Grid Integration of High Levels of Solar Generation

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Issue: The adoption of Renewable Portfolio Standards (RPS), and other similar policies, has given rise to concerns regarding the impact high levels of solar generation[1] may have on electric grid systems. The basis for this concern is the variability of solar generation output. This variability is caused by the daily movement of the sun and changes in the weather, i.e. cloud development and movement (Solar Variability). The impact of this Solar Variability, and policy-based solutions for addressing it, are the topic of this paper.

Background: Analysis and review of the impact of high levels of solar generation on electric grids has only recently been initiated. The majority of the scholarly research dates back, at most, a couple of years.[2] Regulatory and policy based review began only within the last year.[3] As the ongoing analysis and review is revealing, integrating solar generation is quickly proving to be a complex and challenging task. The technical elements require significant modeling efforts, and therefore formulation of "best guess" assumptions. Deep expertise in areas of traditional grid operations and solar generation performance are also needed. The regulatory and policy aspects are multi-jurisdictional. State commissions, the Federal Energy Regulatory Commission (FERC), and balancing area authorities will all need to address potentially overlapping and never-before considered issues regarding operations, policies, and cost allocation and recovery.

Concerns: A number of concerns arise from the current state of solar integration efforts. The "traditional" view of grid operations -- i.e. one that presumes that load creates grid instability and that generation is dispatched in a manner to address that instability – underlies many of the concerns. This traditional view fails to recognize that all generation presents at least the potential for some type of grid instability or impact. This recognition failure then has the effect of attributing the cumulative historic generator

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[1] The impact of high levels of wind generation is also a critical issue, but this paper addresses only solar generation.
[2] *For example, see generally* Understanding Variability and Uncertainty of Photovoltaics for Integration with the Electric Power System, Mills, Ahlstrom, Brower et al (December 2009). Available at: http://eetd.lbl.gov/ea/emp/reports/lbnl-2855e.pdf; Western Wind and Solar Integration Study, prepared by GE Energy for the National Renewable Energy Laboratory (May 2010). Available at: http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf; Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power, Andrew Mills and Ryan Wiser, Lawrence Berkeley National Laboratory (September 2010). Available at: http://eetd.lbl.gov/ea/ems/reports/lbnl-3884e.pdf
[3] *For example, see generally* California Independent System Operator, *Integration of Renewable Resources*. Available at: http://www.caiso.com/23bb/23bbc01d7bd0.html; California Public Utilities Commission, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans,* R.10-05-006. Available at: http://docs.cpuc.ca.gov/published/proceedings/R1005006_doc.htm; *Application of Nevada Power Company d/b/a NV Energy for approval of its 2010-2029 Triennial Integrated Resource Plan*, Docket No. 10-02009. Available at: http://www.nrel.gov/eis/pdfs/solar_power_high_penetration_chadliev.pdf; The Federal Energy Regulatory Commission, *Integration of Variable Energy Resources,* RM10-11-00. Available at: http://www.ferc.gov/whats-new/comm-meet/2010/111810/E-1.pdf

impact (CHGI) of all types of generation on solar generation, simply because solar is the last party to the "stack."

By way of example, in the California market, certain categories of power (such as imports, nuclear, Qualifying Facility (QF), and some types of hydroelectric generation) undeniably present inflexibility issues that impact the grid. Similarly, even the most flexible gas resources have limited operating ranges and can be subject to unexpected outages. For the most part, these generator limitations (i.e. CHGI) have been operationally addressed through balancing area coordination of the entire generation fleet. The related costs have been rolled into general concepts of grid reliability, and then attributed, both conceptually and financially, to load. Solar generation, because it is the "last in the stack," risks being both conceptually and actually charged with the impact of not only its intrinsic Solar Variability, but also the CHGI that has traditionally been assessed to load.

Existing scheduling, dispatch and settlement protocols further exacerbate the CHGI issue. Because they were developed based on the requirements of non-renewable generation such as gas, nuclear and coal, the existing protocols are not well suited for solar generation. The historic paradigm assumes baseload generators, such as nuclear and coal, run all the time, serving the minimum level of expected load. Additional load and fluctuations of that additional load, both expected and unexpected, are usually "followed" by more flexible resources such as gas. From this paradigm protocols such as hourly scheduling were established. Hourly scheduling makes sense for scheduling traditional generation, such as nuclear, coal or gas, because it is not designed to change output quickly or because it is not generally susceptible to sub-hourly fuel fluctuations. Solar Variability, on the other hand, can occur on a sub-hourly basis, and thus solar generation is poorly served by traditional generation protocols such as hourly scheduling.

