**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)

**REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)
REGARDING TRACK 3 ISSUES
IN THE 2012 LONG-TERM PROCUREMENT PLAN OIR**

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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In accordance with the schedule established in the November 1, 2012, e-mail ruling of the assigned administrative law judge, Pacific Gas and Electric Company (PG&E) files these reply comments on Track 3 proposed rules.

In these reply comments PG&E does not discuss all of the recommendations made by other parties in their opening comments, and reserves the right to comment on additional issues and proposals if opportunities for comment or testimony are provided.

First, PG&E reiterates its request that flexibility procurement requirements and products and multi-year forward procurement requirements be addressed in the current resource adequacy (RA) proceeding, not this proceeding.

As discussed in more detail below, PG&E reiterates the request it made in its opening comments that the California Public Utilities Commission (Commission) modify bundled procurement plan rules to allow investor-owned utilities (IOUs) to utilize utility-developed offset credits to meet the greenhouse gas (GHG) compliance obligations, and to use all approved procurement methods to obtain allowances and offset credits. PG&E also reiterates its request that the Commission clarify Energy Resource Recovery Account (ERRA) compliance filing requirements.

Additionally, PG&E responds to several proposals made by other parties in their opening comments. PG&E requests that the Commission adopt Southern California Edison Company's (SCE) proposed change to allow IOUs to enter into procurement contracts of up to five years in length without having to obtain Commission preapproval.

While existing generation should, generally speaking, be allowed to participate in short and intermediate-term solicitations under the IOUs' bundled procurement plans, long-term requests for offers (LTRFOs) to meet incremental need identified in the long-term procurement plan (LTPP) proceeding should continue to be limited to new or repowered resources.

Calpine Corporation's (Calpine) proposed credit and collateral rules, which would generally increase the financial risk placed on IOUs as they procure electric power and therefore increase the financial risk faced by IOU customers, should be rejected.

Parties' proposals to place additional restraints on the IOUs' activities to meet their GHG obligations should be rejected. Further, no changes to the Commission's loading order policy, discussed recently in D.12-01-033, are appropriate at this time.

The Independent Energy Producer Association's (IEP) proposal to condition utility-owned generation (UOG) of renewable resources on a failure of a renewables solicitation should be rejected. The current practices for selecting Independent Evaluators (IEs) should be continued, as should the current practices for publication of non-confidential Procurement Review Group (PRG) information. The Commission should reject the efforts of several parties representing direct access providers and community choice aggregators to avoid their fair share of costs incurred for system or local reliability.

Contrary to the repeated assertions of Sierra Club California (Sierra Club), the Bagley-Keene Opening Meeting Act is not applicable to the PRG. And the issue of the allocation of charges imposed by the California Independent System Operator (CAISO) raised by IEP is beyond the scope of Track 3.

I. THE COMMISSION SHOULD AUTHORIZE INVESTOR-OWNED UTILITIES TO UTILIZE UTILITY-DEVELOPED OFFSET CREDITS TO MEET THEIR GREENHOUSE GAS OBLIGATION, AND TO UTILIZE ALL APPROVED PROCUREMENT METHODS TO OBTAIN ALLOWANCES AND OFFSET CREDITS

As it did in its opening comments, PG&E urges the Commission to modify current procurement rules to allow utility procurement of offset credits that are developed by the utility, without need for a separate application. PG&E further urges the Commission to modify current GHG procurement rules by removing the restriction that requires all allowance and offset credit transactions to be conducted through an RFO or on an exchange.

II. THE COMMISSION SHOULD CLARIFY COMPLIANCE FILING REQUIREMENTS IN THE ENERGY RESOURCE RECOVERY ACCOUNT PROCEEDING

As it did in its opening comments, PG&E recommends that the Commission review the Quarterly Compliance Report (QCR) filing requirements as they relate to contract amendments and establish uniformity among the utilities' respective filings. Also, the Commission should clearly define if and when it is appropriate to review an amendment to a contract in the QCR and when it is not.

III. THE COMMISSION SHOULD ADOPT SOUTHERN CALIFORNIA EDISON COMPANY'S PROPOSAL THAT INVESTOR-OWNED UTILITIES BE AUTHORIZED TO ENTER INTO CONTRACTS OF UP TO FIVE YEARS IN DURATION WITHOUT SEEKING PRE-APPROVAL

SCE urges the Commission to adopt a change to the bundled procurement plan framework to authorize utilities to enter into contracts of duration up to and including five years (i.e., "five years or less") without seeking the Commission's preapproval. Currently, utilities are limited to entering into contracts that are "less than five years" in duration. (SCE Comments, pp. 3-9.)

