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.	Rulemaking 10-05-006 (Filed May 6, 2010)

PACIFIC ENVIRONMENT'S OPENING BRIEF ON TRACK I AND III ISSUES

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A. *TRACK I SETTLEMENT* – Pacific Environment urges the Commission to approve the proposed settlement agreement as a fair and reasonable resolution of the bulk of the Track I issues in this proceeding.

B. *SDG&E's LCR REQUEST* – Pacific Environment urges the Commission to reject SDG&E's request for 415 MW for its local area. SDG&E's request is based on modeling assumptions that ignore multiple renewable and energy storage resources being developed in its territory and that are significantly lower than the Commission's Standardized Planning Assumptions for key inputs such as energy efficiency. SDG&E's request for 415 MW is also significantly higher than the actual need of 180 MW found in its modeling attempt. SDG&E has failed to demonstrate why its request is needed, and has failed to consider the ability of preferred resources to meet any purported need in its local area.

TRACK III SUMMARY AND RECOMMENDATIONS

A. *GREENHOUSE GAS (GHG) COMPLIANCE PLANS* – Pacific Environment urges the Commission to issue an interim decision until market experience is gained and the utilities' plans are revised to consider emission reductions as a compliance strategy. Further, Pacific Environment recommends that the Commission not allow recovery of the costs of allowances or offsets until those instruments have been used. Finally, Pacific Environment recommends the Commission strengthen its oversight of GHG transactions by requiring advice letters for offsets and having an independent evaluator review the utilities' plans.

B. *ONCE-THROUGH COOLING POLICY* – Pacific Environment generally supports Energy Division Staff's proposed limitation on utility contracts with once-through (OTC) units, but recommends that it be clarified to indicate that OTC unit's compliance will be determined by reference to both the Clean Water Act and the State Water Resources Control Board's established OTC policy. Pacific Environment further recommends that the Commission reject SCE's proposal related to adoption of a new generation mechanism.

C. *BID EVALUATION PROCESS* – Pacific Environment recommends that the utilities' bid evaluations should incorporate environmental justice considerations, adhere to the Commission's need determinations, comply with the loading order, and better assess project viability. Due to significant concerns related to allowing utility owned generation (UOG) in the request for offer (RFO) process, Pacific Environment also urges the Commission to reject PG&E's request to allow all types of UOG offers to be considered in RFOs.

D. *PROCUREMENT OVERSIGHT RULES* – Pacific Environment generally supports Energy Division Staff's recommendations for increasing oversight of the procurement process. In addition, Pacific Environment recommends specific ways to strengthen the role of the Procurement Review Group and Independent Evaluators. Finally, Pacific Environment recommends that the Commission not adopt the entire procurement oversight rulebook to supersede Commission decisions on which they are based.

ACRONYM LIST

ALJ	Administrative Law Judge
BBEES	Big Bold Energy Efficiency Strategy
BPP	Bundled Procurement Plan
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CEC	California Energy Commission
DR	Demand Response
DG	Distributed Generation
DRA	Division of Ratepayer Advocates
EAP	Energy Action Plan II
ED	Energy Division
EE	Energy Efficiency
EJ	Environmental Justice
ERRA	Energy Resource Recovery Account
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
IE	Independent Evaluator
IEP	Independent Energy Producers
IOU	Investor-Owned Utility
LCR	Local Capacity Reliability
L & R	Load & Resource
LTPP	Long-Term Procurement Plan
LTRFO	Long-Term Request for Offers
MW	Megawatt

OTC	Once-Through Cooling
PE	Pacific Environment
PG&E	Pacific Gas & Electric
PPA	Power Purchase Agreement
PRG	Procurement Review Group
PV	Photovoltaic
PUC	California Public Utilities Commission
QCR	Quarterly Compliance Report
RAM	Renewable Auction Mechanism
RFO	Request for Offers
RPS	Renewable Portfolio Standard
RA	Resource Adequacy
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
TURN	The Utility Reform Network
UOG	Utility-Owned Generation
WPTF	Western Power Trading Forum

BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006 (Filed May 6, 2010)

PACIFIC ENVIRONMENT'S OPENING BRIEF ON TRACKS I AND III

Pacific Environment submits this Opening Brief in response to the Track I and Track III testimony submitted by parties in this proceeding, as well as the evidentiary hearings held in August 2011. This brief is timely submitted in accordance with the schedule set by Administrative Law Judge ("ALJ") Allen during the evidentiary hearings.

INTRODUCTION

California has one of the most aggressive, forward thinking renewable energy requirements in the country. Senate Bill 1X requires California to receive 33 percent of its electricity from renewable sources by 2020 and the Energy Action Plan's loading order requires utilities to procure energy efficiency, demand response, and renewable resources before procuring fossil fuel resources. California's Global Warming Solutions Act further mandates significant cuts in greenhouse gas emissions, including within the electricity sector, a goal that can only be accomplished through a transition to renewable resources. Despite this framework, the utilities have dragged their heels by procuring unnecessary fossil fuel resources. At the same time, the utilities have consistently overlooked the potential of preferred resources to meet perceived system and local needs. This over-procurement of fossil fuel resources has hindered California's environmental goals and crowded out preferred resources.

In this proceeding, the utilities have yet again paid too little attention to California's environmental requirements. For instance, in their plans related to procurement of greenhouse gas (GHG) related products, none of the utilities evaluate how potential GHG emission reductions could be factored into their compliance plans even though the central goal of California's GHG requirements is the reduction of GHG emissions. To improve the procurement process, and meet California's energy goals in the future, the Commission should increase oversight and transparency of the process, while requiring consideration of issues such as the loading order and need that will help assure that future procurement is conducted consistent with California's RPS and GHG requirements. As an important step to improve the current plans, the Commission should require the utilities to evaluate the potential of reducing GHG emissions as a compliance option. In addition, the Commission should have the Energy Division, rather than the utilities, contract with the Independent Evaluator. Steps like these and the others highlighted by Pacific Environment in this proceeding will help assure that California meets its energy and environmental goals in the future.

PROCEDURAL AND STATUTORY BACKGROUND

In 2002, California enacted AB 57,[1] requiring that utilities file long-term procurement plans (LTPP) every two years and obtain the approval of the Commission in order to procure energy. A major purpose of this law is to ensure that utilities come into compliance with California's RPS, which is aimed at increasing energy diversity and reliability, and addressing public health and environmental impacts.[2] AB 57 specifically requires that procurement plans include "[a] showing that . . . the electrical corporation will first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[3] AB 57 further requires that plans contain a showing that the utility will increasingly fulfill its unmet resource needs with renewable resources.[4] These requirements are

[1] Pub. Util. Code, §§ 454.5 *et seq*.
[2] *See* Pub. Util. Code, § 399.11(a).
[3] Pub. Util. Code, § 454.5(a)(9)(C).
[4] *See* Pub. Util. Code, § 454.5(a)(9)(A).

also reflected in the Energy Action Plan's (EAP) loading order, which "describes the priority sequence for actions to address increasing energy needs."[5]

In addition to the loading order requirements, California enacted AB 32, requiring among other things that greenhouse gas emissions be reduced to 1990 levels by 2020, with a further 80 percent reduction by 2050.[6] Following the passage of AB 32 and SB 1368,[7] the Commission "must now consider carbon risk when filling net short positions with fossil resources, so as not to 'crowd out' preferred resources."[8]

In the 2006 LTPP decision, the Commission found that "all three LTPPs were deficient and spotty in regards to addressing filling their net short position with preferred resources from the EAP loading order and particularly inadequate in accounting for GHG emission reductions."[9] Despite the loading order's requirement that conventional resources be employed as a last resort, the LTPPs were "for the most part, filling and projecting to fill their projected net short positions with conventional resources."[10] Due to this lack of compliance with the loading order, the Commission found that "[g]oing forward the utilities will be required to reflect in the design of their requests for offers (RFO) compliance with the preferred resource loading order and with GHG reductions goals and demonstrate how each application for fossil generation comports with these goals."[11]

On May 6, 2010, the Commission initiated this LTPP proceeding by issuing its Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term

[5] *EAP II*, at p. 2.
[6] Health & Saf. Code, § 38550; Governor's Executive Order S-3-05 (June 1, 2005).
[7] SB 1368 "limits long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard," established by the CEC and PUC. *See* SB 1368 Emission Performance Standards, *available at* http://www.energy.ca.gov/emission_standards/index.html.
[8] R.10-05-006, Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, (May 6, 2010) ("Order Instituting Rulemaking").
[9] D.07-12-052, at p. 3.
[10] *Id*.
[11] *Id*. at pp. 3-4.

Procurement Plans.[12] The Commission divided the proceeding into three separate phases: Track I examines the "jurisdictional needs for new resources to meet system or local resource adequacy"; Track II addresses "the development and approval of individual IOU 'bundled' procurement plans consistent with § 454.5"; and Track III considers various "rule and policy changes related to the procurement process which were not resolved" in the last LTPP proceeding.[13]

The parties submitted Track II testimony and briefs earlier this year. On June 10, 2011, the Assigned Administrative Law Judge (ALJ) ruled that four Track III issues – i.e., GHG allowance/offset procurement, once-through cooling, bid evaluation, and procurement oversight – would be included in the Track I schedule.[14] Pursuant to this ruling, the utilities and the California Independent System Operator (CAISO) submitted opening testimony on Track I and the four Track III issues on July 1, 2011. The other parties submitted opening testimony on the Track I and Track III issues on August 4, 2011, and the utilities and other parties submitted reply testimony on August 11, 2011. The ALJ held an evidentiary hearing on Track I and III issues on August 15-19 and August 30, 2011.

DISCUSSION

I. TRACK I ISSUES

The purpose of Track I is to identify system need, including system need to integrate up to 33 percent renewable energy. After many months of work to identify the potential integration need, Pacific Environment, the utilities, the California Independent System Operator (CAISO), along with many other parties representing consumer, environmental, and utility interests, entered into a settlement stipulating that there is no need for procurement of new renewable

[12] *See* Order Instituting Rulemaking.
[13] *Id.* at p. 9.
[14] *See* R.10-05-006, *Administrative Law Judge's Ruling Denying Motion for Reconsideration and Motion Regarding Track I Schedule and Addressing Rules Track III Issues* (June 13, 2011).

integration resources at this time. In addition to the integration issue, the settling parties also agree that there is no local capacity reliability (LCR) need in Pacific Gas and Electric Company's (PG&E's) and Southern California Edison's (SCE's) territories at this time. Given that the majority of the evidence in the proceeding shows that there is no renewable integration need or PG&E or SCE LCR need at this time, the settlement represents a reasonable resolution of Track I integration issues and should be approved.

The remaining Track I issue, untouched by the settlement, is SDG&E's LCR need. SDG&E requests 415 MW of procurement authority despite finding a 393 MW surplus in 2020 using the Commission's preferred assumptions. Problematically, SDG&E's modeling ignores multiple preferred resources already on-line or coming on-line in SDG&E's territory, and requests far more MW than it can demonstrate a need for. Pacific Environment urges the Commission to deny this procurement authority. As with the other utilities, pursuant to the settlement agreement, SDG&E's LCR request should, at the very least, be subject to further study by CAISO.

A. The Commission Should Approve the Track I Settlement Agreement.

The purpose of Track I is to identify jurisdictional needs for new resources to meet system and local resource adequacy, including issues related to renewable planning and replacement generation for planned OTC retirements.[15] On August 3, 2011, the majority of the parties to this proceeding submitted a motion for approval of a settlement that would resolve all Track I issues, with the exception of SDG&E's request for new procurement to meet LCR needs, and the possible need to procure currently un-contracted existing resources.[16] Pursuant to the terms of the settlement, PG&E and SCE agree not to request additional procurement authority

[15] *Order Instituting Rulemaking*, R.10-05-006, at p. 12 (May 13, 2010).
[16] Attachment A to Motion for Settlement Approval, Proposed Track I Settlement Agreement Between and Among the Parties, at p. 2 (Aug. 3, 2011) (hereinafter "Proposed Settlement").

for LCR at this time.[17] Additionally, the settlement lays out multiple recommendations that the Commission may choose to employ in the future, including continued refinement of renewable integration analysis, and the analysis of the variety of resources that could be used to help integrate renewables, such as demand response, energy storage, and other smart grid technology.[18]

To approve a settlement, the Commission must find that it is reasonable in light of the whole record, consistent with the law, and in the public interest.[19] The proposed settlement meets these criteria and should be approved.

1. ***The Proposed Settlement Is Reasonable.***

The proposed settlement resolves nearly all Track I issues in a reasonable manner.[20] Pursuant to the settlement agreement, the utilities have agreed not to request procurement authority to integrate renewable resources.[21] This is consistent with the outcome of CAISO's modeling of the four primary cases based on the Commission's Standardized Planning Assumptions, which found no additional need.[22] The parties had a full opportunity to review CAISO's testimony and other relevant documents to address their various concerns before entering into the agreement.[23]

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[17] Proposed Settlement, at p. 7.
[18] Proposed Settlement, at p. 6.
[19] Rule 12.1(d) of the Public Utility Commission's Rules of Practice and Procedure Rule 12.1(d).
[20] A settlement does not need to resolve all issues in a proceeding to be found reasonable. *See* D.10-12-035, at p. 2 (approving settlement that is "comprehensive, but it does not resolve issues in numerous Commission proceedings implementing recent statutory requirements that pertain to QFs of 20 MW or less.").
[21] Proposed Settlement, at p. 4, 7.
[22] *See* D.09-10-017, at pp. 8-9 (finding settlement reasonable when it was consistent with Commission findings regarding energy efficiency, demand response, and other resources in the 2006 LTPP).
[23] *See* D.09-10-017, at p. 4 ("Parties had the opportunity to fully review PG&E's prepared testimony and DRA and TURN have participated in the Procurement Review Group (PRG) process. We are confident that parties have addressed concerns and found a reasonable compromise in the following provisions of the Settlement Agreement.").