Finally, a general lack of understanding regarding how solar generation will perform on a balancing-area-wide basis may cause overestimations of the impact of Solar Variability. The research cited in footnote 2, along with the research of Thomas E. Hoff and Richard Perez,[4] compellingly demonstrates the importance of solar generator "geographic diversity." As demonstrated in the geographic diversity research, a disperse portfolio of solar generation "smoothes" the impact of the weather –based (i.e. cloud) Solar Variability to the extent that the grid impact is potentially de minimis.

Taken as a whole, the concerns identified above hold considerable potential for chilling the continued development of solar energy. To ensure the continued progress of solar energy development, the following should be proactively pursued: 1) establishment of solar generation integration requirements that are fact-based, informed, well vetted, and accurate; 2) development and implementation of elegant, efficient, and cost-effective

[4] *See generally* PV Power Output Variability: Correlation Coefficients, Thomas E. Hoff, Clean Power Research, and Richard Perez, The State University of New York at Albany. Available at: http://www.cleanpower.com/Content/Documents/research/capacityvaluation/PV%20Power%20Output%20Variability%20-%20Correlation%20Coefficients.pdf

solutions to minimize Solar Variability, and 3) embodiment of fair and equitable principles of cost allocation in all related policy decisions.

Solutions: Separating the Solar Variability due to the daily movement of the sun (Diurnal Movement Variability, or "DMV"), from the Solar Variability due to weather change (cloud development and movement) (Weather Based Variability, or "WBV"), is a key element in solution development. DMV is predictable and known, while WBV is, essentially, unpredictable. Because DMV is predictable and known, the impacts of DMV can be addressed ex-ante, thereby allowing for the elimination of this grid impact in a least cost manner. WBV, on the other hand, is more likely to require ex-post solutions, which means the grid impact can be minimized, but not completely avoided. The importance of this distinction is apparent in the current California Public Utilities Commission long term planning proceeding.[5] In the proceeding, the DMV and WBV are not distinguished from each other.[6] This lack of separation potentially subjects the integration modeling in that proceeding to overestimating the amount of new gas resources needed to firm, follow or back-up solar generation.

Once isolated, DMV can be addressed ex-ante through policies that allow DMV to be firmed or shaped in a manner that best neutralizes this type of variability (DMV Shaping). Take, for instance, the case where the most desirable solar generation shape is one that ramps consistent with load. To the extent that solar generation ramps up faster than load, compensated curtailment can be explored. Likewise, to the extent solar generation ramps down faster than load, acquisition of clean firming energy, such as hydroelectric generation or energy storage, can be explored. FERC's Integration of Variable Energy Resources Notice of Proposed Rulemaking (NOPR)[7] is currently considering three elements,[8] including sub-hourly scheduling, that relate directly to making DMV Shaping a reality. When combined with advocacy directed at balancing area authorities and state commissions, the NOPR holds considerable promise for advancing this issue.

Assuming DMV is addressed through DMV Shaping, the next solution is to minimize the impacts of WBV to the extent possible. One critical way to achieve this is through the promotion of policies that ensure that the smoothing impacts of geographic diversity are appropriately recognized and incorporated into grid planning and operations. To illustrate, if a cloud passes over a specific solar generator, the momentary change in output of that solar generator should be smoothed by other, geographically disperse solar generators. This smoothing effect minimizes the impact, on a fleet-wide basis, of the WBV. Nevertheless, depending on the manner in which any particular balancing authority operates, on a meter-by-meter basis, individual generators could be charged for WBV that, in effect, had only a de minimis impact on the grid. Exploration of protocols

[5] California Public Utilities Commission, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans,* R.10-05-006. Available at: http://docs.cpuc.ca.gov/published/proceedings/R1005006_doc.htm

[6] *See generally,* http://www.cpuc.ca.gov/PUC/energy/Renewables/100824_workshop.htm

[7] The Federal Energy Regulatory Commission, *Integration of Variable Energy Resources,* RM10-11-00. Available at: http://www.ferc.gov/whats-new/comm-meet/2010/111810/E-1.pdf

[8] i.e. 15 minute sub-hourly scheduling, forecasting requirements, and making ancillary services available to generators.

to address or avoid this possibility should be pursued with balancing area authorities and, to the extent necessary, before FERC and appropriate state commissions.

