Constraints

Designing new DG interconnection rules provides an opportunity to resolve recurring barriers encountered by applicants for interconnection of DG systems. These barriers have been well-documented (NREL 2000, Schwartz 2005); three areas in which a DG developer typically confronts problems include:

- *Technical Barriers* resulting from utility requirements (including requirements for safety measures) regarding the compatibility of DG systems with the grid and its operation. For example, customers may be faced with costly electric grid upgrades as a condition of interconnection. Another frequently cited technical requirement that is particularly costly for smaller DG is the visible shut-off switch located outside the premises that can be accessed by the utility to ensure that no power is flowing from the DG unit. These shut-off switches range from $1,000 to $6,000 for small systems (e.g., 30 kW to 200 kW), depending on their location and whether they are installed as part of the original facility design or after the system began operations.
- *Utility Business Practices*, including issues that result from contractual and procedural interconnection requirements between the utility and the project developer/owner. For example, customers may face a long application review period or lengthy technical study requirements, with high associated costs.
- *Regulatory Constraints* arising primarily from tariff and rate conditions, including the prohibition of interconnection of generators that operate in parallel with the electric grid.[29] In some instances, environmental permitting or emission limits also can create barriers. For more information on the barriers posed to DG systems by tariff and rate issues, see Section 6.3, *Emerging Approaches: Removing Unintended Utility Rate Barriers to Distributed Generation*.

Some states are beginning to address these areas of concern through a combination of policy actions and regulatory changes to remove or alter requirements that they believe are not appropriate for the scale of small DG units.

Interaction with Federal Policies

States have found that several federal initiatives can be utilized when designing their own interconnection standards:

- In May 2005, FERC adopted interconnection standards for small DG systems of up to 20 MW. The rulemaking addresses both the application processes and technical requirements. Concurrently, through a separate rulemaking, FERC has addressed an application process and technical requirements for systems under 2 MW. States can use the new FERC standard interconnection rules as a starting point or template for preparing their own standards.[30]
- Under the Public Utilities Regulatory Policy Act (PURPA), utilities are required to allow interconnection by Qualifying Facilities (QFs).[31] Utilities may have standard procedures for such interconnection and some states may regulate such interconnection. New interconnect rules for DG may be more or less favorable than the existing regulations for QFs and also may not be consistent with existing rules for QFs. For example, in Massachusetts the application timelines and fees in the QF regulations are different than the DG interconnection tariff, which could create confusion and delay in establishing an interconnection.
- EPAct 2005 requires electric utilities to interconnect customers with DG upon request. The Act

29 When a CHP system is interconnected to the grid and operates in parallel with the grid the utility only has to provide power above and beyond what the onsite CHP system can supply.

30 FERC's interconnection rules, however, apply only to the third party and wholesale power transactions they regulate. Most DG systems fall under state, rather than FERC, jurisdiction, since most are connected at the distribution-system level and do not involve third-party exports via the utility grid.

31 A QF is a generation facility that produces electricity and thermal energy and meets certain ownership, operating, and efficiency criteria established by FERC under PURPA.

specifies that the interconnection must conform to IEEE Standard 1547, as it may be amended from time to time. In addition, the state regulatory authority must begin to consider these standards within one year of enactment (September 2006) and must complete its consideration within two years (September 2007). However, states that have previously enacted interconnection standards, have conducted a proceeding to consider the standards, or in which the state legislature has voted on the implementation of such standards do not have to meet these time frames.

- EPAct 2005 requires electric utilities to make available upon request net metering services to any electric customer. The state regulatory authority is required to consider net metering within two years of enactment (September 2007) and after three years of enactment must adopt net metering provisions (September 2008). However, states that have previously enacted net metering provisions, have conducted a proceeding to consider the standards, or in which the state legislature has voted on the implementation of such standards do not have to meet these time frames.

Interaction with State Policies

Interconnection standards are a critical complementary policy to other clean energy policies and programs such as state RPS (see Section 5.1, *Renewable Portfolio Standards*), clean energy fund investments (see Section 5.2, *Public Benefits Funds for State Clean Energy Supply Programs*), and utility planning practices (see Section 6.1, *Portfolio Management Strategies*).

Best Practices: Designing an Interconnection Standard

Best practices for creating an interconnection standard are identified below. These best practices are based on the experiences of states that have designed interconnection standards.

- Work collaboratively with interested parties to develop interconnection rules that are clear, concise, and applicable to all potential DG technologies. This will streamline the process and avoid untimely and costly re-working.
- Develop standards that cover the scope of the desired DG technologies, generator types, sizes, and distribution system types.
- Address all components of the interconnection process, including issues related to both the application process and technical requirements.
- Develop an application process that is streamlined with reasonable requirements and fees. Consider making the process and related fees commensurate with generator size. For example, develop a straightforward process for smaller or inverter-based systems and more detailed procedures for larger systems or those utilizing rotating devices (such as synchronous or induction motors) to fully assess their potential impact on the electrical system.
- Create a streamlined process for generators that are certified compliant to certain IEEE and UL standards. UL Standard 1741, "Inverters, Converters and Charge Controllers for Use in Independent Power Systems," provides design standards for inverter-based systems under 10 kW. IEEE Standard 1547, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," establishes design specifications and provides technical and test specifications for systems rated up to 10 MW. These standards can be used to certify electrical protection capability.
- Consider adopting portions of national models (such as those developed by the National Association of Regulatory Utility Commissioners [NARUC], the Interstate Renewable Energy Council [IREC], and FERC) and successful programs in other states, or consider using these models as a template in developing a state-based standard. Also, consistency within a region increases the effectiveness of these standards.
- Try to maximize consistency between the RTO and the state standards for large generators.
- Developing consistency among states is important in reducing compliance costs for the industry based on common practices.