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

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	R.12-03-014 (Filed March 22, 2012)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) TRACK 1 OPENING BRIEF

CHARLES R. MIDDLEKAUFF
MARK R. HUFFMAN

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3842
Facsimile: (415) 973-0516
E-Mail:MRH2@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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SUMMARY OF RECOMMENDATION

Pacific Gas and Electric Company recommends that

- The Commission make its need determination in Track 1 be based on the local capacity technical study that the California Independent System Operator has presented in Exhibit ISO-1.
- The Commission not establish any "preferred resources" set-asides as a part of Track 1. All resources and all technologies, including combined heat and power and storage, should be allowed to compete on an equal footing to meet the identified need.
- The Commission reject the joint proposals of Alliance for Retail Energy Markets, the Direct Access Customer Coalition, and the Marin Energy Authority to modify the CAM.
- The Commission reject the joint proposal of Alliance for Retail Energy Markets, the Direct Access Customer Coalition, and the Marin Energy Authority that LSEs be given the option to "opt-out" of CAM.
- the Commission reject the South San Joaquin Irrigation District's proposal that D.08-09-012 be modified, to foreclose the application of CAM in the context of any municipalization.
- The Commission maintain its adopted Track 1 schedule to reach a Track 1 decision by the end of this year.
- The Commission determine that the costs that Southern California Edison Company incurs to meet Local Capacity Requirement needs in the LA Basin should be allocated to all benefiting customers in Southern California Edison Company's service territory—including bundled service, direct access, and community choice aggregation customers—but not to any customers outside of Southern California Edison Company's service area.

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PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) TRACK 1 OPENING BRIEF

Pursuant to the schedule established during the last day of Track 1 hearings, Pacific Gas and Electric Company (PG&E) files its opening brief in Track 1 of the Long-Term Procurement Plan (LTPP) proceeding.

I. EXECUTIVE SUMMARY

The need determination the Commission makes in Track 1 should be based on the local capacity technical study that the California Independent System Operator (CAISO) has presented in Exhibit ISO-1. Other parties' proposals that the Commission makes its need determination using studies with very different assumptions, studies that assume less "unmanaged" demand to begin with, and more contributions from sources such as uncommitted energy efficiency, demand response, combined heat and power, and distributed generation, should be rejected. Proper planning in the face of uncertainty requires that the system be designed to operate reliably under a reasonable range of outcomes, not just those outcomes that would have the least need for additional resources.

The Commission should not establish any "preferred resources" set-asides as a part of Track 1. While the California Cogeneration Council and the California Energy Storage Association may be arguing for combined heat and power and storage set-asides, respectively, no set-asides should be created in Track 1.[1/] Set-asides increase costs for ratepayers and should be avoided. The actual selection of resources to meet a forward procurement requirement should be done through a competitive procurement process that enables all resources and all technologies, including combined heat and power and storage, to compete on an equal footing.

The direct access and community choice aggregators' proposals to modify the cost adjustment mechanism (CAM) should be rejected. All of the proposals for change made in this proceeding would simply shift an unfair portion of the capacity costs of ensuring that the CAISO system can be operated reliably onto investor-owned utility (IOU) bundled customers, and away from direct access and community choice aggregation customers. Nor should load-serving entities be given the option to "opt-out" of CAM. If adopted, the opt-out proposal could very well adversely impact reliability and impose additional administrative burden on the IOUs and the Commission.

The South San Joaquin Irrigation District's proposal that D.08-09-012 be modified, to foreclose the application of CAM in the context of any municipalization, should be rejected. Depending on the circumstances, including whether the municipalization is a "large municipalization" as discussed in D.08-09-012, fair treatment of remaining bundled customers may not be possible unless CAM is applied.

With respect to the timing of Track 1, the Commission should maintain its schedule, established in the May 17, 2012 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, to reach a Track 1 decision by the end of this year.

Finally, the costs that Southern California Edison Company (SCE) incurs to meet local capacity requirement (LCR) needs in the LA Basin should be allocated to all benefiting customers in SCE's service territory—including bundled service, direct access, and community choice aggregation customers—but not to any customers outside of SCE's service territory.

1/ PG&E supports the qualifying facility/combined heat and power Settlement adopted in D.10-12-035, and the targets it contains.

Neither PG&E nor San Diego Gas & Electric Company (SDG&E) allocates the costs to meet LCR needs in their respective service areas to customers in SCE's service territory. It would be unfair to customers in PG&E's and SDG&E's service territory to have to bear a portion of the costs of ensuring that the local requirements in SCE's service territory are satisfied.

These recommendations are discussed in the following sections, in the order established in the common briefing outline circulated by SCE.[2/]

II. DETERMINATION OF LOCAL CAPACITY REQUIREMENTS (LCR) NEED IN CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO) STUDIES

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B. Consideration Of Preferred Resources, Including Uncommitted Energy Efficiency, Demand Response, Combined Heat And Power, And Distributed Generation, In Determining Future LCR Needs

The load forecast used by the CAISO for its LCR studies is reasonable. It provides an appropriate basis for evaluating the resources that are likely to be necessary to maintain reliable system operation in 2021. Therefore, the need determination The Commission makes in Track 1 should be based on the local capacity technical (LCT) study that the CAISO has presented in Exhibit ISO-1 to the Commission for its consideration.