After DMV Shaping is enabled and the WBV smoothing of geographic diversity is properly incorporated into grid operations and planning, the final area of advocacy should address the costs related to any remaining WBV (Residual WBV). To the extent that Residual WBV impacts are entirely attributable to solar generation, the costs should be appropriately allocated. On the other hand, careful attention must be given to recognizing the unaccounted for CHGI, and ensuring that solar generation, simply because it is the last in the stack, is not solely responsible for mitigating, and paying for, the impacts.

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COMMENTS OF THE VOTE SOLAR INITIATIVE
IEPR COMMITTEE WORKSHOP
DISTRIBUTED GENERATION – 12 GW BY 2020
Docket 11-IEP-1G

Submitted May 23, 2010
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I. Developing Interim and Regional Targets for 12,000 MW by 2020

1) Please suggest a methodology for setting interim and regional targets building to the 12,000 MW goal by 2020. Considerations to address include: state and local policies, the capability of the distribution system, economics, and resource availability. To aid discussion, staff has identified the following options for parsing out the goal:

- **Set targets for each load serving entity or county.**
- **Set targets per sector, for example, residential, commercial, public, or other.**
- **Set separate targets for installations that serve on-site load and for projects that produce energy for wholesale**
- **Set targets by utilities' portion of coincident peak.**
- **Set targets based on resource potential and/or best use of the distribution system.**

In our view, the task should start with the correct setting of the goalposts--which, in our opinion, is to achieve the level of renewables necessary to ensure success in the fight against climate change (that is an amount beyond the current 33% requirement). Distributed generation--both wholesale and behind-the-meter--is a key part of the solution, as it provides unique market models and the potential for a new renewable generating portfolio that is more efficient, resilient, geographically disbursed, and sustainable. In pursuit of this goal, over the past nine years Vote Solar has worked hard to develop DG markets in California, including the implementation of the California Solar Initiative; critical net metering and interconnection policies; interventions into five (and counting) utility general rate cases to ensure that solar system owners receive fair value for their generation; and the implementation of groundbreaking wholesale distributed generation programs including the 1 GW Renewable Auction Mechanism, the 1.1 GW worth of utility DG PV programs, and ~1 GW of feed-in tariff programs throughout the state. We are also heavily engaged in California's Long Term Planning Process (R.10-05-006), where issues and challenges associated with grid integration of the state's 33% RPS are being raised. Chief among the concerns are whether (and how much) new fossil generation may be needed to ensure resource adequacy and grid reliability at deep levels of grid penetration.

The sum total of these experiences leads us to believe that the state's DG targets and policies should not be considered in isolation. While distributed generation is necessary for success in the fight against climate change, it is not sufficient. As the KEMA memos highlight, achieving the necessary levels of renewable generation while ensuring grid reliability is a massive undertaking that requires changes to market policies, grid operation protocols, and the physical infrastructure. In general, expanding geographic distribution of generators and expanding balancing area cooperation can help mitigate some of the challenges of utilizing and maximizing the benefit of renewable and distributed generation. Similarly, a reassessment of grid operation protocols is necessary to fairly allocate costs, remove barriers, and bring the full suite of potential tools (e.g. demand response, compensated curtailment, energy imbalance markets, etc) to the table.

More simply put, distributed generation is a means to an end, and achieving that end is made easier by expanding the context to include the full suite of options and solutions. We believe that the 12 GW DG target should be matched with a reassessment of market policies, grid operation protocols, and physical infrastructure investment to achieve the larger goal of enabling a low-to-no carbon grid.

Some responses to specific questions as follows:

As a matter of practicality and equity, targets should be set for for each utility territory. Establishing goals based on other political or geographic subdivisions (such as counties) do not necessarily incorporate grid constraints or resource availability, and do not synchronize well with typical policy tools.

For behind-the-meter generation, it is appropriate to design programs and targets for each customer class; targets should be broadly proportional to the size of the customer class. For wholesale generation, targets should generally focus on achieving the highest value of generation for the lowest cost (and developing sustainable, equitable, long-term market structures to deliver it). As wholesale projects are not linked to load, there does not need to be a requirement that a wholesale generator be a utility customer, and therefore parsing targets by customer class is similarly unnecessary.

