**PACIFIC GAS AND ELECTRIC COMPANY'S
COMMENTS ON THE CALIFORNIA ENERGY COMMISSION'S
2009 INTEGRATED ENERGY POLICY REPORT
DRAFT COMMITTEE REPORT
Docket No. 09-IEP-1A**

I. INTRODUCTION AND SUMMARY

A. PG&E Shares the California Energy Commission's Concerns and Overall Objectives

The broad landscape covered by the California Energy Commission's ("CEC") *2009 Integrated Energy Policy Report, Draft Committee Report* ("*Draft IEPR*") is impressive, and PG&E shares with the CEC a serious commitment to address the many energy issues before us not only toward the important goal of decreasing greenhouse gases and developing a more robust energy delivery sector, but also toward doing so in a smart, efficient and cost effective way that reflects the serious economic situation the state faces.

PG&E appreciates the effort the CEC made in developing the *Draft IEPR* and in describing the challenges California faces, and potential directions it may choose. California needs creative and imaginative solutions to achieve its energy and environmental objectives. While PG&E supports many of the conclusions and recommendations in the *Draft IEPR*, there are some parts of the report that require modification. PG&E's main comments on the *Draft IEPR* outline several key procurement issues that are presented first, and then a topic by topic discussion follows. Specific changes that PG&E proposes to the *Draft IEPR* are included in Appendix A to these comments.

B. Summary of Major Comments on the *Draft IEPR*

Procurement is Not Broken

As the CEC knows, the method by which the Investor-Owned Utilities (IOUs) secure generation for their customers has undergone significant changes over the past few decades. In the 1990's, California had a system that was overly paralyzed by analysis in the "Biennial Resource Planning Update" days. In the late 1990's, California adopted a system with too much reliance on the open market that resulted in the 2000-2001 energy crisis. Since that time, the CPUC has adopted a hybrid market approach, where the amount of additional need is determined by the CPUC and resources to meet that need are procured through CPUC approved processes. While the hybrid market system is not precisely defined, the CPUC has continued to improve it. PG&E is aware that the Committee has expressed concerns about the utility procuring a mix of its own resources and those of private generators, and we note that this concern seems lessened from the 2007 IEPR to the *Draft IEPR*. PG&E hopes that is a reflection of a growing sense of what the hybrid market under the CPUC supervised procurement structure can bring – balanced, well-priced, well-reviewed projects that can move forward without extensive regulatory delay, to bring needed new generation to our customers.

Currently, about 70% of energy for PG&E's bundled electric customers comes from contracts and spot market purchases with the remaining 30% drawing from utility-owned resources. These resources include our extensive hydroelectric portfolio and Diablo Canyon; both resources have been in the portfolio for decades and have no GHG emissions. PG&E's procurement of new resources since 2003 includes annual competitive solicitations for new renewables that amount to roughly 70 contracts for almost 6000 MW of capacity. In addition to renewable generation, PG&E has conducted two Requests for Offers (RFOs) for new, largely gas-fired, operationally flexible resources. In our 2004 LTRFO, PG&E was tasked with procuring 2,200 MWs. The RFO resulted in five Power Purchase Agreements (PPA) with third-party generators for about 1,500 MW, one Purchase Sale Agreement contract (a "Build, Own, Transfer" model) for the Colusa facility, a 660 MW combined-cycle facility, and one Engineering, Procurement and Construct ("EPC") contract for the 163 MW Humboldt facility. In addition, the nominal 530 MW Gateway combined-cycle facility became a utility-owned resource through the utility's completion of a partially built plant that arose as part of a settlement of claims arising from the energy crisis. Finally, PG&E's 2008 LTRFO resulted in four contracts -- 2 PPAs for about 900 MWs and one PSA contract for roughly 600 MW, as well as a contract with an existing Qualifying Facility (*i.e.*, combined heat and power) facility.

Renewable Progress; Slow but Steady

A substantial theme in the *Draft IEPR* is that the state has many barriers to address as it brings in a higher level of renewables to meet both its 20% target and to address the recent Governor's Executive Orders for 33% renewables. While PG&E has executed contracts for well over the 20% RPS requirement and continues to execute additional contracts for renewable energy, PG&E's ability to meet the targets depends upon timely delivery of this renewable energy. Tight credit markets and substantially reduced capital availability, however, are continuing to present a significant challenge for a number of developers of the proposed renewables facilities who have signed contracts with PG&E. In addition, the timely development of these and other renewable energy generation facilities is subject to many uncertainties and risks, including permitting and siting, technology, fuel supply, the construction of sufficient transmission capacity, and the integration of higher intermittent renewable generation. At both the federal and state levels, programs and measures are being implemented to provide alternatives for financing renewable projects, streamline project permitting activities, and expedite transmission access. PG&E believes that these programs and measures, if successfully implemented, should promote a more timely completion and commercial operation of renewable facilities on which PG&E is relying to meet the 20% mandate. It is not for lack of effort that PG&E has not yet achieved the targets. PG&E is disappointed to see the recommendation that the CPUC consider penalties for non-compliance for utilities that do not meet the RPS targets. Each of the State's investor-owned utilities has demonstrated a commitment to achieving the 20% RPS target.

Here are some of our key efforts to help address the various barriers:

- Procurement of Renewables:
  Because of the challenges facing renewable developers, PG&E is continuing to evaluate its current contracts and is working with counterparties on ways to remain in contract, including possible partnerships and renegotiations of contracts to address cost increases. Additionally, PG&E continues to hold annual renewables RFOs and conduct bilateral negotiations.

  In addition to procuring from independent power producers, PG&E has also proposed an innovative 500 MW Solar PV program, wherein 250 MW would be utility-owned and another 250 MW available to third party developers. The CPUC is expected to act on this proposal in early 2010.

  Lastly, PG&E continues to explore new, long-term supply opportunities, including accessing WaveConnect wave power, renewables in British Columbia, and general cleantech start-up support.

- Integration:
  PG&E developed a model with the Brattle Group (The Renewable Integration Calculator or Model) to understand and quantify the operational impacts of higher levels of intermittent resources, the drivers of those impacts, and the resulting integration needs and costs of different renewable portfolios. PG&E is working with the CAISO, as part of its 33% RPS integration project, to calibrate the inputs to the model. This tool can assist in the resource planning process.

- Feed-in Tariffs:
  PG&E has been supportive of the CPUC's activities in this area to create a streamlined contracting process for small renewable generators. While this process does not implement the CEC's size or pricing recommendations, the Renewables Auction Mechanism (RAM), once implemented, will offer "head-to-head" competition across renewable generators able to offer comparable projects and provide the means for small renewable generators to participate in the broader RPS program and to bid the price they need to sustainably generate renewable energy.

