: Chelsie Rae Lee
Title: Senior Project Manager
Dated: 07/27/2011

Question 01:

1. Please provide the baseline settlement result using both individual and aggregated baseline with 30%, 35%, 40%, 50% and no cap adjustment for CBP-DA and CBP-DO for the month of July, August and September 2010; and compare those 2010 baseline settlement results with the 2010 M&E results.

To obtain a monthly load impact measurement for CBP (DO and DA options), average load impacts across all event hours within a month for each product (1-4 hour and 2-6 hour) within an option (either DO or DA), and then aggregate the performance of the two products to obtain monthly performance for an option. To maintain confidentiality, results should be reported at the option level but not the product level.

As an example of how this is implemented: in August 2010 for SCE's CBP Day-Ahead, the 1-4 hour product was called for a total of 21 event hours and the 2-6 hour product was called for a total of 23 event hours, with 19 of those hours concurrent. [The 1-4 hour product was called over seven separate event days with event durations ranging from 2 hours to 4 hours. The 2-6 hour product was called over six separate event days with event durations ranging from 2 hours to 6 hours.] Average August performance for the DA 1-4 hour product was obtained by averaging across the 21 event hours for which it was called. Similarly, average August performance for the DA 2-6 hour product was obtained by averaging across the 23 event hours for which it was called. These two average hourly event performances were then added to obtain the average August performance for the DA option.

Please use the attached spreadsheet as the format and include supporting work papers.

Response to Question 01:

To give a complete analysis, SCE provides the requested data in the attached spreadsheet and also provides implementation timing information for consideration.

Baseline Implementation Timing

If changes to the adjustment cap and aggregated nature of baselines are approved in this Application, SCE would implement Capacity Bidding Program (CBP) updates in 2012 and Demand Bidding Program (DBP) updates in 2013. In 2013, SCE plans significant changes to the

DBP program including removing the ability to participate as an aggregated group. Since baseline changes associated with moving to an aggregated baseline for DBP would cost between $250,000 and $400,000 (based on systems costs incurred in 2010 related to the change to a 10-in-10 baseline), it would be more cost effective to wait until 2013 when program changes will make this update unnecessary. Requiring changes to DBP before 2013 would require expenditures that SCE did not budget for or request in this cycle. As long as all customers are participating individually, the aggregated and individual baseline calculations will have the same result, therefore a system change related to aggregation would not be needed.

SCE anticipates a decision on the DR Application no later than December 2011. If a decision is provided later than December 2011, these delays may prohibit system changes from being implemented before the 2012 summer event season. To modify the baselines for Demand Bidding Program, SCE must begin system changes no later than January 1, 2012 to implement the new functionality prior to June 1, 2012. SCE does not support making baseline changes to the Demand Bidding Program between June 1 and Oct 1. To modify the baselines for the Capacity Bidding Program, SCE must begin system changes no later than February 1, 2012 to implement the new functionality prior to April 15, 2012. SCE does not support making baseline changes to the Capacity Bidding Program between April 15 and Oct 31. Modifications to the systems that support the Demand Response Contracts can be implemented during the next operating month after the contract amendment is executed and can be modified at the start of any month during the year.

The spreadsheet is located on the following page.

The SCE spreadsheet is located at the following link:

http://www.cpuc.ca.gov/PUC/energy/Demand+Response/a1103001_appendices.htm

SDG&E response to Energy Division Baseline Data Request of 7/26/11

SDG&E is providing an excel workbook that contains the baseline information that is requested. This summary will provide important information on the context of how to interpret the requested information. The email request does not specify to only provide the analysis for those customers who selected the adjustment, but that what was agreed to on the IOU and ED conference call.

In the MS Excel spreadsheet: SDGE Baseline_Results_Jul_Sep10_Adj_send_v3.xls there are several tabs. The first tab labeled: "Results" shows the analysis as asked for by the Energy Division. The results are summarized and provided in the template that the energy division provided. Since the request was for only those CBP customers who selected the adjustment some of the results can be misleading. For instance for the CBP DA result table for July…the M&E load impact portion for those selecting the adjustment is only 3% of the total CBP DA program load impact. After applying the adjustments, the resulting Baseline Load Impacts as a percentage of the 2010 M&E load impacts in many cases are over 600%. If the "no adjustment" customers were included in this analysis the percentages would appear to be more reasonable at 102% for July CBP DA as shown on Table LW/KS-12 page LW/KS29 in Chapter V Opening Testimony – May 27th.

SDG&E has provided additional analysis with tabs labeled appropriately for both "adjusted" and "no adjustment". SDG&E also is providing an analysis of the nominated load by individual and aggregated. The nominated load includes both "adjusted" and "no adjustment" nominations together. Those tabs are labeled: Summary_Adj=no_nominated and Summary_Adj=yes_nominated. The purpose of including these tabs is to show how the baseline reductions using the adjustment factors relates to what was actually nominated. SDG&E feels that this provides for a more complete analysis of its baseline proposal.

Additional tabs are included to show the details of each summarized scenario. If there are questions SDG&E will be available to provide explanations to the different analyses that are presented.

The spreadsheet is located at the following link:

http://www.cpuc.ca.gov/PUC/energy/Demand+Response/a1103001_appendices.htm

PACIFIC GAS AND ELECTRIC COMPANY
Demand Response 2012-2014 Projects
Application 11-03-001
Data Response

PG&E Data Request No.:	ED_007-01		
PG&E File Name:	DemandResponse2012-2014-Projects_DR_ED_007-Q01		
Request Date:	July 26, 2011	Requester DR No.:	ED (7/26/11- E-Mail)
Date Sent:	August 3, 2011	Requesting Party:	Energy Division
PG&E Witness:	Michael Alexander	Requester:	Dorris Lam

RE: CBP BASELINE

QUESTION 1

Please provide the baseline settlement result using both individual and aggregated baseline with 30%, 35%, 40%, 50% and no cap adjustment for CBP-DA and CBP-DO for the month of July, August and September 2010; and compare those 2010 baseline settlement results with the 2010 M&E results.

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As an example of how this is implemented: in August 2010 for SCE's CBP Day-Ahead, the 1-4 hour product was called for a total of 21 event hours and the 2-6 hour product was called for a total of 23 event hours, with 19 of those hours concurrent. [The 1-4 hour product was called over seven separate event days with event durations ranging from 2 hours to 4 hours. The 2-6 hour product was called over six separate event days with event durations ranging from 2 hours to 6 hours.] Average August performance for the DA 1-4 hour product was obtained by averaging across the 21 event hours for which it was called. Similarly, average August performance for the DA 2-6 hour product was obtained by averaging across the 23 event hours for which it was called. These two average hourly event performances were then added to obtain the average August performance for the DA option.

Please use the attached spreadsheet as the format and include supporting work papers.

IOUs Data Request - CBP.Baseline.xls

ANSWER 1

Table 1 shows the customer count and the regression-based load impact estimates of Capacity Bidding Program (CBP) customers who elected a morning-of adjustment in 2010. Tables 2 and 3 provide comparisons of the aggregated and individual baselines with a morning-of adjustment capped at 30%, 35%, 40%, and 50%, as well as an uncapped adjustment for CBP customers, while using the regression-based load impact estimates as benchmarks.

Table 1: 2010 Load Impacts (MW) of CBP

	2010 M&E LI Results (MW)			Customer Count		
DR Programs	**July**	**Aug.**	**Sept.**	**July**	**Aug.**	**Sept.**
CBP-DO	20.8	20.6	15.9	230	260	259
CBP-DA	5.9	6.4	7.9	29	35	32

Table 2: 2010 Settlement Load Reduction Estimates of CBP Day-Of (DO) Customers Using Various Baseline Scenarios Prescribed by Energy Division

	Settlement Baseline	**2010 Load Reduction Estimates (MW) Using Settlement Baseline**			**Baseline LI as a percentage of 2010 M&E Results**		
		July	Aug.	Sept.	July	Aug.	Sept.
CBP - DO	10-in-10 individual 30% cap	18.9	15.8	11.8	90%	77%	74%
	10-in-10 aggregated 30% cap	19.5	21.6	14.3	94%	105%	90%
	10-in-10 individual 35% cap	18.4	16.4	12.2	88%	80%	77%
	10-in-10 aggregated 35% cap	18.9	21.7	14.5	91%	105%	91%
	10-in-10 individual 40% cap	17.9	16.9	12.5	86%	82%	79%
	10-in-10 aggregated 40% cap	***18.5***	***21.7***	***14.5***	***89%***	***105%***	***91%***
	10-in-10 individual 50% cap	17.9	17.5	12.9	86%	85%	81%
	10-in-10 aggregated 50% cap	18.5	21.7	14.6	89%	105%	92%
	10-in-10 individual with no cap	***18.2***	***20.6***	***14.0***	***87%***	***100%***	***88%***
	10-in-10 aggregated with no cap	18.5	21.7	14.6	89%	105%	92%

