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California Energy Commission
Docket Office
Attn: Docket No. 06-IEP-1C and 03-RPS-1078
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Re: 2006 Integrated Energy Policy Report Update – RPS Mid-Course Review

Pacific Gas and Electric Company (PG&E) respectfully submits the following comments regarding the CEC's August 22, 2006, workshop examining a mid-course review of the Renewables Portfolio Standard Process.

Thank you for considering our comments. Please feel free to call me at the number above if you have any questions.

Sincerely,

Les Guliasi

Attachment

Comments of Pacific Gas and Electric Company
On the CEC's August 22, 2006 Workshop Regarding
Mid-Course Corrections to the Renewable Portfolio Standard

INTRODUCTION:

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide written comments on the progress being made toward California's renewable energy resource goals, and the opportunity to participate at the workshop convened on August 22, 2006, ("Workshop") by the Integrated Energy Policy Report (IEPR) Committee ("Committee"). Roy Kuga, Vice President of Energy Supply, and Chifong Thomas, Principal Transmission Planning Engineer of Electric Asset Strategy, presented the views of PG&E at the Workshop. These written comments incorporate highlights from PG&E's discussion of issues at the workshop and respond to the 15 questions posed by the Committee's Notice in more detail than was possible at the Committee's workshop.

A. PG&E is Making Steady Progress Toward Meeting its RPS Goals

The Committee's July 6th Workshop notice called for a mid-course review of the RPS program because, among other things, the amount of new RPS capacity that has been brought on-line to date has been relatively small. In response to that workshop, PG&E's written comments included a summary of signed contracts, which showed that PG&E is making steady progress toward achieving its 20% renewable goal. At the completion of the 2005 RPS Solicitation, PG&E expects to have contracts for 16-18% of retail load to be delivered in 2010.

In addition, PG&E has recently announced a memorandum of understanding to purchase up to 500 MW of solar power from Luz II, and has announced its intent to study the potential for substantial volumes of renewable power to be delivered from British Columbia.

PG&E is also working with developers of emerging technologies on smaller projects to encourage technical innovation. In short, PG&E is committed to meeting its RPS goal to get new resources online by 2010 and expand renewable supplies.

Even though the Workshop was intended to investigate whether a simpler, more transparent RPS process would assist the pace of renewable procurement, most, if not all workshop participants concurred that most of the issues on the agenda, that is, Time Of Delivery (TOD) factors, calculation of the Market Price Referent (MPR), and the Transmission Ranking Cost Report (TRCR), did not handicap renewables development. Instead, there was substantial agreement that inability to finance their projects based on revenue streams funded by Supplemental Energy Payments (SEPs) was one of the most significant barriers to development, along with the uncertain availability of tax credits, lack of transmission, and the scarcity of equipment. The California Public Utilities Commission (CPUC) representative stated that developers advised him that the SEP process, confidentiality issues, and the retention of public good funds by the Department of Finance limited their development of bids. The CalWEA representative stated that the MPR process at the CPUC was one of the most transparent processes, and while the TOD process was less transparent, it did not present a problem for bidders. The Independent Energy Producers (IEP) representative stated that his members were not concerned about TOD factors, or that the MPR was unknown when bids are submitted. However, he emphasized that if the project is eligible for SEPs, payment certainty is critical to enable financing of the project. The GPI spokesman concurred with the expressed need for SEPs certainty. Representatives of the three major utilities also noted the developers' concern about the ability to finance their projects based upon SEPs.

Workshop participants confirmed what the Committee had already heard at its July 6 workshop – that secure project financing was the key to new renewable generator development. Fine-tuning the process by which the buyer and seller reach agreement was a second-order issue. PG&E urges the Commission to address the role of SEPs and to propose, by legislation if necessary, the means to make SEPs financeable so that the public good charge will actually be used to promote the development of renewable energy central generating resources.

