BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans	Rulemaking R-10-05-006

OPENING BRIEF OF THE GREEN POWER INSTITUTE
ON THE 2010 LONG-TERM PROCUREMENT PLANS

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Introduction

Pursuant to the Dec. 3, 2010, *Scoping Memo* for this proceeding, and a series of follow-up *Rulings* culminating in the June 13, 2011, *Administrative Law Judge's Ruling Addressing Motion for Reconsideration, Motion Regarding Track I Schedule, and Rules Track III Issues*, the Green Power Institute (GPI) respectfully submits *Opening Brief of the Green Power Institute on the 2010 Long-Term Procurement Plans*, in R.10-05-006, the **Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans**.

We summarize the main points of our *Opening Brief* here:

- The GPI is a participant in the pending proposed Settlement agreement among parties regarding findings of need for new resources for renewables integration.
- The four priority scenarios developed by the Commission do not adequately represent the range of possible renewable energy futures that could be deployed to meet the state's new 33-percent-by-2020 RPS law.
- The Commission's decision to exclude any consideration of a variety of new technologies for improved operations of the electric grid of the future biases the analysis to over-predict the need for new integration resources.
- The analytical methodology that has been applied does not adequately take the level of accuracy of the input-assumption set into account, and therefore pushes some of the comparisons and conclusions beyond the point of reasonability.
- The results presented in the CAISO and IOU *Testimonies* do not show any real, significant differences among the various Commission-developed scenarios studied.
- We recommend that a 40-percent-by-2025 renewables, and a coal phase-out scenario be added in the next LTPP. CAISO's results show that it is not infeasible to expect California to phase out coal by 2020.

- Although we do not question the need for utilities to exercise skill and caution in purchasing greenhouse-gas compliance products, we question whether the hedging model they propose is the right one for this new market.

Assumptions

One of the Commission's major concerns with the 2006 LTPPs, which was called out in the Decision (D.07-12-052) resolving the then current LTPP proceeding, R.06-02-013, was the lack of comparability among the plans of the different IOUs. In order to try to correct this deficiency, a great deal of effort has been expended in both the predecessor to this proceeding, R.08-02-007, and in the early part of this proceeding, R.10-05-006, in developing a common assumption set, and a set of standard scenarios for achieving 33-percent renewables-by-2020, for use by the utilities in the preparation of their 2010 LTPPs. In the opinion of the GPI, this has been a largely fruitful exercise, and has materially elevated the quality of the resulting LTPPs.

While there are significant advantages to using a common set of input assumptions, it also has to be acknowledged that one of the weaknesses of using a common assumption set is that if some of the elements of the assumption set are flawed, the entire analysis can be weakened by these flaws. Regarding the 2010 LTPPs, our concern is less with the actual numbers that have been selected for the standard dataset, but rather with what has been explicitly excluded from the standard assumption set. In particular, we believe that the decision to exclude a consideration of how smart-grid technologies have the potential to improve operations of the electricity grid of the future, to exclude a consideration of the contributions that storage systems and vehicle charging will make to grid operability, and to exclude the benefits of technological improvements in general, both in renewable energy generation, and in transmission and distribution, seriously flaw the results of the studies, and tend to systematically overstate the costs of implementing California's renewables and climate-change policies.

Through eschewing by assumption all of these new tools (smart grid, storage, vehicle charging, improving technology in general) that are expected to improve the operations of the electricity grid of the future, even as new sources of grid variability and unpredictability are added, the analysis is virtually forced to consider only the use of natural-gas fired generators for providing the range of services required for grid operations (e.g. ramping, reserve, regulation). In fact, there is every reason to believe that by 2020 the tools and technologies that have been excluded from consideration in the 2010 LTPPs will allow the grid to be operated virtually without the need for dedicated fossil generators for integration purposes. Time will tell if we are right in this prognostication, but a key step to making it a possibility is for the LTPP modeling efforts to at least consider such scenarios.

We are also concerned about the assumptions that underlie the environmentally-constrained scenario, which is one of the four mandatory scenarios that the Commission specified for use in the 2010 LTPPs (see discussion below, *Scenarios*). Our concern is both about the arbitrariness of the environmental criteria that were used in the environmental-ranking analysis, and more fundamentally about the issue of proportionality in carrying out such detailed environmental analysis of the renewables options, when the greater environmental concern should be about the fossil-fuel generators that the renewables are supposed to displace.

The problem is that with the analytical methodology that has been developed for the 2010 LTPPs, environmental screening is being applied to all of the renewable generators in constructing the renewables scenarios, but no environmental screening is being performed during the part of the analysis that identifies and fills-in the need for fossil resources. This places disproportionate attention on the liabilities of renewables, while ignoring the much greater liabilities that renewables policies are intended to ameliorate. The result is a highly unbalanced analysis.

We also note that the Standardized Planning Assumptions assume that Rule 21 will be used to interconnect all wholesale DG PV resources. Rule 21 is applicable currently to only a small sub-set of this resource potential. The large majority of wholesale DG PV projects will probably interconnect under FERC-jurisdictional WDAT or CAISO GIP procedures. Moreover, both CAISO and PG&E have expanded Fast Track eligibility in 2011 to 5 MW in some situations (up from 2 MW previously), potentially allowing many more projects to interconnect without upgrades to distribution lines. We ask the commission to revisit E3's assumptions about interconnection costs for wholesale DG PV projects in light of these changes to interconnection procedures.

