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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots and Budgets for 2012-2014.	Application 11-03-001 (Filed March 01, 2011)
Application of San Diego Gas & Electric Company (U902M) for Approval of Demand Response Programs and Budgets for Years 2012- 2014.	Application 11-03-002 (Filed March 01, 2011)
Application of Southern California Edison Company (U338E) for Approval Demand Response Programs, Activities and Budgets for 2012-2014.	Application 11-03-003 (Filed March 01, 2011)

COMMENTS
OF THE DIVISION OF RATEPAYER ADVOCATES
ON THE PROPOSED ALTERNATE DECISION

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TABLE OF CONTENTS

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**COMMENTS
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I. INTRODUCTION

Pursuant to Rule 14.3 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the Division of Ratepayer Advocates ("DRA") hereby submits these comments on the Alternate Proposed Decision ("APD") of Commissioner Mark J. Ferron to the Proposed Decision ("PD") of Administrative Law Judge ("ALJ") Hymes in Pacific Gas and Electric Company ("PG&E") Application ("A.") 11-03-001; Southern California Edison Company's ("SCE") A.11-03-003 and San Diego Gas and Electric Company ("SDG&E") A.11-03-002. The APD authorizes revised funding for these three Investor Owned Utilities ("IOUs") for their proposed Demand Response ("DR") programs and activities for years 2012-2014.

DRA commends Commissioner Ferron for a thoughtful and fair APD that, like the earlier PD by ALJ Hymes, attempts to balance ratepayers' interests with the flexibility necessary to implement the Commission's new cost-effectiveness protocols. Although DRA prefers adoption of ALJ Hymes' PD, DRA can support the APD as an alternative, with modifications. DRA identifies certain technical and factual errors in the APD in these comments and proposes changes to correct those errors. The proposed changes are also presented in the form of redline changes to ordering paragraphs in the Appendix to these comments.

II. DISCUSSION

A. Technical Errors in the APD

Several technical errors in the APD must be addressed, and remedied in the final decision. These include:

1. Finding of Fact ("FOF") #47 contradicts FOF #46. FOF #46 states that the utilities have not effectively used existing budgets to achieve Commission objectives to integrate Demand Side Management ("DSM") programs, but then notes in FOF #47 that SCE's integrated DSM programs have performed successfully with less than their authorized budget. The APD should clarify which statement it believes is true.

2. Conclusion of Law ("CoL") #3 should be modified. With respect to the cost-effectiveness of the programs in this proceeding, CoL Nos. 2, 4, 5 and 6 all clarify that the particular cost-effectiveness tests used in the APD are "[s]olely for the purposes of this proceeding." However, this clarification is omitted in the CL #3, which provides a 10 percent error band for cost-effectiveness Benefit/Cost ("B/C") ratios. Since the error band is integral to how the APD views the cost-

effectiveness of programs in this proceeding, the APD's language—"[s]olely for the purposes of this proceeding"—should also be added to the CoL #3.[1]

B. Factual Errors In The APD

DRA also notes the following factual errors in the APD that should be modified in the final decision.

1. The Commission Should Affirmatively State, As A Finding Of Fact, That PG&E's Current LOLP Model Is Not Publicly Available Or Independently Verifiable.

Based on the facts on the record, DRA proposes the Commission include a *new* Finding of Fact in the APD which states that PG&E's current LOLP model *cannot* be shared in the public domain and *cannot* be verified independently.[2]

This fact is not disputed. At hearings, when the DRA asked PG&E witness, Mr. Gavelis, if PG&E plans to offer its LOLP proprietary model into the public domain, Mr. Gavelis responded, "Well, first, it wasn't PG&E's model. It was Global Energy's PROSYM model. So, no. The short answer is no, we are not going to provide PROSYM to the public."[3] Upon further cross examination on whether the model can be verified independently, Mr. Gavelis replied, "since PG&E only controls the inputs and outputs, then that is all that can be verified."[4]

Although the cost-effectiveness protocols adopted by the Commission in D.10-12-024 permits the use of an alternate model in addition to the E3's default model, the protocols also state a preference that such alternate model can be: (1) shared in the public domain, and (2) verified independently.[5] PG&E's current LOLP model is neither

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[1] *See* DRA Proposed Revisions, Appendix.

[2] *See* DRA Proposed Revisions, Appendix.

[3] RT, Vol. 1, p. 40 (July 19, 2011).

