

STATE CLEAN ENERGY – ENVIRONMENT TECHNICAL FORUM
Distributed Generation & CHP Interconnection Standards
February 9, 2006 Call Summary

Participants: 43 participants from 22 states and several national organizations (see the participants list).

Background Document: Distributed Generation and CHP Interconnection Standards
(download at: <http://keystone.org/html/documents.html#dg>)

EPA Clean Energy-Environment Guide to Action now available on EPA's website
<http://www.epa.gov/cleanenergy/stateandlocal/>

Key Issues Discussed

- Collaborative processes for development of rules; dispute resolution processes
- Screening and standardizing to reduce time and cost of interconnection application
- Network versus radial interconnections
- Technical and administrative factors to consider
- Integrating DG to defer distribution investments
- Accommodating small DG projects

Summary of Presentations

A. Overview of DG interconnection Issues — Wayne Shirley, Regulatory Assistance Project
(download presentation at <http://keystone.org/html/documents.html#dg>)

- Begin with **standardized engineering guidelines** for interconnection, e.g. IEEE 1547 which has been codified as part of EPACT 05, but it remains to be seen how uniform it will become; states hopefully will begin adopting it. Inconsistency in engineering requirements between utilities affects both the project developers and manufacturers. Consistency will help manufacturers standardize design
- **Other key elements** for successful Interconnection Standards:
 - Standardized contracts & fees
 - Nominal or no fees for small systems
 - Pre-certification of off-the shelf DG systems – especially inverter-based systems
 - Stream-lined applications and review processes for smaller systems
 - Limitation of “study” requirements for smaller systems
 - Regional uniformity
- **Consistency between wholesale (FERC jurisdiction) and retail** interconnection standards(state jurisdiction) would also be preferable
- **Barriers:**
 - Time and process costs are the biggest problem. Projects are vulnerable because they have thin margins of profitability. Utilities don't always see adding DG to system to be in their best interest and can discourage project developers with:
 - Application fees
 - Engineering Studies required

- Interconnection hardware
- Limiting operating hours
- Utility imposed testing (pre-operational and operational)
- Standby & backup rates and demand ratchets
- **Mid-Atlantic Distributed Resources Initiative (MADRI)** – RAP assisted states in the original PJM footprint to develop regional standardized interconnection guidelines; made considerable progress, but there are remaining areas of disagreement
 - Fees & timelines, though inconsistency is not a major issue as long as they are reasonable. Other issues are more problematic:
 - PJM - approved vs. IEEE 1547 as basis of physical standards
 - Isolation devices required
 - Fault current as a % of short circuit interrupt capability
- **Additional assistance** available to states through EPA on interconnection standards, partial-load rates (i.e. standby rates) and CHP as an eligible Portfolio Standard resource.
- For more information **contact Katrina Pielli, EPA, at Pielli.Katrina@epa.gov** ; 202.343-9610

B. Massachusetts DG Collaborative: Fran Cummings, Massachusetts Technology Collaborative (download presentation at <http://keystone.org/html/documents.html#dg>)

- **Goal:** Uniformity of interconnection standards across distribution companies for all DG
- **Process** for Development of Interconnection rules
 - Collaborative process started in 2002; see presentation for outline of steps involved
 - Submitted final uniform interconnection tariff to Department of Transportation & Energy in 2005; approved by end of 2005; with exception of indemnification language.
 - Final Report due which will track and analyze every interconnection to document timing and finalize unresolved interconnection issues eg. network interconnections (downtown Boston); Current standard limit interconnection on downtown networks to small solar projects, while large CHP developers are not addressed yet.
 - Collaboration is hard work, requires commitment of staff time and regulatory mandate that brings parties to the table
- **Analysis:**
 - Current study of existing DG interconnections in downtown network and cost-benefit analysis of 8 feeders where DG might be a possibility. Would like to determine whether there is enough DG potential to defer investment, which will allow us to have conversations about proactively promoting DG where it has system benefits.
 - **Pilots: Interconnect** DG in a specific distribution feeder in a congested area to see how much we can get in a small area over next couple of years.
 - **EPRI project** – ratemaking approaches that would decrease disincentive for utilities to interconnect.
 - Invited any interested DG developers to engage in process now

C. New Jersey's Interconnection and Net Metering Requirements (NJAC 14:4.8 and 9): Mike Winka, Director, Office of Clean Energy; NJ Bureau of Public Utilities (download presentation at <http://keystone.org/html/documents.html#dg>)