Moreover, the Commission has recently undertaken a settlement process to resolve quickly the many issues being addressed in the newly convened Rule 21 Working Group (now known as the Distribution System Interconnection Settlement or DSIS; an Order Instituting Rulemaking is expected to be issued very soon). If this process is successful, it is likely that some significant changes will be made with respect to interconnection of renewables on the distribution grid by the end of the year. This timeframe is sufficiently fast to incorporate the results into this LTPP and we urge the Commission to do so.

Scenarios

In addition to working on developing a common assumption set to be used in the 2010 LTPPs, a great deal of effort has been invested, both in the predecessor to this proceeding, R.08-02-007, and in the early part of this proceeding, R.10-05-006, in developing a common set of renewables scenarios for achieving the state's 33-percent renewables-by-2020 goal. In the end, the utilities were directed to analyze four priority scenarios, which were designated:

- Trajectory
- Environmentally Constrained
- Cost Constrained
- Time Constrained

Three additional scenarios were also recommended, a low- and high-demand variant of the Trajectory scenario, and a reference 20-percent renewables scenario. In addition to these Commission-developed scenarios, the three IOUs, in a joint effort, developed and analyzed an additional three scenarios. Our discussion focuses on the seven Commission-specified scenarios, unless otherwise indicated.

The seven Commission-specified scenarios are described as different combinations of six renewable resource types:

- Biogas (landfill gas, dairy digesters, waste-water treatment)
- Biomass
- Geothermal
- Hydro
- Solar (solar-thermal electric, large-scale PV, small-scale PV)
- Wind

The four priority scenarios all have the same demand driver, so the amount of renewable energy that must be procured in 2020 (33-percent of demand) is the same for each scenario. Thus, the priority scenarios can be thought of as four different combinations of the same aggregate amount of renewable energy generated from the six renewable energy sources under consideration. Early in the process it appeared that the Commission was leaning towards constructing scenarios that were distinguished in large part on the basis of emphasizing one or another of the six renewable resources, or limiting one or another of the resources. In the end, in an effort to produce scenarios that have an element of realism, or more particularly, to meet specific policy objectives, the Commission decided to go with scenarios that are based on defined driving functions: current contracting trends (trajectory), environmentally constrained, cost constrained, and time constrained.

In recognition of the fact that the procurement of renewables is an ongoing process, the Committee adopted the approach of identifying a discounted core of new renewable resources, which is extracted from the existing portfolio of RPS contracts for new projects for each IOU. Each of the four priority scenarios incorporates the defined discounted core of new projects and build-out from there, based on the defined driving function for the scenario. For all scenarios it is assumed that the existing (2010) fleet of renewable generators will continue generating at the current (2010) level throughout the timeframe of the analysis (2011 – 2020).

The GPI has been a consistent supporter of using a discounted core of projects already in development to be included in the construction of the various planning scenarios for the 33-percent RPS analysis. However, we do not think that the methodology for constructing the core that was used in developing the various 2010 LTPP scenarios is the correct one to use. The methodology that has been used involves starting with the broad set of projects that are in the Commission's RPS project database as having RPS contracts, or contracts under serious negotiation, and selecting those projects that have met selected milestones, such as obtaining permits or breaking ground.

Rather than trying to pick individual project winners and losers for the discounted core, even using selection criteria that are reasonably transparent and objective, we believe that the discounted core should be selected by starting with the same broad set of projects that are in the Commission's database, but rather than picking winners and losers, each project should be treated on a probabilistic basis, and discounted by a factor that represents the probability that the project will successfully achieve operational status. The probability of success may be related to a variety of factors, such as the resource type, the technology, and the developmental milestones that the project has already achieved.

Assigning probabilities can be done on a very simple basis, or in a more detailed analysis. For example, a rudimentary analysis might use a success-probability of 70 percent for all conventional (commercially-proven technology) renewable projects with power contracts, and 50 or 60 percent for projects with contracts that use technologies that are at an earlier stage in the commercial-development cycle, such as some of the solar projects. Projects in the database that have contracts still under negotiation might be assessed an additional five-percent discount. Of course, the analysis can be performed on a more detailed basis, taking into account factors like local resource quality, transmission access, and developer experience. It is important to note that most or all of the data needed for the analysis are already available to the Commission. We are proposing an approach that is no more difficult than the one that was used, but our approach does not pick winners and losers, and produces a more mathematically-sound result.

The following two charts show graphically the composition of the seven Commission-specified scenarios from two different perspectives. Figure 1 illustrates the renewable components of the seven standard scenarios. Figure 2 illustrates how the contributions of the various renewable resources vary by scenario. The scenarios, as defined by the Commission and shown as vertical columns in the charts, are estimates of contributions in 2020 from **new** (post 2010) renewable generating resources. The second chart shows the composition of the 2010 baseline of renewable resources, as well as RPS procurement in 2005, in addition to the seven defined scenarios for new resources.

