**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering	Rulemaking 14-07-002 (Filed July 10, 2014)

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING POST-WORKSHOP COMMENTS ON THE NEM PUBLIC TOOL

RANDALL J. LITTENEKER
STACY W. WALTER

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2179
Facsimile: (415) 973-0516
E-Mail: rjl9@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

October 1, 2014

TABLE OF CONTENTS

Page

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering	Rulemaking 14-07-002 (Filed July 10, 2014)

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING POST-WORKSHOP COMMENTS ON THE NEM PUBLIC TOOL

I. INTRODUCTION

On September 5, 2014, Administrative Law Judge Simon issued a Ruling seeking Post-Workshop Comments on the Net Energy Metering (NEM) Public Tool. It included 29 questions. PG&E's responses to these questions are below. PG&E looks forward to working together with the CPUC, the solar industry, and other interested stakeholders on this important work.

II. PG&E'S RESPONSE TO QUESTIONS

Question 1. Are there any comments or concerns regarding the proposed approach of developing a public tool in conjunction with a report containing the range of results from the tool? If so, what alternative approaches should be considered?

PG&E Response To Question 1:

PG&E supports development and use of a transparent public tool that can be used to inform all parties of the trade-offs among choices for design of the NEM successor tariff. We also expect that a report on the range of results would be a good starting place for discussions. In addition to containing a range of results, PG&E would also expect the report to include a complete description of the model itself. PG&E suggests that as a result of all responses to the instant set of questions, the tool is designed to accommodate a wide variety of options for both input variables and NEM successor tariff structures.

PG&E also suggests the results of the public tool be designed in such a way as to provide meaningful, apples-to-apples comparisons of the various proposals. For example, any analysis using the tool should produce *at a minimum* a complete presentation of all changes to inputs from the base case and a complete list of results of the tests included in the CPUC's Standard Practice Manual (SPM).[1] As explained more fully in response to Question 3, PG&E believes the SPM benefit-cost tests can be used to measure how effectively a proposed NEM successor tariff satisfies some of the requirements of AB 327.

PG&E is concerned that, while the public tool can produce results for comparison of options, any results based on stakeholder adjustment of base case inputs would not be subject to open review or discussion. Therefore, PG&E proposes that the record prepared to support the NEM successor tariff include a test of the reasonableness of assumptions and changes to the base case inputs in the various proposals. Because some facts are highly disputed, and because a good understanding of the actual facts is needed for decision-making, it is essential that the Commission adopt a schedule that allows for filing of testimony and the opportunity to test parties' input assumptions on the key disputed facts in hearings.

Further, PG&E highlights the need for clarity about the impact of policy choices made by the Commission in this proceeding. Our understanding is that E3 proposes to calculate the adoption rate (MW per year) using an "adoption curve" described at a very high level by E3, which is based not only on the cost/benefits of distributed generation (DG), but "policy

---

1 The CPUC's Standard Practice Manual can be found on the CPUC web site at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Cost-effectiveness.htm . As stated there, the four tests described in the Standard Practice Manual are the Total Resource Cost (TRC), Program Administrator Cost (PAC), Ratepayer Impact Measure (RIM), and Participant Cost Test (PCT). These tests assess the costs and benefits of demand-side resource programs from different stakeholder perspectives, including participants and non-participants.

adjustments."[2] Since it is not clear what these policy adjustments are or their impact, PG&E recommends that the Commission clearly define any policy adjustments in the public tool, and require E3 to separately provide estimates of the impact of these adjustments on adoption, the net cost or benefits of DG and the resulting impact on NEM and non-NEM customers. Additional details of the proposed calculation of the adoption curve are also needed.

PG&E has an additional concern with the proposed application of an adoption curve to assess the sustainable growth of the NEM-DG market. PG&E cautions that while the level of adoption for a given proposal may be of interest, it is not the appropriate metric to use as any measure of whether a proposal supports sustainable growth as adoption levels are highly susceptible to exogenous, macro-economic trends and policy decisions (e.g., codification of Zero Net Energy). Further, the use of adoption level as a metric could lock-in inefficient business practices. For this reason, PG&E proposes an alternative approach of measuring sustainable growth by comparing the cost of the NEM-DG system to the potential value of the energy offset, as further described in response to Question 3.

Finally, PG&E recommends that the Public Tool be designed to use as inputs the level of and the composition of the renewable portfolio included in the 2014 Long Term Procurement Plan (LTPP) scenarios. The scenarios adopted by the Commission for the 2014 LTPP include several scenarios with different levels of and mixes of renewables.[3] The composition of the underlying renewable portfolio can have a dramatic impact on the avoided cost/value of DG-generated energy. The model, with the use of toggles, should be able to select the underlying scenarios and dynamically adjust the corresponding avoided costs and the incremental costs. The

---

2 See Slide 21 from E3's December 20, 2013 Market-Driven Distributed Generation in the 2024 Common [TEPPC] Case, which is available at: https://www.wecc.biz/Lists/Calendar/Attachments/5811/131220_E3_TEPPC_MktDrivenDG_2024CC.pdf

3 See May 14, 2014, Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 LTPP and 2014-2015 CAISO TPP.

ability to dynamically update avoided costs and incremental costs will be extremely helpful to evaluate the impacts of different levels of DG considered in the Public Tool in addition to the renewables portfolios and the DG amounts already embedded in the LTPP scenarios.

Question 2. Are there any lessons learned from prior public tools (e.g. utilities' rate design tools), or examples of public tools that have been done well, that could inform the development of the proposed Public Tool? For reference, the Nevada Net Metering Public Tool was mentioned during the public workshop held on August 11, 2014 as an example of a public tool that was done well. Please be specific in your recommendations for what did and did not work well.

PG&E Response To Question 2:

PG&E appreciates that the public tool will be used to model many complex proposals. Lessons learned from past analysis of NEM programs have demonstrated the sensitivity of any modeling efforts to the assumptions made during their design. It is important that the most recent input information be incorporated including gas price forecasts and market prices of renewable generation, both utility-scale and rooftop. Similarly, it is important that the model account for fundamental changes to market dynamics, like the emergence in recent years of Third Party Owned (TPO) financing options, which render obsolete notions of payback being the primary driver of customer adoption.

Also, because several of the analyses to be done are dependent on participant bill savings, it is imperative that bill savings be done correctly, including a representative sample of participating and nonparticipating customers. Further, the most recent utility rates must be included, especially incorporating the results of the residential rates OIR.

Because of the sensitivity of results to input assumptions, inputs included in the base case must be clearly described and subject to scrutiny by parties and a reasonableness test. Where parties provide their own inputs, these should be well documented and open to cross-examination.

In general, any method used to predict consumer behavior/DG adoption should be well-supported and flexible enough to account for market changes (e.g., third-party financing models) that drive different consumer behavior patterns. The model should produce reasonable results given current and expected market dynamics and should be capable of back-casting historic DG adoption patterns.

Finally, due to the sensitivity of DG avoided costs to the underlying IOU renewable portfolio composition, the model should incorporate the 2014 LTPP renewable portfolio scenarios as baseline scenarios against which to measure the avoided costs attributable to DG.

Modeling Approach

Question 3. The primary evaluation measures proposed for the model include:

a. Cost impacts to non-participating customers ($/year, $ lifecycle)
b. Renewable distributed generation (DG) adoption rate (MW per year)
c. Renewable DG value proposition (e.g. IRR $, payback period (years)
d. Calculation of total costs and total benefits ($/year, $ lifecycle)

Are there any other metrics that should be considered in the model? Are there any other output metrics that should be considered to evaluate whether "customer-sited renewable distributed generation continues to grow sustainably"?

PG&E Response To Question 3:

a. PG&E concurs with the recommendation to evaluate impacts on non-participating customers, and suggests using the RIM test as described in the Standard Practice Manual. Specifically, PG&E supports calculation of ratepayer impacts for all generation, noting that the RIM test was designed to evaluate energy efficiency programs which account for onsite reductions in usage and have no exports to the grid. This is the appropriate measure of compliance with PUC Section 2827.1(b)(4).

b. PG&E disagrees with use of adoption rate as a primary evaluation metric for sustainable growth in the model. While interesting, there are several reasons *not* to consider adoption as a metric to measure sustainable growth. First, the future level of adoption will be sensitive to effects beyond the CPUC's ability to control, such as macroeconomic conditions, international trade tariffs, and natural gas prices. The IOUs and their customers should not be responsible for insulating the DG market from market risks, as an adoption based metric might imply. Second, current market and policy dynamics complicate the evaluation of adoption rate as a metric for sustainable growth. For instance, regardless of the NEM successor tariff design, a decline in the acceleration of DG adoption in 2017 is likely if the federal Investment Tax Credit is reduced from 30% to 10%. If the Commission wishes to use adoption as a metric for sustainable growth, then it must account for macroeconomic and policy dynamics in its evaluation. Finally, if adoption is set as a metric against which to benchmark the performance of the NEM successor tariff, it could lock-in inefficiencies and insulate the market from competitive pressures that drive additional savings for customers. PG&E further reiterates that adoption rate is but one indicator of the ability of a proposal to sustain growth. See response to question 3c for a description of an alternative metric for sustainable growth.

c. PG&E suggests that, like the tool E3 developed for Nevada, this tool report the results of the participant cost test. (PCT)

Additionally, PG&E requests that CPUC and E3 establish an additional metric to measure the value proposition for the NEM-DG customer and vendor. The proposed metric would reveal the total available value to the customer and vendor by comparing the total available bill savings attributable to the NEM-DG system to the levelized cost of energy (LCOE) from the NEM-DG system. The available bill savings under a given NEM successor proposal should be calculated and normalized on a dollars-per-kWh basis to generate an “effective compensation rate” for the NEM-DG system. The effective compensation rate should be developed to reflect both the specific installation vintage year (to reflect both the changing underlying rates) and specific customer demographics (to reflect customer rates and usage). The effective compensation rate would then be compared to the LCOE from the NEM-DG system, also based on vintage to determine whether the proposed NEM Successor Tariff provides sufficient opportunity for "sustainable growth." It would also be instructive to compare the effective compensation rate to the avoided cost of the DG-NEM system.

