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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)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) OPENING POST-WORKSHOP COMMENTS

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Southern California Edison Company (SCE) respectfully submits the following responses to the California Public Utilities Commission's (Commission's) questions pursuant to the Administrative Law Judge's September 5, 2014 Ruling (Ruling) Seeking Post-Workshop Comments.

I.
INTRODUCTION

On August 11, 2014, the Commission's Energy Division staff conducted a public workshop on the "Public Tool" for testing options for a successor to the existing net energy metering tariffs pursuant to Assembly Bill (AB) 327, otherwise known as the Ratepayer Equality Act. AB 327, the relevant provisions of which are codified in California Public Utilities Code Section 2827.1,[1] instructs the Commission to develop a successor to the utilities' existing Net Energy Metering (NEM) tariffs.

Pursuant to Section 2827.1, the successor contract or tariff may, but need not, include net energy metering. Section 2827.1 authorizes the Commission to impose just and reasonable fixed

[1] Unless otherwise noted, all statutory "section" references are to the California Public Utilities Code.

charges on customer-generators that the utilities serve on the successor contract or tariff that differ from non-customer generator fixed charges, provided those fixed charges are authorized in a rulemaking proceeding involving the large electrical corporations.

In addition to these discretionary features, AB 327 imposes several mandatory requirements on the successor contract or tariff. First, the successor contract or tariff may not have a program or sizing cap, provided that systems over 1 megawatt (MW) do not have a significant impact on the distribution grid, are sized to the onsite load, and are subject to reasonable interconnection charges under Rule 21 and other law. Second, the successor contract or tariff must, among other things, ensure that customer-sited renewable generation continues to grow sustainably, include specific alternative designs for growth among residential customers in disadvantaged communities, establish terms of service and billing rules for customer generators, be based on the costs and benefits of the renewable electrical generation facility, and ensure that its benefits to all customers and the electrical system approximately equal its total costs.

To model and evaluate whether the parties' proposals are consistent with these statutory mandates, the Commission retained Energy + Environmental Economics (E3) to create a Public Tool. On September 5, 2014, the Administrative Law Judge issued the Ruling requesting that parties comment on 29 questions regarding the development of the Public Tool. The Commission's hard work and diligence is obvious from the Workshop and the 29 questions. SCE appreciates the opportunity to support the Commission's efforts by answering the 29 questions. For ease of reference, SCE's comments set forth the Energy Division staff's questions followed by SCE's response.

II.

ANSWERS TO QUESTIONS

A. Overview of the Proposed Approach

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?

Response to Question 1: SCE does not have concerns regarding the proposed approach of developing a public tool in conjunction with a report containing the range of results from the tool. Several aspects of the report, such as solar economics, may be informed by the upcoming

Residential Rate Order Instituting Rulemaking (R.)12-06-013. The Commission should therefore defer issuing the report until it has issued its final decision in that rulemaking to consider as an input to the tool and report. A single public tool for all of the Investor-Owned Utilities (IOUs)[2] is appealing, but a separate analysis may ultimately be necessary for each IOU, particularly with regard to cost of service and non-residential rates.

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 (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.

Response to Question 2: Past experience demonstrates that the public tool development process would benefit from as much input as possible from all stakeholders. Accordingly, the Commission should ensure that all parties are given notice and an opportunity to be heard in all aspects of the tool's development.

Nevada's NEM public tool process did not afford all parties that opportunity. As a result, the Nevada public tool overstated generation capacity and transmission and distribution avoided costs. Other small modeling mistakes were discovered after the tool was released. To avoid that outcome, the Commission should inform all parties when it makes changes to the tool and allow the parties sufficient time to comment on each version of the tool. The Commission should explain which comments have been incorporated into the tool, how they were incorporated, and why. Once a version of the tool is functioning, the Commission should fully vet the tool by holding one or more workshops to demonstrate the tool for parties, obtain additional input, and further refine the tool.

