

The PG&E 2007 Renewables RFO Bidders Conference included a question and answer session. The questions and answers discussed at the Conference are reproduced here; some of the responses have been updated to reflect more current information than was available at the time of the Conference.

1. Question: Can you tell us more about the information PG&E would like for a site purchase bid?

Answer: Identify the site, provide coordinates, a legal description of the property, and a street address, if one exists, to describe its location, and state what makes the site suitable for renewable development. Provide studies of renewable resource potential, such as wind or solar readings. Describe the proximity to and availability of any fuels or resources needed, such as biomass or water. Describe the ownership and use of adjacent land. The more information you give us, the better a job we can do in assessing the value of the site.

2. Question: How much interconnect capacity is available at Palo Verde and how much would it cost?

Answer: Palo Verde is connected to Southern California Edison's (SCE) area. We are willing to consider it as a delivery point, but we are not in a position to provide the current availability of interconnect capacity at Palo Verde or its costs. We understand that SCE's Transmission Ranking Cost Report (TRCR) addresses the potential for renewable resource interconnection at this point. The SCE TRCR can be accessed through the SCE web site: http://www.sce.com/NR/rdonlyres/31DA69AF-0E4B-4A4D-8591-216CADC677AA/0/20070312AppendixD2007_Transmission_Ranking_Cost_Report.pdf

3. Question: Will PG&E pay for a project's network upgrades directly, or is the developer required to front the cost and recover it over 5 years?

Answer: Generally, under applicable FERC rules, the developer would fund the project. PG&E would reimburse the cost over the first 5 years that the generator is on-line.

4. Question: Does PG&E prefer a project that a) maximizes generation output or b) that generates fewer megawatt hours (MWhs) but concentrates them in the peak period?

Answer: There is no simple answer. Your bid will be evaluated based on market value, so either option could be attractive. The Time of Day (TOD) factors, which differentiate the all-in bid price by periods, show the relative

value of generation during different periods. PG&E's procurement will ultimately be measured by volume since that is how the RPS targets are defined. To make your bid more competitive, you may submit two different offers or variations and let us evaluate them both.

- 5. Question: How many of the 27 renewable contracts signed in the past four years are solar? Additionally, how many of these 27 contracts are less than 20 megawatts (MWs), greater than 20 MWs, and operational?**

Answer: To date, we have not filed any solar contracts for Commission approval; however, there are a number of negotiations in progress for different solar technologies and there should be contracts forthcoming. We do encourage solar technology offers, and are very interested in its potential benefits. In general, we have filed contracts that range from 1 MW to 120 MW, and we will consider offers from any generator of 1 MW or greater in our RPS solicitation.

- 6. Question: In the evaluation of transmission cost adders, it is not clear how the bidder can know about other offers at the same cluster and therefore, know if they are A or B (A or B represent offers, with A being ranked higher than B).**

Answer: It is true that under the solicitation, we do not let bidders know what offers are in competition. We encourage you to submit multiple offer variations in addition to your preferred variation, for example, one with optional dispatch down and another with a different generation profile, so that your project can be evaluated under either level of transmission upgrades in any generation period in the offer evaluation. We'll determine which of your variations has the least cost and best fit and evaluate your offer on that basis.

- 7. Question: Are winning offers from solicitations over the past 4 years available for review?**

Answer: No, but we have done a number of press releases when we signed contracts or filed advice letters. The press releases, including names and quantities, are available on our website. A list of the contracts that we and the other California investor-owned utilities (IOUs) have filed is available on the CEC website:

http://www.energy.ca.gov/portfolio/contracts_database.html

- 8. Question: Can the interconnection study process begin when shortlisted? Does PG&E have a schematic showing timing and flow of documents in decision making? What is parallel and what is sequential?**

Answer: Yes, but the interconnection process can begin even prior to offer submittal. You are welcome to apply to the CAISO and begin the studies now, before shortlisting. We do not have the information on a flowchart. The CAISO's explanation of its Large Generator Integration Procedures (LGIP), including its interconnection study timeline, can be viewed at <http://www.caiso.com/1841/18419740650d0.pdf>

All wholesale procedures, both the Large Generator (LGIP) and the Small Generator (SGIP) (note that until FERC approval of the SGIP, small generator interconnections are governed by Amendment 39 to the CAISO Tariff) can also be viewed on the PG&E website at: http://www.pge.com/suppliers_purchasing/new_generator/wholesale_generators/index.html

9. Question: Please discuss distribution interconnection costs. Do we have access to full distribution system information and studies?

