Pacific Gas and Electric Company

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California Energy Commission
Dockets Office, MS-4
Re: Docket No. 12-IEP-1D
1516 Ninth Street
Sacramento, CA 95814-5512

Re: 2012 Integrated Energy Policy Report Update/Renewables: Comments of Pacific Gas and Electric Company on Retail Rate and Cost Issues with Renewables Development

I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments in the California Energy Commission's ("CEC") 2012 Integrated Energy Policy Report ("IEPR") Update on retail rate and cost issues with renewable development. PG&E's comments respond to specific CEC questions on these issues.

Customer electric rates are influenced by both the total cost of renewables and rate design. Today, however, when it comes to the affordability of electric energy, rate design is the more significant driver of increases in residential customer rates, as highlighted in PG&E's comments. Current rate design restrictions have led to rates that are far removed from the actual cost of service and, absent reform, could significantly undermine advancement of California's energy and environmental policies including renewable generation. For PG&E, just 23 percent of all residential sales bear the burden of additional costs, including those costs resulting from the renewables mandates. This situation is not sustainable and has already led to a "rate revolt" in the Central Valley in 2009. Rate reform is crucial to ensuring that electric energy remains affordable for all customers.

To allow for easier review of PG&E's comments, the questions provided in the Workshop Agenda (as applicable to PG&E) are repeated verbatim below, along with PG&E's responses. PG&E is happy to discuss these comments with the CEC staff should additional information be needed.

II. RENEWABLES AND DISTRIBUTED GENERATION COSTS VARY WIDELY BY TECHNOLOGY AND LOCATION

PG&E procures power from renewables and other types of distributed generation through a variety of procurement mechanisms, including the annual Renewables Portfolio Standard ("RPS") request for offers ("RFOs"), the Feed-In Tariff ("FIT"), the Renewable Auction

Mechanism ("RAM"), the 250 MW Solar Photovoltaic ("PV") Program, and the Combined Heat and Power ("CHP") solicitations, to name a few. Numerous other mechanisms offer incentives to small renewables and/or distributed generation (e.g., the California Solar Initiative or "CSI" and the Self-Generation Incentive Program or "SGIP"), although these programs do not necessarily contribute to PG&E's procurement goals (e.g., the RPS).

As a threshold issue, in providing the information below, PG&E notes that the "cost" of renewables may differ significantly from the "price" that PG&E pays for renewables. In this section, PG&E refers to "cost" as the hard costs of constructing, operating, and maintaining the asset, as well as the very significant "soft" costs like financing costs. Cost, however, is expected to be different from the price per megawatt-hour that PG&E may pay under a contract.

1. ***What are the latest range of cost estimates for developing and operating different large-scale and DG renewable generation projects in California?***
    a. ***How have these costs changed in the last 5 years? Have cost improvements changed the relative value of different renewable?***
    b. ***What are the key components and drivers leading to the change in costs? To what extent are these drivers specific to California?***
    c. ***What variables affect project cost differentials between developers and regional zones in California? (e.g., transmission upgrades, differences in property tax obligations)***
    d. ***What RD&D efforts could help further reduce balance of system costs?***

At the workshop, Black and Veatch ("B&V") presented the levelized cost of energy ("LCOE") for several project types. LCOE calculations generally estimate a project's total cost over its expected lifetime, including construction and finance costs, and then divide that total cost by its projected lifetime electric generation (megawatt-hours, or MWh). LCOE is a useful tool, but B&V's LCOE assumptions offer an incomplete picture of the project's total cost because B&V's LCOE estimates do not account for the timing, location, or reliability of the electric generation and inclusion of these variables would likely increase the LCOE. Furthermore, B&V's LCOE estimates may be misleading as to the total cost impact of various technology selections, because the LCOEs do not include the costs to expand the transmission network, upgrade the distribution system, or the costs to integrate various generation technologies.