- Transmission:
  PG&E and other California IOUs have been working closely with state and federal agencies and representatives of leading environmental groups on the Renewable Energy Transmission Initiative (RETI), which is expected to identify a prioritized listing of Competitive Renewable Energy Zones (CREZ) and conceptual transmission plans to access those zones. Improving the permitting process for transmission lines to reach the CREZs is a critical path item to achieving the 33% RPS goal established by Governor Schwarzenegger's recent Executive Order.

- Permit Streamlining:
  PG&E has participated in the Renewable Energy Action Team's public comment process, and proposed several approaches to improving the permitting process. Specifically, PG&E has recommended that state and federal agencies:
    - Coordinate roles through assignment of topic leads in order to minimize duplication and thereby reduce agency workload.
    - Develop clear and consistent information requirements and communicate them with one voice.
    - Develop clear schedules that apply not only to the applicant, but to the agency actions as well.
    - Notice public meetings in such a way as to accomplish compliance with both state and federal laws.
    - Provide guidance on mitigation and other policy requirements to help developers understand the true costs before bidding into an RFO.
    - Provide clear guidance concerning under what circumstances and for what types of impacts a statement of overriding consideration would be appropriate.

Transmission – New Planning Mechanisms:

Many have called for more comprehensive transmission planning in order to access remote renewables, to assure that only needed capacity is built, and to reserve, if possible, some corridors for future expansion. PG&E believes that the Renewable Energy Transmission Initiative (RETI) has provided an important foundation for this work, and that RETI will continue to be an important forum for providing stakeholder input into the transmission planning process. PG&E also recognizes the importance of the technical studies that are being undertaken by the California Transmission Planning Group (CTPG). PG&E believes that the results of these studies will provide some of the necessary technical information to further refine or potentially modify the recommendations made by RETI on priority transmission projects. Ultimately, it is the responsibility of transmission owners to bring forth projects that meet electric transmission needs, whether those be economic, reliability, or access to geographically constrained renewable resources. PG&E appreciates the opportunity to both participate in and leverage information from the RETI and CTPG processes in its own evaluation of transmission projects. PG&E encourages the CEC to rely on information provided by these forums rather than creating a separate plan in the Strategic Transmission Investment Plan (STIP) process.

Efficient Distributed Generation Must Reduce GHG:

Several sections of the *Draft IEPR* highlight the emission-reducing, system-strengthening values that distributed generation ("DG") can bring to our customers. We believe in and support clean distributed generation and efficient, GHG-reducing combined heat and power ("CHP") facilities, and note that in certain times and configurations these facilities can support the distribution and transmission system. But as many in the CEC staff know, not all DG is clean, not all CHP is GHG-reducing, and not all installations will automatically benefit transmission and distribution. We would like the report to better reflect the mixed record of resources in this area, toward the goal we all share, that only the societally desirable forms of these alternative resources be encouraged.

II. SECTION BY SECTION DISCUSSIONS

A. Electricity Sector

1. Load Forecast

PG&E commends the hard work done to date on how to quantify the "incremental uncommitted" impacts of energy efficiency programs for use in the Long-Term Procurement Plan ("LTPP") at the CPUC. We have concerns regarding the analysis of such impacts, and, ultimately, whether the "managed forecast" that results from that analysis is reasonable. PG&E continues to prefer its own forecasts, and pledges to continue to work with the CEC to understand why its forecasts tend to trend lower than those of the IOUs.

2. Energy Efficiency (EE)

i. EE Projections Within the Load Forecast

The EE section of the draft is only partially complete – the material on "committed" EE programs may have technical issues, and the section on "uncommitted" programs appears incomplete. The two types of EE are not integrated, leaving an incomplete foundation for qualitative or quantitative recommendations. PG&E has the following observations and suggestions for inclusion into the body of the *Draft IEPR*:

- Page 50-68:

  The two sections on EE, both the forecast and incremental EE, mix topics. For example, the paragraph on lighting standards is in the former, but should be in the latter. The very title of the first section, "Effects of Efficiency Programs on the Forecast" sets the stage for a narrow, incomplete view. PG&E feels that the first EE section ought to be an overview of "committed" EE programs and what's included in the definition, along with a discussion of "uncommitted" programs and how those are defined.

  The role of standards should have its own section, and delineate between committed (standards in place) programs and those expected to be developed. The treatment of utility programs (IOU and POU) should also be balanced, with treatment of both committed and uncommitted. The uncertainties around uncommitted programs should be balanced by statements that for 30 years, California has continued to commit significant resources to EE – historically the uncommitted turns into the committed.

PG&E feels that there is insufficient treatment given to industrial, and to a lesser extent agricultural, EE savings. These sectors, as well as new construction, represent the longest lasting savings. A fair presentation would feature each of these components in a graph, and then an overall graph combining all of them. The visual presentation of the “committed” EE programs on page 51 should be deleted, or scenarios of “incremental” should be added. This would provide the reader with a full picture of EE’s importance.

- Page 177-178 on “Uncommitted Energy Efficiency Goals”:
  PG&E recommends that this material be combined into the material presented at page 50 as it seems structurally inconsistent to place this at the back of the report. A helpful addition to this section would be scenarios for savings from Federal standards, CEC standards, committed IOU and POU programs, and scenarios on uncommitted programs.

ii Zero Net Energy

The support for zero-net energy is laudable, but the CEC should not prematurely commit to exclusively on-building or on-site solutions for the following reasons:

- Both EE and renewable technologies are still rapidly advancing.
- “In-vicinity” renewables may prove to be more economical and provide a functionally equivalent solution.
- The connection to land use should be made clear; it may be far less costly and produce much higher quality of living if the problem is approached from a site perspective, not from requiring every building to meet certain overly expensive requirements.

On page 4 in the third paragraph there is an initial statement about Zero Net Energy (ZNE) buildings. PG&E agrees with the sentiment, but feels that the language could be more visionary and inclusive. The more profound vision is a community with ultra-low energy buildings, a residential-business mix and configuration minimizing personal and commercial transportation, on-site or near-site renewables all integrated to increase the quality of life (local recreation/green space, access to efficient transportation for travel out of the community, etc.).

First, in the body of the *Draft IEPR*, specifically pages 55-58 regarding ZNE, PG&E again feels that the language ought to expand the CEC’s vision on this topic. One could think about ZNE in terms of on-site energy production. Increasing the efficiency required by code could be a useful step. Trying to include more building types under codes might fit in this vision, complimented by further attempts to step up enforcement and ensure that measures are installed properly. One could increase the scope of projects covered by Titles 24 and 20 (in this case to renewables and plug loads), and there should be more discussion of renewable technologies other than solar PV. To meet the bold ZNE goals of the state, creative and aggressive strategies will need to be used, including thinking about the size and location of buildings, off-site distributed generation, community-scale generation, and occupant behavior. The thought behind the section on developing building standards for water efficiency is a good, forward-thinking step.

