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)

COMMENTS OF THE DIVISION OF RATEPAYER ADVOCATES ON THE SCHEDULE AND PRELIMINARY SCOPING MEMO

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I. INTRODUCTION

Pursuant to Ordering Paragraph 6 of the March 22, 2012, Order Instituting Rulemaking (OIR), the Division of Ratepayer Advocates (DRA) respectfully submits the following comments on the preliminary scope and schedule for this proceeding as set forth in the OIR. DRA recommends the following:

(1) The schedule should be modified to address only local capacity need and procurement rule changes in 2012. Further, PG&E's Application for the Oakley Plant should be dismissed without prejudice until the Commission determines local capacity need in this 2012 phase of this proceeding. Table 1 contains DRA's recommended proceeding milestones. DRA's proposed schedule is consistent with the California Independent System Operator's (CAISO) recommendation, and realistic given the time needed to test, comment upon, and adopt essential and complex model outputs.

(2) The parties should continue working with the CAISO on CAISO's renewable integration model in 2012. DRA, which is replicating the model, should be given the opportunity and time to validate the CAISO model in late 2012.

(3) The Commission should wait to address system need (including renewable integration) and utility bundled plans until 2013.

(4) The Standard Planning Assumptions should cover a broad range of load scenarios that include Very Low, Low, Medium, High and Very High load cases to obviate the need for the CAISO, utilities and other parties to use their own scenarios and bog down the proceeding.

(5) The Standard Planning Assumptions should include certain input assumptions to the renewable integration model. Table 2, "Renewable Integration Model Inputs –Minimum To Be Included In Standard Planning Assumptions," contains DRA's recommended minimum list of assumptions.

(6) The Standard Planning Assumptions should specify the time it takes to bring various categories of resources online, including Once Through Cooling (OTC) plants modified to be in compliance with State Water Resources Control Board regulations. Doing so will help determine the timing of the resource need.

(7) The Assigned Commissioner should include the following additional issues within the scope of this proceeding, to be addressed in 2012:

(a) Developing standard rules for treating for dispatchable plants at risk of retirement, to avoid the recent one-off treatment of Calpine's Sutter Energy Center.

(b) Preserving competition in the resource adequacy market, which is challenged by the CAISO's plans to expand its backstop procurement authority.

(c) Discouraging procurement of new generation in excess of the authorized need established in the LTPP.

(d) Ensuring utilities reduce their need to procure Greenhouse Gas (GHG) compliance instruments by pursuing cost-effective GHG emissions reductions on a portfolio-wide basis.

(e) Addressing any unresolved issues or issues that need to be revisited from the 2010 Long Term Procurement Proceeding (LTPP) related to GHG compliance product procurement authority.

(f) Establishing a fair standard under which to compare Utility-Owned Generation (UOG) renewable applications to other recent renewable proposals and contracts.

(g) Making enhancements to the Energy Resource Recovery Account (ERRA) compliance filing requirements to provide, on a quarterly or semi-annual basis, a year-by-year, ten year rolling forecast of ERRA that illustrates the cumulative impact of procurement-related decisions on system average cost and rates for various classes of customers.

(h) Establishing a Distributed Generation (DG) Procurement Planning Process to achieve a holistic, integrated policy, planning, and implementation framework.

II. SCHEDULE AND RELATED ISSUES

A. The Proposed Schedule Requires Modification and Prioritizations.

The preliminary schedule on page 14 of the OIR does not permit adequate development of the record, in DRA's view, and could benefit from prioritization so the most pressing tasks happen first. It is simply not possible to address local capacity need, system need, renewable integration, and procurement rules by the end of the year.

Technical studies on local capacity and transmission are complex, and will take time to understand and analyze. On the renewable integration model improvements, members of the technical advisory group have seen no changes to the model, or received any information from CAISO on what the model runs are indicating since the last meeting on February 10, 2012.

The CAISO will have to re-run all its studies on local capacity, transmission, and renewable integration to accommodate Standard Planning Assumptions that have yet to be issued, and then the parties will need to comment on the studies before the Commission adopts them in this proceeding.

This task alone will take at least 2 months and would be completed in the end of May 2012, in DRA's estimation, under a very aggressive schedule.

