Microgrids: A Regulatory Perspective

California Public Utilities Commission

Policy & Planning Division

Christopher Villarreal
Principal Author
POLICY AND PLANNING DIVISION

David Erickson
Principal Author
ENERGY DIVISION

Marzia Zafar
Director
POLICY AND PLANNING DIVISION

April 14, 2014

Table of Contents

I. Introduction

The nature of the production, delivery, and consumption of electricity is changing at an increasing pace. Many of these changes are occurring due to the rapid advancements in technology - solar panel production, density and output of battery storage units, software, and systems capable of autonomously responding to signals or pre-set operations – which are increasingly tailored specifically for a wide variety of scenarios. These scenarios range from the individual premise, all the way to community energy systems. When all of these technologies are organized by an individual customer or operator, these technologies can operate without the need of the local utility. In many respects, the question is not does the industry encourage or discourage this development - this development is happening whether the utility, or regulator, encourages it or not; the larger question is what does the utility, and regulator, do to utilize these technologies effectively, both in their own operations, but also in planning their future needs. These emerging strategies are collected under one term: Microgrid.

A microgrid can be as simple as a generator, be it natural gas or combined heat and power, located near a building, like a hospital, that is able to provide needed power during an outage, or as robust as an entire neighborhood that is outfitted with solar and other technologies capable of producing enough electricity to serve their local needs for hours, whether or not there is a grid emergency or blackout. These systems contain technology that is capable of managing power flows, voltage, and load.

In these instances, customers are seeking out two primary services: reliability and resiliency. Considering the fragility of the existing grid, there is an increasing interest in driving certain resources further down into the distribution system - examples of this include efforts by the states of Connecticut, New Jersey, and New York to harden their grids in response to emergency events, such as an extreme weather event. Having sufficient resources, both at the utility-scale, but also at the local level are becoming increasingly important to manage the variety of challenges facing today's electric utilities.

Additionally, many customers are seeing the potential benefits of investing in their own technologies to both ensure their own level of reliability, but also to better manage their own usage. The interaction between the customer-side efforts and the electric grid is still in its infancy, but managing the grid remains the responsibility of the utility. How these technologies, architectures, and services interact and interconnect within a microgrid and with the larger grid raises many questions regarding the future of the utility. This paper attempts to outline and address many of these questions.

Utilities, and their regulators, are entrusted with the duty to provide electricity that is reliable and safe to their customers, but the historical method by which that was achieved is beginning to change. Added to the imperative to provide safe and reliable electricity comes the need to be more resilient and secure in the delivery of electricity. Finally, this all needs to be done at a reasonable cost, but who will be left to pay? Microgrids are coming; how utilities and regulators respond will go a long way to determining how innovation and services will impact the electric grid.

II. What is a Microgrid?

In order to detail the challenges and recommendations for addressing the future role and impacts of microgrids upon the regulated utilities, there needs to be a more precise definition of a microgrid. Indeed, before even providing any analysis of the impacts of microgrids, there must be some understanding and definition around the term "microgrid" that will provide a context for this paper.

Several definitions of a microgrid exist. The U.S. Department of Energy (DOE) defines a microgrid as:

> "A group of interconnected loads and distributed energy resources (DER) with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid [and can] connect and disconnect from the grid to enable it to operate in both grid-connected or island mode."

The State of Connecticut adopted substantially the same language in legislation passed in response to Super-storm Sandy, which knocked out power to significant portions of that state. The legislation passed by Connecticut allocated funding for the state to pilot several microgrids across the state to support reliability and resiliency efforts of the state.[1] Specifically, the legislation adopted a "microgrid grant and loan pilot program to support local distributed energy generation for critical facilities," which will be used to increase the reliability of specific local critical facilities, such as hospitals, navy bases, police stations, and schools.[2] More recently, the Connecticut Department of Energy and Environmental Protection issued their second Request for Proposals which will provide additional funds for more microgrid projects.[3]

---

[1] Connecticut Public Act 12-148, Section 7.

[2] A list of projects selected in the first round of funding can be found here: http://www.governor.ct.gov/malloy/cwp/view.asp?A=4010&Q=528770 (last accessed April 2, 2014).

[3] CT Dept. of Energy and Environmental Protection, Request for Proposals, Microgrid Program, Notice of Available Funds (issued March 6, 2014) (http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/dbd7e9fe5adcdfce85257c93004522f4/$FILE/FINAL%20RFP%20-%20Round%202.pdf, last accessed April 2, 2014).

A standardized definition or description of the types of microgrids is required in order to address the regulatory implications of various architectures. An example of a basic microgrid configuration is shown in Figure 1:

