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Docket #11-IEP-1G and #11-IEP-1H Distribution Infrastructure and Smart Grid

Re: Southern California Edison Company ("SCE") Follow-up Comments Regarding the Committee Workshop on Distribution Infrastructure Challenges and Smart Grid Solutions to Advance 12,000 Megawatts of Distributed Generation

To Whom It May Concern:

On June 22, 2011, the California Energy Commission ("Energy Commission") held a Committee Workshop on Distribution Infrastructure Challenges and Smart Grid Solutions to Advance 12,000 Megawatts of Distributed Generation (the "Workshop") in connection with the 2011 Integrated Energy Policy Report ("2011 IEPR"). SCE submitted its initial comments on the Workshop on July 6 and appreciates the opportunity to provide these answers to the Energy Commission's specific questions included as an attachment to the Workshop notice.

In Section I, below, SCE will address its plans to address LER development and the timing for implementation of these plans, Section II will deal with specific questions concerning the interconnection of LERs to the distribution system, Section III will address the use of smart grid technology to support California's environmental goals, and Section IV will discuss the use of inverter functions to support integration of LERs.

I. Planning for the Future

1. What is your vision for your distribution system?

SCE's vision is to provide a safe and reliable distribution system, that enables efficient interconnection of customers and devices and that is able to support delivery and integration of all resources. SCE also encourages the interconnection of clean energy generation that results in minimal environmental impacts, while maintaining and/or improving the overall reliability and stability of the system. In order to implement SCE's vision, the distribution system would require ongoing maintenance, prudent infrastructure replacement, and advancement of the communication and control systems to optimize asset utilization. In light of increasing policy demands, SCE strives to provide a stable infrastructure that maintains the level of service expected by its customers.

2. **Have you developed a plan and roadmap of distribution system upgrades to address aging infrastructure issues? How are these plans integrated with your smart grid deployment plans?**

SCE's plans for upgrading its aging infrastructure are currently detailed in SCE's recent General Rate Case ("GRC") filing to the California Public Utility Commission ("CPUC").[1] By way of background, SCE's 2009 expenditures for distribution infrastructure replacement totaled $66.6 million[2] and capital distribution inspection and preventative maintenance programs totaled $212.3 million.[3]

SCE's overall strategic direction with respect to system upgrades and integration with SCE's Smart Grid Deployment Plan ultimately will be determined through the GRC process. The Smart Grid Deployment Plan identifies all of the key initiatives, the expected outcomes, and the overall cost of smart grid programs. The CPUC determines the reasonableness of individual smart grid proposals and ultimately the level of funding through the GRC process. Future planning, beyond the three-year time horizon of the GRC, is also discussed in SCE's Smart Grid Deployment Plan.[4]

In its 2012 GRC, SCE has proposed that the overall costs associated with the Smart Grid Deployment Plan will be $397 million for the period from 2012 to 2014. This excludes the Edison SmartConnect program ($324M in 2012) and platform investments (e.g. Meter Back Office, Telecommunications Network, and Cyber Security – totaling $459M in 2012 - 2014).

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[1] SCE-03: Transmission And Distribution Business Unit (TDBU) Volume 03, Part 3 - Infrastructure Replacement Programs, p. 1 (November 2010), available at: http://www3.sce.com/sscc/law/dis/dbattach3e.nsf/0/5685F8B38E83AC8C882577E300237379/$FILE/S03V03P03.pdf.

[2] *Id.* at p. 13.

[3] SCE-03 : Transmission and Distribution Business Unit (TDBU) Volume 04, Part 1 – Customer Driven Programs Part 2 – Inspection and Maintenance, p. 60 (November 2010), available at: http://www3.sce.com/sscc/law/dis/dbattach3e.nsf/0/CD40D91B61D25FCC882577E3002382E1/$FILE/S03V04P01.P02.pdf.

[4] [http://www3.sce.com/sscc/law/dis/dbattach10.nsf/0/E0C44EC3257C5C27882578C00075F1E0/$FILE/A.11-07-XXX_SGDP-+SCE+Application+For+Approval+Of+Its+Smart+Grid+Deployment+Plan.pdf

SCE does not attempt to estimate future costs beyond 2014 as technological progress, generation choices, and other market drivers will determine the ultimate direction and cost of the smart grid.

3. Have you received American Recovery and Reinvestment Act ("ARRA") funds for smart grid projects? What is the status of your ARRA projects and how might they advance distributed generation?