Therefore, DRA recommends prioritizing tasks, addressing the most critical steps before the end of this year, and deferring consideration of the remaining items to next year. The priority in 2012 should be to determine local capacity need and address procurement rules. The Commission should address system need, renewable integration, and the utility bundled plans in 2013.

DRA also urges the Commission to dismiss without prejudice PG&E's Application on the Oakley Generating Station (which as of this writing has not been accepted for filing) until it makes a decision on local capacity need in this proceeding. This proceeding is the appropriate place to determine need for additional capacity, and not in a separate individual application for a new plant unrelated to the additional need authorized in the LTPP. As DRA states later in these comments, it is important to avoid procurement which exceeds the need authorized in the LTPP, and it is critical to ensure the LTPP process is not undermined through separate, individual applications for new generation.

B. The Commission's Priority in 2012 Should be to Determine Local Capacity Need and Address Procurement Rules, While the Commission Can Address System Need, Renewable Integration, and the Utilities' Bundled Plans in 2013.

In comments filed in response to the Proposed Decision in Track 1 of Rulemaking (R.) 10-05-006, the CAISO urged the Commission in the 2012 LTPP to determine local capacity need first by year-end 2012 and system need, including renewable integration, by year-end 2013.[1] DRA agrees. Based on its 2011/2012 transmission planning process, the CAISO identified the Los Angeles Basin, Big Creek/Ventura and San Diego as the critical transmission-constrained areas that deserve attention.

Therefore, DRA proposes a schedule allowing the Commission to decide local capacity need and procurement rules by year-end 2012. Addressing the procurement rules in 2012 is desirable because they are inputs to the development of utility bundled plans. System need, including renewable integration, and the utility bundled plans would then be decided by year-end 2013. Table 1, below – DRA's Proposed Schedule – provides the proceeding milestones and schedule DRA recommends.

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[1] Comments of the CAISO Corporation on the System Track I and Rules Track III Proposed Decision, March
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In order to continue progress on the renewable integration model this year, DRA proposes milestones for the CAISO to provide parties access to the model input files in July 2012, for filing the renewable integration study (using the adopted Standard Planning Assumptions) in September 2012, and for DRA to perform and submit its validation report on the CAISO's renewable integration model in November 2012. Comments on the renewable integration studies would then be due in February 2013, after workshops are held the month before. Thus, DRA's recommended schedule would enable the Commission to issue its decision on local capacity need and procurement rules by year-end 2012, while establishing a solid foundation in 2012 to determine system need and renewable integration need in 2013.

TABLE 1: DRA PROPOSED SCHEDULE

Proceeding Milestone	Date
Comments due on Preliminary Scoping Memo and Schedule	April 6, 2012
Ruling on Proposed Standardized Planning Assumptions	Mid-April 2012
Workshops on Proposed Standardized Planning Assumptions, local capacity studies, transmission studies, renewable integration model (2 days)	Mid-Late April 2012
Prehearing Conference (PHC)	April 18, 2012
Comments/Reply and Party Alternative Proposals on Proposed Standard Assumptions	Late-April to Early May 2012
Scoping Memo (with adopted Standardized Planning Assumptions, including assumptions for Renewable Integration Model)	Mid-May 2012
Revised local capacity and transmission studies submitted (based on adopted Standard Planning Assumptions), follow-on workshops	Late-May 2012
CAISO provides parties with access to renewable integration model input files (based on adopted Standard Planning Assumptions)	July 2012
Testimony, Briefs, and Hearings on Local Capacity Need and Procurement Rules	Approximately Late-July through Late-September 2012
CAISO submits Renewable Integration Model Results (based on adopted Standard Planning Assumptions)	Early October 2012
Proposed Decision on Local Capacity Need and Procurement Rules	November 2012
DRA submits Validation Report on CAISO Renewable Integration Model	Mid-December 2012
Decision on Local Capacity Need and Procurement Rules	December 2012
Workshop on the CAISO Renewable Integration Model Results	Mid-January 2013
Comments/Replies on Renewable Integration Model Results	February 2013
IOUs file Bundled Procurement Plans	Q1 2013
Preliminary Scoping Memo and Schedule for Determining System Need and Addressing IOU Bundled Procurement Plans	Q1 2013

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12, 2012, in R.10-05-006, pp. 1-2.