Since 2011, two-thirds (67%) of residential NEM customers have had a power purchase agreement (PPA) or lease.[4] PG&E's proposed effective compensation metric better represents customers' ability to reduce their bills by adopting DG when compared to internal rate of return (IRR) or payback. This alternative approach also has the benefit of being relatively straight-forward and transparent in assessing whether a NEM successor tariff supports sustainable growth in DG. The ability of the NEM successor tariff to support sustainable growth is evaluated by simply comparing the LCOE to the "effective compensation rate" and determining whether there is sufficient margin to stimulate consumer adoption and provide a reasonable return on equity to DG companies.

Finally, PG&E strongly recommends against using payback as (a) a metric to measure value of the system and (b) a driver for customer adoption modeling. PG&E engaged Navigant Consulting Inc. to evaluate whether payback period is a robust measure by which to forecast adoption and "sustainable growth." Navigant concluded that payback period is not a good measure of sustainable growth because it has no coherent relationship to the third-party owner (TPO) business model, which has become prevalent in the residential sector. PG&E recommends that any adoption modeling necessary to calculate the benefits-costs of the alternative proposals be based on a comparison of LCOE to the competing IOU rate under the NEM successor tariff, rather than payback, as this is a better reflection of market dynamics and drivers of consumer behavior.

Payback is typically defined as the upfront cost incurred by the consumer divided by the annual benefit seen by the consumer. This is a simple investment-oriented approach that roughly indicates the duration required for the accumulated benefits to exceed the upfront costs. The

---

[4] Analysis of California Solar Initiative database at: http://www.californiasolarstatistics.ca.gov/

emergence of the Third-Party Owned (TPO) business model, however, has radically transformed the decision presented to consumers. The TPO model presents a choice between two rates of electricity, rather than an upfront investment decision that may produce energy savings benefits over the life of the system. The TPO model's success is largely based on the value of restructuring the delivery of NEM-DG so that the customer faces a more psychologically appealing decision by eliminating the up-front cost for the system. Forecasting the adoption of TPO solar PV is a crucial component of the Public Tool. A payback-based forecasting approach will substantially underestimate solar market adoption occurring under the TPO model. This is important in the proceeding as underestimation of solar market adoption will lead to false conclusions about solar market sustainability. Navigant's analysis indicates that a payback-based modeling approach may underestimate long-run solar market adoption in the TPO market segment by roughly a factor of ten.

d. PG&E supports inclusion of total costs and total benefits, using the calculation methodologies as described in the Standard Practice Manual. However, PG&E does not support a Societal Test, which can include claimed benefits that have no connection to utility rates, such as increased jobs or alleged health benefits. A Societal Test can be used in broader policy discussions if reliable figures are available as data inputs, but it is not an appropriate metric in ratemaking proceedings or to evaluate legislative compliance for the Commission or IOUs.

PG&E points out that if the Societal Test is used by parties to include benefits with no connection to utility rates, such benefits will likely not have been tested before the Commission. PG&E suggests such assumed benefits be submitted as testimony subject to cross-examination in hearings before becoming part of the record to be relied on in designing a NEM successor tariff.

In addition to the "effective compensation rate" metric described above, PG&E recommends two additional metrics be used to assess NEM Successor Tariffs. The first proposed metric is the effectiveness of NEM-DG to reduce greenhouse gas (GHG) emissions, which can be expressed in terms of (a) MMT of CO2 emissions reduced per increment of NEM-DG MWh, and (b) its cost in terms of $ per MTon of CO2 reduced by DG. This additional metric could provide a basis for comparing the cost-effectiveness of different technologies or programs to meet the state GHG goals.

The second additional metric is the incremental net benefit (or net cost) of incremental NEM-DG additions, expressed in $/MWh of net benefits (or net costs if incremental costs exceed incremental benefits). This metric will consider all benefits and costs of DG for all customers (participant and non-participants).

Other Considerations.

The modeling approach outlined above addresses most of the requirements of AB 327. The two requirements that cannot completely be addressed, both contained in PUC Section 2827.1(b)(1), are sustainable growth and disadvantaged communities. We address sustainable growth here and disadvantage communities in Question 28, below.

As discussed above, PG&E believes that the LCOE should be calculated; and the effective compensation rate for each proposed contract or tariff should be compared to the LCOE over time as the best indicator that a proposal can ensure continued growth of the renewable customer generation market. There is likely no good direct measure for continued growth, given the large number of factors that affect customer behavior, but which are beyond CPUC control, such as potential growth of new financing models like PACE. However, comparison of the LCOE to each proposal's participant tariff "effective compensation rate" is the best indicator of whether a proposal creates the opportunity for the market to continue to grow. The LCOE includes the cost of the system, including panel prices, balance of system costs, interconnection costs (if born by the participating customer), labor and ongoing operation and maintenance costs. It also includes softer costs such as acquisition costs, and overhead costs. The effective compensation rate will provide an apples-to-apples comparison of the system energy cost (LCOE) and the value available to the customer/vendor (bill savings or feed in tariff (FiT) value) for each proposed NEM successor tariff. It will not serve to evaluate the sustainability of a given proposal from the utility/nonparticipating customers' perspective – there are other metrics for that, such as the RIM and PAC tests mentioned in footnote 1 above. The gap between the LCOE and the effective compensation rate reflects a margin that can presumably be shared between renewable generation vendors and participating customers.

There are two important reasons that this methodology will optimally measure sustainable growth. First, the difference between LCOE and participating customer costs that can be offset with renewable generation will be independent of such things as California's economic growth. PG&E believes this independence of factors beyond the CPUC's power to control makes this margin a better metric of sustainable growth than adoption rates. The second reason is that more and more customers are choosing to install renewable generation under a lease or PPA arrangement. Customers are saving from the first day of installation, effectively with a zero payback period. As a result, examination of the margin between LCOE and participant avoided costs will work better than examination of payback periods. Payback period is essentially irrelevant for customers who choose a lease or PPA arrangement.

Question 4. Using the E3 avoided cost calculator, the proposed avoided cost components to measure the benefits of renewable distributed generation are listed below. Note that items *a-g* were included as part of the 2013 NEM Ratepayer Impacts Evaluation (2013 NEM Report).

a. Energy purchases
b. Generation capacity
c. Transmission and distribution capacity
d. Greenhouse gas emissions
e. Losses
f. Ancillary services procurement reduction
g. Reduced Renewables Portfolio Standard (RPS) procurement
h. Additional value (included as a user defined input in the total resource cost / societal test) Are there any avoided cost components that should be added to or removed from this list? Please give specific reasons for each proposed addition or deletion.

PG&E Response To Question 4:

PG&E does not propose to add or remove avoided costs from the above list. However, PG&E does make specific suggestions in response to Question 5 as to how avoided costs should be updated to reflect more current information and different scenarios representing possible future changes to the system's loads and resource mix, including integration costs. To the extent practicable, the principle of interdependence between avoided costs, DG penetration levels and system resource mix should be reflected in the Public Tool.

PG&E agrees with the list of costs that can potentially be avoided through customer generation; however, we point out that some claimed benefits that could be considered "additional value" have no nexus with rates (benefits such as increased jobs or environmental benefits not captured in GHG emissions reductions). Benefits with no nexus to rates should be restricted to the Societal Cost Test (SCT) and not be an option for any of the other benefit-cost analysis. There can be no avoided cost, if there is not a cost in the first place, so "additional value" with no nexus to utility rates cannot be avoided.

Finally, PG&E suggests that one outcome of a NEM successor tariff proposal could be conveyance of any Renewable Energy Credits (RECs) to the utility. The model should account for benefits provided by that proposal. PG&E notes that it expects to achieve renewable power sales of approximately twenty-seven percent in 2014 energy sales, and suggests that the value of any REC will diminish as utilities approach RPS mandated goals.