SCE is the principle investigator on the Irvine Smart Grid Demonstration ("ISGD") and the Tehachapi Wind Energy Storage Project ("TSP"), which are co-funded by the U.S. Department of Energy ("DOE") through the use of ARRA funds. With respect to the status of the projects, SCE has signed agreements with the DOE and is negotiating with subcontractors and sub-recipients. In parallel, both projects are moving into their respective design phases.

The ISGD envisions a vertical slice through the smart grid from the transmission system through the distribution system and into customer homes. The project will demonstrate the distribution system of the future, investigating the impacts and potential benefits of zero net energy homes, distributed generation, demand response, energy storage, plug-in electric vehicles ("PEVs") and an approach to self-healing circuit technology.[5]

4. What strategies will your be implementing to achieve this vision in the near-term (1-2 years), mid-term (2-5 years), and long-term (5 years or longer)?

SCE continues to implement its infrastructure replacement program to strengthen the distribution system and provide a solid foundation to enable interconnections and customer growth. SCE also is completing smart meter deployment and expects to have all customer installations completed by the end of 2012. Additional near-term programs include continuing the company's circuit and capacitor automation programs to reduce outage times and improve voltage control. SCE will be deploying a new Distribution Management System ("DMS") with an Advanced Load Control System ("ALCS"). More detail on these systems is provided in the response to question #6 below. SCE also is proposing to the CPUC to pilot self-healing circuit automation and smart distribution transformer programs. Finally, in the short term, SCE has proposed upgrading its wireless communications system that serves the company's field area network.

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[5] Details of the ISGD proposal available at: http://www.sce.com/PowerandEnvironment/smartgrid/resources.htm.

For the medium term, SCE is looking to complete its DMS/ ALCS implementations, while continuing the company's circuit automation program. SCE also anticipates utilizing many of the technologies demonstrated in the ISGD program. The results from ARRA-funded projects and other utility pilot programs should provide useful information for developing technology/policy cost assessments.

For the long-term, SCE will continue its ongoing automation initiatives. For any new initiatives, SCE will evaluate the technology progress and the adoption of different modes of LERs before proposing any specific program. With the increasing use of intermittent renewable resources on both the transmission and distribution systems, SCE expects there will be an ongoing need to interconnect and manage these resources with advanced energy and voltage control systems.

5. **What are the most pressing technical challenges associated with the integration of 12,000 MW of LERs by 2020?**

There are many technical challenges going forward. Many of these are addressed in SCE's responses to the inverter questions specified Section IV. One of the most difficult challenges is to determine what technical problem to solve. The unknown adoption rate of various technologies including LERs, storage, and PEVs makes it difficult to assess which issues will be most prevalent. When the market becomes clear, SCE can conduct detailed studies and testing to develop the appropriate standards for the distribution system to accommodate the technology and manage the impacts.

Although the focus of this Workshop has been on distribution challenges associated with a significant expansion of LERs, it is important to recognize that there are overarching grid reliability challenges as well. In other forums, the Energy Commission and other state agencies are considering the implications of renewable intermittency on grid operations, for example. In addition, there is growing recognition that heavy reliance on solar technology may shift the peak operation of flexible generating units to the evening hours, thus changing traditional practices for managing grid reliability through a planning reserve margin criterion.

Another pressing technical challenge for SCE will be ensuring that the interconnection and operation of LERS can be managed safely. Although utility systems have recently grown in leaps and bounds with respect to technologies utilized, the system was not originally designed to operate with large amounts of LERs.

6. **In addition to meters, please provide an overview of what commercially available technologies you are currently using or planning to secure in the next two years that will improve your ability to monitor and manage increasing penetrations of LERs?**

SCE has extensively employed capacitor automation to manage voltage close to the load. SCE will continue with this approach and will investigate the opportunities for more sophisticated voltage control through its proposed Integrated Smart Distribution ("ISD") pilot and the Irvine Smart Grid Demonstration.

SCE is in the process of deploying a new distribution management system with advanced load control that will provide better monitoring and overall control of the distribution system, which is a key step to enabling increased penetration of LERs. Existing circuit automation and next generation, self-healing ("disturbance isolating") technologies, such as those proposed in the ISD pilot, will also help to manage the impacts of increasing penetration of LERs.