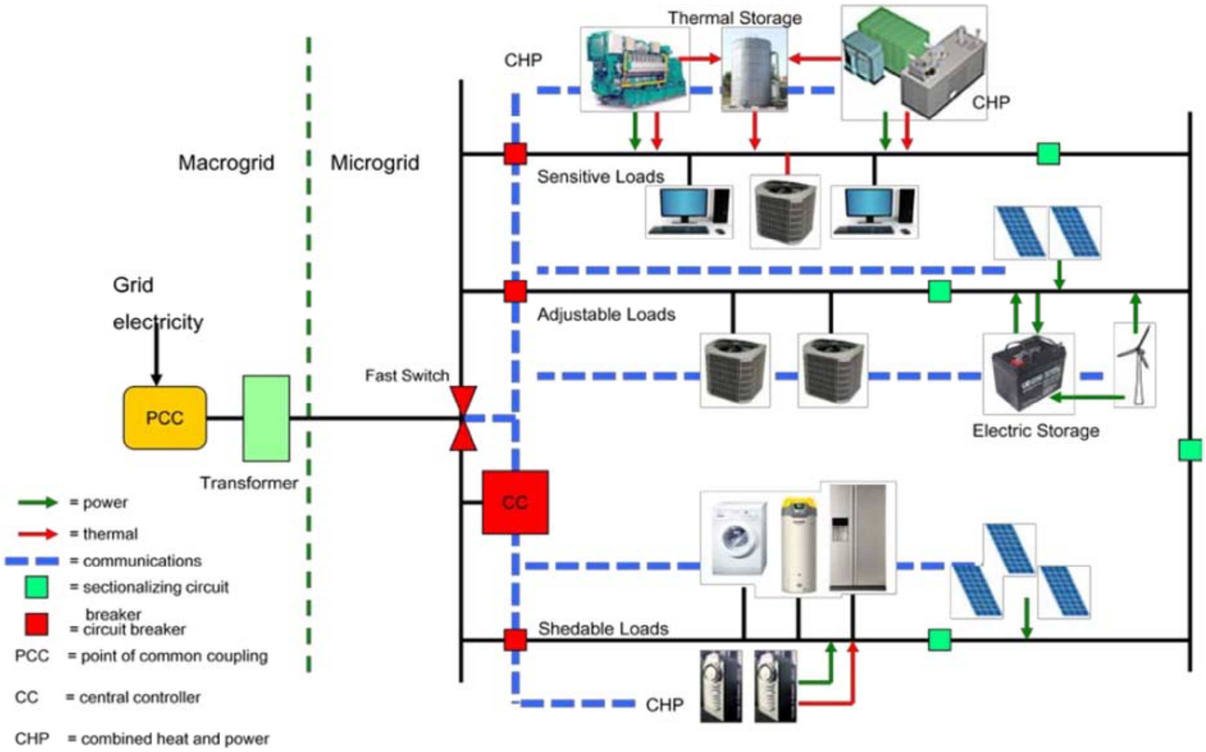

Figure 1

This figure illustrates two basic microgrid types. In both cases, the electric consumption of the microgrid is measured by one or more meters at the point of common connection or at the site of the load. For example:

a. Single customer microgrid – Contains a dedicated distribution system. Depending on the type of customer, there may be multiple meters or a single meter.

b. Behind the meter microgrid – This customer is net-metered or uses Self Generation Interconnect. Both this type of microgrid and the single customer microgrid may island. In the diagram above, the meter would be located on the microgrid side of the point of common connection.

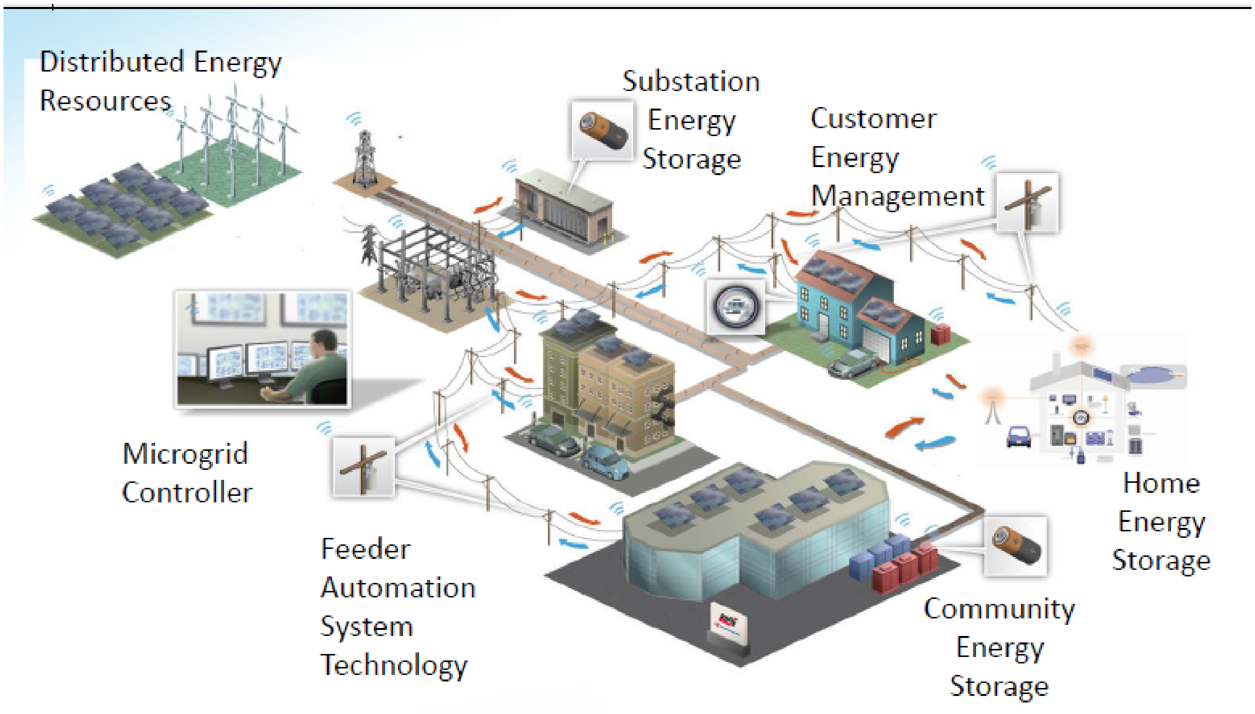

Figure 2

Figure 2 illustrates what is referred to as a general microgrid or "Advanced Microgrid." This type of microgrid contains multiple customers, multiple resources, resource interconnection on both sides of the meter, islandable, capable of providing grid services, using existing distribution network, but potentially involving dedicated distribution infrastructure. For purposes of this paper, the advanced microgrid will be the primary architecture that is the subject of the technical description and policy analysis in this paper.

III. Benefits of Microgrids

Microgrids fundamentally rely on integrated control systems to coordinate distributed generation including intermittent renewables, with storage units and/or demand response operations. These resources are known collectively as distributed energy resources (DER). Management of these resources as a microgrid allows for a single connection point with the distribution system.[4] The reliability and resilience mentioned above are dealt with locationally; in other words, the needs are determined by the individual customer sites (*e.g.*, hospitals, police/fire, water/wastewater systems, and emergency facilities). By allowing the customer or

[4] "The Advanced Microgrid: Integration and Interoperability," Sandia National Laboratories (March 2014) (http://nyssmartgrid.com/wp-content/uploads/The-Advanced-Microgrid_Integration-and-Interoperability-Final.pdf).

microgrid operator to manage itself according to its needs, and then acting as an aggregated single entity to the distribution system operator allows for a number of innovations and custom operations; the interconnect point only needs to know whether power needs to be sent into the microgrid or whether power is flowing out.[5]

Microgrids are able to overcome the problems of grid-scale integration by utilizing distributed energy resources as a "local portfolio" that can be managed at a distribution level, based on local conditions. Further, operation of the distribution system at the local level (customer or load level) is simplified and improved by the integration of microgrids into the electricity grid.

