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California Energy Commission
Docket Office, MS-4
Re: Docket No. 08-IEP-1A
1516 Ninth Street
Sacramento, CA 95814

RE: 2008 Integrated Energy Policy Report Update

PG&E is pleased to provide comments on the CEC's Draft 2008 Integrated Energy Policy Report Update. Please feel free to call me at the number above if you have any questions.

Sincerely,

Mark Krausse

Attachment

Pacific Gas and Electric Company
Comments on the CEC's
DRAFT 2008 IEPR UPDATE
October 16, 2008

Introduction

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to work with the California Energy Commission (CEC) as it finalizes its 2008 Update to the Integrated Energy Policy Report (IEPR). PG&E finds much to support in this document, and applauds the efforts of the staff, the IEPR Committee, and the CEC's consultants in developing this review.

PG&E will provide comments chapter by chapter, commenting both on larger thematic policy questions, as well as providing, in some cases, more minor comments related to a specific assertion or conclusion in the report.

PG&E's key points are:

1) PG&E agrees with the CEC that there are significant barriers to achieving a statewide renewable energy portfolio goal of 33%, and many of these barriers are of concern even at lower targets. These barriers, rather than PG&E's contracting process, are what need fixing. PG&E has signed over 50 contracts and assured over 3500 MW of renewable energy for its customers. However, many of the barriers identified by the CEC, such as transmission and permitting, may detrimentally impact the ability to develop these proposed projects.

2) PG&E supports a quick resolution for the energy efficiency overlap issue in the CEC's demand forecast. This issue needs to be resolved by June of 2009 so that the utilities can develop their long-term procurement plans at the California Public Utilities Commission (CPUC). PG&E staff remains ready to help in this effort.

3) PG&E believes that the CPUC has adequate control of the overall procurement process for both renewable and all-source generation solicitations, and that the process is fair, thorough, and adequately overseen by the PUC. PG&E does not believe that the CPUC needs to take "complete control of the procurement process" as the draft report suggests.

Chapter 1: Renewable Procurement

A. Renewable Procurement Practices

PG&E agrees with the Energy Commission assessment that:

> "significant barriers to achieving (the 33%) goal include the need for transmission additions and upgrades to access renewable resource areas; the challenge of integrating large amounts of resources into the state's electricity system; the impacts of renewable contract delays or cancellations; potential cost and rate impacts of adding renewables to the system, and permitting issues for renewable generation facilities in environmentally sensitive areas" (p. 2).

Many of these barriers have also slowed the utilities' progress toward fulfilling the 20% goal. PG&E, along with the CEC and other entities, is involved in several efforts that will lead to more and better renewables at a faster pace, including:

- The CEC-led Renewable Electric Transmission Initiative (RETI)
- Various integration studies
- The California Independent System Operator (CAISO) led effort to address the transmission queue issue
- Supporting and exploring energy storage technologies
- The CAISO studies regarding operational changes needed to accommodate 20% and 33% renewable electricity into the electric system
- Developing better forecasting techniques for wind and solar generation
- Encouraging muni participation in the state's renewable goals

PG&E strongly disagrees, however, with draft IEPR Update recommendation that the "CPUC must take control of the procurement process for new renewable resources and conduct its own evaluations of renewable proposals based upon cost criteria, as well as likely project success, locational benefits, and land use and environmental considerations, without the direct participation of the IOUs (p. 37), and with the similar recommendation for all-source procurement on page 69, for several reasons.

First, it is not altogether clear what is meant by "take control," although in the October 9th workshop, Commissioner Byron clarified that he was not "looking for the state to take over [procurement]," but rather wanted the procurement process to be more competitive, fair and transparent. PG&E believes that the CPUC has active and effective oversight of utility power procurement, and that the process is fair and competitive, with only a necessary component of confidentiality to ensure the best result for customers. The CPUC's involvement includes litigating the long-term procurement plan (LTPP) proceeding, establishing the rules for the procurement review group (PRG) and independent evaluator (IE) involvement in the RFO and the selection of the winning bidders, and final review of all the contracts the IOUs enter into. Through the PRG review process, the CPUC and other non-market participants can suggest additions to the shortlist or make recommendations. After selection, the CPUC requires detailed analysis of all facets of contracts submitted to it for approval.

