**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)

POST-WORKSHOP COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY (U902E) ON NEM PUBLIC TOOL

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Dated: October 1, 2014

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I. INTRODUCTION

San Diego Gas & Electric Company ("SDG&E") hereby submits its Post-Workshop Comments in response to the ALJ Ruling seeking comment on the proposed NEM public tool. Through these Post-Workshop Comments, SDG&E addresses the questions set forth in Attachment A to the September 5, 2014 Ruling of ALJ Simon. To the extent a question is not addressed herein, SDG&E reserves the right to address related issues that may be raised through the Post-Workshop Comments that are submitted on behalf of other parties through Reply Comments. The following comments follow the sequence of questions set forth in Attachment A to the September 5 Ruling of ALJ Simon. To the extent a question is not addressed herein, SDG&E reserves the right to submit information concerning that question in Reply Comments that may be submitted in response to the Comments of other parties on that question.

II. RESPONSES TO QUESTIONS

A. Overview of the Proposed Approach

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?**

SDG&E believes that a Public Tool will be beneficial to all parties. If designed properly, the Tool has the ability to provide a transparent analysis of how different proposals impact customers and show potential cost shifts.

SDG&E emphasizes the importance of ensuring transparency of cost shifts and subsidies. SDG&E believes that transparency in how the Public Tool operates goes hand-in-hand with transparency of the outputs and the eventual development of a NEM tariff. To this end, SDG&E requests that all parties be allowed to examine the Tool and related assumptions and formulas before the final Tool is ultimately adopted.

Also, aligning with the need for transparency is the need for reporting from the Tool to be clear. The different potential cost-shifts should not be aggregated into a single number. The Tool should be able to report each component in order to promote transparency, guide policy and allow differently situated customers to see the impacts of each decision and subsidy.

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** http://puc.nv.gov/About/Media_Outreach/Announcements/Announcements/7/2014_-_Net_Metering_Study/ **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.**

SDG&E reserves the right to submit comments on this question in response to the comments of other parties.

B. Modeling Approach

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"?

SDG&E submits that "b" is consistent with current PV forecasting methods provided by the California Energy Commission. However, both b and c are measuring the same thing since the DG adoption rate is a function of the payback period, which in turn is an implicit measure of the internal rate of return. Instead, there should be a single measure, the participant cost test, to parallel the non-participant cost test and to provide similar information as the adoption rate and value proposition.

SDG&E cautions against using output from an adoption rate model since it is not clear that "growing sustainably" implies any particular adoption rate. It is also not clear the extent to which the payback period and adoption curves include barriers to PV adoption that do not exist in California, such as the degree of customer awareness and local government permitting issues.

Calculation of adoption rates is not necessary and can be misleading given that it is driven off of customer economics which are dependent on bill credits which are driven by avoided rates. It is far better to simply look at the customer's economics as a measure of sustainability than to add additional uncertainty into the equation by developing an adoption algorithm driven by those estimated customer economics.

Another metric that should be included in the model is the percentage of the cost of service that participating customers are paying by the type of service provided (Dist, Trans, Commodity, etc.). This output measure should have options to include or exclude payments that are normally in departing load charges such as the public purpose programs charge ("PPP") as part of the cost of service. Customer-sited renewable distributed generation cannot grow sustainably with cross-subsidies. It is also critical to include a calculation of a customer's contribution to PPP as those costs support other CA policy objectives.

