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)

RESPONSE OF THE DIVISION OF RATEPAYER ADVOCATES TO THE REVISED ASSIGNED COMMISSIONER'S RULING SETTING FORTH STANDARDIZED PLANNING SCENARIOS FOR COMMENT

DIANA L. LEE
IRYNA A. KWASNY
Attorneys
Division of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703- 4342
Email: Diana.lee@cpuc.ca.gov

October 5, 2012

29822187

I. INTRODUCTION

The Division of Ratepayer Advocates (DRA) submits this response to the September 25, 2012, "Revised Assigned Commissioner's Ruling Setting forth Standardized Planning Scenarios for Comment" (September 25, 2012 ACR). The September 25, 2012 ACR invites parties to provide formal comments on the standardized planning assumptions that will be used in Track II, the systems need track, of this long-term procurement planning (LTPP) proceeding, which are appended to the September 25, 2012 ACR.[1] DRA's comments are set forth below.

II. DISCUSSION

A. The value of the Replicating Transmission Planning Process (TPP) Scenario is unclear, but it should not form the basis for authorizing procurement.

DRA is concerned both by the inclusion of the "Replicating TPP" scenario as a high priority scenario and by the creation of the "Stress Peak Case" sensitivity. It is unclear why the Energy Division suggests consideration of moving away from a 1-in-2 load forecast. DRA is unaware of evidence that shows a 1-in-2 load forecast is ineffective in meeting system needs. The proper forum to discussion changes to the load forecast metric is a proceeding such as a planning reserve margin rulemaking or the resource adequacy proceeding. As the planning reserve margin is based on a 1-in-2 load forecast, to deviate from this metric would create inconsistencies in the Commission's planning assumptions.

The Revised Scenarios state that:

> "[t]he Replicating TPP Scenario reflects a high unmanaged load future combined with 1-in-5 peak weather conditions. Accordingly, this scenario may stress operating flexibility by committing available resources for energy and thereby limiting their use for flexibility."[2]

The Revised Scenarios do not explain the purpose of stressing operating flexibility through a higher load forecast. However, raising the load forecast will stress operating flexibility, and will almost certainly show a need for system flexibility.

---

[1] "Revised Scenarios for Use in Rulemaking 12-02-014 (Revised Scenarios).

[2] Revised Scenarios at 10.

As operating flexibility is a system issue, a 1-in-2 load forecast is the appropriate metric. In the 2010 LTPP, the high load trajectory case was the only scenario that showed a flexibility need in 2020.[3] It appears that the CAISO used this scenario because no other scenario showed need, and thus, it was the only way to study how operating flexibility might be needed in the future. DRA is concerned that the CAISO will continue to cite flexibility need in numerous locations without clearly indicating that the flexibility need is the product of an unreasonably high load forecast. At this point, it appears that the "Replicating TPP" scenario and "Stress Peak Case" sensitivity are designed in search of a flexibility need that does not exist using the current methodology.

Attempting to determine operating flexibility needs before completion of the modeling efforts in Track III are completed in essence puts the cart before the horse. The basic foundation for modeling system flexibility need has not been finalized, and the Commission has not yet approved use of the CAISO's product simulation model to determine operating flexibility need.

Given the importance of aligning scenario planning where possible between the Commission and the CAISO, DRA understands the desire to add the "Replicating TPP" case to the list of high priority scenarios. However, the drastic difference between the planning assumptions of the TPP and LTPP is what gives DRA pause in accepting this case as a possible planning scenario. If the "Replicating TPP" scenario and "Stress Peak Case" sensitivity are designed specifically for the Operating Flexibility modeling effort, they should be identified as such, and it should be explicitly stated that they will not form the basis for procurement authorization. If the "Replicating TPP" scenario is proposed as a possible basis for authorizing procurement, DRA requests that the Commission send out the ruling on proposed scenarios to all service lists relating to Energy Efficiency and other Demand Side programs. DRA believes this is a necessary step if removing a central purpose for demand side programs, namely the avoidance of constructing new power plants, is being considered in the LTPP proceeding. Demand Side stakeholders should have an opportunity to comment on this type of a drastic change in Commission policy.