Another worthwhile example is the development process of the public rate and bill impact models the IOUs developed at the end of 2012 and into 2013 with significant stakeholder input and guidance from the Commission staff. The Commission staff ultimately requested

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[2] The IOUs include SCE, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E).

additional reasonable revisions and requirements from the models as the proceeding went on through continued requests from parties in light of the feasibility of the changes.

B. 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"?[3]

Response to Question 3: Evaluation measures should also include impact on overall system average rates. With respect to subpart (d), the Commission should also clarify from whose perspective the total cost and benefits are calculated.

Question 4: Using the E3 avoided cost calculator[4], 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 (GHG) 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)

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[3] Section 2827.1(b)(1).

[4] Found at: http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm.

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.

Response to Question 4: The Public Tool should only account for costs and the associated values of those costs that are directly reflected in the IOUs' authorized revenue requirements. Because the Public Tool is being developed to estimate the cost-shift burden and avoided cost benefits, this basic requirement is imperative and recognizes that costs that are not recovered from participating customers are recovered from non-participating customers to meet the authorized revenue requirement. If a cost attribute is not in alignment with authorized revenue requirements, then the amount of cost burden will be over- or understated. Examples of costs that should be included are: distribution and generation capacity, generation energy, GHG, and Public Purpose Program Charges. Intangible costs that are not directly tied to utility revenue requirements, such as societal benefits and the global cost of carbon, should not be included as part of the cost/benefit analysis for renewable DG. If the Commission wants to include additional values, it should consider benefits that actually accrue to ratepayers on their electric bills, as opposed to elsewhere.

Question 5: Are there any avoided cost components from the 2013 NEM Report that should be updated or modified?[5] 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.

Response to Question 5: With respect to generation capacity, the users of the public tool should not be able to use a vintage Effective Load Carrying Charge (ELCC) to estimate capacity value benefits. Doing so assumes that the ELCC applicable at the time of installation remains the same throughout the resource's operating life. As a result, the capacity value of the solar installations will be overstated by maintaining a fixed value of capacity over the operating life of the system, based on the system's vintage or year the system was installed. Allowing the use of a vintage ELCC can overstate the capacity benefits by over 62 percent. By contrast, a non-vintage ELCC, as assumed in E3's 2013 NEM Report base case, accounts for the reduced

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[5] *See* E3's Avoided Cost Model for avoided cost assumptions from the 2013 NEM Report. http://www.cpuc.ca.gov/NR/rdonlyres/C091FB9E-1C2C-4E54-A44A-817827F8941E/0/E3NEMAvoidedCostModel.xlsm.

load carrying requirements of individual renewable resources as new resources are brought online and gradually shifting the peak towards hours where solar capacity factors are low.

In addition, SCE would like E3 to use the class and function specific hourly cost allocators SCE provided for the 2013 NEM report, updated to reflect the 2012 GRC marginal costs and allocations. Those hourly allocators better reflect the "right time, right place" cost of service associated with current rates and the coincidence of renewable DG with the distribution and generation peaks. The hourly allocators will demonstrate renewable DG's ability to avoid costs related to the functional demand peaks.

Finally, the avoided cost components E3 uses should be directly traceable to the IOUs' cost of service studies, actual regulatory and legislated program costs, and authorized revenue requirements.

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.

Response to Question 6: E3 should distinguish avoided costs by class and function as SCE did in the information it provided to E3 for its 2013 NEM study. Specifically, SCE divided the costs associated with distribution infrastructure into two components: grid component costs and design demand costs. The grid component costs are comprised of costs associated with assets that are not avoided when incremental renewable generation is brought on line. Examples of such assets include ducts and structures, poles, wire, land, and some cost associated with transformation. Grid component costs primarily depend on the number of customers on the circuit. Design demand costs are almost entirely associated with higher levels of transformation (e.g. at substations), which can potentially be partially avoided. Distinguishing costs that are truly unavoidable from those that can be partially avoided or deferred will appropriately account for distribution infrastructure upgrade costs that cannot be deferred by installing distributed generation, e.g., the fixed costs of poles, wires, real estate. In addition, distinguishing costs that are truly unavoidable from those that can be partially avoided or deferred adjusts the marginal cost to account for the fact that distributed generation only defers investment in distribution infrastructure if it is at the right location and reduces grid requirements at the right time. Distributed generation on a circuit that is not constrained at the time the renewable DG peaks provides no deferral value. This approach is consistent with cost-effectiveness protocols used by the Commission for customer programs, such as energy efficiency and demand response programs.

