Regulation & tariff structure: paving the way for microgrids across the United States

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1. Paving the way for microgrids across the United States: regulation & tariff structure

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GI Energy's experience of the complexities of developing microgrids has created expertise around the impact that regulation, tariff structure and interconnection requirements can have on a project. We understand that most microgrids require specialized consideration. Though financing options are not detailed here, these factors also ultimately influence GI Energy's microgrid model, which is bespoke to each project. This post touches on the details considered when developing a microgrid, and highlight regulatory solutions currently in progress.

1.1. Introduction

Events like Superstorm Sandy and Hurricane Maria highlight the importance of incorporating resiliency into our electricity grids. The technology solution often used to achieve this resiliency, which can take many forms and include a variety of energy generation assets, is known as a 'microgrid'.

Ultimately, a microgrid is intended to provide power when utility infrastructure, for whatever reason, cannot. Causes for these 'outages' may be related to weather, cybersecurity, or system damage, and are otherwise known as "black sky" events – this contrasts with "blue sky" periods, when the electric grid is operating normally.

Currently, microgrid development can be complex due to existing regulatory rules and the electric utility business model. For the purposes of this discussion, the term "microgrid" is defined as an island-able subset of otherwise distinct utility grid customers. We've decided to focus this post on this type of configuration, which we call 'community microgrids', because they experience the greatest breadth of challenges. This configuration differs from single buildings or multiple buildings in a campus setting who may also seek to island themselves from the grid: because these customers are already treated by the utility as a single off-taking entity, they will likely encounter fewer hurdles to islanding.

A number of states are taking the lead in supporting the development of resilient microgrids. New York and Massachusetts are allocating funding for the feasibility analysis and/or implementation of microgrids. Others are taking steps to create a regulatory approach that address the unique characteristics of microgrids by contemplating new utility tariff structures, and reconsidering the exclusive franchise rights enjoyed by utilities. In addition, microgrid funding programs have been created as a special focus area for state "green banks" (financial bodies designed to encourage sustainable energy investment), like the Connecticut Green Bank Microgrid Financing Program.

Although efforts have been put in place to help microgrid development, and the need for resilient power is clearly demonstrated, the energy industry still needs to negotiate complex questions when bringing this resiliency to fruition. From the customers' point of view, the developer is providing a microgrid which functions in the same way as distributed generation. It's from a developer's perspective that new questions are raised: how will the project's regulatory environment dictate how it functions? How will the transfer of heat and electricity be managed? And what is the expected frequency of black sky days when the microgrid would be in use.

1.2. Valuing Resiliency

The advent of microgrids has introduced what feel like philosophical questions about the value of resiliency, which actually inform the decision-making process when pursuing real microgrid projects. No discussion on microgrids would be complete without an exploration of this aspect. The U.S. military is on an accelerated path to implementing microgrids at numerous bases around the world, and while the military is a special case, it also demonstrates how the value of resiliency to a given customer impacts their uptake of microgrids. For military bases, (as well as hospitals, nursing homes, and first responders) resiliency makes the difference between life and death.

Occasionally, where customers are willing to pay a premium for resiliency because they require it for their operations, resiliency value can simply be negotiated between the customer and developer. It can often be difficult to measure however. The Lawrence Berkley National Lab conducted a study to begin to approximate the value of resiliency for various customer types, by evaluating the cost to the customer from a 16-hour long outage:

1. Residential customer: $32.40
2. Small Commercial and Industrial (C&I) customer: $9,055
3. Medium and Large C&I customer: $165,482

The challenge then, is aligning the capital cost of a microgrid with the customers' perceived value of preventing an outage that may never happen. Since there is no telling when or if a resiliency event will occur, microgrid projects are structured to have an ongoing blue-sky revenue mechanism to recover initial capital expenditure costs. This payback may come in the form of daily use of the system to decrease demand or capacity charges, reap revenues from participating in the wholesale market, or capturing value through mechanisms like net-metering.

Almost all microgrids today have structured a financial payback from revenues earned by using the system daily, despite the utility grid being available. The ability of a project to achieve each or any of these revenues is therefore highly dependent on ongoing regulatory factors.

1.3. Regulatory Considerations in Energy Distribution

The hardware of a microgrid differs from that of traditional distributed energy resources (DER) because it requires distribution infrastructure to send electricity or thermal energy from the generator to other buildings on the microgrid. There are several regulatory implications to adding distribution. The project must weigh the pros and cons of using existing distribution lines or installing its own distribution lines, which are not always straight-forward or consistent between states.

Using existing utility infrastructure in a microgrid is technically feasible today when using switches to isolate specific segments of the distribution line. To avoid the significant costs of laying distribution lines, where possible a microgrid project will likely seek to use existing utility feeders.