Figure 1

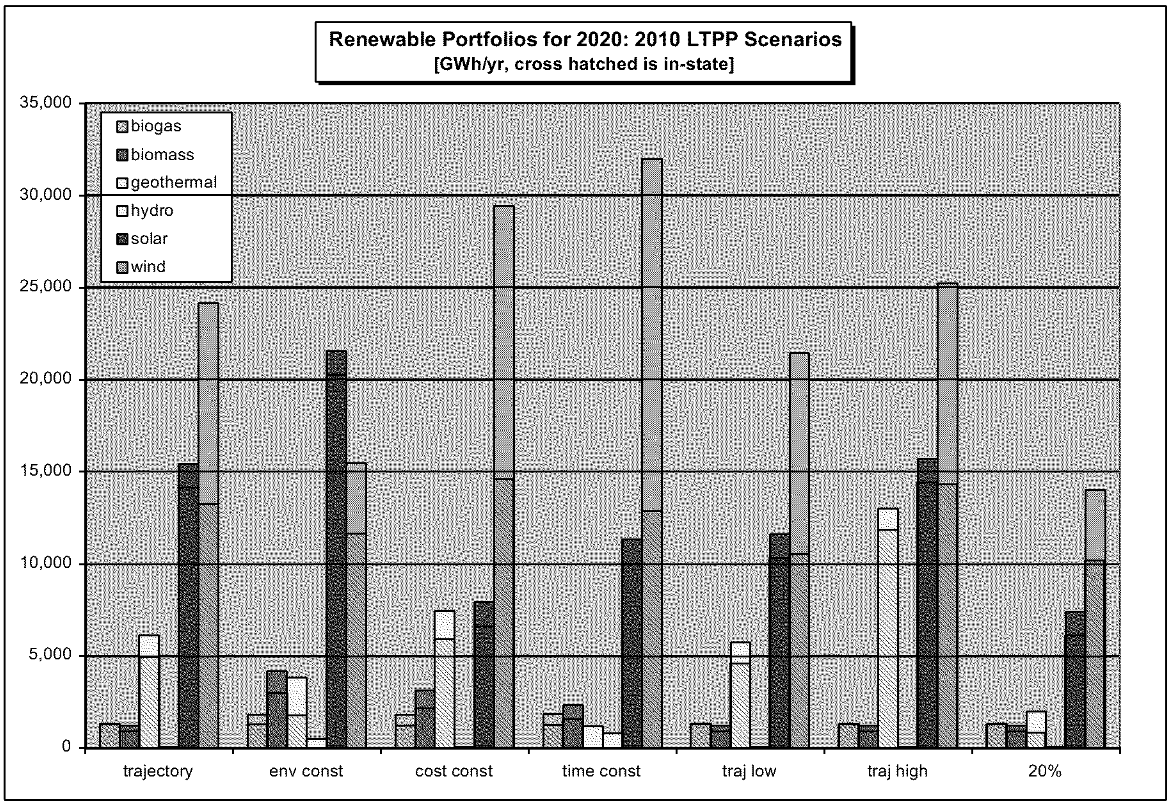

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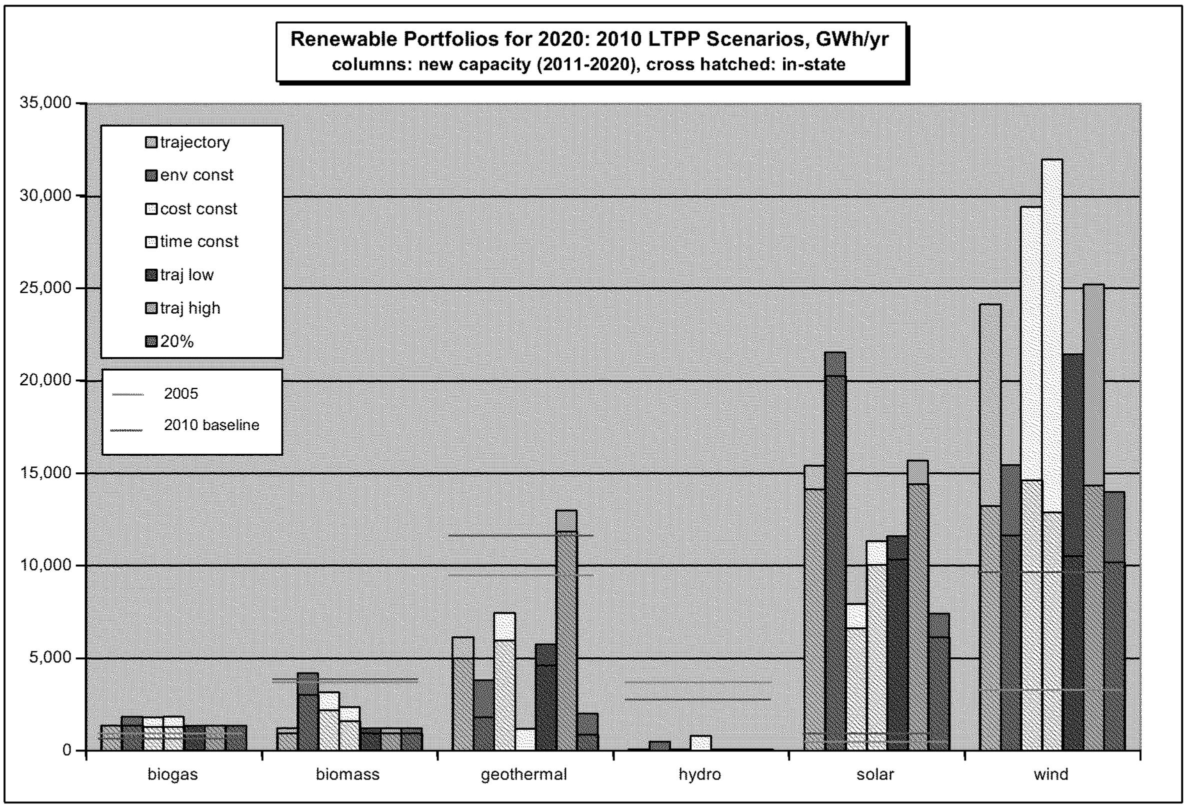
Figure 2



Several observations are worth making:

- There is rather limited variability among the scenarios.
- Some 80% of new renewables in all scenarios are solar and wind, compared to 18% of the existing fleet.
- Every scenario depends on explosive growth in solar, which today contributes only 3% of renewables.
- No scenario explores the impacts of emphasizing baseload renewables.
- Most of the out-of-state procurement is wind.