Furthermore SCE believes that the avoided distribution cost structures provided by SCE for E3's 2013 NEM Study should be used in place of the methodology E3 actually used in its 2013 study to determine avoided costs. E3 used the material SCE provided for the Full Cost of Service study. E3 could also have used that material to determine avoided costs. SCE recommends that it do so for the purposes of developing the Public Tool. E3 also may not have used the present worth methodology to determine transmission and distribution (T&D) avoided costs. Instead, E3 may have relied upon the avoided cost for T&D capacity from E3's 2011 Energy Efficiency Avoided Costs Update.[6] If that is the case, E3 should make a correction for the Public Tool.

With regard to the methodologies used to quantify avoided cost of distribution capacity, the appropriate forum for that activity is the Distribution Resources Plan Rulemaking (R.)14-08-013. In the interim, for the purposes of developing the Public Tool, SCE recommends that E3 use the methodology from utility rate case filings as a reasonable proxy for the long-run marginal cost of T&D investment that is avoided over time with the addition of on-site renewable generation.

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.

Response to Question 7: Participant costs for installed renewable DG should include installed system costs (for participant-owned systems) and costs associated with leases and

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[6] E3's Energy Efficiency Avoided Costs 2011 Update, available at: http://www.cpuc.ca.gov/NR/rdonlyres/18579E92-07BD-4F24-A9B4-04975E0E98F5/0/E3AvoidedCostBackground.pdf

power purchase agreements (PPAs) for third-party-owned systems. Third-party owned systems comprise the bulk of SCE's residential installations. According to California Solar Statistics, to date, third-party-owned systems comprise 72 percent of the new residential capacity installed in SCE's territory. Based on a sample of all third-party-owned systems in SCE's territory, leases represent 38 percent and power purchase agreements (PPAs) represent 62 percent of the installed, third-party owned systems that have received incentives through the California Solar Initiative (CSI). Given that the majority of systems are third-party-owned, both leases and PPAs should be considered as alternatives to installed system costs.

Furthermore, if additional metering is necessary for SCE to bill customers it serves on the successor tariff, the Public Tool should include that additional metering cost as a cost component for participating customers as a part of their interconnection costs, as explained in SCE's response to question 8 below.

Finally, like the Commission's California Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects,[7] SCE recommends that the Public Tool include ongoing costs of operations, maintenance, and taxes associated with the installed system as participant cost components.[8] The cost categories include the participant's costs of regular maintenance and inverter replacements. In the case of third-party-owned systems, some of these costs may be included in the contract costs.

Question 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.

Response to Question 8: With respect to utility costs, to ensure the Public Tool's accuracy, E3 should determine the utilities' costs separately whenever the utilities incur different costs as a result of customer-generation or use different methodologies to determine such costs for their respective General Rate Case (GRC) applications. E3 should ensure that the Public Tool is flexible enough to account for these differences.

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[7] California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects, available at: http://www.cpuc.ca.gov/NR/rdonlyres/004ABF9D-027C-4BE1-9AE1-CE56ADF8DADC/0/CPUC_STANDARD_PRACTICE_MANUAL.pdf

[8] *See id.*, at pp. 8-10 (setting forth the Participant Test).

With respect to interconnection application and supplemental review fees, because the amount each utility can recover is the same under Rule 21, the Public Tool can make a uniform determination for these costs. Other interconnection costs, by contrast, such as studies, metering installation and commissioning, facility upgrade costs, vary among the utilities for a variety of reasons. As with the utility costs discussed above, the methodology and data consistent with that used in each utility's GRC should be used for these cost determinations.