Conversely a measure of the credit provided by the NEM 2.0 structure to a representative sample of customers on a per kWh basis would provide input to the sustainability of the structure. The relative benefit of the NEM 2.0 structure should treat customers equally for the benefit they provide to the grid. The addition of solar by one customer has roughly the same benefit to CA compared to his neighbor installing solar. Whether or not the neighbor uses more or less energy on or off peak doesn't create any difference in the benefit provided by a like solar system all things being equal.[1]

The following considerations should also be included:

- The assessment of cost impacts to non-participating customers should be based on a $/year based on the expenses occurred in that year as opposed to any levelized $/year calculation. This is because the impact on non-participating customers is measured through their bills, not expectations of the benefits or costs of future bills. Levelized or life-cycle costs mask the impact of what is happening to non-participants and are subject to assumptions which can swing the answer substantially such as the discount rate that is used to put a present value on future costs and the escalation assumption that is put on the growth of costs and benefits.
- In order to compare the costs or benefits from DER to the customers who receive the services related to those cost and benefits the output should clearly report the input assumptions on all costs and benefits that the user can change.
- In order to establish how sustainable a NEM 2.0 structure is there needs to be clear reporting of the input assumptions the user changes related to the cost of service. The specifics of the reporting should be further discussed in order to ensure the necessary

[1] There can be circuit based differences in the costs and benefits that solar systems can create.

information is conveyed. This reporting will make the tool flexible enough to consider different mixes of DER technologies. Customers who require different levels and types of services because of their solar, fuel cells, batteries, EVs, etc. will have different costs of utility-provided services.

- Societal Costs and benefits should be separately categorized from costs and benefits to the grid.

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.

SDG&E reserves the right to submit comments on this question in response to the comments of other parties.

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.**

Yes, avoided RPS costs should be updated and should be utility-specific with the latest procurement costs. They should have a resource balance year similar to capacity to account for the procurement position of SDG&E that will achieve 33 percent well before 2020 and will not likely avoid renewables until after 2020.

In addition, hourly energy price profiles should be modified to reflect future conditions with more renewables just as the ELCC captures changing capacity value. To better capture the range of outcomes a higher renewable scenario should be included. This scenario would incorporate a higher percentage of utility procurement of renewable resources from utility scale renewables.

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.**

While not a utility avoided cost, the analysis should include consideration of the customer benefit of receiving a Renewable Energy Credit ("REC"), whether they elect to monetize it or not. The value of a category 1 REC should be included as a customer benefit in the participant test. Solar customers keep the REC which has a value whether or not the customers decides to sell the REC or keep it to ensure that they are consuming green energy.

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.

The Billing and metering costs should be included as part of the costs components.

Integration costs should be included including the net increase in ancillary service costs, if any. The recent CAISO and LBNL studies should be used as a basis for considering the integration costs.

8. **How should the utility costs 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.**

Utility costs should be determined separately for each IOU. At a high level, utility costs fall into two categories: cost of providing service and cost of regulatory compliance, such as the costs of public policy programs, With regard to cost of providing service, each utility service territory is unique with its own load profile and customer composition. Therefore the costs of the system and the costs of integrating DER will vary by service territory.

Costs of providing service are driven by a number of utility specific issues that need to be assessed independently including:

- System and bundled load shape
- Customer composition and class load shape
- Resource Portfolio (including RPS level and renewable resource composition, availability of Hydro, etc.)

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?**

SDG&E believes that tools to estimate adoption rates are misplaced in the determination of an appropriate NEM structure. Rather, a sensitivity analysis at different levels of adoption should be conducted to assess participant economics and non-participant costs. Using adoption levels simply clouds what is the fundamental sustainability analysis. From a quantitative perspective, participant adoption levels are driven by the cost of a customer's PV system and the bill credits a customer realizes. From the non-participant perspective the issue is one of cost shifts when determining whether a NEM 2.0 structure is sustainable. Assessing the cost shift can be done by assessing the structure under different adoption levels and does not require a forecast of adoption rates. Calculating adoption levels ultimately distracts from these key critical quantitative assessments of participant and non-participant economics.

That being said, the logistic growth model is one of the most common methods used for adoption/saturation forecasting. The S-Shaped curve produced by the logistic expression fits most technology saturation trends such as personal computers and smartphones and will likely occur for solar technology and electric vehicles.