An example of this type of microgrid is located in San Diego Gas & Electric's (SDG&E) service territory in Borrego Springs, a desert community to the east of San Diego. Borrego Springs is situated in the middle of a state park, surrounded by mountains, and at the end of a 69 kV transmission line. The geography and topology of the town and its tendency for flash floods during monsoon season often results in the loss of electricity service for minutes, if not hours at a time. On September 6, 2013, a large storm and subsequent flood cut off electricity and washed away several utility poles, making restoration of electricity to the town difficult. Fortunately for the residents, SDG&E had installed several batteries and generators in the town and was able to bring power back on to portions of the town throughout the night.[6] The community was, in effect, islanded, or disconnected, from the utility's transmission system that normally serves the area. In essence, SDG&E's resources acted as a microgrid since these resources were not connected with the transmission system, but were managed and operated locally.[7] Since then, SDG&E has continued to invest and test other technologies that can be paired with locally sited renewable generation to both increase the amount of electricity that can be generated and delivered, as well as to allow for its batteries to be charged on solar power as opposed to the on-site diesel generators.[8]

A. Increased Reliability and Resilience

One of the primary characteristics of a microgrid, as mentioned in an earlier section, is the ability to "island" or disconnect from the area electric power system (EPS), and continue to

[5] Other services may also be flowing in and out of the microgrid through the distribution grid, but at a fundamental level, whether the distribution grid needs to send or receive electricity will be integral for the safe and reliable operation of the distribution grid.

[6] "Microgrid Powers Borrego During Emergency," San Diego Union Tribune (November 10, 2013) (http://www.utsandiego.com/sponsored/2013/nov/10/sgde-repair-crews-storm/).

[7] "SDG&E Borrego Springs Microgrid Demonstration Project," Presentation by Tom Bialek to California Energy Commission (June 8, 2012) (http://energy.gov/sites/prod/files/30_SDGE_Borrego_Springs_Microgrid.pdf)

[8] Additionally, the diesel generators are subject to local noise and air quality restrictions which limit the ability of the batteries to operate to support local needs, since the generators charge the batteries.

provide power to its customers[9] during events when either the EPS is down, or there is a fault condition on the local distribution feeder. Building a microgrid around a combined heat and power system (CHP) that is providing power to a campus, for example, can result in resilient facilities that can ride out even extremely disruptive events.[10] The ability to island can also be effective if distribution feeders are partitioned in order to isolate faults. Sections of a distribution feeder can safely be kept energized by islanding feeder sections using power electronics technology, while isolating the section where the fault occurs. This allows crews to work safely to restore the fault condition, while maximizing the number of customers that continue to receive power.[11]

B. Intermittent Renewable Integration

Grid-scale integration of solar photovoltaic and wind generation create operational challenges on a macro-level. The output of solar power systems changes frequently depending on the position of the sun and clouds. The output of a solar electric array also changes seasonally, with the highest output occurring in summer. The presence of clouds at particular times, and the type of cloud cover that may be present, causes small, fast variations in solar output. Solar-powered electric generation systems, including both solar photovoltaic and solar thermal, respond to changes in the solar irradiance on very short timescales, particularly when there is no storage to "buffer" the output of the solar array. Wind power is subject to some of the same types of daily and seasonal variations. Due to these characteristics, integration of these generation resources into the grid at utility-scale creates new operational needs, including short, steep ramping, over generation risk, and greater frequency response.[12] These conditions require new operating capabilities for resources that are able to start and stop quickly, with short notice, sustain ramping, and respond for a set period of time. There is also a need to be able to accurately forecast operating capability in different time scales. Clearly, since the existing grid was designed to handle large, rotating generators with very stable output, grid conditions created by the addition of intermittent resources (and other policy mandates) can be enormously challenging to plan for and integrate for grid operators, both at the system operator scale, and at the distribution operator scale.

---

[9] "Microgrid Powers Borrego During Emergency," San Diego Union Tribune (November 10, 2013) (http://www.utsandiego.com/sponsored/2013/nov/10/sgde-repair-crews-storm/).
[10] "Lessons from Sandy: How One Community in Storm's Path Kept Lights On," Christian Science Monitor (November 12, 2013) (http://www.csmonitor.com/USA/2012/1115/Lessons-from-Sandy-how-one-community-in-storm-s-path-kept-lights-on). *See also*, "Microgrid: Keeping the Lights On," Triton, University of California, San Diego (Winter 2014) (detailing the microgrid experiences of UC San Diego) (http://alumni.ucsd.edu/s/1170/emag/emag-interior-2-col.aspx?sid=1170&gid=1&pgid=4665)
[11] "Automated Distribution Feeder Fault Management: Possibilities and Challenges," Electric Energy T&D (July/August 2009) (http://www.electricenergyonline.com/show_article.php?mag=&article=370).
[12] The CAISO "duck graph" shows the ramping necessary to maintain reliability (http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf).

The microgrid control system can effectively manage local intermittency of renewable generator output through coordination of storage and demand with generator output. The ability to simultaneously coordinate, a) reductions in customer premise demand using automated demand response technology; b) battery storage charge and discharge operations; and, c) renewable generation output are key features of microgrid energy management systems. Rapid monitoring and control of these variables, on an hourly to millisecond timescale, can be more effectively (and cost-effectively) accomplished at the microgrid level than would be required even at the distribution system operator level. Local characteristics such as microclimates and customer mix can be taken into account in control algorithms. These factors allow microgrids to provide reliable, lower cost electricity by decreasing the required peak and base-load capacity through effective utilization of intermittent renewable generation balanced with storage and demand modulation.