Second, this section on pages 55-58 repeatedly mentions "cost-effective energy efficiency measures" in the context of ZNE. The main point to make here is that, as we currently measure cost-effectiveness, many of the measures needed to achieve ZNE will not be considered cost-effective. As the State pushes towards increased penetration of ZNE concepts going forward, we encourage the CEC to think deeply about how ZNE may be cost-effective by future metrics or factors and whether or not current cost-effectiveness standards may deleteriously affect increased deployment.

Third, the beginning of the section (page 56) has the terms zero net energy, zero peak energy use, and net zero carbon listed somewhat casually. It's important to note that they are really different in terms of effect both on the utility and on the customer. ZNE, in practical terms means that the customer has generated enough DG to zero out a bill over the course of a year using net metering. The customer may not have generated as much actual energy as she used from the grid, but if the time of use and generation works out, the smaller amount generated nets out to zero. This is the customer's fundamental financial incentive to have DG. Net zero carbon, in practical terms, means that the customer has to produce enough carbon-free electricity to balance the electricity used from the grid, the transmission losses, and the natural gas used. This results in a much larger, and much more expensive, DG system.

PG&E's current rate design, where the fixed costs of the distribution system are largely recovered in usage-dependent (variable) charges, may not be able to provide sufficient revenues to sustain a high saturation of ZNE buildings. Ultimately, all grid-tied ZNE buildings rely on the utility grid infrastructure. If ZNE buildings are not fully contributing to the infrastructure fixed costs, those costs will be shifted to other (non-participant) customers. PG&E suggests that no discussion of ZNE is complete if it does not address this fundamental issue.

Finally, PG&E offers the following edits for inclusion into the text of the *Draft IEPR*:

- Page 56, Edit to the following two paragraphs (Underline is new text and strikethrough is deleted text):

> In addition to the concept of zero net energy, there is also dialogue about the importance of net zero peak energy use, meaning that the building does not require extra energy during peak energy use times; and net zero carbon, meaning that the building generates <u>onsite and exports to the grid</u> more zero-carbon energy ~~onsite~~ than it uses from the grid in an average year. The ARB's Climate Change Scoping Plan also promotes zero‐carbon footprint new homes, zero net energy homes, and green building standards.

The Energy Commission has adopted several key strategies for achieving the goal of zero net energy homes by 2020 and commercial buildings by 2030. These efforts include reducing the “plug load” energy in buildings by broadening the range of appliances, ~~such as more standards for consumer electronics~~ covered by the Title 20 Appliance Efficiency Standards; <u>this is reflected in more standards for consumer electronics</u>. It also includes <u>expanding the scope of</u> building standards ~~for~~ <u>to</u> <u>include</u> water efficiency, improving education about existing standards and stepping up enforcement, and adopting voluntary “reach” building codes and standards that save energy beyond that required by mandatory, and implementing those reach standards through green building standards. Additionally, the Home Energy Rating System (HERS) Phase II program, effective September 1, 2009, adopted a home energy rating scale that starts at zero (0) to reinforce the long term goal of achieving net zero energy new homes by 2020.

iii. Other Comments

PG&E has the following comments on specific pieces discussing Energy Efficiency issues:

- Page 4, paragraph 2: The quote “Strategies to achieve 100 percent cost-effective energy efficiency, as well as the greenhouse gas emissions reduction goals, include zero net energy buildings, increasingly stringent building and appliance standards along with better enforcement of those standards, and the increased efficiency of the state’s existing building stock”, as stated, is a collection of words and actually contains no sentences.

- Page 60, PG&E suggests the edits below to the following paragraph (Underline is new text and strikethrough is deleted text):

  A major challenge with the building standards is achieving compliance and enforcement. The 536 local building departments in the state are responsible for enforcing the standards by issuing permits and conducting on ‑ site inspections during construction. With the downturn in the economy and reduced budgets, many cities have downsized their building department staff to maintain other vital staff such as police or fire crews. Reduced staff, maintaining complex building standards to comprehensively address all important energy efficiency and climate change mitigation in our buildings, changes in architectural style, and insuring that the Warren ‑ Alquist Act’s emphasis on performance standards that provide flexibility in choice in energy using features and equipment are factors that affect compliance with and enforcement of the building standards. As a result, newly constructed residential buildings have been estimated to be potentially up to 30 percent out of compliance with the 2005 Title 24 Building Standards,[1] which could represent up ~~to 180~~ to165 GWh per year[2] of lost energy savings for each year's implementation of the standards and therefore lost opportunities for GHG emission reductions. The Energy Commission has actively sought sufficient staff resources to maintain a presence in the field to encourage improvements in compliance and enforcement and is actively working with the California Building Officials (CALBO) and California utilities to provide tools and information that will simplify Standards enforcement and provide expanded training for the industry and building officials.

- Page 67, last paragraph, regarding the IEPR Committee recommendation there ought to be "…a (statewide) taskforce comprised of state, local, utility, and industry stakeholders to work collaboratively to clarify definitions, set out strategies, identify potential hurdles and potential solutions, and set schedules and milestones to reaching the goals of 100 percent cost effective energy efficiency by 2016"; such an effort may be duplicative with other stakeholder groups currently looking into this issue, and close coordination will be necessary to ensure redundancy is mitigated.

B. Renewables

i. Penalties

As stated at the outset of our comments, PG&E is disappointed by the CEC's recommendation that the CPUC "be committed to imposing penalties" for non-compliance with the RPS targets. Emphasizing penalties implies that the utilities are an impediment to meeting the state's RPS goals but there is no evidence presented on this point. The CEC clearly recognizes the significant challenges and hurdles faced in achieving the RPS mandate. "Challenges with increasing the amount of renewable resources in California's electricity mix…", "[i]ntegrating the high levels of renewable resources…will be a major challenge", "high cost of emissions controls…", "adding large amounts of renewable resources can have negative environmental effects…" are all phrases peppering the CEC's assessment (p. 6-7). Yet the first recommendation the CEC makes does nothing to address any of these issues. Rather than emphasize possible penalties, the CEC should implement its additional recommendations to "conduct further analysis to identify solutions for integrating renewables…", "support the detailed analysis being conducted by the California Independent System Operator to identify specific system requirements…" and "continue its efforts in the Renewable Energy Action Team to streamline and expedite permitting of renewable energy

[1] ~~43 Quantec, LLC (merged with The Cadmus Group, Inc. in 2008), see [http://www.cadmusgroup.com].~~

[2] First year's savings from 2008 building efficiency standards estimated to be 549 GWh/yr, 128 MW and 18 Million therms/yr. Source: California Energy Commission. *Initial Study/Proposed Negative Declaration 2008 Building Efficiency Standards*, April 2008, http://www.energy.ca.gov/2008publications/CEC-400-2008-009/CEC-400-2008-009-SF.PDF

projects." These recommendations can actually help get new renewable generation built. PG&E asks that the recommendation to impose penalties be stricken from the report because it is not supported by the evidence set forth in the IEPR or by any other data.

