**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.	R.12-03-014 (Filed March 22, 2012)

REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE MAY 10, 2012, ENERGY DIVISION STANDARDIZED PLANNING ASSUMPTIONS PROPOSAL

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Pursuant to the schedule established in the May 17, 2012, *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* (Scoping Memo), Pacific Gas and Electric Company (PG&E) provides reply comments on the *Energy Division Straw Proposal on LTPP Planning Standards* (Assumptions Proposal). On May 31, 2012, parties in this proceeding submitted comments on the Energy Division's Assumptions Proposal as directed by the Scoping Memo. In these reply comments, PG&E addresses additional steps that PG&E encourages the California Public Utilities Commission (Commission) to consider before it finalizes the planning assumptions it will use in Track 2 of this proceeding. PG&E also identifies additional assumptions that will be required for the Track 2 analysis. Finally, PG&E offers several observations regarding specific input assumptions. PG&E's primary point is that the range of possible future scenarios considered should not be too limited.

I. FOUNDATIONAL COMMENTS

A. A Meaningful and Thoughtful Analytical Approach for Phase 2 Analysis is Needed

PG&E re-iterates its opening recommendation that before reaching any decision on planning assumptions or scenarios, the Commission should first: (1) clarify the purpose of the Track 2 decision, and the information it needs to make that decision; (2) identify the analytical framework (scenarios, alternatives, and metrics) to be used in preparation for the Track 2 decision; and (3) investigate the methodology and models to be used in Track 2.

With respect to clarifying the purpose of the Track 2 decision, PG&E recommends that the Commission clarify that the Track 2 decision will: a) determine the range of system need (not a single number); and b) identify the operating attributes required from the incremental capacity to satisfy system need. PG&E believes that the need determination should be technology neutral.

With respect to the analytical framework to be used in Track 2, PG&E recommends the analysis:

- Define scenarios that combine assumptions to arrive at a reasonable range of system need that satisfies a selected reliability planning criteria.
- Consider the types of capacity with different operating attributes to determine which operating attributes are more effective in meeting the identified need. With the right attributes, fewer megawatts (MW) should be needed to meet the identified need.
- Identify metrics to measure the performance of possible alternatives that can meet the identified need. Since the Track 2 decision will address the range of physical capacity needed, and the attributes of that capacity, the only metric needed in Track 2 is the effectiveness of different physical and operating attributes of capacity that can meet the identified system need.

With respect to the methodology and models to be used in Track 2, although the California Independent System Operator (CAISO) has done extensive studies regarding renewable integration, the methodology and models used to determine the system's operating flexibility needs continue to evolve. The following section provides additional information as to the key assumptions that drive the system's operating flexibility need.

B. Additional Assumptions For Operating Flexibility Analysis Are Needed

PG&E recommends that the Commission include additional assumptions that are not part of the Energy Division's Assumptions Proposal but are necessary to address operational flexibility needs. Based on the CAISO's on-going renewable integration work, and the CAISO's presentation at the June 4, 2012 workshop, PG&E anticipates that at minimum the following assumptions will need to be considered in Track 2:

- The range of weather uncertainty to be considered in Track 2 to test the system's resource adequacy. The stochastic approach the CAISO is planning to use for the operational flexibility studies will test system adequacy under different weather years.

- The variability and forecast uncertainty of load and wind and solar generation. Given the uncertainty with improvements in forecasting accuracy and minute by minute variability of new wind and solar resources, PG&E recommends using a range, rather than a single point estimate, of forecast errors. Flexibility requirements (such as regulation and load following capacity) are a function of the assumed variability and forecast uncertainty of load and wind and solar generation. Slides 39 to 45 from CAISO's presentation at the June 4, 2012 Operating Flexibility workshop sponsored by the Energy Division illustrate the possible forecast error ranges.[1/]
- The reliability and flexibility targets that the system should meet to determine resource adequacy need to be assumed. Also, assumptions must be made about how to interpret and measure compliance with typical reliability targets such as one day in 10 year loss of load expectation (LOLE). In addition, new flexibility targets need to be assumed such as how much of forecast error or deviations should be covered by regulation and load following requirements. North American Electricity Reliability Council (NERC) control performance standards presented by CAISO at the June 4, 2012 Operating Flexibility workshop could be the basis for future flexibility metrics and targets. See slides 64 to 71 of the CAISO's June 4, 2012 presentation.
- The range of imports/exports that are available to help meet the CAISO's reliability needs if transfer capacity and excess resources are available in neighboring areas. Exports can also help manage over-generation conditions in neighboring areas that have excess downward flexibility. Because of the uncertainties about loads and resources in the neighboring areas, and available transfer capacity, assumptions need to be made about the contribution of imports/exports to the CAISO's reliability and operating flexibility needs. Prior studies have assumed neighboring systems can eliminate all potential over-generation conditions, which is unrealistic given today's existence of negative prices and over-generation with less intermittent resources.