[3] D.12-04-046 at 7 and 10.

B. The mid incremental energy efficiency case should include 1,149 MW of savings from three Big Bold Energy Efficiency Strategies programs.

DRA supports the inclusion of the Commission's Big Bold Energy Efficiency Strategies (BBEES) into the high incremental energy efficiency (EE) assumption. However, excluding some of the programs contained with the BBEES from the mid incremental EE case would overlook significant savings from three programs that the Commission authorizes the Utilities[4] to fund and implement. These ratepayer-funded programs include:

- Energy Upgrade California Program,
- Energy Efficiency Financing Programs, and
- Local Government Regional Energy Network Programs.[5]

These programs were not within the scope of the 2011 Potential Study[6] that was used to develop the EE forecast so the Potential Study, and consequently the California Energy Commission's (CEC) Incremental Energy Efficiency analysis that informs the Commission Scenarios[7] do not reflect their savings. While not measured within the limits of the Potential Study, the three programs are reasonably expected to yield energy savings that should be included in the mid case. In addition, components of the EE Financing Programs and Local Government Regional Energy Network home retrofit programs have the capability to change the economic and market potential for many energy efficiency measures that are used to define the inputs to the Potential Study. DRA recommends the Commission include the low BBEES amount of 1,149 MW of peak demand reductions into the mid case to reflect savings from these types programs for which the Commission has a long-standing policy of support.[8] This amount

[4] DRA's comments refer collectively to Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company as Utilities.

[5] These programs include the Flex Package, Flex Path, and Marketing Programs.

[6] http://www.cpuc.ca.gov/NR/rdonlyres/6FF9C18B-CAA0-4D63-ACC6-F9CB4EB1590B/0/2011IOUServiceTerritoryEEPotentialStudy.pdf (referred to as the 2012 Potential Study in CEC's Incremental Uncommitted Energy Efficiency memo.

[7] http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/Memorandum_IUEE-CED2011.pdf

[8] *See* Attachment A, Table ES-4 from *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast,* January 10, 2010 report prepared by Itron for the California Energy Commission. The 1,149 MW of peak demand results from

(continued on next page)

is reasonable considering the significant ratepayer contribution to the three programs whose savings were excluded from the 2011 Potential Study, to the order of $318 million in the 2013-2014 cycle alone and a commitment to more upcoming energy efficiency program cycles. By continuing to ignore these programs in search of only inputs that can be determined with high degrees of certainty, the Commission risks expending significant ratepayer funding for demand side programs, without allowing them to serve their intended purpose, which is to reduce the need for future power plants. Alternatively, the Commission could apply the high case EE assumption, which includes BBEES, to any scenario that currently uses the mid case assumption achieve a similar effect.

C. The Scenarios should include demand response program benefits reflecting forecasts adopted by the Commission.

The Scenarios appended to the ACR continue to exclude demand response program benefit forecasts that have been adopted by the Commission. DRA has provided extensive technical comments regarding Permanent Load Shifting (PLS) approved in D.12-04-045 and PG&E's Peak Time Rebate (PTR) benefits adopted in D.09-03-026.[9]

The standardized planning scenarios are contradictory on PG&E's Peak Time Rebate program. On the one hand, the July 27, 2012 Assigned Commissioner's Ruling on Standardized Planning Assumptions (July 27, 2012 ACR), Attachment, p. 17, states:

> "Event-based demand response shall be accounted for as a supply-side resource. The most recent Load Impact reports filed with the Commission should serve as the mid scenario. For PG&E [Pacific Gas and Electric Company], this should also include the pending peak time rebate program."