It is also important to note that different types of larger scale and distributed renewable projects impose costs on the grid that are not reflected in the B&V LCOE estimates since they are not directly assigned to the project developer, but instead are paid for by all customers. Absent from the B&V LCOE estimates are interconnection costs for project types exempted from such costs (e.g., net energy metering), transmission system upgrades required to transmit power from transmission- and distribution-interconnected projects, and integration costs incurred to firm up supplies provided by all types of intermittent resources. These costs are reaching a level of significance where direct assignment to the project developer can lead to more economically rational decision-making and help manage overall costs to customers.

In response to questioning at the workshop, B&V indicated that its range of LCOE estimates is based on B&V's experience across the western United States, not just in California. From PG&E's experience, B&V's LCOE estimates are too low. In particular, B&V assumes rather high electric generation for renewables (i.e., a high capacity factor). The LCOE for a project varies inversely with projected amount of electric generation, so B&V's high estimates drive down its LCOEs. In addition, B&V's estimates may not accurately reflect the incremental costs of renewable energy development that may occur on relatively more marginal land. Indeed, parties at the workshop noted that existing renewable resources and those resources currently under development are likely to be sited at the highest quality and best suited locations for renewable development. In contrast, incremental projects sited in less optimal areas may have more risks associated with them (e.g., greater environmental impacts on species, transmission interconnection may not be readily available, higher distribution upgrade costs); these additional risks would only serve to increase the LCOE. Financing costs were also noted as a significant influence on the LCOE estimates; as discussed below, these costs are not necessarily stable given the pending expiration of federal government incentives for renewable energy development. Lastly, it was acknowledged that the LCOE estimates presented by B&V are not "all-in" cost estimates; they do not include the cost of integration, transmission costs, or distribution system improvements.

From PG&E's experience in analyzing LCOEs, certain project component costs have declined recently (e.g., solar PV panels). However, other balance-of-system costs, which include labor and financing, have not necessarily declined. Given the longer time period required to develop projects in California versus other states, costs are being accrued for a longer period of time before the project begins to generate revenue, which increases the financing costs of the project. It is unclear whether the decline in component prices will continue into the future, particularly if the observed cost declines were due to the current economic downturn and resultant oversupply of certain components. Prior to the downturn, significant price increases were, in part, caused by shortages of key components like PV panels and steel for wind turbines. Recent tariffs on solar panels manufactured in China and Chinese-made wind towers may also curb any additional cost declines for solar PV and wind.

Other cost uncertainties in projecting the LCOE include the availability of production tax credits in the post-2012 timeframe for wind, and investment tax credits in the post-2016 timeframe for solar PV technologies.

A number of variables can affect an individual developer's costs, including the land acquisition costs, permitting costs, financing costs, labor costs, profit margins, perceived development risk, tax incentives, and distribution upgrade costs (highly location dependent). As noted at the workshop, the developer's "soft" costs make up about 30-40 percent of the total project costs. However, this information is not available to the investor-owned utilities, given it would place the developer at a disadvantage during negotiations, so PG&E cannot comment on the extent of "soft costs" in B&V's LCOE estimates.

Current research focusing on reducing project development costs in which PG&E is involved with or aware of includes:

- Department of Energy ("DOE") SunShot Rooftop Solar Challenge (http://www1.eere.energy.gov/solar/sunshot/rooftop_challenge.html). Three of the 22 funded projects are based in or have a significant presence in PG&E's service territory. These projects focus on reducing costs and improving efficiencies associated with local permitting and interconnection generally by establishing and communicating best practices across team members. Total DOE funding for the three projects is approximately $1.9M.
- CSI Research, Development, Demonstration and Deployment (RD&D) program (*http://www.calsolarresearch.org/*). Several of the 24 funded projects funded by this $50M solar research program seek to directly or indirectly reduce project development costs. Examples: *Reducing California PV Balance of System Costs by Automating Array Design, Engineering and Component Delivery (SunLink Corporation), Low-Cost, Smart-Grid Ready Solar Re-Roof Product Enables Residential Solar Energy Efficiency (ConSol, GE)*, and *Integrated Energy Project Model (kW Engineering).*

Research and Development ("R&D") on integrating intermittent renewables and ensuring system reliability could help reduce total system costs, but will not necessarily reduce specific project development costs. Research that informs the best equipment to be installed at the distribution-level to manage voltage and address other engineering concerns is also of value.