B. The TOD process may be having unanticipated consequences for the SEP payment process

As acknowledged by Workshop participants and described in more detail below, the TOD process is not overly complex. TOD factors simply differentiate a project's payments between time periods, and allow the utility to value the power of the project output in each time period. Although the specific values used for RPS, CEE, etc. may differ, the underlying principles and methodologies are consistent and well-understood by parties.

However, The RPS TOD factors do have an impact on the proportion of the payments a project receives that would be funded by SEPs, as opposed to payments from a utility. Even if two otherwise identical projects propose to charge the same average price per kilowatt hour for the same number of kilowatt hours, and therefore charge the same total amount for their output the project that would deliver a higher share of those kilowatt hours in time periods with higher TOD factors would obtain a lower proportion of those revenues from SEPs, or even none at all.

However, the CEC would only provide SEP funds for the first ten years of a project's contract. As a result, projects whose revenues would include a higher proportion of SEPs tend to have more difficulty obtaining financing that projects that would rely less heavily on SEPs.

Because uncertainty surrounding SEP payments may influence a generator's ability to finance its project, differences in TOD factors may influence the generator's decision to offer power to a utility with less attractive TOD factors.

If the Commission does not want to disadvantage offers for particular projects at particular utilities, it could require a single set of TOD factors for calculating payments and evaluating SEPs. Thus, PG&E would not object to using SCE's TOD factors for projects in Southern California, if ordered by the Commission.

C. The State should not adopt Standard Offer Contracts or Require the Utility to Purchase All Power Below the MPR.

The Commission suggests that streamlining the contracting process could help the state meet its RPS targets. PG&E does not believe the contracting process is the major impediment to meeting RPS goals. Rather, the state should focus on more substantial hurdles to renewable development. For example, financing is contingent upon approved payment streams, the availability of production tax credits may influence the funding process, the manufacture of equipment may take more time than anticipated, needed transmission takes time to build, and technological improvements to reduce cost takes time to evolve.

PG&E does not believe that a standard contract, or a requirement that utilities buy power at the MPR, are in the best interest of ratepayers. As described in response to questions 8 and 9, such a requirement means that renewable bidders would no longer have to compete with each other, and would provide no incentive for the bidder to reduce its price or provide innovative proposals to address operating and other concerns. Conversely, bidders would have no choice, either, and might have to internalize this inflexibility as higher costs. The result is increases to ratepayers of hundreds of millions of dollars.

D. The State should not consider major changes to the TRCR

The Legislature has determined that the cost of interconnection must be considered along with the cost of generation when determining which potential generator is the least-cost best-fit generator. The transmission ranking costs set forth in the TRCR are designed to replicate as closely as possible the costs of the transmission facilities that will be required by the Independent System Operation (ISO) as a condition of interconnection of each RPS bidder's generation facility. The TRCR establishes a cost for each interconnection cluster during a snapshot in time, to be used simultaneously for all bids participating in a solicitation. The cost of transmission is imputed from a common scenario to each renewable bid to calculate the total cost of each proposed project to the consumer. Those costs are used as proxies to allow RPS bidders to avoid the costs and potential delay associated with the ISO Interconnection Process that could discourage bidding into an RFO.[1]

The Workshop notice identified transmission availability as a concern; in that case, further tweaking or fine tuning the TRCR as a method of selection of the short list would be of marginally added value. PG&E proposes that the CEC, CPUC and utilities should focus their resources on planning, developing, siting, and building needed transmission facilities so that transmission availability will not be a barrier to procurement of least-cost best-fit renewable resources.

TRCR serves a number of useful purposes in addition to developing the short list. Any changes to the TRCR development process could impair the usefulness of the report as a common planning tool for potential generators, and should be avoided.

- The TRCR provides a means to ensure transmission costs are accounted for when considering bids.

- The TRCR methodology estimates the actual transmission costs by using the same Federal Energy Regulatory Commission (FERC) rules that must be followed in the CAISO interconnection process and using the most up-to-date system and queue information available.

- The TRCR provides RPS bidders valuable siting information at no cost prior to entering the CAISO interconnection process, where project-specific cost estimates are provided at the developers' expense.