Finally, with respect to renewable integration costs, each IOUs' costs will differ based on individual costs and flexibility needs. SCE anticipates that the Commission will adopt these differing integration costs in the Renewable Portfolio Standard (RPS) rulemaking (R.)11-05-005. The Commission should use the costs adopted in the RPS proceeding in the development of the Public Tool.

The following methodology is proposed for each of the utility cost components.

- Interconnection Costs: Pursuant to Commission Resolution E-4610 and Decision (D.)14-05-033, the IOUs have been tracking and recently reported NEM interconnection costs to the Commission.[9] SCE recommends that E3 use the same methodology and cost components for the NEM Public Tool. These interconnection costs are those incurred by utilities, and participants in some cases (i.e., interconnection facility upgrade costs), for interconnecting both NEM systems and qualifying NEM-paired storage systems. Each of the interconnection cost components are briefly described below.
    - Application processing and administrative costs including application processing (e.g., validating and approving single line diagram, interconnection agreement, electrical inspection clearance from governmental agency having jurisdiction, and other required documents), and back office tasks (e.g., initial billing setup), inquiry calls and emails, and permit-to-operate (PTO) mailer.

[9] SCE submitted some of its costs in Advice Letter 3103-E on September 19, 2014. It will update that submission with the data it collected for facility upgrade costs on October 20, 2014.

- Distribution engineering costs include cost of technical analysis, studies, and screens consistent with Rule 21 (e.g., voltage rise, 15 percent penetration, transformer loading).
- Metering installation and commissioning costs include residential and non-residential meter changes, remote meter programming, material, supplies, procurement costs, labor for installation, testing, engineering, and quality assurance necessary for interconnection.
- Facility upgrade costs include the costs of new interconnection facilities to serve individual customers (participant cost) and distribution upgrades that have the potential to serve multiple customers (utility cost).

- Billing and metering costs. E3's methodology to determine billing and metering costs for NEM customers should account for the following:
  - Metering costs: Most SCE NEM customers use standard SCE SmartConnect (AMI) or interval meters that can be reprogrammed over-the-air to allow for NEM billing. Most of these metering costs are currently recovered through the customer's otherwise applicable tariff (OAT) and should continue to be recovered as part of the OAT, unless additional metering is specifically required to bill customers on the successor tariff. In that event, additional metering costs should be included as a cost component for renewable DG customers and should be accounted for as interconnection costs in "Metering installation and commissioning costs," as described above.
  - Billing services: SCE currently recovers the costs of providing billing services to NEM customers through charges already included in the customer's OAT. Any additional or incremental billing costs specifically attributable to customers served on the successor tariff should be included as a potential input in the Public Tool.
- Integration costs. The methodology used to determine integration costs for on-site renewable DG should be the same methodology used to determine integration costs for utility procurement of renewables. As noted above, SCE anticipates that the Commission will adopt utility-specific integration costs in the Renewable

Portfolio Standard (RPS) rulemaking (R.)11-05-005. The Commission should use the costs adopted in the RPS proceeding in the development of the Public Tool, unless the Commission adopts an alternative methodology in time for E3 to incorporate the approved methodology in the Public Tool. Specifically, SCE supports PG&E's proposal in the RPS proceeding for a renewables integration adder for the Public Tool.[10] At a high level, integration costs should include fixed costs for new long-term flexible requirements, as well as variable costs associated with increased ancillary services and flexible ramping. Each of these components varies by renewable technology and is briefly described below:

- o The fixed cost of new flexible requirements is the utility's cost of meeting flexible resource adequacy (RA) obligations, accounting for any market premium anticipated for flexible RA resources over non-flexible RA resources. SCE's flexible capacity need is expected to be zero until 2020, when it begins to increase due to higher penetration of renewables. In the RPS proceeding, SCE and PG&E are recommending that this cost be based on the expected flexible capacity need in 2024, assuming data from the 2014 Long Term Procurement Plan (LTPP) trajectory scenario and 33 percent RPS requirement.