C. Relationship of the Microgrid to the Macro-grid

Microgrids can be viewed as a fundamental building block in creating the 21st century "smart" electric grid. In this context, a microgrid functions as a "cell" in a matrix of interconnected DER and customer loads, all controlled by the interaction between the microgrid operator and the distribution utility. In this scenario, the existing transmission and distribution system could be repurposed to support interconnection of microgrids so, together, it can create a higher reliability system by, in effect, "backing each other up." This potential future architecture of massively distributed energy resources and intelligence with hierarchical controls can deliver higher reliability, through resource redundancy and local resource management targeted with meeting critical customer needs. At the same time, the microgrid can provide valuable grid services and resources to the macro-grid. Furthermore, microgrid controls and communications can contribute not only to the optimization of the generation and load in the microgrid, but with the distribution grid as well.

This potential future macro-grid could be described another way as a collection of networked microgrids sharing distributed, renewable energy production and storage, based on an interaction among control systems that manage supply and demand on micro and macro levels. This concept will depend on realizing a variety of microgrid functions that involve relationships to the ISO-managed markets. There is also an impact, going forward, on existing planning processes, both at the distribution level and at the transmission level. Finally, there is an impact on procurement planning for the utilities to adjust for the changes in the need for utility-scale resources.

D. Microgrids as a Grid Resource

Microgrids serve as a multi-function grid resource. From the system operator standpoint, a microgrid can serve as:

- A reliable, dispatchable energy resource;
- An ancillary service resource;
- A load shed resource; and/or,
- A consumption resource (to handle over generation)

To the extent that a microgrid, or the business entity representing the microgrid, can participate in wholesale markets, revenue streams can be associated with these bulk electric system (BES) needs. A microgrid in a particular area can be designed and operated so as to address macro-grid conditions, at either the BES or local area power system, starting at low voltage levels in a particular area, all the while generating revenue streams that are associated with each of the services mentioned above.

E. Effect on Grid Operations

Independent system operator (ISO)-managed grid operations today are conducted using economic dispatch principles. Energy is bid into the wholesale market and dispatched according to market price. The net load of the grid is affected by the deployment of customer side resources as a reduction in demand. Customer-side resources are also treated as load reduction by the EPS or distribution system operator (DSO).

From a management standpoint, customer-side resources today are not usually visible to either the ISO or to the DSO. Microgrids change that equation to the degree that they participate in wholesale markets as described above, or provide EPS services (such as volt/VAR control) to the DSO. Individual distributed energy resources that comprise the microgrid, along with controllable load, can be dispatched to serve the local load and generator output conditions, while appearing as an aggregate resource to the ISO or DSO. This will allow the ISO or DSO to use the microgrid as a resource for the macrogrid conditions, without being concerned with the details of operation or having visibility into the internal operation of the microgrid.

Similarly, the microgrid management system can help provide distribution level services as part of a distributed control system. Individual resources, such as smart inverters that can supply reactive power or voltage support, can be controlled at a more local level. This functionality saves the engineering cost and need for monitoring that more centralized distribution system management implementation requires.

F. Effect on Transmission and Utility Scale Resource Planning

As microgrid implementation expands, utility procurement will need to adapt to changing requirements for resource adequacy and long term procurement. Transmission planning scenarios will need to adapt to reduced need for both existing fossil central station generation, as well as new utility-scale renewable generation resources. The process for distribution resource plans, now required by Public Utilities Code Section 769,[13] will have to parallel transmission and resource procurement planning. Similarly, contractual arrangements between utilities and microgrid operators as part of resource procurement will need to be developed that are transparent to regulatory oversight, in terms of providing customer protection from abusive pricing and ensuring adequate incentives and cost recovery for both developers and utilities. The challenge associated with this is that utilities engage in a 10 year forward procurement mechanism, which may result in stranded costs if demand is lower than planned, whether it is from demand response, energy efficiency, or microgrids, and the utility ends up over-procuring resources, or procures resources not flexible enough to address the emerging grid conditions.[14]

IV. Current State of Policies and Regulations Affecting Microgrid Development

Our current regulatory structure is built around the historical model of the electric utility as a "natural monopoly." Classically, the utility natural monopoly is vertically integrated, owning generation, transmission and distribution systems that serve all electric customers in a geographic service territory. More recently, with restructuring, electricity is now treated as a commodity, centrally produced by large generation facilities owned by independent power producers, who sell the electricity in a market to utilities who provide electricity to retail customers.[15] Customer consumption is measured by a meter and billed based on a unit price, similarly to water or gas. In order to protect the economic interests of the ratepayer from the monopoly, the Commission was granted the power to set rates, and to oversee the activities of the monopoly utility.

The regulatory authority for electricity production and delivery is established in the definitions of a "public utility" in Section 216, and an "electrical corporation" in Section 218 of the California Public Utilities Code. Section 216(a) and (b) define a "public utility" as including every "electrical corporation" along with other corporations dealing with transportation, gas, water

---

[13] http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=769.

[14] The CAISO "duck graph" shows the ramping necessary to maintain reliability (http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf). Additionally, in recent testimony submitted by SDG&E, they are proposing to extend residential peak hours to 9:00 PM to address many of these same needs; previous peak hours ended at 6:00 PM. *See* Prepared Testimony of Chris Yunker, Chapter 1, R.12-06-013, Phase 1 (February 28, 2014). *See also* "Laundry after work? SDG&E may make you rethink," San Diego Union Tribune (February 20, 2014) (http://www.utsandiego.com/news/2014/Feb/20/time-based-electricity-prices/) ("We have this wonderful abundance of renewable energy in the middle of the day, but at the end of the day, when people really need it, those resources aren't available," SDG&E spokeswoman Stephanie Donovan said. "We're going to have to shift the time period so that people really see that.").

[15] In response to the Energy Crisis, this was modified to allow for the utility to engage in forward contracting with generators.

and similar essential commodities and services. This section states that whenever a corporation defined as a public utility

> *"performs a service for, or delivers a commodity to the public or any portion thereof for which any compensation or payment whatsoever is received, that [corporation] is a public utility subject to the jurisdiction, control, and regulation of the commission and the provisions of this part."*

An electrical corporation, in turn, is defined as including, "every corporation or person owning, controlling, operating, or managing any electric plant for compensation." This set of definitions and the regulatory authority of the CPUC defined by these Public Utility Code sections hint at some of the challenges that the existing regulatory structure poses to microgrid development.

