**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Loans.	R.12-03-014 (Filed March 22, 2012)

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

CHARLES R. MIDDLEKAUFF
MARK R. HUFFMAN

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3842
Facsimile: (415) 973-0516
E-Mail: MRH2@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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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 these comments on the May 10, 2012, E*nergy Division Straw Proposal on LTPP Planning Standards* (Assumptions Proposal). Energy Division requested that parties submit their comments in a template issued by Energy Division. Attached to this filing as Appendix A are PG&E's comments regarding the issues identified in the Energy Division template. In addition, PG&E has the following general comments regarding the Assumptions Proposal.

I. THE ASSUMPTIONS PROPOSAL IS PREMATURE.

The Scoping Memo anticipates that Track 2 (the system reliability track) will require at least two Commission decisions, one adopting standard planning assumptions towards the end of June 2012 and a second decision adopting scenarios in November 2012.[1/] PG&E believes it is premature to debate and adopt planning assumptions before considering renewable integration issues, including the methodology and models that will be used to determine the need for flexible capacity to integrate renewable resource additions. Parties should discuss and provide input on, and the Commission should adopt, planning assumptions after understanding the analysis that

1/ Scoping Memo, Schedule for Track 2, p. 10.

will be used to estimate the system need for flexible capacity. PG&E proposes that the following items be addressed by the Commission prior to a final ruling on planning assumptions or scenarios:

A. Clarify the purpose of the Track 2 decision, and the information that the Commission needs to make this decision.

B. Identify the analytical framework (scenarios, alternatives, and metrics) to be used to develop the information to issue decisions in Track 2.

C. Investigate the methodology and models to be used in Track 2.

PG&E believes that addressing these preliminary, but critical, issues up front will provide clarity and more productive participation by the parties in this proceeding. After the above three items are defined, PG&E believes that the Commission should determine the key variables and specific assumptions for Track 2. The following section provides additional detail supporting PG&E's proposal.

A. The Purpose of the Track 2 Decision

PG&E anticipates that this Long-Term Planning Process' (LTPP) Track 2 decision will further address the physical, technology neutral, system need for resources (*i.e.*, supply or demand-side resources) to meet the reliability and flexibility needs of the system over the next 10-year planning horizon, in addition to the substantial work already done by the California Independent System Operator (CAISO) to date on this issue.[2/] PG&E anticipates that a Track 2 decision will be driven by the need for incremental flexible capacity to integrate renewable resources already identified by the CAISO, above and beyond the local capacity need that is determined in Track 1 of this proceeding. Specifically, PG&E recommends that the Track 2 decision address the following:

- Identify a range of system need (not a single number) to address the uncertainties of the input assumptions, and the different effectiveness levels of resources that could be used to meet the system need; and

2/ The Scoping Memo specifies a 20-year time horizon with a higher level of detail in the first 10 years. Scoping Memo, p. 9.

- Identify the operating attributes required from the incremental capacity to satisfy system need. PG&E anticipates the effectiveness[3/] of resources to meet system need will depend on their physical and operating attributes, such as start times, minimum operating capacity, ramp rates, and location. The determination should be technology neutral.

B. Analytical Framework

PG&E believes that the analytical framework consists of: (1) scenarios; (2) alternatives; and (3) metrics to be used to evaluate alternatives.

A Scenario, as defined by Energy Division's Assumptions Proposal, is a complete set of assumptions defining a possible future world. PG&E supports this definition. As such, a scenario should bracket the range of uncertainty of system need over the selected time horizon.[4/] Scenarios should combine assumptions to arrive at a reasonable range of system need that satisfies a selected set of reliability planning criteria, such as considering the system's reliability and flexibility requirements, the probability of customer outages should not exceed a 1 day in 10 year frequency.

Alternatives are possible physical and operating attributes of resources (supply and demand side-resources) that could be used to meet the identified need. Resources with certain operating attributes are more effective in meeting the identified need than other resources. For example, with respect to the system need for flexible capacity to integrate renewable resources, resources with short start times, fast ramp rates and low minimum operating capacity are likely to be more effective in meeting incremental needs for flexible capacity. That is, the more effective a resource, the fewer MW that will be needed to meet the same MW of identified need for flexible capacity to integrate renewables.

Metrics 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

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3/ As explained later, effectiveness metric is simply the amount of megawatts (MW) of identified need met with a MW of capacity with different attributes. For example, a 70% effectiveness metric would mean that a MW of capacity with a particular set of attributes can meet only 0.7 MW of identified need.

4/ *See* Assumptions Proposal, p. v.

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. Since less MW of capacity with best fit attributes are needed to meet the identified system need, PG&E proposes that the effectiveness metric is simply the amount of MW of identified need met with a MW of capacity with different attributes.

C. Methodology and Models

Although the CAISO has done extensive studies regarding renewable integration, the methodology and models used by the CAISO in its integration study continue to evolve. Past CAISO integration studies used the Pacific Northwest National Laboratory's (PNNL) model to estimate regulation and load following requirements, and Plexos to determine the system's deficiencies of flexible capacity. The CAISO and others are currently in the process of developing and testing new or modified stochastic models to quantify resource need considering weather and other uncertainties.