Limited Variability among Scenarios

As figure 1 shows, all of the Commission-specified scenarios are similar: primarily wind and solar, with smaller amounts of baseload renewables, and a bit of out-of-state hydro in two of the scenarios. Most of the variability among the scenarios is in the amounts of solar, and out-of-state wind. Biogas is virtually the same in all of the scenarios, while biomass and geothermal show a small amount of variability.

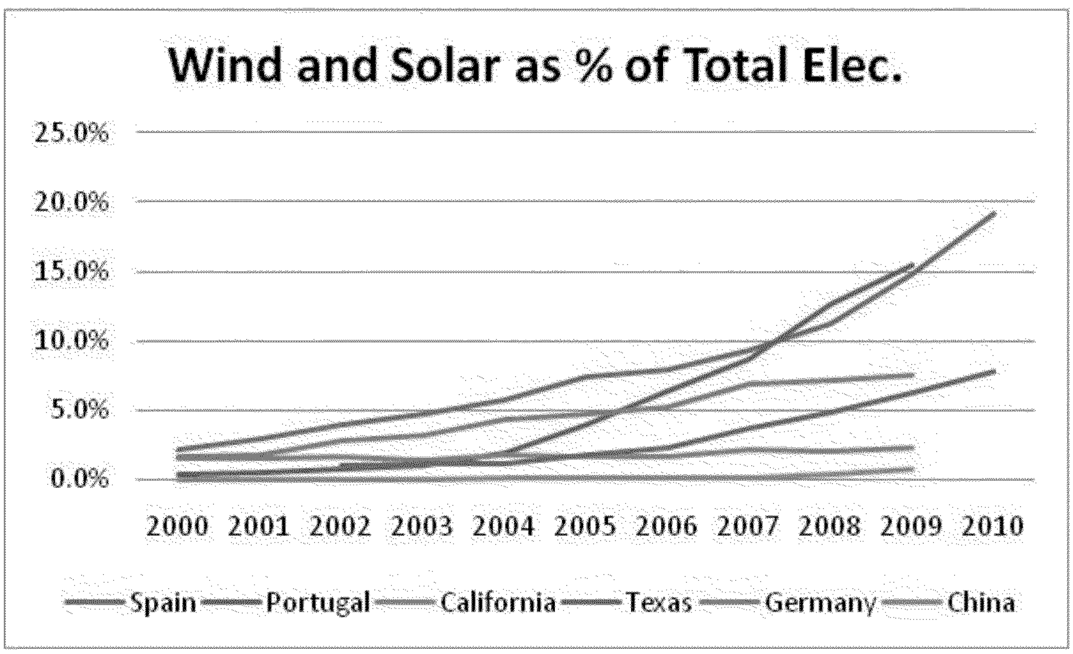
The GPI would have liked to have seen much greater variability among the priority scenarios in terms of their renewables composition, in order to provide for a broader perspective on what a 33-percent renewables future could look like. In future rounds of the LTPPs, it is our recommendation that rather than base the composition of the scenarios on different defined driving functions, they should be based on providing a wide and illuminating view of the range of possible combinations of resources that can provide the overall renewables target. As long as all of the scenarios have the same demand function, it is simply a zero-sum game among the six renewable resources. We believe that the most productive approach is to acknowledge this, and design scenarios that are intended to show a range of structurally-distinct trajectories to renewables growth, rather than trying to construct scenarios based on various defined driving functions.

Growth Concentrated in Solar and Wind

Solar and wind, the two intermittent renewable energy sources, contribute 75 – 88 percent of the new renewables in the four priority scenarios, a resource mix that is radically different than the mix of the currently-operating renewable generation fleet in California. As the horizontal lines in Figure 2 show, since the inception of the RPS program in California geothermal energy production has been the dominant renewable contributor, providing roughly half of California's renewable energy throughout the past decade. Biomass provided more renewable energy than wind in the early years of the program (see, for example, the data in Figure 2 for 2005), but wind far surpassed biomass in its contribution by 2010. Solar, while doubling in output between 2005 and 2010, nevertheless contributed only three percent of California's total renewable energy supply in 2010.

As Figure 2 shows, the only two renewable resources that have seen significant quantitative growth in output over the past five years are wind and geothermal, and much of the geothermal growth was the result of a re-contracting of some of the Calpine geysers properties in 2007. Thus the only renewable resource that has achieved significant growth in terms of new generating capacity placed into service during the course of the first decade of the RPS program is wind, and a good deal of the increased wind capacity is from out-of-state resources that only recently became eligible for the California RPS as the result of legislative and regulatory rule changes allowing the use of unbundled and tradable RECs. While California led the world in renewables for many years prior to the 2000s, since then we have been overtaken by many other jurisdictions and have seen relatively modest growth in renewables, as illustrated in Figure 3. This LTPP should be focused on helping California achieve the substantial renewables growth necessary to meet the 2020 RPS mandate.