PG&E agrees with SCE's recommendation. The IOUs should be authorized to enter into contracts up to and including five years without seeking the Commission's preapproval. As SCE notes, the Commission had previously identified SCE's proposed change as "simple, minor and common-sense" but did not adopt the change stating "we are concerned that there are multiple previous decisions and existing regulations that contain provisions that specifically apply to contracts of "less than 5 years.' (SCE Comments, p 3 (citing D.12-01-033, p. 41).). In its comments, SCE provides a comprehensive review of previous decisions addressing such provisions and demonstrates that there is no reason for further concern based on either these decisions or the reasoning behind them. As SCE explains, this simple change to add one day to IOUs' procurement authority can simplify transactions. PG&E joins SCE in requesting that the Commission adopt this straightforward change.

IV. EXISTING GENERATION SHOULD, GENERALLY SPEAKING, BE AUTHORIZED TO COMPETE IN SHORT-TERM AND INTERMEDIATE-TERM REQUESTS FOR OFFER UNDER INVESTOR-OWNED UTILITIES' BUNDLED PROCUREMENT PLANS, BUT NOT IN LONG-TERM REQUESTS FOR OFFERS TO MEET INCREMENTAL NEED IDENTIFIED IN LONG-TERM PROCUREMENT PLAN PROCEEDINGS

In its comments, Calpine observes that "IOU resource solicitations typically do not treat new and existing resources as potential" (Calpine Comments, p. 6), and asserts that this approach should be changed.

PG&E does not object to Calpine's proposal insofar as it recommends that, generally speaking, retrofits to existing generation assets should be eligible to compete in short-term and intermediate-term solicitations pursuant to IOUs' bundled procurement plans.

However, as PG&E discussed in earlier comments in Track 1 of this proceeding, insofar as Calpine is arguing that existing resources should be able to compete in LTRFOs to provide incremental capacity to meet long-term needs identified in the system (or local) need portion of the LTPP proceeding, PG&E objects to Calpine's proposal, and urges the Commission to reject it. Existing facilities, including upgrades to existing facilities, do not provide the same benefits as a new or repowered resource.

In the last LTRFO in 2008, PG&E sought to procure an authorized amount of new resources. PG&E's solicitation protocol precluded offers from existing capacity resources unless the offer was from a repowered facility. (A repowered facility is fundamentally different from an existing resource that has been retrofitted. A repowered facility is, in essence, a new facility on a site where a different facility had previously been located. More specifically, a "repowered facility" is a generation facility where substantial replacement of old equipment has occurred, such that the facility's performance and economic life are similar to that of a new facility of like technology.) Such repowers should continue to be considered conforming offers in long-term solicitations.

PG&E recommends against the inclusion of retrofits to existing facilities that have a useful life of less than 30 years. Long-term contracts of ten years are more are driven by the economics to incentivize construction of new resources. The investment and risk criteria for a retrofit to an existing resource are driven by the short to intermediate-term procurement market. Incremental capacity resulting from such retrofits to existing facilities is more applicable to short and medium-term procurement under the authorized bundled procurement plan procedures. It may be impractical to separate the incremental, retrofit capacity from the rest of the existing plant. The likely result would be the need to structure a contract for the full facility, which might result in over-procurement. In addition, contracting with older, existing units may support less efficient and higher GHG-emitting resources.

V. CALPINE'S CREDIT AND COLLATERAL PROPOSALS SHOULD BE REJECTED

In its comments, Calpine suggests four credit and collateral-related changes to procurement practices: (a) netting of collateral across different legal entities and master agreements; (b) removal of cross default provisions; (c) requesting of IOU collateral posting based on the premise that IOUs do not currently do so; and (d) capping of collateral requirements. (Calpine Comments, pp. 10-14.) Calpine's outlined requests are not justified, are in contrast to the industry and best credit risk management practices, and should be rejected.

As a preliminary matter, Calpine's suggestion that the focus of collateral should be on liquidated damages is inaccurate. (Calpine Comments, p. 11.) Regardless of whether they are characterized as liquidated damages or actual damages, the damages to which Calpine refers are intended to only address occasions when a counterparty's non-performance is for a limited period, and the essence of the agreement and viability of the counterparty and its ability to meet the future contractual commitments is not at risk.