SCE is also proposing to pilot a limited number of smart distribution transformers to better understand the impacts of a variety of technologies (e.g., distributed and renewable generation and PEVs) on its fleet of approximately 700,000 distribution transformers. Very importantly, SCE continues to build a distribution system model on its Real-Time Digital Simulator to study the impacts of increased LERs and other technologies on its electricity grid. These studies are critical to clearly understanding the potential impacts and providing factual information with which to make decisions.

7. How are you planning to leverage load management programs and storage to help manage increased penetrations of LERs?

SCE is in the process of implementing its DMS/ALCS system. The relationship between load management and increased LERs penetration is currently unclear; however, later releases of the system (after 2014) are expected to support integration of PEVs. Traditional demand response programs that curtail customer load during stress conditions -- subject to limits on how many times these curtailments may occur -- are of limited benefit in addressing regularly occurring operational conditions, such as the intermittency of solar power during partly cloudy days.

As mentioned above, a key component of the Irvine Smart Grid Demonstration program includes determining the reliability benefits and cost-effectiveness of energy storage in a live circuit application. SCE is also an active participant in the CPUC's Order Instituting Rulemaking on storage and has published a whitepaper on its approach to evaluating energy storage[6] that is receiving national attention.

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[6] http://www.edison.com/files/WhitePaper_SCEsApproachtoEvaluatingEnergyStorage.pdf

II. Interconnecting LERs to the Distribution System

1. Modifications to the Wholesale Distribution Access Tariff for some utilities and the California Independent System Operator Generation Interconnection Procedure allow for the study of interconnection applications in clusters. It is assumed that these new coordinated processes will be more efficient. Beyond revisions to these processes, please provide suggestions for how the overall process could be improved?

Modifications to CAISO and Wholesale Distribution Access Tariff ("WDAT") interconnection procedures to implement cluster studies were only recently approved by the FERC in December 2010 (for the CAISO) and April 2011 (for SCE's WDAT). SCE agrees with the assumption, stipulated in the question, that these modifications should improve the interconnection study process over time. Among other things, the modifications provide an integrated set of interconnection procedures for generation that is interconnected at either the transmission level (CAISO) or the distribution level (WDAT), regardless of the size of the generating facility. However, given that the FERC has only recently approved these interconnection process modifications, they should be allowed sufficient time for full implementation, before additional process reforms are considered. Following a reasonable interval of time for the implementation of these reforms and appropriate stakeholder analysis, the need for additional process improvements may become apparent.

Additionally, the above tariff and interconnection procedure modifications are not the only recent process improvements. SCE also has greatly increased staff and resources involved in administering the interconnection process. These include the hiring and deployment of professionals who process the intake of new interconnection requests, perform interconnection studies, and negotiate interconnection agreements with interconnection customers.

One of SCE's major concerns is that similar generators are able to interconnect under different tariffs with different process requirements. Efforts also are underway to reexamine California Rule 21 interconnection procedures, including the reestablishment of the California Rule 21 Working Group. The overarching goal is to assess changes to the California Rule 21 interconnection procedures to bring the procedures in line with more efficient CAISO and WDAT interconnection procedures.

2. What analytical tools or models do you currently use to analyze the impact of LER projects on system performance? What new tools have you added or plan to add in the next two years that will improve your ability to quickly, but safely process the growing number of interconnection applications?

SCE currently uses various software tools to analyze LER project impacts. These include: 1) Cyme Cymdist for distribution system analysis; 2) General Electric's Positive Sequence Load Flow ("PSLF") for subtransmission and transmission system load flow analysis; and, 3)

Computer Aided Protection Engineering ("CAPE") for subtransmission and transmission system protection analysis. All of these tools are widely accepted in the electric utility industry. SCE continually evaluates additional functionality of current software, as well as any new software packages that become available, to determine if they provide any additional value to LER project interconnection analysis. SCE's focus is on continuous improvement of software tools and data conversion/management to increase efficiencies in the study of all generation impacts, whether distributed or central-station.

3. **Given that a growing number of wholesale or system-side renewable LERs projects are applying for interconnection, many of which may not be located within or close to load centers, what planning process should be used to determine the need and timing for expanding the distribution infrastructure to accommodate these new generators? Should the process be coordinated with the CAISO? How should the costs for these upgrades be allocated and what suggestions do you have for allocating these costs in the future?**

Prior to the interconnection reform efforts identified in SCE's response to Question #1 in this Section II, the CAISO and SCE already were coordinated in evaluating the system impacts from new generating resources on each party's respective system (CAISO for the transmission system and SCE for the distribution system). The recent reforms made this coordinated effort more complete, because the new interconnection procedures integrate distribution level and transmission level interconnection requests into the cluster study process regardless of project size or point of interconnection. Under the cluster study process, WDAT interconnection requests are aggregated with CAISO interconnection requests, so that the collective impact of generation is evaluated first on the distribution system and, if applicable, also on any upstream impacts to the transmission system.

