Issues for States Interested in Expanding the Use of Distributed Generation
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Distributed generation (DG) is commonly understood as the siting of smaller-scale electric generation facilities (<20 MW) close to loads or end users. Distributed resources can either be interconnected directly to the distribution system or act as stand-alone generators. Technologies such as reciprocating engines, microturbines, fuel cells and photovoltaics can serve in several capacities including backup or emergency power, peak shaving, or baseload power. Combined heat and power (CHP) generation also presents outstanding opportunities for utilizing waste heat and achieving dramatic gains in energy efficiency.

DG can benefit stakeholders across the entire electrical system. Customer-owners of DG typically cite reduced power costs and increased reliability as the motivation for installing DG. Given the uncertainties of restructuring and volatility of natural gas prices, power from a DG unit can be less expensive than conventional electric service. The enhanced efficiency of CHP (a.k.a. co-generation) also contributes to cost savings. The power quality needs of today's high-tech economy play to another strength of DG. Modern DG technologies are often more reliable than today's central station based infrastructure that relies on the transmission grid to get power to market.

DG can be attractive to utilities as well. Companies like Detroit Edison and Portland General Electric are finding that DG is often a least-cost alternative to wires solutions for accommodating load growth and addressing congestion in the distribution system. DG is less capital intensive and can be up and running in a fraction of the time necessary for the construction of large central generating stations. Certain types of DG can dramatically reduce emissions as compared to these plants. DG also reduces the exposure of critical energy infrastructure to the threat of terrorism.

DG offers grid benefits like reduced line loss and increased reliability. From a grid security standpoint, many small generators are collectively more reliable than a few big ones. They can be repaired more quickly and the consequences of a small unit's failure are less catastrophic. DG is also well suited to provide the ancillary services necessary for the stability of the electrical system.

If DG is so great, why does it represent a mere fraction of our nation's resource mix? The primary reason is that under the prevailing regulatory regime, developed before DG technologies were available, utilities have a considerable economic disincentive to embrace distributed resources. Under traditional cost-of-service regulation, distribution company profits are directly linked to sales. The more kWhs of electricity that move over their lines, the more money they make. Interconnecting with customer-owned DG is plainly not in line with a utility's profit motive. Further, states typically do not require least cost planning for the distribution system. Distributed resources that may very well represent least-cost solutions to load growth and congestion issues are less likely to be considered along-side wires solutions.

Other barriers to the deployment of DG exist on the customer side. In most states, a utility has no obligation to connect DG to its system unless the unit is a qualifying facility under PURPA or meets the requirements of a state net metering law. If a utility does choose to interconnect, lengthy case-by-case impact studies and redundant safety equipment can easily spoil the economics of a DG project. If a customer wants the utility to supply only a portion of their load or provide backup power in case of unit failure, "standby" and "backup" rates can be cost prohibitive. Exit fees and competitive transition charges associated with switching providers or leaving the grid entirely can be burdensome. And obtaining all the necessary permits can be quite difficult.

Overcoming the barriers to DG development will require action by federal, state and local governments and the private sector. States, in particular, are in a good position to effect change, given their jurisdiction over the retail sale of electricity. Below are four areas in which state action can facilitate the deployment of distributed resources. Many DG proponents cite performance-based regulation as the most effective step states can take. Under such a regime, the cost of providing distribution service and the approval of rates of return are determined according to how well utilities help customers obtain least-cost end-use services, instead of according to sheer kWh throughput. Performance-based regulation is not addressed here, however, on account of the scope of change necessary to implement it. This synopsis focuses on more practical ways regulators and energy officials can level the playing field for DG.

<u>Local Integrated Resource Planning</u>

Many states presently require utilities to submit integrated resource plans (IRPs) every several years or so to assure the acquisition of least-cost resources to meet forecasted load and encourage public input to the process. Emphasis is placed on demand-side measures so that a full range of solutions is considered. Without integrated resource planning, utilities might be more likely to overlook the environmental benefits and avoided costs of renewable energy and efficiency measures.