Question 5. Are there any avoided cost components from the 2013 NEM Report that should be updated or modified? For example, during the August 11, 2014 public workshop, some parties identified the need to model a higher goal under the RPS, and/or a higher cost of greenhouse gas emission reductions. Please give specific reasons for each proposed change.

PG&E Response To Question 5:

As a general principle, PG&E believes that model inputs should be updated when more accurate and recent data is public, readily accessible, and materially impacts the results. With this principle in mind, PG&E offers the following suggestions where simple updates are warranted. These updates should not be burdensome or controversial to implement as they are based on the results adopted by the CEC in the 2013 IEPR (#1 and #2), aggregated contractual data compiled by the CPUC (#3), and trajectory scenario assumptions used by the CAISO in the 2014 LTPP (#4).

Another important principle for effective modeling is that, to the extent practicable, avoided costs should be dynamically adjusted to reflect the impact of changing energy resource mix. PG&E recommends that the Public Tool be designed to (a) incorporate RPS levels and resource portfolios reflected in the more recent scenarios adopted by the Commission in the 2014 LTPP, (b) use the LTTP scenarios to dynamically estimate avoided costs and incremental costs, and (c) dynamically estimate the avoided cost based on DG adoption levels.

In addition to recommending adoption of the above principles, PG&E recommends the following adjustments to the base case avoided costs in the Public Tool:

1. <u>Gas Prices</u>

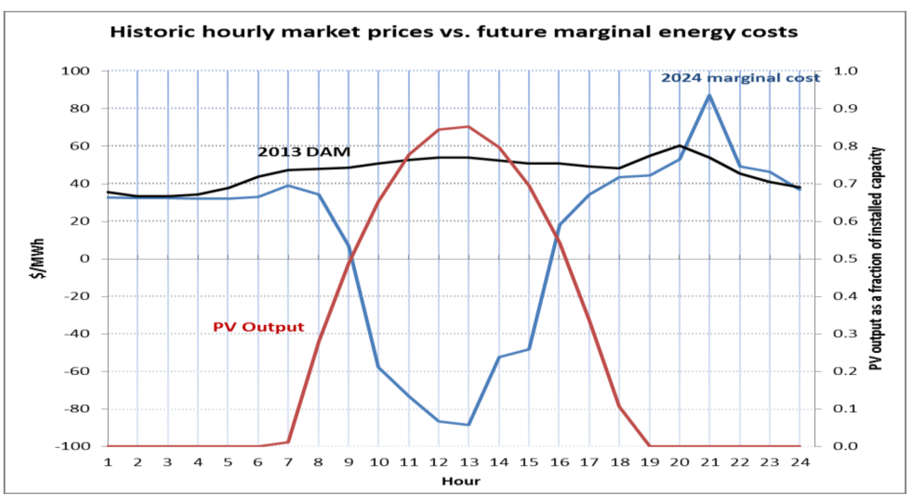
Gas prices materially impact most of the value streams in the avoided cost model: primarily Energy and Capacity, but also Avoided RPS, Emissions, and Losses. The current default inputs are based on the Market Price Referent methodology, but are high when compared to the 2013 IEPR forecast, and the 2024 Gas Prices used in the 2014 LTPP. E3 should update the gas prices in the model to reflect the most recent forecasts available, specifically the 2013 IEPR forecast, which is also used as the basis for 2024 gas prices in the 2014 LTPP.

2. CO2 Prices

E3's base values for CO2 prices are also not based on the most recent information. PG&E recommends that E3 use the 2013 IEPR Forecast, as it has updates to the TDV calculator.[5] This forecast extends through 2035, at which point the base values should be escalated at the assumed rate of inflation which is used elsewhere in the model.

3. Avoided energy purchase costs

The level and the hourly shape of the energy prices, and therefore the resulting DG avoided energy cost will be significantly impacted by the planned increases in the supply of renewable generation, and in particular by the addition of solar generation as shown in the graph below.[6] Figure 3 below shows lower energy prices, compared to actual 2013 energy prices, and even negative marginal energy costs in hours that coincide with PV generation hours for the month of April. This is publicly available data from the CAISO 2024 trajectory scenario LTPP model results.



5 TDV Model: http://www.energy.ca.gov/title24/2016standards/prerulemaking/documents/2014-07-09_workshop/2017_TDV_Documents/

6 The chart compares the average hourly 2013 CAISO day-ahead market prices for the month of April with the marginal energy costs from the CAISO's evaluation of the Trajectory scenario from the 2014 LTPP for April. Also plotted is the average hourly behind the meter generation profile for April included in the 2014 LTPP scenarios.

Given these anticipated changes and the fact that the public tool horizon extends far beyond 2024, the use of historical day-ahead market hourly prices shapes as proposed for the Public Tool is not appropriate to estimate future DG avoided energy purchase costs or marginal energy costs. In addition, increasing levels of DG PV adoption has a similar impact on energy prices, and this impact should be accounted for endogenously in the public tool.

4. Avoided capacity costs

Similar to its impact on avoided energy, the contribution of DG to reliability or resource adequacy, and therefore its avoided capacity cost, will also be significantly impacted by the future penetration of large-scale renewables, and in particular of solar generation additions. PG&E recommends that DG's avoided capacity cost be calculated using the Effective Load Carrying Capacity or ELCC approach, as required by SB X1-2. [7]

E3's October 2013 NEM Avoided Cost Model used the ELCC approach to estimate the marginal contribution to reliability of DG. PG&E supports a similar approach here, however, the load and resource assumptions should be updated to reflect the load and resource assumptions in the more recent 2014 LTPP scenarios, except that the ELCC methodology should be used to calculate resource adequacy capacities for wind and solar to be consistent.[8] As with energy prices, it is critical to dynamically calculate the associated avoided costs for different scenarios.

5. Avoided RPS

It is well-known that the costs of renewables, particularly Solar PV, have come down considerably over the past few years. Given this rapid change in the market, it is especially important to use the most up-to-date price information when forecasting RPS costs. Starting in

7 See http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html

8 Additional adjustments should be made for recent procurement authorizations and CAISO import constraints.

2011, Senate Bill 836[9] has required that the CPUC report to the Legislature "the costs of all electricity procurement contracts for eligible renewable energy resources." Colloquially known as the Padilla Report,[10] this aggregated, non-confidential information would provide a better basis for the "Marginal Resource Cost" input on the *'Avoided RPS'* tab in the model.

The default version of E3's model currently assumes the average marginal resource cost is $127.95/MWh. Given that recent public data exists that is based on actual contractual data, E3 should update the model input on the average 2013 procurement cost for bundled RPS procurement, which is $84/MWh.

In addition to updating to current RPS prices, E3 should use a reasonable curve to represent the continued cost reduction of RPS resources, similar to E3's *Cost and Performance Review of Generation Technologies* completed for WECC in 2012. As mentioned above, PG&E expects to achieve a percentage of mid to upper 20's of renewable power in its resource mix for 2014. The value of avoided RPS purchases will diminish as utilities approach any RPS goal.

One more factor that E3 should consider when calculating avoided RPS costs in the Public Tool is the likelihood that increased DG can result in curtailment of RPS resources in order to maintain system balance. If negative energy prices are used during these periods of oversupply, the cost of increased curtailment would be captured, as these prices represent the opportunity cost of renewable curtailment. If negative energy prices are not used during periods of oversupply, simulations could be used to estimate the amount of RPS curtailment created by increased DG, which would offset a portion of the avoided RPS associated with DG.

---

9 SB 836: http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0801-0850/sb_836_bill_20111008_chaptered.html

10 2013 Padilla Report: http://www.cpuc.ca.gov/NR/rdonlyres/775640F8-38D7-4895-9252-7E17261776FE/0/PadillaReport2014FINAL.pdf

6. Avoided Transmission and Distribution Capacity

As the CPUC has found on multiple occasions, it is possible that DG systems interconnected to the distribution system can potentially defer distribution capacity expenditures, but these are time and location specific, not general.[11] This potential is limited, primarily due to the lack of confluence of the following elements: (a) the need for distribution capacity expenditures; (b) the availability of DG in the correct amounts and in the right location; (c) the alignment between peak output time of the predominant form of DG, photovoltaic, and the peak demand time of the majority of PG&E distribution facilities; and (d) operating considerations associated with single large DG systems and aggregations of small systems. Moreover, at best, the influence of DG on capacity expenditures will likely be short-term deferrals of projects because the amount of DG on any one circuit or substation transformer is generally small. For this reason, the base case should not include any T&D deferral value.

7. Greenhouse gas emissions

The market heat rate used to estimate CO2 avoided emissions should be updated to reflect the 2014 LTPP scenarios. PG&E does not believe that an average market heat rate is appropriate; rather a weighted average based on the production profile of DG resources would be more appropriate. Alternatively, if the marginal energy costs from the LTPP scenarios are used in lieu of a market heat rate to estimate avoided energy purchase costs, no separate calculation of avoided emission costs should be made as these are already included in the marginal energy costs and doing so would double count this element.