The purpose of collateral is not to cover payment for damages associated with an isolated non-performance incident. By contrast, the purpose of collateral is to provide the contract replacement value and additional costs for which a defaulting party would be required to pay in the case of the default and termination.

Calpine's effort to link the two should be rejected. Credit risk management, including collateral requirements, seeks to address the risk of non-performance under default when a full replacement of an agreement for the balance of the term is at risk.

A. Netting Of Collateral Requirements Across Different Legal Entities Should Not Be Allowed

Calpine advocates the netting of collateral across different legal entities. This is contrary to standard industry practice. Further, one of the primary reasons that a legal entity such as Calpine creates separate legal entities for different components of its business is often so that another entity *cannot* offset amounts owed by one sub-entity against amounts owed to another sub-entity, especially in the case of bankruptcy of the sub-entity that owes money. At a minimum, under these circumstances the netting of collateral requirements across separate legal sub-entities can create disputes over what collateral is available to offset the amount owed by any one particular sub-entity.

This means that creditors such as the IOUs might very well receive less money if bankruptcy occurs, and netting of collateral across the legally distinct sub-entities has been allowed. Therefore, Calpine's proposal should not be adopted.

In its basic form, transaction netting occurs when two legal entities carry out a variety of transactions under a single master agreement. In this scenario, all transactions are valued based on the damages that a party would incur by replacing all of the terminated transactions in the market, and those values are then netted together. The outstanding exposure is secured through financial collateral if the exposure exceeds an unsecured credit threshold that was negotiated based on the credit strength of the parties.

If additional transactions are executed through multiple master agreements, the parties can opt to negotiate a master netting or bridging agreement through which the two parties define credit terms and legal terms for netting the exposure of all transactions, and application of collateral for all master agreements. The decision to use a master netting agreement is a matter between the two parties and in large part dependent on the credit strength and capacity of each party.

However, the situation changes when a company establishes multiple distinct legal entities, either for financing objectives or to legally separate and protect assets. Calpine, for example, has taken the “separate legal entities” approach with its assets in California. Limited liability companies are often used for this purpose. In this situation, each legally distinct affiliate or subsidiary of the parent entity would need a separate master agreement with its counterparty. In other words, even if the parent company and many of its legally distinct entities transact with the same counterparty, the fact that the affiliates and subsidiaries of the parent entity are legally distinct requires separate master agreements. Under this scenario, it is not a common practice to establish a master netting agreement for bridging the credit terms because:

- The netting of exposure and collateral across separate legal entities raises significant legal hurdles in case of default and termination; and
- Distinct legal entities may have separate creditors, each requiring different claims on assets for project financing, liquidity or working capital.

Additionally, netting of exposure and collateral can only be effective if each of the separate master agreements subject to the netting is terminated at the same time.

For these reasons, it is not a good idea to net transactions or collateral across multiple, separate legal entities and their respective master agreements. Such an approach has the potential to expose customers to increased financial risk associated with the procurement activities.

Furthermore, netting of transactions across entities might very well not reduce collateral requirements for an entity such as Calpine, even if it were allowed. Using Calpine and PG&E as an example, Calpine's transactions are sales to PG&E. Even if a master netting agreement were negotiated between PG&E and Calpine, the amount of collateral required of Calpine would not fall significantly without any offsetting purchases from PG&E. In other words, since all of Calpine's transactions are similar type and are sales, are directionally the same, additional transactions would likely require the same amount of incremental collateral from Calpine to mitigate risk.

In sum, Calpine's proposal regarding collateral netting is not prudent credit risk management. Calpine's decision to allocate its assets across various distinct legal entities has necessitated it to execute multiple master agreements. If utilities were required to do the type of netting Calpine proposes across separate, distinct legal entities, it would imprudently increase exposure to ratepayers. Current industry practices regarding collateral should remain in place.

B. Cross-Default Provisions Should Not Be Eliminated

Calpine advocates the elimination of cross-default provisions. (Calpine Comments, p. 13.) This is contrary to standard industry practice and should not be adopted. If Calpine is allowed to net across entities <u>and</u> there is no cross default provision, then IOUs and customers by extension have much greater exposure if a counterparty defaults.

Calpine states that the cross default provisions "allow the buyer to terminate other transactions with a seller in the event that a seller fails to perform under one transaction. Cross-default provisions impose additional risk and, as a result, additional costs on sellers." (Calpine Comments, p. 13.)