The methodology and models being used by CAISO in its integration study use additional assumptions not covered by the Assumptions Proposal. It is essential that the Commission consider these additional assumptions before deciding on planning assumptions or scenarios for Track 2 because these additional assumptions are equally, if not more important than those covered by Energy Division's Assumptions Proposal. Section II, below, provides an overview of the key assumptions that drive the system need for flexible capacity, based on PG&E's participation in past and currently ongoing integration studies by the CAISO. Additional information about methodologies and assumptions used for renewable integration will be presented to parties in the LTPP proceeding at a workshop planned by the Energy Division for June 4, 2012.

II. ADDITIONAL ASSUMPTIONS WILL LIKELY BE NEEDED

Based on past and on-going work by the CAISO and its advisory group, and considering the models CAISO has used and is considering using to estimate system need, PG&E anticipates that the additional assumptions described below, which are not addressed by the Assumptions Proposal, will need to be considered in Track 2.

A. Weather impact on load/wind/solar generation

The standard assumptions and most of the integration studies filed presented to the Commission in the 2010 LTPP proceeding only considered normal weather conditions when determining resource need. The only exception was a sensitivity presented by PG&E, Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E), which showed that above normal load due to weather could have a significant impact on the need for incremental capacity.[5/] In addition to affecting load, weather impacts renewable generation patterns and the system's flexibility requirements.

The stochastic models being considered and developed by the CAISO, as well as off-the-shelf loss of load probability models such as GE-MARS, can consider weather impacts on need. Actual hourly and intra-hourly profiles for load and renewable generation are needed to represent load and renewable generation under different weather years. If actual renewable generation profiles for different weather years are not available for the desired locations, synthetic profiles need to be developed using actual weather data.

PG&E recommends that at least three weather years be used to represent weather uncertainty on load and renewable generation. In concept, the representation of weather uncertainty should be detailed enough to estimate the need for resources to satisfy typical reliability targets, such as customer outages not exceeding a 1 day in 10 year frequency.

The stochastic representation of weather uncertainty is also an essential input to determine the reliability contribution, or net qualifying capacity (NQC), of planned renewable resource additions using the effective load carrying capacity (ELCC) approach. The Commission is required to update the NQC of wind and solar energy resources toward meeting

5/ July 1, 2011 Joint IOU Supporting Testimony, Table 3-1.

the resource adequacy requirements using the ELCC approach.[6/] Because the ELCC-based NQC of renewables is expected to decrease with their level of penetration, it is likely that continuing to use current NQC values would lead to a false sense of security from over-estimated planning reserve margins.

B. The Role of Imports and Exports When Estimating System Need

The CAISO's interchanges with neighboring areas is also an important factor to consider. To the extent transfer capacity and excess resources are available in neighboring areas at the time of the CAISO's system peak, imports can contribute to meet the CAISO's reliability needs. Currently, the CAISO depends on about 10,000 MW of imports during peak hours.[7/] Changes in loads and resources in neighboring areas, transmission between the CAISO and other areas, and incremental renewable imports can affect the reliability contribution of imports available to the CAISO. In addition, once-though cooling (OTC) resource retirements also change the ability to import power into southern California. PG&E recommends that the Energy Division solicit the CAISO's careful review of these factors that affect the reliability contribution of imports before the Commission decides on planning assumptions related to imports for Track 2.

Imports and exports can also contribute to CAISO's flexibility needs. Neighboring areas should have excess flexible resources, and excess transmission to be able to contribute to the CAISO's regulation and load following flexibility requirements. The CAISO and its advisory group have recently performed several sensitivities to determine the extent to which the CAISO can count on the flexibility of neighboring balancing authorities for integration. Since its July 1, 2011 filing in the 2010 LTPP proceeding, the CAISO has improved the representation of reserve requirements and resource commitment and dispatch outside of California. Improving the representation of out-of-area conditions is necessary to determine to what extent there is surplus of flexible capacity and transfer capacity to import regulation or load following reserves into the

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6/ Public Utilities Code Section 399.26(b)(2)(d).

7/ *See* CAISO's 2012 Summer Assessment, Table 1.

CAISO's area. Specifically, the CAISO:

(1) added contingency and flexibility reserves (regulation and load following) outside of California, which were not modeled in prior studies filed in the 2010 LTPP,

(2) improved the commitment and dispatch of coal resources outside of California to recognize these resources' limited number of starts per year, and their minimum operating capacity, and

(3) recognized differences in CO_2 cost for dispatch purposes outside of California.

The CAISO is also investigating the ability of neighboring areas to absorb surplus generation in the CAISO's area to avoid over-generation conditions. Past simulations have not shown any hours of over-generation in 2020, which is unrealistic given that today, with fewer renewable resources and additional flexible capacity, the CAISO already experiences over-generation. Again, PG&E recommends that the Energy Division consult with the CAISO and use the results from ongoing studies before making any decisions as to the ability of the CAISO's neighboring system to contribute with flexible capacity.

C. Forecast Errors of Load, Wind, and Solar Generation

The system flexibility requirements used in planning studies consist primarily of regulation and load following capacity. Load following requirements are significantly larger than regulation requirements because they are intended to cover the forecast error for load, wind and solar generation over an hour, rather than a few minutes. Load following requirements are essentially a function of the CAISO's ability to forecast load, and wind and solar generation for operating purposes. The longer the uncertainty window, the greater the forecast error.