C. The Standard Planning Assumptions Should Cover a Broad Range of Load Scenarios, and Also Include Additional Input Assumptions

DRA recommends that the Standard Planning Assumptions include a broad range of load scenarios – Very Low, Low, Medium, High, and Very High – in order to obviate the need for the CAISO, utilities, and other parties to introduce their own scenarios, which could bog down the proceeding and cause delays. The latest California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) includes demand forecasts that cover Low, Medium, and High cases. The Very High case could represent a load scenario that is ten percent greater than the Medium case. The Very Low case could represent a load scenario that is ten percent less than the Medium case. The Very High and the Very Low load scenarios could serve as the bookends within which the Commission could decide the need for additional resources.

DRA also recommends that the Standard Planning Assumptions include the expected average time it takes to bring different types of resources online – existing plants retrofitted for OTC compliance; new generation; energy storage; and preferred resources like Demand Response. Depending on the time it takes to bring these resources online, the Commission may not need to take action on supply resource need until five years – or four, or three years – prior to an expected need.

The average timing for each type of resource should be calculated from the time the Commission issues a final decision on additional need to the time the resource is brought online. Brownfield sites (*e.g.*, those on which OTC plants sit) do not require the same degree of infrastructure improvements as greenfield sites. Including these inputs as part of the Standard Planning Assumptions will help inform consideration of the timing of resource need. Bringing new resources online that are not needed for the next several years can be risky, costly to ratepayers, and may create overcapacity that impacts the generation markets and the economic viability of existing resources. Knowing the timing of resource need will help avoid such premature decision-making, save ratepayers money and avoid expensive overcapacity.

Finally, DRA recommends that the Standard Planning Assumptions include critical input to be used in the renewable integration model. Table 2, "Renewable Integration Model Inputs – Minimum To Be Included In Standard Planning Assumptions," below contains the minimum set of input assumptions that DRA believes the Assumptions should include. This input will allow the CAISO to re-run its renewable integration model in September of this year (and perhaps even earlier), DRA to validate the CAISO model a month or two later, workshops shortly thereafter, and parties to file comments on the model in early 2013.

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TABLE 2 - RENEWABLE INTEGRATION MODEL INPUTS –MINIMUM TO BE INCLUDED IN STANDARD PLANNING ASSUMPTIONS

Model Input	Traditional Source	Comments
Statewide Summer Peak Demand (MW)	CEC Load Forecast	CEC forecast typically excludes distributed generation (CHP, solar) and demand response resources. Weather-normal forecast (1 in 2 peak summer demand).
Statewide "Uncommitted" Energy Efficiency (EE) effect on Future Summer Peak Demand	CEC Incremental Uncommitted Peak Savings Estimate	Typically, CEC core forecast excludes "uncommitted" energy efficiency savings. Range in 2011 CEC forecast reflects different levels of policy commitment to EE, and in general reflects effects of standards, utility EE programs, and the CPUC EE goals.
Demand Response (DR)	Demand Response Load Impact Report, CEC Forecasts	The bulk of DR is considered as a supply-side resource. DR peak impacts are reported for 1-in-2 and 1-in-10 year peak demand forecast; DR value choice should align with peak demand scenarios; both should be available to be modeled. Non-dispatchable DR should be included as load modifier.
Wind and solar renewable resource portfolios – installed capacity	CPUC trajectory, cost-constrained, environmentally constrained, time-constrained.	The mix of resources have different impacts on peak load during critical times – wind output in summer peak is lower than average wind output; solar photo voltaic output at 3 PM is relatively high, but drops off in late afternoon while peak demand is still high.
In-state vs. out-of-state renewable resources	CPUC scenarios.	Within the range of renewable portfolio options, there is a range of in-state vs. out-of-state resources (generally, wind is largest out-of-state resource). More in-state resources "free up" transmission to deliver (import) more energy during critical periods.
Renewable supply output at peak times	Varies according to time of day and time of year. Sometimes greater than Net Qualifying Capacity (NQC), sometimes less. CAISO, CEC data.	A critical aspect of all the modeling approaches is to ascertain expected renewable supply output during critical times (e.g., summer peak 3 PM; or sunset period). The NQC is an average annual value, but critical summer peaking period output matters more than annual average energy effects to determine if more resources are needed to integrate renewables. Installed capacity, NQC, and output at critical peak time(s) should all be reported.
Hydro output	Statewide (August). CEC	Output can vary depending on hydrology (wet year, dry year).
Imports	CPUC, CEC, CAISO	Generally transmission is modeled at its highest level of simultaneous import capacity. However, during extreme load periods or emergency events, increased levels of imports are possible. Especially for "extreme" scenarios, maximum values of transmission imports should be used during critical times.
Performance / availability of traditional resources	Fossil generation total outage range – CAISO.	The model should incorporate the impact of planned outages (non-peak months) and forced outages (peak periods) to reflect reality. Forced outages can be full, or partial.