Table 3: 2010 Settlement Load Reduction Estimates of CBP Day-Ahead (DA) Customers Using Various Baseline Scenarios Prescribed by Energy Division

	Settlement Baseline	**2010 Load Reduction Estimates (MW) Using Settlement Baseline**			**Baseline LI as a percentage of 2010 M&E Results**		
		July	Aug.	Sept.	July	Aug.	Sept.
CBP - DA	10-in-10 individual 30% cap	7.3	8.0	8.9	125%	125%	113%
	10-in-10 aggregated 30% cap	7.0	8.4	9.0	119%	133%	114%
	10-in-10 individual 35% cap	7.2	8.1	9.0	122%	128%	113%
	10-in-10 aggregated 35% cap	7.0	8.5	9.0	119%	133%	114%
	10-in-10 individual 40% cap	7.1	8.2	9.0	120%	129%	113%
	10-in-10 aggregated 40% cap	***7.0***	***8.5***	***9.0***	***119%***	***134%***	***113%***
	10-in-10 individual 50% cap	7.1	8.3	9.0	120%	130%	113%
	10-in-10 aggregated 50% cap	7.0	8.6	9.0	119%	135%	113%
	10-in-10 individual with no cap	***7.1***	***8.8***	***9.5***	***120%***	***138%***	***120%***
	10-in-10 aggregated with no cap	7.0	8.7	9.5	119%	137%	120%

One may note that in table 2 the load reduction estimates for July using settlement baselines decrease as the adjustment cap increases. This “anomaly” results from a few large customers with adjustment factors falling between 0.5 and 0.6. As such, setting a

cap less than 50% would increase the adjustment factors that are applied to the baselines.

As show in Table 1, CBP is predominantly comprised of customers with day-of (DO) notice. The DO program was, on average, 7.8 times as large as the day-ahead (DA) program in customer count, and 2.5 times as large with respect to load impacts.

There is convincing evidence, especially from the DO program, to suggest the aggregated 10-in-10 baseline outperforms the individual 10-in-10 baseline with respect to accuracy. From Tables 2 and 3, one can judge the accuracy of a baseline by its deviation from the regression-based load impacts; the closer the MW estimate by a baseline to the regression-base load impact, the more accurate the baseline. For the DA program, the individual and the aggregated 10-in-10 baselines provide comparable MW estimates. However, for the DO program, which contains most of the loads and customers, the MW estimates using aggregated baselines are generally closer to the regression-based impact estimates than are the MW estimates using individual baselines, for any given cap except the uncapped adjustment for August. This finding is consistent with the Christensen 2009[1] study that also concludes that an aggregated baseline is preferred to individual baseline in most cases.

In addition, in comparing the two competing proposals by SDG&E (Supported by PG&E) and DR Aggregators, i.e., an aggregated 10-in-10 baseline with a 40% cap and an individual 10-in-10 baseline with a uncapped adjustment (see the numbers in bold), both DA and DO programs offer evidence that the aggregated baseline with a 40% cap are superior, i.e., more accurate. With the exception of DO in August, the MW estimates by the aggregated baseline with a 40% cap almost always have estimates closer to the regression-based load impacts.

Finally, a 40% cap may function as a preventive measure against gaming, *without sacrificing the accuracy of the baseline*. The 40% cap is enough to accommodate the vast majority of the customers who do not have highly volatile loads, while discouraging customers from artificially inflating their loads in the morning before an event. There is no systematic evidence from Tables 2 and 3 to suggest the aggregated baseline with a 40% cap is less accurate than the individual baseline with an uncapped adjustment. In fact, the aggregated baseline with a 40% cap is slightly more accurate than the individual baseline with no cap, in most of the cases.

Given 1) PG&E's findings in this analysis, which corroborates the Christensen 2009 with respect to baseline accuracy, and 2) the need for gaming prevention, PG&E recommends that the aggregated 10-in-10 baseline with a 40% cap on the morning-of adjustment proposed by SDG&E be adopted for all DR programs that require a baseline, with the exception of the Aggregator Managed Portfolio (AMP). For programs

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1 Christensen Associates Energy Consulting, *2008 Load Impact Evaluation of California Statewide Aggregator Demand Response Programs, Volume 2: Baseline Analysis of AMP Aggregator Demand Response Program*, May 1, 2009. See page 5.

that have no third-party aggregation, the aggregated baseline with a 40% cap on the day-of adjustment is no different than the individual baseline with the same cap.

Demand Response Cost Effectiveness Related Data

Energy Division sent the following data request to PG&E on June 10, 2011:

Could you please send a version of the DR Reporting Template cost-effectiveness spreadsheet that includes a separate analysis for the DBP program?

PG&E responded by providing Energy Division with updated versions of their DR Reporting Template which include a separate analysis of the Demand Bidding Program. One spreadsheet uses the E3 default method for determining the A factor, and the other uses PG&E's LOLP model for determining the A factor. Both spreadsheets can be found on the CPUC website at:

http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

Energy Division sent the following data request to SDG&E on July 22:

<u>Cost-effectiveness analysis of the Peak Time Rebate program</u>: We have a question about the calculation of bill reductions and incentives. Our understanding of the PTR program is that customers receive an incentive, as per SDG&E's Schedule PTR (21713-E), which states "A bill credit of $0.75/kWh will be paid for each kWh of actual reduction in consumption during each Peak Time Rebate (PTR) event. Customers with enabling technology will receive a higher bill credit of $1.25/kWh." In addition, a customer which reduces its consumption during a PTR event will also experience a bill reduction, simply because of the reduction in consumption. In your DR Reporting Template from May 27, 2011, the bill reduction calculated is the reduction due to decreased consumption. Nowhere in the cost-effectiveness analysis of the PTR program can we find a calculation of the $0.75 and $1.25 per kWh incentive. Please explain why you omitted the incentive cost from the spreadsheet.

On August 2, 2011, SDG&E made the following response:

D.08-02-034 directed PTR incentive payment costs to be recovered via the Energy Resource Recovery Account from the specific residential class and small commercial class that received such incentive payments. SDG&E did not include the PTR incentive in the cost effectiveness tests because, similar to rates such as CPP Default, the incentive is not paid to the customer but is instead a bill reduction recovered through the ERRA.

We find this response difficult to understand. The PTR tariff states that a bill credit will be paid to customers. If, as SDG&E argues, this cost should be considered to be a bill reduction rather than an incentive, then SDG&E should have added this cost to the calculation of the bill reductions. However, SDG&E does not include this as *either* an incentive *or* a bill reduction in its calculations, but rather leaves it out entirely.

Energy Division has provided an analysis of the cost-effectiveness of the PTR program with the incentive cost added in. These calculations assume that all participants will receive the $0.75/kWh incentive. The table below shows (1) SDG&E's PTR results as submitted; (2) the same results with the addition of ($0.75/kWh x the energy savings) as incentives; and (3) SDG&E's PTR results as submitted, with the addition of ($0.75/kWh x the energy savings) as additional bill savings.

(1) SDG&E PTR without incentives		
	net benefits	benefit/cost
TRC	$19,298,279	3.92
PAC	$21,018,290	5.29
RIM	$18,724,942	3.60
(2) SDG&E PTR with incentives of $0.75/kWh		
TRC	$12,685,107	1.96
PAC	$12,200,727	1.89
RIM	$9,907,379	1.62
(3) SDG&E PTR with $0.75/kWh added to bill reductions		

TRC	$12,734,014	1.97
PAC	$21,018,290	5.29
RIM	$9,972,588	1.63

Demand Response Auto DR and PLS Related Information

PACIFIC GAS AND ELECTRIC COMPANY
Demand Response 2012-2014 Projects
Application 11-03-001
Data Response

PG&E Data Request No.:	ED_003-01		
PG&E File Name:	DemandResponse2012-2014-Projects_DR_ED_003-Q01		
Request Date:	July 5, 2011	Requester DR No.:	ED (7/5/11- E-Mail)
Date Sent:	July 15, 2011	Requesting Party:	Energy Division
PG&E Witness:	Michael Alexander	Requester:	Aloke Gupta

QUESTION 1

In LI forecasts shown on p.2-4, both event-based ("temporary") and long-term ("permanent") demand reductions appear to be mixed.

a) How should we interpret the permanent load impacts on lines 1, 2, 3? Are these incremental or cumulative each year (relative to some reference)? Please explain the methodology here (what would be the reference, for example, for each year?).

b) Does the LI shown for PDP include the impact of the underlying TOU rate? If yes, above questions apply here too. Moreover, this would then seem to be mixing apples and oranges. Please comment.

c) How would your methodology for estimating the permanent LI (for PLS, TOU, PDP, for example) reconcile with CEC's load forecast?

   i) Wouldn't CEC's load forecast normally be NET of these permanent reductions.

   ii) We are concerned about double counting here. Please comment.

d) We suggest that LI forecasts need to be separated based on permanent vs. temporary. Please comment.