Programs that address wholesale or behind-the-meter generation will inevitably differ, and as such it makes sense to establish separate targets for each.

Programs (rather than targets) should harness the most valuable elements of distributed resources--essentially, to value value. Resources that can beneficially impact peak demand or defer T&D investment should be valued accordingly.

2) Related to the above question, some utilities have noted in the California Public Utilities Commission's Rule 21 Working Group and its Renewable Distributed Energy Collaborative (Re-DEC) that up to 15 percent of peak load for individual circuits could reliably interconnect with minimal system upgrades. Other utilities have said that individual circuits could handle distributed generation additions for up to 50 to 100 percent of minimum load. Could a 15 percent of peak load or 50 to 100 percent of minimum load penetration rate be implemented statewide? If so, how much renewable capacity would be installed per utility?

No response at this time.

3) Please provide comments on any methodologies discussed at the workshop. Indicate whether you support or oppose a particular approach and the rationale for your position.

No response at this time.

4) Should the state create incentives or penalties to ensure achievement of targets? If so, please suggest program design and implementation.

The state has established both incentives and penalties in support of increasing distributed generation. There are currently established programs (in various stages of implementation and with various prognoses for success) designed to deliver about 6 GW of DG (CSI plus net metering goes to about 3 GW, RAM is 1 GW, utility DG PV programs total 1.1 GW, and the various feed-in tariff programs total about 850 MW). Each of these programs is designed to deliver a different outcome, for a different market participant, and harness a different value of distributed generation. For example, the CSI (plus net metering) is designed to enable self-generation, a market with significant advantages for both participants and policymakers (For participants, it allow long-term hedging of energy costs, and because the generation reduces utility bills, it is not taxable revenue. For policymakers, the market is sustainable at grid parity, and does not depend on utility purchasing decisions). The RAM delivers an elegant market solution for delivering low-cost wholesale DG, and will result in a lively market for <= 20 MW sized generators[1]. Some utility DG PV programs are designed to deliver low-cost groundmount systems, and others to deliver rooftop generation--an outcome with higher costs, but also likely higher value to ratepayers. SMUD's feed-in tariff program, which pays about 14 cents/kWh for the output from generators up to 5 MW, has received tremendous participation, while others in the state, with lower project size and lower compensation levels, have seen much less uptake. We are hopeful that the implementation if SB 32, currently underway, will provide the change necessary to secure an adequate level of compensation to stimulate market participation.

Each of these programs can and should be expanded and modified to increase market participation necessary to reach 12 GW.

5) If the state established regional targets, should there be options to trade allocation requirements? If so, how should this be implemented?

As a matter of equity and pragmatism, targets should be set on the basis of utility territories, and there should not be an option to trade allocation requirements. The introduction of tradable allocation requirements may reduce the ability for certain ratepayers to benefit, and presents unnecessary administrative burdens.

6) What are the near-term and long-term actions needed to achieve 12,000 MW by 2020?

We believe that the 12 GW goal should be approached within the framework of the larger goal

[1] Southern California Edison's Renewable Standard Contract program, a precursor to the RAM, resulted in 2.5 GW of bids for 250 MW of generation; all winners were below the Market Price Referent. http://votesolar.org/2011/01/sce-adds-250-mw-of-pv-below-the-cost-of-a-combined-cycle-gas-turbine/

of maximizing renewable generation and reducing carbon emissions. This will require a deliberate examination and reassessment of market policies, grid operation protocols, and the physical infrastructure.

As outlined above, California already has market mechanisms to ostensibly deploy around 6 GW of renewable DG. Some of these programs are working well, and simply need expansion. Others need to be implemented correctly in order to deliver results. And as costs come down and technologies mature, new market mechanisms may be needed to deliver results different from what may be obtained under the current programs. Finally, a market is only as strong as its weakest link, and the current weakest link is the state's interconnection procedures. A focus on improving the process should be the highest priority.