C. The Net Effect of All Assumptions Must Show a Wide Range Between Scenarios

Guiding Principle E in the Assumptions Proposal states that infrastructure portfolios should be *substantially unique* from each other. PG&E strongly supports this idea. It should be a fundamental principle used in developing the scenarios to be analyzed. It permits a broader,

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1/ Reference slides can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/32D2572E-7B0B-4DAD-8D99-AB13CBA1470F/0/201206OpFlexMeetingpresentationPDF.pdf more robust evaluation of the various futures that may occur. To achieve this, the net effects of all the assumptions within a scenario must be meaningfully different when compared to other scenarios. Otherwise, developing an informed range of potential need will not be possible.

As an example of where the current proposed assumptions do not meet this fundamental principle, the difference between the Assumptions Proposal's highest and lowest net managed load scenarios will only be in the range of two to eight percent from the mid scenario. Such a narrow range is likely to lead to results between scenarios that are not meaningfully different, and do not appropriately demonstrate the range of possible outcomes that should prudently be planned for. Slide 37 from the June 4, 2012 Operational Flexibility CAISO presentation highlights the major drives of resource need other than the flexibility requirements found in past integration studies for which ranges, rather than point forecasts, would be useful to consider in future Track 2 analysis.

Also, while the Commission will ultimately adopt a set of planning assumptions, scenarios, and sensitivities, it is vital that other parties, including the utilities, be able to present other sets of assumptions that they feel are appropriate to evaluate.

II. SPECIFIC COMMENTS ON THE ASSUMPTIONS PROPOSAL

A. Load Forecast

The California Energy Commission (CEC) recently adopted statewide load forecasts. PG&E appreciates the long effort that went into the development of these forecasts. However, as discussed above, because the baseline and alternative load forecasts used in this proceeding will serve to "bracket" the possible planning assumptions used in the development of long term procurement plans, it is critical to ensure that the assumptions present a breadth and range from which meaningful procurement alternatives can be developed.

In reviewing Table ES-1 of "California Energy Demand 2012-2022 Final Forecast"[2/], PG&E was struck by the fairly narrow range of alternative forecasts, both in terms of energy and

2/ California Energy Demand 2012-2022 Final Forecast, p. 2.

peak demand. For example, for the period 2012-2022, the CEC shows 1.2 percent annual growth of net energy for load in the mid case scenario. The high case shows growth at just 0.5 percent higher at 1.7 percent average annual growth, which results in statewide load that is only 16,000 GWh (five percent) higher than the mid case in 2022. For the low case, the variance is even less. Average annual growth in the low case is 1.0 percent, just 0.2 percent less on an annual basis than the mid case. This results in net energy that is less than 10,000 GWh (3 percent) below the mid case in 2022.

Using historical data provided in the California Energy Demand (CED) document, along with data found in the 2002 CED document, PG&E has created a 30-year time series of California net energy. Using this time series, PG&E has created a 20-year series of rolling 10-year compound growth rates. Within the 20-year series, there are 10 periods (half the period from 1990 through 2010) in which the compound growth rate exceeds the high case growth rate of 1.7 percent. The highest of these 10-year growth rates is 3.1 percent over the period from 1980 to 1990.

If this growth rate were used as the high case scenario in this proceeding, it would result in usage of over 388,000 GWh in 2022, a 22 percent increase above the mid case scenario. To be clear, PG&E is not advocating that a 3.1 percent growth rate be used as a high case scenario. It is clear, however, that a 1.7 percent annualized growth rate (yielding a five percent upper bound in 2022) provides an upper range that is quite narrow compared to historical observations.

As mentioned above, the CEC's low case shows 1.0 percent growth over the forecast period, a small decrement below the mid case. Interestingly, the most recent 10-year period, from 2000-2010, shows annual growth of only 0.4 percent. If this rate was employed on the forecast, 2022 energy usage would amount to a little under 290,000 GWh, a nine percent reduction from the mid case.

Based on this historic information, PG&E recommends that this proceeding use "ten percent" alternative scenarios. That is, PG&E recommends the use of alternative scenarios that show a ten percent change in energy demand with respect to the 2022 mid case scenario usage total. PG&E's recommended range should be used instead of the much narrower bands suggested by the Energy Division. The wider range will provide greater planning distinctions to procure needed energy to a variety of future outcomes.

Regarding peak demand, the 2002 CED volume did not include annual peak values for the 1980s decade, so PG&E was unable to develop a comparative analysis similar to the one presented for net energy. However, based on the range of net energy that should be considered, the low and high scenarios for peak demand in the Assumptions Proposal, both under six percent in 2022, define too narrow a range of analysis of peak demand. This range is too narrow for developing distinctive alternative procurement plans. PG&E recommends that it be broadened to ten percent in either direction, as well.