[4] *Id.*, p. 42.

[5] D.10-12-024, Attachment 1, 2010 Cost-Effectiveness Protocols, p. 23.

available in the public domain, nor can it be verified independently, and this should be stated accordingly in the final decision.

Inclusion of this Finding of Fact in the final decision is necessary because the Commission's policy on the use of proprietary models should be clarified. The LOLP model that PG&E currently uses will not be available in the public domain nor can it be verified independently. The APD appears to reject the LOLP model primarily because APD finds that "PG&E provides insufficient evidence that the LOLP model is more accurate than the default E3 model."[6] While the APD correctly notes the LOLP model is proprietary,[7] the APD should further clarify that the LOLP itself is rejected because it is not available in the public domain and it cannot be verified independently, as required by the cost-effectiveness protocols adopted by the Commission in D.10-12-024.

2. There Is No Factual Evidence Supporting Findings Of Fact 21 And 22

The load impact protocols require that the customer's baseline load, on the day of the event, be established by averaging customer load on the previous 10 days before the demand response event. To account for sudden changes in the load on the day of the event, the protocols currently allow an up or down adjustment to the customer's baseline load by 20 percent. The DR aggregators argue that even a 40 percent adjustment underestimates customer actual load.[8] The Commission has not yet determined what the accurate adjustment to the baseline should be. The APD states,

> The Commission finds the results of the utilities data response to be of limited use. There is no clear evidence to determine the most accurate day-of adjustment that should be used for all the Utilities. More studies are needed to make an informed decision on baseline settlement.[9]

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[6] APD, Finding of Fact ("FOF") #6.

[7] APD, FOF #7.

[8] APD, p. 59.

[9] APD, p.63.

Clearly, the Commission acknowledges that more studies are needed before determining the most accurate baseline adjustment cap. Yet, the Commission makes a definitive finding that the 20 percent day-of cap for a 10-in-10 baseline understates load reduction and underpays customers for their actions. Accordingly, Finding of Fact #21 should be modified to indicate that the 10-in-10 baseline *may* understate load reduction and *potentially* underpay customers for their actions.[10]

For the same reasons, Finding of Fact #22, which finds that a 40 percent cap for day-ahead and day-of adjustment to 10-in-10 baseline as a fair interim solution, is also not justified and should be deleted.[11]

3. The APD, Like The PD, Misstates DRA's Recommendation On Budget Shifting.

The language regarding fund shifting should be modified since its explanation of DRA's testimony is inaccurate. The APD states: "As recommended by DRA and agreed to by SCE, we require the Utilities to file a Tier 2 advice letter before shifting more than 50 percent of a program's funds to a different program within the same budget category."[12]

This requirement currently exists today. Further, this is an inaccurate statement of DRA's recommendation in its testimony. DRA stated in its prepared testimony that "the Utilities are currently required to file a Tier 2 advice letter to request authorization to shift more than 50% of a program's funds to another program within the same budget category."[13] The next sentence states: "DRA recommends that the Commission extend the requirement to file a Tier 2 advice letter to request authorization to increase individual DR program budget by more than 50% of its original budget through fund shifting."[14]

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[10] *See* DRA Proposed Revisions, Appendix.

[11] *Id* (emphasis added).

[12] APD, p. 28.

[13] Exhibit DRA-1 and DRA-1c, p. 8.

[14] *Id* (emphasis added).

Both SCE[15] and SDG&E[16] support DRA's recommendation for a corollary rule to extend the Tier 2 advice letter requirement when a utility proposes to increase individual DR program budget by more than 50 percent of its original budget, regardless of budget category.

Accordingly, both the language of the APD at page 28 and associated Ordering Paragraph #3 should be modified in the final decision, as shown in DRA's Proposed Revisions.[17]

4. The APD's Directive In Ordering Paragraph 10 On PG&E AMP Contracts Contradicts The APD's Policy Goals Enumerated In Ordering Paragraph 12 For DR Integration.

In the Ordering Paragraph #10, the APD directs PG&E to renegotiate the terms of its expired Aggregator Managed Programs ("AMP") for 2013 and 2014 to effectively improve the cost-effectiveness of AMPs, as measured by the Total Resource Costs ("TRC") test, to attain a B/C ratio of at least 0.9. DRA finds several inconsistencies with this directive.