ii. Feed-in Tariffs

The *Draft IEPR* also suggests the CPUC complete its efforts to implement technology-specific feed-in tariffs for wholesale distributed generation. PG&E has been supportive of the CPUC's activities in this area to create a streamlined contracting process for small renewable generators. While this process does not implement the CEC's size or pricing recommendations, the Renewables Auction Mechanism ("RAM"), once implemented, will offer "head-to-head" competition across renewable generators able to offer comparable projects and provide the means for small renewable generators to participate in the broader RPS program and to bid the price they need to sustainably generate renewable energy. The RAM will also resolve issues with respect to whether the states have authority to set a price in the wholesale electric markets.

iii. Delivery Requirements

On the matter of delivery requirements and firming and shaping agreements as described on page 75, the language in the *Draft IEPR* stating that such agreements may inadvertently allow non-eligible resources to be counted for RPS compliance is incorrect and should be stricken. The Western Renewable Energy Generation Information System (WREGIS), implemented under the CEC's direction, tracks all renewable generation created at a particular facility and was specifically developed to avoid this issue. In no case, whether the energy is delivered simultaneously to the state or through a firming and shaping agreement, is there an opportunity to count more energy toward the RPS goal than was generated at the renewable facility.

The *Draft IEPR* also discusses delivery requirements in the WECC and states that Arizona has the most restrictive delivery policy among the WECC. However, this analysis is incomplete because it fails to look at Arizona's requirements holistically. A more robust view of Arizona's RPS would show that Arizona's target is less aggressive than California's and more in-state tools count toward Arizona's target. For example, efficiency measures count toward Arizona's goal - Solar Water Heat, Solar Space Heat, Geothermal Heat Pumps, CHP/Cogeneration, Solar Pool Heating (commercial only), Daylighting (non-residential only), Solar Space Cooling, Solar HVAC all count towards Arizona's goal. Distributed PV also counts toward the Arizona RPS – PV installed through California's CSI Program does not, nor does any other renewable customer generation that serves customer load. Arizona also provides extra credit multipliers for certain technologies and in-state facilities, making it easier to meet its target[3]. California has no such multipliers. PG&E cautions the CEC when making such analyses of RPS portfolio requirements across varying states to look at the entire program and its

[3] Database of State Incentives for Renewables and Efficiency – Arizona. Accessed 27 October , 2009 http://www.dsireusa.org/incentives/allsummaries.cfm?State=AZ&&re=1&ee=1

components as a whole, rather than individual stand-alone elements which can provide misleading results.

Finally, California has always relied on imports – this is not a new phenomenon. To subject renewable generation to stricter import requirements than for fossil resources, as could be construed from the *Draft IEPR*, runs counter to the policy of the state for increased levels of renewable generation.

C. Distributed Generation and Combined Head and Power

PG&E generally supports the *Draft IEPR* analysis and recommendations regarding DG and CHP provided the final IEPR incorporates a few critical modifications. PG&E generally supports the call for further research into integration of DG and the utility grid; in fact PG&E suggests this research be expanded. PG&E generally supports the discussion around the benefits of renewable CHP and the recommendations supporting it. PG&E appreciates this opportunity to make some suggestions that will enhance the usefulness and credibility of the IEPR.

In summary, the necessary improvements to the *Draft IEPR* are:

- The IEPR should caveat its reliance on the recent CHP market analysis.
- The IEPR should carefully structure discussion of the benefits of DG and CHP.
- The IEPR should carefully structure discussion of GHG emissions reductions.
- The IEPR should reconcile discrepancies between the discussion on CHP and the clear implication of the ICF study.
- The IEPR should include a discussion of market barriers, rather than adopt the ICF analysis without question.
- The IEPR should exclude or drastically modify the GHG emissions reductions analysis based on the ICF study.
- The IEPR should expand the research on integration of DG and the utility grid.
- The IEPR should modify the CHP recommendations as PG&E suggests.

Each of these critical modifications is discussed in further detail below.

<u>The CEC should heavily caveat its reliance on the ICF Draft Combined Heat and Power Market Assessment</u>

PG&E lauds the CEC's recent effort to update the CHP market potential work that ARB relied on in the Scoping Plan. The Draft Combined Heat and Power Market Assessment represents a noteworthy commitment to transparency and an open analysis process. PG&E notes, in particular, that the technical potential derivation is a significant improvement over the earlier study. However, the report is in no way timely with respect to the 2009 IEPR or the ability of the IEPR to rely on the findings of the updated market assessment. The IEPR report should clearly express this and caveat the use of the report appropriately.

There are several reasons why the IEPR should exercise caution when relying on the new market assessment. The recently released draft report differs substantially from the preliminary findings presented in July of this year and interested parties had little time to review the differences. Although the process leading to the Draft ICF report was more transparent than the previous report, the use of the report in the IEPR left little or no time for thoughtful or thorough review of assumptions, data used, analysis methods or conclusions. The *Draft IEPR* includes several tables and figures from the market assessment report, however the draft copy of the market assessment report was not available for public review until October 12th, some several weeks after the *Draft IEPR* was posted. The CEC held a meeting with the consultant who authored the report and PG&E appreciates the open discussion that resulted. However, the meeting was on October 13th, meaning participants had less than a day to read the report prior to the meeting.

PG&E appreciates both the CEC's and the consultant's willingness to respond to questions about methodology, but it is clear no further input is likely to change the report. It is beyond challenging to respond in a meaningful way to such an important subject when the study results are published in the draft IEPR prior to the study being released, and interested parties only received the study the night before an informal workshop to review the results.

PG&E suggests the CHP discussion includes an explanation that the ICF Draft Report was not adopted, or even publicly available, at the time the *Draft IEPR* was written; that parties had little or no time to suggest changes to any of the date sources, assumptions, or methodology; and therefore the results included in the IEPR should not be cited.

<u>The IEPR should carefully structure discussion of the benefits of DG and CHP</u>

PG&E appreciates the potential for customer generation to contribute to policy goals of the State of California, however not all customer generation is created equal. There are several statements in the *Draft IEPR* which, if taken out of context, could lead to the misleading conclusion that the CEC supports all customer generation, even generation that increases GHG emissions in California. PG&E assumes the CEC does not mean to imply that *any* DG or CHP will contribute to GHG emissions reductions and suggests the IEPR be more carefully worded. For example, on page 91, rather than saying “Distributed generation and CHP are valuable resources options …” the report should say “Under the right circumstances, distributed generation and CHP can be valuable …” Where the report now says “distributed generation reduces the need to build new transmission and distribution infrastructure …” it should say “under the right circumstances, distributed generation can reduce ...”

The IEPR should carefully structure discussion of GHG emissions reductions.