This description does not acknowledge the useful purpose that cross default provisions satisfy. Cross default provisions are common industry practice for transactions under a master agreement. The intent of the provision is to determine and establish a level of non-performance that can potentially cause an entity to default on its obligation. Furthermore, cross default is often a bilateral provision, so both buyer and seller have cross default thresholds.

In addition, cross default provisions do not automatically terminate a transaction or transactions under a master agreement. The cross default provides the counterparty the right but not the obligation to terminate a contract. The aim of the cross default provision is to protect each party from deteriorating credit conditions of its counterparty, to allow it to assess whether or not the counterparty can meet its contractual obligations, and give the non-defaulting party the ability to act accordingly.

C. The Requirement To Post Collateral Should Be Negotiated Between The Parties Depending On Creditworthiness And Product Risk Profile

Calpine asserts that "the IOUs generally do not post collateral themselves, so the exposure to collateral requirements is asymmetric. While limiting IOU posting requirements may limit the direct cost of collateral to the IOU, it shifts risk onto sellers and raises the costs that they must recover through contract payments." (Calpine Comments, p. 13.)

Calpine's assertion is not valid and is without merit. The requirement to post collateral for each party is negotiated and based on the creditworthiness of both parties, terms of the contract, and the size of the transaction. For PG&E, its tolling agreements have provisions defining unsecured credits granted to PG&E or the counterparty, if any. The master agreements further stipulate that any such unsecured credits are tied to the credit ratings. Also, posting requirements in PG&E's RA agreements are symmetrical. Most RA and tolling agreements are negotiated based on the creditworthiness of both the counterparty and PG&E as well as the size of the transaction.

However, the risks of transactions with respect to buyer and seller are not symmetric. The seller is exposed to price movements between its sale price and zero. By contrast, the buyer is exposed to market prices that have no price cap, which represents unlimited risk. For this reason, it is not surprising that the collateral obligation of the buyer and seller are sometimes different.

For these reasons, no changes to current requirements on IOUs to post collateral are necessary, or should be adopted.

D. Capping The Collateral Amount Must Remain On A Case By Case Basis, Based On Combination Of Creditworthiness And The Risk Of Transactions

Calpine argues that the amount of collateral required should be capped. (Calpine Comments, pp. 13-14.) No such absolute limit on collateral caps should be adopted. Instead, collateral caps, if any, should continue to be assessed on a case-by-case basis and based on the nature of the transaction.

When assessing collateral requirements for transactions, PG&E considers a variety of factors. Those factors include the cost of carrying collateral and other project financing challenges, overall risk of the transaction, regulatory obligations as well as counterparty's credit rating and overall risks of default to the utility and its customers. For example, weighing these considerations, PG&E's collateral requirements for RA and renewable transactions already call for fixed collateral amounts, as opposed to variable obligations.

In addition, PG&E's tolling agreements incorporate an appropriate level of collateral depending on the size and creditworthiness of the counterparty. Furthermore, while PG&E's tolling agreements do call for a variable collateral posting tied to a mark-to-market formula, validated by both parties, these contracts do generally cap the total collateral obligation.

As with its other collateral-related proposals, Calpine has not offered adequate justification for adoption of its proposed changes.

Calpine's assertion that cost of collateral is 5 percent for all scenarios (Calpine Comments, p. 13) is wrong. First, the amount of collateral is only fixed for those specific transactions that cannot be marked to market or are part of a regulatory settlement, such as Renewable Portfolio Standard (RPS) or RA products. The majority of commodity transactions executed under various master agreements (gas and electric power agreements) do not have fixed collateral, the amount of collateral is based on the mark to market value of transactions and netted against any available unsecured credit negotiated, and is a variable amount for both parties. In addition, for the most part, RPS, Combined Heat and Power (CHP), tolling and RA agreements are based on competitive solicitations and winning bidders reflect the cost of collateral and variable costs, among other considerations, in their bid prices.

Finally, the cost of carrying collateral is based on the creditworthiness of the counterparty. The amount that Calpine is paying for collateral is reflective of the market's view of Calpine's risk, and perhaps the market's view of the risks associated with Calpine's organizational structure segregating assets among various legal entities.

In conclusion, PG&E's contractual engagements and risk management practices are prudent and consistent with industry practice. Calpine's recommendations are without merit, and if adopted would increase the financial exposure borne by ratepayers in connection with power procurement activities. Calpine's recommendations should be rejected.