1.3.1. Distribution Infrastructure Ownership

By using existing lines, significant regulatory complication can be avoided: utilities are granted franchise rights to distribute energy to customers in a given area. This means that ownership of distribution lines and provision of distribution services is exclusively granted to the utility. When its lines are not owned by the existing utility, a microgrid is itself at risk of being – expensively – classified as a utility, and a slew of regulatory burdens from the state's public utility commission comes into play.

Many private developers will not pursue a microgrid project if it requires them to become a utility, as it adds additional cost to the project without proportionally adding resiliency value.

However, using existing distribution lines can strike at the heart of the microgrid's purpose, which is to power buildings when the grid is disrupted. In most cases, large swaths of the grid can go down due to one failure in the system. This is where switching come in, to alleviate the problem: feeder connections or parts of feeders can be isolated to continue energy distribution to microgrid-tied buildings. There is a risk, still, that the same distribution lines used for the microgrid will be affected during a black-sky event and prevent the microgrid from functioning. (Overhead utility distribution lines are more susceptible to disruption than underground ones.) In addition, while electric distribution lines are more likely to be in place between the buildings on a microgrid, existing thermal energy distribution piping will hardly ever be present, thus necessitating their new installation for the microgrid. For these reasons, the installation of new electric and thermal distribution lines may still be necessary in a given project.

Regulatory amendments will be required to accommodate projects where redundant (duplicate) distribution infrastructure is either technically necessary, or the most cost-effective option. In some states, there are no or only partial rules on the books to clarify the public utilities' preference or requirement for a multiple-customer microgrid. However, this is changing. New York's Reforming the Energy Vision specifically called out distribution ownership as an open question to address through its proceedings. In New Jersey, rules N.J.S.A. 48:3-51 and 48:3-77.1 do address part of the issue: multiple customers transferring energy from one site to another have the option to use their own distribution lines or the utilities' if they are geographically contiguous to one another (and only cross one right-of-way). On the other hand, the existing electric distribution system must be used when transferring over multiple rights-of-way. Many other states are taking similar steps to accommodate the development of microgrids, including Ohio, Massachusetts, and California.

1.3.2. Interconnection

An additional regulatory consideration is interconnection agreement rules for microgrids. Few rules exist to clarify the interconnection requirements and process for microgrids in particular, and instead refer to separate DER system interconnection. Traditional DER projects, except for solar PV, are usually interconnected to prevent electricity back-feeding onto the grid. This is based on the traditional model whereby the utility has been given an exclusive right to deliver power. Given today's desire for resilient microgrids, and the fact that utilities cannot own generation in deregulated states, these is a need to coordinate operations and the use of existing assets with the utility. A microgrid will require electrical connection that allows electricity to be fed back onto the grid for electricity to reach microgrid customers. Fortunately, many states have begun developing procedures for interconnection, identifying it as a critical regulatory shortfall to much-needed microgrid infrastructure investment.

1.4. New Energy Tariff Development

In a world where electricity only flowed in one direction (generator to customer), creating and interpreting the incumbent tariff structures was straightforward: the utility designed rates to recover fixed costs (e.g. any administration and overhead costs), generation costs (e.g. any costs incurred in securing energy and capacity needs) and grid maintenance costs (i.e. the cost incurred in the upkeep of transmission and distribution T&D assets). Typical utility bills include a fixed customer charge, a volumetric charge and, for larger commercial and industrial customers, an additional demand charge that represents the peak capacity that needs to be built and maintained by the utility. In a world with microgrids, electricity begins flowing in both directions – existing tariffs aren't designed to handle this.

Consider a hypothetical scenario: a hospital under normal conditions is likely to pay the utility a fixed charge, a volumetric charge and a demand charge. It is likely to be on a tariff rate structure that has been pre-defined to recover the capital and ongoing costs incurred by the utility to service that hospital.

When the hospital decides to install on-site generation, it is likely to see a direct reduction in the volumetric component of its utility bill. However, it is unlikely that the hospital will be able to meet all of its electricity needs through the DER alone, and will want the added reliability of being connected to the grid. The utility will have to continue to maintain all the T&D infrastructure as well as capacity availability for this hospital, in the event of DER failure. This example highlights the difference between reliability and resiliency; the utility infrastructure represents *reliability* with a history of performance, while the DER represents added *resiliency* in the rare event that the otherwise reliable utility infrastructure fails.

If the original rate structure was designed in such a way that a lot of the costs were embedded in the volumetric components of the tariff, then one might argue that the hospital is receiving an unfair advantage. It is now paying a lower bill (due to lower volumetric consumption from the grid) despite having all the backup grid infrastructure at its service... On the other hand, the very presence of DER on the grid will result in lower demand needs, lesser grid stress and broad societal benefits in terms of reduced emissions and investment deferral of additional central generating assets.