Other parties would have the Commission make its need determination using studies with very different assumptions, studies that assume less "unmanaged" demand to begin with, and more contributions from sources such as uncommitted energy efficiency (EE), demand response (DR), combined heat and power (CHP) and distributed generation (DG). The Commission should reject these recommendations. Proper planning in the face of uncertainty requires that the system be designed to accommodate a reasonable range of outcomes, not just those outcomes that would have the least need for additional resources.

2/ In this brief PG&E has omitted common outline headings where PG&E has not addressed the identified topic.

1. Energy Efficiency, Demand Response, Combined Heat And Power, And Distributed Generation

The treatment of incremental EE, DR, CHP, DG and demand in the CAISO's Ex. ISO-1 LCT study, which several parties criticize in their testimony, is reasonable for evaluating local capacity needs. Several parties argue that the CAISO's Track 1 analysis is flawed with respect to the assumptions made about these variables.[3/] PG&E disagrees. Determining local reliability needs requires a conservative approach, as was taken by the CAISO. Specifically, only those resources (demand or supply-side) that have a high likelihood of being realized should be assumed to be available in evaluating whether the system can be expected to operate reliably.[4/]

Taking EE, for example, one modeling approach would be to allocate EE resources, adjusted for customer class, proportionately across the service territory. In particular, a proportionate amount would be allocated to the local area under consideration.

However, that forecast of local EE availability is fairly uncertain. It is very likely that EE resources will not be distributed evenly across the system. Some areas will have relatively more, while others will have relatively less, compared to the forecast. Because of this, if one were to rely on such a "proportionate allocation" forecast to evaluate local capacity needs, then local reliability could be seriously compromised.[5/]

This same concern applies to CHP (and other distributed generation). While it is possible to encourage installations at certain localities (for example, by the use of a location adder in the CHP feed-in-tariff), this does not guarantee that the resources will appear in the desired location.[6/]

This concern applies to DR resources, as well. Parties argue that DR savings that are likely to be achieved on a system basis can also be achieved on a local planning basis. It is unlikely that this will be the case across all areas, and the areas where it will not happen are

3/ *See, e.g.*, Ex. DRA-3, p. 1; Ex. TURN-1, p. 9.
4/ Ex. PG&E-1, p. 19.
5/ Ex. PG&E-3, p. 19.
6/ Ex. PG&E-3, p. 19.

unknown. There is significant variation with how DR resources are adopted across an IOU's service territory. All DSM resources depend on customer adoption and on a forecast basis it is impossible to geographically predict customer choice. Including these savings without significant reductions to account for potential shortfalls could put local reliability at increased risk.[7/]

In their testimony, several parties mention one or more of the following proposals:[8/]

(1) the 12,000 MW renewable DG goal; or

(2) the 6,500 MW CHP goal from the Governor's Clean Energy Jobs Plan.

None of these proposals have been fully described or defined, nor have they been evaluated for cost effectiveness compared to other options. At this point, they are aspirations whose fulfillment may require future actions, by utilities, private parties, and regulators, that may or may not actually occur.[9/] At this time these potential resources do not fully meet the standard of "cost-effective, reliable, and feasible" in Public Utilities Code Section 454.5. It would be overly optimistic to assume these levels for these resources in the Commission's evaluation of local capacity needs,[10/] resulting to increased risk to local reliability. In short, it is too optimistic at this time to simply assume that 100 percent of incremental EE, DR and CHP can be counted on to meet local resources needs.

Using a conservative approach to determine local reliability needs is the more prudent approach to take for planning and procurement. It is the approach that the CAISO has taken in its analysis, and PG&E urges the Commission to take the same approach in making its determination of need in Track 1.

2. Load Forecast

The California Environmental Justice Alliance (CEJA) suggests that the CAISO's

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7/ Ex. PG&E-3, p. 20.
8/ *See, e.g.*, Ex. DRA-3, pp. 8-10; Ex. CCC-1, p. 5.
9/ Ex. PGE-1, p. 20.
10/ Ex. PGE-1, p. 20.

reliance on a 1-in-10 demand scenario is inappropriate.[11/] CEJA is incorrect. The CAISO's use of a 1-in-10 demand scenario to determine local capacity needs is a reasoned, conservative approach.

CEJA does not elaborate as to why it believes the CAISO's analysis to be inappropriate. It is not. Load projections should be adequate to represent a range of resource need that might occur. The CAISO's use of a 1-in-10 peak load scenario is consistent with this approach.[12/] The Commission must ensure the system will be reliable under a variety of possible future states, including a high load stress condition. The CAISO's studies must therefore evaluate need under these assumptions, in order to enable the Commission to make an informed judgment of the resources that should be added to ensure that the CAISO will be able to operate the system reliably under a wide range of potential future states. The 1-in-10 peak load scenario appropriately captures the high load stress scenario.

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IV. PROCUREMENT OF LCR RESOURCES AND INCORPORATION OF THE PREFERRED LOADING ORDER IN LCR PROCUREMENT

A. Incorporation Of The Preferred Loading Order In LCR Procurement

PG&E is committed to meeting its future energy needs in accordance with the preferred loading order. However, the Commission should not establish any "preferred resources" set-asides as a part of Track 1. In particular, the California Cogeneration Council (CCC) may be arguing for a CHP set-aside, while the California Energy Storage Association (CESA) may be arguing for a storage set-aside.