The Public Utilities Code goes on to list exclusions from this definition:

> S. 218(b) (c) & (d) – "Electrical corporation" does **not** include a corporation or person employing [a particular generation technology] for the generation of electricity for… (2) The use of or sale to not more than two other corporations or persons…**unless** there is an intervening public street constituting the boundary between the real property on which the electricity is generated and the immediately adjacent property [where the electricity would be used].

This somewhat convoluted wording specifies that if a generator supplies electricity for sale to others, who are not tenants of the premise where the generator is located, it is an electric corporation. The definition of electric corporation excludes a generator using "not a conventional power source" may supply power to properties immediately adjacent to the location of the generator, if there is an intervening public street, or there are more than two customers.

More generally, the existing rules set out in the Public Utilities Code envision a particular service and regulatory model that is increasingly strained by the development of policies related to solar, net energy metering, distributed generation, and behind-the-meter microgrids. These new innovative business models products, and services that allow customers to choose from a variety of product and service suppliers for on-site generation which by-pass the utility entirely, call for update to the rules and expectations from the electric utility. Nevertheless, the utility as the DSO is unlikely to disappear in the foreseeable future; how the utility best manages the provision of electricity in the face of these disruptive technologies remains uncertain.[16]

In light of this uncertainty, it is important to examine the constraints that are placed on the use of utility poles, wires, and other distribution infrastructure. At some point in the future, it may become economically feasible for large numbers of customers to produce their own electricity and disconnect from the grid entirely. Until that time, interconnection with the existing distribution infrastructure will be necessary in order to share electricity production resources.

A. Interconnection Rules

Distribution interconnection rules that have been established by the Commission only recognize three types of generation interconnection: net metering, self-generation (non-export), and wholesale distribution access tariff (WDAT). Net metering is on the customer side of the meter and involves a bill credit for exported energy.[17] It is not visible to the California ISO, and is connected at distribution-level voltage. There is a limit of 1 megawatt (MW) of nameplate capacity. Self-generation interconnect is effectively wheeled to the customer via the distribution grid, but is not intended for net production. Wholesale distribution access interconnect is visible to the CAISO and is interconnected on the utility side at distribution level voltage. There is a limit of 3 MW at the 12 kV PCC and 5 MW at the 60 kV PCC.

It is important to note that none of these interconnection techniques support a general advanced microgrid as defined above, but all require the approval of the utility. Depending on the conditions on the distribution feeder and the size of the generator, system impact studies for interconnection may be required. Implementation of a general microgrid would most likely require negotiation of operating agreements between distribution utility and the microgrid owner/operator to delineate bilateral responsibilities that insure system stability.

A net metered microgrid could not support energy sharing, although virtual net metering supports multiple users behind a single point of common connection. Due to these constraints, there will be a need to have rules capable of handling different types of interconnection that may not be currently considered by the Commission and utilities. For example, some question that would need to be considered includes:

- Does the interconnection tariff envision the ability of a microgrid to act as a resource that is capable of consuming and producing electricity in short bursts of time and alternating between production and consumption?

[16] This paper is not assuming any particular future utility business model; rather, the purpose of this paper is to highlight to increasing role of certain technologies, such as microgrids, and the potential impact on utilities and regulation.
[17] The credit is priced at the full, bundled retail rate of electricity for that customer.

- Does the limitation of generator size inadvertently limit the types of services a microgrid may be capable of performing, such as voltage or reliability support?

- How should the maximum total generation or load located at a point in the distribution system be evaluated? What safety protocols should be put in place? How are system upgrades evaluated?

- How are the costs of any distribution system upgrades allocated?

Islanding, or disconnection of the microgrid from the utility distribution grid for some period of time, is a controversial area. Utilities are concerned about the safety implications of keeping areas of the grid energized, while other areas are undergoing an outage. The ability for an area of the grid to island and provide its own power during a wide area outage, such as can occur during storm events or other natural disasters, is one of the key advantages of a microgrid.

However, this benefit must be rationalized with the need for the utility to maintain safe operations for its workers and the public. The ability to island fundamentally challenges the traditional model of the utility as the provider of "high reliability" service that is there when the customer needs it. Similarly, the microgrid relationship to the BES as a provider of services challenges the traditional "one-way" nature of utility service, as well as the obligation to serve.

B. Retail Tariffs and Bundling

Retail electric tariffs in a regulated utility state (or retail regulated state like California) usually consist of three parts: generation, transmission, and distribution.[18] In this situation, net metering is usually structured to net out the full bundled cost (in regulated jurisdictions)[19] of imported electricity against electricity produced and exported onsite. The meter is located at the point of common connection and registers the net electricity use. In this scenario, an onsite power system vendor can execute a power purchase agreement with an individual customer and offer that customer a competitive rate on electricity generated by the onsite system, which is usually owned by the vendor. The economics of rooftop solar systems usually are favorable for the customer in this scenario because the electricity cost is competing against the full bundled (G+T&D) rate.[20]

However, it would be difficult to implement a microgrid that uses resource sharing (*i.e.*, multiple resource types providing electricity to multiple customers via the distribution system)

---

[18] There may be additional fees or charges also collected for specific utility programs or other societal programs. These fees or charges may be charged on a volumetric basis (*i.e.*, multiplied by the kWh) as opposed to a flat fee.

[19] In California, customers taking service from a Community Choice Aggregator (CCA) pay the CCA for the generation portion of the bill and pay the electric utility for transmission and distribution rates. The CCA sets the retail rate for generation and the credit for net energy metering.

[20] This may vary depending on the rate structure and rate tier of the customer.

in this scenario because there is a limit on how much an individual onsite resource can export. Furthermore, existing laws and rules limit the ability of a customer to purchase electricity from any other provider other than the incumbent utility. Also, with electricity produced by net metered resources, a microgrid could not be islanded under current rules because net metered systems have to power down in the event of an outage or grid failure.[21]

In a deregulated electricity market, the microgrid operator could use the distribution network to wheel wholesale connected electricity generated by wholesale distribution connected generation, including electricity generated from behind-the-meter systems. However, due to the competitive basis for electricity prices in deregulated markets, the electricity provided by the microgrid operator would have to compete with the cost of generation for electricity supplied by the utility. Transmission and distribution charges would still be added to the customer's bill on a volumetric basis, along with demand charges. In this scenario, even with the efficiency advantages of microgrid-based control, it would be difficult to compete with electricity produced by central station hydro, nuclear, or natural gas generation at the BES level.[22]

Another barrier to realizing the reliability benefits offers by microgrids is that intentional islanding is not supported by most distribution utilities. In addition, a microgrid that is still interconnected to the bulk electric system would be subject to standby charges, as described below. This further adds to the potential cost of microgrid power, which makes the ability to compete even more difficult.