ANSWER 1

The event-based and non-event based (referred to as “permanent” in this data request) load impacts on p 2-4 of PG&E’s Opening Testimony are not mixed, as each was summed under a different category. PG&E included both event-based and non-event based load impacts in its DR portfolio, as directed by the Administrative Law Judge (ALJ’s) Guidance for this 2012-2014 Demand Response Application. ALJ Hecht directed the IOUs to provide load impact estimates based on the Load Impact Protocols adopted in D.08-04-050, which considers non-event based programs as part of a DR portfolio. It should be noted that on May 27, 2011, PG&E served Supplemental Testimony and Supporting Appendices in compliance with the Assigned Commissioner

Ruling and the ALJ's Scoping Memo. Load impact tables in PG&E's Opening Testimony have been updated using PG&E's April 1, 2011 load impact reports. Table 1 shows PG&E's latest portfolio-adjusted ex ante load impacts under normal (1-in-2) weather conditions for 2011-2014. The line items in Table 1 correspond to those on p 2-4 of PG&E's Opening Testimony.

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
PORTFOLIO-ADJUSTED EX ANTE LOAD IMPACTS (MW) FOR JULY UNDER 1-IN-2 WEATHER CONDITIONS FOR 2011-2014

DR Resource	2011	2012	2013	2014
Permanent Load Shift (PLS)	3	7	16	29
Time-of-Use (TOU) Rates – Non-Residential	296	286	277	282
TOU Rates - Residential	15	15	14	14
Load Impact (LI) (MW) of Non-Event Based Resources	**314**	**308**	**307**	**324**
AMP – Day-Ahead	40	40	40	40
AMP – Day-of Notification	149	149	149	149
BIP - Day-of Notification	182	205	221	234
CBP - Day-Ahead Notification	25	25	25	25
CBP - Day-of Notification	30	30	30	30
DBP - Day-Ahead Notification	8	8	0	0
PeakChoice – Committed Load, Day-of Notification	18	20	21	22
PeakChoice – Committed Load, Day-Ahead Notification	3	4	5	6
PeakChoice – Best Efforts, Day-of Notification	1	2	2	3
PeakChoice – Best Efforts, Day-Ahead Notification	1	1	8	8
Peak Day Pricing (PDP) – Non-Residential	22	66	81	75

Peak Day Pricing (PDP) - Residential	9	7	7	7
SmartAC – Non-Residential	2	3	4	5
SmartAC –Residential	86	99	100	97
LI (MW) of Event Based Resources	**575**	**659**	**692**	**701**
Total LI (MW) of DR Resources	**889**	**967**	**999**	**1,026**

a) Broadly speaking, customer load impacts from non-event based programs e.g. PLS and TOU rates are cumulative in the sense that impacts reflect the load reduction relative to their pre-enrollment load, regardless of when customers come to the programs. For these programs, load impacts are assumed to take place as a one-time shift when customers are first enrolled and their impacts become part of the system load forecast thereafter.

That said, there are caveats regarding treatment of TOU rates in the system load forecast. The non-residential TOU load impacts combine both “embedded” and “incremental” non-event based load reductions. Embedded load impacts are attributed to customers who have historically taken service under TOU rates, i.e. the load response is already incorporated in PG&E's system load forecast. These are typically large customers (greater than 200 kW) and some small and medium business customers (20 to 200 kW) who have been enrolled in opt –in (voluntary) TOU rates for a number of years. Their load impact estimates represent the effect of moving from a hypothetical flat rate (non TOU), to a TOU rate as a non-TOU rate may not be offered to these customers. On the other hand, incremental load impacts are attributed to customers who have historically taken service under flat rates and migrate to TOU rates. Therefore, these estimates represent “new” or incremental load impacts for PG&E that may affect resource planning. These would be customers who newly enroll in or are defaulted onto the rates during the forecast horizon. The latest non-residential TOU evaluation shows that incremental impacts comprise less than 8% of the total estimated 2014 winter and summer TOU load impacts. The methodology for estimating the two types of load impacts of non-residential TOU rates involves applying the appropriate price elasticities to model customers’ response to the migration to a TOU rate for the first time from a counter-factual flat rate[1].

The residential TOU load impacts in Table 1 are already embedded within PG&E’s system load forecast, reflecting the residential customers who have historically been enrolled on PG&E’s E-7 and E-6 rate schedules. The vast majority of PG&E’s residential TOU customers are enrolled the E-7 rate, which was closed to new customer enrollments in 2007. Since these customers have faced TOU prices for several years, their aggregate load shape has shifted in response to the on-peak price signal within the

[1] See section 3 of Christensen, *2011 to 2021 Ex Ante Load Impact Evaluation of PG&E’s Non-Residential TOU Rates*, April 1, 2011.

tariff.[2] The embedded load impacts are expected to decline over time due to attrition, since PG&E does not plan to market its E-6 rate. As such, PG&E does not anticipate any significant incremental load impacts for its residential TOU rates.

To estimate its residential TOU load impacts, PG&E compared its TOU customers' electricity usage to that of a statistically valid control group developed from the residential population. This methodology involves constructing a control group that mirrors the self-selected residential TOU customers. The control group's load shape serves as the counter-factual reference from which the TOU load reductions are estimated.[3]

b) No, the non-residential PDP load impacts presented in Table 1 reflect the effects due to PDP and do not include the impacts of the underlying TOU rates.

c) In producing its system load forecast, PG&E differentiates between the event-based resources and non-event based resources. For TOU rates (non-event based resource) that have been in effect for years (especially for large customers), load impacts have been incorporated in the system load. Accordingly, no adjustments are made to the load forecast for non event-based resources. On the other hand, load impacts of event-based DR programs are added back to the peak forecast, such that it reflects the peak demand in the absence of the event-based DR resources.

With respect to nomenclature, while this data request lists PDP among non-event based programs which provide "permanent" load impacts, PDP is actually an event based program whose load impacts are presumably not "permanent" and are treated accordingly.

i) Assuming "permanent" reductions" are equivalent to load impacts of non-dispatchable DR programs", it is PG&E's understanding that load impacts of non-dispatchable programs are counted toward California Energy Commission's (CEC) demand forecast. Event-based load impacts are however, treated as a supply-side resource, and are not accounted for on the demand side. See page 28 of the CEC's California Energy Demand 2010-2020 Adopted Forecast[4]. PG&E is in no position to represent the CEC regarding its forecasting practices and therefore recommends the Energy Division confer directly with Energy Commission forecasting office regarding its load forecast.

ii) As explained above, event-based and non-event based load impacts are treated separately in PG&E's load impact forecast. Event-based load impacts do not include imbedded load impacts of non-event programs. Therefore

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[2] Although some residential TOU customers have enrolled in the new E-6 TOU rate since 2007, these customers comprise less than 3% of the total residential TOU customer population. Thus, for all practical purposes, any potential incremental load they provide is minor.

[3] See Freeman, Sullivan & Co., *2010 Load Impact Evaluation of Pacific Gas and Electric Company's Time-Based Pricing Tariffs*, April 1, 2011.

[4] http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF

PG&E believes there is no double-counting in estimating the load impacts of its DR resources.

d) PG&E agrees with the suggestion that “permanent” load impacts should be separated from “temporary” load impacts in the forecast. In fact, PG&E’s ex ante load impacts are already broken out accordingly, using slightly different terms—*event-based* (*temporary)* and *non-event based* (*permanent)*.

PACIFIC GAS AND ELECTRIC COMPANY
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Request Date:	July 5, 2011	Requester DR No.:	ED (7/5/11- E-Mail)
Date Sent:	July 15, 2011	Requesting Party:	Energy Division
PG&E Witness:	Ulric Kwan	Requester:	Aloke Gupta

QUESTION 2

PGE asserts ADR customers have a "higher participation rate" What is that higher rate vs. non-ADR customers? What is the source for this figure or assertion? p.3-7/#30.

ANSWER 2

PG&E has conducted an evaluation of its AutoDR participants' opt-out rate on voluntary programs such as the Demand Bidding Program. PG&E's analysis determined that PG&E has had over 80% participation in its voluntary Demand Bidding Program with AutoDR-enabled customers compared to the average rate of approximately 3%.

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QUESTION 3

PGE's objective is to increase ADR adoption by PDP customers. What is the target or expected adoption rate for ADR among PDP large C&I customers? p. 3-8/#11.

