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 12-03-014 (Filed March 22, 2012)

OPENING BRIEF OF THE UTILITY REFORM NETWORK

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

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OPENING BRIEF OF THE UTILITY REFORM NETWORK

Pursuant to Rule 13.11 of the Commission's Rules of Practice and Procedure, The Utility Reform Network (TURN) hereby submits this opening brief on Track 1 issues. While not addressing all the issues presented in testimony, TURN reserves the right to respond to proposals contained in the opening briefs of other parties in reply briefs.

I. EXECUTIVE SUMMARY

TURN offers the following recommendations in this brief:

- Based on the lack of confidence in the robustness of these forecasts over time, TURN recommends that the Commission authorize, in this proceeding, procurement sufficient to satisfy 2/3 of the Local Capacity Requirement (LCR) amounts sought by the CAISO, after the adjustments to the CAISO analyses in (2) below are applied.

- For purposes of considering the impact on Local Capacity Requirements (LCR) of "uncommitted" preferred resources (DR, EE, CHP, DG),[1] TURN recommends assuming that no less than 50% of the long-term target or program goal of each such resource is achieved.

- If the ISO proceeds to recommend major transmission upgrades to address the loss of the San Onofre Nuclear Generating Station (SONGS), the impact of such upgrades on LCR needs should be considered prior to authorizing the remaining amount of identified LCR procurement need.

- The Commission should direct SCE to explore the potential for converstion of existing Once-Through Cooling (OTC) generating units in SCE's local reliability

[1] Demand Response, Energy Efficiency, Combined Heat and Power and Distributed Generation, respectively.

areas to 'synchronous condensors' to meet LCR needs, particularly Hungtinton Beach units 3 & 4.

• TURN recommends the need in the LA Basin area be set to 2/3 of the CAISO forecast, after the adjustment to include 50% of uncommitted preferred resources. TURN remains concerned that the CAISO's has applied a more stringent reliability criterion to determine the need its recommends for the Ellis sub-area. The Commission should consider non-genreation options for meeting needs in these areas.

• TURN recommends the need in the Ventura/Big Creek area also be set at 2/3 of the CAISO forecast, after the adjustment to include 50% of uncommitted preferred resources. TURN again remains concerned that the CAISO's has applied a more stringent reliability criterion to determine the need its recommends for the Moorpark sub-area. In this case, the Commission should defer procurement in this area until the next Long-Term Procurement Plan cycle.

• The Commission should direct Southern California Edison (SCE) to manage the process for procuring any LCR needs it may identify in an expeditious manner, preferably through the issuance of competitive Requests for Offers (RFOs). The process should, without establishing additional procurement set-asides, accommodate the ability of preferred resources to compete with conventional generation and also consider other alternatives such as transmission upgrades and the development of synchronous condensers. Any RFO should also include measures to mitigate bidders' potential exercise of market power, including a 'circuit breaker' to allow procurement of smaller amounts of capacity if prices exceed a reasonable level and cost-of-service contracts for replacement of existing OTC generation. There is no need to emphasize procurement of flexible capacity in this process.

• The net capacity costs of any capacity procured to meet LCRs per the above process should be allocated pursuant to the Commission's existing Cost Allocation Mechanism (CAM) policy. The Commission should reject the proposals of AReM/DACC/MEA to change current cost allocation policy, including the allocation among customers of costs of resources needed to meet LCR needs, methods for calculating such allocations, or allowing Load-Serving Entities (LSEs) to "opt out" of the CAM.

• The Commission should not invite SCE to file an application to adjust its capital structure due to contracts it may sign to meet LCRs in its service territory.

• The Commission should coordinate consideration of issues in this and other issues that may overlap between this and other reliability and procurement proceedings, including the impact of possible Commission approval any of the capacity contracts proposed by the San Diego Gas & Electric Company in Application 11-05-023.

• The Commission should not initiate an effort to develop a statewide cost allocation mechanism of any sort at this time.

• The Commission should oppose expansion of the CAISO's current "backstop procurement authority".

• The Commission should allow storage resources to compete in any SCE LCR RFOs to the extent they can meet such need under the CAISO's current year-ahead methodology; the Commission should also move quickly to develop cost-effectiveness methodologies for storage resources more generally.

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

A. CAISO's LCR And Once-Through Cooling (OTC) Generation Studies

TURN has significant concerns about reliance on the CAISO OTC studies as the basis for establishing long-term forecasts of Local Capacity Requirements (LCR). The CAISO proposes to rely on studies that have typically been used by the CPUC to determine year-ahead LCR requirements for purposes of establishing long-term LCR need.[2] The Commission has never before relied upon multi-year CAISO LCR studies to issue procurement authorizations.[3] Based on the lack of confidence in the robustness of these forecasts over time, TURN recommends that the Commission authorize, in this proceeding, procurement sufficient to satisfy 2/3 of the amounts sought by the CAISO.

As explained by TURN witness Woodruff, the problem with reliance on the CAISO forecast is that longer-term LCR needs are moving targets that can vary significantly with each new iteration of the study.[4] This fact means that any adoption of a fixed number at this time poses the risks of either under-procurement or over-procurement of capacity in select portions of SCE's service territory.

The CAISO forecasts for the LA Basin vary by over 1,400 MW based on which Renewable Portfolio Standard (RPS) scenario is applied to 2021.[5] The RPS scenarios

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[2] For example, see D.12-06-025.