---

11 See, for example, Decision 03-02-068, where the Commission concluded that although there is potential that distributed generation installed to serve an onsite use will also provide some distribution system benefit, unless it meets the four planning criteria described by SDG&E, such benefits will be incidental in nature. Similarly, see D.11-12-053 (PG&E's 2011 GRC, Phase 2), page 26 finding that "adding solar in one area does not reduce T&D needs in another area, and may not even help in the area where it is installed. If there is no need for T&D upgrades in an area, there are no such upgrades to avoid."

Question 6. Are there any other modifications to how the avoided costs should be determined? Please be specific. Include supporting materials if available and quantitative examples or illustrations when relevant.

PG&E Response To Question 6:

PG&E does not have additional comments at this time.

Question 7. The proposed cost components of renewable DG include:

a. Renewable power purchase agreement or installed system cost (Participant cost)
b. Interconnection cost (Utility cost if exempted; Participant cost if not exempted)
c. Billing and metering cost (Utility cost)
d. Integration costs, including increased ancillary services costs (Utility cost)

Are there any components that should be added to or removed from this list? Please give specific reasons for each proposed addition or deletion.

PG&E Response To Question 7:

PG&E generally agrees with the proposed cost components, with two additional thoughts. First, the Public Tool should include system upgrade costs as part of the interconnection costs.

Second, the Public Tool should also include generation-related integration costs. E3's previously developed NEM Avoided Cost Model used a $7.5/MWh integration cost plus escalation. However, this integration cost is likely to underestimate the integration costs associated with solar given the significant contribution of solar generation to the monthly three-hour ramp requirement recently adopted by the by the Commission as part of its Resource Adequacy ("RA") Program. PG&E recommends that E3 update its integration costs to include:

a) A variable or operating integration costs of $3/MWh for solar based on the range of variable costs from existing integration studies (See 2013 NREL report "A Review of Variable Generation Integration Charges," which surveyed renewable integration costs across the western region;[12] and
b) Fixed integration costs calculated as the product of 1) the increase in flexible RA requirement per MW of installed capacity of DG-PV; and 2) a projected cost premium for Flexible RA capacity, relative to generic, non-flexible capacity.

Question 8. How should the utility costs should be determined? Should utility costs be determined separately for each investor-owned utility (IOU)? Why or why not? Please be as specific as possible. Include supporting materials where available.

12 http://www.nrel.gov/docs/fy13osti/57583.pdf

PG&E Response To Question 8:

As discussed above, utility costs should be calculated both in the benefit cost evaluation from the utility perspective and as the utility costs that can be avoided as a result of the installation of customer renewable generation. It should be calculated separately for each utility. When calculating the utility costs that can be avoided, PG&E believes the source for costs should be the most recently available public information. Costs should be calculated separately for each IOU, because input assumptions such as (for example) the resource balance year (RBY) could be different for each utility.

Question 9. The E3 renewable DG adoption tool currently proposed for the model uses logistic growth curves to model DG adoption based on payback or internal rate of return (IRR).

a. **Are there any alternative approaches or models that should be considered for the purposes of predicting DG adoption rates? Please specifically describe the alternatives and provide any relevant quantitative examples or illustrations.**
b. **What are the strengths and weaknesses of each alternative you propose?**
c. **Are there any factors related to system costs that should be considered in the analysis?**

PG&E Response To Question 9:

As indicated in response to Question 3, PG&E strongly recommends against using payback as (a) a metric to measure value of the system and (b) a driver for customer adoption modeling. PG&E recently engaged Navigant Consulting Inc. to evaluate whether payback period is a robust measure by which to forecast adoption and "sustainable growth." Navigant concluded that (a) payback period is *not* a good measure of sustainable growth and (b) payback-based adoption models are likely to drastically under-forecast customer adoption when TPO financing options are available. In fact, Navigant's analysis indicates that a payback-based modeling approach may underestimate long-run solar market adoption in the TPO market segment by roughly a factor of ten. As an alternative, PG&E recommends that any adoption modeling necessary to calculate the benefits-costs of the alternative proposals be based on a comparison of

LCOE to the competing IOU rate under the NEM successor tariff, rather than payback, as this is a better reflection of market dynamics and drivers of consumer behavior.

PG&E objects to using payback/IRR as a proxy for the general value proposition of DG to customers, because we believe that these metrics no longer reflect the decision making process of most customers. Due to the proliferation of PPAs and leases, 67% of recent residential solar[13] customers experience effectively instant payback periods. This significant market share is in spite of the fact that for most customers, outright purchase of the system results in a higher IRR over the life of the system than leases/PPAs. For this reason, PG&E suggests it is inappropriate to use the maximum market share as a function of payback time as an appropriate metric for the current DG market.

Regardless of the methodology used for adoption forecast, documentation should be provided demonstrating the accuracy of the model in "back casting" adoption. If predicted adoption is used as a metric for "sustainable growth," an inaccurate forecasting model could erroneously predict adoption rates at a given DG cost effectiveness level, resulting the successor tariff providing excessive or insufficient incentives for DG adoption. If the model cannot reliably predict historic adoption, this would indicate that PCT or other DG value proposition metrics would be more useful indicators of market sustainability.

Question 10. The Public Tool will use data from a variety of sources for the purposes of the analysis. The proposed guiding principle for sourcing data is to use the best publicly available data, though there is some information that is not publicly available that will need to be gathered through CPUC data request to the IOUs.

Generally, do you agree with this proposed guiding principle? Why or why not?

PG&E Response To Question 10:

PG&E generally agrees with this guiding principle.

---

13 Analysis of CSI data base for PG&E residential customer installations in 2012 and 2013.

Question 11. There are number of inputs to the analysis. The following table lists those inputs that significantly affect the results of the analysis and the proposed source(s) for each one:

Data	Proposed Source(s)
Renewable DG cost and performance information	LBNL Tracking the Sun report, DOE Distributed Wind Market Report, California Solar Initiative (CSI) database, Black and Veatch Small-scale Bioenergy: Resource Potential, Costs and Feed-in Tariff Implementation Assessment, ITRON SGIP Cost-effectiveness Reports for Storage and Fuel Cells, KEMA Energy Storage Cost-effectiveness Methodology and Preliminary Results (CEC PIER Report).
Renewable DG adoption curves and methodology	E3 DG Adoption tool for the WECC https://www.wecc.biz/Lists/Calendar/Attachments/5811/131220_ E3_TEPPC_MktDrivenDG_2024CC.pdf
Avoided Cost	2012 CPUC NEM study methodology, updated to reflect current natural gas market prices and AB32 CO2 allowance forecast.
Utility revenue requirement forecast	Most recent settled general rate case (GRC) from each IOU (PG&E, SCE, and SDG&E). These will then be projected forward using load growth and efficiency assumptions from the CPUC LTPP and CEC IEPR proceedings, and then trended through 2050 or end of the analysis period. Natural gas prices will be updated to match the avoided costs.
Billing determinants	Most recent settled GRC data from each IOU, IOU hourly customer class load shape data, IOU residential baseline distribution, CEC IEPR data.
Utility revenue requirement allocation factors to classes	Historical shares of revenue requirement to class from the most recent settled class revenue requirement allocations in the GRC data.

a. **Should any of the sources in the table be revisited? Please provide specific reasons for review of any source.**

PG&E Response To Question 11(a):

PG&E cautions that use of the CSI data base or other incentive program self-reporting data bases for system cost information is likely to overstate the costs of solar installations as vendors may be reporting "fair market value" rather than actual system costs. Any evaluation of payback period within the Public Tool should be based solely on estimates of actual system costs rather than fair market value. Where possible, E3 should incorporate independent, third-party, bottoms-up estimates of system costs as the base case for the model. PG&E suggests that more accurate estimates of PV equipment costs can also be found in the NREL/LBNL report titled "Photovoltaic System Pricing Trends: Historic, recent, and Near-Term Projections," September 2014 Edition. Also, estimates of system costs should be benchmarked with public disclosures from DG vendors, including recent SolarCity earnings reports to investors, which indicates substantially lower costs than reported in the CSI database.[14] Finally, E3 and the Commission should calibrate system cost (and vendor margins) to PPA rates seen in other states, such as Arizona and Colorado, where the retail rates against which PPAs compete are significantly lower than California. Preliminary analysis completed by Navigant on behalf of PG&E indicates significantly lower system pricing in markets where the utility avoided rate is lower than California.

b. If you disagree with any of the data sources, please describe and provide a specific reference for any alternative that provides better publicly available data.