PG&E recommends the Commission adopt a range rather than a single estimate of the forecast error used to estimate load following requirements. That range should reflect the uncertainty over possible improvements in forecasting of wind generation, and the lack of forecasting experience with solar generation. PG&E also recommends the range of forecast error be extended to reflect the start time of resources used to provide system flexibility. Until now, the CAISO's analysis has considered up to a one hour uncertainty window to calculate load following requirements. PG&E believes that the uncertainty extends beyond one hour to the number of hours needed to start resources to cover forecast deviations. For example, if it takes 5 hours to start a combined cycle unit that the CAISO needs to cover forecast deviations, then 5 hours is the uncertainty window over which the forecast error should be calculated to estimate load following requirements. New units will have faster starts, but many of the units in California will still require several hours to start and generate to cover forecast deviations.

D. Flexibility Metrics and Targets

It is well understood that given the expected increase in intermittent renewables, the grid will need to be more responsive and flexible than it is today. However, there are no pre-established flexibility metrics or targets. Today's planning metrics and targets, such as the loss of load probability metric or the 15% to 17% planning reserve margin reliability target, are based on traditional reliability concepts that do not account for the system's need for operating flexibility. In the absence of pre-established flexibility metrics and targets, PG&E recommends assumptions be made as to the percentage of net load forecast deviations that the system should be planned to cover with flexible capacity. PG&E recommends using a range of 90% to 99% coverage for net load forecast deviations. The higher the forecast deviations covered, the higher the regulation and load following requirements to be used in the Phase 2 analysis to manage load, wind and solar variability and forecast errors.

III. MODIFICATIONS TO THE ASSUMPTIONS PROPOSAL ARE REQUIRED

As explained above, PG&E recommends that before reaching any decision on planning assumptions or scenarios, the Commission first: (1) define the decisions needed for Track 2 of the 2012 LTPP cycle, and the information needed to make those decisions, (2) identify the analytical framework (scenarios, alternatives, and metrics) to be used in preparation for the Track 2's decisions, and (3) investigate the methodology and models to be used in Track 2. This will facilitate and ensure that parties' participation in Track 2 is productive. PG&E also recommends that the Commission include the additional assumptions from the CAISO's on-going renewable integration, which are not addressed by Energy Division's Assumptions Proposal.

Nonetheless if the Commission prefers to decide on the initial subset of assumptions presented in the Assumptions Proposal, PG&E has a number of comments regarding the Assumptions Proposal. PG&E used the template provided by Energy Division to provide PG&E's comments in Appendix A to this filing.

Respectfully Submitted,

CHARLES R. MIDDLEKAUFF
MARK R. HUFFMAN

By: /s/
MARK R. HUFFMAN

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3842
Facsimile: (415) 973-0516
E-Mail: MRH2@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: May 31, 2012

APPENDIX A
ENERGY DIVISION TEMPLATE

General

1. Guiding Principles

PG&E provided additional guiding principles in Section I of its comments.

2. Planning area and planning period

Energy Division's Planning Standards Straw Proposal (Assumptions Proposal) anticipates a 20-year planning horizon, with detailed assumptions for the first ten years, and more generic assumptions for the second ten years.[1/] PG&E recommends that the planning horizon be limited to ten years. Estimates that could be provided for the second ten years would be of limited value given that uncertainty grows with time with respect to supply assumptions and the transmission expansion options. In addition, it is time consuming to extend the analysis beyond ten years even with generic assumptions.

Demand-side Assumptions

3. Economic & Demographic assumptions

The Assumptions Proposal considers: (1) Managed Load Scenarios, (2) Peak Weather Impacts, and (3) Economic and Demographic Drivers. Energy Division (ED) proposes to use combinations of demand side resources to modify a future California Energy Demand Forecast (the Revised 2012 CED), to apply weather sensitivities to the CED medium load forecast, and to use the same economic and demographic drivers as in the Revised 2012 CED.[2/]

PG&E believes that this proposal provides an unrealistic narrow range of load uncertainty over the planning horizon. For example, it is unreasonable to expect today's load forecast to be able to predict load 10 years out for the California Independent System Operator (CAISO) grid within a +/- 2,000 megawatt (MW) range, as shown in the Assumptions Proposal.

PG&E recommends that range be expanded to include not just the expected values of the CED scenarios, but the complete distribution of load projections of the three CED scenarios produced by economic and demographic drivers. The range of load projections should be adequate to represent a range of resource need that if procured would limit customer outages to a typical reliability target of outages not exceeding a 1 day in 10 year frequency. PG&E recommends that Energy Division work with California Energy Commission (CEC) Staff to develop and propose such a range in subsequent Track 2 workshops.

4. Load Forecast

For unmanaged load forecast, PG&E recommends that the range of load uncertainty be expanded to include not just the expected values of the CED scenarios, but the complete distribution of load projections of the three CED scenarios produced by economic and demographic drivers.

1/ Assumptions Proposal, p. ix.

2/ *Id.*, p x.

With respect to weather impacts, PG&E recommends that weather sensitivity be applied as part of CAISO's stochastic modeling of loads and resources, where weather impacts can be applied to:

- Both peak and energy load, including different load profiles, rather than only for peak demand, as suggested by the Assumptions Proposal;
- Different load scenarios resulting from economic and demographic drivers, rather than only for a medium load forecast, as suggested by the Assumptions Proposal. It also appears there is little variation in the economic and demographic assumptions provided in the Revised CED scenarios. Even an economic variable, such as real household income, shows little variation across the scenarios, with growth rates of 3.3%, 3.1%, and 2.6% in the high, medium, and low scenarios, respectively.

