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 2012 LTPP PLANNING STANDARDS

KARIN HIETA
Project Manager
Division of Ratepayer Advocates
California Public utilities commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-4253
Email: karin.hieta@cpuc.ca.gov

SARAH THOMAS
MARY MCKENZIE
Attorneys
Division of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue,
San Francisco, CA 94102
Phone: (415) 703-2760
Email: mary.mckenzie@cpuc.ca.gov

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Pursuant to the *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* (Scoping Memo) filed on May 17, 2012, the Division of Ratepayer Advocates (DRA) hereby submits these comments on Track II of the Long Term Procurement Plan (LTPP) Standard Planning Assumptions (Assumptions) presented in the *2012 Energy Division Straw Proposal on LTPP Planning Standards* (Straw Proposal) issued on May 10, 2012.

I. INTRODUCTION

DRA applauds the Energy Division for its excellent work to date on developing its Straw Proposal. We are especially grateful for the opportunity to weigh in at several points along the way to help develop final Assumptions, as set forth in the Scoping Memo schedule. By the same token, we recognize – as did Energy Division's own representatives – that several of the Assumptions are not yet finalized. Therefore, DRA is commenting at a point when key information is not yet available and we must speculate about what will be included in, or excluded, from key reports yet to be released. DRA is concerned that when final data are available and actual megawatts are attached to the Assumptions, the picture may be very different from our current understanding. Therefore, DRA's recommendations may change once more information is made available.

We have used Energy Division's template and numbering system in preparing these comments, omitting those sections on which we do not have Opening Comments. We may address the omitted areas in our Reply Comments, if appropriate.

Our initial recommendations for changes or clarifications to the Straw Proposal are the following:

- The Commission should eliminate the proposal to extend planning out to years 11-20, or at least limited in scope so that for those years the California Public Utilities Commission (Commission) only examines the need for certain long-lead time infrastructure – primarily, major transmission expansions;
- The Commission should use a 1-in-2 forecast instead of a 1-in-10 peak forecast for determining system resource need
- The Commission and California Energy Commission (CEC) should rely on the same Energy Efficiency (EE) forecast numbers to ensure consistency in resource planning;
- The Assumptions should account for energy savings resulting from new codes and standards, and from Energy Upgrade California, financing, and behavior programs;
- The Assumptions should account for incremental nondispatchable Demand Response (DR) by assuming 50 MWs of resources for the three IOUs through 2014 and forecasting amounts through 2022;
- The Assumptions underestimate the amount of Incremental photovoltaics (PV) and should be adjusted to account for expanded net energy metering, other anticipated Commission Decisions and pending legislation that will contribute to load reduction;
- The location definition for new Renewables Portfolio Standards (RPS) resource additions should be expanded beyond "specific local area or generic system" to account for unbundled contracts that may be located out of state;
- Peak Time Rebate (PTR) should be included in event-based DR;
- The High Distributed Generation (DG) Portfolio should be amended to account for declining costs for renewable resources and the extension of federal tax credits.

- The Environmental Sensitivity that assumes renewable resources will be developed in designated preferred locations should be removed;
- The Once-Through Cooling (OTC) assumptions are overly conservative and should be adjusted to account for known and reasonably likely replacements;
- The Commission should direct the investor owned utilities (IOUs) to work with the CEC and stakeholders to deliver locational data on EE savings that can be incorporated into the incremental EE forecast within customer classes for the EE allocation methodology; and
- The DR allocation methodology should try to associate DR impacts to specific buses first, before using other methods to allocate remaining DR impacts.

II. DISCUSSION

A. General

1. Planning Area and Planning Period

The Scoping Memo adopts a 20-year planning horizon, which is longer than necessary for planning supply and demand side resources. There is value in longer term planning for certain long-lead time infrastructure needs – primarily, major transmission expansions. The lead time needed to build new resources varies widely depending upon resource size, type, location, and extent of existing supporting infrastructure (e.g., transmission) already in place to serve the resource. Supply and demand-side resource procurement lead times are almost always less than 10 years, and in the case of EE and DR, far less. Generally, smaller resources and resources at the top of the "loading order" have shorter lead times, while larger fossil-fueled resources have longer lead times (when permitting time is included).