[3] Previous efforts to use CAISO models for purpose of determine mid-to-long term LCR needs in the SDG&E service territory are not comparable. As explained by TURN witness Woodruff, SDG&E had the primary responsibility to propose procurement targets and conducted its own analysis for this purpose. SDG&E's analyses could be easily analyzed by other parties and did not require resimulating the load flow models the CAISO generally uses to set LCRs in other areas. Although the CAISO has made several longer-term LCR forecasts for the PG&E and SCE service territories, the Commission has not issued procurement authorizations based on the results. See Ex.TURN-1, pages 6-7.

[4] Ex. TURN-1, pages 7-9.

[5] Ex. ISO-1, page 6, Table 1. See also Tables 2-6. Replacement OTC generation varies by more than 2000 MW based on the scenario chosen.

were developed several years ago and, due to changes in market conditions for renewable energy and the enactment of a new 33% program via Legislation (SBx2, Simitian), these scenarios can no longer be considered accurate representations of compliance options.[6]

In another example of how the CAISO effort represents a moving target, the ISO 2013-2015 Local Capacity Technical Analysis predicted "in 2015 timeframe, the Western LA Basin sub-area will become the most stringent and binding local area constraint. At that time it is envisioned that the LA Basin local area will be eliminated, and the Western LA Basin local area will become a new local area."[7] Such a change could have significant impacts on LCR needs and procurement strategies. However, under cross-examination CAISO witness Sparks indicated that, since the issuance of that study in 2010, more recent studies suggest that this change will not occur.[8] This see-sawing of expectations within a relatively short timeframe brings into question the durability of any long-term LCR forecast.

Of even greater concern is the fact that the CAISO has made no effort to consider the cost impact on ratepayers of overly conservative assumptions that lead to overprocurement. While TURN expressed concerns about the potentially significant costs of overprocurement, the CAISO has taken the position that the <u>only</u> relevant concern is the risk of underprocurement. While acknowledging that the costs of overprocurement are "relevant" to the Commission's assessment in this proceeding, CAISO witness Millar admitted that the CAISO has not "tried to perform that kind of analysis".[9] CAISO witness Sparks asserted that excessive costs associated with

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[6] In particular, huge declines in cost for photovoltaics were not forecast in these scenarios.
[7] Ex. ISO-22, page 76.
[8] RT Vol. 2, page 268.
[9] RT Vol. 3, page 502.

overprocurement are outweighed by the risk of any potential load curtailments.[10] The CAISO ignores the potential costs to ratepayers and focuses instead on the extremely low risk of criteria violations that could potentially result from significant shortage under extraordinarily stressed system conditions.

To address concerns about the 'moving target' issue and risks of overprocurement in light of substantial uncertainties about long-term generation and transmission, TURN recommends that the Commission authorize procurement sufficient to satisfy equal to 2/3 of the amounts sought by the CAISO after taking an adjustment for the inclusion of 50% of uncommitted preferred resources (see Section II(B)). This authorization should be revisited once SCE identifies generation options and a decision has been made with respect to the future availability of SONGS.

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

The LTPP offers an important opportunity to acknowledge the importance of preferred resources in meeting future system needs. Although this proceeding is primarily focused on local needs, any authorized resource acquisitions will make significant contributions to system needs. The Commission should therefore ensure that preferred resources identified in the state's loading order – Demand Response (DR), Energy Efficiency (EE), Combined Heat and Power (CHP) and Distributed Generation (DG) – are given due weight in any determination of LCR needs.

The Commission has repeatedly cited the 'loading order' as guiding resource planning decisions and has routinely released documents recommitting the state to relying on

[10] RT Vol. 2, page 270.

preferred resources.[11] In order to remain consistent, the Commission must take these commitments into account when establishing targets for the procurement of new conventional generation. The Commission has already adopted long-term goals and program targets for many of these preferred resources. Some of these targets have been supported with committed funding and implementation activities. Others are long-term planning goals that will be revisited and refined in future cycles.

The Commission has long held that adopted energy efficiency goals should be "fully reflected in the IOUs' resource acquisition and procurement plans so that ratepayers do not procure redundant supply-side resources over the short- or long-term."[12] Since the first LTPP cycle in 2004, the Commission directed utilities to "incorporate the most recently-adopted energy savings goals" into long-term procurement plans.[13] TURN supports the continuation of this practice with the caveat that there may be a justification for assuming less than 100% of goals will be realized in each local area.

In the most recent adopted Decision addressing Demand Response program goals, the Commission reiterated the Energy Action Plan II commitment to "meeting 5 percent of peak demand with price responsive DR" and asserted that "the opening of the CAISO's markets to DR coupled with ongoing enhancements of our Resource Adequacy program will facilitate progress toward meeting this goal."[14] The Decision further states the Commission's intention to "support a smooth and rational transition toward a more complete integration of DR into the CAISO's wholesale energy markets and the Utilities Resource Adequacy and long term procurement plans."[15] It seems especially reasonable to incorporate DR forecasts into LCR needs given the fact that some of the

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[11] See Ex-TURN-1, Attachments 3, 4; D.12-04-046, page 43.
[12] D.04-09-060, page 34.
[13] D.04-09-060, page 34. See also D.08-07-047.
[14] D.12-04-045, pages 10-11.
[15] D.12-04-045, page 17.

contingencies identified by the CAISO involve multiple outages and should be considered very rare events.[16] In the event that multiple outages actually occur, the Commission should assume that all available DR would be dispatched and utilized to address immediate reliability needs.

TURN recognizes that there is substantial uncertainty regarding the exact timing, location and success rate of these initiatives. For purposes of considering the LCR impact of "uncommitted" preferred resources, TURN recommends assuming that at least 50% of the long-term target or program goal is achieved. TURN further recommends adapting procurement to enable preferred resources to compete to satisfy LCR needs to the maximum extent practicable.