- **Process**
 - Legislation mandated a collaborative stakeholder process; Set up an on-going workgroup, which meets monthly, to work out differences
 - **Setting strategic goals** and revisiting them repeatedly is important
 - **Integrated Approach:** Net metering without tying it together with standard interconnection regulations and other incentives will not reach goals
- **Goal: Reduce barriers**
 - Keep costs of interconnection low so project developers can achieve 8% return on solar project investment; additional costs like taxes can wreck havoc on thin margins
 - Utilities see it as an intrusion on their system; want to ensure the system is reliable. Level cooperation has come a long way.
- **Standards:**
 - **Net metering** standards developed through stakeholder process;
 - Interconnections standards apply to all DG, but net metering rules apply only to Class 1 renewables in NJ; direction is to extend net metering to all DG
 - MADRI guidance, NJ and others **differentiate by size and complexity**; making it easier for smaller projects
 - **Inverter requirements** is a disconnect; NE Code and IEEE 1547 are in conflict with each other, stakeholders have to decide who pays for what.
 - NJ went with **National Electric Code for isolation device requirements** for DG, utility picks up additional costs. State must decide whether the cost should be socialized or up to project developer/customer.
- **Benefits:**
 - **Application process timeframe** is shortest around thanks to standardized applications and contracts: 21 days for Class 1 renewable projects

D. California: Developing Standardized Interconnection Rules, Mark Rawson, California Energy Commission (Download presentation at <http://keystone.org/html/documents.html#dg>)

- **Process:**
 - CEC works closely with PUC, which directed utilities to develop standardized interconnection standards and then asked CEC to help with collaborative process
 - CEC has sponsored working group which has been meeting for 6 years to develop consistent rules
 - Likened to “Sausage making process” – trying at times, but more robust interconnection rules
- **Goals:** clear and transparent process so DG could get through it in timely manner; Translates directly to savings for DG projects; utilities should be fairly compensated for interconnection costs.
- **Standards (Rule 21):**
 - Technology and size neutral – applies to renewable and fossil fuel DG; Level playing field for all dg providers
 - Covers 3 large investor-owned utilities

- Municipal utilities (such as the City of Palo Alto Utilities) have adopted comparable rules; although not covered by Rule 21
- **Application Screening Process**
 - **8 screening factors which leads to 3 alternative review processes**
 - (1) Streamlined review for certified equipment; (initial fee of \$800); Vast majority go through more streamlined process
 - (2) Supplemental Review if project doesn't meet screening criteria; additional \$600 fee and additional information about project needed; move back to streamlined process if information resolves issues raised.
 - (3) If not, detailed review required, utility provides cost and schedule for additional interconnection study.
- **Supplemental guidelines** developed in collaborative process for approaches to resolve outstanding protection issues; as knowledge builds, CEC upgrades the guidelines; see CEC website
- **Benefits** of standardized interconnection procedures:
 - Interconnection time has dropped - Between 2000 and 2001 when rules went into effect, average interconnection time went from 1 yr to 60 days. (see graph in presentation); only 5% now require detailed studies
 - Fees have dropped significantly resulting in \$26 million in cumulative savings
- **Outstanding issues** - may have renewable and non-renewable at same site with different interconnection requirements

Questions & Discussion

How does the CEC coordinate with the environmental regulators (California Air Resources Board (CARB) regarding the DG project compliance with emissions standards?

- A participant noted that a project that was approved as a certified technology for interconnection purposes was not in compliance with CARB 2007 NOx emission standards.
- California's certification for streamlined interconnection does not include emissions standards; therefore, the two review processes are completely independent. However, the state has invested over \$100 million in R&D to make DG cleaner.
- New Jersey also doesn't coordinate specifically with air regulators, but on application for funding, project developers must meet air emissions to be eligible for grant, single point of contact at NJ DEP who works through the department to resolve questions about permitting approval. By statute agencies are required to collaborate. DEP is represented on the committees and have a vote.
- Massachusetts DOER performs some of the coordinating function, but controlling the emissions of small DG can be a challenging problem. MA DEP and DG Collaborative developed questions on interconnection agreement to determine whether they have or will comply with air standards.

- Regulatory Assistance Project developed model rule for emissions for DG through a national stakeholder process; intent was to create a standard rule easily implemented by states for regional or national consistency and give manufacturers guidance in order to design equipment to meet standards. Emission standards are fuel and technology neutral and output-based to reward improvements in efficiency. CT, MA, ME, RI, and DE have or are about to adopt the standards; CA and TX has similar rules. (see RAP's website www.raponline.org)

What are the most challenging issues going forward?