PG&E Response To Question 11(b):

PG&E generally agrees with the data sources and estimation methodologies outlined above. PG&E is not clear on what is intended by the term "settled" in the references to the GRC provided in the table above. In any event, the Commission should utilize the most recent 2014 GRC Phase I results for PG&E's revenue requirements, regardless of whether that decision was the result of a settlement or full litigation of the case. PG&E cautions that use of the CSI data

---

[14] See, e.g., http://files.shareholder.com/downloads/AMDA-14LQRE/2943043072x0x774881/0428314d-43a7-4acd-916f-9eb054671c4e/SCTY_2Q14_Earnings_Presentation_Draft4.pdf

base for cost information could overstate the costs of solar installations. PG&E provides the following additional suggestions:

- Adoption Curves: PG&E suggests that in addition to estimating an adoption curve, the Public Tool also include calculation of the LCOE for each year where additional installations are evaluated. As discussed elsewhere, the Public Tool should produce a comparison of the LCOE to the participant value or "effective compensation rate" as calculated for each proposed tariff.
- Avoided Costs: See comments in response to Question 5, above.

The Public Tool

Question 12. The proposed term of analysis tracks new renewable DG installations out to 2025 and evaluates their useful lifecycle through 2050. Recognizing that the IOU revenue requirements and usage projections in later years will be more uncertain than in early years, rate calculations in later years may utilize revenue requirement and usage "snapshots." The proposed snapshot periods would cover 5 years; revenue requirements and usage would be the same in each year of the snapshot period.

a. Will this approach adequately describe the economics of program rates in later years? Why or why not?

b. Are there any other factors that should be considered for the purposes of modeling the IOU's long-term revenue requirements? Please specifically describe each factor and provide a source or an example of its use.

PG&E Response To Question 12:

PG&E is comfortable with this approach so long as the 5-year bundling does not start before 2025.

Question 13. The proposed list of technologies to be evaluated in the Public Tool includes solar PV, solar PV coupled with energy storage, wind, and biogas-fueled technologies (including fuel cells).

a. Which, if any, other RPS-eligible technologies should be considered in the Public Tool? Why?

b. Are there adequate sources of sufficient generation and load profile data to be able to model these technologies?

PG&E Response To Question 13:

PG&E recognizes that there are constraints on the modeling effort, including lack of data and small customer participant populations, which would limit the ability to include every eligible technology in the Public Tool. PG&E therefore does not suggest any additions to the technologies that should be considered in the public tool at this time.

For all modeled technologies, PG&E requests that E3 provide transparency on assumptions regarding system sizing, location, system prices and market dynamics, including changes in system pricing over time and customer adoption. PG&E also requests that E3 display and clarify assumptions about baseline customer load profile data in the absence of a NEM-eligible system and a NEM-eligible system paired with storage.

There are some specific concerns with inclusion of NEM paired with storage. The CPUC has found that storage charged by the grid is not eligible for NEM credits for exports.[15] In addition, it will be critical to obtain customer load profiles before and after installation of NEM-paired storage. The primary load profile data available for energy storage is included in the Self-Generation Incentive Program (SGIP) database and the IOUs' Interconnection Databases. PG&E invites E3 to work collaboratively to obtain the data necessary for accurate modeling. In general, there is little if any information about the likely penetration of the various storage technologies, forecasted customer use-cases, and battery performance at this time.

Further, for the DG coupled with storage model, E3 should clearly articulate any assumptions informing the impact of storage on the costs and benefits associated with the NEM generator. Because the DG plus storage business model is nascent, it may prove difficult to provide meaningful analysis as part of this effort. PG&E also anticipates that there may be a wide range of impacts on the PV costs and benefits from the different storage use-cases. PG&E requests that E3 specify within the model the use cases for energy storage, because different use

---

15 D.14-05-033, Conclusion of Law 1.

cases will dictate factors that will affect the costs and benefits of both energy storage and the paired PV system, including system size and operational characteristics. E3 should also specify the conditions under which any storage-related benefits could actually be realized (e.g., hard-coded power electronics software to optimize battery performance around solar output). The uses of energy storage could include smoothing of solar production, generation output shifting, permanent load shifting, peak demand shaving, backup power and CAISO market participation. The E3 model assumptions regarding uses should reflect current industry trends as well as cost/benefit optimization.

If storage is included, the model should limit analysis to sensitivities on the assumptions of how storage affects the costs and benefits of the PV system. Since energy storage paired with NEM-eligible systems are exempt from interconnection application fees, supplemental review fees, costs for distribution upgrades, and standby charges, and eligible for SGIP incentives, the model should reflect those costs shifted to other ratepayers as an additional cost created by NEM generators. Energy storage systems larger than 10 kW must pay net generation output metering (NGOM) fees, and those fees should be included in the model as a cost to the participating customer.

Question 14. Are there any justifications for including non-RPS eligible technologies, or technology applications, in the Public Tool? Please specifically describe:

- **the technology or application;**
- **the reason(s) it should be included in the Public Tool;**
- **sources of information that can be used in modeling the technology or application for the Public Tool.**

PG&E Response To Question 14:

PG&E does not believe there is any reason to expand the Public Tool to non-RPS eligible technologies at this time.

Question 15. Should the impact of smart inverter technologies paired with DG applications be examined? Why or why not?

PG&E Response To Question 15:

PG&E recognizes the potential benefits from smart inverter technologies. They may be able to play a role in mitigating the costs of integration and interconnection of higher levels of renewable customer generation, while reducing the potential for local and system impacts. However, these benefits are potential only, and have not yet been reliably quantified nor fully field tested. Therefore, PG&E believes it would be premature to include these benefits in the Public Tool at this time, as any quantification of benefits would be purely speculative.

PG&E is pursuing EPIC pilot projects that will build understanding of the technological capability and possible impact from deployment of smart inverters. PG&E understands that autonomous settings will be effective in 2016, but recognizes that utility control and interaction – whereby benefits could be realized – is still a long way off.

Question 16. One potential impact of smart inverter technologies, for example could be that the introduction of smart inverters would allow full economic penetration of DG systems without creating distribution power quality problems. Are there other additional benefits of reduced DG integration costs that should be examined? If so, please provide a referenced data source.

PG&E Response To Question 16:

PG&E agrees that smart inverters hold significant promise for enabling the interconnection of higher levels of DG and managing grid impacts. For instance, smart inverters could be used to curtail unwanted surplus generation in real time, thus potentially reducing some of the integration and interconnection costs in the future. The smart inverters could also be set to reduce power when excess voltage is encountered under reverse flow conditions to avoid subjecting existing customers to high voltage.

This capability may enable higher DG capacity penetration to be installed at a given location. However, there has been no broad field verification of these capabilities, or of their effect on system operations. There are simply no studies to support quantification of these benefits at this time, although PG&E is pursuing an EPIC pilot project to better understand smart inverter capability. PG&E believes it is premature to include this potential benefit in the Public Tool at this time, as any value would be speculative.

Question 17. The proposed customer classes to be evaluated in the Public Tool include residential (residential and residential CARE), commercial, industrial, and agricultural. Are there any other customer segments or customer classes that should be included in the Public Tool? Why?

PG&E Response To Question 17:

PG&E believes the customer classes identified are adequate for consideration in the Public Tool. PG&E proposes that the Public Tool be able to estimate cost of service for DG vs. non-DG customer groups within each customer class. These different customer group costs can then be the basis for calculating rates. As explained below, there are significant differences in cost of service between DG and non-DG customers in each class which warrant separate cost of service estimates. PG&E does not oppose evaluating a DG customer class –please see response to question 21.

Question 18. How, if at all, should California's Zero Net Energy (ZNE) goals or impacts be included in the Public Tool?

PG&E Response To Question 18:

PG&E recognizes the innovative efforts and thinking of the CPUC, CEC, and others who have helped shape California’s ZNE goals for new and existing buildings. The most recent progress on these goals includes the establishment of a regulatory ZNE definition in the CEC’s

2013 Integrated Energy Policy Report[16] as well as the CPUC's draft New Residential Zero Net Energy Action Plan 2014-2020.[17]

Consistent with its comments on those efforts, PG&E further recognizes that the conditional nature of the state's ZNE goals warrants sufficient research into whether and how they might come to fruition. For this reason the Public Tool's Base Case Scenario should not contain estimated DG adoption associated with the state's ZNE goals; rather, PV adoption associated with the goals should be available as a sensitivity option in the tool.

To that end the "ZNE sensitivity option" should leverage recent research that estimated over 300 megawatts (MW) of new distributed generation (largely solar PV) annually by 2020 and over 1 gigawatt (GW) annually by 2030 should California building codes adopt the ZNE goals measured with a Time Dependent Valuation metric. [18]

A related matter is the inclusion of expected PV adoption for local jurisdictions that have passed ordinances requiring PV on new construction. Because these policies are not goals, but rather law, estimated PV adoption associated with the ordinances should be included in the Base Case Scenario commensurate with the ordinances' effective dates.

A key consideration for PV adoption associated with both the ZNE sensitivity option and local ordinances is the extent to which code compliance would introduce uncertainty into these estimates. To address this uncertainty, the Base Case Scenario and ZNE sensitivity option in the

---

16 California Energy Commission. (2013). Final 2013 Integrated Energy Policy Report (No. CEC-100-2013-001- LCF). Sacramento, CA. Retrieved from http://www.energy.ca.gov/2013publications/CEC-100-2013- 001/CEC-100-2013-001-LCF.pdf.