2. ***What other costs must be considered when evaluating the total system cost implications from adding new renewable generation projects, what share of total costs do these soft costs represent? How do these costs vary between the different generation technologies that provide distinct operational services?***
   a. ***Financing (interest) costs,***
   b. ***Legal costs,***
   c. ***Cost for siting licenses and permits,***
   d. ***Costs for environmental compliance requirements, and***
   e. ***Other cost components?***

Please see PG&E's response to Question 1.

3. What are your cost projections and what scenarios, trends, factors could change the cost projections? (e.g., lawsuit against Chinese manufacturers, nuclear phase out, changes in transmission, EVs, net metering changes)

Please see PG&E's response to Question 1.

III. VALUE IS MOST IMPORTANT IN PROJECT SELECTION

As noted above, the project cost will differ from the price the utility pays for energy deliveries from the project for a variety of reasons. While a number of procurement mechanisms (e.g., FIT, RAM) are "price-only" (meaning the utility cannot negotiate non-price terms and conditions or consider other elements of value), it is really the value of the transaction that is the most important element to the utility.

A utility's assessment of a project's value considers a number of quantitative and qualitative factors, in addition to price. Those factors include: environmental impacts, portfolio fit (including online date and firmness of delivery), location, project size, delivery term, technology, integration costs, counterparty concentration, supplier diversity, credit, and adherence to other contractual terms and conditions. In addition, a project's consistency with and contribution to the overall RPS program goals is also considered. An overall value for an offer considers all of these elements, in addition to price, energy and capacity value, transmission, and integration costs. Value allows the utility to compare a wide array of projects and select the ones that offer the best value. It is important to note, however, that current regulatory restrictions may not allow utilities to consider all of the elements of value when selecting which projects to add to the portfolio (e.g., integration). Lastly, while project viability is not a value per se, it is an important component of the decision making process.

4. Have the offer prices for renewable energy/projects come down during the past five years?

Over the last five years, offer prices for some technologies have declined (e.g., solar PV); however, PG&E has observed that, within a technology, the range of prices offered has grown significantly. As PG&E noted above, however, price is only one aspect of PG&E's valuation. Only very recently (within the last 12 months) has PG&E seen an improved value in product offerings. However, it is uncertain whether this improved value can be maintained and captured for customers going forward, given many of the cost elements are at risk (e.g., panel prices, financing costs).

5. If so, is this more or less the case for different technologies?

Please see response to #4.

6. Do offer prices currently reflect a competitive market?

Generally, PG&E finds that current offer prices are more competitive than they were a few years ago, due to a variety of market phenomena, including the economic downturn and a reduction in global demand for PV and wind components, along with an increase in manufacturing capability. It is unclear whether these are temporary phenomena or whether a more balanced market will be sustained long-term. PG&E's experience has been that RPS mandates create a seller's market and have set price floors, rather than price ceilings, for renewable energy and that prices are higher than they would be without the mandates. Finally, PG&E notes that while developers may initially offer a project at a lower price (and prices are perceived to be more competitive), developers have not always been able to honor these low prices. Therefore, some passage of time is necessary to determine whether today's offer prices are truly competitive.