Figure 3 *(Sources: CEC and EIA).*



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In our opinion, at least one scenario should have been included in the analysis that is considerably less dependent on solar and wind than the four priority scenarios, instead relying on significant contributions from new biogas, biomass, and geothermal. Perhaps a scenario that specifies new biogas, biomass, and geothermal energy contributions equal to or greater than their respective 2010 levels could provide the basis for this posited baseload-renewables scenario. Such a scenario might provide a very different perspective about grid operations in 2020 than any of the four priority scenarios that were specified for the 2010 LTPPs.

Dependence on Solar Technologies

The GPI is particularly concerned about the dependence of every single one of the seven Commission-specified scenarios on an explosive growth in the generation of energy from solar resources. California has a tremendous endowment of solar resources. However, much of the technology for converting solar energy into electricity is still in the early-commercial stage of development, and has not yet been proven ready for the kind of extensive deployment in the marketplace that is envisioned in all of the scenarios. Our point is not that solar should not be included in these scenarios, but rather that there is a real risk that the technologies needed for such explosive growth in solar will simply not be able to achieve the developmental milestones that will allow the extensive deployment envisioned in every single one of the priority scenarios in the timeframe of the analysis.

California renewable energy policy over the past decade has been strongly supportive of solar energy, providing more extensive subsidies for this particular energy source than any other renewable. Nevertheless, as illustrated in Figure 2, as recently as 2010 solar was still a minor contributor, on a quantitative basis, to California's total renewable energy supply. To expect it to contribute 16 – 46 percent of the new renewable energy need, as the four priority scenarios do, is unnecessarily aggressive. We believe that at least one of the required scenarios should have included a constraint that new solar will not exceed, say, 7.5 percent of the new renewables mix in 2020. That in itself would require an annual compound growth rate for all solar (solar thermal electric, small- and large-scale PV) in California of approximately 10 percent between 2010 and 2020. And that would be the low-solar scenario.

Baseload Renewables

During the course of the development of the mandatory scenarios for the 2010 LTPPs in R.08-02-007 and R.10-05-006, the GPI argued for the inclusion of a 33-percent renewables scenario based on emphasizing baseload renewables (biogas, biomass, geothermal). Our suggestion was not accepted, with the result that on average 80 percent of the new renewables in the priority scenarios are composed of intermittent resources. Considering the fact that one of the primary reasons for conducting the scenario analysis is to estimate the amount of new, integration resources that are needed in the system to handle the intermittents, the scenarios and associated analyses fall short in two important respects. First, scenarios less dependent on intermittent resources, which presumably would require less integration, were not included in the analysis. Second, the baseload and schedulable renewables that are included in the priority scenarios are not considered as being able to contribute to integration, thus missing some of the valuable benefits that these resources are capable of providing to the system in addition to bulk renewable energy. This omission leads to an over-estimation of the need for new fossil resources for integration purposes.

In fact, some baseload renewables today provide valuable voltage and var support services to parts of the grid that are weak, as well as providing reliable, schedulable electricity. As far as we can tell, none of the analyses performed for the 2010 LTPPs gives any credit for these grid-operability services, or for the ability of some baseload renewables that have the ability to provide some kinds of load-following services, should there be appropriate incentives to do so. By ignoring all of these potential benefits, the analysis devalues baseload renewable generators.

Out-of-State Renewables

It is worth noting, as figures 1 and 2 both clearly show, that the great majority of the out-of-state renewables that are forecast to be used in the various Commission-defined scenarios are wind. Moreover, most of the variability among scenarios with respect to wind is variability regarding the amount of the out-of-state wind component, rather than in-state wind. It appears that, based on the data in the adopted input-assumption set, out-of-state wind is the marginal renewable for California under most circumstances. It is unclear how all of that wind energy can be used locally while the RECs are stripped and sold to California retail sellers. This is an issue that ought to be addressed in future rounds of the LTPPs.

Suggestions for Additional Scenarios in Future LTPPs

In addition to producing a broader range of priority renewables scenarios for future LTPPs, we would like to see the Commission both give some thought to extending the analysis beyond the statutory mandate of 33-percent renewables by 2020, for example to 40-percent by 2025, and to consider adding an additional scenario to the mix in which coal-generating facilities are phased out of the California supply mix as rapidly as possible. CAISO's results demonstrate that is not infeasible to phase out coal by 2020, so we urge the Commission to consider this scenario in the next LTPP. Presumably this would have implications for both the renewable and non-renewable components of the state's energy supply mix. We look forward to working with the Commission and parties over the next LTPP cycle to develop more meaningful scenarios for analysis.

Methodology

There is broad agreement among the parties that the overall analytical approach that has been pursued by the CAISO and the utilities in their July 1, 2011, *Testimonies*, is sound. We count ourselves among those parties, but there are two important methodological details that we feel warrant discussion here. First, we are concerned that the level of detail in the analysis that has been performed goes well beyond the point of reasonability, given the level of generic generality of the input-data set underlying the analysis. Second, we are concerned that the integration analysis is based on applying approaches to grid operations that were designed for the system of the past, to the very different system that is likely to exist in the future.

A variety of new technologies and techniques will be available to help operate the electric system in 2020, with a high likelihood that renewables integration, as indeed balancing all sources of variability and unpredictability on the grid, will be accommodated almost entirely without the use of conventional gas-fired generation for integration, the only option that is considered for the job in the 2010 LTPPs.