- The TRCR provides pre-bid information for the bidders to structure their bid to maximize their chance of winning.

- The TRCR provide information to guide the identification of the potential area(s) of need for future transmission projects.

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[1] If the RPS bidder has already obtained a cost estimate through the ISO Interconnection Process, PG&E will use that estimate for purposes of evaluating the total cost of the bid, rather than the estimates in the TRCR

ANSWERS TO QUESTIONS

TOD

Q1: Do current TOD practices dissuade potential bidders or add unnecessary complexity to the bid process?

Response:

No. TOD practices do not discourage bidders whose renewable projects would provide more valuable power than other bidders, and do not add unnecessary complexity to the RPS bidding process. However, it is possible that differences in TOD factors between utilities, and the resulting impact on SEP payments, may influence potential bidders. (See, also, response to Question 2).

PG&E uses TOD factors for different time periods to determine the value of the power that potential renewable projects would provide in different time periods, and to calculate the payments PG&E would make in each period to the sponsors of those projects. As a result, TOD factors make it easier for PG&E to procure the most valuable and cost-effective renewable power resources and energy.

The current practice of determining the TOD factors in time to include them in the RPS solicitation protocol makes the RPS procurement process simpler and more transparent. Before bids are submitted, bidders know the TOD factors that would be used to determine the payments that they would receive, and have the assurance that these factors will not change during the period covered by the procurement contract.

Applying the TOD factors for each time period to the generation that a renewable project would provide in that time period in each year provides a valuable indication of the market value (to customers) of the power that project would provide.

As a result, RPS TOD factors do not discourage bidders whose renewable projects would provide more valuable power than other bidders. Sponsors of potential renewable projects can use those TOD factors to estimate the power prices that would be consistent with the expected market value of the power those projects would deliver to PG&E. In turn, those TOD factors also enable PG&E, as part of its bid evaluation process, to evaluate proposed renewables projects by comparing the market value of the power that would be delivered in each period by different renewable projects.

Q2: How big of an impact do TOD factors have on RPS bid evaluations?

Response:

As part of its RPS bid evaluation process, PG&E applies TOD factors to the annual contract prices that renewable power project bidders propose to charge for power, in order to compute how much PG&E would pay for the power that bidder would provide in each time period in each year. PG&E uses the time-period specific payments to evaluate and compare renewable power projects that bidders offer in each of PG&E's RPS procurements

PG&E then compares those payments to:

(a) forward wholesale market power prices which reflect the expected future market value of the energy that bidder would provide to PG&E in each hour in each time period; and,

(b) the expected future market value of the generation capacity that bidder's project would provide to PG&E each year, based on the qualified Resource Adequacy (RA) value counting rules the CPUC established for different types of renewable generation resources.

PG&E estimates the future RA market value of the capacity of the renewable power project proposed by each bidder, by applying the CPUC's resource adequacy counting rules for the renewable project to the net capacity cost of a hypothetical marginal generation resource (e.g., a new combustion turbine coming on line in 2008).

The CEC also uses the TOD factors of each utility to determine the amounts, if any, of Supplemental Energy Payments for which a renewable project might qualify, subject to the availability of those funds.

The project's need for SEP funds, as distinct from its price, is not a factor in bid evaluation. However, even if two otherwise identical projects propose to charge the same average price per kilowatt hour for the same number of kilowatt hours, and therefore charge the same total amount, the project that would deliver a higher share of those kilowatt hours in time periods with higher TOD factors would obtain a lower proportion of those revenues from SEPs, or even none at all.

Q3: How/why are TOD factors in RPS solicitations different from the following: Time Dependent Valuation (TDV) used in energy efficiency, methods used to calculate the Short-Run Avoided Cost (SRAC) for qualifying facilities, and bid evaluation in all-source procurement?

Response:

Renewable power projects avoid both energy and capacity costs. PG&E used its estimates of the energy and capacity costs that it would otherwise incur in each hour within each time period to determine the RPS TOD factors.