Some specific recommendations:

I. Retail Markets

a. *Fully fund the CSI, smooth the transition to grid parity.* The California Solar Initiative (CSI) is designed to gradually reduce incentives, until grid parity is reached. Unfortunately, due to higher-than-expected performance (and therefore payments), the money is running out faster than expected. Bridging the funding gap is critical for a smooth transition to grid parity. SB 585 (Kehoe), sponsored by the Solar Alliance, helps fix this problem.

b. *Payment for net excess generation*. AB 920 (Huffman), passed last year, requires payment for net excess generation (i.e. if a net metered system generates even more than the total annual load). After months of CPUC rulemaking, the ALJ's proposed decision would value the solar based on a day-ahead short term price (DLAP) instead of something commensurate with a long-term capital asset—and as a result, the price and effectiveness of the program would be significantly diminished. Solar parties are advocating for an alternate decision that would value net excess generation on the MPR at the very least.

c. *Save PACE*. Property Assessed Clean Energy financing programs are promising vehicles to finance renewable energy and energy efficiency retrofits. They were set to launch in most of California when FHFA/Fannie Mae/Freddie Mac essentially blocked them. The California AG and several California cities have filed lawsuits, and there is federal fix-it legislation under way. Getting PACE back on track will be quite helpful in financing clean energy investments.

d. *Raise the net metering cap*. In 2010, the legislature passed and Governor Schwarzenegger signed AB 510, a bill to raise the cap on net metering from 2.5% to 5% of utility system peak load. The state will reach this cap sooner rather than later, necessitating another raise. The majority of current solar installations and jobs in the state occur with this program, and its continued success is key.

e. *Municipal permitting*. In some areas, municipal permitting processes (in terms of time, predictability, and cost) can be a hurdle. There are multiple efforts in the state to make sure that local permitting offices have the resources to provide the level of service necessary to enhance efficient installation processes.

f. *Community solar*. CPUC staff have proposed changes to several aspects of the existing DG programs to expand access to solar and other renewables. Proposed changes to Virtual Net Metering and the Local Government Bill Credit Transfer Program may expand opportunities for renters and multi-unit buildings.[2] Senator Wolk has proposed some related legislation (SB 383). These programs have the potential to expand participation in the renewable energy markets considerably.

II. Wholesale Markets

a. *RAM*. In December of 2010, the CPUC approved a 1,000 MW pilot program for small to mid-sized renewables (under 20 MW). Call the Renewable Auction Mechanism (RAM), the program provides a good way to drive mid-sized renewable markets. There are two problems: SCE and PG&E have filed for rehearing, and second, it was only approved as a 1 GW pilot.

b. *FERC/FPA jurisdictional issues over feed-in tariffs*. There has been ongoing legal wrangling between FERC, the CPUC, and the utilities as to jurisdictional issues over avoided cost (precipitated by AB 1613, the CHP feed-in tariff). FERC has made a 180-degree change in its position, arguing for fairly strong state's prerogative in the matter. Some utilities have indicated that they will take this to court. Until this is settled, market development in this space is at risk.

c. *SB 32*. This bill, passed in 2009, requires a fixed-price feed-in tariff for renewable systems under 3 MW (total of 750 MW statewide). Pricing is based upon the value of distributed generation. The CPUC has just begun rulemaking to implement the program; the discussions are robust, with implementation proposals that run the gamut from workable to unworkable. Utilities have argued that the program is illegal. If past is prelude, a legal challenge from SCE may be expected.

d. *Utility DG PV programs*. Each IOU has a DG PV program; the state combined total is 1.1 GW over 5 years.[3] Each may need fine-tuning as they are implemented.

e. *Interconnection*. This is a huge hurdle, and unless fixed, will be a barrier to success. Due to huge volumes, interconnection requests queues are long, and take an inordinate amount of time to navigate. Last December, FERC approved CAISO's proposed modifications to their Small Generator Interconnection Procedures, resulting in a switch from an iterative process to a batch process. SCE and PG&E are both in the process of proposing similar reforms to their Wholesale Distribution

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[2] http://docs.cpuc.ca.gov/published/proceedings/R1005004.htm
[3] http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Utility+PV+Programs.htm

Access Tariffs. The new processes can take 520 days to get approval, even assuming no upgrades are necessary. Improving this process, and (especially in the short term) synching interconnection requests with procurement processes, will be crucial to the success of the wholesale distributed generation effort.[4] Note that the CPUC has also launched an effort to revisit Rule 21 (this is the interconnection procedure for behind-the-meter installations).