Under the cluster study process, the costs of the network upgrades are allocated pro-rata to all generating facilities that trigger the need for the upgrades, which could include both CAISO and WDAT interconnection requests in the same cluster. Similarly, if upgrades to the distribution system are identified, the costs are allocated pro-rata to the generating facilities that collectively required the distribution upgrades. This cost allocation process is much more equitable than the previous method which relied on a "one-at-a-time" serial approach, whereby the generator who triggers first, pays 100% of the upgrade cost. This serial study process caused numerous problems, including the potential for an endless cycle of project withdrawals that, in turn, caused re-studies of projects still in queue. This is the primary reason why FERC stated that clustering was its preferred method of conducting interconnection studies, as well as why the CAISO and SCE adopted the cluster study process as the default interconnection study methodology. Therefore, at this time, SCE views this cost allocation approach as the fairest, most reasonable method for current and future interconnection requests.

4. **In comments filed for the May 9th Localized Renewable LERs IEPR workshop, the Clean Coalition suggested that "The establishment of**

predefined standardized interconnection costs would avoid these issues [cost-related issues causing multiple studies of projects that add to bottlenecks in the queue and study process], providing transparency and predictability to the process while greatly reducing study requests for projects that will not be built." Would using a similar approach to Germany's in trying to predetermine costs by posing formulas that estimate the technical performance levels of a proposed LERs project improve the interconnection process? Is a standardized table of assigned interconnection costs feasible? If not, why?

To appreciate the magnitude of SCE's challenge of evaluating distribution and transmission system impacts resulting from system interconnection requests, it helps to be aware that SCE has received hundreds of interconnection requests. Additionally, the projects requesting interconnection services have a unique set of characteristics, including a wide variance in size. Projects range from less than 1 MW requests to requests comprising thousands of MW. In addition to size variance, SCE has received requests from a wide variety of generation technology types, and has received interconnection requests for locations throughout its 50,000 square mile service territory. As such, each project has a wide variety of terrain and environmental mitigation factors.

To meet the challenge, SCE uses a number of tools to assist in the evaluation of such a wide variety of interconnection requests, including the unit cost guides which are used for estimating commonly-used or otherwise standardized equipment. The unit cost guides include items such as a cost per mile for transmission lines of certain voltages. SCE plans to expand the unit cost guides to include distribution level equipment in the near future. Additionally, the CAISO requires Participating Transmission Owners ("PTOs") to publish and update these unit cost guides on an annual basis. SCE submits that this process already reasonably approximates a "predefined standardized set of interconnection costs" at this time.

SCE further emphasizes that it is vitally important to preserve the reliability and safety of the electric system and that the best way to assure system reliability and safety with regard to interconnection is to evaluate the collective impact of each interconnection request. It is improbable that a "one-size fits all" pre-defined and standardized set of interconnection costs would be an improvement over the cluster study process. There are many "moving parts" to an interconnection study, including: 1) unique project factors; 2) key assumptions that are reflected in the analysis; and, 3) leveraging the skills, experience, and informed analysis/judgment of a transmission engineer or planner, that would be lost in reliance on a formulaic approach.

a. What are the drivers of interconnection costs? Do costs increase as volume increases?

The amount and size of network upgrades, which constitute the bulk of interconnection costs, are more driven by the voltage of upgrades than any other factor. Upgrades at the 500 kV level (currently SCE's highest voltage facilities) are the most expensive type of upgrades. Upgrades at 220 kV facilities are less expensive than 500 kV and the costs decrease further as voltage levels decrease.