The evaluation procedures PG&E has used in its all sources procurements utilize avoided costs that were derived by using forward market prices for power and natural gas, and a spark-spread options valuation model, in the same way that PG&E used forward market (wholesale) prices and a spark-spread options model to determine the RPS TOD factors that PG&E filed in February 2006.

Therefore, the valuation methods PGE used in its RPS Procurements are the same as the valuation methods PG&E used to derive the RPS TODs that will be used in its all sources procurements.

PG&E assumes that the phrase "Time Dependent Valuation (TDV) used in energy efficiency" refers to the time-differentiated avoided costs that the CPUC requires utilities to use to evaluate the benefits achieved by utility-sponsored energy efficiency programs.

The time-differentiated avoided costs the CPUC uses to evaluate the benefits achieved by utility-sponsored energy efficiency programs are still evolving, as evidenced by the record in recent CPUC proceedings on avoided costs for energy efficiency programs.

The shape of the hourly profile of the time differentiated avoided energy costs that the CPUC requires utilities to use in evaluating the benefits achieved by energy efficiency programs is based on an historical, rather than a future price shape. The shape of the hourly price profile used to evaluate the reductions in energy usage achieved by energy efficiency programs assume that the hourly market price shape in each future year will be the same as the time profile of actual hourly PX market prices in 1998 through 1999 ("the historical PX price shape").

However, the time profile of actual hourly day ahead wholesale market prices since the end of the energy crisis and the time profile of relative forward hourly wholesale market prices during those years ("forward market price shapes") have been significantly different from the relative hourly PX market price shape.

Finally, although the CPUC has indicated that it will explore these and other avoided cost issues in a "Phase Three Avoided Cost" proceeding, that proceeding has not yet been scheduled. PG&E and other parties have urged the CPUC to begin that proceeding as soon as possible, and in the process resolve the inconsistencies that now exist between the way avoided costs are determined for renewable power projects, demand reduction programs, energy efficiency programs, and conventional supply-side generation resources.

The method that is used in California to determine each utility's Short-Run (i.e., variable) Avoided Costs ("SRAC") to determine the amounts utilities pay under PURPA for energy provided by Qualifying Facilities ("QFs") is likely to change significantly within the next few weeks or months, when a decision is announced in a lengthy CPUC proceeding in which all of the investor-owned utilities, parties representing different groups of QFs, and other interested parties (e.g., TURN, DRA, etc.) litigated the method for determining those short-run avoided costs as well as other related issues.

In addition, the formula that is currently used to determine the short-run costs that PG&E and other California investor-owned utilities avoid by obtaining energy from QFs was originally expected to be only a temporary transitional formula that would be replaced once a California wholesale power market was established. Furthermore, the short run avoided costs based on that formula have consistently been substantially higher than actual wholesale power market prices. In particular, the market heat rates implied by that formula and the market natural gas prices on which it is based are significantly different from the market heat rates implied by actual forward market prices for power and actual natural gas prices.

Therefore, the formula that has been used to determine each utility's short-run avoided cost would provide little or no guidance in determining the capacity costs of conventional generation resources that would be displaced or avoided by renewable power projects.

The prices that utilities paid QFs in the past for capacity were determined through settlements of CPUC litigation and state-mandated standard offer agreements, which did not necessarily bear any relationship to the actual capacity costs that investor-owned utilities avoided as a result of buying power from QFs. Even the Time of Use ("TOU") and Seasonal factors that are used to determine how much of an annual capacity price a QF is paid in each season were determined in large part through negotiated settlements. As a result, those TOU and seasonal factors do not necessarily bear any relationship to the capacity costs avoided in different time periods in any given year.

Q4: Why are the assumptions, methodology, and calculations used in developing TOD factors not available in the public domain?

Response:

Actually, this information is publicly available. When PG&E submitted its current RPS TOD factors in February 2006, it provided an explanation of the methods, assumptions, and data that it had used to determine those RPS TOD factors. That written explanation is a publicly available document that can be obtained from the CPUC or from PG&E by contacting Niels Kjellund, nxk2@pge.com.[2] However, certain detailed model and input data must remain confidential.