V. Key Challenges that Need to be Addressed in Developing Microgrids

The key jurisdictional challenges associated with microgrids revolve around the definition and management of the connection of the microgrid to the distribution and transmission systems. There are also a number of other regulatory and market challenges for microgrids. The primary issue is in the provision of electricity in a reliable manner. This issue raises many questions that will need to be considered by a regulatory agency. For example:

- Does the microgrid rely on the distribution or transmission system for backup, and how does that impact reliability?
- To what extent does the microgrid "rely" on the BES, and vice versa?

[21] In other words, when there is an outage at the location of the solar unit, that solar unit also shuts down.
[22] Since locational marginal prices are set at the transmission level, the local benefits of microgrids to the transmission grid may still be masked to the BES.

Next, how are questions related to siting addressed? For example:

- Where could or should the microgrid be located and developed?
- How is the question of optimal location addressed?
- How does the location affect the configuration of the microgrid, especially the relative size of the generation components and the identification of critical and non-critical loads?

The regulatory agency also needs to address revenue, costs, and cost recovery. For example:

- How are the costs of microgrid development allocated and recovered?
- Is metering still relevant in a microgrid?

Finally, there are issues related to procurement planning and resource adequacy. For example:

- How do the utilities adjust their procurement and resource adequacy consideration to accommodate microgrid development?
- Do utilities need to deal with procurement of services offered by microgrids?

One other overarching issue is the manner in which the electric corporation and regulations, as defined by the state Public Utilities Code, will apply to microgrids and their owners/operators. The relevant questions include:

- Are the entities that own and operate microgrids (assuming they are not the incumbent utility) public utilities in the traditional sense?
- Under what purview is the incumbent monopoly-owned distribution system architecture modified and enhanced, and who owns those modifications and enhancements?
- Does the utility own them, or do they become part of the microgrid operator's development cost?

Below we discuss existing regulations, tariffs, other economic and market mechanisms that significantly affect the ability of either the utility or microgrid developers to use these technologies to benefit customers. The current structure of these regulations and tariffs highlight the departure from the traditional utility model that microgrids represent.

A. Standby Charges and Departing Load Charges

Departing load charges apply to California utility customers who generate a significant amount or all of their own power.[23] These charges cover such things as past under collections for forward power procured on behalf of these customers. However, if the generation is "clean" the customer may be exempt from these charges. These charges apply to any customer that no longer receives power from the incumbent utility, including customers who go "off-grid." In California, new Direct Access customers have to pay these charges, as well as customers who shift to a CCA. These charges are "vintaged" because the amount of forward power purchases that these customers are responsible for declines over time, and eventually goes to zero.

Standby charges apply to self-generation customers who remain connected to the grid, whether or not they receive power from the incumbent utility. The customer pays these charges because the utility is required by law to deliver energy automatically if the customer's generator is not working. Standby charges are assessed to cover the cost of providing this service. These costs are assessed based on the size of the customer's generator. These charges are meant to reflect the share of the customer's cost of operating and maintaining the infrastructure to provide them with reliable power.

In the case of microgrids, if a microgrid is capable of supplying most of all of its own electricity needs, and can island, but remain connected to the grid, standby charges may also apply. The question for the regulator is who is responsible for these charges? Is it the microgrid owner/operator, or is it the individual customer? In either case, if the cost of standby service is included in the cost of service to the microgrid customer, it is a factor that will ultimately increase the cost of electricity and the competitiveness of the microgrid. In order for microgrid-based electric supply to be cost-competitive, the nature and amount of the standby charges need to be revaluated by the regulator.

In contrast to the view of the microgrid as a consumer of macro-grid services, a major consideration that distinguishes microgrids from other types of customer generation is the ability to provide services to the grid. In other words, the microgrid can net out the benefits. It is no longer the case with a microgrid that the grid connection exists solely for the benefit of the microgrid customers. The grid connection also benefits the system more broadly to the extent the microgrid provides operational services to the grid, such as ancillary services or frequency regulation. With this consideration in mind, the following questions regarding standby charges are relevant:

[23] These charges do not apply to net energy metering customers.

1. Is interconnection with the BES providing a benefit to the BES, or is it providing a benefit to the microgrid customer?
2. How should the cost of providing standby or grid connection-related services to the microgrid customer be balanced by services or other benefits the microgrid is providing to the BES?
3. How should this interconnection service be managed, *i.e.*, through an interconnection tariff, a retail customer tariff, or should the utility "procure" the microgrid's services?

B. Cost and Cost Recovery

In California, the "bundled" customer (*i.e.*, where generation procurement, transmission, and distribution services are all provided by the incumbent utility to the customer) pays the generation charge as a "pass through," *i.e.*, the utility is required to charge for generation of power consumed by the customer at cost. The way the generation charge is set depends on the customer tariff, but ultimately the total retail cost of generation paid by all customers is the actual total cost of the electricity that is contracted for by the utility.

Transmission and distribution, on the other hand, are the revenue base on which the utility can collect a rate of return. The rate of return is guaranteed by the state. Rates for transmission and distribution are set based on operating costs and a return on equity.[24] Normally, the transmission and distribution costs represent about 40% of the total cost a bundled customer pays for electricity.

For microgrids, the cost of electricity paid by the customer will depend on a number of factors:

- The cost (levelized cost of electricity or LCOE) of the electricity produced by the distributed energy resources supplying the microgrid compared to the retail rate;
- The cost of distribution services set by the distribution operator;
- Any additional costs associated with interconnection to the BES;
- Any additional revenues associated with services that the microgrid supplies to the macro-grid; and,
- Profit for the microgrid owner/operator.