Second, PG&E believes that the contracting process is not what needs fixing. PG&E has signed over 50 renewable contracts and secured over 3500 MW of renewable energy for its customers. The company, along with the PRG, assesses many facets of viability, operational fit, and cost. The RPS statute requires least cost, best fit and other cost controls to protect customers. PG&E negotiates each and every contract in good faith to ensure the best value for customers and that viable projects are developed.

Third, with regard to the notion that the IOUs should make information public on prices, locations and schedules -- the CPUC produces public information on the IOUs' progress toward RPS goals consistent with the CPUC-adopted and statutorily required protections of IOU procurement information. Location and commercial operation date are already public. While the actual price is not, IOUs do indicate whether the price is above or below the public market price referent. Additionally, at times, the CPUC has released price information about renewable contracts aggregated for two or more utilities.

Fourth, with regard to the draft IEPR Update statement that "the CPUC should make public the aggregate amount of above-market funds," the CPUC issued resolution E-4160 in April 2008 addressing ratemaking issues, including publishing information on above-market funds. PG&E is waiting for the resolution of the issue. PG&E does not oppose an aggregate amount being public, but information on funds availability should not be public. The utilities do not want to signal developers whether funds are available or not, as this may detrimentally impact the negotiation of reasonable PPA prices.

B. Distributed Renewable Resources

The draft IEPR Update encourages the development of more small renewable projects in several different sections of the report. PG&E not only agrees that distributed renewable resources are part of the solution, but is proud of its many achievements in this area. For example, PG&E just interconnected its 25,000th net metered solar customer-generator, representing almost half of the nation's interconnected solar customer generation. However, PG&E does not see distributed resources as a significant way to reduce the impacts of integrating renewables. Distributed resources do not help the integration of renewable resources because distributed resources are rarely dispatchable, and therefore cannot contribute to meet the grid's requirements for regulation, load following or ramping, and distributed resources can require upgrades to the distribution system.

PG&E has existing and developing programs to encourage small renewable generators with simplified pricing and contract terms and conditions that are similar, in many ways, the feed in tariffs encouraged in several parts of the draft IEPR Update. These include the public water and wastewater PPA for 1.5 MW or less facilities, the other 1.5 MW small renewable generator PPA, and the upcoming new QF standard offer contract. PG&E has also proposed a new pilot program for renewable projects.

In its 2009 RPS Solicitation, PG&E has proposed a pilot program whereby the Commission would "pre-approve" any contract PG&E submits that does not modify the Commission-approved form PPA terms and conditions, and that is priced at or below the MPR. PG&E has proposed such a contract to reduce negotiation time and CPUC approval time. In addition to speeding up the process, PG&E hopes that the substantial reduction in approval time would create an incentive for sellers to reduce their price below the MPR, contributing to cost containment. PG&E has proposed that this pilot program be limited to 800 GWh; the individual project size is not limited. If PG&E reaches that cap, it would submit contracts for formal CPUC approval, unless the CPUC increases the GWh cap. PG&E has structured the contract to include appropriate performance guarantees and security to protect customers' interests.

PG&E's proposal will allow it to capture, through a competitive process, attractively priced renewables for its customers. The MPR is a standardized price, and caution must be exercised to not put generator interests ahead of customer interests by creating subsidies and special programs for sellers who are economically sophisticated. This will inappropriately and unnecessarily increase energy costs for PG&E customers. The focus should be on least cost to customers, not revenue enrichment for generators.

PG&E sees renewable resources as one of the many tools available to achieve the state's renewable goals, but we don't necessarily agree with the statement (pg. 11) that to meet GHG targets of 80% below 1990 levels by 2050, California needs to achieve even higher renewable generation goals [than 33%]. If the collective goal is goal is to minimize the cost of managing climate change and to reduce emissions in the most economic way for customers, then a multi-sector analysis needs to be completed to determine the most cost-effective tools across all sectors, assessing all the available alternatives. Moreover, this assessment should not be static, but should be updated regularly to incorporate new technologies and their substitution along an abatement cost curve.

Chapter 2: Energy Efficiency Forecasting and CEE Projections

In its May scoping memo, the CEC had hoped, in this IEPR Update, to be able to clearly explain how energy efficiency is incorporated in the demand forecast, and address parties' need to understand how much uncommitted savings (savings from efficiency programs reasonable expected to occur but not yet implemented or funded) are accounted for in the forecast.