- The variable costs of integration account for the California Independent System Operator (CAISO) costs of intermittent generation. Consistent with Commission guidance, the variable costs of integration include the costs of ancillary services and the costs of various reserves needed to offset minute-to-minute, hour-by-hour, and day-ahead variability. Production simulation models are the best way to derive these costs, but in the current absence of adequate models, the PG&E proposal recommends data from Western Electricity Coordinating Council (WECC) studies be used to derive these costs. SCE supports using these studies for the E3 Public Tool to derive the variable costs of integration.

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10 PG&E's July 2, 2014 Opening and July 30, 2014 Reply Comments on RPS Plans and Related Proposals in R.11-05-005.

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?

Response to Question 9: Given that a vast majority of new DG systems today are third-party-owned and obtained by customers through leases and PPAs that often do not impose upfront costs on the customer, a DG adoption model based on payback or IRR may not be appropriate and may, in fact, underestimate adoption. An adoption model that is based on immediate savings may better reflect customer behavior, especially on the part of residential customers. An example of a potential approach is to use historical adoption data to fit diffusion parameters in a Bass diffusion model (Norton and Bass, 1987). These diffusion parameters would be sensitive to the degree of customers' bill savings. This model can look at multiple customer types based on their range of savings for further granularity. SCE has been collaborating with the California Institute of Technology to develop a model that uses a similar approach for residential adoption of photovoltaic (PV) systems.

Strengths of the proposed approach are that it may better represent decision-making behavior and allow stakeholders to evaluate adoption by different customer groups based on historical behavior. A weakness of the proposed approach is that it is uncertain whether it will effectively model non-residential customers.

Factors that should be considered in the analysis include, but are not limited to, ownership model, taxes, rebates and other upfront incentives, and financing cost.

C. Data Sources

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 requests to the IOUs.

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

Response to Question 10: SCE agrees that the Public Tool should rely upon public data if it is available. When public data is not available or non-public data is a better source, such as to quantify avoided costs, then E3 should use the non-public data.

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 Item	**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 costs	CPUC NEM study methodology, updated to reflect current natural gas market prices and AB 32 CO_2 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.

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.

Response to Question 11: E3 should not rely upon the LBNL Tracking the Sun Report to estimate renewable DG costs because renewable DG costs have fallen by 20 percent in the two years since LBNL published the report. E3 should instead rely upon system costs and trends recorded in the CSI program participation database. As of the date of this filing, CSI statistics database was last updated on September 17, 2014 and thus reflects the most current cost trends for renewable DG. It is important to use an accurate cost trend to determine the participant value proposition and rate levels and structures required to balance participant and non-participant interests. Furthermore, because most systems are installed through PPAs, the installed cost of a system is less relevant from a participant perspective than the cost of the power purchase agreement, as compared to the cost of utility service.

D. 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.

Response to Question 12: SCE agrees that there are challenges in forecasting revenue requirements and usage in later years. Any agreed-upon projections in the LTPP proceeding should be used in the Public Tool. Beyond that, it is difficult to provide useful guidance because projections are so uncertain. As for other factor for modeling long-term revenue requirements, as saturation of DG increases, there will be an increase in displaced sales. E3 should apply a factor to the usage snapshot that account for those displaced sales.

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?

Response to Question 13: SCE believes that the list of RPS-eligible technologies (solar PV, solar PV with storage, wind, biogas-fueled technologies) to be evaluated in the Public Tool is sufficient and appropriate, and does not suggest any additional technologies be included in the Public Tool.

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.

Response to Question 14: SCE does not believe that NEM eligibility should be expanded 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?