At the May 17th Workshop, there was some discussion that developers might need 7-9 years lead time to develop new resources once a need is established. Before instituting a 20-year forecast, the Commission should seek more information about the actual time necessary to build and acquire various types of resources. Thus, DRA urges the Assigned Commissioner and Energy Division to 1) limit the planning period to 10 years, or 2) make clear that planning for years 11-20 will be limited to long lead time infrastructure investments.

B. Demand-Side Assumptions

1. Load Forecast

a) The Commission Should Use a 1-in-2 and Not a 1-in-10 Peak Forecast For System Need.

DRA supports the Straw Proposal's use of a 1-in-2 peak forecast as the base case. However, DRA is concerned that the Straw Proposal suggests "[s]ensitivities of alternative peak conditions, such as 1-in-10 weather, should be conducted around the medium load scenario."[1] DRA opposes using a 1-in-10 statewide forecast sensitivity case in the context of *system* need, which is what is being determined in the LTPP. The CAISO's use of a 1-in-10 forecast for *local* studies is appropriate because local regions may well experience a 1-in-10 peak load. The Commission has previously rejected the use of a 1-in-10 forecast for LTPP purposes:

> In a 2004 LTPP decision, the Commission rejected a proposal to develop demand forecasts for LTPP purposes by using a 1-in-10 peak weather standard. (D.04-12-048, p. 28.) In doing so, it noted that the RA program is based on average weather (1-in-2) and that the PRM, in part, provides a cushion should hotter-than-average weather occur. (*Id.; see also* Finding of Fact 11, p. 180.)[2]

The Commission should similarly reject use of a 1-in-10 forecast here.

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[1] Straw Proposal at x.

[2] R.08-04-012, Order Instituting Rulemaking, April 16, 2008 at 6.

2. Incremental Energy Efficiency

a) It Is Unclear That the Straw Proposal Includes All Appropriate Energy Efficiency Either In Its Base Case Or As Incremental EE.

Because the California Energy Commission's (CEC) contribution to the Straw Proposal is based on old data, it is not clear where and whether the impact of this Commission's new Energy Efficiency (EE) decision will be adequately included. Therefore, the Straw Proposal requires clarification, and perhaps modification, so that the Commission and CEC use consistent EE data.

It should be noted that DRA supports the CEC's efforts to determine energy efficiency savings by busbar for consideration in the determination of local capacity requirements. To enhance this effort, DRA urges utility cooperation in providing the CEC with data on the geographic distribution of energy efficiency savings within customer classes. DRA provides additional comments on this in the Allocation Methodologies below.

b) Either the CEC Should Include EE Caused By New Codes And Standards In Its Base Case, Or This Commission Should Account For Such EE As Incremental To The CEC's Numbers.

The three scenarios (low, mid, and high) should include the impact of the new federal energy and water efficiency standards on clothes washers and dishwashers as they impact California's market. These savings are real and quantifiable. According to the Department of Energy (DOE) and the American Council for an Energy Efficient Economy (ACEEE), new federal efficiency standards on clothes washers and dishwashers enacted in May of this year will reduce the energy consumption of affected households by *1- 49%* after the standards go into effect in 2015 and 2013, respectively.[3]

c) The Straw Proposal Should Likewise Include EE Savings From Energy Upgrade California, Financing, and Behavior Programs – Either as Base Or Incremental EE.

Likewise, an estimate of the increase in savings to account for the Energy Upgrade California (EUC) program and expanded financing and behavior programs should be reflected in either the base forecast or in all three scenarios of the CEC's incremental EE forecasts, not just in the high-case scenario[4]. EUC and expanded financing and behavior programs are not speculative programs; they are a mandated part of the IOU EE portfolios in D.12-05-015. It is expected that these programs will deliver long-term savings. There is clear direction in D.12-05-015 – the Commission's latest EE decision – for utilities to focus a significant portion of their 2013-2014 portfolio development on deep retrofit (long-term) programs such as EUC and on financing and expanded behavioral programs.[5] For example, D.12-05-015 directs IOUs to allocate $200 million of ratepayer capital towards financing alone. Therefore, it is reasonable to expect that some level of savings will result from these initiatives. It would be an imprudent use of ratepayer capital

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[3] The cited information is derived from data provided by the Department of Energy (DOE) and American Council for an Energy Efficient Economy (ACEEE), at http://www.aceee.org/press/2012/05/new-clothes-washer-and-dishwasher-st and http://apps1.eere.energy.gov/news/progress_alerts.cfm/pa_id=728 (May 25, 2012).