Moreover, the settlement is supported by the majority of the parties to this proceeding,[24] including the three investor-owned utilities, consumer advocates such as the Division of Ratepayer Advocates (DRA) and The Utility Reform Network (TURN), renewable energy industry advocates such as the California Wind Energy Association, other energy providers such as Calpine Corporation, and multiple environmental groups including Pacific Environment and the Sierra Club, among other parties.[25] The Commission has previously stated that if "two adversaries can put together a negotiated settlement, it meets the reasonableness test."[26] Thus, this proposed settlement represents a reasonable resolution to a dispute between diverse parties representing a variety of interests.

2. ***The Proposed Settlement Is Consistent with the Law.***

"A settlement that implements or promotes state and Commission policy goals embodied in statutes or Commission decisions would be consistent with the law."[27] Since the proposed settlement results in no new requests for need from both PG&E and SCE, it will help to achieve several environmental goals and policies. The proposed settlement helps ensure that the utilities focus on expanding energy efficiency, demand response, and other alternative resources, without these resources being pushed aside for new fossil-fuel procurement – a result consistent with California's RPS requirements, GHG emission reduction goals, and the State's loading order preference for alternative resources. Finally, because the settlement results in no new procurement, it complies with Public Utilities Code mandates to ensure just and reasonable rates by not procuring unneeded resources.[28]

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[24] *See* D.10-12-035, at p. 3; D.06-07-032, at p. 8 ("the fact that such a large percentage, just over 50% [of Qualifying Facilities], have signed the Settlement Agreement attests to its reasonableness from the QF perspective, as well as the utility's.").
[25] Note that a settlement need not include all parties to the proceeding to be found reasonable. *See* Rule 12.1 (a) ("Settlements need not be joined by all parties."); *see also* D.06-07-032 (approving settlement regarding Qualifying Facilities where not all Qualifying Facilities had signed the agreement.).
[26] D.06-07-032, at p. 8; *see also* D.09-10-046, at p. 7 ("the Settlement is a reasonable compromise of strongly held views.").
[27] D.10-12-035, at p. 26.
[28] *See* Pub. Util. Code §§ 451, 454.5(d)(1).

3. ***The Proposed Settlement Is in the Public Interest.***

The Commission has previously found that it is in the public interest to resolve proceedings through settlements rather than continued litigation.[29] Given the number of parties in this proceeding, the diverse positions these parties represent, and the contentious issues involved, further litigation would likely be a costly and lengthy process.[30]

This settlement also benefits the public by establishing a process whereby CAISO, along with other stakeholders, will evaluate types of resources other than fossil fuel facilities that can integrate renewable resources.[31] By agreeing to consider other types of resources, the settlement resolves this potentially contentious issue. Indeed, many parties, including Pacific Environment, have raised and likely would continue to raise the argument that CAISO's model is incomplete without considering the ability to use other alternative resources, such as energy storage and demand response, to integrate renewables.[32]

Further, although the parties dispute the input assumptions and modeling results, Pacific Environment believes that the end result of the settlement – that no utility will request procurement for integration of renewables, and that PG&E and SCE will not request LCR procurement authority – benefits the public. By not procuring additional facilities at this time, ratepayers are benefiting by not funding the cost of unneeded facilities. Avoiding or reducing costs to ratepayers is a factor the Commission considers in determining fairness of a settlement.[33]

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[29] *See* D.09-10-017, at p. 11; D.09-10-046, at p. 7 ("The Commission has a history of favoring settlements. Commission approval of the Settlement will provide speedy resolution of contested issues.").
[30] *See* D.10-12-035, at pp. 36-37 ("the case in favor of adopting [the settlement] is compelling. The relationship among these parties has been contentious and litigious for most of the last 30 years. It is apparent that the disputes arising from this relationship impose large costs upon the parties as well as the Commission, the FERC, and the courts. The uncertainty may also be delaying implementation of state policy goals for CHP and GHG emissions reductions. It is clearly in the public interest to adopt a settlement framework that resolves the ongoing controversies in a manner that is acceptable to the settling parties.").
[31] *See* Proposed Settlement, at pp. 6-7 (discussing schedule for Phase II study and analysis); *see also* Tr. 363:15-364:8 (Rothleder, CAISO).
[32] *See, e.g.,* Ex 1801 (Track I Testimony of Large-Scale Solar Association), at pp. 12-13; Pacific Environment's Comments on Nov. 2010 CAISO Workshop, at pp. 2-12 (Jan. 14, 2011).
[33] *See* D.06-07-032, at p. 9 ("Settlement Agreement will benefit the public since it reasonably balances competing issues and reaches a result whereby ratepayers will be paying less for energy.").

For these reasons, the Proposed Settlement is reasonable, consistent with the law, benefits the public, and therefore should be approved by the Commission.

B. SDG&E's Request For Local Capacity Is Unneeded, Unsupported, and Should Be Rejected.

SDG&E requests authority to procure 415 MW for local capacity reliability.[34] SDG&E's 415 MW request is based on its load and resource calculations which result in a 393 MW surplus using most of the Commission's standardized assumptions and a 180 MW deficit using SDG&E's preferred assumptions.[35]

In addition to the fact that SDG&E's calculations do not support its request,[36] SDG&E's request should be denied for many other reasons including: 1) it fails to account for numerous renewable resources and programs; 2) it dramatically lowers the Commission's already conservative energy efficiency assumptions; 3) it fails to consider energy storage; 4) it lowers the Commission's demand response assumption; 5) it overestimates the impact that OTC retirements will have on its local area; 6) it only conducted a quick screening analysis rather than a detailed evaluation to determine LCR need; and 7) it requests a significant cushion without demonstrating its necessity. While the examination of any one of these changes is sufficient to cast doubt on SDG&E's purported need, when considered together, SDG&E presents an unrealistic model that does not reflect what its load pocket will look like in 2017, the first year SDG&E finds a need. For all of these reasons, the Commission should reject SDG&E's request for procurement authority.

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[34] Ex. 310 (Track I Testimony of SDG&E), at pp. 11-12.
[35] *See* Ex. 310, at p. 5, Table 1; *id*. at p. 8, Table 2.
[36] *See* Tr. 214:5-215:26 (Anderson, SDG&E); *see also* SDG&E Response to DRA Data Request Question 1 (in PE Track I Test. Appendix). Also note that SDG&E modeled the Commission Assumptions from the Trajectory Case, but states that the results would be similar under the other Commission cases. *See* Tr. 214:13-214:16 (Anderson, SDG&E); *see also* Ex 310 at p. 3.

1. *SDG&E Fails To Adequately Quantify Renewable Build-Out By Ignoring Multiple Renewable Energy Programs and Projects.*

In its trajectory LCR case, SDG&E assumes only 68 MW of renewable build-out in its territory for the year 2020.[37] In contrast, the Commission's assumptions for the trajectory case estimate a 508 MW renewable build-out for 2020.[38] In making this low estimate, SDG&E relies only on its projections for the Renewable Auction Mechanism (RAM) program.[39] It ignores all other renewable development projected by the Commission based on its unfounded belief that all other renewable development will be located in the Imperial Valley, rather than in San Diego.[40] SDG&E's assumption represents a vast underestimate of the San Diego area's likely renewable build-up and ignores several Commission programs and San Diego's ideal location for solar-PV development.

Initially, SDG&E only projects 68 MW from the RAM program,[41] even though SDG&E has stated that the RAM will require SDG&E to acquire 81 MW of renewable resources,[42] and in another filing, 155 MW.[43] SDG&E also fails to consider any contribution from its Commission-approved Solar Energy Project, which authorizes SDG&E to procure 100 MW of solar PV resources.[44] This 100 MW would primarily consist of 1-2 MW distributed generation resources, but can include up to 5 MW projects in some instances.[45] Throughout the decision, the Commission repeatedly emphasized that these projects would be sited within SDG&E's service

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[37] *See* Ex. 310, at Table 2, p. 8. In addition, since SDG&E relies on the CEC's IEPR forecast, it also includes the assumptions related to renewables that are embedded in the demand forecast. The CEC's IEPR includes the CSI program, but does not include the feed-in tariff program or the PUC's

[38] Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, R.10-05-006 (Dec. 3, 2010)), Attachment 1: Standardized Planning Assumptions (Part 1) for System Resource Plans, at p. 19.

[39] Tr. 237:23-238:7 (Anderson, SDG&E); *see also* Ex. 312 (SDG&E Track I Test. – Supporting Papers), line 49 (RPS assumption of 68 MW is "75Mw RAM at 90% RA.").

[40] *See* Ex. 311 (SDG&E Track I Test.), at p. 4; Tr. 238:27 - 239:2 , 241:25 - 242:28 (Anderson, SDG&E).

[41] Tr. 237:23-238:7 (Anderson, SDG&E); *see also* Ex 312, line 49 (RPS assumption of 68 MW is "75Mw RAM at 90% RA.").

[42] *See* Pacific Environment Cross-Examination Exhibit 506 (Excerpt of SDG&E's Smart Grid Deployment Plan).

[43] *See* Advice Letter 2232-E, Attachment B at p. 2 (Feb. 25, 2011).

[44] D.10-09-016, at p. 2; *see also* Tr. 238:8-11 (Anderson, SDG&E); *see also* Pacific Environment Cross-Examination Exhibit 506 (Excerpt of SDG&E's Smart Grid Deployment Plan).

[45] D.10-09-016, at p. 2.

territory, and repeatedly stressed the numerous benefits of small-scale solar PV projects, including that "small-scale PV facilities can be located close to load centers."[46]

In encouraging the Commission to approve its program, SDG&E also reiterated that the primary purpose of the program was to develop small-scale solar PV projects,[47] and has stated in subsequent advice letter filings that these "sites will be in SDG&E's service territory."[48]

Additionally, SDG&E has stated that for the PPA portion of the program, it "will issue annual RFOs, procuring a maximum of 15MWdc each year from 2011 through 2014," and 14 MW in 2015.[49] In addition, "[u]nsuccessful projects in one year will increase the MWdc solicited in the following year."[50] Providing that SDG&E meets this goal, this would create 74 MW of local solar-PV by 2015, which is both more MW than SDG&E's projected local need in 2017, and more than the 68 MW SDG&E assumed in its modeling.

Separate from its Solar Energy Project, SDG&E has also submitted an advice letter requesting approval of a 25 year renewable PPA for a 26 MW solar PV facility located within its service area; the facility is expected to achieve commercial operation in 2012.[51] In addition, it recently filed an advice letter for 125 MW of concentrated solar PV projects that would be in San Diego's service area, not in Imperial Valley.[52]

Furthermore, under Senate Bill 32's feed-in-tariff program, SDG&E also has an allocation of 41.4 MW of renewable energy, which it fails to consider.[53] SDG&E's 68 MW assumption also fails to consider Governor Brown's goal to build 12,000 MW of distributed

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[46] D.10-09-016, at p. 3; *see also id.* at p. 3 ("We believe the adopted Solar Energy Project will provide more options and additional flexibility to invest in renewable generation and wll enable further development of small-scale PV in SDG&E's service territory.").
[47] *See* D.10-09-016, at p. 26.
[48] Advice Letter 2210-E, Appendix A: Request for Information, at p. 1 (April 15, 2011).
[49] Advice Letter 2211-E, at p. 3 (Dec. 1, 2010)
[50] Advice Letter 2211-E, at p. 3 (Dec. 1, 2010).
[51] Draft Resolution E-4407 (The Energy Division has suggested that the Commission approve this facility).
[52] Advice Letter 2270_E, *available at* http://www.sdge.com/tm2/pdf/2270-E.pdf.
[53] Tr. 240:17-25 (Anderson, SDG&E); *see also* Pacific Environment Cross-Examination Exhibit 506 (Excerpt of SDG&E's Smart Grid Deployment Plan).

generation by 2020,[54] a significant amount of which could occur in SDG&E's territory. Also currently before the Commission in the planning phase is the Tule Wind Project, proposed to be located in San Diego County.[55]

These projects and programs are separate from the RAM program, and should have been added into SDG&E's renewable assumption.[56] Indeed, the Commission has previously found that "SDG&E is a unique case among the three utilities in that within service area resource additions almost certainly will provide local reliability benefits, unlike SCE or PG&E."[57] SDG&E's witness acknowledged this point, agreeing that "the local area and the system area are almost the same" and noting that "[a]ll of the load in San Diego's system is . . . based in the local area."[58] Consideration of all of the renewable programs and projects in its modeling would wipe out SDG&E's purported need, and even create a surplus.

2. *SDG&E Fails to Adequately Consider Energy Efficiency Gains.*

SDG&E's alternative assumptions underestimate energy efficiency (EE) gains. The Commission uses an EE assumption of 544 MW for 2020, while SDG&E uses a 260 MW assumption, a 284 MW difference.[59] SDG&E admits that if the Commission's 544 MW assumption is realized, there would be no need.[60]

Problematically, SDG&E's lower EE assumption fails to quantify a number of EE programs and standards including the Big Bold Energy Efficiency Strategy (BBEES), which SDG&E excludes from its EE calculation.[61] SDG&E also does not include savings from the

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[54] *See* Ex. 405, at p. 16.
[55] A.09-08-003, San Diego Gas & Electric East County Substation Project, *available at* http://www.cpuc.ca.gov/environment/info/dudek/ecosub/ecosub.htm.
[56] *See* D.07-12-052, at pp. 5-7 (IOUs should not assume fossil-fuel generation will be procured, but should first consider preferred and renewable resources). These programs are also not embedded in the CEC's forecast. See CEC 2011-2020 Demand Forecast, at pp. 29-30.
[57] D.04-12-048, at p. 161.
[58] Tr. 212:13-14 (Anderson, SDG&E).
[59] Tr. 216:11-217:19 (Anderson, SDG&E).
[60] Tr. 217:24 -218:7 (Anderson, SDG&E).
[61] Tr. 225:13-25 (Anderson, SDG&E).