By contrast, the CAISO proposes to assume that 0% of uncommitted EE, DR and CHP goals are achieved in the relevant timeframe. This assumption is unduly pessimistic, would potentially undermine the effectiveness of preferred resource programs and could severely erode the value of any such resources that are ultimately developed. To the extent that identified LCR needs are fully satisfied with incremental conventional generation resources, any additional preferred resources developed in these areas may not provide meaningful value for ratepayers. As explained by Kevin Woodruff, "the programs themselves rely on cost-effectiveness calculations that assume economic value tied to the displacement of new conventional generation capacity. Reliance on the CAISO approach is tantamount to concluding that these DR, EE and CHP programs are not expected to provide any capacity value."[17]

[16] For example, the CAISO has identified certain category D situations in the Ellis and Moorpark subareas where the second contingency is a common mode outage of two transmission lines. See RT Vol. 2, pages 245-250.

[17] Ex. TURN-1, page 9.

CAISO witness Millar admitted that EE, DR and CHP are not included in the future forecast unless they are either "funded" or clear standards have been adopted.[18] Since the most recent Commission decision that "funded" energy efficiency programs provides budgets only for 2013 and 2014, it would be impossible to satisfy the CAISO standard for EE programs extending beyond that date.[19] The CAISO effectively assumes that there will be no new Commission-funded EE after 2014 that can contribute to lowering LCR needs. This assumption should not be endorsed by the Commission. Ironically, the incremental generation that will be authorized in this proceeding is similarly not "funded" (or "committed") at this time. The disparate treatment of 'uncommitted' generation and 'uncommitted' preferred resources is not justified.

Moreover, the CAISO offers inconsistent positions even with respect to uncommitted preferred resources. While the CAISO refuses to assume a success rate above 0% for uncommitted EE, DR, and CHP, they do forecast between 271 and 687 MW of distributed generation in the LA Basin over the study period even though this assumption is based on a CEC forecast, does not reflect funded projects, and is essentially an uncommitted resource.[20] CAISO witness Millar claimed that these DG numbers "are reasonable ranges for forecasting" in light of the state's overall commitment to a 33% renewable energy portfolio and taking account of the fact that the forecast had been generated, and adopted, by the CPUC.[21] Millar further explained that the most important factor for DG is not "whether it came from a committed or uncommitted program" but rather "that it's a reasonable forecast provided by the people developing forecasts."[22] The Commission should accept this invitation to

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[18] RT Vol. 3, page 506.
[19] D.12-05-015.
[20] RT Vol. 2, pages 220-222.
[21] RT Vol. 3, pages 487, 489-490.
[22] RT Vol. 3, page 493.

provide similar forecasts for uncommitted DR, EE and CHP resources to be developed through 2021.

TURN recognizes that there is uncertainty about whether these uncommitted targets will be achieved and the extent to which they will yield savings in specific LCR areas. As a result, TURN recommends assuming 50% of the forecasted savings associated with EE, DR and CHP for each LCR area. This reduction should ensure that the inclusion of uncommitted preferred resources represents a conservative approach that balances the need to value these program goals with the realization that the exact location of their placement cannot be known with certainty.

C. Appropriate Assumptions Concerning Retirement of OTC Generation

TURN recognizes that the Commission cannot modify the schedule established by the State Water Resources Control Board for the retirement or refurbishment of Once Through Cooling (OTC) generation units. Speculation as to whether the Water Board may extend the schedule should not drive the planning assumptions used by the Commission. The fact that the Water Board allows for a suspension of retirement dates due to reliability reasons should be viewed as a "fail safe" in the event of unexpected delays or unforeseen circumstances.

One exception relates to the San Onfore Nuclear Generating Station. To the extent that one or both units are prematurely retired and local mitigation measures involve significant new transmission upgrades, the ability to site, permit and construct new transmission within the OTC retirement timeframe could be challenging. In this event, the Commission should work with the Water Board to determine whether delays associated with new transmission could justify a slight delay in specific OTC unit retirements.

As indicated in the previous paragraph, reliance on the adopted retirement dates should not be used to force any emergency measures that would prove extremely costly. The Commission should make a good faith and serious effort to address reliability issues consistent with the adopted retirement schedule. Requests for schedule extensions should only be considered under extreme circumstances where the optimal comprehensive solution to local reliability may require slight retirement delays for particular OTC units.

D. Transmission And Other Means Of Mitigation

TURN supports a review of non-generation options that can mitigate local reliability constraints through 2020. These options include transmission upgrades and the use of synchronous condensers. The Commission should direct SCE to explore these options in tandem with soliciting new and repowered generation resources in order to determine the least-cost, and most environmentally preferable, alternative for ratepayers.

1. Consequences of early SONGS retirements on LCR needs

The evolving status of the San Onofre Nuclear Generating Station could require major changes to any forecasts of the quantity and location of new generation to meet LCR needs. As of today, there is no realistic restart date for SONGS Unit 2 or 3. It is possible that both units will never return to operation and plausible that only Unit 2 will return to service at less than full power. During evidentiary hearings, CAISO witness Sparks explained that the loss of SONGS would force the CAISO to consider "major transmission upgrades" to compensate for the absence of that generating capacity.[23]

The CAISO is supposed to present modeling results to a stakeholder group in December of 2012 that evaluate the long-term reliability impacts if SONGS is not

[23] RT Vol. 1, page 93.

available.[24] In the event that SCE determines that one or both SONGS units cannot be returned to service and the CAISO modeling shows the need for major transmission upgrades, the impact on LCR need could be very significant. The addition of a major transmission upgrade could actually reduce the need for new generation in the LA Basin.