In general, set-asides increase costs for ratepayers and should be avoided. The actual selection of resources to meet a forward procurement requirement should be done through a competitive procurement process that enables all resources and all technologies, including preferred resources and storage, to compete on an equal footing. No set-asides should be

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11/ Ex. CEJA-1, p. 32.
12/ Ex. PGE-1, p. 21.

established to meet the need identified in Track 1, as the result is certain to increase costs and risk to reliability

1. CHP

CCC states that "[i]f the state is serious about its CHP goals, the only way to achieve them is to maintain a place in the IOUs' portfolios for CHP, as determined in these LTPP proceedings. This includes assuming that CHP can meet both local and system capacity needs. Otherwise, the IOUs will eliminate the need for CHP, by filling that need with conventional resources and then arguing there is no need for further CHP resources."[13/]

No CHP set-aside, above and beyond the targets agreed to in the qualifying facility (QF)/CHP Settlement and approved by the Commission in D.10-12-035, is necessary or appropriate. The CAISO's testimony presented in this proceeding, and discussed by CCC, provides estimates of the amount and type of capability needed in the system. If CHP resources can provide the desired attributes—and can do so in a cost-effective and environmentally sound manner when compared to other alternatives—then CHP should be selected to meet the resource need. Creating a set-aside for CHP is not "assuming" it will provide local and system capacity needs (as suggested by CCC), it will only increase prices whenever CHP cannot do so competitively.

CHP is already brought into the IOU portfolio in several ways and does not need an additional set-aside. The existing programs that support CHP include the QF/CHP Settlement, Assembly Bill 1613, Public Utility Regulatory Policies Act (PURPA) power purchase agreements (PPAs) for QFs less than 20 MW, and the Self-Generation Incentive Program.[14/] These programs offer CHP facilities of all sizes a preferred procurement process. The IOUs' obligation to purchase CHP under the CHP Program is clearly defined in the QF/CHP Settlement's term sheet. PG&E supports the QF/CHP Settlement and recommends that existing

13/ Ex, CCC-1, p. 14.
14/ Ex. PGE-1, p. 16.

programs be given a chance to demonstrate success in achieving the state's policy goals,[15/] which does not require any additional CHP preference through the LTPP.

CHP resources should be allowed to participate in these local area procurement processes and be evaluated based on their ability to support cost-effective local area reliability.

2. Storage

CESA makes three main recommendations in its testimony. First, CESA recommends that the Commission's long-term procurement planning assumptions should begin including energy storage immediately, and that the Commission should place a very strong emphasis on energy storage in all planning scenarios.[16/] Second, CESA proposes that the Commission should focus on assumptions needed to model the performance, costs, and benefits of energy storage.[17/] And third, CESA recommends that the Commission adopt a multi-year procurement mechanism that includes energy storage. CESA explains that the Commission should develop processes for multi-year procurement that provide reasonable rates of return for energy storage investments, including industry infrastructure and individual projects.[18/]

CESA's first and second recommendations are more focused on Track 2, the system need determination track of this proceeding. But with respect to Track 1, CESA has presented nothing to suggest that the CAISO's Track 1 analysis has erred in its treatment of storage. PG&E has no objection to consideration of energy storage as one of the alternatives available to the meet the local capacity need identified in Track 1. However, PG&E opposes adoption of any preference or "set aside" for storage resources in Track 1.[19/]

CESA's third recommendation for a multi-year procurement process is outside the scope of Track 1. Multi-year procurement requirements are the subject of Track 3. Also related to the issues raised by CESA, the Commission has indicated that it will "immediately begin the effort

15/ Ex. PGE-1, p. 16.
16/ Ex. CESA-1, pp. 7-9.
17/ Ex. CESA-1, pp. 12-14.
18/ Ex. CESA-1, pp. 14-16.
19/ Ex. PGE-1, p. 18.

to finalize a framework for filling flexible capacity needs" in the ongoing resource adequacy rulemaking. PG&E supports the adoption of a multi-year procurement requirement for load serving entities (LSEs) to meet their projected reliability and flexibility requirements. PG&E, however, does not support the adoption of an energy storage procurement requirement, as CESA proposes.[20/] Specifically with respect to the topic of Track 1, whether there is a need for local capacity to ensure continued reliable operation of the system, all resources, including storage, should be allowed to compete to meet the identified resource need.

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VI. COST ALLOCATION MECHANISM (CAM)

A. Should CAM Be Modified At This Time?

The CAM should not be changed at this time. All of the proposals for change made in this proceeding would simply shift an unfair portion of the capacity costs of ensuring that the CAISO system can be operated reliably onto IOU bundled customers, and away from direct access, community choice aggregation (DA/CCA) and future municipal departing load customers. The current CAM, which provides a fair way to apportion these costs, should not be modified to incorporate these one-sided modifications.

1. The Process And Criteria For Determining CAM Resources Should Not Be Changed

The Alliance for Retail Energy Markets (AReM), the Direct Access Customer Coalition (DACC), and the Marin Energy Authority (MEA) (referred to jointly as the DA/CCA Parties), proposed new proposed processes and criteria for determining "cost allocation mechanism" (CAM) resources. The DA/CCA Parties' proposals are biased and unfair to bundled customers, and so should be rejected.