The curve represents a slow start as the technology is expensive and untested, followed by an "explosive" period as technology emerges and becomes exponentially cheaper/more economical until it reaches an inflection point where the technology matures, the economies of scale are exhausted, and market becomes saturated reducing the amount of new customers available and willing to buy the product starts to decrease over time. Eventually, as we near satiation, the new adopters are such a small portion of the existing stock that the graph appears to level off. However, the solar PV is a global market so a global assessment is what is required to look at questions such as economies scale and market saturation.

This same type model can be applied on an individual customer basis to represent the range of customer preferences and unspecified barriers. Some customers will accept a 10-15 year payback, while others require a 3-5 year payback. Currently, the CEC employs a bass-diffusion curve model to model adoption based on cost-benefit analysis in order to analyze at which point solar panels become economical to the marginal customer.

The CEC adoption forecast model should not be used because it does not provide any additional information beyond what the economics to a participating customer provide. It provides less reliable future PV adoption than an assessment of the economics available. We have not seen any additional methods that could potentially be used as an alternative to this model. However, SDG&E believes developing the S-shape curve based on historical data and data outside California: (1) would take away from the fundamental quantitative analysis that is useful in assessing NEM 2.0 structures; and, (2) would underestimate adoption rates unless adjustments are made for awareness, familiarity of technology, and reduced unaccounted-for barriers such as local permitting and financing constraints.

<u>**Data Sources**</u>

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?

SDG&E agrees that the most recent and best publicly available data be used as inputs for the Public Tool. The difficulty will be to determine what data is considered "best." Parties may very well disagree as to what the "best" and most accurate data is.

Regarding information gathered by the CPUC via data requests, SDG&E believes this information should be afforded all the safeguards of confidential data. The requested data by the CPUC should be limited in scope and quantity to only that information which is necessary for the end-goal. Further, if that information is to be shared outside of the CPUC with a consultant then the proper Non-Disclosure Agreements must be in place. Finally, aggregated data should be used when possible.

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:

SEE TABLE IN RULING – PAGE 4

Rows

- **Renewable DG cost and performance information**
- **Renewable DG adoption curves and methodology**
- **Avoided costs**
- **Utility revenue requirement forecast**
- **Billing determinants**
- **Utility revenue requirement allocation factors to class**

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

For avoided costs, see response to question 5.

With regard to utility revenue requirement forecast, SDG&E recommends utilizing data request provided in support of CEC IEPR submitted biennially by each IOU. This will provide a consistent reference point for each IOU as well as more comprehensive information for all revenue requirements.

With regard to billing determinants, should be based on current authorized/effective billing determinants for the development of rates and rate design. Authorized billing determinants used for rate design may be considered confidential depending on vintage. In the event that they are determined to be confidential, the prior authorized billing determinants should be used.

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.

SDG&E reserves the right to submit comments on this question in response to the comments of other parties.

<u>The Public Tool</u>

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?**

An SDG&E forecast to 2050 doesn't exist, since uncertainty about the sales forecast increases as the forecast time horizon increases. It would be inappropriate to extend the current 2024 forecast out to 2050.

    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.**

While the IOUs response to the IEPR data request provides a reasonable starting point for analysis, however, as with any forecast should not be expected to reflect actual revenue requirements.

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?**

The model should be designed to evaluate the individual services that customers require including distribution demand (non-coincident demand), system peak demand (on-peak demand) reliability (standby), balancing (exports), customer costs (call center, meter, etc.) and recovery of CA policy programs such as low income and EE (PPP). If all of the individual services provided by the utility are evaluated and reported on separately then the model will be able to reasonably evaluate any number of technologies.

Such analysis is consistent with the deployment of ZNE construction which should be considered in the model as it is the state's policy objective. NEM 2.0 will directly impact CA's ability to achieve sustainable ZNE which is supported by the CEC, CPUC and building industry partners through the adoption of the 2013 California Building Energy Efficiency Standards.. NEM 2.0 will need to support ZNE and be able to recover the cost of services provided to ZNE customers so that NEM and ZNE can be sustainably adopted.