- California – how to resolve both technical and policy questions regarding combined technologies at same customer site, e.g. net metering, how to account separately because renewable is exempt from some charges.
- Network distribution interconnection - California is looking to MA experience for guidance.
- Dispute resolution process – need to reform existing process to address stakeholders' concerns that it is not effective when problems have arisen, may use mediators to streamline it.
- Massachusetts - difficult keeping participants at the table with demanding information and time requirements; utilities can pass through the costs but other participants don't have the resources to stick with it without funding; CA concurred, tried to establish action items and prioritize issues for collaborative process.
- New Jersey – Network distribution interconnection challenges starting to crop up, 1% of capacity has been processed, but will eventually meet fault levels and thresholds and will need to address potential constraints.
- Net metering for non-renewable technologies.

What was cost and timeframe of MA study of costs & benefits of DG to distribution network? Have there been issues of information confidentiality in conducting reviews?

- Eight customer-side DG locations will be analyzed to compute reliability impacts. Utilities provided information on investment expected for distribution expansion/improvements. Navigant used alternative method (usage by customer class); results interesting but wouldn't necessarily suggest other states take this path, difficult to get into issue of what is good for customers and what is good for distribution system in collaborative process. Developing interconnection standards is easier than developing proposal on how to design DG interconnections to meet distribution needs.
- California used collaborative process to provide input to Southern California Edison procurement process that integrates DG with utility distribution upgrades; both the utility and the DG project developers better understand the timing and needs to defer investment. Published report on collaborative process, but won't know how successful it will be until procurement solicitation is issued.

- RAP – states need distribution engineers and also people who understand contracting and ratemaking, so they can make judgments about how this fits in with overall policy. Need both administrative and technical Task Force.
- Stressed the importance of adequate access to good information. Regulators must make it clear up front that utilities should share information with collaborative process. CA echoes this.

Do states that self insure also need indemnification insurance to protect against damage to grid?

- CA interconnection rules require utilities and interconnecting entities to have liability insurance and allows parties to self-insure. NJ does not have an insurance requirement as a condition of interconnection. The question was raised whether damages resulting from interconnection should be covered by ratepayers or DG owner.

Below is language in Southern California Edison’s interconnection agreement regarding liability insurance:

7. LIMITATION OF LIABILITY

Each Party’s liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney’s fees, relating to or arising from any act or omission in its performance of this agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever.

8. INSURANCE

8.1 In connection with Producer’s performance of its duties and obligations under this Agreement, Producer shall maintain, during the term of this Agreement, general liability insurance with a combined single limit of not less than:

- (a) Two million dollars (\$2,000,000) for each occurrence if the Gross Nameplate Rating of Producer’s Generating Facility is greater than one hundred (100) kW;
- (b) One million dollars (\$1,000,000) for each occurrence if the Gross Nameplate Rating of Producer’s Generating Facility is greater than twenty (20) kW and less than or equal to one hundred (100) kW; and
- (c) Five hundred thousand dollars (\$500,000) for each occurrence if the Gross Nameplate Rating of Producer’s Generating Facility is twenty (20) kW or less.
- (d) Two hundred thousand dollars (\$200,000) for each occurrence if the Gross Nameplate Rating of Producer’s

Generating Facility is ten (10) kW or less and Producer's Generating Facility is connected to an account receiving residential service from SCE.

Such general liability insurance shall include coverage for "Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations."

- 8.2 The general liability insurance required in Section 8.1 shall, by endorsement to the policy or policies, (a) include SCE as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that SCE shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to SCE prior to cancellation, termination, alteration, or material change of such insurance.
- 8.3 If Producer's Generating Facility is connected to an account receiving residential service from SCE and the requirement of Section 8.2(a) prevents Producer from obtaining the insurance required in Section 8.1, then upon Producer's written Notice to SCE in accordance with Section 9.1, the requirements of Section 8.2(a) shall be waived.
- 8.4 Evidence of the insurance required in Section 8.2 shall state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by SCE.
- 8.5 Producer agrees to furnish the required certificates and endorsements to SCE prior to Initial Operation. SCE shall have the right to inspect or obtain a copy of the original policy or policies of insurance.
- 8.6 If Producer is self-insured with an established record of self-insurance, Producer may comply with the following in lieu of Sections 8.1 through 8.4:
 - (a) Producer shall provide to SCE, at least thirty (30) calendar days prior to the date of Initial Operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under Section 8.1.
 - (b) If Producer ceases to self-insure to the level required hereunder, or if Producer is unable to provide continuing evidence of Producer's ability to self-insure, Producer agrees to immediately obtain the coverage required under Section 8.1.

<p>NEXT TECHNICAL FORUM CALL: March 9th, 2-3:30 EST TOPIC: Output-based Regulations to Promote Combined Heat and Power</p>