II. Discussion on European experience integrating large amounts of DG

7) How are the European electrical distribution systems similar to or different from California?

8) What challenges have European countries encountered from integrating distributed renewables that are applicable to California, what actions did they take to address the challenges, and what lessons are applicable to California?

9) As California builds out its distribution system, what lessons can be learned from the European experience?

The challenge of integrating distributed generation--as with integrating renewable energy in general--is partly about physical infrastructure, and partly about operational approaches. The KEMA memos indicate that success is dependent on a holistic approach that includes the full suite of tools available to manage grid impacts and operations, and incorporates both market policies and operational protocols.

California has yet to systematically assess and implement the full suite of tools available to minimize the challenges associated with increasing renewable and distributed generation. We believe that such an effort could result in a more efficient and equitable result, and should be undertaken.

For example, the variability of solar generation is often cited as a concern. As we outline in that attached whitepaper, *Grid Integration of High Levels of Solar Generation* (prepared in response to issues raised during the current CPUC Long Term Planning Process), a deeper look at the predictability of variability, as well as a data-driven analysis of actual impacts on an aggregate rather than single-system basis, indicates that the impacts can be minimized through geographic distribution of generation, and dealt with through operational protocols and market policies.[5]

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[4] Recorded webinar and PPT on recent developments here: http://votesolar.org/resources/get-some-sun-solar-webinars/

[5] An article on this subject was published in Renewable Energy World: *Grid Integration of Solar Electricity, the Sheep in Wolf's Clothing of Grid Planning*, by Kelly Foley, February 15, 2011. http://tinyurl.com/3n4mrzl

Another example is the approach to managing investments in the distribution grid. Germany socializes costs associated with interconnection. California's approach relies on protocols established for an outdated model, and prioritizes load over generation. For example, California utilities have been making investments to prepare the grid for the anticipated growth in electric vehicles. Despite the fact that only a certain subset of customers will purchase EV's, the cost of preparing the grid for this new load--which will have a non-trivial impact on the distribution system--is largely socialized. It is not clear why distributed generators should be treated in a comparatively discriminatory manner. The regulatory compact gives utilities monopoly control over the distribution system in exchange for providing service in pursuit of the common good of all ratepayers. At this juncture of history, it should be clear that the common good is not just to serve load, but to build the kind of system necessary to deliver a low-or-no emission grid that maximizes reliance on renewable energy.

The full suite of tools should be examined, including: sub-hourly scheduling, increasing balancing areas, energy imbalance markets, and demand response. New operational requirements such as increased telemetry and forced curtailment should be balanced by market mechanisms that ensure fair outcomes--approaches that socialize not just the benefits but also the costs. In sum, California should undertake a reassessment that begins with the proposition that renewable resources should be viewed as the grid's core, and other resources should be strategically deployed to maximize renewable generation.

III. Discussion of "Developing Renewable Generation on State Property, Installing Renewable Energy on State Buildings and Other State-Owned Property"

10) Please provide comments on the staff report and on lessons learned from the European or local experience that may be applicable to California.

IV. How Research Development and Demonstration (RD&D) can Help Advance Distributed Generation

11) What is the role of RD&D in advancing distributed generation and helping achieve the Governor's Clean Energy Jobs Plan and other current and future state policy goals such as the Renewable Portfolio Standard and AB 32?

12) Please comment on the maturity of distributed generation technologies. Which technologies or components should RD&D efforts focus on to address some of the barriers for advanced DG deployment?

13) Are currently existing technologies and tools enough to power facilities with nearly 100 percent renewables in a technically and economically feasible manner? What are some emerging technologies that may be able to reduce costs when produced at scale?

14) What issues impede the deployment of distributed generation technologies in utility distribution territories that RD&D can help address? If so, please identify the issue and how RD&D can help in a manner that benefits both the utilities and customers.

15) What other future research direction, focus, strategies or initiatives may be recommended for PIER to undertake so that RD&D can better help advance DG?

No response at this time.

notes

[1] Southern California Edison's Renewable Standard Contract program, a precursor to the RAM, resulted in 2.5 GW of bids for 250 MW of generation; all winners were below the Market Price Referent. http://votesolar.org/2011/01/sce-adds-250-mw-of-pv-below-the-cost-of-a-combined-cycle-gas-turbine/