California State Building Code improvements, the federal appliance standards,[62] and the non-utility programs of the California Center for Sustainable Energy.[63]

SDG&E also relies on an artificially low 70% realization rate for its energy efficiency assumption.[64] A 70% realization rate conflicts with previous SDG&E statements supporting the use of a 100% realization rate.[65] This rate is also markedly lower than the realization rate the Commission has used in the past. For instance, the last EE report published by the Energy Division used between a 79 to 94% realization rate for SDG&E programs,[66] and a 79 and 82% realization rate for other utilities.[67] Additionally, a 2009 Commission decision increased SDG&E's realization rate to 100% for its Energy Savings Bid program, in order to "reflect[] the unique nature of [this] program[], the utilities' on-site inspections and other features that result in a higher realization than standard statewide programs."[68]

Further discrediting its EE assumptions here, SDG&E has met and exceeded the EE goals established by the Commission in previous years.[69] The Commission also noted in the 2006 LTPP decision that meeting further EE goals would become easier for SDG&E in coming years due to Smart Grid upgrades to be completed by 2011.[70]

SDG&E's EE assumptions suffer other flaws. SDG&E's witness acknowledges that different EE programs can be expected to have different realization rates,[71] but SDG&E does not attempt to quantify realization rates between programs to reach a more accurate figure.[72] Finally,

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[62] Tr. 226:1-227:16 (Anderson, SDG&E).
[63] Tr. 243:14 -244:3 (Anderson, SDG&E).
[64] Tr. 218:28-219:3 (Anderson, SDG&E).
[65] *See* DRA Cross Exhibit 414.
[66] R E-4272, Attachment: Energy Efficiency 2006-2008 Verification Report, Prepared by Energy Division, at pp. 71, 137 (Oct. 15, 2009).
[67] R E-4272, Attachment: Energy Efficiency 2006-2008 Verification Report, Prepared by Energy Division, at p. 71 (Oct. 15, 2009) (79% realization rate for SCE, 82% used for PG&E, and ED's statewide assumption was 79%).
[68] D.09-12-045, at pp. 76-77; *see also* D.04-12-048, at p. 231 ("SDG&E should meet or exceed the Commission's EE goals over the next ten years.").
[69] D.07-12-052, at p. 51.
[70] D.07-12-052, at pp. 52-53.
[71] Tr. 224:11-225:8 (Anderson, SDG&E).
[72] Tr. 248:17-23 (Anderson, SDG&E).

the Commission's assumption of 544 MW savings from SDG&E's EE programs is conservative. The Commission's Standardized Planning Assumptions for EE omitted several sources of energy savings, including Title 20 standards and federal appliance standards. These were excluded based upon reliance on the CEC's 2009 Demand Forecast, which does not include more recent Title 20 and federal standards.[73] Savings were also excluded for new standards for battery chargers, clothes washers, and televisions, among other appliances.[74] The Commission's Planning Assumptions also relied on the "low" Big Bold Energy Efficiency Strategies scenario.[75]

3. *SDG&E Fails To Consider Energy Storage.*

Despite previously acknowledging the usefulness of storage on the grid,[76] SDG&E fails to include any renewable storage system in its LCR modeling, arguing that storage figures are too uncertain.[77] However, SDG&E has a number of energy storage projects being constructed and developed in its territory. In fact, SDG&E recently filed a request to recover over $54 million in capital costs to install energy storage projects in 2011 and 2012.[78] SDG&E's plans include development of many 50 kW batteries, 4 MW of substation energy storage in 2011,[79] and another 4 MW in 2012.[80] SDG&E is also engaging in the development of consumer energy storage systems through upgrades.[81]

Despite these current projects, SDG&E has not considered *any* energy storage being added to its territory before 2020 in its modeling.[82] While SDG&E claims that "[t]here is no

[73] Ex. 1600 (Track I Testimony of NRDC), at p. 3, n. 10.
[74] Ex. 1600, at p. 3.
[75] Assigned Commissioner and ALJ Joint Final Scoping Memo AssumptionsScoping Memo and Ruling, Attachment 1, at p. 10 (December 3, 2010); *see also* Ex 1600, at p. 3.
[76] Ex. 106 (Joint Utility Track I Testimony), at pp. 3-2; Ex. 2400 (CAISO Track I Testimony), at p. 43 ("Based on the magnitude and frequency of the observed shortfalls, storage or curtailment opportunities should be considered in lieu of additional capacity.").
[77] *See* Ex. 314 (Track I Rebuttal Testimony of SDG&E), at p. 2.
[78] Tr. 234:26-235:12 (Anderson, SDG&E).
[79] Tr. 235:25-236:4 (Anderson, SDG&E).
[80] Tr. 236:7-11 (Anderson, SDG&E).
[81] Tr. 236:22-26 (Anderson, SDG&E); *see also* A.11-06-006 (SDG&E's Smart Grid Deployment Plan Application, which details, among other policies, increasing energy storage options through customer side upgrades).
[82] Tr. 234:16-20 (Anderson, SDG&E).

definitive study that establishes the amount of storage that might be needed in the future, if any,"[83] the Commission has already acknowledged the major contribution energy storage will play in California's grid.[84] At the very least, energy storage in 2017 (the first year SDG&E finds a need) will certainly be more than the zero MW SDG&E has assumed, and SDG&E should have at least considered the MW from its current energy storage plans.

4. *SDG&E's Demand Response Assumptions Are Conservative.*

SDG&E also deviates from the Commission's demand response (DR) assumptions. Where the Commission assumed 302 MW of savings from demand response, SDG&E only assumes 219 MW,[85] which is 83 MW difference. SDG&E states that the figure it uses is consistent with its DR application currently before the Commission.[86] However, that application is only related to SDG&E's DR program until 2014, not until 2020.[87] As established during the cross-examination of SDG&E's witness, this proceeding is the only justification SDG&E can point to for lowering its DR numbers.[88] It is unreasonable to allow SDG&E to procure additional fossil fuel resources based in part on a lower projection of DR that has not yet been decided by the Commission, and will not cover the majority of the 2011-2020 timeframe at issue. Additionally, as DRA has pointed out, SDG&E relied on the Commission's 302 MW DR assumption in its BPP.[89]

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[83] Ex. 314, at p. 2.
[84] *See, e.g.*, Public Utilities Commission Policy and Planning Staff White Paper, *Electric Energy Storage: An Assessment of Potential Barriers and Opportunities*, at pp. 2, 9 (July 9, 2010).
[85] Tr. 227:21-28 (Anderson, SDG&E).
[86] A.11-03-002.
[87] *See generally* A.11-03-011, Joint Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo (March 1, 2011).
[88] *See* Tr. 229:19-230:2 (Anderson, SDG&E).
[89] Ex. 405 (Track I Testimony of DRA), at p. 15.

5. *SDG&E Overstates Both the Impact That OTC Retirements Will Have and the Urgency of Approving Procurement at this Time.*

SDG&E first finds a need in 2017 when the Encina OTC power plant is projected to be retired.[90] SDG&E overestimates the impact that OTC retirements will have on its local need. SDG&E fails to acknowledge that one of its OTC units has already been replaced by the Palomor and Otay Mesa facilities[91] and that it plans to replace the Encina facility with the proposed Carlsbad Energy Center, in addition to a number of facilities that have come online specifically to replace older generating units like the South Bay and Encina OTC plants.[92] Further, many of these OTC units are rarely used, and could easily be replaced by preferred resources.[93] For instance, the 83 MW of DR, 284 MW of EE, and hundreds of MW of renewable distributed generation (DG) that SDG&E ignored in its modeling assumptions would be more than sufficient to cover the deficiency it found in 2020.

Similarly, SDG&E overestimates the urgency of its LCR needs. Especially because SDG&E does not find a need until the end of 2017, when the first OTC units will be phased out, there is no reason to authorize any procurement authority at this time.[94]

6. *SDG&E's Request Should Be Denied Because It Relies on an L&R Model That Is a Screening Tool Not a Long Term-Planning Tool.*

As the Commission has previously established[95] and SDG&E acknowledges, LCR analysis is generally evaluated on a year-ahead basis.[96] Specifically, the Commission has held

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[90] Ex. 310, at Table 2 p. 8.
[91] *See* D.06-09-021, at pp. 6, 14.
[92] *See* D.08-12-058 at pp. 25-27.
[93] *See* Ex. 505 (PE Track III Testimony), at p. 6, *citing* Pacific Environment, *How California Can Reduce Power Plant Emissions, Protect the Marine Environment, and Save Money* (November 2009), *available at* http://www.pacificenvironment.org/downloads/PacEnv_GreenOpportunity_final.pdf; *see also* Ex. 504 (PE Track I Test.), at p. 20 *citing* Powers, Bill. *San Diego Smart Energy* 2020 (2007), *available at* http://sdsmartenergy.org/smart.shtml.
[94] *See* Tr. 586:19-28 (Minick, SCE) ("I'm quite knowledgeable about LCR analysis and system planning analysis. And I don't think right now based on my knowledge of the time it takes to build generators and the information that is available to determine whether they are absolutely needed for LCR purposes it has to be done by December 2011 or December 2012.").
[95] D.06-06-064, at p. 2 (LCR need is demonstrated annually).

that to ensure procurement is based on up-to-date information "an annual determination of LCRs through a process that allows meaningful party participation is appropriate."[97] SDG&E's expert witness agrees that CAISO does not make LCR determinations "for five years or ten years," and that the current process is one year.[98]

Using L&R tool to project local need nearly ten years from now is problematic. Utilities have thus far been able to procure their local needs in the year-ahead timeframe without major incident,[99] and SDG&E has failed to show why procurement based solely on the CAISO's screening tool[100] is needed or justified.

Further, CAISO is typically the entity that conducts LCR modeling, not the utilities.[101] CAISO has testified that it needs to conduct further modeling before determining LCR need, and the other utilities have agreed to a proposed schedule that will include this further analysis.[102] CAISO's additional analysis will include an examination of local capacity requirements impacted by OTC retirements.[103]

The other utilities have also agreed that further work needs to be done to determine if there is an LCR need.[104] Specifically, SCE's expert witness testified that completion of a LCR need determination for SCE's territory will depend upon completion of further analysis.[105] SCE's expert witness went on to list several types of analysis that would need to be completed

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[96] *See* Ex. 310 at p. 2 ("CAISO determines on an annual basis if there are sufficient resources in the load pocket."); Tr. 231 (Anderson, SDG&E) (agreeing that "CAISO determination of LCR need is also on a year-ahead basis.").
[97] D.06-06-064, at p. 78.
[98] Tr. 231:4-14 (Anderson, SDG&E).
[99] *See* Tr. 593:1-3 (Minick, SCE) ("Edison purchases LCR resources one year in advance.").
[100] *See* Tr. 232:14-233:2 (Anderson, SDG&E).
[101] D.06-06-064, at p. 27 ("For 2008 and beyond, we expect that we will continue to rely on the CAISO to perform annual LCR studies or study updates to identify load pockets and associated LCRs."); *see also* Tr. 588:2-7 (Minick, SCE); ("the ISO is responsible for doing LCR analysis."); Ex. 310, at p. 2 ("CAISO determines on an annual basis if there are sufficient resources in the load pocket.").
[102] *See* Tr. 361:1-26 (Rothleder, CAISO) (Agreeing that CAISO is recommending that "further work . . . needs to be done before the LCR need is determined.").
[103] *See* Tr. 361:5-10 (Rothleder, CAISO).
[104] *See* Tr. 583:27-584:27 (Minick, SCE); Tr. 359:18-361:18 (Rothleder, CAISO).
[105] Tr. 583:27-584:12 (Minick, SCE).

prior to determining LCR need,[106] and reiterated that there was not sufficient urgency to justify LCR procurement without completing this analysis.[107] Notably, SDG&E has not completed the types of additional analyses that CAISO and SCE's witnesses recommend, such as a power flow analysis,[108] a stability analysis,[109] and a skip ramifications study.[110]

Even relying on SDG&E's own assumptions, SDG&E does not identify a need until 2017, making it especially unnecessary to allot SDG&E procurement authority at this time. SDG&E's LCR needs should be determined along with the other utilities once CAISO has completed its LCR studies.[111]

7. ***SDG&E Requests a Significant Cushion Without Demonstrating Necessity or Reasonableness.***

Despite only finding a need between 41 and 180 MW when relying on its own assumptions, SDG&E requests authority to procure 415 MW of new resources.[112] To explain this difference, SDG&E argues that it requires a 300 MW "cushion."[113] Yet, SDG&E's witness admitted that this cushion was only an approximation.[114] SDG&E's witness further admitted that the 300 MW cushion "wasn't meant to be a specific number" and that no sensitivity analysis was conducted in calculating it.[115] Rather, as SDG&E's witness explained, this number could in fact

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[106] *See* Tr. 588:10-18 (Minick, SCE).
[107] Tr. 585:9-586:28 (Minick, SCE); *see also* Ex.215 (SCE Track I Reply Test.), at p. A-2.
[108] *See* Tr. 233:7-10 (Anderson, SDG&E).
[109] Tr. 233:25-28 (Anderson, SDG&E).
[110] *See* Tr. 588:10-18 (Minick, SCE).
[111] D.06-06-064, at p. 79 ("Whether a local area will be deficient can only be determined after the CAISO has analyzed the effectiveness factors of all of the units actually procured to meet the Local RAR in a local load pocket.").
[112] Ex. 310, at pp. 11-12.
[113] Ex. 310, at pp. 5-6.
[114] *See* Tr. 250:4-250:12 (Anderson, SDG&E).
[115] Tr. 250:13-28 (Anderson, SDG&E).

be lower[116] since it is merely "just what we put into the IOU cases for the purpose of looking at the integration need."[117]

SDG&E's speculative cushion demonstrates that its request is based largely on guesses and estimates. SDG&E's speculation about future need should be rejected. When asking for procurement authority, which will incur additional ratepayer costs, this number should be based on more than guess work and speculation.[118] Procurement authority should be based on careful study and evaluation of all resources, including whether preferred resources could be acquired over fossil fuel units.[119] A more detailed evaluation should be conducted before procurement is authorized pursuant to Section 454.5 of the Public Utilities Code.

8. *SDG&E Fails to Demonstrate That Its LCR Request Is Needed.*

SDG&E fails to show that its request for 415 MW of LCR procurement is needed. SDG&E has changed multiple Commission mandated inputs, producing an inaccurate and overly-conservative model. SDG&E ignores multiple projects and programs that if considered would have entirely eliminated its purported need. Finally, SDG&E does not actually find an LCR need until seven years into the future; LCR need should not be determined until the completion of further study. Thus, the Commission should deny SDG&E's request for LCR procurement.