TURN is concerned that this sequence of events could strand investments in new generation that currently appears to be needed to meet future LCR needs. At the very least, it calls for the Commission to authorize less than the maximum procurement quantities sought by the CAISO at this time. If the ISO proceeds to recommend a major transmission upgrade to address the loss of SONGS, the impact of this upgrade on LCR needs should be considered prior to authorizing the remaining amount of identified LCR procurement need.

2. <u>Possible conversion of existing generating units to synchronous condensers</u>

Another issue that arose during evidentiary hearings relates to the potential conversion of existing generating units to synchronous condensers and the development of new generation that has the ability to act as either a synchronous condenser or a generator (depending upon system needs at any point in time). CAISO witness Millar indicated that the CAISO is interested in exploring this possibility for Huntington Beach units 3 & 4 but was concerned about whether it was appropriate to use Reliability Must Run (RMR) contracts for this purpose.[25] He also suggested that new generating units could be constructed with the ability to function as synchronous condensers.

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[24] Ex. ISO-1, page 15; RT Vol. 1, page 92.
[25] RT Vol. 3, pages 365-366.

TURN believes that the Commission should explicitly direct SCE to explore the costs and practical barriers to converting Huntington Beach (and any other retiring OTC units) to synchronous condensers. Information should be solicited from all relevant owners of generation in early 2013 in order to determine if this option is desirable. To the extent that new investments need to occur at these plants, it would be preferable to spread cost recovery over a multi-year contract rather than a single-year RMR payment.

III. DETERMINATION OF LCR NEED SPECIFIC TO LA BASIN AND BIG CREEK/VENTURA AREA

A. <u>LA Basin</u>

As indicated in Section II, TURN recommends that the Commission authorize procurement equivalent to 2/3 of the CAISO forecast after taking an adjustment to include 50% of uncommitted preferred resources. TURN further urges the Commission to have SCE investigate additional non-generation options for mitigating potential resource needs in the LA Basin including distribution and transmission upgrades that would allow additional load transfers.

For the Ellis subarea, TURN remains concerned that the CAISO has used a more stringent reliability analysis by applying Category D criteria which have the effect of causing higher estimates of LCR need.[26] Since a single company current owns all the OTC assets in this subarea, there are significant market power concerns that make the consideration of replacement capacity very challenging.[27] The Commission should therefore emphasize the consideration of non-generation alternatives in order to provide a comparison between options for meeting potential LCR needs.

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[26] Ex. TURN-1, pages 11-12.
[27] Ex. TURN-1, page 20.

B. Big Creek/Ventura Area

As indicated in Section II, TURN recommends that the Commission authorize procurement equivalent to 2/3 of the CAISO forecast after taking an adjustment to include 50% of uncommitted preferred resources. For the Moorpark subarea, TURN is concerned about the use of Category D criteria and the fact that a single entity owns the subarea OTC assets (as is the case with the Ellis subarea). Moreover, TURN agrees with SCE that the Moorpark sub-area deserves additional analysis that includes smaller generation sizes and reviews additional transmission mitigation options.[28] In order to allow this analysis to proceed, no solicitations should be conducted to procure new or repowered generation for this subarea until the next LTPP cycle. This recommendation is consistent with SCE's proposal.

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

A. Incorporation Of The Preferred Loading Order In LCR Procurement

In order to properly incorporate preferred resources into LCR procurement, both the Commission and SCE must make additional efforts to ensure that these options can be considered as viable alternatives to conventional generation. There are two key elements that will allow a fair consideration of alternatives. First, the Commission must ensure that there are clear criteria for determining the ability of preferred resources to comply with, and count towards, Resource Adequacy (RA) requirements. In the absence of such clarity, SCE would be hard-pressed to select a non-conventional resource that may not actually mitigate local reliability needs.

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[28] Ex. SCE-2, pages 19-20. See also, RT Vol. 1, page 102; RT Vol. 6, pages 1019-1020.

The second element for success is a related requirement that any RFO used to satisfy identified procurement needs should identify the performance characteristics needed to be eligible to count as local RA. As explained by TURN witness Woodruff:

> It is possible to compare different types of resources competing to provide local reliability services in the same RFP. However, the differential costs and performance parameters of such resources – including their ability to comply with, in some cases, still evolving criteria for providing local RA capacity – may make their comparison on an "apples-to-apples" basis challenging. However, for the sake of consistency with both the Commission's policy supporting competitive procurement and its resource planning goals, this challenge should be accepted.
>
> Any RFO resulting from this docket to meet local capacity needs in Edison's territory should require that resources offer the performance characteristics needed to be eligible to count as local RA capacity, to the extent such characteristics are known at that time. If such characteristics are not entirely known yet, the RFO should specify them as well as possible and provide a summary of those characteristics that may be clarified before the RFO process is completed and Edison identifies its "short list". But the evaluation of bids received in response to the RFO, negotiation of contracts with short-listed bidders, and Commission review of any contracts arising from the RFO may be challenging if RA counting rules for some resources are not certain yet.[29]

For purposes of meeting approved LCR needs, TURN does not support the adoption of set-asides or procurement 'silos' for any subset of preferred resources. While TURN does support dedicated procurement mechanisms for renewable resources used to meet identified program targets (i.e. RPS, Feed-in Tariff, Renewable Auction Mechanism), the use of similar mechanisms would not be appropriate for LCR purposes. TURN's primary concern is that SCE must be able to consider a variety of alternative options for meeting specific LCR needs. Mandating a minimum quantity of a particular type of resource for the purpose could prove counterproductive under various scenarios. For example, additional analysis could reveal that cost-effective transmission and distribution upgrades could successfully mitigate significant identified LCR needs. In

[29] Ex. TURN-2, pages 18-19.

this event, it would not be useful to mandate a specific quantity of preferred resource procurement.