III. RECOMMENDED ADDITIONAL PROCUREMENT RULE ISSUES

DRA recommends adding the issues below to the scope of this proceeding, and addressing the following issues in 2012. Appendix A to these comments provides a summary of each issue DRA proposes to add to the scope of the proceeding. DRA believes they are issues of high priority that will not unduly extend the schedule (with DRA's proposed modifications).

A. The Commission should establish a policy on dispatchable resources that are at risk of retirement. The Commission should adopt a policy framework and set of rules to preserve a competitive market for Resource Adequacy and to ensure that the CAISO's backstop procurement mechanism does not overcompensate plant owners and result in ratepayer overpayment.

The CAISO backstop procurement tariff for resources at risk of retirement provides a very high-priced capacity payment[2] to plants that have no Resource Adequacy contract but that will be needed in the following year. The CAISO plans to file a tariff soon with the Federal Energy Regulatory Commission (FERC) to obtain authority to apply this backstop capacity payment mechanism to dispatchable resources that are at risk of retirement, are not needed in the next five years, but that will be needed in six years. The tariff may include other payment mechanisms to cover the cost of other options to plant retirement such as mothballing.

DRA is concerned that the CAISO's current backstop capacity payment price is significantly more than the capacity price generators can obtain from utilities in competitive Resource Adequacy solicitations. This overpricing creates perverse incentives for generators, as demonstrated by recent events that involve attempts by the CAISO and Calpine to avoid retiring the Calpine-Sutter plant. In this situation, the Commission, in its desire to avoid FERC action on a CAISO tariff waiver request to bail out the Calpine-Sutter plant, urged Calpine-Sutter to participate in PG&E's Resource Adequacy solicitation and submit a bid that was competitive. During the Commission meeting on March 22, 2012 when Resolution E-447 related to the Sutter plant was adopted, Commissioners Florio, Sandoval, and Ferron indicated Calpine's bid was significantly higher than the other bids, and that Calpine essentially based its bid on the CAISO's very high backstop payment price. The Commission should consider addressing this gaming issue systematically instead of on a one-off basis devoid of a clear policy framework. In his dissent on Resolution E-4471, Commission Ferron

[2] The CAISO's backstop capacity price is currently \$67.50 per KW-year. The midpoint price for Resource Adequacy capacity contracts is \$18 per KW-year.

stated: "We must also be mindful that there is a wider universe of similar vintage plants [to Sutter] in similar economic situation, and if we agree to the kind of ad hoc intervention contemplated by the Resolution, then we may find a long queue of similar requests. I believe that if we attempt to assist Calpine with their Sutter predicament at the high price in the Resolution, we would be retarding the development of a longer-term market solution, and at an unreasonable short-term cost to ratepayers." DRA agrees and recommends that a policy framework be established to address this problem.

B. The Commission should adopt rules to discourage procurement of new generation in excess of the authorized need established in the LTPP

The LTPP process is conducted over two-year cycles during which the Commission establishes need for additional resources system-wide and sets procurement rules. However, this process has been undercut through individual utility applications seeking authority and cost recovery for new plant capacity that exceeds the additional need authorized in the LTPP. The Commission should establish a set of safeguards to ensure the LTPP is the final word and is not undermined in this way.

C. The Commission should require the utilities to make a showing that they have made reasonable efforts to reduce their need to procure GHG compliance instruments by pursuing cost-effective GHG emissions reductions on a portfolio-wide basis.