First, the DA/CCA Parties' version of cost causation unfairly assumes that CCA and DA customers have first rights to and can meet their requirements exclusively from existing

20/ Ex. PGE-1, p. 18.

resources. The DA/CCA Parties would require that bundled customers pay the marginal and presumably higher cost of any new resources as well as the cost of replacing existing resources.[21/]

Second, the DA/CCA Parties indicate that in determining when CAM procurement should occur, the Commission should determine "[i]f the load of the bundled utility customers is driving the peak or decreasing the system load factor. . . ."[22/] In terms of cost causation, the load of any customer – not just a utility's bundled customers – may increase or decrease the need for new capacity. PG&E opposes this cost causation proposal.

However, if the Commission were to adopt this cost causation proposal, then the Commission should require all DA and CCA providers to submit procurement plans, including detailed load and forecast data, in procurement proceedings that – following open scrutiny and review similar to that applied to IOU forecasts – can then be used to determine DA and CCA load impacts on the need for new resources.[23/]

In the past, DA providers and CCAs have not submitted their own load data and forecasts in these proceedings. However, if the DA/CCA Parties' cost causation proposal is adopted, this would result in the Commission having an incomplete picture.[24/] If the DA/CCA Parties truly support their proposal, they should be willing to agree that all DA providers and CCAs be required to submit procurement plans to the Commission that include detailed load forecast information.

The DA/CCA Parties recommend that their process be adopted in March 2013 when the IOU bundled procurement plans are currently scheduled to be filed.[25/] If the Commission adopts this aspect of the DA/CCA Parties' proposal, it should require all energy service providers (ESPs) and CCAs to file their own LTPP procurement plans at that time, which would include

21/ Ex. PGE-1, pp. 7-8.
22/ Ex. AReM-1, p. 21.
23/ Ex. PGE-1, p. 8.
24/ Ex. PGE-1, p. 8.
25/ Ex. AReM-1, p. 34.

load forecasts.

2. Proposed Modifications To The CAM Charge Methodology Should Not Be Adopted

The proposed modifications to the CAM charge methodology should not be adopted. The proposed changes to the CAM calculation: 1) the inclusion of additional forecast revenue to offset the CAM charges;[26/] 2) the levelization of the annual revenue requirement for IOU-owned generation (UOG) and front-loaded power purchase agreement (PPA) costs;[27/] and 3) the imposition of a cap for CAM costs;[28/] should each be rejected.

The DA/CCA Parties propose that the proxy calculation used to determine net CAM costs be changed to include additional incremental ancillary service revenue, renewable integration value and the options value of a long-term tolling agreement into the imputed revenues that offset the resource's cost in determining the CAM amount. The current approach was part of a Settlement Agreement approved in D.07-09-044.[29/] The Commission found that the Settlement was reasonable and that it balanced the interests of the various parties.[30/] It is not reasonable to go back now to alter only certain aspects of that Settlement, since it was a compromise on the various issues between all the parties. The DA/CCA Parties provide no reasonable justification for this proposed change to the Settlement Agreement.

Furthermore, the use of only non-spin imputed revenues in addition to imputed energy revenues, the current approach, was not an oversight. The imputed energy revenue already includes all the hours in which the resource is determined, after the fact, to have been economic to dispatch given actual day-ahead energy prices.[31/] Therefore, it would not be reasonable to impute any additional ancillary services revenues in those hours.

26/ Ex. AReM-1, p. 39-43.
27/ Ex. AReM-1, pp. 44-47.
28/ Ex. AReM-1, pp. 47-48.
29/ The Joint Parties' Proposal was part of a settlement agreement in R.06-02-013 that was adopted in D.07-09-044 and is contained in Section IX of Appendix A of that decision.
30/ D.07-09-044, p. 11 and Finding of Fact 6.
31/ D.07-09-044, Appendix A, Section IX.B.2.a.

For the remaining hours, the hours when it would not have been economic to dispatch the unit in the day-ahead energy market, imputed revenues for providing non-spinning reserves are included if economic and if the resource can provide such service.[32/]

The imputed day-ahead energy revenues are a proxy for all the energy or ancillary service revenue the resource could capture when it was economic to dispatch, and the imputed non-spin revenue is a proxy for all the incremental ancillary service revenue the resource could capture when it was not economic to dispatch. Thus, the current approach fairly estimates the market revenues that would have been received.

Therefore, the DA/CCA Parties' proposal to include additional imputed revenues on top of those adopted in D.07-09-044 should be rejected. It is a one-sided change to an adopted Settlement that would double count imputed revenues in an attempt to lower the CAM charge.

Turning to the DA/CCA Parties' proposal to levelize the annual revenue requirement for UOG in calculating the CAM charge, it is inconsistent with the statutory language in Public Utilities Code Section 365.1(c)(2)(C). That provision of the Public Utilities Code requires the use of the annual revenue requirement for UOG that is subject to the CAM, not the levelized costs.

Moreover, the DA/CCA customers should pay the same costs as bundled customers based on the normal trajectory of revenue requirements, which start higher and end lower than the levelized value.[33/] Using a levelized cost creates an unfair advantage for DA and CCA customers.