Different weather can also impact the reliability value (*i.e.*, net qualifying capacity (NQC)) of renewable resources. When using weather sensitivities, consistent weather assumptions should be used to represent load and renewable generation. Weather sensitivities will also impact the CAISO's operating flexibility requirements for regulation and load following capacity.

a. Is the most recent revised demand forecast appropriate to use in the absence of a recent adopted demand forecast?

In the absence of an adopted forecast, using the current CED revised forecast would be a reasonable starting point for analysis as a general statement. However, more important than using the recently released revised forecast is having a range of load forecasts that capture the uncertainty of demand for the planning horizon. This is a more important planning issue than the vintage of the forecast.

5. Incremental Energy Efficiency

The Assumptions Proposal proposes to use three incremental energy efficiency (IEE) scenarios: (1) a Low Scenario equal to 5% lower than Mid-CEC IEE forecast; (2) a Medium Scenario equal to the CEC Mid IEE forecast; and (3) a High Scenario 15% higher than Mid-CEC IEE forecast. This approach does not address how demographic and economic load forecasts and demand-side resource forecasts will be used to develop scenarios; therefore, it is difficult to tell the resulting range of managed load that will be ultimately used in Track 2's analysis, and to comment on the proposed IEE ranges.

PG&E offers the following initial comments on the proposed IEE forecasts:

- ED provides no support for the proposed IEE projections. PG&E recommends that the CEC and ED provide the necessary evidence explaining how the proposed range meets the Public Utilities Code § 454.5 criteria. IEE projections to be used in Track 2 should be "cost effective, reliable and feasible" as required by Section 454.5. IEE used in the plan should not include aspirational goals which are not supported as being cost effective, reliable and feasible.

- The Assumptions Proposal does not contain any sort of numerical information as to the IEE savings over the planning horizon; therefore, it is difficult to react or comment on the proposed IEE range.

- ED should also propose how the high, medium and low IEE projections should be combined with the unmanaged load forecasts resulting from economic and demographic drivers. Presumably, IEE programs will also be affected by these drivers, so their impacts will need to be somewhat correlated to the unmanaged load projections.

6. Non Event-Based Demand Response

Most Demand Response (DR) is accounted for on the supply-side via Event-Based programs. ED proposes to use the same non-event DR embedded in the CEC's load forecasts for all scenarios. PG&E offers the following comments:

- PG&E is not clear what is the magnitude of the non-event DR in the various CEC load forecasts, and whether the load impacts change from scenario to scenario based on economic and demographic drivers.

- As with IEE projections, DR projections to be used in Track 2 should be "cost effective, reliable and feasible" as required by Section 454.5.

7. Incremental small photovolatics (demand-side)

The Assumptions Proposal proposes to use three forecasts of incremental behind the meter solar photovoltaic (PV): (1) low with no increase from the PV already embedded in the CED forecast; (2) mid with 300 MW incremental PV; and (3) high with 700 MW incremental PV, compared to the embedded PV in the CED forecast. PG&E requests that ED provide sufficient information to evaluate its proposal:

- PG&E is not clear whether the MW of PV in the ED's Assumption Proposal are statewide or CAISO levels. If statewide, the amounts should be reduced to correspond to the CAISO's area.

- PG&E is not clear whether the MWs of PV in the Assumption Proposal are installed MWs or peak impacts.

- PG&E is not clear whether the PV amounts will change from scenario to scenario based on economic and demographic drivers.

- PG&E notes that the CED forecast has its highest incremental PV in the "low" scenario and its lowest incremental PV in the "high" scenario. This is the opposite of the trend in the Assumption Proposal. The ED should provide information reconciling this difference.

- PG&E was unable to reproduce the 2,200 MW of incremental PV identified as "reflective of no net change from" the CED. The ED should provide sufficient information to reconcile its forecast to the source material.

PG&E also believes that the CEC and ED should provide information supporting the proposed PV projections as being "cost effective, reliable and feasible" as required by Section 454.5 for use in Track 2.

8. Incremental combined heat and power (demand-side)

The Assumptions Proposal proposes to use three forecasts of incremental behind the meter combined heat and power (CHP): (1) low with no increase from the level already embedded in the CED forecast; (2) mid with 1,672 MW incremental CHP; and (3) high with 1,968 MW incremental CHP, compared to the embedded CHP in the CED forecast. All incremental amounts assume a 75% capacity factor. PG&E requests that ED provide sufficient information to evaluate its proposal:

- PG&E is not clear whether the MW of CHP in the ED's Assumption Proposal are statewide or CAISO levels. If statewide, the amounts should be reduced to correspond to CAISO's area.

- PG&E is not clear whether the MW of CHP in the Assumption Proposal are installed MWs or peak impacts.

- PG&E is not clear whether the CHP amounts will change from scenario to scenario based on economic and demographic drivers.

- PG&E notes that the CED provides a forecast of "non-PV" which includes demand-side CHP. If CED is the source for the "Low" scenario, the ED should explain what portion of the CED forecast was assumed to be CHP.

- PG&E was unable to reconcile the mid and high forecast (1672 MW and 1968 MW) included in the Assumptions Proposal with the ICF "Base Case" and ICF "Mid Case" scenarios. The ED should provide sufficient documentation to reconcile its forecast MWs with the ICF source material.[3/]

PG&E believes the ICF study the ED proposes to use as a basis of CHP projections overstates both the technical potential and market adoption rate for CHP. On March 12, 2012 PG&E submitted comments to the CEC to this effect.[4/]

ICF bases its technical potential analysis on usage patterns and business type, but ignores physical barriers such as space limitations or age of buildings. The study accounts for economic drivers (price, rates and payback criteria) but ignores any non-economic factors, such as availability of air permits or zoning restrictions.