Determining the appropriate tariff structure for large-scale, advanced microgrids connecting several critical facilities (community microgrids) raises a number of additional questions:

- What is the appropriate way to treat non-DER customers who are part of the microgrid by virtue of their location?
- Who should invest in and own any additional distribution infrastructure?
- How should the costs associated with additional infrastructure be socialized and recovered?
- How are utility standby rates spread equitably across microgrid customers if only some of the microgrid customers host DERs and are levied with standby rates?
- Should non-generating microgrid customers also change to a new tariff?

1.5. Designing Effective Microgrid Tariffs

Even where rules exist that have successfully supported the development of a microgrid, they may still not be conducive to supporting others with different use cases and characteristics. Because existing tariffs don't consider microgrids' unique benefits and costs to the customers, or to the grid itself, there is a need to re-examine them, and likely create an entirely new microgrid tariff. Microgrids impact the grid differently, and a separate tariff from standalone DERs is the cleanest approach. Revising existing DER tariffs to apply to both microgrids and standalone DERs will imperfectly fit both project types, and risks negatively impacting existing DER assets.

Many utilities utilize a form of standby tariff for DER customers (and thus, is the default for many microgrid customers). This shifts the customer onto a tariff structure that is largely comprised of demand-based charges, which in principle is meant to recover costs from the customer for the maintenance of capacity and grid infrastructure. However, there is a need for these alternative rates to evolve and embody the following principles of effective DER rate design:

- A customer should be able to connect to the grid for no more than the actual cost to the utility of connecting them (allowing for the regulated utility profit margin).

- Customers should pay for grid services and power supply in proportion to how much (and when) they use these services
- Customers who supply power to the grid should be fairly compensated for the full value of the power they supply
- Tariffs should balance the interest of all stakeholders: the utility, the DG customer and the non-DG customer

There are several existing and developing mechanisms in place, which attempt to create a fair and equitable compensation structure for all stakeholders. While each of these solutions appear to be uniquely crafted, at their core they are attempts to set optimal prices across the two basic components of a rate, i.e. the fixed and volumetric charges (with an added layer of time as well). The table below summarizes these mechanisms:

Utility Payment Mechanism	Description	Pros and Cons	
High Customer Charge	Shifts the recovery of costs from volumetric to fixed charges. It provides the utility a guaranteed level of cost recovery from non-DG customers	**PROS**	• Can allow utility to recover cost of servicing DG customers
		CONS	• Sends the wrong price signal (lower volumetric cost can result in higher consumption) • Does not adhere to the basic principles of rate design
Minimum Bills	The customer pays a minimum amount each month for his/her connection and for a block of usage. The minimum bill guarantees the utility a minimum level of revenue each month from each customer, regardless of the customer's actual net usage.	**PROS**	• Additional revenue stability for utilities
		CONS	• Sends the wrong price signal (limit to energy efficiency savings) • Disadvantages low-usage customers
Connection Charge	A fixed fee is imposed on DG customers who use the utility distribution system but have low net volumetric use.	**PROS**	• Can allow utility to recover cost of servicing DG customers
		CONS	• Incremental soft cost increase for all DG, regardless of size and use case
Value of Solar Tariffs	A combination of the salient features of Net Metering and Feed-In Tariffs. Based on a comprehensive assessment by the utility and/or its regulators of the value of solar generation to the utility and society	**PROS**	• Accounts for all embedded societal costs and benefits to society arising from DG • Dollar credit to utility bill as opposed to kWh offset
		CONS	• Complexity and long administrative process in determining the true value • Need for additional mechanisms for data capture, loss computation, etc.

Minnesota was the first state to adopt a value-of-solar tariff in 2014, and states like Massachusetts and New York have followed suit, creating their own mechanisms for valuing solar energy to replace net-metering. Following this lead, a “Value of Microgrids” tariff is a possible development in the future. A special tariff like this would be able to set a value to the resiliency that a hospital, pump station or grocery store customer, for example, provides to an entire community when installing microgrid DG on a utility grid, but that is not adequately captured in existing utility tariff mechanisms.

1.6. Conclusion: navigating microgrid development

Across the U.S., different states have made significant headway towards accommodating the development of microgrids. Each approach is unique to the state’s deregulation status, proposed utility business model of the future, and position on DER proliferation. The eventual solution will vary state-by-state, but much can be learned from each approach. GI Energy is monitoring the proceedings carefully, and is working in multiple states to develop microgrids despite current regulatory barriers. The future is bright for microgrids, and GI Energy anticipates the possibilities will be far greater as states continue to address the regulatory barriers and uncertainty.

If you would like to discuss any of the issues raised here, please do not hesitate to contact Corina Solis on csolis@gienergyus.com or (917) 484-8509