17 California Public Utilities Commission, & California Energy Commission. (2013). New Residential Zero Net Energy Action Plan 2014-2020. Retrieved from http://www.cpuc.ca.gov/NR/rdonlyres/D8EBFEE4-76A5-47AC-A8F3-6E0DAB3A9E5D/0/DRAFTZNE_Action_Plan_Comment.pdf

18 "Technical Feasibility of ZNE Buildings in California (ZNE Technical Feasibility)", Arup, December 2012, Table 17, pp. 43. Retrieved from http://calmac.org/publications/California_ZNE_Technical_Feasibility_Report_CALMAC_PGE0326.01ES.pdf

Public Tool should include a mechanism for varying the elements of code compliance, subject to uncertainty, such as sizing equipment according to the Time Dependent Valuation metric.[19] Duly addressing the state's ZNE goals and local PV ordinances in the Public Tool enhances the instrument's usefulness to stakeholders for sensitivity testing the implications of these policies for net energy metering.

The complexity and uncertainty involved in accounting for policy-driven adoption, whether ZNE or local ordinances, supports PG&E's argument that adoption as defined by the Public Tool should not be the metric by which "sustainable growth" potential is measured.

Question 19. Should the Public Tool include a cost of service analysis, similar to the 2013 NEM Report? If so, why? If not, why not?

PG&E Response to Question 19:

Yes. However, the related report of findings should be clear that paying costs of service to meet the load of a particular customer does not mean that this customer is paying their fair share of policy-driven subsidies imposed on all other customers, such as the CARE subsidy.

Question 20. To support greater usability of the tool, it may be desirable to limit the number of inputs that a user can modify in the Public Tool. What are the three most important inputs that the user should be able to modify in the Public Tool (e.g., the Resource Balance Year, the cost of carbon, increased RPS procurement, etc.)? Please provide reasons why each input chosen is among the "most important."

PG&E Response To Question 20:

PG&E urges the Commission to retain a broad opportunity for parties to choose different inputs. Designing a NEM successor tariff will involve balancing disparate interests, as delineated in PUC Section 2827.1(c). Unless an input is universally accepted by all parties (such as current rate design or the final residential rates adopted in the Residential Rate OIR) the effect different assumptions have on the result will be controversial. Transparency requires that different proposals be compared on an apples-to-apples basis. There may be many situations where an

---

19 2013 Final IEPR pp. 36 and 40-42.

input assumption can make the difference between a tariff that meets the statutory direction and one that does not. That being said, if the number of inputs that can be modified is restricted, PG&E urges the CPUC to use disparity of party positions, the defensibility of the position, and impact on the cost-shift estimates as the decision criteria for inclusion. PG&E lists the three input assumptions we believe will have the greatest impact when comparing results and which we believe are most controversial.

Resource Balance Year – Parties have historically had widely divergent views of the appropriate Resource Balance Year. Since avoided generation capacity is a function of the RBY, PG&E believes parties must be able to alter this input from the base case assumption.

Renewable Energy Equipment Costs, especially PV Costs. This is embedded within the adoption rate model, as well as the various benefits tests, and it largely drives the outcomes. It would be useful if Public Tool users could change the cost assumptions and have that automatically update the outputs from the adoption model (as well as the avoided cost model) in the public tool:

Lower DG costs → higher adoption → lower marginal avoided cost based on high adoption

Higher DG Costs → lower adoption → higher marginal avoided cost based on low adoption

Changing this single cost assumption should drive all of these changes in order to maintain the "feedback loops" and accurately reflect market dynamics.

Avoided Energy Costs and Price Shape – It is apparent that as more and more PV is brought on-line to meet RPS requirements, the peak load will not be the driver of market prices. Rather, *net* load will be the driver of the value of customer generation. The public tool will need to take into account the fact that as the state deals with an increasing number of days where renewables must be curtailed, the value of customer generation that occurs simultaneous to that curtailment becomes less and less – even having a negative value for days with over-generation during hours when the customer generator is producing.

Pricing Mechanisms and Rate Designs

Question 21. Should participating customer-generators be modeled as a separate customer class for cost allocation and rate design purposes? If so, why? If not, why not?

PG&E Response To Question 21:

PG&E has no objection to developing the Public Tool to show customer-generators as a separate class. PG&E believes that there are significant differences in service costs between DG and non-DG customers in each class which warrant separate cost of service estimates. However, PG&E does not believe it is necessary to model customer-generators as a separate customer class for purposes of the Public Tool. It is essential, however, for the Public Tool to be able to assess proposed successor tariffs (using various rate designs) relative to the cost of service for DG customers in particular. PG&E believes this is possible without establishing a separate customer class. For example, cost of service may be measured as increments or decrements to the full cost of service for the existing, non-NEM customer class.

Should a separate cost allocation be deemed necessary at this time for customer-generators, careful consideration should be given to the purpose that would serve as well as the steps necessary to develop a cost allocation. For example, complete cost allocation would typically require calculation of peak and non-coincident load responsibility and projected marginal cost revenue responsibility and billing determinants.

PG&E proposes that the Public Tool also estimate cost of service costs for DG vs. non-DG customer groups within each existing customer class, whether residential, industrial, commercial, etc. These different customer group costs can then be the basis for calculating rates.

Question 22. The following compensation structures are proposed to be included in the Public Tool:

- **NEM structure;**
- **Feed-in Tariff (FiT) for only generation exports to the electric grid; and**
- **FiT for all system generation.**

a. What, if any, variations to the above compensation structures should be modeled in the Public Tool (e.g., possible variations of NEM could include compensation based on specific components of the underlying rate structure)? Please provide specific reasons for the variations proposed. Provide quantitative examples or illustrations if relevant.

PG&E Response To Question 22(a):

PG&E agrees generally that the three suggestions are valid for inclusion in the Public Tool with the following suggestions:

- The NEM structure should include specific elements, for example, retail compensation for at-site load offsets should be adjustable to include payment of NBCs for departed load served by the renewable generation, and payment of a standby charge. Also, the NEM structure should allow for a DG-customer-specific underlying rate that better reflects the cost to serve DG customers than the broad retail rate.
- PG&E suggests the Public Tool have an option to allow the FiT to be set equal to the avoided cost (as opposed to the generation rate).
- PG&E suggests the Public Tool also allow for FiT to be enhanced with "adders." The adder could be thought of as a transparent subsidy mechanism.
- The Public Tool should also allow for each element of the compensation structure to be temporally modified to phase-in and out subsidies and adjust to market price referents.

Question 22(b). What, if any, other potential compensation mechanisms not mentioned above should be modeled in the Public Tool?

PG&E Response To Question 22(b):

PG&E does not have any additional suggestions regarding compensation structures to examine. The details of PG&E's proposals are below.

Question 22(c). At what frequency, for either NEM or an export-only FiT, should exports be netted against imports in the Public Tool (e.g., hourly or 15-min.)? Please provide specific reasons for your choice of frequency. Include quantitative examples or illustrations if relevant.

PG&E Response To Question 22(c):

There is no need for any netting at all unless the NEM successor tariff is still set at retail rates and is allowed to offset usage at other times. NEM customers are typically receiving service using a SmartMeter, which can separately track all exports and all usage. Therefore, if there is a compensation rate that is distinct from the retail rate, there is no need to net.

If a customer cannot take advantage of a SmartMeter (or one with the same functionality); or if the customer has opted out of SmartMeter, then the netting should be done on the smallest interval allowed by the meter the customer uses.

Question 23. Residential rate designs proposed to be included in the Public Tool are given below. These rates would be applicable to both participating customer-generators and non-participating customers:

a. Existing rate design (e.g. inclining block rate with 4 tiers)
b. 3-tier non-time of use (TOU) rate
c. 2-tier (baseline = 50% - 60% of average usage) with geographic baseline quantities
d. Seasonal TOU (summer 3 periods, winter 2 periods)
e. 2-tier with seasonal TOU
f. Marginal cost-based rate components
g. Option to use a late-shifted summer peak with TOU rates
h. In combination with above rate components, the implementation of a fixed charge
i. In combination with above rate components, the implementation of a minimum bill.

Within the framework set forth above, please describe any specific rate design choices that should be included as options in the Public Tool. Please provide all information necessary for using those choices in the Public Tool. For example, for TOU rates, please specify the hours defining each TOU period; for tiered rates, please specify the block sizes.

PG&E Response To Question 23:

PG&E interprets this question as pertaining to rates that would apply generally to residential customers irrespective of whether or not they are customer-generators (since Question 24 applies to rates applicable only to residential customer-generators). However, PG&E proposes that the Public Tool allow for the design of a specific DG Customer Tariff distinct from the residential tariff described above.