Response to Question 15: If the Commission intends to have the tool address customer costs associated with integrating distributed energy resources, the impact of smart inverter technologies paired with DG applications should be examined. Research indicates that smart inverter technologies may promote safety and reliability when integrating increasing amounts of distributed energy resources onto the grid. That research has influenced interconnection standards, particularly in California, to such a degree that smart inverters will likely be required by proposed Rule 21 changes after December 31, 2015.

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.

Response to Question 16: By way of background, existing inverters do not provide any volt/volt-ampere reactive (VAR) control for grid support. In addition, existing inverters have a narrow voltage/frequency ride through capability, which causes them to immediately disconnect from the grid under disturbance conditions, eliminating the flow of energy from these resources onto the grid. Under disturbance conditions, disconnection enables the utility to maintain the safety and reliability of the grid by switching around the problem and preventing utility employee and public exposure to energized electrical equipment. While this procedure works for current levels of renewable DG at the hundreds of MW levels, it is not scalable to projected future levels of high penetration because instantly losing thousands of MW could greatly exacerbate a system disturbance and cause more widespread impacts.

Future inverter standards (smart inverters) will require advanced features that can safely and reliably enable higher penetration of distributed energy resources on the grid. While such inverters won't necessarily solve all of the potential problems, they will not exacerbate a system disturbance by immediately disconnecting from the grid. Newer inverters will provide for better voltage/frequency ride through, which will keep them online within safe parameters. These inverters will also have the ability to provide static and dynamic volt/VAR support and power factor controls, as well as a slow start up rate, which can help to prevent over voltage situations on the grid.

While smart inverter standards provide a means to more safely and reliably interconnect higher penetrations of distributed energy resources, they are not a panacea for the impacts of these resources on the grid. Distribution systems were designed to take power in one direction from the generator/transmission system and deliver it to the customer. It is generally accepted that bi-directional power flows will impact utility protection schemes and add to the short circuit current requirements of substation circuit breakers. Utilities will also have to study the impacts of renewable DG during circuit transfers and reconfigurations, where the loss of local renewable DG could cause overloading in other parts of the circuit or substation. Existing voltage support devices (e.g., capacitors, voltage regulators, and transformer tap changers) will likely need to be reprogrammed or retrofitted to support changing conditions, be moved to more optimal locations, or, in some cases, be removed/disabled.

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?

Response to Question 17: The Public Tool should also include the streetlight customer class. In SCE's service territory, municipal customers have expressed an interest in installing medium scale solar projects on metered streetlight service accounts, representing an evolution in networked renewable DG application installations. These types of installations may require unique rate treatment. In addition, as discussed in greater detail in SCE's response to Question 21, the tool should also be able to separately model the residential and non-residential classes by size, *i.e.*, monthly peak demand.

Question 18: How, if at all, should California's Zero Net Energy (ZNE) goals or impacts be included in the Public Tool?[11]

Response to Question 18: The Public Tool should study the cost shift associated with California's Zero Net Energy (ZNE) goals by assessing the total: (1) benefits that ZNE customers receive from the utility; (2) compensation ZNE customers receive; and (3) cost impact of ZNE customers on non-participating customers.

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?

Response to Question 19: AB 327 requires the Commission to conduct a cost of service analysis. Section 28271.1(b)(3)-(4) requires the Commission to "[e]nsure that the standard contract or tariff made available to eligible customer-generators is based on the costs and benefits of the renewable electrical generation facility" and "that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs."

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,

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[11] For information about ZNE, *see* http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/eesp/.

the cost of carbon, increased RPS procurement, etc.)? Please provide reasons why each input chosen is among the "most important."

Response to Question 20: If there is a limit on the number of inputs that a user will be able to modify, SCE recommends that the inputs that have the greatest impact on the result should be modifiable. The three most important inputs that a user should be able to modify are (1) netting structure, (2) rate structures that include a combination of fixed and variable charges applied as riders to the OAT or a stand-alone rate schedule (to handle ZNE), and (3) the compensation rate for exports to evaluate different cost impacts to DG participants and non-participants. Other inputs that should also be modifiable by the user are (1) separate rate class revenue allocation and rate design for participating customers, (2) resource balance year to determine appropriate avoided costs, and (3) capacity value by time-of-use (TOU) period over time.