The 2010 LTPP, R.10-05-006, considered GHG product procurement policies that authorize the Investor Owned Utilities (IOUs) to procure GHG products in order to comply with the California Air Resources Board's (ARB's) cap-and-trade program.[3] The expected authorization will provide the IOUs with upfront standards they must follow in procuring GHG compliance instruments. However, the Commission's review of GHG procurement policies in R.10-05-006 was narrow in scope, and did not consider the ability of an IOU to make its own portfolio-wide GHG emissions reductions – by, for example, pursuing higher levels of EE – in order to lower its need to procure GHG compliance instruments. In other words, the IOUs currently have the authority to procure GHG products that are needed to comply with ARB's cap-and-trade program; however, there is no requirement to ensure that IOUs are internally pursuing all cost-effective, portfolio-wide emissions reductions as a component of their compliance with cap-and-trade requirements.

[3] 2010 LTPP Proposed Decision, pp 38-55.

While the IOUs' GHG procurement plans must establish upfront standards by which to satisfy GHG compliance obligations, ratepayers also need assurance that procurement planning in a GHG–constrained system considers the economic effect of reducing GHG emissions as opposed to purchasing GHG compliance instruments each year. Therefore, DRA recommends that the Commission require the IOUs to make a showing that they have made reasonable efforts to reduce their need to procure GHG compliance instruments by pursuing cost-effective GHG emissions reductions on a portfolio-wide basis. The Commission should consider the process by which the IOUs are required to demonstrate these reasonable efforts as part of the 2012 LTPP.

The Commission has already made clear that as part of long term procurement planning, the IOUs must ascertain what mix of procurement choices will maximize GHG reductions at the least cost to ratepayers:[4]

> "…the utilities should be actively engaged in projecting absolute emissions for various procurement scenarios, estimating the costs of those plans for various GHG allowance prices, and making procurement decisions based on these assessments."[5]

However, the 2010 LTPP did not focus extensively on GHG emissions reduction strategies, and did not address the issue of how the IOUs will evaluate plans to reduce actual emissions in the context of a GHG–constrained system. The Joint IOUs conceded in 2011 that "the primary focus of Track I of [the 2010 LTPP] has been on understanding the operational and reliability implications of integrating renewable energy totaling approximately one third of overall California electricity consumption, not on strategies for achieving GHG compliance. Thus, there is relatively limited insight that can be drawn from the analysis conducted in this Long-Term Procurement Plan."[6]

D. To the extent that there are unresolved issues or issues that need to be revisited from the 2010 LTPP related to GHG compliance product procurement authority, the Commission should consider those issues in this proceeding.

The Final Decision in the 2010 LTPP is expected to authorize the IOUs to procure GHG compliance instruments in order to comply with the ARB's cap-and-trade program.[7] The upfront standards by which the IOUs must procure GHG compliance instruments include the types of

[4] D.07-012-052, p. 229.
[5] *Id.*, p. 228.
[6] Joint IOU Supporting Testimony on System Resource Plan (Track I 2010 LTPP), July 1, 2011, p. B-2.
[7] 2010 LTPP Proposed Decision, pp. 38-55. As of this filing, the Final Decision in the 2010 LTPP is currently pending approval.

instruments, the methods and locations for procuring these instruments, and the procurement limits that are allowed. At the time of this filing, the final GHG procurement rules have not been established, and there are several pending issues that may merit reconsideration during the 2012 LTPP. DRA recommends that the Commission consider any such issues in this 2012 LTPP.

For instance, DRA advocated that the 2010 LTPP Final Decision maintain the Proposed Decision's requirement that GHG offset sellers assume the risk that offsets will later be invalidated because they do not deliver true GHG reductions. DRA asked the Commission to reassess this requirement when there is market information on the price premium offset sellers will include for this risk.[8] SCE claimed in its comments on the 2010 Proposed Decision that the requirement that offset sellers assume the risk of invalidated offsets would transfer the benefits of purchasing offsets from the IOUs' bundled customers to third parties such as banks and traders.[9] However, the price premium for accepting this risk is unknown. As the market for GHG compliance offsets in California develops, and market information becomes available, the Commission will be able to make an informed decision on whether this requirement is a cost-effective way to protect ratepayers from the risk of offset invalidation.

Likewise, to the extent that the 2010 LTPP Final Decision authorizes the IOUs to engage in GHG trading to manage their electricity price risk, it may make sense to require the IOUs to make a showing that this GHG trading activity has reduced their overall commodity cost exposure. Thus, DRA requests that the Assigned Commissioner include GHG compliance product procurement issues within the scope of this 2012 LTPP proceeding.

E. A fair comparison standard should be adopted to compare UOG renewable applications with other renewable proposals and/or contracts.