First, in the Ordering Paragraph #11, the Commission authorizes PG&E to extend its current AMPs through December 31, 2012. Therefore, there is ample time for PG&E to negotiate the contract terms for 2013 and 2014. Since these contracts could be negotiated from scratch, there is no reason why the Commission could not require the new AMP contracts to meet the DR protocols' standard for demonstrating cost-effectiveness by requiring the TRC test value of new AMPs to be at least 1.0. The diluted standard of 0.9 should not be used for the limited purpose of approving programs filed only in this proceeding.

Second, in the Ordering Paragraph #12, the Commission directs Investor Owned Utilities ("IOUs") to work with the Commission Staff, the California Independent System Operator ("CAISO") and the Procurement Review Groups to develop the Request for

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[15] SCE's Opening Brief, p. 79.

[16] SDG&E's Opening Brief, p. 24.

[17] *See* DRA Proposed Revisions, Appendix.

Proposals ("RFP") requirements to meet future system needs, notably integration of DR with renewable resources. The DR aggregators as a group are more likely the most competent party to configure and prepare DR resources to meet these future needs. Since SCE and SDG&E do not plan to negotiate new contracts until the Commission establishes direct participation rules in CAISO's wholesale markets, their new aggregator contracts likely would reflect those requirements in the RFP to meet future system needs. Allowing PG&E to negotiate new AMP contracts for 2013 and 2014, without requiring these to conform to the RFP, would be inconsistent with the Commission's goals for DR resources stated in Ordering Paragraph #12. DRA strongly recommends the Commission first establish the RFP requirements, and then allow all three IOUs to negotiate new contracts for 2013-2014 and beyond that conform to such requirements.

The APD should delete the Ordering Paragraph #10 to be consistent with meeting APD's goals for future needs.[18]

5. Approval Of BIP Program Should Be Conditional Upon The FERC's Approval Of CAISO's Reliability Demand Response Resource Product.

The APD notes that, on February 16, 2012, the Federal Energy Regulatory Commission ("FERC") rejected the CAISO's proposed Reliability Demand Response Resource ("RDRR") tariff and provisions.[19] The CAISO developed the RDRR tariff to transition IOUs' reliability programs (primarily the IOUs' Base Interruptible Program, or "BIP") to integrate into the CAISO market and operations. The Commission has not opined upon whether the IOUs' reliability programs—which are typically called after a CAISO emergency—will continue to receive Resource Adequacy ("RA") credits if the RDRR tariff is not approved by the FERC. The APD should make the approval of IOUs' BIP programs conditional upon approval of the RDRR tariff by FERC to ensure that

[18] *See* DRA Proposed Revisions, Appendix.

[19] APD, p. 14.

ratepayers will not be paying twice for the same RA capacity the IOUs' BIP programs were expected to provide.[20]

6. Ordering Paragraph 75 Conflicts With The Cost-Effectiveness Requirements In The APD And Violates Parties' Due Process Rights.

In the Ordering Paragraph #75, the APD, for all compliance submissions ordered in the APD which require cost-effective analyses, directs the Commission Staff to provide further guidance to the parties on the format and assumptions for the cost-effectiveness compliance submissions within 15 days of the issuance of the decision. There are several compliance submissions ordered in the APD that require IOUs to make changes to their costs and/or benefits to programs in order to demonstrate that they are cost-effective. Further guidance to the parties on the format and assumptions for the cost-effectiveness compliance *in this proceeding* is not necessary and will only result in further confusion.

The APD already adopts s policy on how it will use the cost-effectiveness results for approving IOUs' programs in this proceeding.[21] Principally, the APD established that: 1) the program's TRC test results should attain a minimum benefit/cost ratio of 0.9 and 2) the cost-effectiveness of programs should be evaluated using the E3 model results. If now, as directed by APD, the Commission Staff, on its own, is to establish a new format and new assumptions for cost-effectiveness determinations for compliance submittals in this cycle, this will circumvent the due process rights of DRA and other parties to this proceeding. The APD provides no discussion on whether parties may submit input on either the new guidelines or assumptions, or whether stakeholders would have an opportunity to comment on IOU's revised submissions. Therefore, the APD should reaffirm that the compliance filings shall be based on the cost-effectiveness protocols adopted in D.10-12-024. The APD should maintain the same evaluation format

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[20] *See* DRA Proposed Revisions, Appendix.