7. How do utilities decide what constitutes a reasonable price for the contract/set of products being offered?

When allowed to do so, PG&E evaluates offers on a variety of qualitative and quantitative factors. Based on comparisons to other offers, PG&E selects those offers with the greatest value to its ratepayers. Again, the best value may not always be the lowest price, given the best value will reflect the value to the portfolio on a number of items, including price, capacity value, transmission costs, project viability, and environmental elements, among other things. Integration costs should also be among the factors considered in whether a project offers the best value to PG&E's portfolio; historically, PG&E has not been allowed to consider integration costs. In its 2012 RPS Plan, however, PG&E has proposed to add this as a criterion.

However, a number of procurement mechanisms (e.g., FIT, RAM) do not offer the opportunity to choose the offer with the best portfolio value; instead, PG&E must sign contracts with developers on a first-come, first-served basis at a fixed price (FIT), which going forward into the expanded FIT program, vary based on market responses or follow a price-only selection criterion (RAM). The limited evaluation criteria in FIT and RAM may affect the value of offers in other solicitations where PG&E is allowed to assess value. For example, if more solar PV is signed through the RAM, the value of solar PV in other solicitations may decline, given PV's fit in the overall portfolio will change.

8. What Costs are considered in utility procurement?

Please see above responses on the qualitative and quantitative factors considered in utility procurement, where possible.

9. How are the quantities and costs/value of dependable capacity, curtailment, (avoided) ancillary services, etc. determined?

Dependable capacity values are determined by the California Independent System Operator ("CAISO") (net qualifying capacity) and the California Public Utilities Commission ("CPUC") (resource adequacy requirements). Curtailment and any payment for curtailment may be a negotiated contractual term that considers system reliability needs as well as the potential for lost tax credits if the generator does not run, among other things. Ancillary services values are dependent on whether the plant can respond to market requests for the services; intermittent renewable resources generally do not provide ancillary services values. All of these factors, along with the overall resource delivery profile, location, and level of firmness of the energy delivery impact the value of energy.

10. How are resources that provide different products/services (e.g., solar thermal vs. solar PV) compared?

Please see above responses on the qualitative and quantitative factors considered in utility procurement, where possible.

11. How are resources that provide very different products/services compared (e.g., wind vs. solar. vs. biomass) compared?

Please see above responses on the qualitative and quantitative factors considered in utility procurement, where possible.

12. To what extent does portfolio fit influence the evaluation of renewable projects?

Portfolio fit is a critical aspect in the evaluation of renewable projects. Recognizing the difference in energy delivery profiles relative to load shape for different renewable resources and how it may create excess or shortage of energy will influence the value of a resource. In addition, diversification of resources is a key component of determining portfolio fit.

13. If projects/offers are assessed as components of a utility's (future) portfolio, how is the portfolio selected?

Please see above responses on the qualitative and quantitative factors considered in utility procurement, where possible.

14. How have portfolio fit considerations influenced, if at all, the types of renewable resources that utilities have targeted by utilities or chosen for contracts?

Please see above responses on the qualitative and quantitative factors considered in utility procurement, where possible.

15. To what extent is dispatchable, baseload, renewable generation participating in RFOs?

Recent renewable RFOs have been dominated by solar PV and wind offers, both of which are intermittent and non-dispatchable. PG&E has received some offers from geothermal and solar thermal facilities, although the number of these offers is quite small compared to the total offers, both in terms of the number of offers and the MWs offered.

16. How do costs associated with these resources generally compare with those of intermittent resources?

PG&E does not receive cost information from bidders. Rather, it receives an all-in price for the product offered. As noted above, as more and more solar PV is added to PG&E's portfolio, the value of incremental solar PV to the overall portfolio declines. Therefore, it is possible for baseload resources, even with a higher price per megawatt-hour than intermittent technologies, to offer greater value to the portfolio.

17. Do existing valuation methodologies properly assess dispatchable, baseload renewable generation in a high intermittent generation setting?

No. As noted in PG&E's response to question #7, current valuation methodologies do not include the cost of integrating intermittent renewable resources, nor do they appropriately value the operationally flexible characteristics of dispatchable, baseload renewable generation. PG&E has proposed in its 2012 RPS Plan to include an integration value in its assessment of RPS offers.