To the extent that the selection of preferred resources for LCR needs would count towards preferred resource targets adopted in other proceedings, the Commission should direct SCE to determine acceptable premiums that would justify selection in an RFO. For example, if the selection of a photovoltaic resource would reduce SCE's otherwise applicable RAM, FIT or RPS obligations, any premiums associated with those avoided obligations would not be incurred. It may therefore be appropriate to develop proxy premiums that could be applied to preferred resource bids for purposes of assessing their cost-effectiveness as compared with conventional resources. This approach would preserve the overall goal of cost-minimization and ensures that total portfolio costs are taken into account in meeting LCR needs.

Finally, TURN expects parties will provide additional information on this subject in comments to be filed in response to the ALJ's September 14 Ruling Seeking Comment on Workshop Topics.

B. <u>Other Commission Policies and Consideration Affecting LCR Procurement</u>

TURN reserves the right to respond to proposals made by other parties in the reply brief.

C. <u>If A Need Is Determined, How The Commission Should Direct LCR Need To Be Met</u>

The only possible way to ensure that LCR procurement occurs in a timely, orderly and coherent fashion is to have the procurement process managed by SCE since all the resources (whether generation, transmission, or distribution) would be located in the SCE service territory. TURN witness Kevin Woodruff explained that "the only entity capable of conducting such procurement effectively is Edison itself."[30] Based on the testimony and hearings in this proceeding, TURN offers the following proposals with respect to the process for moving forward.

SCE should administer the process in several, quickly-executed stages. First, SCE should be directed to report to the Commission in this proceeding on its framework to evaluate options for meeting LCR need. These options should include conventional generation, preferred resources, transmission upgrades, synchronous condensers and distribution-level enhancements. This report should be followed by comment by parties and be followed by a ruling from the Assigned Commissioner providing direction and guidance for implementation. Based on this ruling, SCE should proceed to solicit and assemble a portfolio of actions to meet approved LCR needs. The portfolio should be submitted to the Commission for approval through an application process. In the application process, the Commission shall consider updated LCR forecasts and assess the reasonableness of options presented by SCE prior to issuing any final approvals. The application should include any suggested transmission or distribution investments that would substitute for new or repowered generation.

In soliciting LCR resources, SCE should use competitive solicitations to the maximum extent possible. The need for competitive solicitations is particularly important for any resources that may be contracted under cost-based contracts.[31] For new generation, SCE should solicit for terms of 10, 20 and 30 years in order to determine the optimal PPA duration to serve ratepayers at lowest cost.[32]

These solicitations should include a 'circuit breaker' mechanism to allow the

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[30] Ex. TURN-1, page 2.
[31] Ex. TURN-2, Rebuttal Testimony of Kevin Woodruff, pages 16-17.
[32] RT Vol. 4, pages 754-755. (SCE witness Cushnie indicated a willingness to consider 20 year contracts)

procurement of lower amounts of capacity if prices exceed a reasonable level, especially in the event that prices deviate from fundamental costs.[33] TURN also recognizes that the presence of extreme market power in certain sub-areas may make solicitations problematic.[34] When such market power exists, SCE should consider offering cost-of-service contracts to uniquely situated resources, especially for the purpose of repowering existing OTC units. Any cost-of-service contracting process should involve both an Independent Evaluator and an Independent Transmission Engineer.[35] The Commission can authorize such cost-of-service contracts pursuant to §454.6 which specifically addresses the repowering of existing thermal units.

TURN recognizes that this approach would provide substantial discretion to SCE in assembling a portfolio of options. SCE is a proven leader in developing innovative procurement strategies and should be given the opportunity to pursue all available options without real-time micromanagement. That said, SCE should also be prepared to identify viable options that were not selected in order to give the Commission an opportunity to approve a modified portfolio based on the feedback of a variety of stakeholders.

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[33] Ex. TURN-1, page 3.
[34] Ex. TURN-1, page 2. ("there is market power – in fact, virtually monopoly power – in some sub-areas, such as Ellis. Such differences in market power among regions may call for very different procurement approaches, as presented below.")
[35] Ex. TURN-2, Rebuttal Testimony of Kevin Woodruff, page 17.

D. Appropriate Method(s) of Procurement

As indicated in the previous section, TURN believes that the Commission should direct SCE to primarily rely upon competitive solicitations except to the extent that direct bilateral negotiations are needed due to market power issues.

E. Timing Of Procurement

The Commission should initiate the first phase of the procurement process in early 2013. As stated in Section (C), the initial steps should involve the development of a framework for identifying and soliciting all available resources and investments that can satisfy LCR needs. SCE should submit this framework for comment in early 2013 and the Commission should issue a ruling providing guidance sometime in the second quarter of 2013. Once the ruling has been issued, SCE would develop and conduct solicitations with the goal of assembling a portfolio of resources and investments that can be submitted for Commission review and approval in early 2014.