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

The ability to model a technology or any combination of technologies is ultimately driven by a rate design's ability to adequately recover a customer's costs for individual services that are provided by the utility. In that sense, what is required is the individual customer information on the services that are provided by the utility which would be recovered through fixed, demand and energy based charges. A representative sample of customers with annual hourly demands would allow different technologies and combinations to be layered on top. The resulting determinants can be used to assess how reasonable a given structure was in recovering the customers cost of service and cost responsibility for other things such as PPP costs that support CA policy objectives.

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.**

See response to 13.

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

An Assigned Commissioner's Amended Scoping Memo and Ruling, dated May 13, 2014, required the IOUs to file proposed changes to Rule 21 to require Smart Inverters. The IOUs filed the recommended changes on July 18, 2014. A proposed decision is expected by the end of 2014.

The impact of smart inverter technologies paired with DG should not be examined in the Public Tool if the smart inverters become mandatory. Since all new facilities will require smart inverters rather than limited, traditional inverters the value of the smart inverter will be a constant. It should be reflected in added costs, if any, and added benefits in reduced integration costs related to voltage regulation.

If smart inverters do not become mandatory this item may need to be considered.

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.**

Without developing the appropriate rate structures customers who install smart inverters will be unable to receive compensation for the services that they might be able to provide to the grid. For example while inverters with advanced functionality can mitigate some of their intermittent power production, they can also provide or absorb reactive power to assist with voltage regulation. However, there is currently no means to compensate customers for that service.

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?**

SDG&E reserves the right to submit comments on this question in response to the comments of other parties.

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

See response to 13a above.

A critical component of the Public Tool will be reporting on a rate design's ability to collect a NZE customers cost of service.

This is one of the reasons that the individual benefits attributed to DER (Transmission, Distribution, Generation, Energy, GHG, etc.) should be reported separately so that the cost recovery of those assigned benefits can be assessed when analyzing how well a NEM 2.0 structure recovers a customer's cost of service. If PV is assumed to have a distribution benefit for which a PV customer is then credited, the cost of that credit needs to be recovered from distribution customers. This is the same for generation capacity, energy, transmission, etc. To support ZNE analysis, inputs for each cost category need to allow for users to specify where each cost component is collected through each individual rate component. Only then can stakeholders assess whether the structure adequately meets the criteria that the total benefits and total costs are approximately equal for all customers.

Given the state's goals for all new residential construction to be net zero starting in 2020 a rate design that does not adequately recover the cost of service and public policy costs such as PPP from a ZNE customer will undermine California's ability to sustainably move to a ZNE regime.

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

Yes, the report should include a cost of service analysis. NEM 2.0 customers should be required to pay for their cost of service. This includes meeting a customer's demand at any time of the day and standing by to serve a customer if and when that customers DER system has an outage.

Having a baseline of what a customer's cost of service is, by type of service provided (i.e. commodity, distribution, transmission, etc.) will be required to understand the dynamics of different combinations of DER and what rate structures are resilient to multiple combinations of technologies. It is also required in order to assess a NEM 2.0 structure's sustainability in minimizing cost shifts and appropriately crediting DER customers at different levels of adoption.

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."

The three most important inputs the user should be able to modify include the following:

1. A simple user interface that can assign cost categories to rate components

- Rate design is complex and yet very important to the process. To be able to conduct the necessary analysis, the user should be able to choose have as simple an interface as possible while providing for the granularity that is ultimately required to assess the NEM 2.0 rate structures as discussed in question 22 below. This includes mapping where utility costs and any economic incentives provided to participating customers are collected. This is necessary so that an assessment of whether the total benefits and total costs are approximately equal for all customers.