PG&E is concerned with the slow progress and the absence of a clear commitment in the draft report to resolve the uncommitted EE overlap issue in the CEC's load forecast. The CEC forecast is used in many important California policy, planning, and procurement proceedings. This forecast provides the analytical foundation for the state's resource needs and assessment. It is critical that this forecast include regulatory mandates from the CPUC and other agencies to ensure consistency of plans and actions and that this analysis be clearly and transparently apparent in the CEC load forecast. The definition and basis for the 'baseline' or 'business as usual' forecast needs to consistent across state agencies so that agency efforts in AB 32, procurement proceedings, CAISO transmission planning studies, and CEC reports such as the IEPR and the AB 2021 report, are all coordinated.

The IEPR Update should include a specific list of milestones and a clear timetable to resolve this issue by June 2009 to make the Staff's demand forecast usable. PG&E staff remains available to assist in this effort, and will take part in the proposed working group. PG&E notes it is familiar with its own forecast and its own energy efficiency projections, but has less familiarity with the CEC's end-use demand model, since such models are not the dominant model used for demand forecasting. PG&E supports the IEPR Update suggestion that it might "continue independent efforts to evaluate alternative forecasting methods, focusing on matching methods to the purposes of forecast."

Specific recommendations

- By June 2009 the CEC should agree to a "basecase" forecast which fully incorporates the current CPUC adopted energy efficiency goals so that the basecase forecast can be used directly in the CPUC's LTPP proceeding, in the CAISO Transmission Planning studies, in the ongoing CARB AB32 analysis, as well as in any other application in which forecast users expect to see the CEC's best guess regarding the future level of electricity demand in California. Based on discussion at the August 2008 workshop this appears to be the consensus expectation of forecast users.

- PG&E strongly supports a common set of protocols for EE assessment and impact across all agencies. The latest Itron studies/targets which are used in CPUC forums and the CEC EE assessments used in the IEPR and for AB 2021 need to be cross calibrated to each other and coordinated so that EE impacts are not double-counted and are consistent across the agencies. PG&E recommends that a formal process be instituted to reconcile alternative estimates using different methodologies.

Chapter 3: Electricity Procurement Practices and Resource Planning Activities

The CEC has recommended:

> "The CPUC should take complete control of the procurement process and conduct a fully transparent method of ranking projects in the RFO bid evaluation phase that delineates how they consider project permitting. As part of the *2009 IEPR*, the Energy Commission will conduct a public process and invite the CPUC to help develop criteria for incorporating a project's progress in planning or permitting into the RFO bid evaluation." (P. 69)

As discussed above, PG&E believes its procurement process is fair and thorough, and is adequately overseen by the CPUC.

In the CEC's workshop regarding procurement this July, several non-IOU parties supported the existing PRG process and the other components of IOU procurement. For example, Mike Florio of TURN said "So we really see the PRG as the best tool we have been able to come up with so far for dealing with this issue" (i.e., moving quickly to get contracts approved and signed). Simon Baker of the CPUC's Energy Division said "We have had five years of experience with the procurement review group and we are very happy with it. We think it works." David Ashuckian, who supervises the DRA's procurement section, said he saw the PRG as an avenue of important information for DRA.

The CEC has expressed a concern that the PRG process is a "black box." In a competitive market, some information needs to be kept confidential from market participants to ensure bidders are providing bids that represent the price they need, not the cost they've learned the market can bear. The participation of various non-market participants in the PRG strengthens the choices PG&E makes in evaluating its bids, and we again invite the CEC to allow its staff to rejoin the PRG to help us in that effort.

In workshops, the CEC has expressed some concern about not only the overall procurement process, but also about the process for comparing proposals for utility-owned projects versus projects owned by independent power producers. PG&E wishes to reiterate that it believes the current process, which is monitored and reviewed by the CPUC, is fair and thorough. PG&E also believes that the selection between utility-owned generation and PPAs should be made on the merits of the bids received. PG&E's policy has been, and will continue to be, that the best, most cost-effective new generation resources should be selected for customers to ensure reliability, regardless of whether the resources are utility-owned or proposed by an independent power producer.

Chapter 4: Assessment of California's Operating Nuclear Plants

PG&E will limit its comments in the draft IEPR Update. PG&E has been actively involved in providing the CEC with feedback in its AB 1632 proceeding, and will continue to do so through the completion of the report. PG&E appreciates that the Commission's consultants incorporated much of the information submitted in our data responses, and believe that in many areas the report accurately describes the operation of the Diablo Canyon Power Plant.