Public Utilities Code Section 399.14(b)(2), which is a result of the new 2011 Renewable statute, SBX 1 2, prohibits the Commission from approving UOG renewable projects unless they provide "comparable or superior" value to ratepayers when compared to recent proposals or contracts with other eligible renewable projects. Currently, this comparison is done on a case-by-case basis. There is no standard by which to fairly and consistently compare UOG to third party projects across all UOG renewable applications. The Proposed Decision in Track 1 and Track 3 of

[8] DRA's Reply Comments on the Proposed Decision on Track I and III Issues, R.10-05-006, March 19, 2012, p. 2.

[9] Opening Comments of Southern California Edison Company on Proposed Decision of Administrative Law

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the 2010 LTPP adopts a fair comparison standard for conventional generation, but stops short of requiring the same for renewable resources, deferring this determination to the RPS proceeding (Rulemaking 11-05-005). This issue is not slated for consideration in the RPS proceeding at this time, and a fair comparison standard is necessary to advance regulatory clarity and certainty in an area where it is badly needed. Thus, DRA recommends that the Assigned Commissioner include development of a UOG standard within the scope of this proceeding. Pending any decision in the RPS proceeding that addresses the fair comparison standard for renewable generation, the process adopted in the LTPP proceeding can be used in the interim.

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Judge Peter Allen, March 12, 2012, p.11.

F. The Commission should require utilities to submit a report providing a forecast of their Energy Resource Recovery Account (ERRA) Expense Claims that illustrates the Cumulative Impact of Procurement Decisions on System Average Cost and the Rates for Various Classes of Customers.

The Commission's ERRA proceedings were originally designed as a vehicle to ensure "timely recovery of prospective procurement costs incurred pursuant to an approved procurement plan" after the 2000-01 Energy Crisis and ensuing procurement legislation changed the rules for after-the-fact reasonableness reviews of utility procurement decisions.[10] However, the ERRA process has developed into a mechanism by which the utilities seek to pass large and unexpected new expenses onto ratepayers with little advance warning of the magnitude of the rate increases to come.

ERRA has become unwieldy. It has gone beyond including procurement related expenses and now covers California Alternate Rates for Energy (CARE), Energy Efficiency, and other programs. ERRA expenses in 2011 were $3.4 Billion and $3.3 Billion for PG&E and SCE, respectively. SDG&E has not filed its 2011 ERRA, but its 2010 ERRA expenses were $663 Million.

DRA has two recommendations on ERRA in this proceeding. First, ERRA compliance reports should be enhanced to provide useful information that enables the Commission to understand the cumulative impact of its procurement authorizations on system average cost and rates for various customer classes. As the LTPP looks ten years out, DRA believes a rolling year-by-year 10-year forecast report of ERRA expenses would provide the Commission with this useful information. The Commission can hold workshops to flesh out the requirements for this enhancement to the compliance reporting.

Second, DRA also recommends that the Commission hold workshops designed to make improvements to ERRA. Decision 02-10-062 authorized the establishment of ERRA only for cost recovery of procurement-related expenses and contracts.[11] Two key issues for DRA are: (1) cost recovery of non-procurement expenses in ERRA, as ERRA was originally designed only for recovery of procurement-related expenses;[12] and (2) cost recovery of capital cost in ERRA, as

[10] Public Utilities Code Section 454.5(d)(3).

[11] D.02-10-062, Finding of Fact 23, p. 71

[12] For example, one utility's ERRA includes a "Medical Program Balancing Account" which records the difference between medical, prescription drug, dental and vision (healthcare) expenses; "Pension Costs

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ERRA is only for recovery of expense-related procurement and procurement contract administration.[13]

G. The Commission should establish a Distributed Generation (DG) Procurement Planning Process to achieve a holistic, integrated policy, planning, and implementation framework.