Some of the data PG&E used to derive those RPS TOD factors were obtained from commercial vendors under contracts that specifically prohibit PG&E from disclosing those data to third parties. However, interested parties can purchase most of those data themselves from those commercial vendors.

The models and the other data that PG&E used (e.g., internal estimates of forward prices for natural gas and power beyond the next two to four years) are commercially sensitive, and their public disclosure might put PG&E at a disadvantage in negotiating purchases of

[2] Pacific Gas & Electric, **Supplement to the Draft 2006 Renewables Portfolio Standard Solicitation Protocol of Pacific Gas and Electric Company (u e-39) filed December 22, 2005 and TOD Factors Benchmarking Study** (February 8, 2006).

energy and capacity from third parties. PG&E has disclosed these models and data to non-market participants who signed non-disclosure agreements, including a number of non-market participants and evaluators who regularly review various PG&E decisions under guidelines established by the CPUC.

Q5: What modifications should be made to make TOD factors more easily benchmarked and ensure TOD factors help the state achieve 20 percent renewables by 2010?

Response:

PG&E included in its February 2006 RPS TOD filing at the CPUC a detailed explanation of how interested parties could use commercially available data and their own models to benchmark those TOD factors. No modifications to PG&E's TOD factors are necessary to enable benchmarking. The other California investor-owned utilities also included similar benchmarking methods in their RPS TOD filings.

Workshop participants, such as IEP's Mr. Kelly, said there was "not a lot of concern about TOD factors", and indicated that TOD factors do not impair the development of renewable resources. In fact, Mr. Kelly indicated that TOD factors help signal the demand for power at different times, and therefore, they provide an incentive to generate when the market demand for power is higher.

<u>Minimizing Contract Failure</u>

Q6. Lack of close coordination between transmission and project development, unfamiliarity with detailed permitting processes and incomplete communication could result in projects not coming on-line by 2010. What steps are utilities taking to minimize contract failure and delay?

Response:

The commercial reality is that projects can take several years to come online after contract execution. While lack of familiarity with the permitting process and incomplete communication could result in projects not coming on-line by 2010, there are other more critical factors that could delay project construction after regulatory approval. As previously noted, financing is contingent upon approved payment streams; the availability of production tax credits may influence the funding process; and the manufacture of equipment may take more time than anticipated.

PG&E is taking steps to minimize the impact of contract failure and delay. PG&E is engaging in voluntary over procurement to accommodate potential contract failure. In 2004, PG&E's renewable procurement, as measured by contracts for future deliveries, exceeded 2% of its retail sales volume, resulting in a GWh figure that was nearly 230% of the mandatory target. PG&E currently anticipates signing contracts resulting from its 2005 RPS solicitation for the delivery of renewable generation totaling 2-4% of its annual sales. PG&E will likewise include a margin of safety in its 2006 procurement.

The best way to reduce contract failure is to execute contracts with projects that are advanced enough to fully understand their economics, permit conditions, and deliverability. The developers themselves determine that the risk of contract failure and delay has been minimized when they are confident enough to post security deposits to assure performance. We have encountered situations where developers whose projects have been short listed during an RPS solicitation have turned down PG&E contract offers because their projects were not sufficiently advanced to meet the delivery requirements and other contract terms. While everyone wants to see more contracts, it is ultimately more productive – and reduces wasted developer money and time – for a developer to wait to sign a contract until they know a project is viable enough to meet the performance obligations.

Finally, PG&E now prepares semi-annual compliance reports to the Energy Division of the CPUC to monitor project development progress more closely. Specific notice must be provided to the Energy Division when a major project milestone is missed.

Q7. At the July 6 workshop, participants suggested that developers may need support from the state, particularly in obtaining permits and complying with regulations to keep milestones on schedule. What type of support could help developers and utilities prevent delays and contract failure?