18. What work has been done to date by the CPUC on cost containment regulations?

As of this date, parties have submitted a variety of comments to the CPUC on cost containment issues. From PG&E's perspective, any cost containment mechanism must be clear, stable and meaningful. Furthermore, it must be transparent, easy to administer and useful in the procurement process. A fixed cost cap, set at the beginning of the program, is the preferred mechanism to promote procurement stability and to allow parties to know when they have definitively reached the cap. PG&E supports crediting all RPS-eligible procurement expenditures toward the cap, although should a party's already-procured resources cause it to exceed that cap, there should be no disallowance of already-approved procurement costs.

19. What cost-containment mechanisms for the RPS might be considered?

See PG&E's response to the questions above.

20. What analysis or analytic capabilities/tools could be developed for use in planning by utilities, the California ISO, or policy-makers that would allow more accurate assessment/control of the costs of reaching 33%?

From PG&E's perspective, the best way to control the cost to get to 33 percent renewables is to allow flexibility to choose among the best alternatives for reducing the cost of greenhouse gas emissions. By developing metrics that would show the cost of each incremental unit of renewables and the amount of greenhouse gas emission reduction from that unit of renewables, the CEC, the Air Resources Board ("ARB"), or the Legislature could compare the cost per ton of different measures to achieve greenhouse gas emissions ("GHG") and select the most cost-effective measures for California, including measures outside the electricity sector (e.g., transportation, which accounts for 40 percent of California's GHG emissions).

Should policymakers choose to look at renewables in a silo, rather than just as a measure to reduce greenhouse gas emissions, other considerations should include:

1) Adding new transmission lines and bolstering the transmission backbone – The cost of transmission is significantly less than the total cost of renewable generation. By adding some additional transmission lines and enhancing the existing network, instead of focusing on a precise "right" amount, more price-on-price competition between renewables could lead to more attractively priced renewable energy, all other things equal. Allowing power to flow freely throughout the state will allow renewables to develop in areas best suited to their technology, when coupled with environmental and other constraints.

2) Requiring distributed generation to site in areas that are the least burdensome to the grid – Limiting the areas and quantity of distributed generation that can connect to the grid can also reduce customer costs by avoiding untimely and expensive upgrades when compared to the amount of generation that can be located on the distribution system.

3) Completing the research that will inform decisions regarding the best tools for reliably operating the system with increased amounts of intermittent renewables –

This research will yield meaningful information that can inform the estimation of additional costs to the system.

PG&E has made additional suggestions on how to assess the cost of achieving 33 percent RPS in its February 16, 2012 comments on cost containment issues at the CPUC.[1] These comments included suggestions on updating the E3 RPS calculator, use of the investor-owned utilities' RPS Plans, and other suggestions.

IV. TODAY'S RESIDENTIAL RATE DESIGN IS NOT SUSTAINABLE

As noted at the workshop, today's residential rate structure is not sustainable. The bills faced by customers are not only impacted by costs but also rate design. In fact, in the residential customer class, restrictions on rate design have led to rates that are far removed from cost-of-service that, absent reform, could significantly undermine advancement of California's energy and environmental policies including renewable generation. For PG&E, just 23 percent of all residential sales bear the burden of additional costs including those resulting from renewables – a situation that is not sustainable and has already led to a "rate revolt" in the Central Valley in 2009. Furthermore, instituting a fixed charge which approximates the portion of PG&E's cost structure represented by fixed costs can ensure that customers who do reduce their usage through onsite generation will continue to pay for the costs required to serve them.