[21] APD, Section 6.2.

and assumptions for IOUs' compliance filings as the APD's evaluation format and assumptions for programs already approved in the APD. Keeping the same evaluation format and assumptions would provide transparency, consistency and allow proper evaluation of IOUs' compliance. Accordingly, DRA recommends the final decision delete Ordering Paragraph #75.[22]

In future cycles, it would be more appropriate to make changes to the cost-effectiveness protocols in the Demand Response rulemaking, R.07-01-041.[23] To do so, the Commission may expand the scope in a new Scoping Ruling. Then, as an attachment to that ruling, Staff may propose a revised format and assumptions for subsequent review and comment by all parties.

7. The APD Should Clarify That The Utilities Revised Cost-Effective Analyses Demonstrate That Their Programs Are Cost-Effective Using E3's Model Results.

As discussed above, DRA recommends the Commission not change the current evaluation format and assumptions for IOUs' compliance filings required under APD's Ordering Paragraphs Nos. 20, 36, 37, 38, 40, 44, 55, 58, and 79. Since the APD concludes that the Commission should only consider the E3 model results when reviewing cost-effectiveness,[24] these ordering paragraphs should clarify that IOUs' compliance filings should be based on the E3 model results.[25]

8. The APD Errs In Its Characterization Of CPP And In Affording Special Treatment For SCE's CPP And RTP Programs

The APD begins its discussion of dynamic rates with a significant inaccuracy in its characterization of CPP. The APD states:

> The Utilities' Dynamic Pricing programs provide electric rates that reflect wholesale market conditions. Dynamic

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[22] *See* DRA Proposed Revisions, Appendix.

[23] Conclusion of Law # 7 and Ordering Paragraph # 5.

[24] Conclusion of Law #1.

[25] *See* DRA Proposed Revisions, Appendix.

> Pricing programs available to customers include Critical Peak Pricing and Real Time Pricing. Critical Peak Pricing imposes a short-term rate increase on customers during critical conditions. Real Time Pricing programs charge customers rates similar to actual hourly wholesale energy prices.[26]

The first sentence is factually inaccurate, at least with respect to CPP. The CPP program imposes a *pre-determined* short-term rate increase on customers on 9 to 15 anticipated peak demand days, irrespective of the wholesale market conditions on those days, or the actual system need for demand response.

In addition, although SCE's Critical Peak Pricing ("CPP") and Real Time Pricing ("RTP") programs are not cost-effective,[27] the APD authorizes substantial marketing, education and outreach ("ME&O") budgets. The APD reasons, "Because dynamic rate programs are in the purview of GRCs or dynamic rate proceedings, we do not make program modifications in this proceeding."[28] The APD further states that, "We direct that funding for these programs after this DR cycle not be included in future DR applications."[29] DRA finds APD's reasoning inconsistent, insufficient, and impractical to implement.

First, the APD is inconsistent about its treatment of Dynamic Pricing programs. The APD properly considers the cost-effectiveness of SCE and SDG&E's Peak Time Rebate ("PTR") programs but does not address the cost-effectiveness of SCE's CPP and RTP.

Second, not requiring changes to the costs or benefits of SCE's CPP and RTP programs to make them cost-effective is also inconsistent with the Energy Action Plan, which calls for procurement of cost-effective DR resources.

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[26] APD, p.131.

[27] SCE's CPP has a TRC B/C ratio of 0.4 and RTP has a B/C ratio of 0.87.

[28] APD, p.135.

[29] *Id.*

Third, directing utilities "to not include funding for these programs in future DR applications"[30] does not address the main issue. The main issue is how and where the cost-effectiveness of CPP and RTP would be addressed if not in this DR proceeding. The GRC proceedings typically do not address the cost-effectiveness of dynamic pricing programs based on any protocols. The current SCE GRC proceeding (for 2012 Test Year) does not request funding for marketing, education and outreach ("ME&O") activities for CPP or RTP or address the cost-effectiveness of these programs. If the cost-effectiveness of CPP or RTP is not addressed in this proceeding, the earliest it could be addressed is in SCE's 2015 Test Year GRC cycle. The APD's reluctance to address cost-effectiveness of CPP or RTP would mean, in practice, it will not be addressed anywhere at all. The Commission should not allow this situation to continue any longer.