Answer: For distribution interconnection costs, we refer to the PG&E's Wholesale Distribution Tariff (WDT). For Wholesale Distribution Generation Interconnections, the study process with deposit (cost) info can be found in Attachment E of the WDT: http://www.pge.com/docs/pdfs/biz/transmission_services/contracts_tariffs/wdt.pdf

The customer will be responsible for fronting a processing/deposit fee to begin the study process. If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is \$500.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit a deposit not to exceed \$1,000 towards the cost of the feasibility study. The customer pays for all actual study costs.

If a system impact study is required, then an additional deposit (based on the cost estimate for performing the study) may be required before proceeding with the study. The customer pays for all actual study costs.

The customer will receive a copy of the study for its interconnection request but will not receive distribution system information that is not applicable to the request.

10. Question: When will negotiations close for the 2006 RPS? How will process differ this year to get negotiations to close by end of year?

Answer: For the 2006 solicitation we are anticipating completing negotiations and filing contracts by the end of June; it is possible that some negotiations or filings may extend beyond that date. It is possible that there would be some overlap with remaining bidders in this next solicitation, but it is our intention to close within 6 months after shortlisting.

11. Question: Do you have a preference for shorter term, 10 year, or longer term, 20 year, contracts?

Answer: We do not have a preference between 10 and 20 year contracts. We encourage multiple variations of 10, 15, or 20 year contracts – or shorter term if the bidder desires. As between contracts of varying length, value will drive our preference, all other factors being equal.

12. Question: Regarding the interconnection process, what if the estimated on-line date is wrong? What if the interconnection date is wrong? How much flexibility do you have?

Answer: There are provisions in the Power Purchase Agreement (PPA) that allow the commercial on-line date to be delayed or accelerated. As it relates to the interconnection itself, you have up until the interconnection agreement is signed to delay the on-line date by up to 3 years.

13. Question: What if by the time you come on-line your substation of choice is not the best at that time? Is there any flexibility to mutually agree to change it?

Answer: If you are thinking about different locations, we would likely have to go through the interconnection process from the beginning and re-examine the entire plan. By the generator on-line date, agreements have usually been signed and facilities have been engineered and constructed. A change would likely require a new interconnection request.

14. Question: Are there remarket opportunities for projects located in SMUD's service territory?

Answer: Generally, yes. We would attempt to take power in that service territory and transmit it to NP15 for serving PG&E's load.

15. Question: In your evaluation, will PG&E give consideration to greenhouse gas credits, specifically the combustion of methane, digested from a renewable resource? Methane, when naturally emitted

from a renewable source, is 21 times more harmful as a greenhouse gas than carbon dioxide.

Answer: We will accept methane as a renewable resource and evaluate such offers on the basis of their contribution to PG&E's RPS targets.

16. Question: Generator Cost Responsibility: Is this the “all-in” cost? Should it include the cost of delivery to CA? Does contract price include generation cost, cost of interconnection to deliver to CA? Anything else?

Answer: Yes, it should include all of those components. You may give us two prices, one in which you propose to deliver to the bus-bar or trading location outside California, and a second price that details what you would charge to deliver the energy to the California border. We'll evaluate both proposals. If your project is shortlisted, we can negotiate the ultimate delivery point.

17. Question: Can a bidder specify more than one contract price, say for delivery at a different TOD or season?

Answer: Yes, you may submit variations on pricing.

18. Question: For “As available” resources like wind, when is the Supplemental Energy Payment (SEP) calculated? Is it calculated after the delivery of energy or based on estimated deliveries?

Answer: SEP awards are based on the estimated deliveries as provided in the generation profile. SEP payments will be based on actual deliveries.

19. Question: Regarding an intermittent resource from out of state sites, once it is scheduled for delivery into California, it would be a firm resource. Could you take intermittent resources from out of state if it's not possible to schedule those resources? If so, how would you do that? Would PG&E or the supplier be responsible for scheduling?

Answer: The CEC's recently revised RPS eligibility guidelines allow banking and shaping of deliveries, which means that delivery of power to California can occur at a time other than when the power was generated. With respect to scheduling and physical delivery into CAISO, it is still necessary to schedule power on at least an hour-ahead basis to import power over an inter-tie (meaning schedules are final 2 hours and 45 minutes before the operating hour).

PG&E will accept bids from out-of-state generators with delivery points either at the California border or out-of-state. If the bid is shortlisted, PG&E and the Bidder will decide the optimal delivery point.