V. INCORPORATION OF FLEXIBLE CAPACITY ATTRIBUTES IN LCR PROCUREMENT

A. If A Need Is Determined, Should Flexible Capacity Attributes Be Incorporated Into Procurement

TURN does not believe that it is important to explicitly incorporate flexible capacity attributes into the upcoming LCR procurement process. Although flexible operation may generally be a desirable attribute, it is a serious challenge to establish specific values for different dimensions of flexibility. Until additional system modeling can be performed on renewable integration, the likely range of values for flexibility cannot be ascertained. Moreover, the new combined cycle plants and combustion turbines likely to bid into RFOs will possess tremendous flexibility so there is little chance that the failure to explicitly value this attribute will lead to the development of inflexible resources. TURN is concerned that efforts to place explicit values on flexibility are premature and may lead to unnecessary bid inflation. To the extent that more flexible utilization and dispatch conditions for new resources can be secured, SCE should consider these as qualitative values that can be used to choose between comparable-priced alternatives.

B. Additional Rules, Not Already Covered By Resource Adequacy (RA) Rules, To Govern LCR Procurement

TURN does not offer any proposals regarding additional rules to govern LCR procurement. To the extent that such proposals are made by other parties, TURN reserves the right to respond in reply briefs.

VI. COST ALLOCATION MECHANISM (CAM)

A. Proposed Allocation Of Costs Of Needed LCR Resources

The consideration of cost allocation issues should be guided by §365.1(c)(2)(A) of the Public Utilities Code, added by Senate Bill 695 (2009, Kehoe), which directed the Commission to allocate to all benefitting customers the net capacity costs of "generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory". Since the new resources that may be authorized in this proceeding are explicitly intended to meet local area reliability needs on behalf of all customers, the Commission should presume that the costs of any new LCR resource commitments satisfy the statutory test and should be allocated to the customers of any load-serving entity operating in the service territory of the incumbent IOU.

As explained by TURN witness Woodruff, all customers benefit equally from grid reliability regardless of whether they take energy service from an IOU, an Electric Service Provider (ESP) or a Community Choice Aggregator (CCA). Since differential reliability cannot be allocated to specific customers based on their retail provider, "all customers should expect to pay equally for the costs of investing in new resources needed to provide reliability."[36] Because new resources are "typically much more costly than existing resources", it is reasonable for the costs of these more expensive resources to be allocated to all customers.[37] Otherwise, the load-serving entity making a commitment to new resources would be forced to pay higher costs while not being able to realize any greater reliability benefits for its customers.

TURN does not see any reason to make material modifications to the Cost Allocation Mechanism (CAM) at this juncture. While recognizing that some technical calculation adjustments may be appropriate, TURN strongly opposes efforts to make significant changes to CAM. In light of the substantial commitments to new resources needed to address the retirement of OTC units in the LA Basin, the Commission should avoid excessive tinkering with the CAM mechanics or obligations. In particular, the Commission should reject the proposals by Direct Access (DA) providers and CCAs to cap CAM costs, to levelize the CAM charge, or to allow an opt-out for any Load-Serving Entity on the terms suggested in this rulemaking.

B. <u>Should CAM Be Modified At This Time?</u>

The Commission should decline to adopt the specific modification proposals made by AREM/DACC/MEA designed to result in DA and CCA customers paying for less than a proportional share of reliability-related costs. Moreover, the Commission should not take a leap of faith that these LSEs are able to successfully develop the new capacity needed to meet future reliability needs given the absence of any track record in California that supports this conclusion. Despite being authorized to conduct direct transactions with retail customers since the late 1990s, Direct Access providers have

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[36] Ex. TURN-2, Rebuttal testimony of Kevin Woodruff, page 3.
[37] Ex. TURN-2, Rebuttal testimony of Kevin Woodruff, pages 3-4.

failed to demonstrate their ability to stimulate the development of new generating capacity. Until there is a sufficient demonstration that these load serving entities are using their procurement to add new resources to the system, the Commission should give little weight to claims that the CAM is stifling innovation or preventing the full exercise of customer choice.

It is also important to note that the only currently operating CCA (Marin) is located in PG&E's service territory. Any new CCAs likely to form during this LTPP cycle (e.g. San Francisco) are almost certain to also be located within PG&E's footprint. Since the CAM procurement under consideration in this case would be conducted in SCE's service territory, there will be no financial impact from the CAM on existing or future CCAs. Any longer-term changes to the CAM that pertain to CCAs can therefore be deferred until a future LTPP cycle or other appropriate proceeding.

AREM/DACC/MEA propose three specific CAM calculation changes that are extremely problematic. First, the proposal to cap CAM costs for DA/CCA customers is without merit. As explained by TURN witness Woodruff, there should not be either a ceiling or a floor on the allocation of CAM costs.[38] To suggest that only a ceiling, and not a floor, should be adopted, violates basic principles of fairness and equity.

Second, the Commission should reject efforts to establish the CAM based on forecasts of the "option value" of CAM resources.[39] Instead, the Commission should rely upon the actual revenues realized by the resource through a market-based energy auction. The AREM/DACC/MEA proposal assumes an idealized version of the maximum potential market revenues that could be earned by the generation resource. As TURN witness Woodruff points out, this theoretical exercise ignores market realities and could

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[38] Ex. TURN-2, Rebuttal testimony of Kevin Woodruff, pages 8-9.
[39] Ex. AREM-1, pages 42-43.

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significantly overstate the actual revenues that would be earned by the generation resource in real-world operations.[40] There is no basis for using a flawed theoretical model to determine CAM costs when actual operational experience and cash flows associated with the resource can be utilized.