[4] *see* p. xiii of Straw Proposal

[5] *See* D.12-05-015, Ordering Paragraph 22 (financing). On expansion of behavioral programs, *see id.,* Conclusion of Law 13 and Findings of Fact 13, respectively: "It is reasonable and prudent to set consistent assumptions for program participation at 5% of households, signaling our expectation that behavioral programs should be substantively, but not excessively, represented in IOU program portfolios," and "By 2014, PG&E plans to roll out behavior programs to 20% of households; SCE plans to roll them out to 0.4% of households; SDG&E plans to reach 3.3% of

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if estimates of savings from these programs were not included, at some level, in all scenarios. If the magnitude of the percentage increase in savings from these programs is the source of uncertainty, then the percentage allocations may differ in the low, mid and high case scenarios. The uncertainty in the magnitude of savings should *not* result in the assumption that *no* savings are expected for low and mid case scenarios. DRA recommends that reasonable estimates of savings from EUC, financing and expanded behavioral programs be incorporated into any energy efficiency scenario being considered for the demand side decrements to long term procurement.

3. Non Event-Based Demand Response

The Straw Proposal undercounts non-event based Demand Response (DR), and should be modified. Energy Division proposes using the values embedded in the CEC's California Energy Demand (CED) forecasts. However, even while noting the likelihood of increased impact of nondispatchable (non event-based) DR, the latest draft of the CED 2012-2022 indicates that the final CED 2012-2022 *may not include* incremental nondispatchable DR:

> Nondispatchable program impacts are likely to increase in the coming years, and expected impacts incremental to the last historical year for peak (2011) would affect the demand forecast. So far, staff has identified only a very small incremental impact from current committed programs (less than 20 Megawatts (MW) each for PG&E and SCE). *These impacts are not incorporated in CED 2011 Revised since analysis is ongoing*; further discussion with the utilities may identify additional potential from Nondispatchable

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households; and SCE plans to emphasize the home energy audits and to maintain its programs on a pilot scale.

> programs, which could be included in a final, adopted version of CED 2011. (Emphasis added.)[6]

DRA calculates the total nondispatchable DR as approximately 50 MW for all three IOUs through 2014. The Commission should assume that non event-based DR will continue in similar amounts after 2014. If the final CED for 2012-2022 fails to include nondispatchable DR, the Commission should adjust the planning assumptions to reflect approximately 50 MW for all three IOUs through 2014, continuing on a linear trajectory through 2022.

4. Incremental Small Photovoltaics

The Straw Proposal underestimates the amount of customer-side solar Photovoltaics (PV) that should be counted in the demand-side assumptions. The Straw Proposal confirms that demand-side solar PV, which is anticipated from existing programs, is embedded in the Revised CED 2012-2022.[7] Appendix B of the Revised CED discusses a predictive model that CEC staff developed to forecast the growth of PV and solar water heating systems in the residential sector, and CEC staff is currently working to develop such a model for the nonresidential sector. DRA recommends that Energy Division work closely with CEC staff to finalize the predictive model for the nonresidential sector and ensure that the Commission's recently adopted decision to expand Net Energy Metering (NEM) and other forthcoming decisions on customer-side solar PV are accounted for in the demand forecast. Specifically, DRA recommends increasing the amount of

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[6] Revised California Energy Demand Forecast 2012-2022, February 2012, at 33-34. *See* http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-SD-V1.pdf

[7] Revised California Energy Demand Forecast 2012-2022, February 2012. *See* http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-SD-V1.pdf

assumed customer-side solar PV by 1,400 – 5,250 MWs[8] to account for the following increase in program capacity caps and MW additions:

- During its May 24, 2012 business meeting the Commission adopted a decision that will increase capacity installed under a NEM billing arrangement, an increase in approximately 2,800 MW (from 2,400 MW to 5,200 MW). These additional MWs should be accounted for in the CEC's predictive models.
- A Petition to Modify D.10-01-022 proposes to increase residential incentives for solar water heating by 100%, and commercial incentives by 30%. If the Commission approves the Petition, these higher incentive levels should be incorporated into the CEC's predictive models.
- Based on the definition of aggregate customer peak demand adopted in D.12-05-036, Assembly Bill 2165 could increase the amount of capacity that can be installed under fuel cell net metering by approximately 700 MW. The cost of fuel cells is projected to decrease significantly over the next ten years; this should be accounted for in the nonresidential sector predictive model.
- In its current form, Senate Bill (SB) 843 proposes to replace the existing Renewable Energy Self-Generation-Bill Credit Transfer (RES-BCT) program, capped at 250 MW, with a community-based renewable energy self-generation program capped at 2,000 MW.

While pending legislation is not yet adopted, it does indicate the Legislature's intent to focus on expanding both customer-side and utility-side distributed generation resources. Such policy direction should be acknowledged and accounted for when planning for system needs 10 years out.

[8] The 1,400 MW on the low end of the range includes half of the expected increase resulting from the recent NEM decision. The 4,200 MW on the high end of the range includes the full 2,800 of anticipated NEM, plus 1,750 MW resulting from SB 843 and 700 MW resulting from AB 2165.

C. Supply-Side Assumptions

1. What Additional Information is Needed for Resource Locations?

The location definition for new RPS resource additions should be expanded beyond "specific local area or generic system" to include unbundled contracts as well. Under SB 2 1x, the IOUs are permitted to procure a limited amount of unbundled RPS resources to fill their net short position. These unbundled resources can be located both in-state and out-of-state. Therefore, it would be more accurate for the RPS scenarios to include an expanded definition of generic system RPS resources that accounts for in-state and out-of-state unbundled RPS projects. Per SB 2 1x, the IOUs' unbundled limitations that should be included in this assumption are as follows: 25% in Compliance Period (CP) 1 (2011-2013), 15% in CP 2 (2014-2016), and 10% in CP 3 (2017-2020).

2. Event-Based Demand Response

With certain exceptions, DRA supports the Straw Proposal's suggestion to use the June 1, 2012 DR Load Impact Reports as the mid scenario. The Straw Proposal specifically indicates that PG&E's Peak Time Rebate (PTR) program should be included in event-based DR.[9] However, PG&E's PTR program is currently pending and PG&E is arguing against implementing PTR in its 2010 Rate Design Window.[10] Energy Division staff has informed DRA that the June 1, 2012 Load Impact reports will not include load impacts for PG&E's PTR program. If PTR is not included in the Load Impact Reports, DRA recommends

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[9] Straw Proposal at xvii.

[10] A.10-02-028.

that the Commission include a load impact of 235 MW for PTR, as determined in D.09-03-026.[11]

In addition, Load Impact Reports do not include DR programs not currently in operation such as Advanced Metering Infrastructure (AMI) enabled DR. It is highly likely that the Commission will approve new AMI enabled DR programs between 2015 and 2022, after the current DR cycle (2012-2014) is over. For example, D.12-04-045 recently approved SDG&E's Small Customer Technology Deployment (SCTD) program, which is a Home Area Network (HAN) based Automated Demand Response (ADR) technology enabling program. In D.12-04-045, the Commission expressed its expectations for SCTD "to drive the market to develop HAN-related devices that are easy to self-install and available at a reasonable cost to the average customer. We also expect this program to encourage third party providers to offer HAN-based devices to customers."[12] Furthermore, D.12-04-045 approved PG&E's DR-HAN Integration project, consisting of two components[13]:

1. IT integration to establish back-end HAN-based DR capabilities to support both pilot and general deployment of HAN-based DR program, and

2. "Evaluation Project" - Small-scale initial rollout or pilot of HAN-based DR program to 2000 homes and small and medium business customers equipped with PG&E provided load-control devices.

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[11] While PG&E projected a 260 MW peak load reduction from default residential PTR, D.09-03-026 appears to have adopted a modestly lower figure. Per p.133 of D.09-03-026, "we adopt PTR savings through 2030 in the amount of 5,714 MWs as opposed to PG&E's forecasted amount of 6,307 MWs." This amounts to a reduction of fewer than 10% in PG&E's projected residential PTR aggregate peak load reduction over the multiyear analysis period. Applied to PG&E's single-year (2012) estimate of 260 MW, the adjustment adopted in D.09-03-026 would yield a projected peak load reduction of 235 MW for 2012.