The number of interconnection requests is not the primary driver of the required voltage level. Instead, it is the aggregate capacity of all the interconnection requests in a cluster study group, combined with the latent/spare capacity of the existing network, which typically are the determining factors as to the voltage level required for the network upgrades. Only to the extent that a large number of interconnection requests leads to a large amount of capacity in the study process does the number of interconnection requests matter. In addition, the high level of congestion on the existing grid similarly contributes to the need for large-scale network upgrades (such as new 500 kV lines and substation facilities), which usually are very costly.

b. **Currently, the CAISO is using a cluster approach for interconnecting to transmission systems. After conducting a study of the impacts of a cluster of proposed projects, the CAISO determines the costs of interconnecting the cluster of projects, then allocates the cost to the number of participants in the cluster. Would this approach be feasible for the utilities to use to establish a standardized interconnection cost table for distributed generation?**

This question is unclear because the same clustering approach used by the CAISO in evaluating the transmission level interconnection requests is used by SCE to evaluate WDAT/distribution level requests. The unit cost approach is used in both the CAISO and WDAT study approaches. The clustering approach is a study and cost allocation methodology. It does not, in and of itself, assist in establishing any kind of standardized interconnection cost table because of the many variables involved (state of existing capacity, location of new resources, terrain, population density, and environmental mitigation factors, etc.) that are unique to each interconnection request/generating facility.

5. **Should a new integrated infrastructure planning process that includes both distribution and transmission studies be established to ensure that investments in both the transmission and distribution systems are coordinated statewide?**

The CAISO and SCE already integrate the study process between the distribution and transmission systems, to the extent feasible. There is a reason and role for centralized transmission planning at the statewide level, performed by the CAISO, that is separate and apart from distribution level planning performed by each of the utilities. Distribution systems vary more widely from IOU to IOU and from IOU to LSE. Moreover, impacts to the distribution system typically are confined to the localized circuit or nearby circuits, but not to circuits located hundreds of miles away. In other words, what is impacting the distribution system in the Los

Angeles metro area typically does not have a cascading impact to a distribution system in the Palm Springs area. Likewise, distribution system standards vary more greatly between distribution providers. Thus, SCE does not see the immediate benefit of statewide planning for the distribution systems. The distribution system represents the "last mile" or customer end of the network. As such, planning is necessarily more responsive to load and interconnection requests, instead of being proactive. Moreover, having a proactive approach to distribution planning could lead to more stranded assets because load patterns can change suddenly (e.g., during a recession). It is more effective and efficient to have statewide planning address expansions to the "backbone" transmission network on a more proactive basis, which is one of the goals of the CAISO's Revised Transmission Planning Process.

6. What best practices exist for interconnection? Is there any stakeholder consensus regarding the interconnection process?[7]

SCE noted in its participation at the Workshop that recent interconnection process reforms have been implemented to address the very large volume of generator requests, as well as the intricacies of the tariffs that control the interconnection process for SCE's service territory. SCE continues to submit that these reforms, including use of the cluster study process, are the current "best interconnection practices" and most viable approach to resolving historical interconnection process issues while also assuring ongoing system reliability and safety to customers, generators, and other stakeholders. Some counterproposals are based on the premise that the IOUs' transmission/distribution systems are identical or substantially similar to those systems of other utilities. This premise is factually flawed. Key differences between IOUs and other providers of electricity include: system design, system size, CAISO/regional integration, the level of regulatory oversight, and the volume of interconnection requests. CAISO and FERC both agree that recent reforms, based on the premise that the IOUs' systems differ from other systems, are expected to be an improvement. Therefore, in the absence of compelling data with regard to the impacts of these differences, SCE plans to continue implementation of the recent interconnection reforms.

III. Smart grid to Support State Environmental Goals

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[7] Question #6 is an additional question that the Energy Commission raised at the Workshop.

1. **For the Investor Owned Utilities: Smart Grid Implementation Plans will be filed at the CPUC on July 1, 2011. What smart grid technologies have already been included in your current General Rate Case (GRC) at the CPUC, or if you are just filing your GRC, what smart grid technologies are you requesting funding for?**

The baseline technologies as of December 31, 2010 are described in detail in SCE's Smart Grid Deployment Plan. SCE proposed projects in the GRC filing include deployment of phasor measurement and wide area situational awareness capabilities, developing a Centralized Remedial Action System ("CRAS") to better enable renewable generation interconnection, continuing SCE's distribution automation and capacitor automation programs, and installing a new DMS/ALCS system.

2. **For the Publicly Owned Utilities: What smart grid technologies have already been included in your current budget, and or do you plan to include what smart grid technologies are you requesting funding in your next budget cycle?**

Not applicable

3. **Moving forward, when do you anticipate focusing on distribution grid modernization?**

SCE has been focused on distribution grid modernization for the last 15 years with its substation, distribution and capacitor automation programs. The program will determine how synchropasors can best be used to maintain system reliability as more intermittent resources are added to the grid. Synchrophasors can collect and report critical electrical measurements approximately 30 times per second, providing information about grid conditions to system operators so they can make time-sensitive decisions. Operators will need this kind of technology to respond to unpredicted changes in the resource availability.