21. What impact do you expect the costs of reaching renewables goals to have under current rate structures?

Since the 1990s, PG&E's system average rate has increased at less than the pace of inflation. However, as more renewables come on-line in the next few years, PG&E anticipates that its system average rate will increase from 15.3 cents per kilowatt-hour ("kWh") today to 20.6 cents per kWh in 2020. This pace of increase will outstrip inflation. PG&E estimates that 2 to 2.5 cents per kWh of the 2020 system average rate will be attributable to the premium paid to renewable resources versus available alternatives. However, the impact on the upper rate (Tier 4) is orders-of-magnitude higher, in the range of 7 to 10 cents per kWh, because of the rate design restrictions discussed above. There may be additional rate impacts from customer-side programs that do not currently contribute to PG&E's RPS goal, but do result in a shifting of costs between participants and non-participants. See also answer to Question 22.

22. What are the potential rate impacts from funding renewables programs?

Please see the response above for impacts on PG&E's system average rates. PG&E's projected system average rates were presented at the May 22, 2012 workshop and are available

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1 PG&E's comments on the Administrative Law Judge's Ruling Requesting comments on the Procurement Expenditure Limitations for the Renewables Portfolio Standard Program are available at http://docs.cpuc.ca.gov/efile/CM/160220.pdf.

here: http://www.energy.ca.gov/2012_energypolicy/documents/2012-05-22_workshop/presentations/08_Singh_PGE_Rates_2012-05-22.pdf.

For residential consumers, the rate impact from renewables is highly dependent on the customer's usage tier. As explained at the workshop, PG&E's current rate structure imposes a higher cost on customers that use more energy. The "inclining block rate structure" is intended to send customers price signals to conserve energy. However, because 77 percent of PG&E's sales are in the lowest tiers or to California Alternate Rates for Energy ("CARE") customers, at rates that can increase only a small amount annually (if at all), more and more of the cost of renewables is being placed on customers in the higher usage tiers, significantly exacerbating the disconnect between the cost to provide the service and the rate charged to the customer.

As indicated at the workshop, PG&E's average residential rate today is 16 cents per kWh. However, 77 percent of its sales are to Tier 1 and 2 customers who pay less than that amount today, shifting the costs they are not paying to Tier 3 and 4 customers, resulting in rates for those customers in the 30 to 35 cents per kWh range. Without rate reform, Tier 3 and 4 rates are expected to approach levels experienced in 2009, which triggered angry protests by upper-tier consuming households in the Central Valley who faced skyrocketing bills in hot summer months.

23. What is the expected timing of rate impacts?

Renewable energy deliveries are not reflected in rates until the facility has completed construction and begins delivering the energy pursuant to the terms of the contract. There is usually a multi-year delay between contract execution and delivery commencement, given it can take four to six years (if not more) to construct a renewable energy facility.

Between now and 2015-16, PG&E expects its renewable energy deliveries to increase significantly with about 1500 megawatt-hours (MWh) per year of solar PV, several thousand MWh of solar thermal, as well as another 300 MWh per year of wind coming online.

Rate increases begin to grow at a faster rate in the 2014 onward, as increasing amounts of renewables are required for the utility to meet its RPS compliance obligation. The RPS compliance obligation increases from 20 percent average in the first compliance period, to a 23.3 percent average of total deliveries from 2014-2016. As PG&E enters the third RPS compliance period, its compliance obligation further increases to an average of 30 percent of total deliveries from 2017-2020, and the utility is required to achieve 33 percent thereafter. Accordingly, the pace of the rate increases is expected to grow more quickly than in the first RPS compliance period due to the increased deployment of renewables required to achieve the utility's compliance obligation.

24. How do rate design elements, such as fixed rate components or tiered rates, impact how renewables program costs are recovered?

Please see PG&E's responses to the above questions as to how rate design elements affect the recovery of RPS premiums from residential customers. Also, introduction of a fixed rate component to residential rates can provide some relief to upper tier customers to absorb the additional costs of renewables program. PG&E's rate designs for all non-residential customers include fixed monthly customer charges. However, the CPUC has determined that the statutory language put into place by Senate Bill 695 prohibits PG&E from introducing a fixed charge. There is currently a bill in the legislature, Assembly Bill 1755, that would change this and provide the CPUC with the flexibility to approve a residential fixed charge.