[12] D.12-04-045, p. 167 (mimeo).

[13] Id., pp 161-165 (mimeo).

The Commission should use the forecasts provided in the IOUs' AMI Applications as a starting point to account for AMI-enabled DR programs which are not currently in operation and do not show up in the Load Impact Reports.

3. Renewable Resources

a) Establishing the 33% RPS Infrastructure Target Via the LTPP, Understanding That Other Requirements May Also Need A Similar Calculation Within the RPS Proceeding.

DRA is unclear whether the calculation of the renewable net short (RNS) in both the Base Portfolio and the High DG Portfolio assumption will be used for *both* renewable integration modeling efforts and integrated into all of the LTPP scenarios selected. DRA is also unclear if both the Base Portfolio and High DG Portfolio will be used for all LTPP scenarios selected. DRA requests that this be clarified by Energy Division in the upcoming June 4, 2012 workshop on Renewable Integration.

b) Establishing the RPS Supply (i.e. the "Highly Likely Resources") In the RPS Proceeding.

DRA supports using information from each Load Serving Entity's (LSEs) RPS Procurement Plan to calculate the discounted core or amount of "sunk" resources and determine the RNS for the LTPP. It is important that identical information feeds into both the RPS and LTPP proceedings to result in more accurate scenario planning.

c) Base Portfolio

Including a Base Portfolio assumption is reasonable and reflective of the current procurement methodology utilized by the IOUs. Since the IOUs are required to procure based on least-cost, best-fit (LCBF), it is reasonable to assume that any additional RPS procurement used to fill the renewable net short will be selected based on least cost. To assume otherwise would contradict the IOUs' procurement methodology.

DRA recommends the Base Portfolio include the following assumptions: the IOUs procure based on LCBF, resources are selected using current, Commission-approved RPS programs like the Renewable Auction Mechanism (RAM) and the annual RPS request for offer (RFO) solicitation, and prices reflect "learning" (i.e. costs are anticipated to decline), and the continuation of federal tax credits (either PTCs or ITCs) for a majority of projects. DRA also assumes that by following the least cost assumption, the diversity of the RNS supply stack should also be reflective of least cost. At the moment, solar PV and wind are the most cost-effective resource, so this should be emphasized or more weight should be given to these technologies in the scenario planning.

d) High DG Portfolio

DRA supports the inclusion of a High DG portfolio to fill the RNS as this portfolio complements the Governor's call for 12,000 MWs of DG by 2020. As mentioned above, all new procurement selection should also be based on LCBF.

However, three assumptions should be eliminated from, or altered in, the High DG Portfolio:

1. **No Learning:** The assumption that no additional learning will occur for DG projects presumes that there will be no further declines in resource costs. This is inaccurate since prices for various renewable technologies continue to decline, especially for solar PV and wind. Therefore, the Commission should assume a future discount rate for RPS projects to capture the decline in prices over time.
2. **No Extended Investment Tax Credit:** The President recently recommended that Congress extend the Production Tax Credit (PTC) that was scheduled to expire this year through 2016. The Investment Tax Credit (ITC) will also be offered through 2016. Even if the PTC is not extended, it is incorrect to assume that no savings due to tax credits will be realized as the majority of RPS projects rely on tax credits. It would be more reasonable for the Commission to assume that

approximately 66% of projects are able to capture tax credits. This assumption is based on future RPS procurement that will occur between now and 2016. DRA assumes that any additional RPS contracts executed by the IOUs between now and 2016 will not only be applied to the RNS but will also be able to capture either PTCs or ITCs.