VI. NO ADDITIONAL REQUIREMENTS OR CONSTRAINTS ON THE INVESTOR-OWNED UTILITIES' GHG EMISSIONS OBLIGATIONS IS APPROPRIATE

The Division of Ratepayer Advocates (DRA) proposes to place additional requirements on utilities to consider and evaluate GHG reductions that a utility might be able to obtain from its own portfolio when complying with its GHG emissions obligations. (DRA Comments, pp. 2-6.) The Sierra Club would also place additional constraints and requirements on the utilities' GHG compliance efforts (Sierra Club Comments, pp. 1-3), as would the California Environmental Justice Association (CEJA). (CEJA Comments, pp. 4-6.)

No modifications to this component of the utilities' bundled procurement plans are appropriate in this proceeding. For example, PG&E's portfolio-wide emissions reductions already occur in line with the Commission's "loading order" (i.e. cost-effective energy efficiency, demand response, renewable energy and distributed generation, and clean and efficient fossil generation). PG&E considers GHG costs, either explicitly or implicitly, at each step of the loading order.

PG&E has designed its energy efficiency portfolio to capture cost-effective opportunities, and uses a GHG price as an input in determining the cost-effectiveness of proposed opportunities. Similarly, PG&E embeds the GHG price in its cost-effectiveness analysis of demand response. The valuation for renewable energy takes into account the absence of GHG costs for renewable projects. PG&E always considers the cost of power when doing upgrades to its facilities, and GHG costs will be embedded in the market power price. Making investments that directly reduce GHG will become cost-effective at a certain GHG price.

Finally, PG&E uses a GHG price in its forward procurement valuation which, all other factors being equal, would favor the procurement of lower GHG-emitting resources over higher GHG-emitting resources.

A Marginal Abatement Curve (MAC) as suggested by DRA is not necessary, as the loading order combined with the flow through of a GHG price in all of PG&E's investment decisions already allows PG&E to achieve direct GHG emission reductions, to the extent doing so is less costly than purchasing compliance instruments in the California Air Resources Board's (CARB) Cap-and-Trade program. If the price of compliance instruments goes up over time, this will be reflected in the embedded GHG price used in determining PG&E's portfolio-wide generation mix, and this mix will change accordingly over time.

Relying on the economic signals provided by the market price of GHG compliance instruments allows PG&E to prefer lower GHG-emitting resources over higher GHG-emitting resources portfolio-wide, achieving direct reductions of GHG emissions when such reductions are economically preferable to procuring compliance instruments.

In sum, the current bundled procurement process already ensures that these trade-offs are considered in PG&E's procurement activities. Additional constraints and requirements relating to GHG compliance, as recommended by DRA, the Sierra Club, and CEJA, would not aid in this process and should not be adopted.

VII. NO CHANGES TO THE COMMISSION'S LOADING ORDER POLICY ARE APPROPRIATE AT THIS TIME

CEJA argues that "[i]f there is a need for new flexible resources, the Commission should require consideration of preferred resources consistent with the loading order." (CEJA Comments, p. 6.)

This is unnecessary as it is already adopted Commission policy. This issue was addressed by the Commission in the last LTPP, in D.12-01-033. The guidance provided there should continue to be applied.

As the Commission stated there

> The utilities are fundamentally correct that the Commission analyzes and sets goals for programs such as energy efficiency and demand response in other proceedings, and the results of those other proceedings inform the procurement plans to be approved in this proceeding. There is no need to re-analyze or re-litigate those same issues here, particularly since the results of those other proceedings have largely been incorporated into the standardized planning assumptions. (D.12-01-033, pp. 18-19 (footnote omitted).)

The Commission went on to explain

> We understand that opportunities to procure additional energy efficiency or demand response resources may be more constrained than just signing up for more conventional fossil generation, but the utilities should still procure additional energy efficiency and demand response resources to the extent they are feasibly available and cost effective. (D.12-01-033, p. 21.)

These same principles should continue to apply. To the extent that the utilities can procure additional preferred resources that are feasibly available and cost effective compared to the alternatives that would meet the identified need, they should continue to do so. No changes to the currently adopted Commission policy are necessary.