Level of Detail not Consonant with the Quality of the Input Assumptions

The input-assumption set underlying the analysis was developed using an open, stakeholder-driven process, and relies almost entirely on publicly-available data. This ensures a high level of transparency, but to some degree it comes at the expense of accuracy and breadth. Projects are characterized by industry-wide generic data sets, and the renewable resources driving the projects in the database are similarly driven by generically-characterized resource information. In addition, the potential benefits of technology change are largely excluded from the analysis, which covers a ten-year time horizon. Technology change cannot be predicted with accuracy, but it is certainly inaccurate to predict that over the course of ten years it will not occur at all.

The July 1, 2011, *Testimonies* of the CAISO and the IOUs virtually ignore the topic of analytical uncertainty. This omission has the unfortunate result of imbuing the results of the analysis with a level of perceived certainty and accuracy that is simply not supported by the underlying data. In our opinion, the kind of analysis that has been conducted in this proceeding can be used to support broad conclusions about different scenarios. For example, the analysis as conducted can identify broad trends appearing in all of the scenarios, or dramatic differences among the scenarios in the calculated metrics, but they simply cannot be used to draw fine distinctions among the scenarios.

Operating the Grid of the Future with the Tools of the Past

Renewable generating sources in general, and intermittent renewables in particular, present operating challenges and opportunities for the integrated electric grid that are qualitatively different than what is found on a grid that does not include intermittent renewables, or renewables in general. In the opinion of the GPI, it does not make sense to simply assume that the operating techniques that were designed for the old, non-renewables-based system of the past are the best approach for operating the renewables-rich system we are trying to build for the future. It is well known that new technologies, such as smart-grid controls, storage, and plug-in vehicle charging, present potentially valuable opportunities for enhanced, non-fossil-fueled operability of the grid, even on a grid with a high level of penetration of intermittent generating sources. Until the analysis is repeated taking these new opportunities into account, there is a strong, inevitable bias towards over-identifying a need for new fossil generating resources.

Results

The GPI is a party to the proposed *Settlement Agreement* that was submitted to the docket under an August 3 *Motion for Approval of Agreement*, prior to the recent Hearings in the LTPP proceeding, R.10-05-006. The proposed *Settlement Agreement* is mainly concerned with the question of whether the integration analyses have or have not identified a need for new fossil integration resources over the coming decade. We stand behind the *Settlement Agreement's* conclusions on this issue, but reserve the right to proffer our own opinions in the event that the *Motion to Approve the Settlement Agreement* is not endorsed by the Judge in this case.

In the opinion of the GPI, **the overwhelming conclusion of the analyses presented in *Testimony* by the CAISO and the utilities is that it makes little difference which renewables development trajectory is followed**. The costs are all about the same, the environmental improvements are all about the same, and despite the fact that promising new technologies for improving grid operations are left out of the analysis, there is still no identified need for new fossil-fired resources for purposes of renewables integration in any of the PUC-defined scenarios. Indeed the results for the four priority scenarios are functionally indistinguishable, given the closeness of the calculated metrics, and the magnitude of the uncertainties underlying the analysis.

It would be interesting to see whether a more varied set of renewables scenarios would produce results that show real distinctions among different pathways to a 33-percent renewables future. Nevertheless, for now the makeup of the renewable mix of the future does not appear to be overly important. In our opinion it would be more productive to concentrate on creating a robust renewable-energy market, rather than worrying about trying to understand all of the details of a market that is still not growing the way it is supposed to be some eight years since the inception of the California RPS program.

Track III Issue: Greenhouse-Gas Compliance-Product Procurement Plans

There are several issues being addressed in Track III at this point in the proceeding. The GPI is *Briefing* only on the greenhouse-gas-product procurement issue. The June 10 *Ruling* states:

> On the fourth issue - utility procurement of greenhouse gas related products - each utility's testimony should provide a proposed greenhouse gas management framework (including evaluation of greenhouse gas risks associated with utility-owned generation, bilateral contracts, and spot market purchases), and explain how such a greenhouse gas management framework would govern the utility's proposed upfront achievable standards for greenhouse gas allowance and offset procurement.

In our August 4 *Testimony*, the GPI expressed our concern that the utilities be prevented from engaging in arbitrage-for-profit of greenhouse-gas compliance products. Other greenhouse-gas markets around the world have had mixed results. AB 32 is intended to require the utilities to reduce the greenhouse-gas intensity of their generation mix. It is certainly not the intent or expectation of AB 32 to create arbitrage-for-profit opportunities. Another proceeding, R.11-03-012, is addressing issues concerning the use of funds accruing from the free distribution of emissions allowances to the utilities, but some related issues probably will also be managed in this proceeding, and we urge the Commission to do what it can to ensure that the utilities are granted only that authority necessary to procure and sell the greenhouse-gas-related products that are required to conduct their business, while limiting ratepayer exposure to costs.

Setting Initial Baselines

We believe that it is useful to look at the example of the European Union in starting up its carbon market, as well as the early structuring of the RPS program in California, for lessons to be learned in setting up California's new market for greenhouse-gas emissions allowances and offsets. The ultimate purpose of a cap-and-trade program is to reduce greenhouse-gas emissions on a geographically large, economy-wide basis. When such a program is working as planned, the supply of greenhouse-gas compliance products (allowances and offsets) falls over time increasingly below historical demand, and prices should tend to be consistently on the high side, given whatever regime of market constraints or price controls set an upper limit on the market price.