3. **Location:** Any assumptions specifying preferred locations for both the Base Case Portfolio and High DG Portfolio should be eliminated as this assumption does not accurately reflect renewable project development in California. Developers develop renewable projects where it is cheapest to do so and where interconnection is most feasible. There is no reason to assume this current practice will change.

e) Sensitivities

The Environmental Sensitivity assumes that any RPS resource additions will be developed in designated preferred locations. This sensitivity should be eliminated as it does not accurately reflect additional renewable procurement under the Base Portfolio or High DG Portfolio scenarios. Environmental permitting and California Environmental Quality Act review are already required for utility-scale renewable project development, so including another layer of environmental sensitivity does not add any additional value to the planning exercise, especially when it is not mandated for project development. Unless there is future legislation or financial incentives to alter this practice, renewable developers will continue to select project development sites based on cost and feasibility.

f) Long-Term Target

Although DRA does not presently see the need for a forward procurement projection of 20 years, if the Commission decides to move forward with the 20-year LTPP outlook, DRA finds the linear progression to a 40% RPS to be reasonable given that the assumption is made that the IOUs will continue to procure RPS resource additions according to LCBF.

4. Retirements

a) Once Through Cooled Power Plant Assumptions Are Overly Conservative

Energy Division currently assumes all once-through cooling (OTC) plants will retire, except for Track II plants in the Low and Mid scenarios. This assumption is too conservative and does not appear to count likely replacement generation.

In particular, it is unclear if Energy Division considered the following retiring OTC plants in need of replacement capacity or whether the capacity of their replacement generation was counted, and if so, how:

- Huntington Beach Units 3 and 4 (450 MW capacity) have been retired in order to use their permits from the South Coast Air Quality Management District in the operation of Mission Edison Energy's more modern 500 MW Walnut Creek generation station, a 50 MW net gain.[14]
- Contra Costa (674 MW capacity) will retire 4 years early in 2013, when it will be replaced by the adjacent Marsh Landing Generation Station (760 MW capacity), an 86 MW net gain.[15]
- The CAISO 2011/2012 transmission planning process study[16] assumes Moss Landing Units 1 and 2 will remain online.

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[14] *See* http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/powerplants/huntington_beach/docs/hb_revisedip2011.pdf *and* http://articles.hbindependent.com/2011-06-13/news/tn-hbi-0616-power-20110613_1_aes-plans-aes-huntington-beach-llc-aes-southland *and* http://www.energy.ca.gov/sitingcases/walnutcreek/index.html

[15] *See* http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/powerplants/contra_costa/docs/cc_ip2011.pdf *and* http://www.energy.ca.gov/sitingcases/marshlanding/index.html

[16] See http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf

D. Allocation Methodology

1. Energy Efficiency

DRA commends the CEC for taking a significant step towards developing a methodology to allocate EE savings by busbar locations. This methodology geographically distributes EE savings according to customer class. DRA recommends that this proceeding create a process to take this methodology a step further by directing the IOUs to work collaboratively with the CEC and in concurrent stakeholders processes, to gather and deliver locational (climate zone, geographic) data on EE savings *within* customer classes for use in local capacity planning. The need for this differentiation can be illustrated within the residential customer class, in which certain EE measures such as HVAC efficiency or lighting will have a higher impact in hotter climate zones or in more populated areas. One opportunity for the IOUs to present this differentiated data is at the Commission's June 26th workshop responding to D.10-10-033.

The IOUs should be directed to focus their effort on measures that deliver a high degree of savings and in locations that are likely to have the highest capacity need.

2. Demand-Response

Appendix A of the Straw Proposal notes that for allocating incremental EE impacts, the previous method had been to simply reduce all load buses in a power flow base case uniformly across an entire Participating Transmission Owner / Investor Owned Utility (PTO/IOU) area. Although allocating DR impacts of prospective programs to specific transmission system busses on the basis of data from the IOUs is preferable to distributing DR impacts uniformly across all load buses, the allocating methodology must be logical and clearly demonstrated to be more accurate. This would require much more detailed data than what the IOUs have currently provided to Energy Division. To the extent possible, DRA recommends that any methodology should try to associate DR impacts to specific load buses first, and only then use other methods to allocate remaining DR impacts. The IOUs routinely use this type of method to allocate Common and General Plant to different asset classes of plant.

III. CONCLUSION

DRA hopes that these comments and recommendations are helpful to the Commission in its efforts to refine its approach to resource planning.

Respectfully submitted,

SARAH THOMAS
MARY MCKENZIE

/s/ MARY MCKENZIE

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MARY MCKENZIE

Attorneys for the Division of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-2760
Fax: (415) 703-2262
Email: mary.mckenzie@cpuc.ca.gov

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