Rationalizing these factors with the existing tariff and billing structures of the incumbent utility is a key regulatory challenge.

[24] Transmission rates are set by the Federal Energy Regulatory Commission.

The above observations apply to existing financial and business models that have historically been applied to electric utility service. There are new models that enable energy transactions between DER owners and electricity customers that redefine the function of the DSO.[25]

In implementing microgrids, there are several categories of cost that need to be addressed. The first is the cost of the engineering studies that the utilities require to interconnect significant amounts of distributed energy resources to the distribution grid. The second category of cost is the potential upgrades of the distribution grid that may be required to handle multi-way power flow from distribution connected resources. These latter costs may be offset by savings from procuring electricity from other utility-scale generation resources, be they fossil-based or renewables.

More fundamentally, as a microgrid consumes less electricity from the distribution utility, a question of equity rises since utility costs are recovered through rates.[26] In other words, if the microgrid is purchasing less electricity from the distribution utility, either in total or as an off-set due to some tariff, similar to net-metering, these lost utility costs must be recovered by other customers. As discussed below, other means by which the utility can collect revenues may need to be considered by the utility and regulator.

To the extent that microgrids can be located where they can provide benefits to the grid, such as relieving congestion, current mandates[27] suggest that the costs of grid upgrades to support DER may be included in the utility general rate case. This approach would take the burden of grid modernization costs off the developer (and its customers) and allocate it towards all ratepayers that benefit from the presence of the microgrid.

C. Siting

Siting is a critical factor related to bringing down the cost of microgrid deployment, for two reasons:

1. Microgrid benefits can be optimized through properly locating the microgrid in or near areas of the macro-grid that experience congestion or other capacity or grid balancing issues; and,

---

[25] For example, the concept of Transactive Energy can upend the traditional interaction with the customer by sending a series of prices to smart electronics, devices, or energy management systems and allowing those technologies to respond at a given price. *See*, *e.g.*, "GridWise Transactive Energy Framework," The GridWise Architecture Council (October 2013) (http://www.gridwiseac.org/pdfs/te_framework_report_pnnl-22946.pdf) and http://www.gridwiseac.org/about/transactive_energy.aspx.

[26] The Commission opened a rulemaking to investigate the equity of the current rate design, and whether an alternative rate design is more appropriate. *See* R.12-06-013 (opened June 28, 2012)

[27] Public Utilities Code Sec. 769 (directing the development of distribution resources plan).

2. Microgrid costs can be reduced through siting in preferred locations, such as near existing distributed generation, in particular, combined heat and power or where grid infrastructure upgrades are not required.

State regulators and energy policymakers need to analyze the distribution grid statewide and assess the potential for microgrid deployment based on favorable grid conditions in areas throughout the system. Sites should be identified that can support cost-effective development of microgrids, based on a consistent set of criteria including cost, grid benefits, and availability of resources. Indeed, locating microgrids in areas where reliability is an issue can provide a higher quality of service to those customers, including an increase in resiliency in response to some catastrophic event.

D. Relationship with Incumbent Distribution Utility

In most areas of the United States, the existing distribution system is owned and operated by a monopoly DSO, usually under a local franchise agreement. This was considered to be essential in the early days of electrification, because communities wanted to reduce the amount of redundant infrastructure.[28] The monopoly ownership and control of the existing distribution infrastructure creates a problem for independent microgrid development because the DSO is the gatekeeper for modifications to that infrastructure. This is the case both practically and in regulation. The DSO is responsible for safety, cost, and operational stability.

However, the utility control of the distribution system can be addressed by regulators in a variety of ways. If a comprehensive site survey is done, as mentioned above, to determine optimal sites for microgrids, the distribution grid characteristics in the optimal sites can be modeled using automated grid simulation and power flow modeling tools. This approach streamlines the engineering effort required to address the impact of modifications that may be required for microgrid development. A comprehensive model of the distribution grid that enables simulation and modeling will be required in any case in order to streamline any distributed generation implementation.[29] Expanding the simulation capability to include microgrid modeling would give greater flexibility from a policy standpoint.

A second option for regulators would transform the role of the utility into a DSO responsible for ensuring the available capacity for distribution of electricity generated either behind the meter,

---

[28] The local franchise agreement may add complexity to the development of microgrids, especially if the developer is considering adding new infrastructure. The local franchise usually grants the exclusive right to developing and constructing new infrastructure to the franchisee, which is usually the incumbent utility. There may be a need for local governments to modify the franchise agreement or make other considerations for microgrid developers in order for microgrids to be developed in certain municipalities.

[29] This activity is contemplated by Public Utilities Code Sec. 769.

connected on the utility side, or flowing from the transmission grid. The DSO would be able to determine appropriate costs for both interconnection and delivery of electricity traveling over the distribution grid. This approach would allow the customer and other service providers to offer additional products and services in support of a microgrid. It would also ensure that the utility, as DSO, is able to schedule and dispatch the two-way flow of electricity, as well as manage the stability of the distribution system. The DSO approach also addresses the potential loss of revenue as the utility would now be responsible for the maintenance and operation of the infrastructure, and be allowed to earn a rate of return on those assets. This might ultimately lead to a fixed price calculation for access and use of the distribution grid.[30] In this case, the cost to the microgrid operator for using the distribution grid infrastructure is based on the actual operation and maintenance costs, plus a rate of return for the distribution system operator. A fixed cost structure, or "rent," for the use of the distribution infrastructure would simplify the project planning process for developers and potentially lower costs for customers.

Reducing cost and complexity of integration of distributed resources into the distribution system is a primary policy goal. Reducing barriers to owning and operating coordinated sets of resources that make up a microgrid should also be included as a policy goal, since microgrids can provide the benefits of greater reliability and resilience, as well as lowered cost of integration for intermittent, distributed renewable generation and storage. Regulators can work with utilities to make identified areas of the distribution grid available for development, and fix the costs of development (interconnection and safety upgrades), based on the characteristics of those areas. Further, regulators can work with utilities to fix the costs of operation and maintenance of the identified areas, so that those costs can be built into the rates offered to customers in those areas. Ensuring that the utility costs are recovered and are not stranding assets, as well as making the utility indifferent to the presence of microgrids, should be major policy goals as well.