SCE believes there is substantially more work to be done to modernize the grid, as well as to help assure that SCE has a robust infrastructure replacement program in place to maintain the key infrastructure (wires and poles) that the company does not anticipate changing in the foreseeable future.

4. **What emerging smart grid technologies and software offer near term opportunities to support the monitoring and management of LERs on the distribution system?**

SCE believes a foundational distribution management system with a secure, high speed communications network is the key to monitoring and managing LERs. As the penetration levels increase and as market mechanisms and regulatory rules are created to provide access for

LERs to participate in the energy market, these systems need to evolve to accommodate the market rules as well as the market participants. SCE also believes that changes in the controls systems of these LERs will have to be made to make them more grid friendly and help with voltage and VAR controls.

5. **When doing a cost benefit analysis of smart grid technologies, how do you value societal benefits associated with state goals (e.g. environmental benefits, increased renewable generation)?**

Cost/benefit, cost effective and least cost alternative are types of analyses being discussed in the context of the smart grid. Specific direction on how to approach these analyses and which one is applicable under what circumstance, however, is generally lacking. With respect to how to value the social benefits associated with state goals, more work needs to be done. It would seem appropriate to have a standard approach to valuing these types of benefits.

IV. Inverter functions to support integration of 12,000 MW of LERs & Storage. Can California move forward sooner rather than later?

1. **What are the key distribution system operational challenges from high penetrations of distributed generation and storage (including EVs)? Managing fluctuations due to renewable source variability? Managing LER power output to avoid transformer overloads and/or reverse power flow in "sensitive environments"? Managing volt/vars? Minimizing impacts from voltage and frequency deviations? Low voltage ride-through? Mitigating transmission system impacts? Coping with excess "must run" energy? Other?**

SCE has been engaged in testing inverters, building inverter models, and then modeling the effects of high penetration of inverters on the transmission and distribution system. Based on this analysis, several distribution grid integration challenges have been identified and need to be assessed for reliability impacts:

- Protection Challenges
    - Preservation of distribution circuit and substation protection coordination.
    - Distribution circuit protection with reversed current flow. The impact of increased fault current levels on substation breaker ratings.
    - The need for ground transformer banks or ground fault detectors at inverter interconnection locations.
    - Impacts of generation on distribution circuits on subtransmission or transmission protection.
- Engineering and Design Challenges

- Regulation of customer voltage with intermittent generation resources.
- Potentially harmful transient overvoltages caused by inverter disconnection with minimum loads.
- The ability to monitor or control inverters on the distribution system without standard communications protocols.
- Harmonics generated by inverters and their effect on the distribution system.
- Proper sizes and ratings of conductors and transformers.

- System Operation Challenges
  - SCE switches some circuit segments to adjacent circuits to balance loads during different seasons. With generation on these circuit segments, calculating which circuit segments can be switched is more difficult.
  - Generation on a circuit reduces the amount of load that appears to be connected. A system voltage or frequency disturbance might cause this generation to be disconnected. Because of this, the circuit conductors and transformers need to be sized to carry the entire circuit load without generation. Inverter output monitoring would allow proper operation of these circuits and maintain reliability.
  - As mentioned in the previous bullet, system transients might cause loss of generation. When penetration levels get high enough, this loss of generation would not be acceptable. Implementation of low voltage ride through would make the system more tolerant of transients.
  - Sometimes it might be necessary to disconnect a photovoltaic generation installation during system emergencies or when work needs to be done on the circuit. If this can be done remotely, it can save significant time.

2. **How will/should the IEEE 1547.8 requirements address those interconnection challenges? In particular, what communication monitoring and control requirements (including autonomous, pre-set controls) for “sensitive environments” should be included?**

IEEE 1547.8 can help address the operational challenges presented in Question #1. Questions #3 and #4 address some of the inverter functions and communications requirements that may need to be implemented in high penetration environments.