PG&E notes that in the Reopening Direct Access Proceeding (R.07-05-025), Mark Fulmer, one of the DA/CCA Parties' witnesses, took the opposite position regarding using levelized costs. In that proceeding, Mr. Fulmer maintained that to determine an appropriate market price benchmark for renewable resource costs, the actual revenue requirement of UOG

32/ D.07-09-044, Appendix A, Section IX.B.2.b.
33/ Ex. PGE-1, p. 10.

renewable resources should be used, instead of a levelized price.[34/] In that proceeding, Mr. Fulmer's DA/CCA clients benefited from higher UOG revenue requirements in the first years of operation and thus they opposed using levelized prices for UOG resources to determine the market price for renewable resources.[35/] Here, the DA/CCA Parties would benefit from a levelized price and so are taking the opposite position.

The DA/CCA Parties also propose that if a PPA contract is front-loaded then the actual annual costs of the PPA should not be used in calculating the CAM charge, but rather that the costs used in the CAM should be levelized.[36/]

Like the proposal to levelize the UOG revenue requirements, this proposal would shift costs to bundled customers from DA and CCA customers since the bundled customers would be paying for the full costs of the PPA in the early years of the PPA while the DA and CCA customers would be paying a CAM charge based on a lower annual cost.[37/]

The DA/CCA Parties' proposal to create a cap on the CAM charge should be rejected, as well. The DA/CCA Parties' proposal confuses cost and value. CAM stands for "Cost Allocation Mechanism." The DA/CCA Parties mistakenly claim that the CAM attempts to calculate the value of the Resource Adequacy (RA) portion of the resource,[38/] and that if the CAM is ever above some measure of RA value, the CAM charge should be capped at that level.

This confuses what the CAM charge represents, the residual cost of the CAM resource, with short-term RA value. The CAM charge is the residual cost of the resource after the energy and ancillary services revenues are netted from the total costs. This residual cost of a long-term contract will likely be higher than the short-term RA value of the resource.[39/] That does not imply that the cost of the Commission-approved CAM-eligible contract was unreasonable, but

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34/ *See*, R.07-05-025, Tr. pp. 22-23, Fulmer/"Joint Parties" (the "Joint Parties" in R.07-05-025 include the DA/CCA Parties in this proceeding).
35/ Ex. PGE-1, p. 10.
36/ Ex. AReM-1, p. 47.
37/ Ex. PGE-1, pp. 10-11.
38/ Ex. AReM-1, p. 47.
39/ Ex. PGE-1, p. 11.

rather that the cost of new generation for system or local reliability is more expensive than short-term RA.

Furthermore, costs associated with CAM resources are not capped for bundled customers. Thus, the DA/CCA Parties' proposal would have the effect of favoring DA/CCA customers over bundled customers. The DA/CCA customers should be required to pay their fair share of any CAM-related costs.

B. Should Load Serving Entities (LSEs) Be Able To Opt Out Of CAM?

Load-serving entities should not be able to "opt-out" of the CAM mechanism. If adopted, this opt-out could very well adversely impact reliability and impose additional administrative burden on IOUs and the Commission.

Under DA/CCA Parties' proposal, an LSE would only need to demonstrate a 5-year contract term to opt-out.[40/] However, in resource need situations, or when there are no existing resources available with the right type of operating attributes for the LSE to meet its requirements, the LSE will need to commit to new resources. Most new generation resources require long-term contracts, 10 years or more in length.[41/] Thus, the DA/CCA Parties' proposal would not adequately protect system reliability.

Turning to the DA/CCA Parties' proposal for an LSE opt-out mechanism specifically as it relates to the QF/CHP Settlement adopted in D.10-12-035,[42/] applying such an opt-out provision to procurement entered into under the QF/CHP Settlement may impact the IOUs' ongoing procurement of CHP resources.[43/] The QF/CHP Settlement provided for one of two alternatives for allocating CHP procurement costs uniformly to all ESPs and CCAs.[44/] Based on comments filed by DA/CCA representatives at that time, PG&E understood that some ESPs and

40/ Ex. AReM-1, p. 58.
41/ Ex. PGE-1, p. 12.
42/ Ex. AReM-1, p. 54. As PG&E indicated in its testimony (Ex. PGE-1, p. 12 fn. 20) PG&E interprets the reference on lines 19-20 to "D.11-12-035" to be an inadvertent error, and that the reference is intended to be to D.10-12-035, the decision adopting the QF/CHP Settlement.
43/ Ex. PGE-1, p. 12.
44/ A.08-11-001, et al, Settlement Term Sheet, Section 13.1.2 (link provided in Appendix A of D.10-12-035).

CCAs may not want to procure CHP resources, or may be unable to be competitive in doing so.[45/] The Commission's decision to have the IOUs procure CHP on behalf of the DA/CCA customers impacted the CHP targets agreed to under the Settlement and the IOUs' ongoing CHP procurement strategy.