25. Do renewables programs affect groups of customers differently than overall rate design?

Yes. As noted at the workshop, commercial customers generally pay rates that are much closer to their true cost of service and are less impacted than residential customers by the tiered rate design noted above. Also as noted above, in the residential class the increased costs are borne disproportionately by just 23 percent of non-CARE, upper-tier sales, creating a highly inequitable and unsustainable situation. When residential upper-tier non-CARE rates increase, while CARE rates stay constant, the CARE discount increases. This results in higher rates for business and agricultural customers, as well.

Within the residential class, different customer groups are also affected by rate design. For example, those customer-generators who participate in net energy metering may receive a bill credit for most charges on their bill, including transmission, distribution and public purpose program charges. While the customer-generators may produce their own electricity at certain hours of the day, they use the electric grid to balance their energy usage and to draw power when their generating unit is not working (e.g., a customer's rooftop solar panel does not generate at night, but the customer is still able to draw power from the system to keep its lights on). Under today's rate design structure, the costs not paid by the customer-generator are shifted to other customers who do not have on-site generation. PG&E has estimated a high correlation between income and the likelihood a customer will install PV. Customers most significantly impacted are those that are above the CARE threshold, but are either renters or of more modest means and not able to deploy onsite generation to lower their bills.

26. How have, and how can, cost containment mechanisms mitigate rate impacts?

Please see comments above on cost containment mechanisms. However, it is important to note that cost containment mechanisms can only mitigate system average rate impacts -- rate reform, in the form of tier flattening, introduction of fixed charges, or other means, can mitigate the cost impact on higher tier residential rates.

27. To what extent are certain costs not factored into the decision process? (e.g. concerns about net metering and integration… others)

It is unclear as to which decision process is in question. Is this the decision process to require a 33 percent RPS? If so, there has been very little analysis as to the cost of achieving a 33 percent RPS on customers, nor on the impact of that mandate on customers when combined with cost shifting from net metering, other costs to integrate more intermittent renewable energy, or to upgrade the distribution system to handle larger quantities of distributed generation.

The response below is based on an assumption that the question relates to rate design. Those customer-generators who participate in net energy metering may receive a bill credit for most charges on their bill, including transmission, distribution and public purpose program charges. While the customer-generator may produce its own electricity at certain hours of the day, it does use the electric grid to balance its energy usage and to draw power when the customer's generating unit is not working (e.g., a customer's rooftop solar panel does not generate at night, but the customer is still able to draw power from the system to keep his lights on). Under today's rate design structure, the costs not paid by the customer-generator are shifted to other customers who do not have on-site generation. This subsidy, or cost-shift, puts further pressure on Non-CARE upper-tier rates and exacerbates the problem described above. The implementation of tier rate reform, to more fairly distribute cost burdens among all customers, along with reductions in such subsidies, is essential to meeting renewables and other environmental goals.

28. What other factors, decisions, programs, such as system upgrades and OTC regulations, are influencing rates? Of the total rate increases you anticipate over the next five years, what proportion are attributable to renewable energy requirements?

Please see PG&E's comments above for information on the proportion of its rates that are attributable to the RPS premium. Other drivers putting upward pressure on rates include increased spending on aging infrastructure to improve safety and reliability, inflation, higher gas prices, and AB 32 compliance.

29. Are the full costs of procurement choices accurately reflected in rates?

No they are not. Generally speaking, to the extent utilities recover their full cost of doing business, the full costs of procurement will be recovered in rates, albeit in a less-than-equitable manner as noted below. However, to the extent that certain procurement related costs imposed on the system are not the responsibility of the entity supplying the power (e.g., system upgrade and renewable integration costs), these costs will not be appropriately reflected in the procurement decision process, and may lead to higher costs overall.