Response:

Delay and contract failure may be associated with projected financing difficulties, or permitting difficulties. PG&E has previously described how uncertainty associated with the revenue stream may create financing problems, and why it is important that projects be assured of continued SEP payments and tax credits.

With respect to permitting, PG&E believes that the state can help ensure a timely permitting process. Depending on their location, resource type, scale, and resources on-site, projects may require a number of local, state and/or federal permits.

PG&E suggests the state reinstate a team to facilitate and expedite issuance of federal permits. For example, during the Energy Crisis, the Green Team was very effective at interfacing with federal agencies in a coordinated fashion and expediting permit approval.

Streamlining Bilateral Contracts with the 33 Percent Goal in Mind

Q8. European countries have used feed-in tariffs to take the lead in renewable energy development. Can bilateral contracts be streamlined to achieve similar growth in renewable energy development for California?

PG&E does not believe a standard-offer or feed-in tariff is the appropriate means to encourage renewable development.

The CEC notes that the 33 percent goal is important to maintain momentum for continued renewable energy development, to expand investment and innovation in technology, and to reduce renewable energy costs, innovation and support of emerging technologies mean that IOUs will likely be working one-on-one with potential suppliers, and facing unique situations with each potential supplier. Suppliers may have different business structures and differing concerns. Thus, a "one-size-fits-all" approach such as that contained in a standard-offer or feed-in tariff is not the way to encourage innovation in technology.

The potential benefit of a "feed-in" tariff is that it reduces the transactions costs associated with negotiating individual contracts. However, as TURN noted at the workshop, a single feed-in tariff with a single price for all renewable resources is likely to create windfalls for some suppliers and provide insufficient revenue for others. In order to mitigate that problem, multiple "feed-in" tariffs could be adopted, but this would reduce the savings in transaction costs.

Moreover, the state should be aware of the risks associated with Standard Offer arrangements. Individual contract negotiations can be adjusted as market conditions change. Standard Offer contracts generally cannot. Thus, ratepayers may end up offering contracts that are not in their best interest, as happened with the QF Standard Offers in the 1980s.

Q9. Should the CPUC require investor-owned utilities to buy any renewable energy offered at or below the MPR?

Response:

If the question is, "Should the CPUC administratively set a standard offer price for renewables?" the answer is no. Under the RPS rules, bidders offer their prices without knowing the MPR. They compete to win the solicitation. If they simply received the MPR, they would get a windfall: the difference between the price they were willing to offer and the higher MPR. With one exception, all of PG&E's signed contracts have been below the MPR. As PG&E described at the 8/22 workshop, these contracts, at competitively negotiated prices, will save ratepayers hundreds of millions of dollars, as compared to simply paying the MPR.

If the question is, "Under the existing competitive RPS structure, should the CPUC require investor-owned utilities to buy any renewable energy offered at or below the MPR?", there is no need for such a requirement. The RPS statute already provides cost recovery for contracts priced at or below the MPR and the CPUC has correctly found that those payments are per se reasonable.

Lastly, procurement decisions should consider not only price, but transmission constraints, project viability, dispatchability and portfolio fit. Even projects priced at or below the MPR must have deliveries that actually meet utility loads.

A mandate to purchase all renewable energy priced at or below the MPR would not accelerate renewables development, since the CPUC already reviews all utility procurement decisions – both awards and rejections – and has not faulted PG&E's procurement practices under the current ratemaking structure.

TRCR

Building on discussion of the TRCR at the July 6 workshop and in support of the work in the CPUC's renewables transmission proceeding on this topic, the IEPR Committee seeks further clarification and suggestions for improving the TRCR.

Q10. Recognizing that TRCRs are intended to inform bidders of least costly interconnection points, do/should TRCRs take into account infrastructure needed to meet 20 percent by 2010 and 33 percent by 2020 rather than incremental changes to the current grid?

Response:

The TRCR provides information to encourage renewables to locate in areas that would require no or limited transmission reinforcements and, based on areas of high interest for interconnection, guides development of potential future transmission facilities. As such, the TRCR provides a useful guide to enable development of transmission infrastructure to cover the potential developments for 20% by 2010 and 33% by 2020.

