Attachment

Request for Comments

The IEPR Committee requests that parties address the following in the panel discussions and public comment portions of the workshop and in written comments. The questions are organized by topic in the workshop. Written comments are due to the Energy Commission by 5:00 p.m. on July 6, 2011. Please see the workshop notice for instructions on how to submit written comments:

Planning for interconnecting and integrating 12,000 MWs of Distributed Generation into the Distribution System by 2020

Planning for the Future

1. What is your vision for your distribution system?
2. Have you developed a plan and roadmap of distribution system upgrades to address aging infrastructure issues, and the two-way power flow? How are these plans integrated with your smart grid deployment plans?
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?
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)?
5. What are the most pressing technical challenges associated with the integration of 12,000 MWs of Distributed Generation (DG) by 2020?
6. In addition to meters, please provide an overview of what commercially available technologies and telemetry are 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 DG?
7. How are you planning to leverage load management programs and storage to help manage increased penetrations of DG?

Interconnecting DG 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?

2. What analytical tools or models do you currently use to analyze the impact of DG 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?

3. Given that a growing number of wholesale or system-side renewable DG 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?

4. In comments filed for the May 9th Localized Renewable DG 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 DG project improve the interconnection process? Is a standardized table of assigned interconnection costs feasible? If not, why?
    - What are the drivers of interconnection costs? Do costs increase as volume increases?
    - 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?

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?

Smart Grid to Support State Environmental Goals

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?

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?

3. Developing and achieving the vision articulated in SB 17 for a smart grid is an evolutionary process. Smart meters are being installed throughout the state and the focus is on capturing the value of customer data and information. Moving forward, when do you anticipate focusing on distribution grid modernization?

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

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)?

Inverter Functions to support integration of 12,000 MW of DG & 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 DER 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?
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?
3. What advanced DER 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 DER, including EVs and storage?
4. What communications infrastructure will be needed for supporting those functions? What might be the optimal mix of autonomous (pre-set) DER actions, commanded control actions, and/or broadcast actions? Why is interoperability and use of communications standards important?
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.?
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 DER systems while not penalizing those customers who may not be able to install DER systems?
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 DER systems?
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 DG 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?

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?