2. The ability to scale avoided costs as in the Nevada Public Tool

- There are significant disagreements over the ability of intermittent resources to avoid capacity and distribution investment costs. The ability to scale these costs (or the ELCC of the costs) will allow parties to advocate their position while making their assumptions perfectly clear. In addition, these avoided costs should be able to be scaled up and down by cost component (i.e.

Distribution, Transmission, Generation Capacity, Energy, etc.) by year so that sensitivities can be conducted that reflect different levels of technology adoption and RPS costs.

3. Technology costs

- PV costs are high in California compared to other states and in particular with respect to Germany. California should have a lower cost than the rest of the United States based on learning curves, but instead is among the highest. Speculation is that the costs are higher in California due to "value pricing;" prices of rooftop solar installations are higher because the benefits of the current NEM program are very high, providing room for inefficient installers. Since this is a major element of the participant cost, it should be user defined to allow for alternative costs more comparable to the U.S. average experience or the German experience.

Pricing Mechanisms and Rate Designs

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?

SDG&E is generally against modeling participating customer-generators as a separate class. Currently SDG&E has five different customer classes: residential, small commercial, medium and large commercial and industrial, agricultural and streetlighting. Identifying customer generators as a separate customer class would likely require replicating the customer generators by class as well (i.e., differentiating by residential, small commercial, medium and large commercial and industrial). Additionally, there would likely be the need to differentiate customer generators by technology into different classes due to differences in cost of service. This level of segmentation can also cause potential issues with having sufficient sample size for the development of billing determinants and cost studies needed for the development of rate design.

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.

Fundamentally the model should have the ability to map the different categories of costs that make up utility costs (cost of service as well as regulatory compliance/public program costs) to alternative rate recovery structures. This would require the separate identification of the individual cost category, and costs within those categories in some cases, as well as the individual identification of rate recovery structures.

The different cost categories include:

- Transmission: Base Transmission Revenue Requirements, TAC, TRBAA, FERC jurisdictional Reliability Services
- Distribution cost of service: Customer Costs, Distribution Demand Costs
- Generation Resources: Generation Capacity, Residential Energy Costs, Non-bypassable (Cost Allocation Mechanism (which for SDG&E is the Local Generation Charge), Power Charge Indifference Adjustment, On-going Competition Transition Charge), regulatory compliance (Renewable Portfolio Standard, Greenhouse Gas)
- Public Policy Programs: Public Purpose Programs (includes programs for low income (CARE) and energy efficiency)Other programs(California Solar Initiative, Self Generation Incentive Program, Demand Response)
- Nuclear Decommissioning
- Department of Water Resources-Bond Charge

Rate Structure Options include:

- Customer Charge: $/month
- Time of Use Energy Rate: $/kWh (TOU)
- Demand Charge – both non-coincident and peak and ability to combine the two and apply a factor relationship: $/kW Demand

- Demand Charge based on Exports both non-coincident and peak and ability to combine the two and apply a factor relationship: $/kW Export Demand
- Customer Charge that varies by the size of the customer: $/month - kW and ability to apply to minimum demand level.
- Critical Peak Pricing – both system and circuit peak
- Credits for surplus energy (CAISO Duck-belly)

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

The following potential compensation mechanisms not mentioned above should be modeled in the Public Tool:

- Direct Incentives
- Direct payments for attribute (i.e. Capacity)
- Ability to allocate this cost to any rate component as noted in the table above.

The ability to allocate cost components, or a portion of those costs, to any available rate component would allow for an assessment of the ability of a customer to avoid the individual cost component.

As customers diversify they will use some utility services and not others (i.e. DA/ CCA, solar paired with batteries and or EV's, etc require different services than typical bundled customers). The bypass of a utility's commodity cost has a different impact on DA and CCA customers than the bypass of distribution costs. Therefore, the tracking and assignment of collection is critical to the public tool.

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.

If netting, the shortest period allowable by meters should be used. Therefore, the Public Tool needs to model both 15 minutes and hourly.