E. 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?

Response to Question 21: Yes, participating customer generators should be modeled as a separate customer class for cost allocation and rate design purposes, because they display unique load characteristics that are not shared by customers without renewable generators. Moreover, Section 2827.1 requires the Commission to "[e]nsure that the standard contract or tariff made available to eligible customer-generators is based on the costs and benefits of the renewable electrical generation facility" and "that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs." Subpart (c) provides that "there shall be no limitation on the amount of generating capacity or number of new eligible customer-generators entitled to receive service pursuant to the standard contract or tariff after July 1, 2017." These provisions evidence a legislative intent to establish a tariff on a cost-basis that is subject to cost-based revenue allocation consistent with all other classes of customers. An additional benefit of separate class treatment is transparency and better control of cost-shifting between participants and non-participants through direct allocation of class level revenue responsibility and periodic true-ups in GRC Phase 2 proceeding rate changes.

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

Response to Question 22: Three variations to the above compensation structures should be modeled. First, parties should be able to add and the Public Tool should be able to model both fixed and variable charges for each compensation structure so that different combinations can produce the same outcomes with respect to reducing cost shifts. Second, parties should be able to change and the Public Tool should be able to model the underlying rate structure for each compensation structure. Third, the Public Tool should allow parties to limit the bill credit to generation charges only as an alternative mechanism to compensate customer-generators for their energy while recovering from those customer-generators their share of T&D costs. The Public Tool should also model participating customer-generators as a separate customer class with its own rate structure.

If an NEM structure is considered, exports should be netted against imports as instantaneously as is operationally feasible to minimize the discrepancy between the value of energy imported and the value of energy exported within any netting period.

For the export-only FiT model, the frequency at which exports are "netted against imports" is irrelevant because AMI meters are currently configured to measure bi-directional power flow. The AMI can total the bi-directional flow of power in any 15-minute period. Any power flowing from the grid to the customer could be charged the retail rate. Any power exporting to the grid would be compensated at a FiT rate. In SCE's opinion, this structure is principled and fair to all customers, whether they are participating customer-generators or not.

Question 23: Residential rate designs proposed to be included in the Public Tool are given below.[12] These rates would be applicable to both participating customer-generators[13] 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.

Response to Question 23: In addition to the residential rate designs listed, SCE recommends studying the TOU residential rate with the time periods proposed in SCE's Rate Design Window Application (A.) 13-12-015, including (1) on-peak 2pm-8pm weekdays, (2) super-off-peak 10pm-8am every day, (3) off-peak at all other time, and (4) summer June 1 to

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[12] Based on the residential rate design proposals submitted in R.12-06-013 (residential rate redesign) on May 29, 2013, available at: http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:57:8862587465006::NO.

[13] Participating customer-generators means any customer taking service under the successor tariff or contract to be adopted by the Commission in this proceeding.

Oct 1, winter all other times. SCE recommends the inputs of rate design be limited to those decided upon in the decision in R.12-06-013 and other rate schedules proposed by IOUs.

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.

Response to Question 24: Time differentiated $/kWh grid/network usage charges applicable to exported energy that differs from the energy charges applicable to delivered energy is a residential rate design feature that should be included in the Public Tool. SCE also recommends the inclusion of a fixed cost recovery $/kW charge based on the installed capacity of the renewable DG system applied to each monthly bill. Under such a structure, the participating customer-generator would pay a fixed amount equal to the product of the fixed cost recovery charge and the rated capacity of the renewable DG system in each billing period. This type of fixed charge provides a level of certainty for the participant while allocating a fair share of fixed cost recovery to participating customers by recovering revenues that would otherwise be shifted to non-participating customers, such as non-bypassable charges (New System Generation Charge (NSGC), Nuclear Decommissioning Charge (NDC), Public Purpose Programs Charge (PPPC), California Alternate Rates for Energy (CARE) surcharge, Department of Water Resources (DWR) Bond Charge, and Public Utilities Commission Reimbursement Fee (PUCRF)), and T&D charges. As another option, SCE recommends the inclusion of a $/kW demand charge designed to be applied to the monthly metered peak demand, which recovers costs similar to those described above.