3. **What advanced LER inverter functions are being defined that can help meet the high penetration challenges and the 1547.8 requirements? What other functions may be needed to manage high penetrations of LER, including EVs and storage?**

Based on the inverter testing, inverter modeling and system modeling done by SCE over the last year and a half, several inverter functions have been identified to help with high penetration situations. These functions include:

- Ability to regulate voltage and reactive power (volt/var control)
- Fast overvoltage protection when islanded with little load
- Limit fault current contribution
- Potential for low voltage ride-through
- Low harmonic distortion including filtering of pulse width modulation frequencies
- Ability to remotely curtail power output for system emergencies
- Communicate to/from utilities in a standard manner
- Contribute to system voltage and frequency stability

Features that would help manage high penetrations of LERs including EVs and storage are similar to what was mentioned above.

4. **What communications infrastructure will be needed for supporting those functions? What might be the optimal mix of autonomous (pre-set) LER actions, commanded control actions, and/or broadcast actions? Why is interoperability and use of communications standards important?**

A range of communications capabilities will be needed to manage high penetrations of LERs on the distribution system. For smaller residential systems, most of the inverter functions will need to be implemented through pre-set functions. SCADA data showing LER status and output power will be useful to give system operators an indication of the level of generation. This SCADA data will need to be updated on a few seconds to several minute bases depending on the size of the LER system. Some control will also be useful to modify pre-set parameters in the inverters and send disconnection or power reduction commands in emergencies. This communication would only need to be conducted with a latency of several seconds. Standards conformance and interoperability would help utilities more easily manage the range of communications to LER devices.

5. **How can California best utilize the inverter functions which have been defined in the IEC 61850 standard and mapped to DNP3 (and eventually to SEP 2.0)? What implementations and demonstrations of these functions are taking place or planned in the U.S.?**

The inverter functions being defined in IEC 61850 will satisfy most of the control functions being contemplated at this time. While these functions have not been implemented and tested in California yet, lab testing and then field pilots are recommended to prove out these new functions. SCE's LER lab facility is capable of performing testing of inverters less than 100 kW that have these functions. It is recommended that these functions also be implemented on a trial basis on some smaller photovoltaic installations with detailed monitoring. Interaction with existing volt/var control equipment is one of the issues that needs to be resolved. Modeling and demonstration on circuits can help show how this can be accomplished.

6. **Compensation for customers – tariff-based or pricing-signal-based? Rates through energy service providers? Separate contracts with commercial and industrial customers? Different tariffs for different customers? Providing incentives to install LER systems while not penalizing those customers who may not be able to install LER systems?**

Some of the advanced inverter features will be needed to allow interconnection of high penetrations of inverters. Without these advanced inverter features, extra equipment would need to be installed by utilities to allow interconnections. This extra equipment cost would normally be borne by the project that caused the need for the upgrade. In this same way, any cost for the advanced inverter features would need to be borne by the project that caused the need for the upgrade.

Most importantly, any of the traditional incentive mechanisms (feed-in-tariffs, public goods charge funds, rate designs) would result in penalizing a non-participating customer by burdening them with additional costs. In addition, providing incentives does not ensure selection of the least-cost resources.

7. **NIST has proposed five standards for adoption by FERC, including IEC 61850 which supports the inverter functions. These standards are fundamental to smart grid interoperability overall. How important is the adoption of these standards by FERC and/or State regulators to developing uniform and interoperable communications systems between distribution operations and LER systems?**

Completion of updates to these standards so they support high levels of LER inverter penetration is very important and will help California meet LER implementation proposed targets. Adoption of these standards by FERC and/or state regulators is not as critical as long as regulations do not prohibit their use. Making use of these standards mandatory in all cases will significantly limit flexibility by utilities in how high penetrations of LERs can be implemented.

In addition to the NIST identified standards, changes will need to be made to UL 1741 and California Rule 21 to help implement IEEE 1547.8.

8. **In comments filed by SCE in response to Committee Workshop on Renewable, Localized Generation on June 5, 2011, on standards and the standard process, SCE indicated it will take several years to finalize new requirements to take into account the interconnection of high penetrations of solar LERs which are addressed in the current Institute of Electrical and Electronics Engineers (IEEE) Standard 1547. SCE suggests that, "In the interim, load serving entities would need to put their own rules in place to avoid having a large base of installed equipment that does not support the grid under a high-LER-penetration scenario." Could SCE or other utilities comment on what they anticipate these rules would be?**

To clarify the above statement, SCE believes that it will take several years to finalize the standards that allow the utilization of advanced inverter features. In the interim, SCE is interconnecting large numbers of inverter-based photovoltaic installations now. Until the final standards are in place, SCE will need to institute rules designed to ease the integration of high penetrations of LERs. These rules include voltage control, fault current levels, transient overvoltage levels, harmonic levels, low voltage ride through, monitoring requirements, and control/monitoring capabilities.