Similarly, without least-cost planning for the distribution system, utilities have neither an obligation nor incentive to consider the cost savings presented by DG in not having to pursue wires solutions for meeting load growth and relieving congestion. Local integrated resource planning (a.k.a. Energy Resource Investment Strategy) is a process similar to IRP in which distribution utilities would be required to conduct least-cost planning of their systems to identify and implement options for serving load growth within specified zones. For example, state regulatory commissions could identify congested zones in which the installation of DG would be encouraged through the provision of customer credits. Or a utility installing its own DG could be granted the right to recover capital and operating costs on an accelerated basis, or an increased rate of return.[1] Utilities would have a clear incentive to consider a wide array of load growth and congestion solutions.

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[1] R.S. Brent (Solar Turbines Inc.), Distributed Generation – A Fair and Simple Plan for Utilities and Policy-Makers, 2 (2002).

Interconnection Standardization

A customer who wants to interconnect DG to the distribution system typically must undergo a utility's case-by-case interconnection review process. Such a process can be time consuming, expensive and easily spoil the economics of DG development. Typically, unless a project is a qualifying facility under PURPA or falls under a state net metering law, a utility has sole discretion over whether or not to interconnect.[2] DG proponents argue that utilities often waste resources on impact studies and require unnecessary safety precautions because they are unfamiliar with modern DG technologies.[3] Installers thus face higher costs by having to meet interconnection requirements that vary from utility to utility. Additionally, manufacturers are not able to capture the economies of scale in producing package systems with standard safety and power quality protections.

States can simplify the interconnection process by adopting standard interconnection technical requirements, procedures and agreements. National efforts are underway at IEEE and UL to standardize technical requirements. FERC and NARUC have developed draft standard procedures and agreements. Final orders are pending in FERC's Standardization of Generator Interconnection Agreements and Procedures rulemaking (>20 MW). A NOPR in the Commission's Standardization of Small Generator Interconnection Agreements and Procedures rulemaking (<20 MW) is expected next quarter. California, Texas, New York and other states have chosen not to wait for federal action and have adopted their own standard procedures and agreements.

The interconnection process would further benefit from the pre-certification of specific DG technologies. Nationally recognized, independent or government testing labs (e.g., Underwriters Laboratories) would conduct initial testing and characterization of the safety, power quality and system reliability impacts of DG. They would recommend technical parameters that state legislatures, regulatory agencies or individual utilities could adopt. Other testing laboratories would then test specific products and pre-certify that they meet the technical parameters. These so called plug & play standards would allow pre-certified units to be interconnected without further technical review by a utility.

Rate Design

The restructuring of electric markets and an increased reliance on wholesale power purchases have brought distribution into the spotlight. As utilities have divested themselves of generation assets, they have become acutely aware of the importance of distribution services in generating revenue. Some regulated utilities have sought approval of rates with high fixed recurring charges, reflecting the notion that distribution costs are

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[2] Texas has enacted a statutory right to interconnect, and some states including New York, Ohio, and California have adopted rules providing the right to interconnect if certain conditions are met.
[3] Alderfer, R. Brent; Eldridge, M. Monika; Starrs, Thomas J. "Making Connections: Case Studies of Interconnection Barriers and their Impacts on Distributed Power Projects" (PDF 1.8 MB). NREL/SR-200-28053. Golden, CO: National Renewable Energy Laboratory, May 2000.

not particularly usage sensitive and should be averaged among all users. Arguments for such rates include simplicity, surety of distribution company revenues and known costs to customers.

Opponents of high fixed charges disagree with the premise that distribution costs bear little relation to usage. They posit that volumetric distribution charges provide the necessary price signals for customers to employ resources in their most highly valued uses. They maintain that usage-based rates help ensure that customers pay the actual costs they impose on the system so that their consumption neither subsidizes nor is subsidized by the consumption of others.[4]

The dichotomy outlined above is a simplification of rate design issues, but nonetheless is of great concern to customer-owners of DG. Distribution rates and charges can dramatically affect the economics of a project. DG advocates favor usage-based ratemaking for its ability to facilitate economically efficient siting decisions and allocate the actual costs that customers impose on the system. A primary criticism by DG advocates is that distribution rates and charges do not reflect DG's actual costs to the system. They hold that rates should reflect the grid benefits of DG like peak shaving, reduced need for system upgrades, capital cost reductions and increased reliability.