3/ The ICF analysis is discussed on page xiv of the Assumptions Proposal.

4/ http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/comments/Pacific_Gas_and_Electric_Company_Comments_2012-03-12_TN-64134.pdf

PG&E suggests that, before employing the ICF values for LTPP purposes, ED compare the difference between the rate of CHP adoption predicted by ICF in prior reports and actual CHP adoption rates over recent years. Perhaps such an analysis could inform a more moderate LTPP mid case for incremental CHP, both on the demand and supply side.

PG&E also believes that the CEC and ED should provide information supporting the proposed CHP projections as being "cost effective, reliable and feasible" as required by Section § 454.5 for use in Track 2.

a. What capacity factor is appropriate to use?

PG&E has no comment at this time regarding the 75% capacity factor. In general, PG&E believes that capacity factor assumptions about demand-side CHP should be based on Self Generation Incentive Program (SGIP) evaluations. However, PG&E recognizes that the efficiency standards currently in the SGIP should result in higher performance efficiencies in the future, so past SGIP studies may underestimate capacity factor.

9. Traditionally, local area and other assessments utilizing a higher peak forecast have been based on a middle forecast for energy and peak. If this should be changed, please explain why.

PG&E has no additional comments on this assumption.

10. Are there any significant demand-side assumptions that have been missed? If so please identify, provide sources, and the MW and GWh magnitude and likelihood.

The Assumptions Proposal does not contain any sort of numerical information as to the IEE savings over the planning horizon and IEE inputs and assumptions have yet to be released by the CEC; therefore, it is difficult to react or comment on assumptions that might be excluded from the standardized planning assumptions proposal at this time.

PG&E is also concerned that the use of the "expected values" of the high medium and low energy demand and incremental energy efficiency projects significantly understates the real uncertainty around these projections over the forecast horizon. We know from earlier studies (for example the planning reserve margin studies and prior LTPP proceedings) that the standard error of the forecasts for energy demand is approximately 2% on the year-ahead forecast (on a temperature normalized basis). Assuming that energy demand follows a "random walk" process based on underlying economic growth, it is possible to reasonably expand forecast error by using the square root of time risk expansion formula, doing so yields standard forecast error of ~6% on the 10-year time horizon forecast (2% standard error * sqrt of 10 years = 6.3%). The forecast error on the incremental uncommitted energy efficiency is likely as high or higher than energy demand. PG&E recommends that the CEC/CPUC/CAISO consider moving from the expected values of the high, medium and low demand and incremental energy efficiency projections to scenarios encompassing at least one standard deviation of forecast error. Doing so will result in more prudent resource planning and begin to move resource planning into a more probabilistic modeling structure going forward.

PG&E is also concerned that the distributed generation scenarios are missing information about the peak capacity assumption for both PV and CHP and the capacity factor assumption for PV. PG&E is also concerned about the fact the scenarios ignore other technology types, such as wind and fuel cells. The latter especially is expanding significantly at this time.

11. Other comments on demand-side assumptions.

PG&E has no additional comments on demand-side assumptions.

Supply-side Assumptions

12. Should all resources be accounted for by their NQC or a forecast of NQC?

All resources should be accounted for by their NQC. However, as PG&E explained in its comments, the NQC of renewable resources should be calculated using the ELCC approach. Because the ELCC-based NQC of renewables is expected to decrease with their level of penetration, it is likely that continuing to use current NQC values would lead to a false sense of security from over-estimated planning reserve margins.

13. What year and data source should be used for variable resources' production profiles?

Different weather years are needed to ensure that the system is able to meet the desired reliability target, say a not to exceed 1 day in 10 years outage frequency, considering different weather conditions. PG&E recommends that at least three weather years be used to represent weather uncertainty on load and renewable generation, rather than a single weather year. Hourly and intra-hourly profiles for load and renewable generation are needed to represent load and renewable generation under different weather years. If actual renewable generation profiles for different weather years are not available for the desired locations, synthetic profiles need to be developed using actual weather.

14. How should transmission capacity be considered?

The Assumptions Proposal suggests that to be deliverable, a project must fit on existing or Commission-approved transmission. PG&E believes that this criterion might be too stringent since it leaves out several highly likely upgrades. For example, there are upgrades identified by the CAISO as needed in the 2011-2012 TPP results, but several of these upgrades are not yet approved by the Commission. PG&E also believes that the deliverability upgrades required for projects with approved contracts should be considered "sunk" decisions even if those upgrades have not yet been approved by the Commission. To highlight this point, PG&E points to the fact that renewable resources in Clusters 3 and 4 will depend on upgrades to be identified in their Phase 2 studies (to be completed by October 2012). By using the ED's proposed criterion that resources "fit on existing or approved transmission," no renewable resources from these clusters will be considered deliverable in the 2012 LTPP.

15. Should all "known" and "planned" (non-RPS) resources be used in all supply-side scenarios?

See comments below.

a. **Are the definitions of "known" and "planned" clear?**

The Assumptions Proposal states that non-Renewable Portfolio Standard (RPS) Resource Additions are treated in the analysis as existing generation. These additions are categorized as Known Additions if they have a contract in place, have been permitted, and have construction under way, and as Planned Additions if they have a contract, but have not yet begun construction.