There is no requirement to document a contiguous transmission path from the eligible resource into California. For the language of the specific provisions, see pages 25-29 and page 49 of the CEC's Renewables Portfolio Standard (RPS) Eligibility Guidebook at:
<http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-CMF.PDF>

Any offer to provide out-of-state intermittent energy would be evaluated on a case by case basis, to determine its value under different scenarios. For example, we would look at whether it would be cost-effective to remarket it; to use firm transmission to schedule it across the inter-tie; or whether it would be most prudent to use non-firm transmission to bring it in some of the time, remarket it at other times, and procure firm power to make up for the difference. Proximity to a liquid hub, and/or the degree of firmness that can be provided to schedules (such as day-ahead or hour-ahead firm), will help reduce the degree of challenge.

20. Question: Does PG&E have an appetite for acquiring new technologies on a turnkey basis? And if so, do you have any metrics developed that would validate or demonstrate the technology beforehand, before you would trigger a turnkey acquisition event? Do you have any guidelines of how long a validation period is considered sufficient for new technology, i.e. years, months?

Answer: PG&E encourages turnkey bids. We're interested in new technologies and demonstration projects. In terms of ownership, particularly if it's on a larger scale, we would want to make sure the technology will be successful. At a minimum, we would want such projects to be provided on a turnkey basis, and to meet reasonable testing, operation, and reliability standards. While we do not have pre-established metrics, we would entertain initial discussions based upon the conditions contained in the term sheet provided as Attachment I to the Solicitation Protocol.

21. Question: How dependable or how much security is there in the SEPs? Can it be depended on in the long term on a 10 or 20 year project? Is it funded for a certain length of time or is it guaranteed for any length of time? Is the length of the award equal to the length of the contract or can they be different?

Answer: There is no track record yet. SEPs are funds administered by the California Energy Commission (CEC), which are collected from

electricity users through a “public good charge.” The funds are deposited with the state and appropriated annually to meet the CEC’s SEP commitments. The CEC is authorized to award SEPs for terms up to 10 years. Contracts longer than 10 years are eligible to have their entire above-MPR costs funded by SEPs, but the payments will be made over a maximum period of 10 years. The term of any award will be specified by the CEC’s SEP Award Agreement.

There is a spreadsheet on the CEC website that we use and attach it to all our advice letters, even if the project does not need SEP payments. The spreadsheet takes the price that is negotiated, even if it’s higher than MPR, and it looks at the present value of the difference between the price and the MPR. It then pays out the difference over the first 10 years on a present value basis. For example, for a 20 year contract, it covers the 20 years but pays out over the first 10 years.

<http://www.energy.ca.gov/renewables/forms/CEC-SEP-worksheet.xls>

The mechanism for funding SEPs expires in 2012, but the Legislature has previously reauthorized this funding mechanism (which also funds energy efficiency and electric research demonstration, and development) each time it has come up for renewal. Although there is always the chance that the Legislature will determine that other funding needs should take precedence, or will decide not to renew the funding mechanism for some other reason, the success of the funding mechanism and the prior renewals by the Legislature encourage us to believe that a funding mechanism will continue to be available after 2012. There is currently a bill (SB 1036) under consideration in the Legislature to move the administration of SEPs to the CPUC from the CEC. This change could be advantageous to developers, as all of the approvals regarding the contract price and the SEP allocation could be done through a single review process at the CPUC, as opposed to the current two-step review process before two separate regulatory entities. As is the case for all legislation, we cannot predict the success of the bill.

22. Question: How early is too early for a paradigm shifting technology? Is the RFO the right forum for us to approach you or is there another structure that would be more efficient because I see putting in a lot of work on our side into an RFO and a lot of work on your side evaluating something. When it comes to the one slide called Project Viability in terms of both Project Status and Technology Viability, I appreciate your issue that you want something real.

Answer: We have signed contracts for very small amounts, and are open to entering into a transaction for demonstration technologies through the solicitation. We encourage you to participate in this process. This is a vehicle that is ongoing, real, and we will sign contracts through this

mechanism. Recognizing the need for promoting emerging technologies as well, we proposed a separate program for emerging technologies in our long-term plan. We encourage your participation in this solicitation; if your project qualifies for an approved emerging technologies program, we may move your project into that program.

23. Question: Of the 27 contracts projects awarded, none has been solar photovoltaic (PV)? Is the reason based strictly on cost, i.e. higher cost than wind?

Answer: Even though we haven't filed any contracts yet, there are a number of negotiations in progress for different solar technologies and there should be contracts forthcoming.

24. Question: Is there any consideration in the evaluation process to level the playing field between the differences of renewable energy resources?