On the other hand, the revised ACR, while still claiming that Event-Based Demand Response (DR) includes PG&E's PTR,[10] is mistaken in concluding that:

(continued from previous page)
subtracting expected BBEES savings from 2013 and 2014 from 2020 BBEES savings (1,552- (132-271)=1,149*; see also* Comments of the Natural Resources Defense Council (NRDC), The Division of Ratepayer Advocates (DRA), and Sierra Club California on Incremental Energy Efficiency Assumptions In 2012 LTPP Planning Standards, August 8, 2012 at 6.

[9] The Division of Ratepayer Advocates Comments in response to Technical Questions on Proposed Scenarios, September 7, 2012; Additional technical comments, September 11, 2012.

[10] Revised Scenarios, p.12, footnote 20.

"No changes will be made to the event-based demand response forecast in the supply side assumptions. At this time, PG&E's peak time rebate program is still pending before the Commission, and any required savings are still unclear."[11]

PG&E recommended that the mid scenario should assume that the PTR program is fully implemented in 2014.[12] DRA has previously argued that it is unreasonable to assume PTR will provide zero megawatts (MW) in 2022. Even if PG&E's implementation of PTR is delayed, it is likely to be a short-term issue, since Southern California Edison (SCE) and San Diego Gas & Electric Company (SDG&E) have implemented their PTR programs. In addition, DRA has provided to Energy Division (ED) staff, as requested, an updated calculation of PTR MW benefits. This calculation is included here for reference:

Step 1: In PG&E's Supplemental Testimony in the AMI Upgrade case, the following table[13] was provided indicating Peak Time Rebate benefits estimated by PG&E:

Year	2012	2015	2020	2030
Dynamic Pricing - PTR	260 MW	274 MW	300 MW	360 MW

Step 2: Estimating year by year (2012-2030) MW impacts for PTR, based on PG&E's table reproduced above,[14] yields:

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PTR MW	**260 MW**	264 MW	269 MW	**274 MW**	279 MW	284 MW	289 MW	294 MW	**300 MW**	306 MW	312 MW	318 MW	324 MW	330 MW	336 MW	342 MW	348 MW	354 MW	**360 MW**

Step 3: While PG&E projected a 260 MW peak load reduction in 2012 from default residential PTR, D.09-03-026 appears to have adopted a modestly lower figure. Per page 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."

[11] Id., p. 25.

[12] Comments of Pacific Gas and Electric Company on the May 10, 2012, Energy Division Standardized Planning Assumptions Proposal, May 31, 2012, p. 19.

[13] PG&E SmartMeter Upgrade Supplemental Testimony in A.07-12-009, p. 20 Revised Table 5-1, May 14, 2008.

[14] The PTR MW numbers, identified by PG&E in select years, are in bold. DRA used these numbers to extrapolate the numbers for the intervening years.

DRA took the difference between PG&E estimated PTR MWs through 2030 (6,307 MW) and subtracted from it the Commission adopted (D.09-03-026) PTR MWs through 2030 (5,714 MW): 6,307 MW – 5,714 MW = 593 MW, which represents a 9.4% downward adjustment:
593 MW /6,307 MW = 0.094 = 9.4%

Step 4: Applying this Commission downward adjustment (9.4%) to the year by year PTR MWs yields:

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PTR MW	236 MW	239 MW	244 MW	248 MW	253 MW	257 MW	262 MW	266 MW	272 MW	277 MW	**283 MW**	288 MW	294 MW	299 MW	304 MW	310 MW	315 MW	321 MW	326 MW

For the purpose of LTPP scenarios, it can be assumed that PTR will have the same MW value for years 2031 and 2032 as it does for 2030.[15]

Furthermore, the revised ACR fails to include PLS benefits approved in D.12-04-045:

The CEC's demand forecast included a cumulative total of about 30 MW PLS for the three IOUs.[16] The CPUC has approved, however, a total of $32 million for approximately 50 MW of PLS for all three IOUs based upon the IOUs' respective 2012-2014 Demand Response applications submitted in April 2012.[17] Energy Division Staff considers this 20 MW differential between the CEC demand figure and the IOUs 2012-2014 Demand Response applications to be de minimis given the relative uncertainty

[15] Attachment to email sent to ED staff on September 20, 2012 at 2:04 pm. This email also included the excel workpaper for calculations of Step 4 (applying 9.4% downward adjustment).