Third, AREM/DACC/MEA propose that the CAM charge be based on the levelized fixed costs of the asset.[41] Under cross-examination, AREM/DACC/MEA witness Fulmer acknowledged that because the utility would be allowed to recover fixed asset costs based on conventional straight-line depreciated original cost (SLDOC) ratemaking, a levelized CAM charge would lead to a revenue shortfall in the early years of the asset life.[42] This shortfall, under the AREM/DACC/MEA proposal, would be borne by bundled customers and is equivalent to a forced loan.[43]

The disparate treatment that results from this change would favor the short-term interests of DA/CCA customers (who would make lower CAM payments) to the detriment of bundled load (who would pay for the bundled portion of the asset at SLDOC-based rates plus the difference between SLDOC-based rates and the cheaper levelized charge for DA/CCA loads). Bundled customers would be forced to make this loan in the hopes of recovering the balance in the future. But in the event that DA/CCA customers return to bundled service before the end of the asset life, these customers would effectively 'double dip' by realizing the benefit of early year underpayments through a levelized CAM charge and the benefit of lower asset costs in later years when SLDOC-based costs fall below levelized costs. This win-win scenario for DA/CCA

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[40] Ex. TURN-2, Rebuttal testimony of Kevin Woodruff, pages 9-12.

[41] Ex. AREM-1, page 7, 45-46.

[42] RT Vol. 6, pages 1153-1156.

[43] Although AREM/DACC/MEA witness Fulmer disputed classifying this as a "loan", he could not justify his opposition and admitted that "we're just quibbling over the noun loan." RT Vol. 6, page 1156.

customers is not reasonable and is profoundly unfair to bundled customers. The Commission should therefore reject it.

C. **<u>Should Load Serving Entities (LSEs) Be Able To Opt Out Of CAM?</u>**

AREM/DACC/MEA propose an opt out mechanism that would permit Electric Service Providers (ESPs) and CCAs to avoid responsibility for new CAM charges if they commit to procure a specified quantity of new capacity via contracts of at least five years in duration. TURN opposes this proposal and urges the Commission to reject it based on the risks that this untested option could pose to bundled ratepayers and overall system reliability.

In defense of allowing opt-out on the basis of a five-year forward procurement commitment, AREM/DACC/MEA witness Mara explained during hearings that it may be possible to construct a generating unit in less than five years and as little as a year. Despite this optimistic prediction, Mara subsequently conceded that the duration of construction is irrelevant to her proposal because the five-year forward procurement commitment would only be triggered once the new generating unit begins to operate.[44] Mara was unable to cite a single example of a new generation unit being financed and constructed under a five-year power purchase agreement and could not even affirmatively state that new construction is likely to occur with such a short-term commitment.[45] It is well established that developers of new generation require long-term contracts (at least 10 years in duration) with creditworthy counterparties in order to secure financing.[46] There is no evidence of any new generation constructed in recent years without a long-term financial commitment by a utility.

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[44] RT Vol. 7, pages 1166-1168.
[45] RT Vol. 7, page 1168.
[46] Ex. TURN-2, page 4; See also, D.06-07-029, Finding of Fact #6.

Since there is no evidence that any new generation could be developed under a five-year procurement contract, the DA/CCA proposal could not reasonably be understood as a mechanism to stimulate new capacity unless there are radical changes in the overall market environment. Given the fact that the primary focus of Track 1 of this proceeding is to develop mechanisms for the replacement of OTC capacity, the lack of a clear nexus between the opt-out proposal and the conditions needed to build new generation in specific LCR areas represents a fatal flaw.

TURN has serious concerns about the lack of any clear enforcement mechanism and absence of severe consequences for non-compliance under the AREM/DACC/MEA proposal. When asked to explain the consequences if an ESP/CCA opts out on the basis of a five-year contract but the generation unit is not operational in a timely fashion (or at all), Mara stated that there would be "some kind of enforcement mechanisms" adopted by the Commission.[47] Yet AREM/DACC/MEA have not proposed any enforcement mechanism.

Moreover, witness Mara rejected the notion that a failure to comply would have any negative implications on local reliability, calling the prospect "fairly unlikely" because LCR need determinations are merely "estimates" and asserting that the relatively small load of DA/CCA providers means that noncompliance could not cause "a significant reliability issue."[48] In the event that there is an "emergency situation" due to failure of a DA/CCA to meet its opt out obligations, Mara suggested accelerating demand response programs or transporting temporary generation to the local area "on flat bed trucks".[49] When asked about whether the noncompliant DA/CCA should be allocated

[47] RT Vol. 7, page 1170.
[48] RT Vol. 7, page 1170, 1171.
[49] RT Vol. 7, page 1170.

the full costs of any emergency measures, Mara said that she hadn't considered this possibility.[50]

As should be obvious from reviewing the transcript, the AREM/DACC/MEA proposal is based on the notion that failure to satisfy the opt-out obligations would have few, if any, real-world consequences for DA/CCA providers. This cavalier attitude could lead to significant opt-outs by DA/CCAs based on unrealistic (and unfinanceable) contracts for new generation that fails to materialize. Unless the Commission adopted and enforced heavy noncompliance penalties (which AREM/DACC/MEA would undoubtedly oppose), the opt-out proposal could instead become a free pass with potential reliability and cost consequences for bundled customer loads. Rather than take this risk, the Commission should simply reject the proposal and direct the IOUs to conduct procurement needed to bring new CAM resources online.