Consistent with the APD's Ordering Paragraph 20, the APD should require that SCE either decrease the overall budget requested or increase the relative benefits for CPP and RTP programs to make them cost-effective. DRA recommends adding a new ordering paragraph to accomplish this.[31]

III. CONCLUSION

DRA appreciates the opportunity to comment on the APD. DRA prefers the Commission ultimately adopt ALJ Hymes' Proposed Decision, with the changes proposed in DRA's November 17 and 22, 2011 comments. However, should the Commission ultimately authorize this alternate, DRA respectfully requests adoption of the recommendations made herein.

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[30] APD, p.136.

[31] *See* DRA Proposed Revisions, Appendix.

Respectfully submitted,

/s/ LISA-MARIE SALVACION

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*** APPENDIX ***

DRA PROPOSED REDLINES

ADD Finding of Fact:

PG&E's current LOLP model cannot be shared in the public domain and cannot be verified independently.

REVISE Finding of Fact #21

20 percent cap on the day of adjustment for the 10-in-10 baseline may understate~~s~~ load reduction and potentially underpays customers for their actions.

DELETE Finding of Fact #22

~~The 40 percent cap for both the day-ahead and the day-of adjustment for the 10-in-10 baseline provides a fair balance for all customers as an interim solution.~~

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REVISE Conclusion of Law #3

Solely for the purposes of this proceeding, ~~I~~it is reasonable to use a 10 percent error band given the relatively new nature of the cost-effectiveness protocols.

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REVISE Alternate Proposed Decision Discussion on page 28:

As recommended by DRA and agreed to by SCE and SDG&E, we require the Utilities to file a Tier 2 advice letter to request authorization to increase individual DR program budget by ~~before shifting~~ more than 50 percent of original budget through fund shifting. ~~a program's funds to a different program within the same budget category.~~

REVISE Ordering Paragraph #3

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company:

- May not shift funds between categories;

- May continue to shift up to 50 percent of a Demand Response program's funds to another program within the same budget category, with proper monthly reporting;
- Shall not shift funds within the "Pilots" category without a Tier 2 Advice Letter filing;
- May shift funds for pilots in the Enabling or Emerging Technologies category;
- Shall continue to submit a Tier 2 Advice Letter to eliminate a Demand Response program;
- Shall not eliminate a program through multiple fund shifting events or for any other reason without prior authorization from the Commission;
- Shall submit a Tier 2 advice letter before shifting more than 50 percent of a program's funds to a different program within the same budget category; and
- Shall file a Tier 2 advice letter to request authorization to increase individual DR program budget by more than 50 percent of original budget through fund shifting.

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DELETE Ordering Paragraph #10

~~Pacific Gas and electric Company (PG&E) shall renegotiate the terms of its expired Aggregator Managed Programs contracts to effectively improve the cost-effectiveness so that the Total resource Costs tests attain at least 0.9. Within 90 days from the issuance of this decision, PG&E shall submit a Tier 2 Advice Letter that includes the renegotiated cost-effective contracts, along with a revised cost-effectiveness analysis that provides the results of the three cost-effectiveness tests. We authorize PG&E to extend the cost-effective contracts effective 2013 through 2014.~~

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REVISE Ordering Paragraph #s 23, 24, 25, 26, and 27

23. Southern California Edison Company's Base Interruptible Program during 2012-2014 is approved, provided the FERC approves CAISO's RDRR tariff and provisions. A budget of $2,407,226 is authorized for 2012-2014.

24. San Diego Gas & Electric Company's (SDG&E) Base Interruptible Program is approved, provided the FERC approves CAISO's RDRR tariff and provisions, as follows. SDG&E shall decrease the administrative costs of its Base Interruptible

Program by $362,179. SDG&E shall eliminate its Base Interruptible Program-Option B to conform the program to the California Independent System Operators Reliability Demand Response Product.

25. The summer month premium for San Diego Gas & Electric Company's Base Interruptible program is approved, provided the FERC approves CAISO's RDRR tariff and provisions.

26. A budget of $3,816,821 is authorized for San Diego Gas & Electric Company's Base Interruptible Program during 2012-2014 is approved, provided the FERC approves CAISO's RDRR tariff and provisions.

27. Pacific Gas and Electric Company's (PG&E) Base Interruptible Program is Approved provided the FERC approves CAISO's RDRR tariff and provisions. PG&E shall improve the cost-effectiveness of this program by a) increasing the number osf call hours from 120 to 180 hours annually, b) decreasing the DR Systems Support budget by $3,963,399, and c) decreasing the Local Demand Response Marketing, Education and Outreach budget allocated to this program by $140,704. These changes shall go into effect for 2013and 2014.