PG&E notes that the description of the Assembly Bill ("AB") 1613 efficiency standards, now being developed by the CEC will "assure" GHG emissions reductions. (Page 93) PG&E takes this opportunity to reiterate our comments in the CEC efficiency proceeding that the only way to "assure" GHG emissions reductions is to adopt a standard that requires CHP taking advantage of the AB 1613 feed in tariff has GHG emissions that are significantly lower than if the thermal load were being met by an efficient boiler and the electric load were being served by the utility grid. The appropriate carbon neutral point is an 80% efficient boiler and a CCGT with a heat rate of 7210 Btu/kWh. For discussion of the AB 1613 efficiency standard, or any other program that promotes CHP, the IEPR should restrict GHG emissions reductions claims to circumstances where performance beyond the carbon neutral point is assured.

The IEPR should reconcile discrepancies between the discussion on CHP and the clear implication of the ICF study.

During the discussion of the ICF market assessment study, the *Draft IEPR* contains language that is apparently contradicted by the study itself. On page 95, the *Draft IEPR* states that commercial facilities would "use all power generated on site". This is not true, or the AB 1316 program is destined to have very few commercial participants. On the following two pages, there are two tables from the ICF study that indicate some small generators will be exporting to the utility grid because they produce more power than they use. The apparent inconsistency can be either explained, or the reference to commercial sector customers never exporting can be deleted.

The IEPR should include a discussion of market barriers, rather than adopt the ICF analysis without question.

The ICF market assessment started with a technical potential for CHP in California and projected the market penetration based on scenario analysis. The penetration curves were based on a study completed by Primen in 2005 as part of the CEC's previous market potential work.[4] The differences in market penetration in the different scenarios are always driven by economic choices: for example, the expectations for the business associated with the thermal load; CO2 payments; revival of buy-down incentives for CHP; existence of must-take contracts; and existence of must-take contracts at aggressive contract prices. However, as Primen found, and as was discussed at the CEC workshop held in April of 2005 on market barriers, customers do not always make their decisions based on economic criteria. There are some barriers to CHP penetration that are not economically driven and will not yield to economic signals. The *Draft IEPR* discussion of the ICF report (and in fact the ICF report itself) would be stronger for a discussion of the true nature of market barriers to CHP proliferation. The *Draft IEPR* as written gives the impression the answer to increased CHP penetration lies primarily within the power of regulators and utilities. This is simply not true.

[4] See chapter three of the 2005 market potential study.

The IEPR should exclude or drastically modify the GHG emissions reductions analysis based on the ICF study

The ICF GHG emissions reductions assumptions are based on the California Air Resources Board ('ARB") Scoping Plan, with two modifications: the load factor was reduced from 85% to 80.2% and the overall CHP efficiency was reduced from 77% to 67.8%. The apparent reductions in GHG emissions reductions for equivalent MW of installed CHP are almost exclusively due to these two modifications. The rest of the assumptions in the ARB Scoping Study remain the same. In particular, the assumed heat rate for the carbon neutral point is unchanged. The ARB Scoping Plan assumed 963 lbs CO2/MWh for the electricity that would have been delivered from the grid if the CHP had not been installed. This was used by ARB to represent the carbon neutral point for the electricity. As PG&E explains above, using an appropriate heat rate of 7,210 Btu/kWh, the better carbon neutral emissions assumption should be 843 lbsCO2/MWh.[5] Because the ARB overstates the GHG emissions reductions that CHP installations can effect, ICF (and by extension the *Draft IEPR*) perpetuates this overly optimistic result. This is critical because a simple reading of the ICF report or the *Draft IEPR* can appear to independently ratify the ARB assumptions and conclusions when, in fact, it is a circular argument that causes this agreement.[6]

The IEPR report should either clarify the interdependence of the results with a clear statement that IEPR GHG emissions projections depend, in part, on ARB Scoping Plan assumptions, or the GHG emissions projections should be deleted from the report.

The IEPR should expand the research on integration of DG and the utility grid.

On page 221 of the *Draft IEPR*, the CEC recommends that "[t]he Energy Commission and the CPUC should open a joint proceeding to develop a comprehensive understanding of the importance of distribution system upgrades…" to ensure reliability as well as support the integration of larger amounts of DG exports to the grid. PG&E is amenable to such a joint proceeding but such an effort should clearly acknowledge the ratemaking implications of the kinds of changes that would be considered.

The subsequent recommendation on page 211 regarding a requirement that the IOUs conduct assessments identifying ideal locations for DG, however, is extremely challenging in practice to accomplish. PG&E does not support an assessment of specific locations, and suggests that identifying areas or attributes more generically may be a more feasible approach. Recommendations mandating the use of distribution

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[5] Combustion of natural gas produces 117 lbs CO2/MMBtu. Thus an assumed heat rate or 8,230 Btu/kWh can be "backed out" of the ARB emissions assumption by dividing 963 lbs/MWh by 117 lbs/MMBtu times 1000 (to convert MWh to kWh). A similar calculation using the 7,210 Btu/kWh heat rate produces the 843 lbsCO2 per MWh of electricity generated.

[6] PG&E notes that in the current draft of the AB 1613 efficiency standard, the CEC has incorporated a heat rate of 7,750 Btu/kWh, which is inconsistent with the ARB assumption.

system operational models and economic/capital investment models or requiring that IOUs use these analytics to demonstrate cost-effectiveness in grid modernization investments are very concerning. These are very far reaching recommendations that need to be considered very carefully by the CEC. Utilities make investments in their distribution systems for many reasons and cost effectiveness varies depending on the investment. The cost effectiveness of connecting a new customer is measured differently than replacing an obsolete piece of equipment.

PG&E appreciates that expansion of distributed generation can have an impact on the safe, reliable distribution of power to our customers and supports the research recommendations contained in the *Draft IEPR*. PG&E suggests that the research recommendation be expanded to include study into the impact of increasing levels of DG on grid operations as a necessary prerequisite to studying system upgrades that might be necessary to safely accommodate DG interconnections. In general, PG&E believes that workshops should precede any specific recommendations regarding information that should be provided by utilities, tools that should be used in rate cases, tools that should be used in utility planning, etc.

The IEPR should modify the CHP recommendations as PG&E suggests.

In general, PG&E supports the recommendations found in the IEPR with respect to CHP and the role CHP can play in meeting ARB Scoping Plan targets. As has been explained elsewhere, PG&E believes these targets may be optimistic. As is explained in these comments, there may be market barriers resistant to any program that could be designed or implemented by regulators or utility companies. However, the best way to achieve contributions to GHG emissions reductions from CHP would be modify the recommendations in the report to ensure that only CHP that actually reduces GHG emissions receives benefits from programs that are ratepayer funded.