Per footnote 5, the list of rate design choices above is based upon proposals submitted by parties on May 29, 2013 in the Residential Rate Reform OIR (R.12-06-013). PG&E believes the list above reasonably summarizes those rate design proposals, although PG&E provides some suggestions for clarifying language below. In addition, PG&E notes that parties' May 29, 2013 proposals were submitted prior to the enactment of Assembly Bill 327, which removed some (but not all) of the statutory restrictions limiting the Commission's flexibility in designing residential rates. Parties have since updated their proposals and filed supporting testimony, so for the purposes of developing the Public Tool the list should be modified to reflect those more recent rate proposals.[20]

- The inclusion of language about baseline quantities in (c), but not in (b), is confusing. Residential tier boundaries are generally defined in terms of particular percentages of baseline quantities. For example, in the Residential Rate OIR, PG&E has proposed an end-state 2-tiered rate design, with Tier 1 being usage up to 100% of the customer's baseline quantity and Tier 2 being usage above that amount. In contrast, TURN has proposed an end-state 3-tiered rate design, with Tier 1 being usage up to 100% of baseline quantity, Tier 2 being usage between 100% and 200% of baseline quantity, and Tier 3 being usage above 200% of baseline quantity. But, regardless of the number of tiers, proposals generally have tier definitions keyed off customers' specific baseline quantities. Moreover, these baseline quantities are all defined per statutory requirements that they be calculated separately by season, climate zone, and service type (basic or all-electric), based on a certain percentage of historical average usage.
- For clarification, the phrase "non-tiered" should be added to the description of rate design (d).
- PG&E presumes that the phrase "a late-shifted summer peak" refers to pending (and potential future) proposals that would move the on-peak hours for residential TOU rates to later in the day during the summer season. PG&E is nearing completion of an analysis of the appropriateness of its current TOU period definitions, the results of which it anticipates reporting in its 2015 Rate Design Window (RDW) proceeding (scheduled to be

20 The three utilities filed their rate proposals on February 28, 2014 and the other parties filed theirs on September 15, 2014.

filed in November 2014). Depending upon the final results of its analysis, PG&E may propose new periods which better reflect expected future cost patterns in its 2015 RDW. PG&E also notes that the new TOU period definitions may involve re-classifying months to summer and winter seasons, as well as re-classifying hours of the day on weekdays and weekends.

- PG&E's TOU period definitions for its currently available TOU schedules, E-6 and E-7, are specified in the tariff sheets for those schedules, available on PG&E's public web site. The TOU period definitions for its newly proposed (in the Residential Rate Reform OIR) non-tiered TOU rate, Schedule E-TOU, are described in PG&E's February 28, 2014 testimony in R.12-06-013).

The last two items in the list note that the Public Tool should have the ability to model rate designs both with and without a monthly fixed charge or a monthly minimum bill amount. For PG&E, the latter has traditionally been calculated based upon the customer's total bill. However, the Commission in D.14-06-037 (PG&E's 2012 Rate Design Window proceeding) recently approved (but suspended implementation of) a different minimum bill methodology that applies only to the delivery (i.e., non-commodity) portion of the customer's bill. In its September 15, 2014 testimony, ORA proposed that this type of delivery-only minimum bill amount be adopted instead of a monthly service fee. Moreover, Southern California Edison already calculates minimum bill amounts only on the delivery portion of customers' bills. Thus the Public Tool needs to have the flexibility to calculate minimum bill amounts based on both the customer's total bill and just the delivery portion of that bill.

Question 24. The proposed rate design elements that would be applicable only to residential rates of participating customer-generators are:

a. A grid/network use charge on exports ($/kWh exported, $/nameplate kW per month);

b. Non-bypassable public purpose charges.
Please describe any other residential rate design features applicable only to customer-generators that should be included in the Public Tool. Please provide justifications for your proposal. Be as specific as possible and provide quantitative examples or illustrations if relevant.

PG&E Response To Question 24:

PG&E suggests adding the following design elements:

- An installed capacity charge. This charge would be similar in application to a standby charge, but could include non-bypassable charges associated with the departing load as well as all capacity costs that are necessary to serve load when distributed generation is not available.
- A DG Tariff that replaces the tariff identified in Question 23 and applies only to customer generators. PG&E suggests that the Public Tool allow for a DG-specific rate to be modeled generally based on nonresidential rate structures that include demand charges, such as A-10 in PG&E's service territory. This design element should allow the user to test the impact of tariffs that generally recover fixed cost rate components (e.g., distribution, transmission and capacity charges) through fixed, demand-based charges. This design element should allow the user to test the impact of tariffs that recover fixed costs through fixed charges. The demand charge would ideally be based on each customer's maximum demand in a given month, as is the case with the A-10 rate for medium light and power nonresidential customers. However, PG&E recognizes that this demand charge could vary significantly from month to month for residential customers. Therefore, the model should also enable a rate for customer generators with a demand charge that can vary from month to month, but that is based on average max demand for all customers generators within each climate zone (or baseline territory). This would provide for a fixed charge to recover fixed costs, but one that the customer will know each month. Further, the Public Tool should allow the DG Tariff to recover nonbypassable charges associated with load served by the generator.
- The ability to use different compensation rates for the exported electricity, including full retail compensation; generation component of the energy charge on the underlying rate; avoided costs; marginal energy prices (DLAP).

Question 25. The proposed non-residential rate designs to be included for each rate schedule or customer class in the Public Tool are:

a. Existing rate designs;
b. Marginal cost-based rate components.

Please describe any other non-residential designs, or modifications to existing rate designs, that should be included in the Public Tool. Please provide justifications for your proposal. Be as specific as possible and provide quantitative examples or illustrations if relevant.

PG&E Response To Question 25:

For the non-residential sectors, PG&E agrees that the base rate designs that should be considered for the Public Tool are (a) Existing Rate Designs; and (b) Marginal Cost Based Rate Components. With regard to (b), PG&E understands that marginal cost based rate components include cost based customer, demand and energy charges. That is, rates structured to recover customer-related costs in a fixed charge, capacity-related costs in demand charges and variable energy costs in volumetric energy charges. Therefore the Public Tool should enable calculation of a range of charges for these components even though certain non-residential customer rate schedules may not include those charges today. For example, while PG&E's Schedule A-1 does not include a demand charge structure today, the Public Tool should include that capability in addition to any charges that are being proposed for customer generators as set forth in response to Q. 26, below.

Question 26. The proposed rate designs that would be applicable only to non-residential rates of participating customer-generators are:

a. **Rate designs specified in number 25 above plus grid/network use charge on exports ($/kWh for customers without demand charges or $/kW-month for customers with demand charges);**
b. **Rate designs specified in number 25 above with non-bypassable public purpose charge;**
c. **For customers with demand charges, standby charge ($/kW-mo).**

Please describe other non-residential rate design features applicable to only participating customer-generators that should be included in the Public Tool. Please provide justifications for your proposal. Be as specific as possible and provide quantitative examples or illustrations if relevant.

PG&E Response To Question 26:

In addition to the above suggestions, PG&E suggests the model also allow demand charges and installed capacity charges to be included in the Public Tool for non-residential rate design as well as for residential rate design as described in Response to Q. 24.

Question 27. Please provide one or more proposals for determining a pricing methodology for a successor tariff that is a FiT. Please provide justifications for your proposals, including but not limited to any examples of existing programs that use your proposed methodology. Please also provide quantitative examples or illustrations if relevant.

In proposing your preferred FiT structure, please address at least the following issues:

a. Should the FiT be structured to encourage certain operational characteristics, system designs, or locations (e.g. west-facing systems, etc.)? Potential structures to consider include:

- **i. Should there be a TOU variation or seasonal variation to the design? Why or why not? If yes, please propose a structure and rationale for each element of the proposal. Please be as specific as possible, including but not limited to any examples of existing programs that use varying technology types. For example, for TOU rates please specify the hours defining each TOU period; for tiered rates, please specify the block sizes. Please provide quantitative examples or illustrations if relevant.**
- **ii. Should there be a time of delivery (TOD) factor applied to the established FiT rate? Why or why not?**
- **iii. Should the FiT vary by geography? Why or why not? If yes, please propose a structure and rationale for each element of the proposal, including but not limited to any examples of existing programs that use varying technology types. Please provide quantitative examples or illustrations if relevant.**
- **b. Should the FiT vary by each technology type? Why or why not? If yes, please propose a structure and rationale for each element of the proposal, including but not limited to any examples of existing programs that use varying technology types. Please provide quantitative examples or illustrations if relevant.**
- **c. Should the FiT have a fixed escalator from year to year or other mechanism to adjust the value paid per kWh over the contract term? Please provide specific justifications for your choice, including but not limited to any examples of existing programs that adjust the value paid. Please provide quantitative examples or illustrations if relevant.**
- **d. How frequently should the FiT rate be updated and how?**

Please provide specific justifications for your choice, including but not limited to any examples of existing programs that use rate updates. Please provide quantitative examples or illustrations if relevant.
e. Please describe in detail the cost data that would be used by your proposal(s) for the FiT. Please include information on public availability, ease of access to the information, frequency of refresh of the data, etc.