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DELETE Ordering Paragraph # 75

~~For all compliance submissions ordered in this Decision which require cost-effectiveness analyses, Commission Staff shall provide further guidance to the parties on the format and assumptions to be used for the cost-effectiveness analyses. Commission Staff shall provide that guidance within 15 days of the issuance of this decision~~.

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REVISE Ordering Paragraph # s 20, 36, 37, 38, 40, 44, 55, 58, and 79.

20. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall either decrease the overall budget requested or increase the relative benefits for each program approved in this decision to make their programs cost-effective. The cost-effectiveness analysis shall use E3 model results.

36. San Diego Gas & Electric Company (SDG&E) Peak Time Rebate program is approved. SDG&E shall recalculate its cost-effectiveness analysis of its Peak Time Rebate program to include the customer incentives in the analysis and submit the results in a Tier 2 Advice Letter 60 days following the issuance of this decision. <u>The cost-effectiveness analysis shall use E3 model results.</u>

37. We approve Southern California Edison Company's (SCE) Capacity Bidding Program and authorize a budget of $661,287 for this Program. SCE's DR Systems budget is decreased by $1.7 million to reflect the majority of the $1.9 million portion of that budget which is allocated to the Capacity Bidding Program. SCE shall perform an in-depth analysis of its Capacity Bidding Program to (1) propose details of how the full-year program would work; (2) analyze the differences between Pacific Gas and Electric Company, San Diego Gas & Electric Company and SCE's Capacity Bidding Program; and (3) provide a plan for improving the Capacity Bidding Program cost-effectiveness to 0.75 in 2013 and to 0.9 in 2014. SCE shall submit this analysis in a Tier 2 Advice Letter no later than 120 days following the issuance of this decision. <u>The cost-effectiveness analysis shall use E3 model results.</u>

38. Pacific Gas and Electric Company's (PG&E) Capacity Bidding Program is approved. PG&E shall decrease the budget for this program by $1.5 million in the marketing, education and outreach budget category in order for the day-of option of this program to be cost-effective. PG&E shall submit its revised cost-effectiveness analysis with a Tier 2 Advice Letter within 45 days from the issuance of this decision. <u>The cost-effectiveness analysis shall use E3 model results.</u>

44. Pacific Gas and Electric Company's (PG&E) Demand Bidding Program is approved. PG&E shall perform an updated cost-effectiveness analysis and submit it along with a recalculated budget in a Tier 2 Advice Letter no more than 60 days from the issuance of this decision. If the results indicate less than cost-effective, PG&E shall further revise its Demand Bidding Program budget. We authorize PG&E a budget of $3.216 million for its 2012-2014 Demand Bidding Program, contingent upon the receipt of the results of the resubmitted cost-effectiveness analysis. <u>The cost-effectiveness analysis shall use E3 model results.</u>

55. Commission Staff shall seek feedback from interested parties and facilitate a consensus process for Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) to finalize their Permanent Load Shifting (PLS) statewide program design and rules. Within 30 days of notification from Commission Staff, the Utilities shall submit the final proposal, including budget details and revised cost-effectiveness analysis,

of the statewide PLS program with a Tier 2 Advice Letter to the Commission. The cost-effectiveness analysis shall use E3 model results.

58. San Diego Gas & Electric Company's Small Customer Technology Deployment program is approved with the following changes: (1) limit participation in this program to Peak Time Rebate customers only; (2) combine the two programs, (3) within 60 days of the issuance of this decision submit a Tier 2 Advice Letter that includes an updated cost-effectiveness analysis of the combined programs, and (4) 30 days after the completion of the Residential Automated Control Technology Pilot, submit a Tier 2 Advice Letter with updated details of the Small Customer Technology Deployment program informed by the results of this pilot. Commission Staff shall review the Advice Letter as a condition for release of the authorized budget for this program. The cost-effectiveness analysis shall use E3 model results.

79. Unless otherwise specified, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may file a Tier 2 advice letter, within 45 days of the issuance of this decision, showing how a program's benefits will be increased in lieu of decreasing a budget to make a "possibly cost-effective" program "cost effective" as defined in this decision. The cost-effectiveness analysis shall use E3 model results.

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ADD A NEW Ordering Paragraph

SCE shall either decrease the overall budget requested or increase the relative benefits for CPP and RTP programs to make them cost-effective. The cost-effectiveness analysis shall use E3 model results.