Below, PG&E provides specific edits to the recommendations in the Draft IEPR and strongly urges their adoption:

The development of new CHP and repowering of existing CHP can lead to a reduction in carbon dioxide ~~equivalent~~ emissions ~~of 4 million metric tons per year by 2020~~. To realize these reductions, the following implementation measures should be instituted:

- The Energy Commission and the ARB should structure CHP programs to ensure development of both small CHP systems (20 MW and smaller) and large CHP systems (larger than 20 MW) that reduce GHG emissions when compared to meeting the electric load with an equivalent generator with heat rate of 7,210 Btu/kWh and meeting the thermal load with a boiler operating at 80% efficiency. Desirable CHP systems should be dispatchable, appropriately located, and have a load profile that addresses utility net short positions, and CHP tariffs should appropriately value these attributes.
- The Energy Commission and the ARB should establish minimum efficiency standards that ensure GHG emissions beyond carbon neutral installations, GHG emission criteria, and monitoring and reporting mechanisms.

- Where appropriate, Electric utilities ~~should~~ could consider develop programs and solicit projects to promote CHP as a strategy to replace boilers, increase energy efficiency, and reduce emissions. Programs ~~should~~ could include a mix of mechanisms such as energy audits, an electricity export sales tariff~~, and a pay□as□you□save pilot program for nonprofit organizations~~. Utility ownership is acceptable where it does not crowd out private investment.
- Eligibility for CHP systems with a generating capacity of 5 MW or less that ~~meet minimum performance~~ reduce GHG emissions compared to carbon neutral SHP, monitoring and reporting standards should be re-instituted in the Self Generation Incentive Program. ~~The amount of the incentive should be based on efficiency and GHG reduction metrics rather than technology and fuel types.~~

D. Nuclear Power Plants

The first recommendation in this section of the draft report is that PG&E complete and submit for review to the CEC and the CPUC the seismic, tsunami hazard and other studies recommended by the CEC in the AB 1632 report prior to filing license renewal applications with the CPUC and the NRC. PG&E requests that this recommendation be removed.

Prior to the CEC issuing its AB 1632 report recommendations, PG&E had already planned to complete many of the recommended seismic studies as part of its long-term seismic program (LTSP) for Diablo Canyon Power Plant (Diablo Canyon or DCPP), which is a commitment connected to the operating licenses issued by the NRC. PG&E will request ratepayer funding to conduct the 3-D seismic imaging studies recommended in the report, which were not part of PG&E's LTSP.

The results of the seismic and tsunami studies PG&E is undertaking, all of which should be completed no later than 2013, are relevant to the ongoing safe operation of Diablo Canyon. If the results of any of these studies require changes to Diablo Canyon's seismic design, PG&E will confer with the NRC and propose changes to the NRC at the time it discovers those changes are necessary. It is inapposite to link updated seismic data to the license renewal process, which by definition addresses DCPP operations in 2025-2045, not current operations.

Likewise, the assessment of the emergency planning and response requirements assuming a major seismic event is relevant to the ongoing safe operation of Diablo Canyon. If the results of this assessment require changes at the plant, PG&E will confer with the NRC and propose changes to the NRC at the time it discovers those changes are necessary. It is also inapposite to link emergency planning issues to license renewal, which by definition addresses DCPP operations in 2025-2045, not current operations.

Seismic conditions and emergency planning and response are subjects critical to the current safe operation of Diablo Canyon. PG&E takes these issues very seriously and will address them as necessary, consistent with NRC regulations and in a manner designed to protect the health and safety of the public. These issues affect current operations of the plant and are not part of the review undertaken in license renewal proceedings, either at the NRC or the CPUC. As such, there is no reason for the report to recommend that PG&E delay filing license renewal applications until after these studies are completed. If the NRC determines it is not safe to operate Diablo Canyon during 2025-2045 or the CPUC determines it is not cost effective or in the ratepayers' best interest to operate Diablo Canyon during 2025-2045, the state will need all of the time between that determination and the expiration of the current operating licenses in 2024 and 2025 to plan, approve and build generating facilities to replace 2300 MW of base load energy capacity.

Finally, PG&E is near completion of its license renewal feasibility study (LRFS) in preparation for both the CPUC's consideration of the cost-effectiveness of an additional 20 years of operation, as well as for the NRC license renewal proceeding itself. Delaying these filings until all AB 1632 studies are completed would not only potentially require updating the LRFS at considerable cost to ratepayers, it could also jeopardize PG&E's ability to adequately plan for its customers' power needs should the license renewal not proceed.

Moreover, while PG&E is willing to provide the results of these studies to the CEC and the CPUC for their information, concurrent with its submission of the information to the NRC, only the NRC has authority to regulate the operations and maintenance of Diablo Canyon.

As referenced in the draft IEPR (at p. 111), it is PG&E's position that the CPUC license renewal application proceeding will be limited to those issues over which the CPUC has jurisdiction. The CPUC itself recognized this when it directed that the license renewal application filed at the CPUC address whether license renewal is cost effective and in the best interest of ratepayers. Also within the state's jurisdiction are the need for generating capacity, the appropriate type of generating capacity, land use, and ratemaking.

This differentiation between issues under the exclusive jurisdiction of the NRC and issues within the jurisdiction of the CPUC reflects well-established law and precedent regarding the exclusive jurisdiction of the NRC over the safety and nuclear aspects of energy generation. The Supremacy Clause of the United States Constitution states that the "Constitution, and the Laws of the United States which shall be made in Pursuance thereof… shall be the supreme law of the Land; and the Judges in every State shall be bound thereby, any Thing in the Constitution or Laws of Any State to the Contrary Notwithstanding." U.S. Const. art. VI, cl. 2. In light of the Supremacy Clause, Congress may preempt state law and regulation. As the Supreme Court stated:

It is well-established that within Constitutional limits Congress may preempt state authority by so stating in express terms:

> "Absent explicit preemptive language, Congress' intent to supersede state law altogether may be found from a 'schedule of federal regulation so pervasive as to make reasonable the inference that Congress left no room to supplement it,' 'because the Act of Congress may touch a field in which the federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject,' or because 'the object sought to be obtained by the federal law and the character of obligations imposed by it may reveal the same purpose.'"
>
> *Pacific Gas and Elec. Co. v. State Energy Resources Conservation Dev. Comm'n, 461 U.S. 190, 204 (1983) (citations omitted).*

The Federal Atomic Energy Act ("AEA") gives the federal government exclusive authority to regulate the design, construction and operations of nuclear power plants. As the AEA states:

> " the Commission shall retain authority and responsibility with respect to regulation of
>
> (1) the construction and operation of any production or utilitization facility or any uranium enrichment facility…"
>
> *42 U.S.C. sec. 2021 (c).*

Interpreting this provision, the U.S. Supreme Court ruled that it gives the "federal government complete control of the safety and 'nuclear' aspects of energy generation; the states exercise their traditional authority over the need for additional generating capacity, the type of facilities to be licensed, land use, ratemaking, and the like." [7] The Supreme Court emphasized:

> "State safety regulation is not pre-empted only when it conflicts with federal law. Rather, the Federal Government has occupied the entire field of nuclear safety concerns, except the limited powers explicitly ceded to the States. When the Federal Government completely occupies a given field or an identifiable portion of it, as it has done here, the test of pre-emption is whether the matter on which the State asserts the right to act is in any way regulated by the Federal Act."[8]

Accordingly, the Supreme Court found the "field of nuclear safety concerns" to be occupied by federal law and preemptive of state regulation. Id. accord, e.g., County of Suffolk v. Long Island Lighting Co., 728 F.2d 52, 58 (2d Cir. 1984).