The TRCR is based on information provided by the CEC reports (PRRA, RRDR, SVA) on renewable resource potentials, augmented with information provided by the developers in response to the Request for Information before each solicitation. Therefore, it aims to accommodate all of the identified potential areas of renewable resource development. While one would hope that the full and timely development of resources in those identified areas would satisfy the various RPS goals, the TRCR itself is not intended to serve as a transmission plan aimed at a specific level of renewable resource development.

For example, the TRCR reflects transmission available to accommodate generation Capacity (MW), while the RPS Goals are stated in Energy (MWH). So, the same amount of MW transmission capacity can accommodate different levels of Energy production over a time period depending on the expected capacity factor of the resource mix at any particular cluster. For example, the same transmission capacity can accommodate three times more energy from a resource with a 90% capacity factor than a resource with 30% capacity factor. Therefore, one way of achieving the RPS Goal efficiently is to procure generation with higher capacity factors, or procure renewable resources that can use, as much as possible, the transmission system when and where transmission is available.

The TRCR provides information for the developers to site in such areas and for the utilities to choose such efficient resources.

Q11. Does the TRCR reflect only on-line power plants or does it include projects in the CA ISO interconnection queue? If it includes queued projects, are they reflected by queue position or on-line date in allocating costs for network improvement to already congested paths (e.g. Path 15)?

Response:

In accordance with CPUC Decision 04-06-013 (Attachment A), PG&E includes all projects in the Interconnection Queue as of the date the base cases are finalized. Furthermore, before the bid evaluation PG&E also reviews the Interconnection Queue to see if any generators have dropped out, and reviews the list of transmission projects to see if any transmission projects have been approved by the CAISO and PG&E management since the development of the TRCR, and makes adjustments to the transmission availability at the impacted clusters.

With respect to the second question, the TRCR does not allocate transmission upgrade costs to any party currently in the queue with completed interconnection studies because they are in the base case. The parties in the queue with completed interconnection studies would submit the resultant cost estimates with their RPS bid for use in least cost ranking.

The question seems to assume that the TRCR cost allocation can be affected by the selection of projects in the base case. Some participants at the Workshops suggested that PG&E's identification of the oldest fossil fuel units as the generation to be displaced by the operation of renewable generation improperly increased the cost of transmission upgrades. This is not true. In order to maintain the equilibrium between load (and loss) and generation, the study must assume displacement of existing generation by renewables. Consistent with resource management principles, the oldest fossil fuel units would be the first to be retired, so their displacement would provide a viable resource scenario for the purpose of developing the TRCR. In addition, in developing the TRCR, PG&E did not decrease the in-area fossil units below the level that is needed for RMR. Accordingly, the TRCR does not attribute the transmission needed to reduce RMR to renewable generation.

This methodology used in the study of displacing fossil fuel generators starting with the oldest units not only provides an apples-to-apples comparison for all clusters in the system, it also follows the spirit of the state's RPS goals. Artificially displacing less polluting generation (i.e. newer more efficient fossil fuel generators) instead of more polluting generators (i.e. older, less efficient fossil fuel generators) for the sole purpose of creating more transmission for one group of resources in one geographic area, as some parties have proposed, does not align with the RPS goal. Using unrealistic assumptions like this would skew the least-cost best-fit comparison and be unfair to renewable resources in other areas.

Q12. How would the TRCR change if the CA ISO tariff were changed to use an aggregated approach to transmission interconnection cost allocation similar to that approved for Southwest Power Pool? If TRCRs use standard off-the-shelf unit cost guides thought to be largely inaccurate (accuracy of +/- 40 percent), should they be used to exclude bids from further evaluation?

Response:

Because all network transmission in the CAISO controlled grid is customer funded rather than participant funded, among other major differences in market structure, it is extremely difficult to compare the Southwest Power Pool cost allocation methodology to the CAISO controlled grid. That being said, the TRCR is based on a cumulative amount of resources at each cluster before the RPS Solicitation, and therefore the transmission costs associated with each cluster would not change if the ISO tariff were to go to aggregated approach.