In view of the Governor's 12,000 megawatt (MW) DG initiative, and the disparate DG-related programs and sub-programs that now exist, it would be appropriate for the Commission to include within the scope of this case establishment of a DG Procurement Planning Process to achieve a holistic and integrated policy, planning, and implementation framework across disparate DG-related programs at the Commission and within each utilities' business operations. There are now several programs related to DG, including, for example, the Renewable Auction Mechanism, Feed-in-Tariffs, Net Metering, Virtual Net Metering, California Solar Initiative, Self-Generation Incentive Program, Single Family Affordable Solar Housing Program, and the Multi-Family Affordable Solar Program. This confusing alphabet soup of programs requires focus and coordinate, and DRA therefore recommends that the Assigned Commissioner include within the scope of this proceeding development of a plan for addressing DG comprehensively, such as how DG is defined, what counts towards the Governor's DG goal, whether demand side programs count toward DG, and whether DG programs are only focused on reducing local load. If the Commission is not inclined to do so here, DRA recommends a DG OIR that takes all of the disparate DG pieces and puts them together in a coordinated manner.

IV. CONCLUSION

DRA urges the Commission to establish a realistic and manageable schedule to ensure it develops a full record in this proceeding. The modified schedule DRA proposes would address local capacity need and procurement rules in 2012. There is little debate that determining local capacity need is the highest priority this year. Addressing procurement rules this year is also necessary because the IOUs need them in order to develop their bundled plans. System need, including renewable integration, and utility bundled plans could then be addressed in 2013. DRA

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Balancing Account (PCBA) and Post Employment Benefits Other than Pensions Balancing Account (PBOP BA) which records the difference between costs authorized by the Commission and recorded costs after capitalization.

[13] For example, there is a "Mohave Balancing Account" which tracks the difference between recorded *capital-related* expenses, operating expenses, and Worker Protection Expenses.

appreciates the Commission's desire to maintain progress in renewable integration model improvements; therefore, DRA's proposed schedule incorporates milestones in 2012 that would ensure progress is maintained through a collaborative effort with CAISO. Moreover, DRA is replicating the CAISO model and plans to validate the model and share its results for the record.

DRA also recommends the inclusion of additional issues within the scope of this proceeding, as summarized in Appendix A. The issue of multi-year procurement of dispatchable capacity is already in the OIR. It is equally important, DRA believes, to develop a rule to systematically address plants at risk of retirement; to preserve of a pro-competitive Resource Adequacy market in light of extremely high and anti-competitive backstop capacity payments provided by the CAISO; and to avoid separate applications for new generation outside the LTPP that exceed the authorized need in the LTPP and thereby undermine the integrity of the LTPP process. The Commission should also establish a fair standard for comparing UOG renewable projects with other renewable proposals and contracts.

DRA also urges the Commission to order workshops on ERRA to (1) develop standard requirements for a compliance report that provides a 10-year forecast of ERRA expenses to help the Commission understand the impact of procurement-related decisions on system average costs and rates to various classes of customers, and (2) address other issues in ERRA. DRA also believes now is the time to establish a DG Procurement Planning Process that consolidates all DG-related initiatives under a single umbrella to ensure holistic, coordinated policy development, planning, and implementation.

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Finally on GHG issues, the Commission should require the IOUs to show they have reduced the need to purchase compliance instruments by reducing their own portfolio-wide GHG emissions, and should take up any GHG compliance product procurement issues left over from the 2010 LTPP.

Respectfully submitted,

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APPENDIX A
SUMMARY OF ADDITIONAL PROCUREMENT RULE ISSUES

1. What should be the policy on dispatchable resources that are at risk of retirement?
2. What policy framework and set of rules should be adopted to preserve a competitive market for Resource Adequacy and ensure that the CAISO's backstop procurement mechanism does not overcompensate plant owners and result in ratepayer overpayment?
3. What policy framework and set of rules should be adopted to discourage procurement of new generation in excess of the authorized need established in the LTPP?
4. Should the Commission require the utilities to make a showing that they have made reasonable efforts to reduce their need to procure GHG compliance instruments by pursuing cost-effective internal GHG emissions reductions on a portfolio-wide basis?
5. To the extent that there are unresolved issues or issues that need to be revisited from the 2010 LTPP related to GHG compliance product procurement authority, the Commission should consider those issues in this proceeding.
6. What fair comparison standard should be adopted to compare Utility-Owned Generation (UOG) renewable applications with other renewable proposals and/or contracts?
7. Should the Commission require utilities to submit a report providing a forecast of their Energy Resource Recovery Account (ERRA) expense claims that illustrates the cumulative impact of procurement decisions on system average cost and the rates for various classes of customers? Are other modifications to ERRA needed?
8. Should the Commission establish a Distributed Generation (DG) Procurement Planning Process to achieve a holistic, integrated policy and planning framework?