Furthermore, as described above, incremental procurement costs allocated to the residential sector fall entirely on non-CARE Tier 3 and 4 sales. None of the incremental costs of renewables are borne by non-CARE Tier 1 and 2 sales or by CARE sales. This is true not just for incremental generation costs, but also for any incremental transmission costs due to increased renewables. It is a highly inequitable distribution of the cost burden, and it is not a sustainable situation for just 23 percent of residential sales to bear a burden that should be shared by all residential customers.

30. How are ratepayers included in decisions about rate impacts? What has been your experience with customer reactions to proposed renewables rate design? Have programs been re-designed due to customer feedback? What aspects of program design affect customer concerns?

Customer Participation in rate impact decisions: Customers may participate in proceedings that affect rates by intervening at the CPUC. However, individual customers generally do not participate in proceedings and are instead represented by ratepayer advocacy groups. For example, the Division of Ratepayer Advocates and The Utility Reform Networks are two organizations that are generally perceived to represent the interests of residential customers. The California Large Energy Consumers Association ("CLECA") represents a group of large industrial customers, while organizations like Greenlining have historically represented economically-disadvantaged customers.

The CPUC also hosts Public Participation Hearings ("PPHs"), where the public can attend and learn about PG&E's proposed cases and programs. Customers have an opportunity to speak at the PPH, voicing their opinions to the CPUC and PG&E. For example, PPHs are typically held for General Rate Cases ("GRCs"). PPHs were recently held in Fresno on PG&E's proposed Economic Development Rate.

Bill inserts detailing proposed cases, their associated rate impacts, and how customers can participate in the process, are also mailed to customers on a monthly basis. All proposed rate increase cases are reviewed and approved by the CPUC. During the course of review, intervenors may participate to respond to the case.

PG&E's Experience with Customer Reactions: In 2009, PG&E experienced extremely negative reactions to high bills from Central Valley households with electric energy consumption that placed them in the upper rate tiers. While the high upper-tier rates were not at that time driven by renewables cost increases to any great degree, a similar reaction can be expected if, in the future, renewables and other AB 32-related costs drive upper-tier rates back to those high levels.

In response to this negative feedback, PG&E filed an emergency Summer 2010 Rate Relief Application at the CPUC. As a result, PG&E's top-tier rate decreased from nearly 50 cents per kWh to 40 cents per kWh, and its Tier 4 and 5 rates were consolidated into a single Tier 4 rate. In Phase 2 of its 2011 GRC (filed in early 2010 for rates effective in 2011) PG&E proposed a comprehensive series of rate proposals to further reduce upper tier rates including:

- Implement a modest customer charge;
- Collapse Tiers 3 and 4 into a single Tier 3 rate;
- Implement a Tier 3 rate for CARE customers; and
- Reduce baseline quantities.

The CPUC approved the CARE Tier 3 rate and the reduction in baseline quantities. It rejected the proposal to collapse Tiers 3 and 4, although it did approve a reduction in the differential between Tier 3 and 4 rates from 11 cents per kWh to 4 cents per kWh. It rejected the customer charge proposal, claiming it did not have legal authority to implement it. The net result was a further decrease in the top tier rate to 34 cents per kWh.

Going forward, however, the CPUC has limited flexibility to do much more, absent legislative rate reform.

PG&E has also recently proposed a "green rate" option for residential customers who wish to pay a premium for more green power than is required by statute.

Generally, any proposal that shifts costs from one customer group to another customer group is contested by the customer group to whom the costs will be shifted. Today's rate structure contains many hidden subsidies and eliminating those subsidies can help customers better understand the true cost of the services they are buying. However, to the extent one group of customers is receiving today a benefit that is at some other group's expense, the former group generally has a vested interest in maintaining its subsidy and will fight proposals to reduce or eliminate it.

V. CONCLUSION

PG&E appreciates the opportunity to provide these comments and looks forward to continuing discussion of these issues in the 2012 IEPR.

Sincerely,

/s/

Valerie J. Winn

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