ANSWER 3

PG&E does not currently have a target or expected adoption rate for AutoDR among large C&I customers that are enrolled on PDP. PG&E has asked for authorization to provide to PDP customers AutoDR funding to enable them to be more successful on the PDP rate.

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QUESTION 4

Does PGE require use of OADR protocol by customers for them to be eligible for ADR TI? p.3-8.

a) If not, why not do so to encourage standards-based technologies and avoid future obsolescence of proprietary technologies?

b) If not, what is the breakdown of the ADR TI funds usage in the last 3 year cycle for OADR vs. non-standards "compliant" ADR implementations by customers.

ANSWER 4

Yes, PG&E proposes to require the use of the OpenADR protocol for customers to be eligible for the AutoDR incentives in the 2012-2014 period.

PACIFIC GAS AND ELECTRIC COMPANY
Demand Response 2012-2014 Projects
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Data Response

PG&E Data Request No.:	ED_003-05		
PG&E File Name:	DemandResponse2012-2014-Projects_DR_ED_003-Q05		
Request Date:	July 5, 2011	Requester DR No.:	ED (7/5/11- E-Mail)
Date Sent:	July 15, 2011	Requesting Party:	Energy Division
PG&E Witness:	Ulric Kwan	Requester:	Aloke Gupta

QUESTION 5

What is the expected breakdown of the proposed $26M ADR TI budget between C&I vs. SMB. p. 3-12/13.

a) Also, what is the expected breakdown of these funds between conventional ADR technologies vs. ET technologies (such as those listed on p.3-13)?

b) For the latter, please provide further breakdown by the various ET options on p.3-13.

ANSWER 5

For the proposed budget for the AutoDR incentives in the 2012-2014 period, PG&E's target for Large C&I customers is $16 million and the target for SMB is $10 million.

a) For planning purposes, PG&E has targeted seventy (70) percent of the $16 million requested ($11.2 million) for Large C&I customers to conventional AutoDR technologies and thirty (30) percent of the $16 million requested ($4.8 million) for Large C&I customers to the ET technologies.

b) For planning purposes, PG&E has targeted thirty-three (33) percent ($1.6 million) of the $4.8 million requested for Large C&I ET technology incentives to ET/HVAC and sixty-seven (67) percent ($3.2 million) of the $4.8 million requested for Large C&I ET technology incentives to ET/Lighting.

PACIFIC GAS AND ELECTRIC COMPANY
Demand Response 2012-2014 Projects
Application 11-03-001
Data Response

PG&E Data Request No.:	ED_003-06		
PG&E File Name:	DemandResponse2012-2014-Projects_DR_ED_003-Q06		
Request Date:	July 5, 2011	Requester DR No.:	ED (7/5/11- E-Mail)
Date Sent:	July 15, 2011	Requesting Party:	Energy Division
PG&E Witness:	Ulric Kwan	Requester:	Aloke Gupta

QUESTION 6

Please clarify what is meant by "telemetry solutions for DR resources". p. 3-15/#28.

a) Describe the technical requirements to qualify as telemetry solution.

b) What are the communication channels presumed for these solutions.

ANSWER 6

In this context, “telemetry solutions for DR resources” refers to the provision of real-time or near real-time data to demand response providers to provide visibility into the performance of DR resources. This work is directed to meeting the visibility requirements of the CAISO for resources that participate in its markets. The cost of providing real time visibility is currently high and analysis and pilots need to be performed to reduce these costs to remove a high barrier of entry for DR resources to participate in the CAISO markets.

a) The technical requirements are those that are mandated by the CAISO for visibility. Currently, that is a meter data read every four (4) seconds provided to the CAISO no later than one (1) minute after the meter data read.

b) There are no communication channels presumed for these solutions.

PACIFIC GAS AND ELECTRIC COMPANY
Demand Response 2012-2014 Projects
Application 11-03-001
Data Response

PG&E Data Request No.:	ED_003-07		
PG&E File Name:	DemandResponse2012-2014-Projects_DR_ED_003-Q07		
Request Date:	July 5, 2011	Requester DR No.:	ED (7/5/11- E-Mail)
Date Sent:	July 15, 2011	Requesting Party:	Energy Division
PG&E Witness:	Ulric Kwan	Requester:	Aloke Gupta

QUESTION 7

What is the expected breakdown of the proposed $3.7M budget between the three DR only ET projects described on p. 3-15?

ANSWER 7

The DR only ET projects listed on p.3-15 in PG&E's Opening Written Testimony for the 2012-2014 DR Budget Application were intended to be illustrative of the types and focus of the DR-only ET projects that PG&E wishes to perform in the 2012 through 2014 timeframe. A funding level of $3.7 million for DR only ET projects would allow PG&E to evaluate approximately 12 to 18 DR only ET technologies.

Southern California Edison
2012-2014 Demand Response Application A.11-03-003

DATA REQUEST SET A1103003 ED-SCE-003

To: ENERGY DIVISION
Prepared by: David Reed
Title: Manger, DR Regulatory & Reporting
Dated: 07/05/2011

Question 01:

In LI forecasts shown in Table II-3 on v4.19, both event-based ("temporary") and long-term ("permanent") demand reductions appear to be mixed, as discussed below.

1. Does the LI shown for CPP include the impact of the underlying TOU rate?

2. If yes, please break it out and provide it separately.

    1. Also, please explain how we should interpret the permanent load impacts of the underlying TOU that you decide to provide here?
    2. Are these incremental or cumulative each year (relative to some reference)?
    3. Please explain the methodology use by SCE here to determine the permanent impact (what would be the reference, for example, for each year?).
    4. Moreover, this would then seem to be mixing apples and oranges. Please comment.

3. Why isn't the PLS LI included in this table?

4. How would your methodology for estimating the permanent LI (for PLS, TOU portion of CPP, for example) reconcile with CEC's load forecast?

    1. Wouldn't CEC's load forecast normally be NET of these permanent reductions.
    2. We are concerned about the possibility of double counting here. Please comment.

5. We suggest that LI forecasts need to be separated based on permanent vs. temporary. Please comment.

Response to Question 01:

1. No. The large power CPP (>200kW) LI evaluation accounts for the underlying TOU effect. That is, the reference load is based on non-event days, when customers have responded to TOU price signals. Therefore, for this customer segment the CPP LI forecast is solely due to

CPP and does not include any TOU reductions.

For the medium & small CPP (<200kW), SCE removed the TOU effect from the LI calculation to prevent double counting. The CPP participation rate for medium C&I customers, as determined by the Momentum Market Intelligence simulator tool, was 25.33% (*see* A.07-07-026 Edison SmartConnect Errata, p. 19, line 7). By removing the 4.76% TOU effect we are left with a pure CPP participation rate of 20.57%. To get the total event-based CPP LI, the pure CPP participation rate is multiplied by the average customer impact.

2. 2.1-2.4. Not applicable.

3. SCE's second amended testimony to SCE-1, Volume 4, filed on June 1, 2011, includes PLS LI in table II-3.

4. SCE provides the CEC, on an annual basis, with an updated permanent non-dispatchable LI forecast in the Integrated Energy Policy Report (IEPR) proceeding. In the next IEPR update, SCE will inform the CEC of its estimates of the mandatory TOU effect.

   4.1. Yes it would be. It is our understanding that the CEC's demand forecast includes LI from committed non-dispatchable DR programs (*see* Kavalec, Chris and Tom Gorin, 2009.
   California Energy Demand 2010-2020, Adopted Forecast . California Energy Commission. CEC-200-2009-012-CMF).

   4.2. See in response to question #1, SCE has taken the necessary steps to ensure that the LI forecasts are not double counting.

5. See response to question #4, SCE will provide the CEC with CPP LI forecasts separated based on permanent and temporary.

Southern California Edison
2012-2014 Demand Response Application A.11-03-003

DATA REQUEST SET A1103003 ED-SCE-003

To: ENERGY DIVISION
Prepared by: Anna Chung
Title: Program Manager, Auto-DR
Dated: 07/05/2011

Question 02:

Please provide data on the participation rates (that is, responding to events in whatever DR program the customer is involved in) of AutoDR (ADR) vs. non-ADR customers?

Response to Question 02:

In April 2010, the CPUC approved the expansion of Auto-DR incentives to include the Real Time Pricing rate schedule, the Capacity Bidding Program, and the Demand Response Contracts. By June, only Auto-DR customers on the Critical Peak Pricing (CPP) and Demand Bidding Program (DBP) had sufficient data in the summer of 2010 for comparison of participation rates with non-Auto-DR customers.