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[7] *42 U.S.C. sec. 2021 (c). at 212.*
[8] *Id. at 212-13*

In the final recommendation of the Nuclear Plants section, the draft IEPR recommends that the Diablo Canyon Independent Safety Committee evaluate reactor pressure vessel integrity at Diablo Canyon over a 20-year license extension and recommend mitigation plans, if needed. The draft goes on to say that this review should consider the reactor vessel surveillance reports for Diablo Canyon in the context of any changes to the predicted seismic hazard at the site. This review is unnecessary. The NRC reviews reactor vessel pressurized thermal shock (PTS) events as part of its license renewal process.

Reactor vessel PTS are system transients in a pressurized water reactor (PWR) in which there is a rapid operating temperature cool down that results in cold reactor vessel temperatures with or without re-pressurization of the reactor vessel. The rapid cooling of the inside surface of the reactor vessel causes thermal stresses. The thermal stresses combine with stresses caused by high pressure. The aggregate effect of these stresses is an increase in the potential for fracture if a pre-existing flaw is present in a material susceptible to brittle failure. The ferritic, low-alloy steel of the reactor vessel beltline, which is adjacent to the core where neutron radiation gradually embrittles the material over the lifetime of the plant, can be susceptible to brittle fracture.

The NRC regulations governing reactor vessel PTS are contained in 10 CFR 50.61 and 10 CFR 50.61a. The PTS rule described in Title 10, Section 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events,” of the Code of Federal Regulations (10 CFR 50.61), and adopted on July 23, 1985, (50 FR 29937) establishes screening criteria below which the potential for a reactor vessel to fail due to a PTS event is deemed to be acceptably low. The screening criteria effectively define a limiting level of embrittlement beyond which the licensee cannot continue operation without further plant-specific evaluation. A licensee may not continue to operate reactor vessels with materials predicted to exceed the screening criteria in 10 CFR 50.61 without implementing compensatory actions or additional plant-specific analyses unless it receives an exemption from the requirements of the rule.

The NRC has recently concluded that the risk of through-wall cracking caused by a PTS event is much lower than previously estimated. This finding indicates that the screening criteria in 10 CFR 50.61 are unnecessarily conservative and may impose an unnecessary burden on some licensees. Therefore, the NRC developed a new rule, 10 CFR 50.61a, “Alternate Fracture Requirements for Protection against Pressurized Thermal Shock Events,” providing alternate screening criteria and corresponding embrittlement correlations based on the updated technical basis. The NRC approved the final rule on September 22, 2009, which provides alternate fracture toughness requirements for protection against PTS events for PWR reactor vessels. This final rule provides alternate PTS requirements based on updated analysis methods.

The *Draft IEPR*, on page 114, states that “the cooling systems used by [the nuclear plant]s are viewed by the SWRCB as larger sources of biological harm … than any of the cooling systems used by the state’s other coastal plants.” This statement is not true relative to Diablo Canyon. Overall, based on data contained in the SWRCB’s Substitute Environmental Document, Diablo Canyon circulates approximately 22% of the state’s cooling water flow – but accounts for only 8% entrainment and 1% of impingement. Due to the design and location of Diablo Canyon’s intake structure, impingement is virtually non-existent and was found by the Central Coast Board to be so insignificant as to warrant no further action. In almost thirty years of operation, there have been no known deaths of marine mammals or sea turtles due to impingement. Studies of fish populations in the central coast area conducted by researchers from Cal Poly, as well as data collected at Diablo Canyon’s biological monitoring control stations, have not demonstrated any long term declines in fish populations due to entrainment. The impacts of once-through cooling are very site-specific and any discussion of such impacts must acknowledge this fact. Diablo Canyon’s environmental impact due to once-through cooling is minimal.

Further, PG&E has completed a detailed cooling tower feasibility study which has been submitted to both the CEC and SWRCB. This study identifies numerous engineering, environmental and permitting challenges to a retrofit at Diablo Canyon and finds that the costs would exceed $4 billion dollars. PG&E believes that this study, along with a similar study prepared by SCE, should form the basis of the initial reviews directed by the SWRCB's proposed policy.

E. Comprehensive Statewide Planning

PG&E appreciates the CEC’s positive comments about the important and cooperative task we are undertaking with the rest of the CTPG. PG&E has concerns about the CEC proposing responsibilities that will overlap with current CAISO Business Practice Manual responsibilities by putting all planning activities in the state under the CEC’s STIP process. We are especially concerned that the CEC will institute a 30-year long term plan, which they propose would be "prepared and vetted" by the CEC.

PG&E has identified the following areas of concern within the Transmission portion of the *Draft IEPR*, which are discussed below:

- Page 206, line 19:

> The most logical approach to effectively leverage and coordinate the respective functions of the Energy Commission, the CPUC, and the California ISO is an arrangement with lead responsibility for planning infrastructure requirements to reside in the Energy Commission’s IEPR proceeding along with a description of the inputs from other agencies to be relied upon and the results provided to other agencies and the manner in which they are expected to be used.

- Page 209, last paragraph continuing on to page 210:

> The CTPG statewide plan would then be submitted for evaluation to the Energy Commission's Strategic Transmission Investment Plan proceeding. The objective is to ensure that state interests regarding state policy goals and objectives are evaluated in a public forum. Projects conforming to state policy goals and objectives would be given greater weight in the permitting process. The *Strategic Transmission Investment Plan* also targets transmission projects for the Energy Commission's corridor designation process, and this step envisions recommending multiple projects identified in the CTPG statewide plan for simultaneous designation, rather than a piecemeal approach of one corridor designation proceeding at a time.

- Page 210, fourth paragraph:

> For longer term planning, it is impossible to produce a 30-year plan with the same level of detail as the 10-year California ISO Annual Transmission Plan. Instead, the long-term plan would build on the 10-year California ISO plan and CTPG statewide plan and would consider the RETI conceptual plan and WREZ initiative planning output. The Energy Commission would prepare and vet the long-term plan in the Strategic Transmission Investment Plan proceeding, with the cooperation of electric utilities and interested stakeholders. The long-term plan would feed back into subsequent RETI conceptual transmission planning cycles, which this planning approach assumes would be undertaken every two years. The objective of subsequent RETI cycles would be to update the conceptual transmission plan completed two years previously. In addition, like the 10-year transmission planning proposal, the long-term plan would signal transmission corridor needs for the Energy Commission's corridor designation program.