Answer: It is not in our authority to do so. We have to look at how the projects rank on all the evaluation factors combined. Cost is not weighted any more than any other criteria discussed during the presentation. Every category is essentially of equal importance. It's possible that your project could be higher on cost but better in every other attribute, and your project would then be grouped with other projects that don't distinctly rise to the top or go to the bottom. We would consult with the procurement review group (PRG) and independent evaluator (IE) to decide how to move forward with that group of projects. One of the considerations on cost might be how much SEP payment would be required. If the bid price is so high that SEPs are needed, the SEP allocation will determine whether the project can proceed, based on the CEC's sense that, all other factors being equal, some projects may make a better utilization of SEPs on a per watt basis.

Solar or other technologies can supply energy at high value times. This value is reflected in the time of delivery (TOD) factors applied to the bid price. The contract price of each bidder is adjusted by the TOD factors applicable to its generation profile, so that the value of each bid is expressed in comparable terms. Although this is not an attempt to "level the playing field" for differently-priced technologies, the value of energy during different hours is recognized.

25. Question: For a 10 year project credit would be for 6 months worth of revenue and revenue is based on TOD period so it's higher in some months of the year and lower in others. What 6 months of the year would you choose for your credit?

Answer: The protocol is set up to be the maximum 6 months of revenue, usually the summer period. We do encourage you to give us multiple variations that address that credit level and others.

The feedback received, particularly for energy deliveries during the operating period, is that we're asking for a lot of money. We are asking for it from everyone and we recognize that it is a cost. We expect that this cost is factored into all offers. You, as an individual bidder, are not disadvantaged by the cost that you have to factor in to post that amount of collateral. We encourage you to make an offer at the stated amounts in the protocol, as well as other amounts that you may propose.

26. Question: SCE is offering to schedule for its renewables projects, and PG&E is not offering that. Will you consider it and if not, why?

Answer: Our form contract does provide for the seller being the Scheduling Coordinator. If you believe there is a cost advantage in PG&E acting as scheduling coordinator, please make two alternative proposals, one in which you act as scheduling coordinator and a second in which PG&E would provide that service. We're looking out for what is best for our customers. We'll consider the values accordingly.

27. Question: With respect to new technology and proof of concept, would you accept contingent offers such that there would be benchmarks on new technology in terms of proof of concept or would that be premature in this RFO?

Answer: It would be difficult for us to do this in terms of planning for our resource needs. A contingent contract creates challenges, particularly without knowing the price. If your project is priced above the MPR, it provides additional concerns for CPUC approval, and additional uncertainties as to SEPs. We would expect you to bring the finance team along the way and not sign up for a PPA until you have financing reasonably assured. There may be ways to apply proof of concept, but the contract provides for you to get paid based on what you actually deliver -- if no delivery, then no payment. The typical contract will have milestones in it, and there may be different milestones for different technologies. Technology might score low on viability, but the project may be attractive for other reasons.

28. Question: Do you have a preference for buyouts? Is there a disadvantage for insisting on a 20 year contract?

Answer: PG&E encourages utility ownership options; however, the decision comes down to customer value. We don't have a preference for either; we present it as another alternative from which you can choose.

Regarding buyouts, it's possible that you may want PG&E to purchase the project once you have taken advantage of all the tax benefits. With respect to PG&E's evaluation, the exercise of a buyout option will come down to value as compared to continuing the PPA. None of the RPS contracts we have signed thus far are buyout or build-own-transfers. We'd like to see opportunities for utility ownership but you will not be harmed if no such offer is made.

29. Question: If it is a buyout, would it be a fair market value at the end of the 5 or 10 years, or is it stated in the offer?

Answer: We prefer that you put the buyout price in the offer. We could then run an analysis to determine our economics of owning that asset, based on that purchase price at the end of the 5 or 10 year period. The net value is the benefit minus the cost. Based on this purchase price, we would determine what our revenue requirement would be as a utility asset, the cost in terms of dollars per megawatt hour, and how that compares to market or to continuing the PPA. There could also be complicated tax issues to work through as part of a buyout. Please use and comment on the term sheet for buyouts if you make such an offer.

30. Question: What is the relationship between the MPR and TOD factors?

Answer: The following example may help explain how the MPR is adjusted in accordance with TOD factors. For example, if your contract price is \$80/MWh, you get paid roughly double your price, or \$160/MWh, when you deliver at the summer super-peak hours (the applicable TOD factor is 2.037). While the MPR is roughly \$85/MWh (2006 MPR for a 20 year contract starting in 2009), the price you get paid is not actually above the MPR because the MPR gets adjusted as well to a level of \$170/MWh for that period. The same logic would apply to other TOD periods, including those when the TOD factor is less than 1.