For Demand Bidding customers, we used bids as the indicator of a customer's intent to participate in an event. In 2010, on average, 93% of approximately 60 Auto-DR customers submitted bids in DBP events, compared to 34% of approximately 1,300 non-AutoDR DBP customers.

As a default rate schedule, CPP customers are charged for the electricity they use during events. Therefore they have the option to reduce the amount of electricity they choose to use during CPP events. For the purpose of this data request, if we use a simplistic comparison between the two groups, an average of 93% of 35 Auto-DR customers had a net load reduction in 2010 CPP events, compared to 52% of nearly 4,000 non-AutoDR CPP customers. SCE cautions the use of this data to compare these two customer groups, as the majority of CPP customers were defaulted to the program in October 2009 and were on bill protection throughout the summer of 2010 CPP events, which may have affected response rates.

Southern California Edison
2012-2014 Demand Response Application A.11-03-003

DATA REQUEST SET A1103003 ED-SCE-003

To: ENERGY DIVISION
Prepared by: Anna Chung
Title: Program Manager, Auto-DR
Dated: 07/05/2011

Question 03:

What is the target or expected adoption rate for ADR among C&I customers on C&I?

Response to Question 03:

SCE'S target adoption rate for Auto-DR among C&I customers is approximately 10% of the large C&I customers and 1% of the small to medium business customers by the end of 2014.

Southern California Edison
2012-2014 Demand Response Application A.11-03-003

DATA REQUEST SET A1103003 ED-SCE-003

To: ENERGY DIVISION
Prepared by: Anna Chung
Title: Program Manager, Auto-DR
Dated: 07/05/2011

Question 04:

Does SCE require use of OADR protocol by customers for them to be eligible for ADR TI?

1. If not, why not do so to encourage standards-based technologies and avoid future obsolescence of proprietary technologies?
2. If not, what is the breakdown of the ADR TI funds usage in the last 3 year cycle for OADR vs. non-standards "compliant" ADR implementations by customers.

Response to Question 04:

4. - Yes, SCE requires customer technologies to be able to receive and respond to open standard communication protocols such as Open ADR, Zigbee, and Smart Energy Profile, in order to be eligible for Auto-DR technology incentives.

4.1. - See Response #4.

4.2. - See Response #4. In addition, all Auto-DR TI funds were expended on OpenADR compliant implementations to-date.

Southern California Edison
2012-2014 Demand Response Application A.11-03-003

DATA REQUEST SET A1103003 ED-SCE-003

To: ENERGY DIVISION
Prepared by: Anna Chung
Title: Program Manager, Auto-DR
Dated: 07/05/2011

Question 05:

Would any of the the proposed for ADR TI budget be used for SMB customers (as opposed to large C&I customers)? What is the expected breakdown between the two segments.

Response to Question 05:

Auto-DR incentives are available to all non-residential customers, but for purpose of this request, about $6.5 million is estimated for the small to medium business customer class and $21.9 million for large C&I customers, based on our target enrollments (see A.11-03-003, SCE-1, Vol. 2, page 78) for these two customer segments.

A.11-03-002 SDGE Response
Energy Division, Demand Response Program Data Request
DR Applications 2012-2014: Data Request re HAN, ADR, PLS programs

Date Submitted: August 3, 2011

Auto DR

Question 1:

For ADR TI customers, why does SDGE require only 1 year commitment to a DR program (the other IOUs require 3 years)? Doesn't this reduce the CE of the programs?

SDG&E Response:

Person responsible for the response: George Katsufrakis/Michelle Costello

SDG&E is only requiring one year of commitment to a DR program upon completion of the Technical Incentive program. We feel that once the customer has enrolled in the DR program that the requirements or contracts of that program as far as commitment and/or participation should take precedent. Each DR program has contracts and requirements that are specific to the goals and objectives of that program. We wanted to ensure that we minimized any customer confusion about commitments to programs.

While Auto DR customers are required to enroll for only one year in an SDG&E demand response program, SDG&E expects that they will continue enrollment for the duration of the program cycle to maximize their investment in the enabling equipment. SDG&E's load impact forecast reflects this continuation of enrollment, and thus changing the enrollment requirement to a 3-year commitment would not change the load impact forecast. In addition, the relevant technology costs are already amortized over 10 years, with the first 3 years of the payment stream used in the analysis. As both the benefits and the costs would stay the same, the cost effectiveness test results would also be unchanged.

Question 2:

The Small Customer Technology Deployment (SCTD) Program is budgeted at $13M in the current application. However, per SDG&E (Chapter III, p. GMK-55 at the top), it will not launch this program until SDG&E has completed the delayed RACT pilot and SDG&E has received approval of its Advice Letter describing the SCTD implementation plan (which will be filed by SDG&E *after the completion of the RACT pilot*).

a. When is the RACT pilot expected to complete?

b. Please explain why should the Commission approve the SCTD program now as opposed to waiting for approval through the Advice Letter process when results from the RACT pilot are completed?

SDG&E Response:

Person responsible for the response: George Katsufrakis/Michelle Costello

a. The RACT pilot is scheduled to complete by the end of 2011. The report documenting the results of the pilot will be available in the Q1 2012.

b. We are seeking approval of the scope and funding level for the SCTD program in this application. The final design and implementation strategy will be informed by the RACT pilot and approval will be requested via an Advice Letter. SDG&E's intends, as expressed in testimony, that SCTD will not be fully implemented until these steps have been taken. SDG&E does not feel that approval of this funding is appropriate for an Advice Letter and, as such, is requesting it through this application. SDG&E believes that it is very important for the consistency and transition from a customer perspective for no gap to exist between the completion of the RACT pilot and the approval of the scope and funding of SCTD. This is a key element to maintaining positive customer engagement.

A.11-03-002 SDGE Response
Energy Division, Demand Response Program Data Request
DR Applications 2012-2014: Data Request re HAN, ADR, PLS programs

Date Submitted: August 3, 2011

PLS

Question 1:

ALJ's Ruling of 4/29/11 re PLS guidance (Section 3.1.1) directed the IOUs to "agree on consensus values for project lifetime for *different technologies*".

This appears not to have been done. According to SDG&E's Supplemental Testimony, Chapter IV, p.1 (middle), "During that discussion [of the Joint Utilities (JUs)], the [E3] PLS Study was identified as the best source…The assumptions taken from the study and used by SDG&E as a *result of this discussion with the Joint Utilities* [our emphasis] include the following:…Project lifetime: 15 years."

Thus, it appears that the JUs used 15 year lifetime as global average for *all* PLS technologies.

Is this correct? If yes, given the guidance, please explain why you used the same project lifetime average for all PLS technologies?

a. The E3 PLS report indicates that the 15 year figure used in the study is simply an assumption (that is *not* derived from any survey or analysis of industry data) to established a reference base scenario.

If you are asked to reconsider in compliance with the guidance, what would be your recommended lifetime values for thermal storage vs. batteries.

b. If not correct, please show what values were used.

SDG&E Response:

Person responsible for the response: Kevin McKinley/Brenda Gettig

a. When the IOUs met earlier this year to discuss consensus assumptions to be used in a cost effectiveness analysis for PLS, it was agreed that the E3 PLS report was the best and most recent resource available at the time for these types of assumptions. SDG&E followed the direction provided in the April 29th Ruling by meeting with the other IOUs, arriving at a set of consensus assumptions based on the recently published Commission directed PLS study, and using those assumptions in the analysis. At this time, SDG&E does not have an additional recommendation for lifetime values.

b. The statement that SDG&E used 15 years as the equipment lifetime in its PLS cost effectiveness analysis is correct. The 15 year assumption was taken from the E3 PLS report, which was considered the best and most recent source for cost effectiveness assumptions related to PLS program offerings.

Question 2:

Please provide further details on how the PLS program would work? For example, please address the following (or some close variation of these): George K/Michelle C

a. Which technologies would be eligible for incentives?
b. Would there be some type of pre-testing or qualification required for a technology to be eligible?
c. How will PLS performance (load shift kW) be measured or verified to determine incentive level due to a customer?

d. Would the PLS project be eligible for TA (technical audit) funding under IDSM (in case there are EE benefits associated with the PLS project)?