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[116] *See* Tr. 250:13-250:28 (Anderson, SDG&E) (describing 300 MW cushion: "It was just what we put into the IOU cases for the purpose of looking at the integration need."); *see id.* ("I don't believe that there is a precise number that you can say 120 is a good number, but 75 or 200 would be a bad number.").

[117] Tr. 250:25-250:28 (Anderson, SDG&E).

[118] *See* Pub. Util. Code § 451 ("All charges demanded or received by any public utility . . . shall be just and reasonable."); D.11-03-036, at pp. 2-3 (rejecting project that would "subject the ratepayers to unacceptable risks," and that the utility failed to make "an adequate showing of need."); D.07-12-052, at p. 11 ("goal of AB 57 was to allow the IOUs to reliably serve their customers' needs at just and reasonable rates.").

[119] *See* Pub. Util. Code § 454.5(b)(9)(C); Pub. Util. Code § 739.10 ("The commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporations.").

II. TRACK III ISSUES

Pursuant to the June 10, 2011 ALJ Ruling, the Track III issues addressed concurrently with the Track I issues in this stage of the proceeding include: the utilities' GHG compliance plans and procurement strategies, procurement rules associated with OTC facilities, bid evaluation criteria, and oversight of the procurement process.[120] For each of these issues, Pacific Environment urges the Commission to require consideration of California's strong environmental policies and goals. This can be accomplished by: requiring consideration of emission reductions as a compliance option in the GHG compliance plans; recognizing that the goal of the OTC policy is to retire OTC units as soon as possible; requiring explicit consideration of loading order, environmental justice, and need in bid evaluations; and strengthening the role and transparency of the independent evaluator and procurement review group.

A. The Utilities' GHG Compliance Plans Are Deficient.

1. *The Utilities Should Consider Emission Reductions as a Compliance Option.*

To comply with AB 32,[121] the utilities must implement new GHG management frameworks and procurement strategies to reduce emissions produced by the utility sector.[122] The utilities' plans are deficient because they focus only on obtaining and trading compliance instruments rather than on actually reducing emissions.[123]

While both floor and ceiling prices for compliance instruments have been set by the California Air Resources Board (CARB),[124] there are no absolutes concerning how the market

[120] June 10, 2011 ALJ Ruling, R.10-05-006.
[121] Health & Safety Code §§ 38500, *et. seq*.
[122] The general goal of AB 32 is to lower the California statewide GHG emissions levels to levels equivalent to statewide GHG emissions levels in 1990 by 2020. Health & Safety Code § 38550.
[123] Ex. 505 (PE Track III Test.) at p. 36; Ex. 210 (SCE Track III Test.), at p. 6; Ex. 313 (SDG&E Track III Test.), at p. 15; PG&E seeks to obtain offsets as compliance instruments as well as develop its own offsets to meet compliance obligations. Ex. 107 (PG&E Track III Test.), at pp. 3-10.
[124] Ex. 313 (SDG&E Track III Test.), at p. 10.

and its participants will behave. For the utilities, reducing GHG emissions is far less risky than purchasing compliance instruments on potentially speculative and volatile markets.

The utilities express concerns about the behavior of the compliance instrument marketplace.[125] SDG&E acknowledges that there is "currently unknown volatility in the market" for compliance instruments[126] and speculates about whether the market for each of the compliance instruments will become liquid enough for viable participation.[127] In addition, it acknowledges the inherent risks of having either a short or long position in the marketplace.[128] SCE calls the compliance instrument market "new and evolving" and recognizes the need to manage the risks associated with its participation.[129] SCE also acknowledges that "the new GHG cap-and-trade market may be subject to very volatile market prices."[130] These statements demonstrate that the utilities anticipate being subjected to risky fluctuations in carbon market costs.

Conversely, by investing in technology development that would result in GHG emission reductions, in line with AB 32's goal,[131] the utilities would incur a one-time cost that would allow them to reliably meet their continued GHG compliance obligations. This practice is inherently less risky than participation in the speculative and volatile carbon markets and could be more cost-effective as a compliance strategy.

Importantly, the purpose of AB 32 is actual GHG emissions reductions.[132] According to the legislative intent of AB 32, the first of the reduction measures to be contemplated is "direct

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[125] SDG&E refers to the market for compliance instruments as "volatile" a number of times. Ex. 313 (SDG&E Track III Test.), at pp. 8, 12, 15; SCE acknowledges that there is a price risk in the "evolving" market for compliance instruments. Ex. 210 (SCE Track III Test.), at p. 1.
[126] Ex. 313 (SDG&E Track III Test.), at p. 8.
[127] Ex. 313 (SDG&E Track III Test.), at pp. 8-11, 15.
[128] Ex. 313 (SDG&E Track III Test.), at p. 16.
[129] Ex. 210 (SCE Track III Test.), at p. 1; s*ee also* Ex. 215 (SCE Track I and III Reply Test.) at p. 8; Ex. 210 (SCE Track III Test.) at p. 17.
[130] Ex. 210 (SCE Track III Test.), at p. 18.
[131] Health and Safety Code § 38501.
[132] Health & Safety Code § 38501.

emission reduction measures" from sources such as utilities.[133] Thus, to effectuate AB 32's purpose, rate recovery for compliance instruments should be linked with actual GHG reduction goals. In addition, the Public Utilities Code mandates that, "in a long-term plan adopted by an electrical corporation . . . the electrical corporation . . . shall adopt a strategy . . . to achieve efficiency in the use of fossil fuels and to address carbon emissions."[134] Finally, CARB's Scoping Plan for the implementation of AB 32 recommends that California adopt "emissions reduction measures."[135]

The utilities' GHG management frameworks and procurement strategies fail to consider actual reductions in GHG emissions as a way to comply with AB 32. The Commission should require each utility's compliance plan to contain information about how the utility would evaluate plans to reduce actual emissions and how those strategies could be linked to rate recovery.[136]

For example, the utilities could request recovery of costs for implementing new technologies that would result in actual GHG emission reductions. This would provide the utilities with financial incentives to reduce their emissions rather than simply providing financial incentives to purchase as many compliance instruments as they may need.[137] This type of system could result in a larger and more effective decrease in overall emissions during each compliance period, bringing compliance in line with the "direct emission reduction measures"[138] contemplated by AB 32.

By implementing the strategies mentioned above, the Commission would be in accordance with statutory authority from AB 32 and the Public Utilities Code. For the utilities,

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[133] Health & Safety Code § 38505(i); Health & Safety Code § 38561(b); *see also* Health & Safety Code § 38505(e) ("'Direct emission reduction' means a greenhouse gas emission reduction action made by a greenhouse gas emission source at the source.").
[134] Pub. Util. Code § 635.
[135] Ex. 313 (SDG&E Track III Test.), at p. 3.
[136] Ex. 505 (PE Track III Testimony), at pp. 36-37.
[137] Ex. 505 (PE Track III Test.), at pp. 36-37.
[138] Health & Safety Code § 38561(b).

finding ways to actually and quantitatively reduce GHG emissions could become more attractive than simply purchasing compliance instruments in a speculative market. In turn, these practices would further advance the goals of AB 32 for GHG emission reductions to be "real, permanent, quantifiable, verifiable, and enforceable."[139]

2. *Utilities Should Only Recover Costs From Procured Allowances When Those Allowances Have Been Used.*

The utilities propose passing all costs of GHG compliance products, such as allowances and offsets, to ratepayers through inclusion in their Energy Revenue Recovery Accounts (ERRAs).[140] Due to the speculative nature of the carbon market, it is difficult to determine what obtaining compliance instruments will entail financially. The utilities admit that the market is volatile[141] and evolving.[142] Ratepayers should not bear all of the risks of this speculative market. Because the burden of complying with AB 32 and reducing emissions is on the utilities, the proposal of passing all of the costs of GHG compliance onto ratepayers is unfair.[143] Shareholders should bear some risk related to the costs of compliance, and the costs of unused compliance instruments should not be recoverable as there is no guarantee of future use.

Utilities may attempt to procure allowances and bank them for use in future compliance periods.[144] Ratepayers could then be subjected to increased costs for allowances that may never be used, resulting in empty payments to the utilities for reimbursement of unnecessary expenses. Subjecting ratepayers to the risk of such an unknown market is both unfair and unnecessary.[145]

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[139] Health & Safety Code § 38562(d)(1).
[140] Ex. 107 (PG&E Track III Test.), at p. 3-20; Ex. 313 (SDG&E Track III Test.), at pp. 16-17; Ex. 210 (SCE Track III Test.), at pp. 20-21.
[141] Ex. 313 (SDG&E Track III Test.), at pp. 8, 12, 15.
[142] Ex. 210 (SCE Track III Test.), at p. 1.
[143] Ex. 505 (PE Track III Test.), at p. 36.
[144] Ex. 107 (PG&E Track III Test.), at p. 3-3; Ex. 313 (SDG&E Track III Test.), at p. 5.
[145] Ex. 505 (PE's Track III Test.), at p. 36.

Indeed, SDG&E is not opposed to delaying the cost recovery for allowances until the time the allowances are used.[146] This shows that it is not unworkable for the utilities to recover costs of procured allowances only after those allowances are used. By mandating that the cost of allowances not be recovered unless and until the allowances are used, utilities will have a disincentive to purchase excess compliance instruments.

The Public Utilities Code contemplates this risk. Section 454.5 of the Code states that, "an electrical corporation's proposed procurement plan shall include . . . an incentive mechanism . . . and other parameters needed to determine the sharing of risks and benefits."[147] In addition, it requires incentive mechanisms to "contain balanced risk and reward incentives . . . ."[148] Thus, the Code establishes that risks and benefits should be shared in the procurement process. The risks of an incentive mechanism like GHG compliance should not be placed solely on the shoulders of the ratepayers, but should be shared among the shareholders and the utilities.

In line with these requirements, utilities should not be allowed to recover costs associated with procured allowances before those allowances have been used. The Commission should further establish a cost recovery program that incentivizes actual emission reductions rather than promoting reliance on the purchasing and banking of allowances by allowing immediate cost recovery.[149] Incentivizing actual emission reductions would better serve the original legislative intent of AB 32, which contemplated "real, permanent, quantifiable, verifiable, and enforceable" emission reductions.[150]

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[146] Ex. 315 (SDG&E Track III Rebuttal Test.), at p. 3:3-4.
[147] Pub. Util. Code § 454.5(b)(6).
[148] Pub. Util. Code § 454.5(c)(2).
[149] Ex. 505 (PE Track III Test.), at p. 36.
[150] Health & Safety Code § 38562(d)(1).

3. *The Commission Should Have Greater Oversight of the Utilities' GHG Management Frameworks and Product Procurement.*

Due to the uncertainty of the carbon market, the Commission should oversee the utilities' GHG management frameworks and procurement strategies.[151] The utilities propose that they should only be required to annually collaborate with their Procurement Review Groups (PRGs) and submit updates about their GHG procurement transactions in their Quarterly Compliance Reports (QCR).[152] QCR filings and annual meetings with the PRGs are insufficient. Greater Commission oversight should be required to protect ratepayers and to ensure that statutes and Commission requirements are being followed.[153]

a. <u>The Commission should require the utilities to file advice letters for all proposed offsets transactions</u>.

The utilities seek Commission approval to purchase offsets.[154] "An offset is a credit for a verified emission reduction from a source outside the Cap-and-Trade Program, with the intention of reducing emissions in sectors not captured in the Cap-and-Trade Program."[155] According to the last draft of CARB's Scoping Memo, offsets may be used in lieu of allowances or in addition to allowances for up to 8% of a utility's GHG emission reduction obligation.[156] Proposed offsets may be certified by CARB once an actual GHG emission reduction has occurred and that reduction has been verified.[157] CARB certification of offsets may also be subsequently revoked because anticipated GHG reductions have not occurred. Because of these risks, the Commission

[151] Ex. 505 (PE Track III Test.), at p. 37.
[152] Ex. 107 (PG&E Track III Test.), at p. 3-20; Ex. 210 (SCE's Track III Test.), at pp. 20-21.
[153] Ex. 505 (PE Track III Test.), at p. 37.
[154] Ex. 210 (SCE Track III Test.), at p. 6; Ex. 313 (SDG&E Track III Test.), at p. 15; Ex. 107 (PG&E Track III Test.), at p. 3-10 (PG&E also seeks to develop its own offsets to meet compliance obligations).
[155] Ex. 313 (SDG&E Track III Test.), at p. 6.
[156] *See* Ex. 313 (SDG&E Track III Test.), at p. 7; Ex. 107 (PG&E Track III Test.), at p. 3-3; Ex. 210 (SCE Track III Test.), at p. 3, n.7; California Air Resources Board, Final Supplement to the AB 32 Scoping Plan Functional Equivalent Document, at p. 50, *available at* http://www.arb.ca.gov/cc/scopingplan/document/final_supplement_to_sp_fed.pdf.
[157] Ex. 210 (SCE Track III Test.), at p. 6.

should require each of the utilities to file advice letters for each category of offsets they propose to use.

Currently, CARB envisions that offsets may come from livestock manure projects, urban forest projects, U.S. ozone depleting substances projects, and U.S. forest projects.[158] Because each of these project areas exists outside of the cap-and-trade program, utilities that obtain offsets may receive credit for emission reductions without any incentive for actual emission reductions from the sources. This disconnect makes offsets more controversial. The advice letter process would provide a vehicle for utility use of offsets while increasing transparency and oversight of risky, and often controversial, offset transactions.[159]

The utilities recognize the inherent risk related to offsets but claim their plans remedy this concern. For instance, SCE states that it will only utilize offsets that are "CARB certified, that SCE believes *will* be CARB certified, or where the seller has taken on the validity risk."[160] This testimony demonstrates a serious issue: utilities are willing to rely on offsets before certification without assurance that any GHG emissions reductions have occurred or will occur in the future. Seeking approval to use future certified offsets provides no safeguards to ensure that the offsets utilized will be legitimate. This lax proposal highlights the need for the Commission to increase its oversight of offset transactions.