PG&E in general, agrees with the ED proposal on including non-RPS additions as existing generation. PG&E does suggest that the range of assumptions be expanded. It is possible that not all planned resources that the Commission has already approved or are being considered in on-going applications will be in operation when planned. To achieve this expanded range, PG&E suggests two assumptions for this section: one that includes all non-RPS additions (both Known and Planned), and the other that includes 500-1,000 MW less than the full amount in order to consider the delay or failure to construct some of the identified Planned Additions.

16. Deliverability

a. **Are any changes to the definition of future resources considered deliverable warranted?**

The Assumptions Proposal currently states that resources will only be assumed deliverable if they: (1) fit on existing or Commission-approved transmission; or (2) are baseload or flexible resources. PG&E believes that the expectations regarding deliverability status and RA value in existing contracts should be honored for planning purposes. Consistent with Commission-approved protocols, PG&E in its RPS contracting process evaluates the tradeoffs between the cost of deliverability network upgrades, and the Resource Adequacy (RA) value they enable. In cases where the costs outweigh the value, generators are encouraged to interconnect as energy only. Conversely, when the RA benefits are greater than the deliverability network upgrade costs, generators are encouraged to interconnect as fully deliverable.

All Commission-approved contracts have been determined to provide "least-cost best-fit" value based on the deliverability status they indicate in their Request for Offer (RFO) bid and negotiate in their Power Purchase Agreement (PPA). Therefore, even if the network upgrades required for a given generator to become deliverable have not yet been approved, such generators with approved contracts based on Full Capacity Deliverability Status should be considered deliverable for planning purposes. It is more realistic to assume that the required deliverability network upgrades will be built than to assume they will not be built.

With respect to the resources chosen to fill the renewable net short, the ED currently proposes not to include capacity as part of their net market value. PG&E notes that if this assumption were to be used, then the Commission will be planning a system that underestimates future renewable resources' contribution to generic capacity needs. If a substantial number of projects that are planned as energy only end up obtaining full deliverability in reality, there will be an undercounting of the potential NQC megawatt value from these resources.

The Commission should also clarify that this assumption, if adopted, is for planning purposes only and should not be construed as a predetermination that network upgrade costs will exceed RA value for projects participating in RPS RFOs. PG&E believes that the tradeoffs between network upgrade costs and the RA value they enable should be studied as they have been in recent RPS RFOs. By predetermining that the network upgrade costs outweigh the benefits, future resources would request interconnection as energy-only, and the studies required to determine their deliverability network upgrade costs would never be done. Whether or not the benefits of the upgrades outweigh the costs can only be established once the CAISO completes a deliverability study.

b. How should information from other sources, such as distribution resource deliverability be incorporated?

To the extent that network upgrades have been identified as needed through the CAISO's Transmission Planning Process (TPP) or Phase 2 Interconnection Studies, the deliverability enabled by those upgrades should be considered. Whether the deliverability capacity ultimately gets assigned to centralized generators or distributed generators is not important for planning purposes: it is only important how much deliverability is enabled overall. In other words, a subset of the modeled RPS portfolio (not associated with specific projects) should be considered deliverable based on the overall available deliverability capacity. It is reasonable to assume that the majority of available deliverability capacity will be assigned to generators interconnecting at transmission level, and that the remainder will be "filled in" by distributed generators through the new processes described in the CAISO's final proposal for RA Deliverability for Distributed Generation that was recently approved by the CAISO Board on May 16, 2012.

17. What additional information is needed for resource locations?

See comments below in Section 20.

18. Event-Based Demand Response

PG&E does not currently have a Peak Time Rebate (PTR) program, nor has PG&E been ordered to implement one. Whether this program will ever be implemented is still uncertain and is currently the subject of litigation in Application (A.) 10-02-028. As such, the LTPP should recognize the risk associated with assuming any savings associated with this program. The use of high/mid/low scenarios presents the perfect opportunity to incorporate this uncertainty. PG&E proposes that the following scenarios be used.

- High – The high scenario would assume that the PTR program is fully implemented in 2014, as is currently being considered in A.10-02-028. The high case would further assume that the MW that the PTR program would contribute are consistent with the assumptions adopted in the SmartMeter Upgrade (SMU) Decision (D.09-03-026), with appropriate adjustments to the implementation timeline. These values are consistent with the assumptions of the prior LTPP.

- Mid – The mid scenario would assume that the PTR program is fully implemented in 2014 as well. However, the mid case would use more recent estimates of the MW potential of PTR. At the time of the SMU Decision, there was very limited information on the potential of a default PTR program. There is new data that clearly suggests that a default residential pricing program such as PTR will not be as effective as once believed and that the MW estimates adopted in SMU case, while based upon the best information available at the time, were simply too high. The new data on PTR performance includes information gathered from SDG&E's PTR pilot in 2011 that showed the MW to be a fraction of what was previously estimated. Other default PTR pilots have shown similar results. All of this has been thoroughly documented in A.10-02-028. At the request of Administrative Law Judge Roscow, PG&E produced an updated estimate of the potential of PTR, which was submitted as Exhibit PGE-18 in A.10-02-028. This revised estimate is the based upon the most current information and is more representative of a mid-scenario, assuming of course that the program is implemented.

- Low – the PG&E's primary proposal in A.10-02-028 is to vacate the proceeding and not implement PTR. The low scenario should reflect this potential outcome and include no PTR MW.