Any change to the cost recovery structure for the CHP program at this point would add substantial complexity and possibly alter the balance of benefits and burdens agreed to by the settling parties. Further, allowing the opt-out would raise a number of questions not addressed in the DA/CCA Parties' testimony. First, if a LSE procures QF/CHP resources, would the IOUs' megawatt target be reduced accordingly? If yes, QF/CHP parties to the QF/CHP Settlement might express concerns. If no, then bundled customers may see above market costs associated with QF/CHP procurement increase.[46/] Similar questions would arise associated with QF/CHP procurement to meet greenhouse gas emissions reduction targets.[47/]

The DA/CCA Parties' proposal for the timing of LSE opt-out application is also problematic. Under the DA/CCA Parties' proposal an LSE could submit the opt-out application any time after the Commission decision is approved, but before the IOU identifies a short list of potential winning bidders in its Request for Offers (RFO) process.[48/] This approach is problematic due to the uncertainty it would create during the initial phases of an IOU's planning for an RFO or other procurement approaches. Once an IOU receives Commission authorization to procure toward certain targets, it actively engages its internal and external resources to meet those targets. Any LSE opt-out could potentially change the IOU targets, necessitating a shift in the IOU's procurement strategy.[49/]

Another problem with the DA/CCA Parties' opt-out proposal is that it would add

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45/ *See e.g.*,A.08-11-001, et al,, Opening Comments of Shell Energy North America (US), L.P. on the Qualifying Facility and Combined Heat and Power Program Settlement Agreement, filed October 25, 2010, at p. 7 (noting that ESPs and CCAs may not have the ability to procure CHP resources).

46/ Ex. PGE-1, p. 13.

47/ Ex. PGE-1, p. 13.

48/ Ex. AReM-1, p. 56.

49/ Ex. PGE-1, p. 13.

significant administrative complexity, both for the Commission and the IOUs. For example, the DA/CCA Parties propose each non-IOU LSE would have the option to apply for an opt-out each time the Commission issues a decision approving the need for CAM procurement by an IOU, including procurement to meet obligations under the QF/CHP Settlement. If this approach were adopted, some LSE's might opt out and others might not for any particular CAM resource procurement. Tracking the opt-outs, and the impact of each different opt-out on CAM charges on a resource-by-resource basis, would be an administrative challenge for both the Commission and the IOUs.[50/]

Adding to the complexity, the DA/CCA parties also suggest three different opt-out options, chosen at the election of the ESP or CCA.[51/] Tracking which ESP or CCA elected each option, and verifying the necessary calculations to ensure that each ESP or CCA has met the conditions for each opt-out, for each CAM-eligible procurement, would add significant administrative burdens for the IOUs and the Commission.[52/]

Beyond the added complexity, this optionality would allow each ESP or CCA to maximize its ability to opt-out and select the option that minimizes cost for its customers, further shifting costs to remaining bundled customers by increasing the residual quantity allocated back to bundled customers.[53/]

If the opt-out were to apply to QF/CHP obligations, then any ESP exercising an opt-out option would need to file a QF/CHP compliance report, similar to the IOU-filed reports. This also imposes an additional administrative burden on the Commission.[54/]

Finally, the opt-out approach would create substantial additional rate complexity. The current CAM-related rate (the New System Generation Charge or "NSGC") varies by customer class. The opt-out proposal would make it necessary to create different NSGC rates by class for

50/ Ex. PGE-1, pp. 13-14.
51/ Ex. AReM-1, p. 54.
52/ Ex. PGE-1, p. 14.
53/ Ex. PGE-1, p. 14.
54/ Ex. PGE-1, p. 14.

each ESP or CCA in an IOU's service territory based on which contracts each LSE exercised an opt-out option. This kind of contract-by-contract and ESP-by-ESP ratemaking would require significant additional IOU and Commission resources to implement and for the Commission to track.[55/]

In sum, a CAM opt-out approach is not workable. Nor would it work in a manner that would be fair to bundled customers, or maintain reliability. Opt-out would substantially increase the administrative burden for IOUs and the Commission, could adversely impact reliability, and would impose additional burden to bundled customers. Opt-out should be rejected.

C. The South San Joaquin Irrigation District (SSJID) Proposal [addition to common outline]

In its testimony in response to SSJID's testimony, PG&E explains why the SSJID municipalization, if it occurs, should be classified as a "large municipalization" as that phrase is used in D.08-09-012.[56/] However, during hearings counsel for SSJID made clear that SSJID is not requesting the Commission to make that determination in this proceeding.[57/] PG&E agrees with SSJID that this is not the place to address that issue, and therefore is will not brief the substance of the matter here.

In its testimony SSJID also argues that the CAM mechanism should not apply in the context of a municipalization, regardless of whether it is classified as a large municipalization or not.[58/] SSJID's argument should be rejected.

SSJID has appeared in front of this Commission on at least two previous occasions making essentially the same argument it is making in this proceeding—that PG&E should not include, as part of its ongoing obligation to serve, the area that SSJID desires to serve in and around Manteca, Ripon and Escalon. Eight years ago, in August 2004, SSJID's witness Jeffrey

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55/ Ex. PGE-1, p. 14.
56/ Ex. PGE-2, pp. 1-2.
57/ Tr. pp. 615-17, Statement of SSJID Counsel.
58/ Ex. SSJID-1, p. 10.