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.

The model should be flexible enough to assign cost recovery by cost category (Distribution, Transmission, Generation Capacity, energy, etc.) to individual rate components such as fixed charge, non-coincident demand charge, on peak demand charge and energy rate.

For demand charges, the model should be able to incorporate factors onto demand charges by TOU periods. These factors would reduce the measured demand used for billing purposes. For example with a 50% factor for the semi peak, a customer who uses 4 kW in the on-peak and semi-peak would have billing determinants of 4 kW during the on-peak and 2 kW during the semi peak.

kW and kWh exports to the grid also need to be available in the model. Factors, as explained above, should be incorporated into the export demand. In that way a signal could be sent to encourage exports on-peak while discouraging exports during the super off-peak.

The TOU periods should have a toggle for existing and a peak shifted to later in the day.

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.

As noted above, SDG&E submits that additional features that should be considered are:

- kW factors by time period
- kW for exports

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.

The dollar per customer and $/kW, with a higher amount in the dollar per customer month should be included in the Public Tool. Additionally, the tool should include dynamic pricing structures (i.e., CPP) as well as rate design concepts such as VGI.

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.

SDG&E reserves the right to submit comments on this question in response to the comments of other parties.

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 ifrelevant.**

        ii. **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?**

The Feed-in Tariff should be a cents/kWh payment that increases at a fixed rate each year to correspond with inflation based on the costs of the technology to produce the energy for an average service territory location for non-dispatchable renewables. Since these intermittent resources cannot alter their production, there is no need to include a TOD factor.

Factors that reduce output but provide value such as west-facing installations or those with smart inverters can be compensated with a higher cents/kWh payment. There is no need to consider geography since areas with more sun/wind will be compensated more since they will produce more.

For technologies that are dispatchable or paired with storage, TOD factors for payments are useful to deliver the electricity when most desired.

A single payment amount per kWh by technology is the way the FIT program in Germany has worked. While the German program uses a levelized cost, an escalating payment will reduce divergence between utility payments for the power and customer payments for grid services that tend to increase with inflation. The FIT Payment Rate should be reviewed in each General Rate Case Phase 2 or Rate Design Window for the new installations. The FIT would only need to be changed if technological changes lowered the technology cost significantly (as with PV costs between 2008 and 2012), if material costs increased the technology cost significantly (as occurred between 2006 and 2008), or the capacity factor changed from technology or regulatory requirement changes (smart inverters, improved efficiency).

The cost used to calculate the FIT would be based on the LBNL studies of distributed solar and wind costs by sector (residential and commercial) in California and the United States in 2013 and adjusted for changes in average costs in the U.S. going forward. The latter would avoid perverse incentives to keep installation prices high to affect the FIT rate. A weighted average of the California installation costs and U.S. installation costs would account for likely cost reductions possible with a more competitive price regime. The costs would be converted to $/kWh based on a real economic carrying charge approach. For example, solar would be converted using a specified lifetime of 24 years, inverter life of 8 years, and estimated average capacity factor of existing installations in the service area.

The Commission's Renewable Market Adjusting Tariff (Re-MAT) might also be useful as a reference point in designing the NEM FIT. The price for this program is set at the same initial amount for each product, and then this initial price adjusts on a periodic basis for each product type based on market response. Higher than expected adoption, lowers the FIT price by a set amount; lower than expected adoption increases the FIT price. It may be worth exploring whether a market-determined price, like the Re-MAT mechanism, could be an alternative for an NEM FIT.

Disadvantaged Communities

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.**

    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.**

    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?**

    It is premature from the model construction standpoint to delve into this topic.

Other Issues

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.**

SDG&E reserves the right to submit comments on this question in response to the comments of other parties.

III. CONCLUSION

SDG&E appreciates the opportunity to submit the forgoing Post-Workshop Comments.

Dated: October 1, 2014

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