19. Incremental combined heat and power (supply-side)

PG&E believes the ICF study the ED proposes to use as a basis of CHP projections overstates both the technical potential and market adoption rate for CHP. On March 12, 2012 PG&E submitted comments to the Energy Commission to this effect.[5/]

ICF bases its technical potential analysis on usage patterns and business type, but ignores physical barriers such as space limitations or age of buildings. The study accounts for economic drivers (price, rates and payback criteria) but ignores any non-economic factors, such as availability of air permits or zoning restrictions.

PG&E suggests that, before employing the ICF values for LTPP purposes, Energy Division compare the difference between the rate of CHP adoption predicted by ICF in prior reports and actual CHP adoption rates over recent years. Perhaps such an analysis could inform a more moderate LTPP mid-case for incremental CHP, both on the demand and supply side.

a. What capacity factor is appropriate to use?

PG&E does not have a comment on this assumption.

20. 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.

5/ http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/comments/Pacific_Gas_and_Electric_Company_Comments_2012-03-12_TN-64134.pdf

PG&E seeks clarification as to the meaning of "33% infrastructure target," and is unclear on which section of the Energy Division's Straw Proposal describes how such a target would be established via the LTPP.

b. Establishing the RPS supply (i.e. the "highly likely resources") in the RPS proceeding.

In the Energy Division's Straw Proposal on pages xviii and xix, there is considerable discussion about the 2012 Renewable Procurement Standard Plans (RPS Plans) filed by the utilities and other Commission-jurisdictional load serving entities (LSEs) on May 23rd and their potential use in the LTPP and the CAISO's Transmission Planning Process (TPP). While PG&E agrees that it might make sense to use the aggregated information from the RPS Plans in the LTPP, PG&E emphasizes that any project-specific assessments, and the underlying counterparty data that informs them, must remain confidential.

PG&E believes that the workshops proposed by the Energy Division in its Straw Proposal will provide the opportunity to fully address any confidentiality concerns and, if necessary, to flesh out alternative recommendations, while ensuring that planning assumptions are representative of actual expectations. For example, a possible alternative is to use the most recent version of the RPS Calculator (currently version 2.1 from May 21, 2012), run with the most up-to-date information available.

c. Base Portfolio

The Assumptions Proposal proposes to use 2012 RPS Plans to determine renewable supply and to create a new set of portfolios to fill the residual RNS. The proposed portfolios include a Base Portfolio, a High DG Portfolio, and an Environmental Sensitivity Portfolio. The Base Portfolio will create a supply stack from the resources with executed PPAs and will rank those resources by average net market value for technology types (excluding capacity value). Should this process fail to achieve viable portfolios in time for the 2012 LTPP, ED proposes to use two of the existing portfolios proposed for the 2012-2013 TPP.

As discussed above, PG&E believes that maintaining the confidentiality of any project-specific assessments is crucial for the viability of this proposal. Furthermore, if the 2012 RPS Plans are used as the basis for renewable supply, PG&E believes that the RNS should be filled using some assumed technology mix of generic volumes rather than projects with PPAs that were not included in the RPS Plan, as the ED seems to propose. Based on PG&E's methodology for calculating expected renewable supply in its RPS Plan, the PPAs that are currently expected to deliver energy are included in the calculation and those that are not currently expected to deliver are excluded. It therefore makes more sense to use generic volumes to fill the RNS rather than use projects that are not currently expected to deliver.

d. High DG Portfolio

The High DG case will rank MWs based on the least net cost established in E3's preliminary assessment on Technical Potential for Local Distributed PV.[6/] PG&E believes that

6/ http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-

the way the supply stack is defined is unclear, and needs to explicitly define an interconnection constraint. Without a more explicit definition, the available capacity on certain circuits might be overstated. PG&E suggests that using the 15% of peak load constraint instead of the "no backflow" constraint is more appropriate.

e. Sensitivities

ED proposes using an environmental sensitivity portfolio that will be determined by selecting projects in preferred locations and ranking by cost, based on the environmental scores developed for the 33% RPS Calculator used in the 2012-2013 TPP. It is important to note that the efforts by the Desert Renewable Energy Conservation Plan (DRECP) are ongoing and the development focused area boundaries (e.g., RESA, DRECP, etc.) which are used to define a "preferred location," are still in development. Therefore, to the extent the environmental scoring methodology from the 2012-2013 TPP is used in this proceeding, the scoring methodology may need to be updated as the locational information is further defined.

f. Long-term Target

PG&E recommends that the planning horizon be limited to ten years only. Regarding ED's proposal to study a 40% RPS as part of the 20-Year forward analysis, PG&E believes that assuming policy goals beyond a 33% RPS may be premature.

While PG&E has been supportive of achieving higher levels of renewable energy, PG&E does not support policies calling for higher levels of renewables, especially given the existing operational challenges to successfully achieve a 33% RPS. In particular, we have much to learn about how to operate the electric grid with significantly more intermittent renewables connected to both the transmission and distribution grids. Therefore, PG&E supports an overarching goal of reducing greenhouse gas emissions (*e.g.*, energy efficiency, demand response, combined heat and power, etc.) and providing flexible policy choices that allows the selection of the most cost-effective alternatives.

21. Retirements

The Assumptions Proposal proposes to provide a range of values for resource retirements largely based on resource type and plant vintage to capture potential range of "retirements" for use in 2012 LTPP. PG&E suggests that for once-through cooling (OTC) retirements, the assumption that "the earlier of [State Water Resources Control Board] deadline or announced retirement date; Track II treated as retirement" be used for both the Mid and High scenarios. There is substantial uncertainty in the potential of generating units to continue operation under a Track 2 process and therefore this should be confined to a single low scenario.