[16] Email from Chris Kavalec, Demand Side Analysis Office, Electricity Supply Analysis Division, CEC to Noushin Ketabi, Generation and Transmission Planning, Energy Division, CPUC, *sent on* 8/30/2012 *at* 9:09am. *See also* http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V1.pdf at pp. 33-34.

[17] In the 2012-2014 DR applications, PG&E proposed a budget of $15 million for 27 MW of PLS, SCE proposed a budget of $14 million for 19 MW of PLS and SDG&E proposed a budget of $3.4 million for 3.6 MW of PLS storage. R.12-04-045, Decision Adopting Demand Response Activities and Budgets for 2012-2014 (April 19. 2012), p. 147, 226 Finding of Fact 60. The IOUs submitted updated numbers in August 2012 per D.12-04-05 which totaled about 50 MW total. On September 18th, a workshop was held to solicit party feedback to the IOUs' proposals. Email from Joanne Leung, Demand Side Programs, Energy Division, CPUC to CPUC Service Lists R.07-01-041, R.10-12-007, A.12-07-001 *et. al*, *sent on* 8-27-2012 at 11:16am.

surrounding the factors comprising the incremental analysis in the IEPR.

Based on D.12-04-045, it appears that the 50 MW of PLS approved for 2012-2014 is in addition to approximately 20 MW of PLS funded in 2007-2011.[18] Therefore, the differential between the CEC demand figure and cumulative total adopted by the Commission appears to be 40 MW. DRA recommends that the Energy Division obtain and use the most accurate information possible from the IOUs and the Energy Commission regarding PLS that is not reflected in the CEC's demand forecast. Regardless of whether the PLS differential is 20 or 40 MW, this figure should be included in the standardized planning scenarios since it has been approved by the Commission.

DRA is concerned by an apparent systematic and inappropriate discounting of Demand Response in the standardized planning scenarios. In addition to the fact that the standardized planning scenarios exclude PLS and PG&E's PTR benefit forecasts, the proposed scenario tool erroneously uses the month of August of each year to calculate Even- Based DR for each of the three IOUs.[19] For 2022, the planning scenarios should calculate Event-Based DR by picking the maximum DR in any month of the year. For 2022 load impact forecasts, the maximum DR for SCE and SDG&E falls in September, while for PG&E it falls in July. This is the true amount of DR that is forecasted to be available in that specific year under system peak load conditions. By choosing the month of August, the planning scenarios incorrectly reduce Event-Based DR by 46 MW for PG&E, 18 MW for SCE and 32 MW for SDG&E, for a total of 96 MW for all three IOUs.

While Energy Division staff may consider some of these Demand Response benefits to be "de minimis," those benefits amount to 419 MW of improperly omitted DR in 2022, as described in Table 1:

[18] D.12-04-045 at 146-147.

[19] Scenario Tool, worksheet *Notes*, rows 46-53.

Table 1: DRA proposed changes to properly account for DR in 2022

DRA proposed changes	*MW*
PG&E's PTR	283 MW
PLS	40 MW
Adjustment to picking system peak month	96 MW
Total	419 MW

III. CONCLUSION

DRA requests that the Commission revise the scenarios consistent with its recommendations in these comments, in order to produce a more reasonable basis for the Utilities' procurement:

- The Replicating TPP Scenario and Stress Peak Sensitivity should not form the basis for procurement authorization;
- The mid incremental energy efficiency case should include 1,149 MW of savings from three Big Bold Energy Efficiency Strategies programs; and
- The Scenarios should include an additional 419 MW in demand response program benefits reflecting forecasts adopted by the Commission.

Respectfully submitted,

/s/ DIANA L. LEE

____

DIANA L. LEE
Staff Counsel

Attorney for the Division of
Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Telephone: (415) 703-4342
Facsimile: (415) 703-2262
Email: Diana.lee@cpuc.ca.gov

October 5, 2012