VIII. UTILITY-OWNED RENEWABLE GENERATION SHOULD NOT BE CONDITIONED ON AN IMMEDIATELY PRECEDING FAILED RENEWABLES SOLICITATION

IEP recommends that IOUs be required to demonstrate a "failed" renewable solicitation within the six months before a UOG project for renewable generation is proposed. (IEP Comments, pp. 3-4.) IEP analogizes its recommendation to a requirement that is applicable to conventional generation. IEP's proposal is not justified, and should be rejected.

The Renewable Portfolio Standard (RPS) market is significantly different than that for conventional generation. Robust response to an RPS solicitation does not guarantee that the projects chosen from that solicitation ultimately will get built, particularly as the IOUs move towards more small-project procurement. Projects still face significant development hurdles.

While PG&E is optimistic about the success of RPS projects in its portfolio, it is too early to tell whether these projects ultimately will come online. The six-month period is an arbitrary deadline given the long lead time to develop renewables projects, and the penalties associated with non-compliance.

In short, the RPS market is substantially different, and more uncertain, than the market for conventional generation. A blanket rule that an immediately preceding "failed" solicitation is a prerequisite to an IOU RPS project could materially affect the development of RPS resources. Therefore, IEP's proposal for such a blanket rule should be rejected.

IX. THE CURRENT PROCESS FOR SELECTING INDEPENDENT EVALUATORS SHOULD BE RETAINED

DRA proposes that the Commission's Energy Division (ED) select and assess the Independent Evaluators (IE) who examine many IOU procurement activities. (DRA Comments, pp. 6-8.) CEJA makes a similar recommendation. (CEJA Comments, pp. 3-4.) These recommendations should not be adopted.

PG&E recommends that its current process be maintained. PG&E reviews the expertise and strength of each IE, and also assesses the workload and availability of each IE. PG&E then recommends to the ED a specific IE for a specific RFO, Request for Proposal, or other energy procurement activity requiring an IE. The ED has the opportunity to approve, or ask PG&E to reassess or assign a different IE. In addition, PG&E periodically updates and provides the opportunity for its PRG to comment on IE assignments.

The current approach, just described, accomplishes in essence the recommendation of DRA and CEJA of having the ED select the IE assignments, while limiting the additional administrative burden placed on the ED's workload.

X. THE CURRENT PRACTICES WITH RESPECT TO THE PUBLICATION OF NON-CONFIDENTIAL PROCUREMENT REVIEW GROUP INFORMATION SHOULD BE RETAINED

CEJA recommends that the Commission require publication of non-confidential information from PRG meetings. (CEJA Comments, p. 3.) When possible, PG&E can provide non-confidential information as public. For example, PG&E already provides a summary of its PRG meetings on PG&E's external website. However, PG&E will provide confidential information to its PRG in accordance with appropriate Public Utilities Code or Commission decisions or general orders related to confidentiality. No further changes to PG&E's publication practices for PRG meetings should be adopted in this proceeding.

XI. THE COMMISSION SHOULD REJECT THE EFFORTS OF THE DIRECT ACCESS AND COMMUNITY CHOICE AGGREGATION PARTIES TO AVOID THEIR FAIR SHARE OF COSTS INCURRED FOR SYSTEM OR LOCAL RELIABILITY

The Alliance for Retail Energy Markets (AReM), Direct Access Customer Coalition (DACC) and Marin Energy Authority (MEA) propose four procurement rules and extend those rules to make two arguments asserting that Direct Access (DA) and Community Choice Aggregation (CCA) customers should be exempted from their share of non-bypassable charge costs. (AReM/DACC/MEA Comments, pp. 3-8.) AReM/DACC/MEA's recommended rules should not be adopted, and their efforts to circumvent their fair share of costs incurred to provide system or local reliability should be rejected.

AReM/DACC/MEA's first argument is that the IOUs should use the California Energy Commission's (CEC) most recent forecast of DA and CCA load departures to reduce the forecast bundled procurement quantity, and that this forecast DA and CCA load should then be exempt from stranded cost payments (AReM/DACC/MEA Comments, pp. 4-5). This argument goes too far. It is appropriate to remove existing and forecast DA and CCA load, but the forecast CCA load should be based solely on the CCA load that has signed a binding commitment of responsibility. Until a particular CCA has made such a binding commitment, it should not be able to avoid the stranded costs of commitments made on behalf of the departing customers.