- Page 226, first bullet item:

> The Energy Commission staff should work with the recently formed California Transmission Planning Group (CTPG) and California ISO in a concerted effort to establish a 10-year statewide transmission planning process that uses the Strategic Plan proceeding to vet the CTPG plan described in Chapter 4 of the *2009 Strategic Transmission Investment Plan*, with emphasis on broad stakeholder participation.

PG&E agrees that the state needs to better coordinate its electricity policy, planning, and procurement efforts to eliminate duplication and to ensure that planners and policy makers understand the interactions and conflicts that may exist between state energy policy goals.

The CEC proposes to take a much greater role in long term planning. Specifically, the *Draft IEPR* proposes the lead responsibility for planning infrastructure requirements to reside in the Energy Commission's IEPR proceeding." (p. 206) Also, the CEC wants to "…focus its forecasting, planning, IEPR, and Strategic Transmission Investment Plan processes on conducting the statewide integrated planning that is clearly now required." (p. 224). This is seemingly akin to the Integrated Resource Planning (IRP) process that the Energy Division has proposed be a part of the LTPP proceeding. Having the CEC take on that responsibility might be a possible place to do that; however, such a proposal raises a number of concerns, such as:

- What is the division of roles and responsibilities between the CAISO, the CPUC and the CEC? Clearly the CAISO is the ultimate need and procurement authority with respect to transmission infrastructure. Clearly, the CPUC is the ultimate need and procurement authority with respect to its jurisdictional utilities.
- There is a real danger of duplicative work and competing proceedings if coordination is not smooth.
- There is need for the CEC to have a more structured process for collecting input from participants in the IEPR process, and for arriving at decisions on issues than the current IEPR process. In the current IEPR process, issues/schedules seem to have been handled in an ad-hoc basis, which can lead to obvious problems

A statewide process to assess need may be valuable, but such a process must be non-duplicative, and address at a minimum basic reliability and intermittent resource integration needs of the system. PG&E has the following observations on need:

- Perhaps the CEC could decide on the “need assessment” for those entities without other state oversight.
- Of largest concern is the CEC’s proposal for a possible generation need conformance assessment, which would include analysis that indicates what fossil resources would be needed under different futures**.** The concern is that these assessments are duplicative of need determinations in the CPUC’s LTPP proceeding.
- If the CEC decides to do its own need assessment, such assessment should include both reliability and operational needs. The reliability assessment should address the adequacy of the current 15% to 17% Planning Reserve Margin (PRM) requirement in the future. Because of the increased reliance on intermittent and non-dispatchable resources, it is also clear that the system needs to be operationally more flexible than it is today to manage the increased variability and uncertainty (that is the forecast errors) associated with intermittent and other non-dispatchable generation. Therefore, the need assessment should also account for the need for operationally flexible resources to integrate increasing amounts of intermittent resources.

PG&E appreciates the CEC’s hard work in developing their cost of generation (COG) model, and notes its utility in planning processes. We offer the following thoughts on the report:

- PG&E commends the CEC on its COG model, but stresses the need for it to be used by “sophisticated users” who can understand the financial and input parameters.
- PG&E’s key concerns in the COG report are: (1) comparative costs of conventional resources (i.e. combined cycles & combustion turbines) that are based on surveys. The problem is that it shows installed costs of simple cycle combustion turbine to be higher than a combined cycle, which is not true; and (2) the report also shows a tremendous decrease in costs for Average Instant Cost Trend (Real 2009 $/kW) for solar technologies. These costs, as well as nuclear costs, need to be vetted before using them.

G. Natural Gas Sector:

PG&E understands that natural gas price volatility has been a concern at the CEC for some time. With regard to the various comments on price volatility and their impact on customers on page 139, customers are, and have been for quite some time, subjected to not only “price spikes” in natural gas, but also to price dips. We believe that PG&E's core customers prefer price protection against significantly high winter prices, but they also want to benefit from lower bills when prices trend downward. Therefore, PG&E hedges it's winter core portfolio to protect core customers from extreme price run-ups. To help mitigate volatility issues, PG&E has various balanced payment plans that are available for core residential and small commercial customers.

The IEPR could have a stronger vision about what can be done to facilitate biomethane-to-pipeline injection projects. On the subject of how best to facilitate biomethane-to-pipeline injection projects, there are three things that the IEPR can recommend in order to help facilitate these projects. The CEC should request that the CPUC consider allowing gas utilities to:

- Recover in rates the costs of the research and physical testing required to safely accept renewable (non-traditional) biomethane from organic feedstocks into gas pipeline systems;
- Recover in rates the installation costs of transmission pipeline extensions to reach distant viable biomass clusters (this will overcome a lack of proximity to utility transmission pipelines); and
- Create a new electric tariff to offer a lower electric rate for biomethane injection plant facilities.

In addition, the PIER program should provide funding to support research and testing of new feedstocks for the manufacture of renewable biomethane, to help ensure that utility transmission pipelines can safely receive such gas.

H. Local Government Coordination

PG&E commends the CEC’s efforts to provide assistance to local governments on those specific land use planning efforts that tie into energy-related issues. In general, we feel that the information on local governments in the *Draft IEPR* could use further fleshing out. Therefore we suggest a placeholder in the document to address the gap that exists in the document regarding local governments' role in creating and implementing GHG reduction plans. PG&E has the following suggested addition for this placeholder section, as well as particular thoughts on what one might include in a land use recommendation:

- Page 68, suggested text for the GHG reduction plan components could be as follows:

A great opportunity exists for State Agency collaboration with local and regional governments, including using AB 32 and GHG reduction programs to drive local governments and their constituents to reduce energy use. Local Governments are starting to act on behalf of their communities; increasingly they establish community GHG reduction targets and climate action plans that align with recommendations in the AB 32 Scoping Plan Collaboration among State Agencies to develop coordinated information and to leverage resources with Local Governments can accelerate effective local action to improve land use, raise building standards, improve community awareness and increase access to cost effective energy actions needed to meet community goals. As they implement their Climate Action Plans, Local Governments seek assistance from utilities and State Agencies to increase access to services for residents, businesses, schools and other customer segments in the community, and to co-brand success as part of a community climate action campaign. Local Governments make effective partners for State Agencies and utilities to deliver IDSM services to the entire community.

- Page 5, recommendations section text could be as follows:

The CEC should include references to land use recommendations. To really get to the 2050 GHG goals, the at least partial overlap of EE and land use must be explicitly recognized. Also, as the *Draft IEPR* addresses land use recommendations the report explicitly avoids including site planning that could support improved efficiency (e.g. building orientation) or renewable production. These should both be put on the table as areas to be explored, where future regulation, or other guidance, may be important in making the 2050 goals

III. CONCLUSION

PG&E appreciates this chance to offer comments on the *Draft IEPR*. We look forward to the final report, and to continuing to work with the CEC as it looks again at these issues and other important energy policy issues for California in the 2010 Update to the IEPR. For the reasons stated above, PG&E requests that the CEC adopt in the final IEPR the changes proposed by PG&E.