- **f. What other factors or elements should be included in the Public Tool in order to provide adequate representation of your proposal?**

PG&E Response To Question 27:

PG&E proposes the following design and pricing methodology for a Feed in Tariff, or FiT, as the NEM Successor program for customers who choose to install renewable generation sized to all or part of their load.

The FiT would be apply broadly to all customers who installs renewable generation sized to all or part of their annual load at a single point of service. Customers would remain on their Otherwise Applicable Tariff (OAT) for all usage, and the entire output of the renewable generator would be compensated under the FiT. The generator would require a net generation output meter (NGOM) or equivalent revenue grade meter which would be mathematically combined with the customer's revenue meter to calculate the customer's load.[21] Customers would be responsible for the costs of the meter, and the interconnection costs (including any engineering studies and any grid upgrades required to accommodate the renewable generator). Because the customer continues to receive full bundled service on their OAT for all of their usage, there is no need to apply standby charges, nonbypassable charges, or grid impact charges. The customer is paying on average the full cost of service, just as they were before they installed a renewable generation, and the same as any similarly situated customer, and any cost shift is transparently included in the FiT compensation.

The FiT would have a 20 year term.

The FiT price should ideally be set to the avoided cost in order to minimize cost-shift to non-participating customers, ensuring compliance with PUC Section 2827.1(b)(4), and would include a transparent "adder" representing the subsidy set at an amount sufficient to provide an opportunity for sustained market growth, as discussed in response to Question 3 and 22. Presumably this adder would be above the net avoided costs of the generation that would capture

21 This is similar to the methodology employed in Minnesota to determine usage for customers on the VOS tariff.

the remaining cost shifts from the customer's installation. If there are no cost shifts, then the FiT can be set at the net avoided cost of the energy. By *net* avoided costs, PG&E means the avoided cost of the energy minus any costs incurred accommodating the generation that are not paid by the participating customer. These might include integration costs, network upgrade costs, increases in ancillary services, etc. The net avoided cost thus becomes the value to *other* customers of the output of the generator. If this value is insufficient to provide an opportunity for sustained market growth, PG&E would support a FiT price that does not, at the beginning, completely satisfy the statutory requirement that the NEM successor tariff balance the compensation and the value.[22] PG&E proposes that over time, the cost shift be reduced regularly, until the legislative requirements are satisfied.

PG&E proposes that, like other FITs, the NEM Successor tariff constitute a simple purchase of the electricity generated by the renewable generator, including all renewable and environmental attributes. The electricity would become part of the utility portfolio, satisfy any RPS requirements, and be scheduled by the IOU. Of course the avoided cost would include any RPS or GHG emissions value, and the customer-generator would be compensated in the FIT.

The FIT could vary by technology, because the avoided cost and the price sufficient to ensure market opportunity for sustained growth could vary by technology. To the extent the avoided cost varies by geography or time of day, this also might lead to a variance in the FIT. In general, though, to ensure simplicity for participating customers, PG&E suggests it might be better to calculate the avoided cost taking into account such differences as geography and time of day, but design the FiT as a simple per-kWh compensation that, on average, captures the net avoided cost plus the necessary adder.

22 See PUC Code 2827.1(b)(3) and (4).

In the event the FiT can be initially set at a price that does not include an adder to ensure the opportunity for sustainable growth, PG&E suggests the net avoided cost be re-estimated periodically as input values change over time.

PG&E is open to consideration that each FiT price be either escalated (if there is no cost shift and net avoided costs increase) or de-escalated (to remove any cost shift over time) on either a prospective basis, such that it only applies to new installations. Alternatively, PG&E is open to consideration that the FiT price for a given year, or other period of time, range upward or downward for everyone on the tariff. In general, however, PG&E believes participating customers would be better served if each FiT arrangement were based on a set per-kWh amount that did not change during the term of the FiT.

Disadvantaged Communities

Question 28. Section 2827.1(b)(1) requires the Commission to include specific alternatives to the successor contract or tariff that are "designed for growth among residential customers in disadvantaged communities." At the August 11, 2014 workshop, some participants advanced the view that it could be premature to include alternatives for disadvantaged communities in the Public Tool before parties have had the opportunity to comment on some of the underlying policy issues in implementing this mandate, such as determining how disadvantaged communities should be defined for purposes of this task.

a. Please comment on whether it is, or is not, premature to consider specific proposals for alternatives for disadvantaged communities for the purposes of modeling their impacts in the Public Tool.

PG&E Response To Question 28(a):

PG&E believes it is premature to include alternatives for disadvantaged communities in the Public Tool.

Question 28(b). If it is your view that it is premature to consider specific proposals, should the Public Tool be designed with the capability to include later input with respect to this element? Why or why not? If such a capability should be provided, please provide a reasonably detailed description of the functionalities and design of such a capability.

PG&E Response To Question 28(b):

PG&E believes the Public Tool need not include evaluation of proposals for disadvantaged communities. The Legislature was not perfectly clear on what the NEM successor tariff must accomplish with respect to disadvantaged communities, but it may be necessary to design a program or tariff that is only available to these customers.

Question 28(c): If it is your view that it is not premature to consider specific proposals, how should such proposals be developed and incorporated into the Public Tool?

PG&E Response To Question 28(c):

PG&E believes the best next step to address this Legislative requirement would be to schedule a workshop and include stakeholders familiar with disadvantaged communities.

Other Issues

Question 29. Please identify any other elements or approaches that you believe are necessary for the Public Tool to be effective. Please specify how such elements or approaches should be incorporated into the Public Tool.

PG&E Response To Question 29:

PG&E appreciates the opportunity to provide deeper discussion of methods that could improve the Public Tool.

Production Simulation

If production simulations are used to estimate avoided hourly energy costs, the simulations could also consider changes in ancillary services (A/S) and losses due to DG. That is, with respect to A/S, DG reduces contingency reserves, to the extent it reduces load. This is the case because the CAISO as the balancing authority must have contingency reserve requirement equal to the greater of either:

- The loss of its most severe single contingency;
- The sum of three percent of its hourly load plus three percent of its hourly generation. [23]

---

23 See http://www.nerc.com/files/BAL-002-WECC-2.pdf

Therefore, DG-PV could reduce contingency reserve procurement by 3% of the reduction in load it creates.

However, DG-PV also increases A/S in the form of increased regulation and load following reserves. Increases in DG-PV add variability and uncertainty to the resulting load, and therefore require additional ancillary services. These additional ancillary services increase commitment of resources, and less efficient use of resources with the consequent increased fuel and variable generation costs. The increase in fuel and variable costs should be captured by the production costs in each scenario. The CAISO has estimated the amounts of regulation and load following reserves for various scenarios with different levels of RPS resources being considered in the 2014 LTPP.[24]

Modeling Dynamics and Ranges

PG&E acknowledges the challenge of designing a public tool that provides the level of flexibility needed to meet all stakeholder preferences. Where it may be too difficult to enable full user control of an input or to account for the dynamic feedback effects on avoided costs, PG&E encourages the use of discrete tranches of values, for example choice of high, medium or low avoided cost values based on the underlying RPS portfolio or DG penetration level. Similarly, for user inputs, E3 could provide high, mid and low values rather than allowing granular control or preventing user control.

Periodic Review of NEM Successor Tariff

PG&E recognizes the dynamic nature of California's electric power system and encourages E3 to incorporate the major impacts of anticipated changes in resource mix; however, considerable uncertainty exists in such a long term analysis. PG&E encourages the commission to

---

24 See CAISO's 2014 LTPP testimony at: http://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf

consider a reasonable timeframe for revisiting this analysis and the effectiveness of the NEM successor tariff on a regular basis.

True-Up

The commission should consider designing a NEM successor tariff with no annual true-up. The existing NEM tariff has created substantial confusion for customers, especially regarding the annual true-up. To the extent the NEM successor tariff successfully incorporates the requirement that costs and benefits to all customers and to the electric system are approximately equal, there would be less necessity to cap benefits with an annual true-up.

Incorporate Regular Reductions for Any Remaining Subsidies

In PG&E's description of a possible FiT (See Question 27), there is a suggestion that the FiT might need to start with a transparent subsidy at first that would be reduced regularly over time. PG&E similarly suggests that other proposed tariff structures could include a subsidy – whether implicit or explicit – if the Commission deems this necessary to achieve an appropriate balance of Legislative requirements; assuming the Legislative direction cannot be met perfectly at this time. Should the Commission find that a continued subsidy is necessary, PG&E urges the Commission to also incorporate in to an adopted NEM successor tariff a regular reduction to that subsidy over time. The Public Tool should be built with the capability of reducing the subsidy over time.

III. CONCLUSION

PG&E appreciates this opportunity to address these issues as the Commission moves forward with this important work.

///

///

///

Respectfully submitted,

RANDALL J. LITTENEKER
STACY W. WALTER

By: */s/Randall J. Litteneker*
RANDALL J. LITTENEKER

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2179
Facsimile: (415) 973-0516
E-Mail: rjl9@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

October 1, 2014