The utilities argue that the advice letter process for offset transactions would be too burdensome.[161] This argument is without merit. The advice letter process is "a streamlined process"[162] intended to "not be burdensome."[163] Further, the utilities may only use offsets to

[158] *See* Ex. 313 (SDG&E Track III Test.), at p. 7.
[159] Ex. 505 (PE Track III Test.), at p. 37.
[160] Ex. 215 (SCE Track I and III Reply Test.), at pp. 8-9 (emphasis added).
[161] Ex. 109 (PG&E Track III Reply Test.), at pp. 17-18; Ex. 215 (SCE Track I & III Reply Test.), at p. 8-9 (SCE states that the advice letter process is too lengthy); Ex.315 (SDG&E Track III Rebuttal Test.), at p. 2 (SDG&E states that this process would result in "unworkable delay.").
[162] D.07-07-027, at p. 18.
[163] Resolution E – 4137, at p. 23.

satisfy *up to* 8% of their GHG emission reduction obligation,[164] and the utilities are not obligated to utilize offsets. Requiring the utilities to use a simple and streamlined process to comply with a small percentage of their GHG emission reduction obligations would not be burdensome in light of the significant risks.

b. The Commission should require the utilities to participate in more stringent reporting and consultation practices and to submit their compliance plans to an Independent Evaluator.

The utilities' proposed annual PRG consultations and QCR submissions are insufficient to ensure that GHG emission reductions will occur.[165] These meeting and reporting requirements occur infrequently and will likely occur after action by the utilities has been taken. Meeting annually with the PRGs for a post-hoc review and after-the-fact QCR reporting is insufficient oversight of the utilities' compliance plans.

In addition to the utilities' proposed requirements, the Commission should require more frequent meetings with the PRGs as their purpose is to provide insight into more effective procurement strategies.[166] Utilities should meet with PRGs to discuss procurement of compliance instruments before the quarterly CARB auctions to obtain approval for the amount of compliance instruments sought to be procured.[167] This would ensure that more efficient procurement strategies are continually developed. The Commission should also require utilities to submit their compliance strategies to an Independent Evaluator (IE) to ensure that they are considering the ratepayer and environmental impacts of their compliance decisions.[168] The IEs should conduct an environmental analysis regarding the utilities' compliance strategies including

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[164] *See* Ex. 313 (SDG&E Track III Test.), at p. 7; Ex. 107 (PG&E Track III Test.), at p. 3-3; Ex. 210 (SCE Track III Test.), at p. 3, n.7.
[165] *See* Ex. 505 (PE Track III Test.), at p. 37.
[166] PRGs generally are supposed to review the utilities' procurement strategies and make recommendations to both the utilities and the Commission regarding the reasonableness of the proposed strategies. D. 02-08-071.
[167] *See* Ex. 505 (PE Track III Test.), at p. 37 (discussing importance of strengthening IE requirements).
[168] Ex. 505 (PE Track III Test.), at p. 37.

compliance instruments obtained, compliance instruments used, and utility evaluation of potential emission reductions.

By implementing up front reporting and consultation requirements in conjunction with independent environmental analyses by an IE, the Commission would help assure that each of the utilities evaluates the impact of its compliance decisions on ratepayers and the environment.

4. *The Commission Should Not Issue a Final Decision on the Utilities' GHG Strategies Until Market Experience Is Gained and the Utilities Have Considered the Environmental Impact of Their Plans.*

The Commission should issue an interim decision to allow utility participation in CARB's cap-and-trade program and in the markets for obtaining and exchanging GHG compliance instruments, but should not issue a final decision regarding approval of the utilities' GHG management frameworks and procurement strategies until market experience is gained and the utilities have considered the environmental implications of their proposed plans.

a. <u>A Commission decision by the end of 2011 is unnecessary because CARB delayed the beginning of the mandatory compliance period</u>.

The utilities have requested Commission approval of their management frameworks and procurement strategies by the end of the 2011 calendar year to facilitate participation during both the first mandatory compliance period and in the first CARB auction.[169] However, the dates the utilities relied on have been postponed. Currently, the first mandatory compliance period will begin on January 1, 2013, and the first CARB auction will be held in late 2012.[170]

Due to this delay, it is unnecessary for the Commission to issue a final decision regarding the utilities' management frameworks and procurement strategies by the end of 2011.[171] Both

[169] Ex. 107 (PG&E Track III Test.), at p. ES-2; Ex. 313 (SDG&E Track III Test.), at p. 2; Ex. 210 (SCE Track III Test.), at p. 1.
[170] *See* Ex. 109 (PG&E Track III Reply Test.), at p. 16.
[171] Ex. 505 (PE Track III Test.), at p. 33.

SCE and SDG&E have admitted in their reply testimony that due to this delay a final Commission decision by the end of 2011 is no longer necessary.[172]

b. The Commission should issue an interim decision and delay its final decision approving the utilities' GHG management frameworks and procurement strategies until the end of 2012.

The Commission should issue an interim decision regarding the utilities' GHG management frameworks and procurement strategies.[173] An interim decision would facilitate utility participation in CARB auctions as well as GHG compliance markets during 2012, but would allow both the Commission and the utilities to gain valuable market experience and data to better structure GHG management frameworks and procurement strategies in a final decision.

When this LTPP proceeding began, the Commission noted that it would, "leave open the possibility that issue areas may be decided upon individually in interim decisions if necessary."[174] Thus, the Commission anticipated the possibility that interim decisions may be necessary in order to act most effectively.

Notably, the Commission has previously issued interim decisions in similar situations. In D.07-10-032, the Commission retained previously adopted energy efficiency goals for 2009-2011 and declined to change any previously adopted energy efficiency goals for 2011-2013.[175] The Commission reasoned that the interim time period could act as, "a study to guide future decisions regarding appropriate goals through 2020."[176] Additionally, in D.06-04-010, the Commission adopted interim total market gross goals for energy efficiency for the 2012-2020 period noting that the goals should be updated once impact studies had been completed.[177]

Similarly, here, the Commission should issue an interim decision to approve utility

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[172] Ex. 215 (SCE Track I & III Reply Test.), at p. 6; Ex. 315 (SDG&E Track III Rebuttal Test.), at p. 2.
[173] Ex. 505 (PE Track III Test.), at p. 34.
[174] Order Instituting Rulemaking, at p. 22-23.
[175] *See generally* D.07-10-032; *see* D.08-07-047, at p. 5 (discussing D.07-10-032).
[176] D.07-10-032, at p. 118; *see also* D.08-07-047, at p. 5 (discussing D.07-10-032).
[177] *See* D.07-10-032, at p. 143; *see also* D.08-07-047.

participation in CARB auctions and GHG compliance markets, but not issue a final decision until market experience has been gained.[178] As the Commission has previously noted that it "is important to keep policy in line with actual market conditions."[179] Because the market conditions associated with GHG emissions reductions and compliance instruments are uncertain,[180] the Commission should issue an interim decision allowing utility participation in GHG compliance markets but maintain flexibility in the event of market changes or if emission reductions and compliance goals are not being met.

Furthermore, the utilities' strategies are currently deficient since they fail to contemplate actual emission reductions.[181] By issuing an interim decision, the Commission would enable full engagement by the utilities in GHG compliance markets, but would allow more stringent oversight to ensure that utilities are working toward the desired goal of "real, permanent, quantifiable, verifiable, and enforceable,"[182] emission reductions before issuing a final decision.

B. Energy Division's Proposed One-Year Limit on OTC Contracts Should Be Adopted with the Clarification That California's OTC Policy Governs OTC Unit Compliance with the Clean Water Act.

1. *Energy Division Staff's Proposal to Impose a One-year Limit on OTC Contracts Furthers California's Goal of Phasing Out or Repowering OTC Units, and Is Not Unduly Burdensome on the Utilities and Ratepayers.*

Staff's proposal to limit the utilities' contracts with OTC facilities to a one-year period is a reasonable attempt to align procurement planning with California's policy of retiring OTC units.[183] Instituting this relatively minor restriction on the duration of OTC contracts is a practical step toward California's goal of OTC phase-out, as set forth in the *Statewide Water*

[178] Ex. 505 (PE Track III Test.), at pp. 34-35.
[179] D.08-07-047, at p. 23.
[180] Ex. 313 (SDG&E Track III Test.), at pp. 8, 12, 15 (calling the market for compliance instruments "volatile"); Ex. 210 (SCE Track III Test.) at p. 1 (acknowledging price risk in the "evolving" market for compliance instruments.").
[181] Ex. 505 (PE Track III Test.), at pp. 36-37.
[182] Health & Safety Code § 38562(d)(1).
[183] *See* Ex. 505 (PE Track III Test.), at p. 5.

Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling[184] ("Statewide OTC Policy") adopted by the California State Water Resources Control Board in October of 2010.

The Statewide OTC policy directs owners and operators of OTC facilities to comply with one of two compliance alternatives "*as soon as possible*, but not later than" their respective compliance dates.[185] Staff's Proposal places workable restrictions on long-term OTC contracting to further the Statewide OTC Policy's of phasing out or repowering OTC units "as soon as possible." No party in this proceeding disputes the propriety of the Statewide OTC Policy or its compliance deadlines.[186] Moreover, most of California's OTC units are aging, inefficient, and unreliable.[187]

Staff's proposal is consistent with the Commission's policy of encouraging the protection of California's water resources.[188] A one-year limit would incentivize and encourage a transition away from aging OTC resources "as soon as possible," consistent with the Statewide OTC Policy. Likewise, the one-year limit will deter utilities from waiting until near the end of the compliance period and subsequently asking for an extension of the shutdown date.

The utilities and other parties have not adequately demonstrated that incidental burdens caused by Staff's Proposal are unworkable, or that these burdens outweigh California's policy of retiring OTC units as soon as possible. The primary utility argument against Staff's proposal is that the one-year limit would result in higher costs.[189] However, cost increases must be balanced

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[184] *Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*, State Water Board Res. No. 2010-0020 (Oct. 1, 2010), *available at* http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/docs/policy100110.pdf.

[185] *Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*, State Water Board Res. No. 2010-0020 (Oct. 1, 2010) at p. 6 (emphasis added).

[186] *See e.g.,* Ex. 109 (PG&E Track III Reply Test.), at pp. 1-3.

[187] Ex. 504 (PE Track I Test.), at pp. 23-24; California Energy Commission, *Comment to State Water Resources Control Board Concerning Its Coastal Power Plant Preliminary Draft Policy and Related Scoping Document* (May 2008), at p. 2, *available at* http://www.energy.ca.gov/siting/documents/2008-05-20_CHAIRMAN-SWRCB.PDF.

[188] Ex. 505 (PE Track III Test.), at pp. 3-4.

[189] *See e.g.* Ex. 109 (PG&E Track III Reply Test.), at p. 3; Ex. 211 (SCE Track III Test.), at p. 9.

against the benefits of incentivizing early remediation of OTC facilities that are aging, inefficient, and costly to operate both monetarily and environmentally. PG&E offers no support for its claim that allowing contracts with OTC units that exceed one year will achieve "the same goals as the OTC proposal, but at a lower cost to ratepayers."[190] PG&E also mistakenly implies that the Statewide OTC Policy only seeks compliance by the compliance deadlines, when in actuality, the goal is "as soon as possible." Other parties' claims that Staff's proposal could increase costs without proportional benefit are similarly unsubstantiated.[191]

SDG&E and DRA recognize the need for limits on OTC contracting during the phase out period. While they do not specifically endorse Staff's Proposal, they support a one-year restriction during the final two years preceding the compliance deadline.[192] This demonstrates the need for limits, but is insufficient to achieve the Statewide OTC Policy goals. Contrary to claims that the one-year limit "does not advance the OTC compliance targets"[193] and "serves no discernable purpose,"[194] as explained above, the one-year limit incentivizes the stated goal of compliance "as soon as possible."

Finally, the Commission should reject PG&E's alternate proposal to limit OTC contracts by simply applying its existing RFO process. PG&E recommends that until an OTC unit's compliance date, the unit should be permitted to compete in the RFO process unrestricted.[195] Even considering PG&E's contention that it gave "sizeable weight" to environmental criteria in its most recent RFO,[196] the Commission has recognized that PG&E has not always sufficiently considered environmental issues in its RFO process.[197] Thus, PG&E's proposed policy would not adequately ensure that the Statewide OTC Policy is met because simply giving OTC units

[190] Ex. 109 (PG&E Track III Reply Test.), at p. 3.
[191] *See e.g.,* Ex. 1900 (CLECA Track III Test.), at p. 8; Ex. 405 (DRA Track I & III Test.), at p 20.
[192] Ex. 313 (SDG&E Track III Test.), at p. 19; Ex. 405 (DRA Track I & III Test.), at pp. 21-22.
[193] Ex. 405 (DRA Track I & III Test.), at p. 19.
[194] Ex. 313 (SDG&E Track III Test.), at p. 18.
[195] Ex. 107 (PG&E Track III Test.), at p. 1-3.
[196] Ex. 109 (PG&E Track III Reply Test.), at p. 2.
[197] *See* D.10-07-045, at p. 20 (noting "PG&E's low weighting of environmental leadership.").

low environmental scores would not ensure that an OTC unit would not be the winning bid. Further, PG&E's proposal to treat OTC units under the same framework as other generation ignores the Statewide OTC Policy's goal of phasing-out of OTC units "as soon as possible." To meet the goals of the Statewide OTC Policy, the Commission must be proactive in establishing meaningful limitations on OTC contracts.

2. *Staff's Proposal Should Be Amended to Specify That California's Statewide OTC Policy Governs the State Water Board's Determinations Regarding OTC Units' Compliance with § 316(b) of the Clean Water Act.*

Currently the United States Environmental Protection Agency (EPA) is in the process of enacting a rule that would set three possible methods for OTC units to achieve compliance with section 316(b) of the Clean Water Act.[198] The Staff's Proposal should be modified to clearly state that, in determining compliance with section 316(b) of the Clean Water Act, the State Board will apply whichever OTC regulation – either the Statewide OTC Policy or the forthcoming federal EPA regulation – is more environmentally protective. In the event that EPA's rule is less stringent than California's Statewide Policy, California's rule will control.[199] Alternatively, the federal rule will govern if it is stricter than California's policy.[200]

As currently drafted, Staff's Proposal only references the Clean Water Act. Pacific Environment recommends that subsection "a" of Staff's Proposal be revised as follows (new language is italicized):

> A facility is found by the Water Resources Control Board to be fully in compliance with *California's Statewide Water Quality Control Policy on the Use of Coastal and Estuarine*

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[198] *See* Ex. 505 (PE Track III Test.), at p. 1.