For nuclear units, PG&E believes that potential nuclear retirement may only require assessment via a sensitivity, and should not be the focus of a full scenario. For purposes of the 2012 LTPP, if the goal is to determine system reliability, a nuclear sensitivity works. If goal were to try to find how to best replace the nuclear units, then a separate set of scenarios would be needed. PG&E believes this is not a decision that has to be made in the 2012 LTPP.

099E48B41160/0/LDPVPotentialReportMarch2012.pdf

For hydro, renewable, and other resources, the Assumptions Proposal suggests fixed timeframes for unit longevity for the mid and high cases. ED provides no support for the unit lifetimes it proposes. Rather than using broad rules based on hypothetical unit longevity, PG&E recommends that for these categories of resources, a single scenario should be developed that defines a reasonable block of MWs assumed to unavailable. This single scenario would be an alternative to high cases, and the current low case should be used for both low and mid.

a. How many retirement assumption combinations are needed? If more than one, please list the top two most important retirement assumptions to consider sensitivities on.

PG&E has no additional comments at this point.

22. Are there any significant supply-side assumptions that have been missed? If so please identify, provide sources, and the MW and GWh (if appropriate) magnitude and likelihood.

The Assumptions Proposal assumes that imports equal the maximum import capability into the CAISO, as used in the Resource Adequacy program, including expansions identified in the TPP, and that resources outside of CAISO be assumed from the publicly available Transmission Expansion Policy Planning Committee (TEPPC) data for the 2022 Common Case generation table.[7/]

In the 2010 LTPP, the Commission's standard planning assumptions used approximately 17,000 MW NQC for imports in 2020. The CAISO revised this assumption to about 13,000 MW for Summer-peak, depending on the case being analyzed, by defining simultaneous import limits into California based on: planned thermal additions, once-though cooling retirements, renewable resources additions, and neighboring transmission path flows into the Southern California region. As part of the 2012 LTPP, PG&E recommends that the CAISO provide a similar review, and that an update to the Assumption Proposal for imports should be made before the Commission adopts an import assumption for Track 2. Absent such an update, PG&E suggests that ED use the CAISO's revised assumption of 13,000 MW for Summer-peak be used in the 2012 LTPP.

PG&E also recommends that the Energy Division solicit the CAISO's careful review of resource additions outside of the CAISO to ensure that resources assumed in the TEPPC Common Case are feasible and likely. The flexibility of imports/exports to change hourly or sub-hourly is a major driver of integration need, and should be considered carefully. To assume that tie-lines can be filled overestimates the reliability capability they may provide.

23. What is a reasonable number of overall scenarios for <u>supply-side</u> assumptions? What is the purpose behind having that number of scenarios?

PG&E recommends that the assumptions be combined to create as much as four scenarios that bracket the uncertainty range over the planning horizon.

24. Other comments on supply-side assumptions.

7/ Assumption Proposal, p. xv.

PG&E has no additional comments at this point.

Allocation Methodologies

With respect to the allocation of EE and DR impacts presented in Appendices to the Assumptions Proposal, PG&E appreciates the CEC's and ED's efforts. PG&E however, does not see the need to allocate EE and DR impacts for Track 2 analysis given that the purpose of the Track 2 analysis is to determine CAISO system-wide need for resources, and given that the models that are going to be used in the analysis do not represent loads and resource by nodes or constraint areas. Most of the analysis will be conducted either at the CAISO level or at most at the IOU service area. The only exception is that the PG&E service area is broken into two areas (Bay and Valley).

PG&E also has concerns over the allocation of incremental EE and DR load impacts given the somewhat arbitrary methodology used to allocate load impacts, and the uncertainty that this creates on the resources that are likely to be available in a particular node or congestion area.

PG&E also notes that the use of incremental uncommitted EE or DR load impacts is not consistent with the CAISO's planning criteria for transmission planning studies.

25. Energy Efficiency

See response under Allocation Methodologies heading.

26. Demand Response

See response under Allocation Methodologies heading.

27. Other methodologies for assigning resources to busbars.

PG&E has no additional comments at this point.

Other

28. What is a reasonable number of total scenarios + sensitivities to consider?

PG&E recommends that the assumptions be combined to create four scenarios that bracket the uncertainty range over the planning horizon. Those scenarios should combine demand and supply-side assumptions, as well as renewable integration or system variability assumptions to be considered at a future LTPP workshop.

a. Briefly describe the scenarios and sensitivities that are most important to consider. Please refer to the assumptions discussed above to describe and explain this recommendation.

PG&E recommends this question be asked after the additional assumptions, models and methodologies associated with the renewable integration studies are considered.

29. Any other comments.

The Assumptions Proposal indicates that the Market Price Referent (MPR) Model should be used for calculating greenhouse gas (GHG) prices. The model forecasts the implied price of carbon between 2016 and 2030 using the Air Resources Board's method for increasing the GHG allowance floor and the levels in the Allowance Price Containment Reserve, namely Inflation + 5%. PG&E believes that this methodology makes sense through 2020, *i.e.* the timeframe for AB32. For years beyond 2020, PG&E expects that there will either be a different cap-and-trade program or a different method for pricing GHG emissions. Therefore, starting in 2021, PG&E proposes that the GHG price forecast should only increase by the rate of Inflation and not Inflation +5%.