SDG&E Response:

Person responsible for the response: George Katsufrakis/Michelle Costello

a. The technologies that we will target are thermal energy storage (TES) and deep cycle batteries to achieve a permanent load shift for the entire on-peak period. We are not aware of other technologies that we want to target, but we are open to other technologies (excluding gas cooling per the direction from the December 2010 PLS report). It is difficult to create a simple, technology neutral PLS program design that addresses all of the different technologies and cost effective incentive levels. This challenge was recognized in the PLS study and we feel we have arrived at a manageable compromise.

b. The customer has the option of choosing their own vendor or having SDG&E work with the customer to identify opportunities through a verification report produced by the customer or sub-contracted vendor. Upon SDG&E measurement and verification of potential load shift and commissioning, a one- time incentive payment will be provided to the customer.

c. Incentives will be determined using the methodology described in Answer 2B. Additional measurement and verification, however, will be performed. The customer's load shift would be verified through historic usage data and validated during the commissioning inspection. A load impact evaluation of the program will be conducted annually in accordance with the load impact protocols including a ten year forecast based on ex-post event results. The impact evaluation will be completed by April 1st each year and will be filed with the CPUC. Additionally, other analysis related to program design (such as a baseline analysis) will be conducted as needed. One process/market evaluation for the program is planned during the three year cycle to be used to inform future program design and to evaluate and improve the operation of the program.

d. Customers will be provided the opportunity to use the SDG&E Technical Audit program to identify and create a PLS verification report, inclusive of additional energy efficiency and demand response opportunities, rebates and incentives.

Question 3:

If different technologies are allowed (which may have substantially different project lifetimes and round trip efficiencies, for example), would it reasonable to provide different levels of incentives corresponding o the total avoided cost benefit provided by the different technologies (for example, higher incentive for 25 year technology vs. 15 year technology), assuming other factors being same.

Please discuss the merits of this technology type-specific approach vs. a single proposed incentive level for all mature PLS technologies together.

SDG&E Response:

Persons responsible for the response: George Katsufrakis/Michelle Costello

SDG&E's demand response programs, and the associated incentive levels, were developed using the E3 cost effectiveness calculator. Initially the PLS program was developed without the benefit of such a calculator and the program design was informed by the Statewide Joint IOU Study of Permanent Load Shifting. On a going forward basis, SDG&E will use the cost effectiveness calculator. The ability to capture differential PLS technology benefits, like energy savings, should be incorporated into the CE calculator. This is one area where statewide consistency is critical and if differential benefits exist, SDG&E requests that Energy Division set statewide values for these additional benefits.

Question 4:

PG&E has proposed different levels of incentive depending the hours of load shift. Please discuss the merits of SDGE's single incentive level approach vs. SDG&E adopting PG&E's multi-level approach.

SDG&E Response:

Persons responsible for the response: George Katsufrakis/Michelle Costello

In our Locational Demand Response pilot proposal, we will offer premium incentives to customers on the target circuit that install and use Permanent Load Shifting (PLS) technologies. This premium incentive is an emerging technologies track for PLS and in order to qualify for this incentive the installed technology must fall within the definition of emerging PLS technologies; technologies like batteries and small thermal energy storage would qualify. Qualifying technologies installed on the target circuit would receive an additional $250/kW bringing the total incentive to $750/kW. For technologies that cannot shift for the full seven hours but can deliver at least 3 hours of permanent load shifting between 11 AM and 6 PM, the incentive will be reduced to $300/kW.

For the general PLS program we want to encourage customers to shift for the full seven hour time period and will pay the full $500/kW incentive payment. However, in the Locational Demand Response pilot, we are allowing for the smaller, more emerging technologies such as battery storage to be tested and we acknowledge that they may not be able to shift for the full peak period. We will allow for partial shifts of at least 3 hours during the peak of the day on these constrained circuits since this is where and when the shift is most needed, but will reduce the incentive payment to $300/kW.

Question 5:

Rather than having a fixed incentive level, have you considered a declining incentive level that starts out higher (to stimulate the market) and gradually drops in steps tied to cumulative installed volume reaching certain levels (similar to the CSI model)? Please discuss the merits of such an approach and how it might affect market transformation and customer adoption vs. the currently proposed approach.

SDG&E Response:

The CSI incentives are an example of a policy intention to adopt a declining incentive level over time failing in actual practice. This is because CSI is but one of many incentives to promote distributed generation. When viewed in combination with all other existing incentives (such as

net energy metering with badly distorted retail rate design and the Federal Investment Tax Credit), total incentives are actually now at the same level or higher than when solar incentives were first initiated in California, even though the price of solar has declined substantially over this period of time. CSI is an example of why incentives cannot be considered in isolation from each other and why transparency and awareness of all existing incentives is critical when considering additional incentive programs and/or whether a policy to gradually reduce incentives as prices decline could, should, or is actually being implemented. Unlike PLS, CSI is also intended for thousands of small customers, has a budget of over $3 Billion (CSI, NSHP and POU program) and a ten year time horizon. PLS targets key customer with large on-peak demand, with a much smaller budget and a three year time horizon. As such, PLS is an opportunity to demonstrate technology, and not to "move the market". SDG&E feels that because of these differences PLS is not a good fit for the declining incentive design.

What consideration, if any, has been given to aligning the three IOU PLS programs in terms of common program design elements, including incentive levels (since the currently proposed incentives by the JUs are quite similar)?

SDG&E Response:

SDG&E feels that aligning PLS incentive levels with utility specific tariffs and other SDG&E demand response program takes a priority over alignment with PG&E and SCE PLS programs. Aligning SDG&E's PLS program with SDG&E's TOU tariffs is the only way to maximize the true incentive to our customers. Referring to Statewide Joint IOU Study of Permanent Load Shifting, "Figure 11: Broad Scenario Analysis – Rate Payer Neutral Incentive" on page 52 shows a rate payer neutral incentive for a six hour reduction that starts at 11 AM of roughly $500/kW and an incentive for a eight hour shift starting at 11 AM of a little over $600/kW. These values are in alignment with SDG&E's $500/kW and $750/kW incentive level. Per Figure 11 as well as Table 9, rate payer neutral incentives are very specific to each utility.

Please discuss the feasibility and merits of having some level of uniformity in program design across the IOUs (that is, standardizing some program elements - such as those discussed above in #2, 3, 4 – among the JUs)?, including potential advantages (such as better third party & customer education, reduced costs for industry, higher customer acceptance, etc) vs. potential disadvantages of standardizing some program elements.

SDG&E Response:

SDG&E has worked and will continue to work with PG&E and SCE to ensure program uniformity where appropriate.

Persons responsible for the response: George Katsufrakis/Michelle Costello

Question 6:

The PLS CE analysis shows TRC ratio to be significantly less than one. The CE protocols require that "Non-energy/monetary benefits" (perceived by customers, for example) be considered in TRC analysis. Do you agree that this factor, while it may be difficult to quantify, could be an important element in customer's decision to install PLS equipment? Please explain your answer.

SDG&E Response:

Persons responsible for the response: Kevin McKinley/Brenda Gettig

At this time SDG&E does not have any data on the non-energy impacts related to PLS technology. Any consideration of non-energy benefits would need to include the non-energy costs as well (e.g. inconvenience and other negative impacts). Lacking sufficient data on this subject, SDG&E assumed conservatively that any non-energy benefits and costs canceled each other out.

Question 7:

In SCE's Rebuttal (Section VII.D), SCE (Wood) summarizes a finding from E3's report as "customers have been unwilling to make the investment because of TOU risk." We did not find any discussion in the JU proposals re how to address this issue and ask you to comment on the following:

One option to address the TOU risk is to transfer the value of the avoided cost benefit (net of the up-front incentive and other program costs) to the customer in the form of a "guaranteed" TOU differential for the life of the project, regardless of how the actual rates might change over time (essentially a PLS specific tariff or "rider", somewhat similar to having a EV-specific tariff).

Please comment on the feasibility and/or other concerns (or advantages) of such an approach.

SDG&E Response:

In E3's report stakeholders support reducing the risk of tariff modification. E3 concludes that "…retail rate design is very important for PLS **and capturing the most grid benefits**." (emphasis added) SDG&E agrees that retail rate design is critical for capturing the grid benefits of PLS. Accurate price signals are critical for driving grid benefits since they reflect utilization and cost causation. The first step should be to ensure that the rates as a whole reflect accurate pricing and to the extent they do not they need to be addressed. For instance if rates do not recover grid costs based on how the grid is utilized then retail rates will drive behaviors that could ultimately increase costs rather than reduce them. Therefore, it is critical that the benefits PLS systems create are not undermined by fixing TOU differentials and periods based on today's conditions. This is because if future conditions don't match the retail signal that is "fixed" today PLS systems may not be discharged in a manner that creates grid benefits tomorrow.

For example, in SDG&E's service territory we are witnessing escalating adoption of PV systems which are effectively shifting on-peak periods later in the day. Fixing TOU periods now could ultimately create a price signal that influences PLS to charge during a period which today is not on-peak, but in the future could be or discharge in a period that was on-peak and now is not. This issue holds true for all must take renewable energy that is added to the utilities portfolio. As CA seeks to adds increasing amounts of renewables there will be impacts on the on, off and super-off

peak periods. Ultimately, the best assurance that PLS will create both participant benefits and grid benefits are accurate price signals. Fixing TOU period differentials and/or periods does the opposite. It assures that future TOU pricing realties are not being incorporated into future PLS dispatch decisions. While it may provide greater certainty for PLS participants it erodes the value of doing PLS in the first place, grid benefits.