AReM/DACC/MEA's second argument comes out of their second, third and fourth proposed procurement rules (AReM/DACC/MEA Comments, pp. 5-8) and is a restatement of their "Process and Criteria" proposal in Track 1 of this proceeding. (*See generally*, Track 1 Ex. AReM-1.) As in Track 1, their proposal would require bundled customers to cover the costs of new resources required to maintain system reliability. This issue was has already been litigated in Track 1 and there is no reason for it to be immediately re-litigated in this Track of the proceeding.

AReM/DACC/MEA's efforts to escape their fair share of costs incurred to provide system or local reliability are unjustified, have just been litigated in Track 1, and should be rejected.

XII. PUBLIC REVIEW GROUP MEETINGS ARE NOT WITHIN THE PURVIEW OF THE BAGLEY-KEENE OPEN MEETING ACT

The Sierra Club, repeating an assertion that it has made in previous proceedings, argues that PRG meetings are subject to the Bagley-Keene Act. (Sierra Club Comments, pp. 3.-5.) The Sierra Club is wrong on this point, and the Commission should not make any such finding.

The Bagley-Keene Open Meeting Act (Government Code §§ 11120-11132) generally requires that meetings of "state bodies" be open. The Sierra Club argues generally that the PRG is a "state body" under the Bagley-Keene Act. However, this is not the case.

Section 11121(b) of the Government Code, for example, is not applicable as the Commission has not delegated any of its authority to the PRG. The PRG is an advisory group created to review the details of the IOUs' respective procurement strategies and to provide advice to the IOU. (D.07-12-052, p. 119.) PRG member recommendations are made to the IOUs, not the Commission, and are advisory and non-binding with regard to the IOU. (*Id.*) The PRG does not file any report or recommendation with the Commission. Moreover, PRG members are free to advocate their own positions in subsequent Commission proceedings.

Thus, the Commission has not delegated any of its authority to the PRG. Rather, the Commission itself reviews all IOU long-term procurement plans and procurement transactions through a variety of Commission proceedings, including the LTPP proceeding, Quarterly Compliance Reports and annual Energy Resource Recovery Account (ERRA) forecast and compliance proceedings. (*Id.*, pp. 180-181 (describing Commission proceedings and processes to review IOU procurement).) The PRG has no authority to approve or reject any procurement transaction, nor does the PRG have any authority to require the IOUs to conduct certain types of procurement. In short, Section 11121(b) is not applicable because the Commission has not delegated any authority to the PRG.

Similarly, Section 11121(c) of the Government Code is not applicable to the PRG. This statutory section applies to boards or committees that provide advice to a state body. The PRG provides advice to the IOUs, not the Commission. Indeed, the PRG does not provide any report, recommendation, or advice to the Commission. PRG members consider IOU procurement plans and provide advice to the IOUs. PRG members are later free to support or oppose IOU procurement proposals at the Commission.

In short, the Bagley-Keene Open Meeting Act is not applicable to the IOUs' PRGs.

XIII. COST ALLOCATION OF CAISO CHARGES IS BEYOND THE SCOPE OF TRACK 3

IEP argues that "the Commission needs to consider and address cost allocation for products the CAISO charges to integrate renewables and maintain overall grid reliability." (IEP Comments, p. 6.)

In the first place, it is not clear that this topic belongs in the bundled procurement plan portion of the LTPP. This Commission does not have jurisdiction over these charges.

If the Commission nonetheless determines that it should address this topic, then it will have to evaluate what cost allocation is most likely to drive an efficient allocation of resources. Since not only load, but also intermittent generation resources, drive the total integration needs, it is not clear that IEP's recommendation to allocate all of the integration costs directly to load is, in fact, the better approach.

XIV. CONCLUSION

For all the foregoing reasons, PG&E respectfully requests that the Commission address RA issues, including incorporation of a flexibility component into RA and extending RA to a multi-year obligation, in the currently ongoing resource adequacy proceeding. PG&E requests that the Commission modify bundled procurement plan rules to allow IOUs to utilize utility-developed offset credits to meet their GHG compliance obligations, and to use all approved procurement methods to obtain allowances and offset credits. PG&E request that the Commission clarify ERRA compliance filing requirements.

PG&E requests that the Commission adopt SCE's proposal that IOUs be authorized to enter into contracts five years or less in length, without having to obtain Commission preapproval.

At this time, PG&E recommends that no other changes to the current bundled procurement rules be adopted.

Respectfully Submitted,

CHARLES R. MIDDLEKAUFF
MARK R. HUFFMAN

By: *lsl Mark R. Huffman*
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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