VII. OTHER ISSUES

A. SCE Capital Structure Proposal

SCE asks the Commission to authorize it to file an application to adjust its capital structure in the event that new power procurement contracts are perceived to have a "significant adverse impact on SCE's credit ratios."[51] SCE claims that this authorization is important because the significant new power purchase commitments that may be executed for LCR need may diminish SCE's creditworthiness. TURN opposes SCE's request and urges the Commission to, once again, decline to offer a financial sweetener to SCE's shareholders in exchange for fulfilling its responsibility to procure power on behalf of its customers.

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[50] RT Vol. 7, page 1171.
[51] Ex. SCE-1, pages 27-28.

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The Commission has addressed this issue in many previous procurement-related decisions (see D.07-02-011, D.07-12-049, D.07-12-052, D.08-05-035, D.09-06-018). In each case, the Commission has declined to approve the relief requested by the utility. In D.09-06-018, the Commission reaffirmed that "we will take action to address negative impacts on any utility's balance sheet or credit profile when warranted and necessary, and will do so in a manner consistent with the urgency of the matter."[52]

Consistent with these past decisions, the Commission should direct SCE to present any requests regarding changes to its capital structure in a cost of capital application rather than in a procurement docket.

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

TURN agrees that the Commission should ensure coordination between various overlapping proceedings to ensure consistent assumptions form the basis of decision-making across proceedings. In particular, any approval of commitments for new generating capacity not already included in the CAISO modeling should be incorporated into a subsequent CAISO modeling run for purposes of determining LCR needs.[53] Specifically, the Commission may approve SDG&E three power purchase agreements for 450 MW of new peaking units located in its service territory. If some or all of these PPAs are approved, the generation must be included in new CAISO model runs in order to determine the impact of their operation on LCR needs in SCE's service territory.

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[52] D.09-06-018, page 65.

[53] TURN is not suggesting that the Commission should approve the results of the CAISO modeling without the modifications proposed in this brief, but rather than any modifications be applied to the results that include the new capacity.

C. SCE Statewide Cost Allocation Proposal

TURN does not take a position on SCE's unspecific proposal regarding a new forward procurement mechanism since no details have been offered.[54] The Commission rejected a similar proposal by SCE in Decision 12-04-046 to initiate a new proceeding on this subject and should do the same in this case.[55]

As a general matter, TURN shares SCE's frustration with the Commission's recent decision to force the IOUs to execute wasteful contracts with Calpine's Sutter plant and sympathizes with the fact that the disproportionate statewide burden of LCR procurement falls onto SCE. However, SCE cannot credibly assert that the design of a new forward procurement mechanism would easily resolve disputes over cost allocation (especially if Public Power entities that belong to the CAISO are included). SCE also fails to address concerns that a forward capacity procurement mechanism would fundamentally shift procurement from CPUC oversight to FERC jurisdiction. Furthermore, SCE does not address the fundamental problems with having the CAISO solicit and contract for new generation under long-term contracts.

SCE's proposal would only create additional confusion and inaction at a time when there is need for action to address local reliability issues in the LA Basin. Rather than bringing procurement efforts to a full stop for several years to debate the shape and scope of a new procurement entity, the Commission should direct SCE and the other IOUs to move forward with identifying and addressing reliability needs through a combination of forward contracts for generation, the development of preferred resources and cost-effective transmission and distribution upgrades.

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[54] Ex. SCE-1, page 17. ("SCE does not have a specific proposal to offer at this time.")

[55] D.12-04-046, page 28 ("To the extent that the Commission chooses to open a rulemaking proceeding to address the possible issues identified by SCE, the Commission, not SCE, will determine the focus and scope of that proceeding. SCE's proposal for the Commission to open a proceeding to address SCE's proposed new generation auction mechanism is denied.")

D. CAISO Backstop Procurement Authority To Avoid Violating Federal Reliability Requirements

TURN generally understands that the CAISO has authority to procure capacity in the short-term to avoid violating reliability requirements. However, the Commission should resist any extension of the CAISO's authority to procure capacity on a more forward basis. TURN understands the CAISO will be filing for some such authority with the Federal Energy Regulatory Commission following Board approval of an amended version of CAISO management's proposal for forward procurement authority to extend contracts to "flexible" and "local" resources at "risk of retirement".[56] TURN intends to oppose this filing and urges the Commission to do the same. The CAISO has not demonstrated sufficient concerns about cost containment and is likely to misuse such authority to the detriment of ratepayers.

E. Energy Storage

TURN supports the development of energy storage and believes that storage resources should be allowed to compete in the LCR RFOs so long as the specific technology can qualify for a Net Qualifying Capacity (NQC) rating and such an NQC can be credited towards meeting LCR needs. The Commission should prioritize the establishment of NQCs for storage technologies in R.10-12-007 and R.11-10-023 with a goal of allowing storage to compete in a 2014 solicitation.

The major challenge confronting some storage resources is the lack of an accepted methodology for measuring cost-effectiveness relative to bids from generating resources. Moreover, storage technologies are diverse and provide many different grid services so it is difficult to develop a single methodology to value their contribution to the portfolio. The Commission has identified the development of cost-effectiveness

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[56] The relevant Board memo is available at http://www.caiso.com/Documents/Decision_on_FlexibleCapacityProcurement-Memo-Sep2012.pdf. TURN is not aware of the minutes of the September 13-14 Board meeting are available yet.

methodology as a priority in the next phase of R.10-12-007. As with the NQC issue, the Commission should strive to have an accepted methodology in place in time for a 2014 solicitation.

VIII. CONCLUSION

For the reasons outlined in the previous sections, the Commission should adopt TURN's recommendations.

Respectfully submitted,

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