Alternatively, another suggestion that E3 proposes is a super off peak period which would send an accurate price signal. This type of proposal is set up to be handled in the utilities GRC Phase 2. While a special tariff for PLS with a super off peak would work, ultimately all customers should be encouraged to shift energy use to a super off-peak period. This would encourage the same grid benefits that the PLS system is designed to accomplish and therefore should be available to all customers. This is the fundamental reason why it is a better solution than fixing TOU periods and/or differentials, because it is sustainable rate design. If the benefits can be created through an accurate price signal for all customers, a price signal that benefits both participants and bundled rate payers, then it is a practice that creates a sustainable market for PLS as well as any other technology or consumer behavior that accomplished the same fundamental shift in usage that lowers costs and emissions through more efficient grid utilization.

In order to move towards a low carbon future CA ultimately needs greater accuracy in retail rates. This will provide greater assurance that technologies will be developed and deployed which create benefits that can be passed on to participants without shifting costs to other ratepayers. Sustainable rate design does not discriminate between technologies or customer classes nor does it predetermine winners or losers. Rather sustainable rate design creates a platform where technological innovation and customer choice ultimately decide how CA achieves a low carbon future.

Persons responsible for the response: Chris Yunker

Southern California Edison
2012-2014 Demand Response Application A.11-03-003

DATA REQUEST SET A1103003 ED-SCE-009

To: ENERGY DIVISION
Prepared by: Kevin Wood
Title: Manager
Dated: 07/27/2011

Question 01:

ALJ's Ruling of 4/29/11 re PLS guidance (Section 3.1.1) directed the IOUs to "agree on consensus values for project lifetime for *different technologies* ".

This appears not to have been done. According to SDG&E's Supplemental Testimony, Chapter IV, p.1 (middle), "During that discussion [of the Joint Utilities (JUs)], the [E3] PLS Study was identified as the best source…The assumptions taken from the study and used by SDG&E as a *result of this discussion with the Joint Utilities* [our emphasis] include the following:…Project lifetime: 15 years."

Thus, it appears that the JUs used 15 year lifetime as global average for *all* PLS technologies.

Is this correct? If yes, given the guidance, please explain why you used the same project lifetime average for all PLS technologies?

a. The E3 PLS report indicates that the 15 year figure used in the study is simply an assumption (that is *not* derived from any survey or analysis of industry data) to established a reference base scenario.

   If you are asked to reconsider in compliance with the guidance, what would be your recommended lifetime values for thermal storage vs. batteries.

b. If not correct, please show what values were used.

Response to Question 01:

1. SCE reached a consensus with the IOUs (or referred to in this data request as JUs; Joint Utilities) on a 15 year lifecycle for all technologies. This consensus among the utilities was quickly reached after the ALJ's ruling directing the IOUs to file amended testimony on May 20, 2011. The IOUs utilized much of the information received in the CPUC directed PLS report and determined that there was no argument against adopting 15 years as the lifecycle for *all* technologies (the PLS report used an average lifetime generally used for HVAC and building energy analysis). In addition, the IOUs found the 15-year lifecycle reasonable because the DR Reporting Template (aka cost-effectiveness model) provided sensitivity analyses that ranged from 7.5 to 22.5 years; a range that will not only cover the life of a PLS technology, but also the practical <u>or physical</u> lifetime range of PLS equipment. Therefore, it would be very impractical to attempt to create an incentive that varied by lifecycle. Finally, providing a global average for all

PLS technologies supports SCE's technology neutral program for mature technology.

1.a. SCE does not plan to do a case by case study to determine the lifecycle for different types of technology capable of providing PLS. Although SCE recommends a 15 year lifetime value for both thermal storage and batteries, SCE proposes to offer two different incentive levels to support the continued adoption of mature technologies and that of market transformation through emphasis on new and emerging PLS technologies. The mature technologies program will provide a technology incentive of up to $545 per kW and up to $3,000 per kW for emerging technology.

Southern California Edison
2012-2014 Demand Response Application A.11-03-003

DATA REQUEST SET A1103003 ED-SCE-009

To: ENERGY DIVISION
Prepared by: Kevin Wood
Title: Manager
Dated: 07/27/2011

Question 02:

Please provide further details on how the PLS program would work? For example, please address the following (or some close variation of these):

a. Which technologies would be eligible for incentives?

b. Would there be some type of pre-testing or qualification required for a technology to be eligible?

c. How will PLS performance (load shift kW) be measured or verified to determine incentive level due to a customer?

d. Would the PLS project be eligible for TA (technical audit) funding under IDSM (in case there are EE benefits associated with the PLS project)?

Response to Question 02:

a. The E3/Strategen PLS Study categorizes PLS technology as thermal storage, non-thermal storage, and facility process shifting. SCE supports the CPUC's definition of PLS as "when a customer moves energy usage from one time period to another on an ongoing basis" and will adopt this definition to define PLS technology. In order to remain technology-neutral, SCE will establish program requirements based on the definition above.

b. Yes. The technology qualification will be based on the SCE program requirements. It will be up to the vendor/manufacturer to qualify their technology based on California's Codes and SCE's PLS Program rules to participate in SCE's PLS Program. There will have to be an M&E process in place to verify load shift and proper functioning of the technology upon installation. This will determine the how much the customer will receive in PLS incentives.

c. Performance will be measured on an application by application basis similar to SCE's TI (Technical Incentive) Program. Verification of a customer's ability to perform permanent load shifting before installation of equipment will be required. As to whether the customer will receive their incentives through installments pre or/and post installation is still to be decided, but it is certain that testing for verification of permanent load shifting will be required. A preliminary assessment and/or technical audit, similar to AutoDR, will have to be performed by an engineer to determine if there are load shifting opportunities available to the customer. This will be modeled similar to AutoDR where a customer's baseline will be used to determine the

customer's ability to perform PLS.

d. SCE's proposal will not preclude PLS from IDSM audits and will consider EE benefits in the identification of the PLS vendor by the customer. Project benefits will be reviewed on a case by case basis as with other IDSM audit requests.

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DATA REQUEST SET A1103003 ED-SCE-009

To: ENERGY DIVISION
Prepared by: Paul Nelson
Title: Senior Project Manager
Dated: 07/27/2011

Question 03:

If different technologies are allowed (which may have substantially different project lifetimes and round trip efficiencies, for example), would it reasonable to provide different levels of incentives corresponding o the total avoided cost benefit provided by the different technologies (for example, higher incentive for 25 year technology vs. 15 year technology), assuming other factors being same.

Please discuss the merits of this technology type-specific approach vs. a single proposed incentive level for all mature PLS technologies together.

Response to Question 03:

SCE advocates a technology neutral policy approach to let the market determine the best technology that best meets the customer's needs. By, offering a uniform incentive for a specified per-kilowatt of demand shifted, the customer will choose the most cost-effective technology for factors it values most, whether that is a longer life span or better round-trip efficiency. If a technology provides a lifecycle greater than 15-years, then the incentive is for the customer to invest in such technology because they receive the value of long lasting equipment. However, with technological advancement customers may not value longer life span due to obsolesance. Over time, market dynamics will send the proper signal to what performance factors customers' value the most for a quantity of load shifting. The only caveat to this technology-neutral policy would be to offer a higher incentive to emerging technologies to create an incentive for innovation.

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DATA REQUEST SET A1103003 ED-SCE-009

To: ENERGY DIVISION
Prepared by: Kevin Wood
Title: Manager
Dated: 07/27/2011

Question 04:

PG&E has proposed different levels of incentive depending the hours of load shift. Please discuss the merits of SCE's single incentive level approach vs. SCE adopting PG&E's multi-level approach.

Response to Question 04:

SCE assumes that this question is referencing single incentive levels for each technology. SCE has requested two-incentives; one for mature technologies and one for emerging technologies.

There are many different approaches that a utility could undertake when implementing a PLS program. However, SCE's preferred approach is to require a minimum 6-hour shift. This is ideal because it matches SCE's TOU on-peak hours of 12 p.m. - 6 p.m. when generation is most valuable. Anything less than the 6-hour shift would not match those hours and have reduced system benefit. Anything greater than six hours would have rapidly decreasing marginal benefit. Therefore, a shift greater than 6 hours does not warrant a higher incentive.