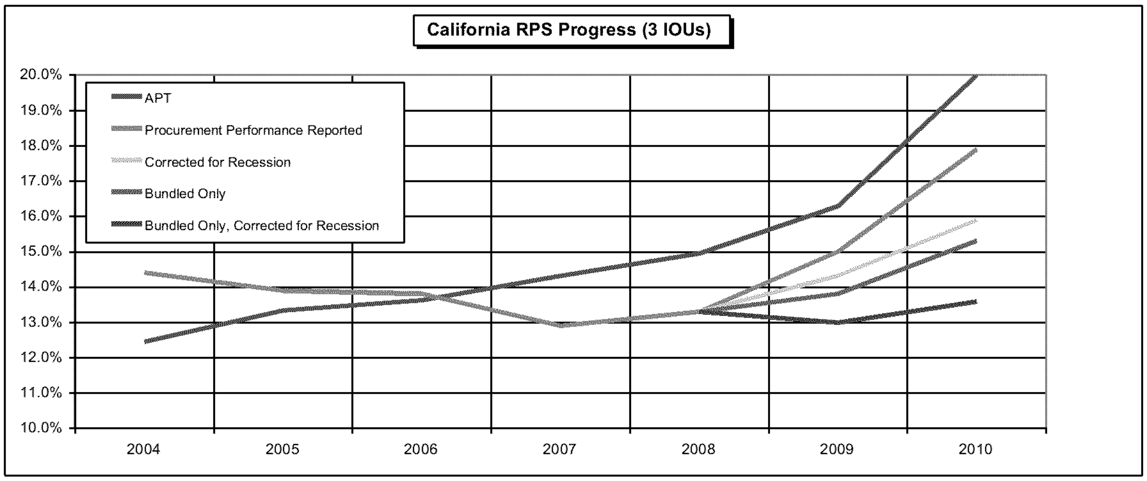
Many of these types of programs, including the ARB's still-under-development cap-and-trade program for California, are intended to begin their operation with a supply of compliance products that is roughly at the level of demand in the economy before the institution of the program. The problem with this approach from a practical standpoint is that it is extremely difficult to determine exactly how many compliance instruments are necessary to just meet current demand, a difficulty that is compounded by the fact that economies can expand or contract over rather short periods of time, either of which changes the demand for greenhouse-gas compliance products.

Like in REC markets, prices for greenhouse-gas compliance products are likely to tend to one extreme or the other of the range of possible market prices. If the greenhouse-gas compliance products are in short supply, which the program ultimately attempts to ensure is the case, then the price of the products will tend to approach whatever limits that the market imposes (price caps, other limits resulting from programmatic cost controls or other market constraints). On the other hand, if the compliance products are in long supply, their price will tend to plummet. This is what happened in the early years of the program run by the European Union. There is little doubt that regulated emitters of all varieties will work hard to push the ARB to maximize the initial supply of compliance products that is introduced into the marketplace. We strongly urge the ARB, and this Commission as their partner, to avoid producing an oversupply of compliance products in the first, multi-year compliance period of the cap-and-trade program. If too many compliance instruments are created, the cap-and-trade program will not function the way it is intended to at its inception, and the fallout could be long term.

The early structuring of the state's RPS market provides an interesting parallel regarding the pitfalls of setting initial baselines, and the resulting negative long-term effects on the pace of the implementation of the program. In the case of the RPS program, the Commission, in the opinion of the GPI, set the initial RPS baselines for the three IOUs at too low a level. This allowed the IOUs to not only easily achieve their compliance obligations in the early years of the program, but achieve a measure of over-procurement that could be banked ahead for future compliance years. Decision 04-06-014, in R.04-04-026, made the final readjustment of the baselines for each of the state's three large IOUs. Each utility was given a lowball baseline, with the result that each was procuring RPS energy at levels well above their APTs from the inception of the program through 2005, despite the fact that renewable energy procurement was virtually unchanged during this period, and APTs were increasing by one percent of retail sales per year.

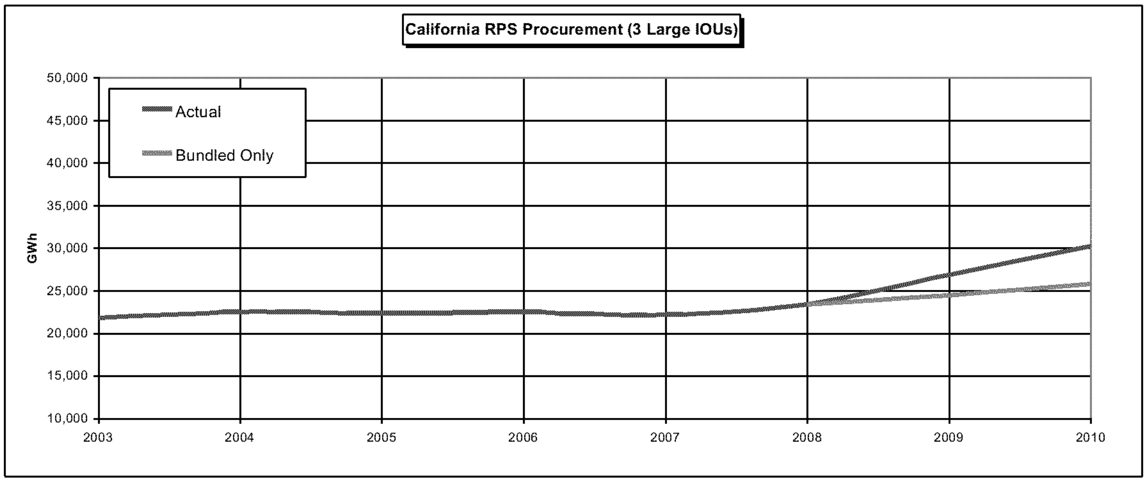
Figure 4 shows the RPS procurement performance (aggregate, 3 IOUs) during the first phase of California's RPS program, which ran from 2003 – 2010. As the figure illustrates, the 2004 baseline readjustment resulted in actual procurement results for that year that were two percentage points higher than the APT (14.5% vs. 12.5%). The APT then began its inexorable rise towards 20 percent in 2010. Had the IOUs' aggregate procurement held steady at 14.5%, the APT would not have caught up with procurement until 2007. In fact, with a falling level of procurement, the APT reached actual procurement in 2006, and the IOUs have been in deficit ever since. Nevertheless, the amount of energy that was banked ahead during the period 2004 – 2006 was enough to offset deficits into 2008. In the opinion of the GPI, had the 2004 baselines been set at a level that was closer to where procurement actually was, the lack of statewide progress in increasing renewable procurement would have become obvious much sooner, and corrective actions might have been able to have been taken.