9. **Also included in the SCE comments, it was suggested that developing models to evaluate the performance of the distribution grid, comparing the results through laboratory tests, field data, and benchmarking models against existing situations in Europe where high penetration levels exist is necessary to mitigate the risk that current system models can no longer predict performance of a future system. Is this type of research currently planned? If not, when and who should do this research?**

SCE has been engaged in testing inverters since early 2010. Data resulting from these tests have been used to refine inverter models so that high penetration scenarios can be explored. This testing and modeling are the bases for SCE's identification of the high penetration challenges and suggested inverter characteristics. This initial work was focused on testing and modeling of large 3-phase inverters since they will be the first ones to test high penetration limits. Presently, SCE is testing inverters used on residential and commercial buildings. These smaller inverters will also enable higher penetrations of LERs on circuits, but it will take several more years for this to happen. SCE is also planning to have an outside lab perform testing of large 3-phase inverters (500 kW) later this year.

Additional lab facilities are being developed and some initial testing of small, single-phase inverters is being undertaken by National Renewable Energy Laboratory ("REL") and Electric Power Research Institute ("EPRI"). NREL is expected to have lab facilities in 2012 to test large 3-phase inverters.

10. Can LERs provide reliability benefits or resource adequacy benefits in targeted areas?[8]

Islanding[9] of utility load would require significant upgrades to protection devices, system monitoring, and communication (within the utility system, as well as between the utility and LERs source(s)). These upgrades would be necessary to properly identify islanded load on the system for the safety of SCE personnel as well as the general public.

A great majority of currently interconnecting LERs are solar photovoltaic. With reliance on the sun, there is an inherent instability in the availability of the generation resource. The required upgrades on the utility system (protection, communication, etc.) would be large given a small probability that there is a solid photovoltaic source available when needed/desired.

Sustained islands would require sufficiently large generation placed in key locations on the system. Although SCE provides direction to applicants via its interconnection maps, LERs are rarely sited in areas of utility need. In addition, sufficient reserves would need to be in place, to prevent system aberrations (e.g voltage sags due to photovoltaic intermittency caused by clouding) which could potentially harm utility and/or customer equipment.

Current tariffs do not allow for islanding of IOU-served load, for many of the reasons listed above. IEEE is in the process of finalizing a guideline on LERs islanding, but in its present form, the document lacks key information on operational procedures for sustained islands as well as information on contingency planning (e.g. loss of communications).

11. Where are the best locations for LERs? Have/can we communicate that information to potential LERs projects?[10]

SCE has established two interconnection maps in Google Earth/Maps to assist developers in the siting of future LERs.[11] The areas shown on the SCE's Solar Photovoltaic Program

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[8] Question #10 and Question #11 are additional questions that the Energy Commission raised at the Workshop.
[9] Islanding refers to the condition in which a LER continues to power a location even though power from the grid is no longer present.

[10] Question #10 and Question #11 are additional questions that the Energy Commission raised at the Workshop.

("SPVP") map identify the approximate area served by distribution circuits that serve load centers within SCE territory and currently have low LERs penetration levels. Specifically, the SPVP map identifies those distribution circuits loaded to >80% of their capacity and also have no more than 2.0MW of interconnected and currently queued LERs. This 2.0MW level is based on the 2.0MW WDAT Fast Track limitation, which previous SCE interconnection studies have shown to be the approximate LERs penetration level where there may be increasing impacts to the distribution system. Similarly, the areas shown on the Renewable Auction Mechanism (RAM) map identify the approximate area served by subtransmission systems that serve load centers within SCE territory that currently have low LERs penetration levels. Both maps also take current transmission level congestion into account, to ensure that proposed LERs are not sited in areas where significant transmission upgrades would be required.

If you have any questions or need additional information about these written comments, please contact Manuel Alvarez at (916) 441-2369.

Very truly yours,

/s/ Manuel Alvarez ..

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[11] *See* SCE's SPVP website available at: http://www.sce.com/EnergyProcurement/renewables/spvp-ipp/spvp-ipp.htm and SCE's Renewable Auction Mechanism ("RAM") website available at: http://www.sce.com/EnergyProcurement/renewables/renewable-auction-mechanism.htm.