[199] *See* 33 U.S.C. § 1370; *see also* Ex. 505 (PE Track III Test.), at pp. 1-2, *citing* State Water Resources Control Board, *Draft Staff Report on Amendment to the Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (as Amended June 23, 2011), at p. 4 ("Because the [OTC] Policy is more stringent than the proposed USEPA rule, it will remain in effect when the proposed USEPA rule is promulgated. The proposed USEPA rule explicitly states that it is within the States' authority to implement requirements that are more stringent than the federal requirements.").

[200] *See id.*

Waters for Power Plant Cooling (effective October 1, 2010) and Section 316(b) of the Clean Water Act. . . . [201]

No party to this proceeding takes issue with this proposed clarification to Staff's Proposal.

3. *The Commission Should Reject SCE's Proposal to Create a New Auction Mechanism Conducted by CAISO.*

In its Track III Testimony, SCE proposes to create a new generation auction mechanism.[202] The proposed auction would be conducted by CAISO and procure new generation for CAISO's local capacity and renewable integration needs with up to twenty year contracts.[203] The Commission should reject SCE's proposal for several reasons. First, it would remove Commission oversight by transferring procurement authority to a balancing authority that tends to more liberally allow procurement.[204] CAISO would be able to approve long-term contracts that, if approved by FERC, would leave the Commission with no means to oppose them except by resorting to the courts.[205] This would severely limit the Commission's ability to assure that renewable policies and requirements are met. The Commission has previously rejected a similar request, finding that it was not shown "how a centralized auction could be structured in order to facilitate and prioritize development of renewable resources while avoiding development of excess capacity."[206]

Second, as acknowledged by SCE's expert witness, CAISO has no expertise in engaging in long-term resource contracts,[207] including "*no* background in the solicitation, evaluation, negotiation and administration of PPAs for *new* power projects."[208] Finally, as CLECA points

[201] Ex. 505 (PE Track III Test.), at p. 3.
[202] Ex. 211 (SCE Track III Test.), at pp. 4-8
[203] Ex. 211 (SCE Track III Test.), at pp. 4-8.
[204] *See* Ex. 1504 (TURN Track I & III Test.), at p. 4. Ex 1900 (CLECA Track III Test.), at pp. 5-6.
[205] Ex. 1900 (CLECA Track III Test.), at pp. 5-6; *see also* Tr. 519:26-520:24 (Neeman Brady, SCE); Tr. 524:24-27 (Neeman Brady, SCE).
[206] D.10-06-018, at p. 78.
[207] Tr. 531:16-28 (Neeman Brady, SCE); *see also* Ex 1900 (CLECA Track III Test.), at p. 4; Ex 1504 (TURN Track I & III Test.), at p. 4 ("CAISO is not suited for making long-term need determinations.")
[208] Ex. 1504, at p. 5 (TURN Track I & III Test.) (emphasis in original).

out, SCE's request is inconsistent with its finding of no local need because a major policy change does not need to be permitted in a year where such an auction is not needed.[209]

The Commission's previous rejection of a similar auction mechanism request, cited a number of concerns including that such a mechanism would not be well-suited to achieving local reliability and operational needs,[210] and would tend to result in "generic RA capacity without significant regard to the locational, environmental, and operational aspects of the resource."[211] SCE's proposal does not offer solutions to these issues, and thus, the Commission should again reject this request for a new auction mechanism.

C. The Commission Should Refine the Bidding Process to Increase Transparency, Reduce Conflicts of Interest, and Ensure That the Utilities Evaluate All Aspects of a Project.

The utilities issue RFOs to publicly and formally request bids to fill their approved need. The utilities may tailor the process to fit their need subject to certain Commission mandated requirements.[212] Using bid evaluation criteria, the utilities select the winning bid and submit it for Commission approval.[213] The RFO process is intended to protect ratepayers by requiring a transparent and competitive bid selection process – a process that results in selection of viable bids that consider environmental impacts and a preference for alternative resources.[214]

Despite these mandates, the utilities' RFOs have historically inadequately considered environmental requirements, including the loading order. To assure that environmental requirements are considered in the future, Pacific Environment urges the Commission to: increase the transparency of the utilities' bid evaluation processes; reduce conflicts of interest;

[209] Ex. 1504 (TURN Track I & III Test.), at pp. 4-5; *see also* Tr. 522:5-28 (Neeman Brady, SCE).
[210] D.10-06-018, at pp. 53-60.
[211] D.10-06-018, at p. 78.
[212] *See* D.07-12-052, at p. 155.
[213] *See* D.07-12-052, at pp. 155, 206, 268.
[214] *See* D.07-12-052, at pp. 8, 155-57, 206, 268.

require consideration of environmental justice issues; and strengthen the requirement to evaluate project viability.

1. *The Commission Should Require the Utilities' Bid Evaluations to Consider Environmental Justice.*

In the 2006 LTPP, the Commission expressly stated "IOUs need to provide greater weight [to criteria] including disproportionate resource sitings in low income and minority communities," in the bid evaluation process.[215] Despite this directive, the utilities have made no meaningful commitment to consider Environmental Justice (EJ) in their bid evaluation processes. While PG&E touches on EJ in its RFO process, its policy does not require serious consideration of EJ in evaluating bids.[216] Pacific Environment urges the Commission to require the utilities to consider EJ and provide specific factors that need to be examined. Pacific Environment also urges the Commission to require EJ issues to be assigned a specific weight in bid evaluation criteria.

Recent procurement proceedings highlight the need to require EJ considerations in bid evaluations. For instance, PG&E failed to adequately evaluate environmental issues in its 2008 LTRFO.[217] Specifically, of the factors weighted in the bidding process, PG&E only gave its "environmental leadership" factor 1/25th the weight of its highest factor.[218] The Commission found that this low weighting of environmental criteria was "exacerbated by PG&E's inclusion of a broad range of ill-defined activities under the [environmental leadership] heading . . . and PG&E's 'after the fact' decision to reduce the weight of any scores that clustered together."[219] The Commission further found that the weights placed on environmental factors "[did] not fully reflect this Commission's stated priorities," and said PG&E "should and could have… more

[215] D.07-12-052, at p. 157.
[216] Ex. 109 (PG&E Track III Reply Test.), at p. 14.
[217] *See* D.10-07-045, at p. 20.
[218] D.10-07-045, at p. 20.
[219] D.10-07-045, at p. 20.

accurately reflected the Commission's stated priorities by giving greater weight to environmental factors and enhancing definitions related to environmental scoring."[220]

Problematically, in this proceeding, the utilities do not make any concrete commitment to consider EJ when selecting bids. For example, PG&E states that it "may" request developers to submit certain data related to EJ during an RFO.[221] That PG&E "may" choose to request information on the EJ implications of a project is insufficient to ensure adequate consideration.

The Commission should develop a standardized EJ scoring and weighting procedure and require the procedure's implementation in the bidding process. Pacific Environment's witness, Dr. Ken Kloc,[222] cites a number of sources which the Commission may reference to develop its own standardized EJ evaluation procedure.[223] Dr. Kloc recommends that, at a minimum, the Commission's EJ scoring procedure consider: "income and race demographics, level of industrialization/urbanization (including goods-movement activities, energy producing activities, and traffic), local air pollution levels, rates of air pollution-related or pollution-exacerbated disease (e.g., asthma and heart disease), and sensitivity factors such as youth and old age."[224] Formulating a standardized EJ scoring and weighing procedure, and requiring its implementation by the utilities, would help to ensure that utilities are adequately considering EJ goals.[225] Additionally, these EJ evaluations, including all supporting environmental impact data, criteria weights, and scoring results, should be made public.

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[220] D.10-07-045, at p. 20.
[221] Ex. 109 (PG&E Track III Reply Test.), at p. 14.
[222] Ex. 505 (PE Track III Test.), at pp. 41-42. issues
[223] *See* Ex. 505 (PE Track III Test.), at pp. 12-14.
[224] Ex. 505 (PE Track III Test.), at pp. 12-13, *citing* ARB, *Proposed Screening Method for Low-Income Communities Highly Impacted by Air Pollution for AB 32 Assessments*, at pp. 4-5 (April 21, 2010), *available at* http://www.arb.ca.gov/cc/ab32publichealth/communitymethod.pdf; Cal/EPA, *Cumulative Impacts: Building a Scientific Foundation*, at pp. 60-69 (December 2010); Pastor et al., *Air Pollution and Environmental Justice: Integrating Indicators of Cumulative Impact and Socio-Economic Vulnerability into Regulatory Decision-Making* (prepared for ARB, April 2010), *available at* http://www.arb.ca.gov/research/apr/past/04-308.pdf.
[225] Ex. 505 (PE Track III Test.), at p. 12.

IEP also supports a more concrete consideration of "environmental characteristics," including valid EJ concerns.[226] Although IEP lists some valid factors, IEP's proposed scoring mechanism also includes vague elements, including assigning a combined weight to all environmental concerns.[227] While IEP's proposed EJ evaluation framework reflects a positive direction in policy, it should be more explicit in the weight given to EJ.

In light of the utilities' continued failure to adequately consider EJ issues in their RFO and bid evaluation policies, the Commission should expressly require the utilities to consider EJ.

2. *The Commission Should Ensure That the Utilities' Bid Evaluation Processes Adhere to the Loading Order and Need Determinations.*

California's loading order requires that the utilities always consider energy efficiency, demand response, and renewable resources prior to procuring additional fossil fuel resources. Similarly, the Commission's need determinations are meant to ensure that ratepayers are provided with reliable energy without overprocuring unneeded resources. The utilities bid evaluation process should ensure that utilities take the loading order and need determinations into account.

Public Utilities Code Section 454.5 requires a utility to "first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[228] The Energy Action Plan similarly requires utilities to first consider energy efficiency, demand response, and renewable resources, with the procurement of new fossil-fuel resources as a last resort.[229]

[226] *See* Ex. 2000 (IEP Track III Test.), at pp. 45-46.
[227] Ex. 2000 (IEP Track III Test.), at pp. 45-46 (listing "cumulative pollution exposure to criteria pollutants within one mile and six miles of the facility; local community outreach plans; quantities and potential costs to IOU and to society associated with project environmental characteristics that are not included in the energy valuation, including environmental costs that have been mitigated using the best-available control technology; whether the project is on a brownfield or a greenfield site; and renewable benefits").
[228] Pub. Util. Code § 454.5(b)(9)(C).
[229] *See* Energy Action Plan II, at p. 2.

The utilities have historically not followed the loading order. In the 2006 LTPP, the Commission stated that "while it is apparent that IOU staff labored to comply with the Scoping Memo, their efforts resulted in plans that do not fully reflect our goals in regards to preferred resources and a commitment of the EAP loading order." The Commission further found all three utilities "deficient and spotty" with regard to adhering to the loading order.[230] Accordingly, the Commission directed the utilities to "reflect in the design of their [RFO] compliance with the preferred resource loading order."[231]

Despite this directive, SCE's and SDG&E's testimony does not address loading order compliance. PG&E's testimony states it will evaluate the loading order through its portfolio fit criteria, but does not specify how this evaluation will occur.[232] In the 2006 LTPP, despite nominal references to the loading order, the Commission found that utilities were "for the most part, filling and projecting to fill their projected net short positions with conventional resources."[233] Here too, PG&E's general reference is insufficient to guarantee adequate consideration of loading order requirements. The Commission should require the utilities to explicitly evaluate compliance with the loading order in their bid evaluation process.[234]

The Commission issues need determinations following a lengthy public proceeding.[235] However, the utilities' RFOs in the past have requested more MW than the Commission has authorized.[236] For example, PG&E's total LTRFO request from the 2006 LTPP decision added 1,559 MW of new fossil-fuel units to its system even though it was only authorized to add 800-1200 MW.[237]

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[230] D.07-12-052, at pp. 7, 3; *see also* Energy Action Plan, at p. 4 (requires "all cost-effective energy efficiency is integrated into utilities' resource plans on an equal basis with supply-side resource options.").
[231] D.07-12-052, at pp. 3-4.
[232] *See* Ex. 107 (PG&E Track III Testimony), at p. 2-4.
[233] D.07-12-052, at p. 3.
[234] *See* Pacific Environment's Track II Opening Brief (Public Redacted), at pp. 8-15 (discussing how utilities could evaluate loading order when making procurement decisions).
[235] D.07-12-052 at p. 211.
[236] *See* Ex. 500 (PE Track II Test.), at p. 25; Ex. 503 (PE Track II Test.) at p. 8.
[237] *See* D.10-07-045, Commissioner Dian M. Grueneich concurrence, at p. 1.

Due to this potential for overprocurement, the utilities should be required to carefully evaluate how many hours a resource may be called upon. Many current power plants only operate a small number of hours per year, including peaker plants that are only used during a few peak hours.[238] This type of need can likely be met by preferred resources such as demand response that can be used during peak hours.[239]

The LTPP need determination should also be periodically supplemented with updated load forecasts and other information. To make sure need determinations are based on the most current information and to keep utilities from over-procuring based on old forecasts, demand forecast should be periodically updated. Pacific Environment has previously suggested that the Commission should require that forecast data be updated every six months to ensure the most up to date information.[240]

3. *The Commission Should Ensure That Project Viability Is Adequately Assessed.*

The Commission has found several problems with the utilities' consideration of project viability. In particular, the Commission held that project viability was not properly assessed in PG&E's 2004 LTRFO.[241] The 2006 LTPP decision implored the utilities to use "greater scrutiny" in assessing viability in light of the failures of the 2004 LTRFO,[242] and directed them to "be more proactive in determining project viability among the offers submitted into RFOs."[243]

Despite these directives, the utilities' testimony in this proceeding provides insufficient information regarding how they will better assess project viability. SDG&E and SCE do not propose any refinements in weighing project viability. PG&E states that it will determine viability by considering the project's schedule, plans, and permitting status.[244] However, PG&E

[238] *See* Ex. 501 (PE Track II Test.), at p. 4.
[239] *See* Ex. 501 (PE Track II Test.), at pp. 9-19.
[240] Ex. 500 (PE Track II Test.), at p. 6.
[241] D.07-12-052, at p. 117.
[242] D.07-12-052, at p. 157.
[243] D.07-12-052, at p. 158.
[244] Ex. 107 (PG&E Track III Test.), at p. 2-7.

does not describe how it will assess the project's technology, or how it will factor in the experience of the bidding party. Additionally, there is no methodology for comparing bids once all the viability factors are measured. This is insufficient to remedy the problems the Commission identified in the 2006 LTPP.