B. Energy Efficiency

PG&E reiterates its position that any forecast of incremental energy efficiency (IEE) reflect only IEE that is cost effective, reliable, and feasible, consistent with the requirements of Public Utilities Code (PUC) section 454.5. PG&E believes that projections of IEE savings due to zero net energy homes and buildings as well as other unproven or non-cost effective IEE projections should be excluded from the IEE estimates for LTPP purposes.

As discussed above, the range of final demands reflected in the scenarios used in this proceeding should reflect the high degree of uncertainty inherent in long term projection, including uncertainty about future levels of IEE. It is well documented that the range of uncertainty regarding even short-term projections of savings due to energy efficiency is large and that ex-ante modeling may overstate the impact of energy efficiency impacts on load reduction relative to ex-post analysis.

The most important variable to consider for LTPP purposes is net demand, not how that net demand is broken down into various components, including IEE. Regardless of the exact range of IEE considered in this proceeding, the range of net demand considered should be broad enough to allow for meaningful evaluation of future uncertainty in realized demand.

PG&E agrees with the Division of Ratepayer Advocate's (DRA) proposal that IEE assumptions should be reviewed further once they are available.

C. Demand Response

PG&E takes issue with the DRA's recommendation that the Commission include a load impact of 235 MW for PG&E's Peak Time Rebate (PTR) program, as determined in D.09-03-026.11.[3/] DRA does not indicate whether this would be a mid, high, or low estimate. As PG&E explained in its initial comments on the Assumptions Proposal (PG&E Comments, Appendix A, pp. 9-10), the load impacts adopted in D.09-03-026 were projections that have since been proven to be overly optimistic. PG&E now forecasts that load impacts will be approximately 108 MW, at best. Therefore, PG&E recommends that its revised, current estimate of 108 MW be used. PG&E does not oppose use of the prior estimate of 235 MW as a high scenario, despite there being virtually no chance that 235 MW of load impacts will be obtained. Finally, PG&E proposes that the low scenario assume zero MW for PTR, to reflect the possibility that the Commission may adopt PG&E's primary proposal in Application (A.) 10-02-028 that the PTR program not be implemented.

When the PTR programs for all three utilities were considered, there was very little empirical data on PTR performance and virtually no data on the performance of default residential pricing programs. Using the best available data at the time, the Commission used similar methods and assumptions to derive and adopt load impacts for all three utilities. At that time, it was assumed that customer participation in and response to PTR would be fairly robust. However, subsequent pilots have proven those assumptions to be incorrect. For example, after observing other default pilots and completing their own default PTR pilot in 2011, San Diego Gas & Electric Company (SDG&E) PTR load impacts are now expected to be roughly 40-50 percent of what they were previously estimated to be. This downward revision is reflected in SDG&E's June 1, 2012 ex ante load impact report provided in Rulemaking (R.) 07-01-041.

PG&E has prepared an updated estimate of PTR load impacts, which PG&E provided in

3/ DRA Comments, pp. 9-10.

the 2010 Rate Design Window[4/] hearings as Exhibit PGE-18. That estimate is derived using information from the SDG&E pilot and other default pilots, and is 108 MW. PG&E's analysis also suggests that there is virtually no possibility that the program will produce the previous, higher estimate of 235 MW.

PG&E's proposals for the mid, high, and low scenarios are reasonable, appropriate, and transparent, and are consistent with the spirit of the Energy Division's scenario based Assumptions Proposal.

D. Distributed Generation

PG&E recommends that stretch goals for distributed generation not be used to determine system need in Track 2, as these stretch goals may not be consistent with PUC Section 454.5. Several parties mention one or more of the following: the 4,000 MW combined heat and power (CHP) goal from the California Air Resources Board's (ARB) Scoping Plan; the 12,000 MW renewable distributed generation (DG) goal; or the 6,500 MW CHP value from the Governor's Clean Energy Jobs Plan.[5/] All of these goals are stretch goals that assume that the specified amount of renewable DG or efficient, greenhouse gas (GHG)-reducing, CHP potential actually exists in California.

Use of these stretch goals in this proceeding is not helpful at this time. They do not provide a reasoned set of bounds on the DG and CHP that may be available on the system for future evaluation of need. It is too optimistic, at this time, to simply assume that these levels of DG and CHP can be counted on, so that no planning is necessary that considers the possibility that this level of resources might not be available.

PG&E believes that Governor Brown's Jobs Plan and the ARB's Scoping Plan represent stretch goals, and should not be used to define scenarios in this proceeding. However, if they are

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4/ A.10-02-028.