The TRCR alone does not exclude bids from further evaluation. The TRCR provides the best information available at no cost to potential bidders before those potential bidders have requested and paid for the interconnection studies under the ISO interconnection process. The TRCR is a comparison of transmission availability between clusters. Any assumed inaccuracy affects all clusters the same way. Therefore, the TRCR remains a useful tool for evaluating the transmission costs of potential bidders early on in the bid evaluation process. Developers desiring more accurate information can choose to commission Interconnection Studies through the ISO Interconnection Process and submit those cost estimates with their bids. Further, as stated in previous comments, PG&E's RPS bid evaluation process considers, up front, all viable alternative commercial arrangements to the transmission upgrades included in the TRCR.

Q13. What aspects of TRCRs used in previous or ongoing solicitations are most likely to result in lost opportunities, and what changes could prevent such losses?

Response:

PG&E does not believe that use of the TRCR has resulted in lost opportunities. The TRCR is only a comparison between potential renewables locations. It does not serve as a barrier to choosing enough resources to meet RPS goals. The amount of resources selected depends on the RPS Goal. If the resources of bidders are needed to meet the RPS Goal, the resource will be chosen regardless of how high the TRCs associated with the clusters. However, ignoring transmission costs would only increase cost to customers by selecting the wrong resources and/or selecting the resources, which could turn out to be undeliverable, but would not increase the amount of renewable resources.

Q14. During RPS bid evaluation, is any network upgrade costs attributed to RPS projects? Are any treated as costs paid by all transmission users?

Response:

Yes. PG&E attributes all network upgrades costs to RPS projects, because these costs are ultimately paid by the transmission customers, regardless of whether they are initially funded by generators or transmission owners. In order to reflect the full cost of the upgrade, PG&E's analysis assumes the transmission costs, like all other costs of the RPS project are paid only by PG&E ratepayers, rather than all transmission users.

Q15. Given that transmission development is needed to meet the state's RPS goals, how can the TRCRs be revised to avoid discouraging competitively priced projects in remote but renewable-rich areas? How can TRCRs be revised to encourage competitively priced projects that can provide VAR support and other transmission system benefits?

Response:

PG&E recognizes that significant renewable supplies may exist in remote areas. In fact, one of the benefits of the RPS solicitation process is the identification of these supply resources from the bids received. Based on the bids it has received, PG&E's Electric Supply Department has written to the CAISO and the transmission owner (PG&E's Electric Transmission Department) identifying the need for transmission to specific resource areas. Accessing remote renewable supplies is not a TRCR issue. The purpose of the TRCR is to efficiently allocate existing transmission.

As mentioned above, the Legislature has determined that the cost of interconnection must be considered along with the cost of generation when determining which potential generator is the least-cost best-fit generator. The TRCR is used to compare renewable generators to other renewable generators so that utilities can use least-cost best-fit criteria when choosing among them. If the TRCR indicates that a particular bid would require customers to incur significant transmission interconnection costs, yet that bid is still the overall least-cost best-fit bid, it will be selected despite the high transmission costs. RPS goals must be met in any event, and procuring non-renewable generation with lower transmission costs is not an option. Ignoring transmission cost when procuring renewables would result in the same amount of renewables but at higher cost(s).

In addition, the TRCR provides the correct price signal to renewable projects in all areas. In any case, the bidders that enter the Interconnection Queue can receive more accurate project-specific information regarding transmission costs associated with their interconnection. The TRCR is technology neutral. In developing the TRCR, all potential renewable projects are assumed to be able to provide their share of VAR support at the generator end. In the existing RPS Solicitation protocol bidders already have the opportunity to describe any benefits that can be provided by the renewable project. In any case, any benefits should be accounted for separately instead of embedded in the TRCR calculation. This would avoid double counting benefits and distinguish between benefits that are more certain from those that are less certain.