Pacific Environment recommends that the Commission require bids to first meet certain benchmark criteria before going through any comparison methodology. For instance, the Commission's viability calculator for RPS projects rates key viability issues such as technical feasibility, company experience, and site control, but uses them as factors contributing to an overall score rather than minimal requirements.[245] The danger in this approach is that a project with no real chance of being completed and serviceable could be approved despite low technology and experience scores. Thus, bids should be required to meet certain minimal standards to assure viability. These standards could include: 1) demonstrated land control, 2) support showing that the use of the specific technology suggested is technically and economically feasible, 3) a permitting plan, and 4) the completion of interconnection feasibility studies. Bids that meet these types of requirements may then be weighed side by side using a methodology akin to the project viability calculator.[246]

Certain indicators should not only be assessed as one weighted factor within a viability determination, but should create a presumption that a project is unviable. This would prevent projects from being approved despite having low scores in certain key areas. The Commission should also give the Procurement Review Group and Independent Evaluator the proper scope and authority to assure these considerations are in play during the bidding process.[247] Additionally, other states have implemented a penalty/reward mechanism for bidders that discourages project delay and other viability issues in order to ensure that the most viable

[245] Ex 505 (PE Track III Test.), at p. 18.
[246] *See* Ex. 505 (PE Track III Test.), at pp. 19-20.
[247] *Se* Ex. 505 (PE Track III Test.), at pp. 24-32 (recommendations for strengthening PRG and IE oversight roles).

projects are being proposed.[248] Texas, for instance, has such a penalty/reward mechanism, and has exceeded its renewable energy goals, reaching its 2025 goal of 10,000 megawatts 15 years ahead of schedule.[249]

4. *Utility Owned Generation Should Not Compete in the RFO Process.*

The Commission has consistently endorsed furthering a competitive market approach to energy procurement.[250] One challenge to a competitive market is the presence of utility owned generation (UOG) bids in the competitive RFO process. As the Commission explained:

> there is an inherent incentive for IOUs to favor IOU-owned resources over third party PPAs . . . Since an IOU can shift the risk of cost overruns and other problems related to the development, construction and operation of a project to ratepayers . . . the IOUs' bid strategies are not constrained by normal bid considerations, such as being responsible for the economic consequences of submitting a low bid that is ultimately selected in the solicitation process.[251]

The presence of UOGs will likely create conflicts of interest and exacerbate impediments to achieving the Commission's goal of a fair and transparent bidding process.[252] For instance, problems with accurate valuations of UOG bid criteria are likely to occur because the utility is acting as both the bidder and the bid selector. At the very least, allowing utility build bids into the RFO process creates the appearance of a significant conflict of interest that would hinder the fair and transparent bidding process.[253]

In the 2006 LTPP, the Commission recognized these issues by placing limits on utility build bids in RFOs.[254] Further, contrary to the Commission's goals of transparent dealing,[255]

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[248] Ex. 505 (PE Track III Test.), at pp. 18-19 (referencing paper discussing Texas' viability measures).
[249] Wind Energy News, *Texas Hits Renewable Energy Target 15 Years Early* (May 17, 2010), http://www.brighterenergy.org/10444/news/wind/texas-hits-renewable-energy-targets-15-years-early.
[250] *See* D.07-12-052, at p. 208; *see also* D.10-12-035, at p. 39 ("Commission has repeatedly stated a policy preference for competitive wholesale energy markets and competitive solicitations." *citing* D.04-01-050 at 63, D.07-12-052 at p. 205, D.08-11-008 at p. 20).
[251] D.04-12-048, at p. 121.
[252] *See* D.07-12-052, at p. 207-208.
[253] Ex 505 (PE Track III Test.), at p. 21.
[254] D.07-12-052, at p. 297-98.
[255] *See* D.07-12-052, at p. 208.

nearly all UOG applications have been introduced outside of the competitive solicitation process.[256] As the Commission has recognized, "[i]n the absence of a fair and transparent evaluation process, it is unlikely that ratepayers will benefit fully either from competition or from the utilities' participation in a hybrid market."[257] PG&E's proposal to allow all UOG into the competitive RFO process contradicts the Commission's goal of a fair and transparent competitive market approach.

Notably, even among the utilities there is a debate as to whether UOG can fairly participate in the competitive RFO process.[258] SCE argues that UOG cannot be fairly compared to PPA bids, and that UOG should not be permitted in the competitive RFO process.[259] SDG&E falls somewhere between PG&E and SCE, asserting that the current practice of allowing UOG into the RFO process is effective in maintaining fair competition and need not be changed, as long as it is not from utility build bids.[260] PG&E is the outlier in its contention that all UOG should be allowed to compete in the RFO process.

In addition to the issues of fairness, numerous parties point out the difficulty of comparing UOG, especially utility build bids, with PPA bids.[261] SCE contends that comparing UOG to PPA bids is "conceptually unworkable."[262] One problem with comparing UOG to other competitive bids is their differing amortization periods. When PG&E compares UOG and PPA offers, "the life of the contract is used for a PPA offer, and . . . for a utility development offer, the expected service life is used."[263] This gives UOG projects an advantage by skewing "any discounted cash flow analysis in favor of the longer lived UOG assets."[264] Another problem with

[256] Ex 405 (DRA Track III Test.), at pp. 30-31.
[257] R.06-02-013, at p. 155
[258] *See* Ex. 107 (PG&E Track III Test.), at pp. 2-14; Ex 210 (SCE Track III Test.), at p. 13; Ex 313 (SDG&E Track III Test.), at pp. 19-22.
[259] Ex. 210 (SCE Track III Test.), at p. 13.
[260] Ex. 313 (SDG&E Track III Test.), at p. 19.
[261] *See* Ex. 405 (DRA Track I and III Test.), at p. 29.
[262] Ex. 210 (SCE Track III Test.), at p. 13.
[263] Tr. 781: 22-25 (Strauss, PG&E).
[264] Ex. 2300 (WPTF Track III Test.), at p. 7.

comparing UOG to PPA is the existence of unequal risk profiles and credit scores.[265] Because "UOG projects have assurance of ratepayer cost recovery while PPA projects must factor a return into their bids,"[266] UOG projects enjoy lower risk profiles and, consequently, higher bid evaluation scores. Finally, UOGs have an unfair advantage in strategic flexibility scoring. According to PG&E, the strategic flexibility of a UOG project is "more readily" captured by the utility than that of a PPA.[267]

Additionally, UOG projects generally have longer terms.[268] Because it is impossible to accurately forecast need 20-30 years into the future, future capacity could be well above actual need because these UOG commitments lock in current assumptions. This likely over-procurement from UOG bids could hinder the Commission's goal of integrating 33 percent renewable energy by 2020.

Finally, the Commission should also not allow the utilities to recover UOG bid development costs from ratepayers as PG&E proposes.[269] Whereas IPPs can only recover bid development costs by gaining revenue from winning bids, PG&E's proposal would allow the utilities to recover costs regardless of whether their UOG bid wins or loses.[270] To further fairness between the utilities and IPPs, "shareholders, not ratepayers, should shoulder the costs for the utilities to develop a bid or recover costs on failed UOG bids."[271] Allowing ratepayer-backed cost recovery from losing UOG bids would compel ratepayers to subsidize these bids without ensuring their viability or competitiveness.

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[265] *See* Tr. 787:25-788:17 (Strauss, PG&E).
[266] Ex. 2300 (WPTF Track III Test.), at pp. 7-8.
[267] Tr. 789:1418-790:16 (Strauss, PG&E).
[268] Tr. 782:5-14 (Strauss, PG&E).
[269] Ex. 107 (PG&E Track III Test.), at p. 2-14.
[270] Ex. 107 (PG&E Track III Test.), at p. 2-14.
[271] Ex. 405 (DRA Track III Test.), at p. 4.

D. The Commission Should Increase Transparency and Strengthen Oversight of the RFO Process.

The California Constitution provides its citizens with due process guarantees against arbitrary adjudicative procedures for statutorily conferred benefits or interests.[272] Public Utilities Code Section 454.5 confers the benefit of public oversight on procurement and rates by granting the Commission authority over allocation, characteristics, and duration of electricity.[273] More recently, consistent with these due process rights, in Senate Bill (SB) 1488, the California legislature provided that the Commission's practices must provide meaningful public participation and open decision-making.[274]

As part of the Commission's implementation of Section 454.5, it created the Independent Evaluator (IE) and Procurement Review Group (PRG) as a check during the procurement process to meet Section 454.4 requirements for upfront standards and review. In practice, however, the IE and PRG have not allowed for meaningful public participation or open decision-making. The Commission has strengthened its procedural requirements in the past to provide meaningful public participation, and should do so here.[275] Here, the Energy Division Staff made several recommendations to strengthen the Commission's oversight of the procurement process. These recommendations should be accepted, and the Commission should strengthen the IE and PRG requirements to allow for meaningful review of the RFO process.

1. *The Independent Evaluator's Role Should Be Strengthened.*

In the 2004 LTPP, the Commission created the IE program to evaluate various aspects of the procurement process including resource solicitations where there are affiliate, utility-built, or

[272] Cal. Const. Art. 1, § 7.
[273] Pub. Util. Code § 454.5.
[274] D.06-06-066 (SB 1488 requires that we examine our practices regarding confidential information to ensure meaningful public participation in our proceedings and open decision making . . . SB 1488 expresses a preference for open decision making, a policy directive we embrace).
[275] *See* D.11-07-028, at pp. 40-42; *see also* D.06-06-037 (modifying D.06-02-010 based on DRA's argument that its due process rights were violated due to failure to provide adequate notice and opportunity to be heard on the issue of adopting a new advice letter mechanism).

utility-turnkey bidders.[276] It also required utilities to consult with an IE on the design, administration, and evaluation of RFOs.[277] The intent was to provide an independent check on the utility's entire procurement process from solicitation and evaluation to final selections.[278] Notwithstanding the Commission's directives, the IE program has not been the rigorous independent check envisioned. Rather, since its inception, IE oversight has been accorded little weight, has been primarily limited to cost issues, and has been hindered by conflicts of interest.

The Commission previously acknowledged that the IE program should be refined, and that it would explore ways to do so in the future.[279] To improve the efficacy of the IE program, Pacific Environment recommends that the Commission assume contracting authority of IEs, attach more weight to IE recommendations, and expand the scope of IE review to include environmental justice, loading order, need, and viability.[280]

a. <u>The Commission should control contracts with the IEs</u>.

Pacific Environment urges the Commission to adopt the Staff's proposal and assume contracting authority of IEs to eliminate any real or perceived conflict of interest. To protect the integrity and independence of the IE process, the Energy Division (ED), not the utilities, should be responsible for the selection and contracting of IEs.

There is an inherent conflict of interest in the current IE and utility relationship. With IE contracting authority resting on the utilities, IEs have little incentive to be a truly independent check in the procurement process. If the IE's compensation is controlled by the utilities, the IE is less likely to be forthcoming or critical of utility practices. Several parties to this proceeding including DRA,[281] TURN,[282]and the Western Power Trading Forum (WPTF)[283] join Pacific

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[276] D.04-12-048, at pp. 135-36.
[277] *Id.*
[278] D.06-05-039, at p. 46.
[279] D.07-12-052, at p. 136.
[280] Ex. 505 (PE's Prepared Track III Test.), at pp. 31-32.
[281] *See* Ex. 405 (DRA Track I & III Test.), at p. 51 (IE may feel beholden to the utility and could be reluctant to produce a report calling procurement or solicitation into question).

Environment in recommending that IEs be retained and paid by the Commission to mitigate this conflict.

Under the current system, a utility chooses an IE from a pool and may tend to choose one whom it believes will support its procurement objectives. The conflict of interest is apparent. The more agreeable an IE is, the more she is likely to be selected and the more she could earn. As WPTF maintains: "It is fundamentally unfair to the firms that have been retained to serve as IEs that they must rely on payment (and hopes of retention in future RFOs) on the utility whose procurement they are expected to review and critique on an independent basis."[284]

Notably, PG&E does not oppose the transfer of contracting authority to the Commission as long as it does not create unacceptable delays in the procurement process.[285] SCE is also not opposed to having the Commission pay for the IEs.[286] While SDG&E objected to the proposal on the basis that the conflict of interest is overstated, it nonetheless agreed that if modified, its only condition is for the Commission to hire IEs based on expertise.[287] Further, the Commission recently recognized the importance of hiring the IE itself in the highly publicized and controversial Smart Meter program.[288] There, it assumed control of the hiring and supervision of the IE investigation while ordering PG&E to pay for the expenses associated with the IE contract.[289]

Lastly, lack of resources is not an acceptable justification for further delay, as the costs for compensating IEs are already billed to ratepayers.[290] SCE confirmed that it recovered IE costs

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[282] *See* Ex. 1504 (TURN Track III Test.), at p. 8 (potential conflict is the reason that IEs in many states are hired by Commissions rather than utilities).
[283] *See* Ex. 2300 (WPTF Track III Test.), at p. 19 (Staff's proposal fails to address issue of how to achieve independence if IE continues to be retained and paid by the utility whose procurement it is supposed to evaluate).
[284] Ex. 2300 (WPTF Track I & III Test.), at p. 20.
[285] Ex. 109 (PG&E Track III Reply Test.), at p. 22.
[286] Tr. 565: 12-25 (Cushnie, SCE).
[287] Ex. 315 (SDG&E Track III Rebuttal Test.), at p. 11.
[288] *See* Commission Press Release, *CPUC Selects Independent Evaluator for PG&E Smart Meters* (May 30, 2010), *available at* http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/115561.htm.
[289] *Id.*
[290] *See* Ex. 505 (PE Track III Test.), at 31.

through ratepayers,[291] and the Commission could likely do the same.[292] Therefore, regardless of who is writing the check, ratepayers will likely bear the costs for the IEs.[293]

The Commission originally contemplated contracting directly with IEs when the IE function was first initiated in D.04-12-048.[294] Now, the majority of interests either support or do not oppose this change in contracting authority. The Commission should adopt the Staff's recommendation to have the ED control IE contracting as it will increase the value of the service an IE provides,[295] improve the credibility of the procurement process, and strengthen oversight.

b. The Commission should give significant weight to IE recommendations.