States are in the best position to remove the barriers to DG posed by dated distribution rate design since they have jurisdiction over setting such rates. Reducing fixed charges and deaveraging certain distribution costs are the first steps towards true cost of service ratemaking which would more accurately reflect the economic costs of distribution service. A utility would thus charge more for service over constrained portions of the system. Customers would have the right price signals to encourage the installation of DG where it makes most sense and, in turn, utilities could avoid the higher costs of upgrading constrained portions of the distribution system.

Other distribution related charges can also jeopardize project economics. *Standby or backup charges* are rates that a customer pays to receive power from the grid at times when its own DG is unavailable. Standby rates are typically based on serving a customer's maximum load at peak demand periods - a worst case scenario which, some argue, shouldn't serve as the basis for ratemaking. *Buyback rates* are the price a utility pays for excess generation from a customer's own DG unit. De-averaged buy-back rates or credits would be higher for energy derived from DG located in constrained areas of the distribution system.

Finally, DG owners sometimes face the implications of "stranded costs" of utility investments in restructured markets. *Competitive transition charges* and *exit fees* can apply when a DG customer-owner seeks to switch providers or disconnect from the grid entirely. These charges can be quite high, especially considering that the departing party will not be using the company's grid. In California, such charges have included unamortized nuclear plant overrun costs and most recently, ill advised power purchases made by the state. One approach may be for states to impose such costs only when

[4] Frederick Weston, Charging for Distribution Utility Services: Issues in Rate Design, 11 (2000).

overall DG market penetration reaches a certain threshold and actual losses are incurred on investments specifically approved under the regulatory scheme.[5]

Permit Streamlining

Much like interconnection, permitting review is typically conducted on a case-by-case basis which can be lengthy, expensive and spoil the economics of a DG project. Regulated areas include air quality, fuel supply, noise, public safety, environmental concerns, aesthetics, land use, and building and fire codes. Most permitting requirements DG developers face are at the local and state levels. Sometimes, these jurisdictions simply do not have DG related permitting processes in place. To streamline burdensome permitting processes, states can adopt standard applications and guidelines.

States and localities are particularly concerned with emissions from DG projects. Emissions standards are usually based upon "emissions per unit of fuel consumed". This neglects the avoided emissions of combined heat and power (CHP) units whose heating and cooling functions would otherwise be achieved through conventional means. DG advocates insist that emissions standards be set according to "emissions per unit of power produced" or with CHP, "emissions per kWh and equivalent energy produced". Standards should be scale-neutral, fuel-neutral, technology-neutral and specific to DG's modes of operation: standby, peaking or baseload.[6] Such standards would be especially helpful when siting DG in non-attainment areas where older, dirtier and cheaper thermal plants are grandfathered under the Clean Air Act.

States could further simplify the permitting process by pre-certifying specific DG technologies. Like interconnection standardization, national labs could set standards and other testing labs could certify that DG technologies meet them. Thus, air quality agencies could approve specific equipment as meeting their emissions standards without any further review.

It is likely that none of the measures suggested above would, by themselves, encourage the deployment of distributed resources as much as adopting performance based regulation. As long as distribution company profits are directly tied to energy throughput, there will be little industry incentive to embrace DG. Yes, instituting yet another layer of regulatory review for least-cost distribution planning could further burden some faltering utility companies. Certainly, there are state sovereignty issues associated with standardizing interconnection and permitting. And, the debate over how to accurately capture marginal costs of distribution will continue to rage as it has for much of the last century. But state action on least-cost planning for the distribution system, interconnection standardization, distribution rate design and permit streamlining represents practical steps towards a level playing field for DG and realizing its benefits for stakeholders across the entire electrical system.

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[5] Amory Lovins et al., Small is Profitable – The Hidden Economic Benefits of Making Electrical Resources the Right Size, 336 (2002).
[6] *Id.* at 327.