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DATA REQUEST SET A1103003 ED-SCE-009

To: ENERGY DIVISION
Prepared by: Kevin Wood
Title: Manager
Dated: 07/27/2011

Question 05:

Rather than having a fixed incentive level, have you considered a declining incentive level that starts out higher (to stimulate the market) and gradually drops in steps tied to cumulative installed volume reaching certain levels (similar to the CSI model)? Please discuss the merits of such an approach and how it might affect market transformation and customer adoption vs. the currently proposed approach.

What consideration, if any, has been given to aligning the three IOU PLS programs in terms of common program design elements, including incentive levels (since the currently proposed incentives by the JUs are quite similar)?

Please discuss the feasibility and merits of having some level of uniformity in program design across the IOUs (that is, standardizing some program elements - such as those discussed above in #2, 3, 4 – among the JUs)?, including potential advantages (such as better third party & customer education, reduced costs for industry, higher customer acceptance, etc) vs. potential disadvantages of standardizing some program elements.

Response to Question 05:

By definition, mature technologies should not require ratepayer subsidies to maintain a self-sufficient industry. Mature technology manufacturers need to decide during the 2012-2014 program cycle whether they will find opportunities to reduce costs to ensure a quick pay-back or convert their offerings to emerging technologies. SCE focused on creating a ratepayer- and technology- neutral incentive program.

The IOUs have been working together to design a common PLS program where applicable. Each IOU represents a different customer territory and, therefore, will design a program that best fits the needs of its customers. The IOU's will continue to work together on creating a consistent PLS Program, but SCE will not adopt a program decision just for the sake of consistency with the other IOUs if it does not meet the needs of our customers.

Standardizing incentives amongst the IOUs would not be ideal for customers because each IOU has its own costs and benefits. Our rate structures are created based on SCE-specific costs and benefits and not that of PG&E and SDG&E.

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To: ENERGY DIVISION
Prepared by: Kevin Wood
Title: Manager
Dated: 07/27/2011

Question 06:

In PG&E's Rebuttal (Chap. 3A, A2 (2)), PG&E indicates that part of the rationale for the proposed PLS program budget level is that this level provides "a reasonable level of market transformation to technologies that are near maturity". Please explain or discuss any available data or other basis to suggest that the incentive levels proposed by you would be attractive enough to stimulate sufficient industry interest and customer adoption to enable market transformation.

Response to Question 06:

SCE created a ratepayer neutral incentive program based on the ratepayer neutral incentives provided by the Permanent Load Shifting Study. The Study does not specify either program size or incentive levels required for market transformation. The PLS vendors have made statements regarding program size and incentives required for market transformation. However, data requests of the vendors have not produced analysis or research supporting the statements (see attached files).

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To: ENERGY DIVISION
Prepared by: Maggie Poon
Title: Project Manager
Dated: 07/27/2011

Question 07:

The PLS CE analysis shows TRC ratio to be significantly less than one. The CE protocols require that "Non-energy/monetary benefits" (perceived by customers, for example) be considered in TRC analysis. Do you agree that this factor, while it may be difficult to quantify, could be an important element in customer's decision to install PLS equipment? Please explain your answer.

Response to Question 07:

Non-energy/monetary benefits include better public image, improving the environment, etc. While non-energy/monetary benefits are important elements in customer's decision to install PLS equipment, the quantifiable benefits, such as the amount of financial subsidy customers receive from PLS, probably remains the major factor in their decision making process. In addition, as the CE protocols mention, non-energy/monetary benefits are difficult to quantify, so it is challenging in assessing such values.

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To: ENERGY DIVISION
Prepared by: Paul Nelson
Title: Senior Project Manager
Dated: 07/27/2011

Question 08:

In SCE's Rebuttal (Section VII.D), SCE (Wood) summarizes a finding from E3's report as "customers have been unwilling to make the investment because of TOU risk." We did not find any discussion in the JU proposals re how to address this issue and ask you to comment on the following:

One option to address the TOU risk is to transfer the value of the avoided cost benefit (net of the up-front incentive and other program costs) to the customer in the form of a "guaranteed" TOU differential for the life of the project, regardless of how the actual rates might change over time (essentially a PLS specific tariff or "rider", somewhat similar to having a EV-specific tariff).

Please comment on the feasibility and/or other concerns (or advantages) of such an approach.

Response to Question 08:

It has been a long-standing CPUC policy to develop rates based upon marginal cost principles to achieve fair and economically efficient rates. As referenced in Exhibit SCE-7, SCE's rebuttal testimony, in June, SCE filed its 2012 GRC Phase 2 which included generation marginal costs. (See SCE's 2012 GRC Phase2, which includes a generation cost forecast for 2012-14. A. 10-06-007, Exhibit SCE-7 (SCE-2) pp 22-26. The GRC testimony includes an explanation for the significant decrease in the ratio between on-peak and off-peak period from 2009 GRC filing. (In the 2009 GRC, the summer ratio was 1.47 and 2012 GRC ratio is 1.32.) Two reasons for the declining price differential are a combination of increasing amounts of solar photovoltaic generation and carbon emission policies. As the renewable portfolio standard compliance increases to 33% by 2020 and the cost of carbon emissions increases, then it is likely for the time of use (TOU) cost differential to decline further. To lock in current price differential for the life of the project would violate the CPUC's cost allocation and pricing principles.

Implementing a guaranteed TOU differential for PLS customers based upon a total resource cost (TRC) metric would be an unfair burden to non-participants if the cost of service changes. This is because other customers would pay for the difference between the cost of service and the revenue collected from PLS customers; which would also reduce the ratepayer (RIM) test. In the future, the cost differential is likely to change dramatically creating difficulty in accurately transferring the avoided cost benefit into locked TOU a rate differential. It is also possible, that the locked in rate could be less advantageous than the otherwise applicable tariff, causing issues about a two-way commitment. To indemnify the PLS customer from project risk must not be

taken lightly as is any revenue shortfall would result in an unfair transfer of cost to other customers.

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DATA REQUEST SET A1103003 ED-SCE-009

To: ENERGY DIVISION
Prepared by: Paul Nelson
Title: Senior Project Manager
Dated: 07/27/2011

Question 09:

In SCE's Rebuttal (Section VII.E), SCE (Wood) indicates that T&D O&M "is not avoided by DR". Is this statement specific to "event-based DR" or does it apply to a PLS based program involving long-term, "permanent" demand reduction as well?

a. If the former, please indicate what the revised D-factor would be for PLS?

b. If the latter, please explain why T&D and the associated O&M would not be avoided (or deferred) if demand is reduced "permanently" via PLS?

Response to Question 09:

To summarize, a) the D-factor is unchanged because T&D O&M is not avoided by either demand response or PLS, and b) this is because the cost to patrol and inspect T&D facilities is not impacted by the customer's reduction in demand on event days or due to the shift in load to another time period.

Here is a more detailed explanation. The cost to deliver power through the transmission and distribution (T&D) to customers consists of two portions. First, is the capital cost such as substation equipment (land, buildings, and switching gear) transformers, poles, and wires. Second is the operations and maintenance (O&M) cost to patrol, inspect, and maintain the capital equipment which does not vary with the usage of the circuit.

Because SCE builds its system to meet the customer's peak demand, the T&D capacity is already in place to meet a customer's peak demand, including those that select a demand response program. Thus, a demand response customer does not avoid T&D investment. However, subject to the criteria of right place and certainty, a demand response customer could defer the upgrade of a transformer to a larger size due to customer growth. The right place criterion is used to determine if a customer is on a circuit that could benefit from load reductions as some existing circuits are in areas of none or very little load growth. If the transformer capacity already meets the customers' needs and if the load in the area is not growing, then there is no deferral benefit. SCE performed an analysis on which circuits could benefit from DR programs, and the results were used to develop the D-factor.

While there may be transformer upgrade deferral benefits, however, the customer will not defer the cost of substation equipment, poles, or wires because they still receive electric service from an already built service. The O&M cost to patrol and inspect T&D a facility is also not avoided

due to demand response because T&D O&M is driven by their connection to the grid not by their usage. As SCE explained in the testimony it has removed the O&M component from the avoided T&D cost for SCE through the D-factor calculation.

Permanent load shifting (PLS) is different from DR in that the load is permanently shifted to another time period and not simply avoided. The assumption that there is always a T&D benefit associated with a shift from the on-peak period is an erroneous assumption because not all of SCE's circuits peak in the generation on-peak period. As mentioned in the testimony, (A.11-03-003, Exhibit SCE-5, (SCE-1, Volume 4) page 35, footnote 24.) a circuit peak study showed that 30% of SCE's circuits peak from 6pm-6am. Therefore if a PLS customer is on one of these circuits, then the load sifting would increase costs, not avoid costs. As for T&D O&M cost, the requirement to patrol and inspect T&D facilities is generally unchanged by the shift in customer's load.

(END OF APPENDIX)