For the IE to act as an independent check in the procurement process, its recommendations must be afforded proper weight. The IE's purpose is "to ensure a fair, competitive procurement process."[296] This purpose is obfuscated if the IE is relegated solely to an advisory tool. Pacific Environment urges the Commission to give weight to IE reports and to require the utilities meet a heavy burden to overcome IE recommendations.

Currently, there is no standard for weighing IE recommendations, leading the Commission to inconsistently apply these recommendations. For example, the Commission arrived at different decisions in cases where the IEs raised cost-related issues.[297] The Commission also approved projects where the IE either raised or took issue with very limited solicitation, calling into question how robust the solicitation process really was.[298] Projects have also been submitted

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[291] Tr. 578:13-19, 579:2-9 (Cushnie, SCE).
[292] *Id.*
[293] *Id.*
[294] D.04-12-048, at p. 136.
[295] *See* Ex. 405 (DRA Track I & III Test.), at p. 51.
[296] D.07-12-052, at p. 140.
[297] *See* D.10-07-042, at pp. 51-52 (project rejected when IE report showed overpriced projects being selected by the utility); *see also* D.07-01-041, at pp. 10-11, 24 (project approved despite IE questiones regarding costs).
[298] *See* D.09-01-008, at pp. 6, 10-11, 15 (IE report explained that despite a limited solicitation process, cost of the project was reasonable and bidders were not disadvantaged); *see also* A.09-04-018, at p. 8, Reply Brief of the Division of Ratepayer Advocates in Opposition to the Fuel Cell Applications (IE report stated that "PG&E appears to have conducted only a very limited degree of outreach to the fuel cell generation industry.").

to the Commission for approval without an IE report[299] or with provisions negotiated when an IE was not present.[300]

Ultimately, these cases demonstrate that uniformly applying weight to and requirements for IE recommendations, and imposing a burden to overcome them, are necessary steps to improve oversight of the procurement process. Understanding why an IE recommendation was not followed will also promote transparency and consistency.

c. The scope of the IE program should be expanded.

An IE report should cover the "entire solicitation, evaluation and selection process . . . [because] [t]his will serve as an independent check on the process and final selections."[301] Thus, the scope of the IE program should be expanded to include environmental justice, loading order, need, and viability issues.[302] If the IE has strong oversight of these issues during parts of the procurement process that is not open to public comments, it would help ensure protection of the ratepayers and the environment.

Although the Commission supports broad IE oversight during the solicitation process,[303] in practice, IEs have failed to act as an independent check against the utilities due to a limited scope of review. When non-cost related issues such as environmental justice, viability, need, or loading order were raised by the IE, the Commission often gives them little consideration or deems them outside of the IE's jurisdiction.[304] For example, in Resolution E-4350, the IE's scope of review did not include strong oversight authority on viability issues. As a result, issues raised were not adequately addressed until the project had already been selected and put forth for

[299] Resolution E-4261, at p. 13; Resolution E-4262, at p. 24 (Commission approved project when a supplemental IE report was submitted after-the-fact).
[300] Resolution E-4309, at pp. 11-12 (Commission instructed the provisions in question to be amended and counseled utility to include the IE in the process going forward).
[301] D.06-05-039, at p. 46 *interpreting* D.04-12-048, at p. 136 (utility shall consult with IE and PRG on the design, administration, and evaluation of the RFO to ensure that overall scope is not overly broad or too narrow).
[302] *See generally* Pacific Environment's Opening Brief on Track II Bundled Procurement Plans; *see also* Ex. 505, at pp. 10-20.
[303] D.06-05-039, at p. 46 *interpreting* D.04-12-048, at p. 136.
[304] *See* Resolution E-4350, at pp.7-8, 16; D.08-05-028, at pp. 4-9.

Commission approval.[305] In another case, the IE concluded that the utility conducted a fair and reasonable RFO process without addressing need and over procurement despite strong arguments by DRA that the utility did not justify its need for resources.[306] However, because over-procurement was deemed outside the IE's scope of review, the need issue was not raised until after the utility selected the project and sought Commission approval. Despite this problem, the project was approved.[307]

These cases demonstrate that the scope of the IE program has been too limited to serve as an independent check on the procurement process. Expanding the scope of IE review to include environmental justice, loading order, need and viability is a necessary step toward strengthening procurement oversight.

2. *The Commission Should Increase Transparency and Strengthen the Procurement Review Group.*

a. Non-Confidential PRG information should be publicly accessible.

Pacific Environment urges the Commission to allow public access to non-confidential PRG information.[308] Allowing the public to view non-confidential information and comment on the bidding process will help ensure the PRG is safeguarding consumer interests. Currently, PRG materials, findings, and recommendations are kept confidential. The Commission is allowed to access all PRG material but such material cannot be used as testimony in hearings. A process cloaked in secrecy cannot possibly convey confidence or demonstrate unequivocally that the public's interests have been served.

[305] Resolution E-4350, at pp. 7-8, 16 (IE reported that project approval rested on the relative importance of securing renewable power from "highly viable projects" and contracting at competitive prices; however, the IE punted the question of viability to the Commission instead and the project was approved).
[306] D.08-05-028, at pp. 4-9.
[307] *Id.* at pp. 9, 17.
[308] *See* Ex. 505 (PE Track III Test.), at p. 24.

Although the Commission found that the PRG generally played a valuable role in identifying potential issues regarding utility procurement,[309] this is insufficient to determine whether requirements under Section 454.5 of the Public Utilities Code are being met. For example, the Code requires utilities to meet unmet demand through increased efficiency and demand-reduction resources.[310] If PRG findings remain confidential, the public cannot know whether the Commission is approving projects that provide them with the most cost-effective energy available. In addition, there is no quorum requirement for a PRG meeting to take place as all PRG participants are free to attend or not to attend.[311] Hence, there is no assurance of a consistently vigorous PRG review because participants can participate at will.

In D.11-07-028, the Commission reviewed its procedures for maintaining information as confidential under Public Utilities Code Sections 454.5 and 583 pursuant to SB 1488. It recognized that SB 1488 directs the Commission to ensure that its practices "provide meaningful participation and open decision-making."[312] To accomplish this, the Commission held that all market participants can and should be able to review confidential information through a reviewing representative.[313] The Commission viewed this as the "least restrictive means to achieve the public interest in protecting the confidentiality of market sensitive information."[314] These findings should apply here. Accordingly, Pacific Environment urges the Commission to adopt procedures consistent with its findings in D.11-07-028, and allow the public access to publicly available PRG material.

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[309] D.03-12-062, at p. 46.
[310] Pub. Util. Code, § 454.5(b)(9)(C).
[311] Tr. 545:11-18-546:4-20 (Dagli, SCE).
[312] D.11-07-028, at p. 22.
[313] *Id.* at p. 2.
[314] *Id.* at p. 23.

b. The Scope of PRG review should be clearly defined.

The Commission authorized the establishment of the PRG in the 2002 LTPP proceeding to ensure that procurement contracts entered into by utilities are subject to sufficient and expedited review and pre-approval.[315] It was also intended to assure just and reasonable rates by preventing "anti-competitive conduct between utilities and their affiliates."[316]

To perform these evaluations substantively and assure utility compliance with procurement rules and requirements,[317] the PRG must also be empowered to review adherence to environmental justice mandates, loading order, need determination, and project viability considerations.[318] The need for hindsight review is reduced if the PRG's review is more comprehensive to begin with. As with the IE, the scope of PRG's review should be clearly defined to include the four factors stated above in order to assure that the Commission's duties under the Public Utilities Code can be met.[319]

c. PRG recommendations should be afforded greater weight.

The Commission could improve PRG's ability to prevent anti-competitive conduct by giving it greater weight. Currently, PRG recommendations are advisory and treated as discretionary by utilities.[320] As with IEs, PRG recommendations can be given greater weight by requiring utilities to explain why they have not followed a PRG recommendation.[321] This accountability could, in turn, improve the oversight process.

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[315] D.02-08-071, at p. 24.
[316] D.04-12-048, at p. 129; *see* D.04-01-050, at p. 195; D.03-12-062, at pp. 44-45.
[317] *E.g.* Pub. Util. Code, §§ 453, 454.5 *et seq.*, 701.1 (c); D.07-12-052, at p. 1, *EAP II* at p. 2 (requiring consideration of environmental justice, loading order, best fit/least cost, need and viability).
[318] *See* Ex. 505 (PE Track III Test.), at pp. 7-22, for a detailed discussion on how each of these issues could be evaluated.
[319] *See* Section I.C. above for discussion concerning the scope of IE review.
[320] D.07-12-052, at p. 119.
[321] *See* Section II.D.1 above for discussion concerning according IE recommendations greater weight.

d. Additional procedural safeguards are necessary.

Additional safeguards can further strengthen the Commission's oversight of the procurement process. Pacific Environment urges the Commission to adopt several of the Staff's recommendations related to PRGs. First, utilities should provide confidential meeting summaries to the PRG within 14 days prior to the next scheduled meeting to ensure sufficient time for review, as opposed to only 48 hours prior as PG&E suggests.[322] The 14-day requirement is a reasonable recommendation by Staff and is not overly burdensome, particularly since SDG&E noted that it is already providing the same information to the PRG in a "timely fashion."[323]

Likewise, providing information on a web-based calendar that discloses the date, time, duration, attendance, and non-confidential information discussed will further enhance transparency in the process. SDG&E's practice is to provide a list of attending PRG members, their organizations and an agenda of meeting topics on their PRG calendar, which can be accessed at any time.[324] This is indicative that the proposed requirement is not overly burdensome.

Lastly, Pacific Environment recommends that the Commission require at least one PRG member to possess an environmental background to help assure compliance with environment requirements. The Staff's proposal for eligible PRG participants does not explicitly include parties qualified to address environmental concerns.[325] In the 2006 LTPP, the Commission stated that utilities must consider the environment impacts of proposed projects and conform to environmental policies.[326] Since the utilities must consider environmental impacts of proposed

[322] Ex. 107 (PG&E Track III Test.), at p. 4-8.
[323] Ex. 313 (SDG&E Track III Test.), at pp. 31-32.
[324] *Id.* at p. 31.
[325] ALJ's June 13, 2011 Ruling, at Appendix B, p. 12.
[326] D.07-12-052, at p. 1.

projects and conform to environmental policies already in place,[327] it necessarily follows that the PRG should include at least one member with environmental credentials.

3. *PRG Oversight of Congestion Revenue Rights (CRR) Should Be Strengthened.*

Staff's proposal would require that a utility report specific information when proposed or completed CRR procurement is reported to the PRG.[328] Pacific Environment agrees that the proposal would strengthen procurement oversight. PG&E opposed the reporting of the impacts of congestion risk on Time to Expiration Value at Risk (TeVar) calculations and the reporting of expected value of CRR to ratepayers on the basis that the impacts of CRR procurement on TeVar are "not material."[329] However, PG&E did not provide any information to support its claim of immateriality, especially in light of testimony that shows the import of this information to consumer groups.[330] Both SCE and SDG&E also claimed that calculating the expected value of CRRs is impractical or impossible given their current modeling capabilities and SCE argued that it would provide negligible value.[331] However, the Staff's proposal stated that "[t]o the extent that exact calculations of these quantities are not practical, the IOU shall present a best-estimate and describe the estimation methodology."[332] As such, the utility's arguments are not credible and the Commission should accept the Staff's proposal concerning CRR information.

4. *The Procurement Rulebook Should Be Treated as a Reference Guide and Not as an Enforceable Set of Rules.*

Pacific Environment opposes Staff's proposal to adopt the complete set of the procurement oversight rules in Attachment 1 to ALJ Allen's June 13, 2011 Ruling as a set of

[327] D.07-12-052, at p. 1.
[328] ALJ's June 13, 2011 Ruling, at pp. 15-16.
[329] Ex. 107 (PG&E Track III Test.), at p. 4-7.
[330] *See, e.g.,* Ex. 400 (DRA Track II Test. Public), at p. 24 (due to significant risks in hedging practices, more oversight is important for TeVar calculations).
[331] Ex. 211 (SCE Track II Test.), at p. 29; Ex. 313 (SDG&E Track III Test.), at p. 34.
[332] ALJ's June 13, 2011 Ruling, at p. 16.

enforceable rules that supersede prior decisions.[333] Nevertheless, as discussed above, Pacific Environment does support a number of the Staff's specific proposals, and recommends the Commission adopt them. Adopting a wholesale set of draft procurement rules without the benefits and safeguards of the formal rulemaking process is misguided. Initially, these rules do not specifically address or discuss issues such as loading order and environmental justice that the Commission has required utilities to consider in the procurement process in prior decisions. In addition, these rules, removed from their factual context, could create confusion, particularly for practitioners who rely upon the Commission's decisions. More importantly, Staff's proposal could run afoul of the procedural rights afforded to interested parties when the Commission amends or repeals a prior decision.[334]

CONCLUSION

For the foregoing reasons, the Commission should adopt Pacific Environment's recommendations.

Respectfully submitted,

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[333] ALJ's June 13, 2011 Ruling, at pp. 2-3, Appendix B.
[334] Pub. Util. Code, §§ 1708, 1708.5.