In the report's focus on the technical aspects of vulnerability and potential risks and issues that need to be addressed the report loses sight that Diablo Canyon is:

- The largest source of emission free generation in the State
- Among the least cost sources of generation in the State and within PG&E's portfolio; and
- The most reliable power in the state.

PG&E believes that the AB 1632 report and the IEPR Update should clearly state these important assets of the Diablo Canyon facility. Such acknowledgement is factually accurate and complements the thorough review conducted by the report authors.

Chapter 5: Evaluation of the Self-Generation Incentive Program (SGIP)

PG&E will comment more fully on the CEC and its consultants' review of the SGIP program when the study is completed and available in draft form, currently expected in mid-October.

PG&E has been involved with the nomenclature and methodologies of benefit/cost analysis (BCA) for many years in the energy efficiency realm. BCA is typically done from three perspectives, each of which illustrates an important viewpoint: participant BCA; non-participant (ratepayer) BCA; and societal BCA. The list of benefits and costs contained in Table 5 is currently incomplete, contains double counting and/or needs further explanation. Some examples:

- The benefits for non-participants appear to double count congestion savings.
- In the Societal BCA both economic impacts and indirect economic impacts need to be included.
- While the benefits of the SGIP program are for the most part complete, many costs are missing. Under the Participant BCA, the costs of any required system upgrades (which participating customers must pay) are not included.
- For the non-participant BCA, the missing costs include: incentives; increases in congestion costs; costs shifted when standby charges are waived, or don't fully reflect costs of standby services; and interconnection costs when the utility is responsible for costs of required system upgrades.
- Finally, in the Societal BCA the missing costs include: equipment costs, installation costs; required system upgrades; costs for any increases in congestion; environmental justice costs; and any societal or environmental costs (such as disposal costs of PV panels).

PG&E looks forward to the conclusion of the TIAX/Rumla study of the SGIP program. PG&E expects that with its adoption of the societal perspective and a healthy valuation of air emission avoidance values, the study is likely to conclude that at least for the renewable half of the SGIP installations, the SGIP program has a strong positive benefit/cost ratio. PG&E would like to see the study done from the non-participant perspective as well. Although we have not yet seen the conclusions, PG&E appreciates and supports the recommendation that the CPUC consider eligibility for the program based on efficiency and performance, not fuel type, and that the CPUC consider expanding the program to include storage.

However, PG&E was generally surprised to see recommendations advanced for the whole SGIP program while the results of the analysis are not yet in.

PG&E was also surprised to see that the recommendations include a suggestion that the CPUC should require IOUs meet a portion of system upgrades with CHP. The CPUC has already addressed this in R.99-10-025 and concluded, after fully litigating the matter (including holding hearings on the issue), that distributed generation like CHP allows a utility to avoid T&D costs only in certain limited circumstances. Specifically, D.03-02-068 adopted a set of four criteria proposed by SDG&E as necessary requirements in order for a utility to be able to defer T&D capacity additions and avoid future cost: [1]

1) The distributed generation must be located where the utility's planning studies identify substations and feeder circuits where capacity needs will not be met by existing facilities, given the forecasted load growth;

2) The unit must be installed and operational in time for the utility to avoid or delay expansion or modification;

3) Distributed generation must provide sufficient capacity to accommodate [the utility's] planning needs; and,

4) [D]istributed generation must provide appropriate physical assurance to ensure a real load reduction on the facilities where expansion is deferred.

Unless these four conditions are met (and only for as long as they continue to be met), customer-sited DG units (including CHP) do not allow the utility to confidently defer investments in T&D capacity, and thus provide no T&D avoided cost benefit.

PG&E notes that many of the recommendations for CHP are already in place or expected in the near term. For example:

- AB 1613, which may create a feed-in tariff for CHP up to 20 MW, among other alternatives, is currently being implemented by the CPUC.

- A QF contract for eligible renewable, cogeneration and CHP qualifying generation is expected to be finalized soon

[1] D.03-02-068 at 18.

- The CPUC intends to again address the development of a method to estimate the benefits and costs of all customer generation, including CHP. PG&E has called for this methodology development for many years and looks forward to working with the CEC, CPUC and all parties on its development.

Conclusion

The Committee and the staff have pulled together a significant amount of material regarding important challenges to the state in the many energy areas, particularly procurement and forecasting. PG&E appreciates this opportunity to comment on the Committee's draft and looks forward to the final report in early November. Additionally, PG&E will continue to work with the Commission on many of these items as they come up in next year's full IEPR cycle.