Shields presented testimony in R.04-04-003, a precursor rulemaking to the LTPP proceeding.[59/] In that proceeding, SSJID requested that the Commission relieve PG&E of the obligation to engage in long-term procurement in the area that SSJID desires to serve. According to SSJID's testimony at that time, SSJID was expecting to be providing service on or before January 2007.[60/]

Six-and-one-half years ago, in A.05-06-028 (PG&E's Advanced Metering Infrastructure (AMI) Application), SSJID presented a very similar argument with respect to PG&E's investments in AMI in the area that SSJID desires to serve.[61/] SSJID noted that it had submitted a proposal to the San Joaquin County Local Agency Formation Commission (LAFCO), and expected LAFCO approval by May 2006.[62/] SSJID implored the Commission to prohibit PG&E from installing AMI infrastructure in the area that SSJID wished to serve, pending the resolution of the SSJID's plan to provide retail electric service, and take steps to ensure that electric customers in SSJID's service territory were not saddled with costs related to PG&E's AMI program once these customers left PG&E service and began taking service from SSJID.[63/]

SSJID went on to describe that upon LAFCO's approval, it intended to proceed with the acquisition of PG&E's existing distribution facilities, and expected to commence providing retail electric service in early 2007.[64/]

However, SSJID's LAFCO application was denied in June 2006. SSJID then sued LAFCO in San Joaquin County Superior Court, claiming among other things that LAFCO did not have the authority to deny its request. The Court rejected SSJID's claim. SSJID then reapplied to LAFCO in August 2009. As of today, SSJID still has not obtained approval from LAFCO to move forward with its plan.[65/]

As the SSJID experience clearly illustrates, it would be a mistake for the IOU to exclude

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59/ Ex. PGE-2, pp. 2-3, citing the "Prepared Direct Testimony of Jeffrey K. Shields on Behalf of the South San Joaquin Irrigation District," August 4, 2004.
60/ Ex. PGE-2, p. 3; Ex. PGE-X-SSJID-1; Tr. pp. 1361, 1363, Shields/SSJID.
61/ Ex. PGE-2, p. 3; Ex. PGE-X-SSJID-2; Tr. pp. 1365-66, Shields/SSJID.
62/ Ex. PGE-2, p. 3.
63/ Ex. PGE-2, p. 3.
64/ Ex. PGE-2, p. 3.
65/ Ex. PGE-2, p. 3.

planning for an area as soon as an entity expresses a desire to municipalize that portion of the IOU's service area. The same facts illustrate why, in an appropriate circumstance, the Commission should consider the application of the CAM in connection with a "large municipalization." The Commission should reject SSJID's request that the Commission provide a blanket exemption from application of CAM to all municipalizations that might occur in the future, regardless of the surrounding circumstances.

VII. OTHER ISSUES

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B. Coordination Of Overlapping Issues Between R.12-03-014 (LTPP), R.11-10-023 (RA), And A.11-05-023

Track 1 Should Be Addressed This Year

The need for resources due to local reliability considerations should be addressed this year, in Track 1. This timing was established in the May 17, 2012 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge (Scoping Memo).[66/]

The Scoping Memo's determination to address local capacity needs in Southern California this year, and to address the broader question of system reliability needs next year in a second track, makes sense for several reasons. First and foremost, based on the CAISO's analysis, there is a pressing need for capacity to meet local requirements.[67/] Therefore, this question should be addressed now. Other parties' disagreement with the CAISO's analysis, and differing opinions on the level of local capacity need in Southern California, do not support deferring a decision on the matter. Since the CAISO, who has responsibility to operate the CAISO grid reliably, has concluded that there is a substantial need, the Commission should address the matter immediately to reach its own judgment. The Commission should act now so that, if it agrees with the CAISO's conclusion that resources are needed, there will be enough time for that need to be addressed.

66/ Scoping Memo, pp. 7-8.
67/ Ex. PGE-1, p. 1.

Second, the basic analytic approach for evaluating local capacity needs is already established. The CAISO has used the same approach for evaluating local capacity needs, based on established reliability criteria, for several years. The CAISO study here is longer term than the CAISO local capacity studies that have been used to determine year-ahead local capacity requirements for resource adequacy purposes, but the basic analytic framework is the same.[68/] Therefore, as the CAISO has completed and presented its analysis, it makes sense for the Commission to use that, as well as the input other parties have provided in their testimony and during hearing, to reach its independent determination of local capacity need.

There is more uncertainty associated with the CAISO's multi-year forward conclusions regarding local capacity needs here than there is with the CAISO's one-year forward conclusions presented in connection with year-ahead local capacity resource adequacy obligations. However, this is an unavoidable consequence of the fact that the further into the future one attempts to look, the more uncertainty there is. The higher level of uncertainty does not mean that the CAISO's multi-year study is flawed, but instead simply reflects the uncertainty inherent in long-term planning.[69/]

Third, evaluating system need in 2013 will be a challenging enough task. Local capacity needs should be addressed this year, instead of deferring the issue to 2013, in order to help limit the number of issues that must be addressed in Track 2.[70/]

In particular, DRA's suggestion that the Track 1 decision on local capacity need be deferred, in order to take into account the final Commission-adopted planning assumptions in Track 2,[71/] should be rejected. Not only would this delay the Track 1 decision, but it would almost certainly cause delays in both the Track 2 and Track 3 decisions, as well. New information will always be available, but given the local need identified by the CAISO, the

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68/ Ex. PGE-1, pp. 1-2.
69/ Ex. PGE-1, p. 2.
70/ Ex. PGE-1, p. 2.
71/ Ex. DRA-3, p. 3.

Commission should move forward now, using the information at hand, to evaluate the CAISO's analysis and conclusions.

C. SCE Statewide Cost Allocation Proposal

The costs that SCE incurs to meet the LCR need in the LA Basin should be allocated to all benefiting customers in SCE's service territory—including bundled service, DA and CCA customers—but not to any customers outside of SCE's service territory. This is consistent with the direction of Public Utilities Code Section 365.1(c)(2)(A), which indicates that resources procured to meet "local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory" should be allocated to the bundled customers of the IOU procuring the resource, as well as CCA and DA customers, but not to customers outside that electrical corporation's distribution service territory.