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.

Response to Question 25: The Public Tool should allow non-residential TOU rate designs the flexibility to shift on-peak times to later hours as SCE has proposed for its optional residential rates. Based on Loss of Load Expectation studies conducted over the last year, SCE anticipates its "net" peak load conditions to shift later in the day as central station solar power plants and DG PV installations continue to increase within SCE territory. Distribution circuit peak conditions may also shift to later in the day. SCE provided this information to E3 for its September 26, 2013 NEM Study Introduction (Appendix C). The Public Tool should support a fixed grid charge and a variable design demand charge combination to collect T&D revenue requirements. The fixed portion or "grid charge" is based on infrastructure costs to serve a number of customers. The variable portion or "design demand" is based on the demand placed on the wires and substations. SCE's current non-residential T&D charges are variable based on monthly metered maximum demands.

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.

Response to Question 26: The Public Tool should include a T&D facilities charge consisting of grid and design demand components as described above in response to Questions 6 and 25.

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 (TODD) 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?

Response to Question 27: SCE believes that the Public Tool should be capable of modeling one flat, *i.e.*, not time differentiated, FiT rate and one TOU-based FiT rate. The attributes of the FiT rate are as follows.

First, the FiT rate should be based on market price benchmarks in the wholesale energy markets, such as the CAISO's default load aggregation point (DLAP) prices, consistent with SCE's existing Net Surplus Compensation Rate established in D.11-06-016 pursuant to AB 920 (2009). Once determined, the same FiT rate could apply to all installations in the utility's service territory in any given calendar year, with all exports from the customer-generators, or all system generation depending on the compensation structure, compensated at this rate for the entire contract term.

Second, the FiT rate should reset once per year at the end of the year, and the reset value should apply for all installations in the subsequent calendar year.

Third, Time of Delivery (TOD) factors can be applied to the FiT rate to better reflect the time-differentiated energy value that customer-generators' exports provide to the system.

Fourth, the FiT rate should not vary by geography, in part because of administrative complexity, and also because factors such as locational benefits should be handled in the utility's distribution planning process. Furthermore, such locational factors constantly change as the grid configuration changes.

Fifth, the FiT rate should not vary by technology type. SCE is agnostic to various renewable technologies and believes that rather than signaling a preference through different payment rates, a uniform price signal should be used in order to let the marketplace respond with the optimal technology option.

Sixth and finally, there should not be any fixed annual escalators to the FiT rate from year to year or any other mechanism to adjust the value paid per kWh over the contract term.

F. 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.

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?

Response to Question 28: The Public Tool should be capable of modeling any proposals for disadvantaged communities that parties propose. Without a working definition of "disadvantaged communities" and the parties' formal proposals on this aspect of the successor tariff, it is difficult to comment on the specific features that should be included in the Public Tool. The commission should have a dedicated workshop or create an opportunity for parties to submit comments on the features or an alternative to the successor tariff designed for disadvantaged communities. Once those attributes are developed, a determination can be made with respect to inclusion in the Public Tool.

G. 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.

Response to Question 29: The Public Tool should have the flexibility to model any well-formulated proposal and assess the most important impacts, including cost impacts and benefits to ratepayers. The tool should continue to be developed in an inclusive stakeholder process where inputs from different parties are discussed and considered when relevant, and all inputs, assumptions, functionalities and outputs that are incorporated are explained in a transparent manner.

III.
CONCLUSION

SCE appreciates the Commission's obvious hard work and diligence in developing a comprehensive and inclusive process for informing the development of the Public Tool and the opportunity to answer the Commission's questions.

Respectfully submitted,

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