Figure 4



In part because of the fact that the initial baselines were set too low at the start of the RPS program, the rapid increase in renewable energy procurement that the RPS program was intended to foster never happened. Figure 5 shows the total amount of RPS procurement during the first phase of California's RPS program. As the figure shows, in-state renewable energy production has barely changed over the course of the first decade of the program, and total procurement has increased rather modestly, from 22,000 GWh to 30,000 GWh over a 7-year period, an average compound growth rate of 4.5 percent.

Figure 5



Hedging and the Market for Greenhouse-Gas Compliance Products

The three IOUs all point to some form of hedging strategy as a means for controlling the risks of price spikes in the greenhouse-gas compliance-product market, citing the strategies they employ in managing price risk in the natural gas market. In the opinion of the GPI, the cyclical natural gas commodity market is not a good model for the market for greenhouse-gas compliance-products that is being created in conjunction with the ARB's establishment of a cap-and-trade program to reduce greenhouse-gas emissions. Although, as discussed above, it is certainly possible that during the first compliance period for the program (2013 – 2014) an oversupply of compliance products will be made available, in the longer term the supply of products should become increasingly scarce, with inevitable upward pressure on prices.

The fact that compliance instruments can be banked forward between the multi-year compliance periods tempers what might otherwise be a tendency for price spikes near the end of the periods. This being the likely future, the proper procurement policy for retail sellers might well be to simply diligently participate in auctions, and acquire as many allowances as reasonable in each auction. Concurrently, retail sellers with emissions needing allowances should always be looking for price points at which it becomes economically feasible to switch to lower-emitting alternatives.

PG&E's Redactions

Page 3-11 of PG&E's *Testimony* (Exhibit 107) states: "PG&E requests that the Commission approve the following procurement strategy for GHG-related products." What follows, eight pages of text, has been entirely redacted by PG&E, raising substantial concerns for GPI and, we believe, many interested parties. Neither SCE nor SDG&E redacted **any** of their GHG-procurement plans, and it is not at all clear why PG&E feels that so much of its plan must be redacted. We note that PG&E did not justify its redaction as required by D.06-06-066 and subsequent clarifying Decisions in the confidentiality rulemaking, R.05-06-040.

During the August Hearings in this proceeding, during my questioning of PG&E witness Ms. Melissa Brandt on the topic of these heavy redactions, ALJ Allen cautioned the witness and PG&E counsel that the *Testimony* in question truly is over-redacted, and ought to be fixed. We request that the Commission order PG&E to reissue this section of their *Testimony* with an appropriate and properly-justified level of redaction, if any.

Urgency in Acting on Greenhouse-Gas Product Procurement Plans

In their July 1, 2011, *Testimonies* in this proceeding, all three IOUs request a Decision on their greenhouse-gas product procurement plans by the end of the current calendar year (2011). Since that time the ARB has announced that the startup of the cap-and-trade program will be delayed a year, now to begin on January 1, 2013. This removes the extreme time pressure to make a quick determination, and allows the Commission to properly deliberate and act.

Through the August Hearings, PG&E continued to cling to the position that a determination on their procurement plan for greenhouse-gas compliance products was needed before the end of 2011, despite the fact that both SCE and SDG&E acknowledged that a determination by the end of the first quarter was more than sufficient to allow them to prepare for the first scheduled auction of allowances, which will be in August, 2012. Considering the redaction issues facing the PG&E plan (see above, PG&E's Redactions), which has the potential to delay the approval process for them, we urge the Commission to fully deliberate the issues without feeling rushed, and target an end of March, 2012, Decision for all three IOUs.

Conclusions

The 2010 LTPPs show substantial improvements over the 2006 plans, in large part a result of the planning efforts undertaken by this Commission in R.08-02-007 and R.10-05-006, to develop a common input-assumption set and set of standard scenarios for achieving 33-percent renewables-by-2020 for use in the system LTPPs. Nevertheless, we believe that there continues to be room for improvement in the process, and hope to see progress made in the next, 2012 LTPP cycle. We hope to see a broader range of renewables scenarios developed, a consideration of new and emerging technologies and approaches for operation of the integrated electricity grid, and serious consideration of the issue of uncertainty in the analysis. With regards to Track III issues, we are concerned that the IOUs are planning to model their procurement strategies for greenhouse-gas compliance products on the natural gas market, a cyclical and volatile commodity market, which is unlikely to be representative of the likely functioning of the newly-developing greenhouse-gas emissions compliance-product market.

Dated September 16, 2011, at Berkeley, California.

Respectfully Submitted,

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