In its testimony SCE states that "[i]n the absence of a multi-year forward procurement mechanism that can secure generation capacity to meet the identified Local Capacity Requirements ('LCR') need and fairly allocate costs to all Load Serving Entities ('LSE'), SCE proposes that the Commission authorize SCE to procure new LCR generation needed in the LA Basin area on behalf of all system customers."[72/]

In response to a PG&E inquiry, SCE clarified this statement in discovery. SCE clarified that "all system customers" means "all customers served by SCE's electrical system and is limited to procurement of new generation capacity intended to meet CPUC-authorized LCR need in SCE's service territory."[73/] Thus, generally speaking, SCE's cost recovery proposal is consistent with legislation and Commission policy.

However, later in its testimony SCE states that "to the extent the LCR resources provide flexibility benefits (i.e., integration services for intermittent resources) to the entire CAISO

72/ Ex. SCE-1, p. 2.

73/ Ex. PGE-1, pp. 2-3, citing SCE's response to Question 1a of PG&E Data Request No. PGE_SCE_001, included as Attachment 1 to Ex. PGE-1.

system, SCE is interested in seeking a broader cost allocation from all CPUC jurisdictional customers benefitting from the increased flexible capacity."[74/] There is no basis for PG&E's customers to be allocated a portion of the costs for SCE's procurement to meet LCR needs in the LA Basin or elsewhere in the SCE service territory.

SCE appears to suggest that some of its LCR costs may be allocated to PG&E's customers because incremental resources procured to meet the LCR need in the LA Basin may also provide operational flexibility that helps the entire CAISO system integrate intermittent renewables, and that PG&E's customers benefit from such increased flexible capacity. PG&E disagrees with this premise. It is inappropriate to burden PG&E's customers with any portion of SCE's costs for procurement to meet the LCR needs in the LA Basin or elsewhere in SCE's service territory.[75/]

SCE has provided neither any analysis nor credible precedent to support having the Commission allocate to PG&E's customers a portion of SCE's costs to procure incremental capacity to meet the long-term LCR need in the LA Basin or elsewhere in SCE's service territory. In contrast, the CAISO's testimony appears to support PG&E's view. The CAISO's testimony suggests that there is some threshold of flexibility needed for new capacity to satisfy the LCR need for the LA Basin, regardless of the amount of flexible capacity needed for the system to integrate intermittent renewables. The CAISO's testimony of Robert Sparks discusses the flexibility attributes that should be possessed by capacity procured to meet the LCR need in the LA Basin.[76/]

> The OTC generation characteristics include ramp rates and minimum output levels that allow the generation to be ramped-up quickly following the first transmission contingency in order to ensure reliable system operation following the next transmission contingency. The flexibility of the OTC generation allows efficient system dispatch when all transmission equipment is in-service, but still provides for reliable system

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74/ Ex. SCE-1, p. 26.
75/ Ex. PGE-1, p. 4.
76/ Ex. PGE-1, pp. 4-5, citing Ex. ISO-1, p. 15.

> operation following a transmission contingency. Replacement generation should have similar flexible characteristics. Quick starting generation would also provide for efficient system dispatch, but still provide for reliable system operation following a transmission contingency.[77/]

Finally, any such allocation of the costs of "flexible" capacity from one service area to another could not be a one way street. Many of the resources in PG&E's and SDG&E's service areas also provide operational flexibility to the CAISO system. Since no flexible capacity costs are allocated from PG&E and SDG&E to SCE's service area, it would be completely unfair, and one-sided against customers in PG&E's and SDG&E's service areas, for a portion of the costs of flexible capacity from SCE's service area to be allocated to PG&E's and SDG&E's service areas as a result of this proceeding.

In short, the costs that SCE incurs to meet the LCR need established in Track 1 should not be allocated to customers in PG&E's and SDG&E's service areas.

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VIII. CONCLUSION

For the foregoing reasons, as well as those presented in its prepared and oral testimony, PG&E respectfully requests that

- The need determination the Commission makes in Track 1 be based on the local capacity technical study that the California Independent System Operator (CAISO) has presented in Exhibit ISO-1.
- The Commission not establish any "preferred resources" set-asides as a part of Track 1. All resources and all technologies, including combined heat and power and storage, should be allowed to compete on an equal footing to meet the identified need.
- The Commission reject the DA/CCA Parties' proposals to modify the CAM.
- The Commission reject the DA/CCA Parties' proposal that LSEs be given the

77/ Ex. ISO-1, p. 15.

option to “opt-out” of CAM.

- the Commission reject SSJID’s proposal that D.08-09-012 be modified, to foreclose the application of CAM in the context of any municipalization.
- The Commission maintain its adopted Track 1 schedule to reach a Track 1 decision by the end of this year.
- The Commission determine that the costs that SCE incurs to meet LCR needs in the LA Basin should be allocated to all benefiting customers in SCE’s service territory—including bundled service, direct access, and community choice aggregation customers—but not to any customers outside of SCE’s service area.

Respectfully Submitted,

CHARLES R. MIDDLEKAUFF
MARK R. HUFFMAN

By: /s/
MARK R. HUFFMAN

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3842
Facsimile: (415) 973-0516
E-Mail: MRH2@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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