5/ *See, e.g.*, California Cogeneration Council Comments, p. 2; Sierra Club Comments, p. 12, 19-20; California Environmental Justice Alliance Comments, p. 12; Interstate Renewable Energy Council Comments, p. 5.

used to define a scenario, PG&E cautions that it is not as simple as adding 12,000 MW of renewable DG or 6,500 MW of CHP DG. Other considerations that must be addressed before using these goals include: to what extent do the goals include existing programs and installations; and (assuming the goals can be achieved), what proportion of the generation serves at-site customer load and what proportion is exported to the grid under a power purchase agreement, feed in tariff, or other supply side option.

As PG&E indicated in its initial comments to the Assumptions Proposal (Appendix A, p. 5), the Revised February 2012 ICF International CHP Policy Analysis (ICF study) overstates both the technical potential and market adoption rate for efficient, GHG-reducing, CHP. Even with this overestimate, ARB's goal is not met in the mid and base cases of the ICF study and the Governor's goal is not met in any of the ICF cases.

E. Supply Side Combined Heat and Power

For this proceeding, the procurement of any incremental CHP generation should be assumed to be conducted pursuant to the framework established by the qualifying facility (QF)/CHP Settlement approved in D.10-12-035, where GHG reduction goals, not MW targets, are the long-term drivers of additional CHP. Based on this, PG&E supports the following range of CHP MWs to be considered in this proceeding: (1) a low-case of zero incremental CHP, assuming new efficient facilities replace existing inefficient facilities; (2) a more moderate LTPP mid-case with incremental CHP based on actual CHP adoption rates over recent years; and (3) a LTPP high-case with incremental CHP in the range of the ICF mid-case.

PG&E supports efficient CHP that can provide a cost-effective source of electricity to our customers and reduce greenhouse gases statewide. The range PG&E recommends to be considered is in line with this frame of reference. PG&E cannot support unqualified CHP MW targets; as use of such targets risks supporting the installation, or continued operation, of net GHG emitting CHP.

As more renewable power is added to the grid, GHG benefits from fossil-fuel combined heat and power systems will decline. For example, the ICF study found that CHP facilities may provide no GHG benefit as early as 2025, after accounting for the impact on the 33 percent Renewable Portfolio Standard policy.[6/]

Both the 4,000 MW CHP goal from the ARB's Scoping Plan and the 6,500 MW value from the Governor's Clean Energy Jobs Plan are stretch goals that assume that the specified amount of efficient, GHG-reducing, CHP potential actually exists in the California. As PG&E indicated in its initial comments (Appendix A, pg. 10), the ICF study overstates both the technical potential and market adoption rate for efficient, GHG-reducing, CHP. Even with this overestimate, ARB's CHP goal is not met in the mid and base cases of the ICF study, and the Governor's CHP goal is not met in any of the ICF cases. Therefore, the ARB's and the Governor's CHP goals should not be used as estimates in this proceeding.

F. Renewable Resources

In opening comments, PG&E recommended that while it may make sense to use the aggregated information from the 2012 Renewable Procurement Plans (RPS Plans) to develop RPS portfolios to be used in this proceeding, any project-specific assessments must remain confidential. On Friday, June 1, 2012, parties filed responses to Energy Division's "Request for Pre-Workshop Comments on a Renewable Net Short Position Calculation," in R.11-05-005. These responses provide considerable discussion and voice significant concern regarding publicly disclosing internal RPS forecasts. PG&E, along with Southern California Edison Company (SCE) and SDG&E, emphasized the importance that project-specific assessments should remain confidential, and that public disclosure of such information would be cause for serious concern. In addition, as discussed in PG&E's comments, to the extent the Commission and the CAISO require project-specific information that can be vetted publicly, PG&E recommends that the project-specific information used be based on simplifying assumptions or rely on external, independent evaluations. PG&E looks forward to continuing this discussion

6/ See Figure ES-6 of the ICF paper, *Combined Heat and Power Policy Analysis and 2011-2030 Market Assessment*, ICF for the CEC, February 2012.

and participating in the Renewable Net Short workshop on June 12, 2012.

G. Transmission Buildout and Deliverability

The transmission assumptions used in the 2012 LTPP should be consistent with the results of the CAISO's 2011-2012 transmission planning process (TPP). Resources included within the renewable supply calculation should be assumed to be deliverable for planning purposes in this proceeding.

As the Large Scale Solar Association's comments state on this topic, this proceeding should use assumptions "that reflect "sunk" decisions and completed planning efforts," and "the transmission projects included in the plan and expected to be online within the planning period should be assumed irrespective of the status of CPUC approval."[7/]

While Commission approval for both TPP-driven transmission upgrades and deliverability network upgrades lag behind the CAISO TPP, it is still reasonable to assume that these highly likely upgrades will be built, and they should therefore be included in any modeling efforts that are part of this proceeding.

Respectfully Submitted,

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7/ See Page 1 of *Comments of the Large-Scale Solar Association on the Energy Division Straw Proposal on Standardized Planning Standards.*