VI. Emerging Role of State Regulation in Microgrid Development

State utility commissions must play a role in enabling the development of microgrids as part of the larger process of grid modernization. Grid architectures and the governing standards will define how the technical interfaces function. Regulatory requirements will follow in order to define the framework for financial transactions that occur among the various parties involved with the microgrid. However, microgrid architectures and technical standards must adhere to requirements for reliability, environmental protection, safety, security, and resilience as

[30] Alternatively, it is also conceivable that locational marginal prices for the distribution grid could be developed which would provide price signals for potential development of microgrids and associated services.

defined by state legislatures and public utility commissions. Ultimately, the interests of both society and the ratepayer must be served, in part, through the development of markets with a robust competitive framework.

Robust microgrid standards and an open architecture will allow for competition among system components vendors. In order to support interoperability of components, systems must support standard interfaces and communications. The microgrid standards should also enable developers to fashion value propositions that reduce cost and offer flexibility to the end user. Finally, the standards should allow the broadest flexibility possible to the existing utilities to incorporate microgrids into their operations while expanding the ability of the customer to access options and appropriate price points for the level and type of service received.

The role of standards cannot be understated. Standards can be used to both ensure that the technical ability of the microgrid is able to physically interconnect and operate with the utility distribution grid, as well as ensuring that all system components use the same set of interfaces.[31] With regard to the physical interconnection of components to a microgrid, ensuring open standards and access for these products and services, will enable them to be valued at an appropriate price. Standards such as these will enable service providers and customers to evaluate costs and services on an "apples-to-apples" basis.

The regulator can help with the development, adoption, and implementation of the "rules of the road" for microgrid development. These rules of the road can include the engineering specifications (*e.g.*, specific technical standards, such as IEEE 1547 or IEC 61850), the communication requirements (*i.e.*, what protocols will be used for communications between the microgrid and the distribution grid), information exchange (*i.e.*, what information needs to be exchanged between the microgrid and distribution grid), and additional monitoring, control, and telemetry requirements, which may include CAISO requirements.

A. Definition of a Microgrid Reference Architecture

As described earlier, there are several types of microgrids architectures, ranging from a single customer location to the installation of distributed generation designed to serve a wider geographical range. Understanding and describing these different architectures is necessary to identify policy and technical requirements for microgrids that address different use case applications. Microgrid reference architectures or standard microgrid configurations for serving different customer groups allow for both the smooth interconnection of resources required for new services, and also limit the potential for negative impacts on the utility distribution grid or BES. Additionally, the identification of the architectures and corresponding use cases can help

[31] In California, the Commission's Rule 21, which governs the contractual and physical interconnection between the utility and DER, is based on existing standards, such as IEEE 1547, IEC 61850, and UL 1741.

identify the benefits of various microgrid architectures, such as microgrids providing higher reliability, resilience, or value through islanding, or arbitrage.

B. Characterization of Suitability of Locations for Microgrid Development

Of equal importance are understanding the architectures and services of a microgrid and identifying the physical and geographical conditions that enhance a microgrid's impact and performance and value to customers. For example, identifying geographical locations that suffer certain rates of outages, based on SAIDI and SAIFI,[32] can help identify particular areas where a utility may want to consider investing in microgrid technology to enhance service quality.[33] Alternatively, the state regulator may want to consider incentive mechanisms to drive development of microgrids in those areas. Other attributes that may be worthwhile to consider include location relative to load pockets, areas of the transmission and distribution grid that are historically congested, areas of high penetration of renewable generation (both utility scale and distributed), and other high cost areas to serve.

Location matters! Siting microgrids in areas with a capacity glut or high reliability numbers may negatively impact the grid at that point. Determining appropriate measures to identify these attributes, and provide for an appropriate mechanism to economically price these higher value locations and services can help with siting microgrids where they can provide the most benefit. State regulators and policymakers may want to consider funding studies, or alternatively, build study processes into utility grid planning that identify areas of the distribution grid that are optimal for microgrid development.[34]

C. Establishment of Market Mechanisms to Enable Third Party Provision of Microgrid Services

As described above, microgrids can provide a number of benefits to the grid by the provision of additional services, beyond the simple production or storage of electricity. Microgrids can provide many different services to the grid including:

- any necessary voltage support for distributed generation and solar,
- consumption of excess generation by charging batteries, other storage devices, or customer products, and
- Provision of additional wholesale ancillary services, such as regulation, and so forth.

---

[32] System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) are standard measures of utility reliability.
[33] *See*, for example, SDG&E's Borrego Springs microgrid project, *supra*.
[34] As noted earlier, the development of utility distribution resources plans, as directed by Public Utilities Code Sec. 769, is directly applicable to microgrid siting.

Much like the Commission's energy storage proceeding, determining how to both appropriately value these services and provide a mechanism to collect and allocate revenues for these services will help drive the development of microgrids.[35]

D. Certification of Third Parties

In order for the Commission, utility DSO, and the CAISO, some requirements for third parties should be identified though the development of standards or contracts. The ability of a third party microgrid operator to interact and offer services directly to the utility and wholesale market does require some assumption of risk and financial responsibility from the microgrid operator. In other words, for a developer to have knowledge of an optimal site and financial resources to develop a microgrid project, does not necessarily mean they should be allowed to build, operate, and maintain the microgrid. The ability to fully address all permitting and site associated regulations and ordinances is a key capability for a developer. For example, a microgrid operator may be relying too heavily on back-up generation and require coordination with a local air quality district for available run times.[36] In another example, the microgrid operator may not be operating their microgrid in a safe, reliable, or secure manner and may negatively impact the service quality of its customers, as well as the grid at large. Requiring standards or contracts and some level of certification of microgrid operators and monitoring their practices may help assure that these new technologies will benefit the grid and customers.

E. Determination of Utility Relationship to Microgrid

Finally, state utility commissions may need to determine the ability of a utility to own and operate a microgrid. Traditionally, the Commission has frowned upon the utility from owning technology or infrastructure behind the meter; in some instances, the microgrid may be located near the customer and support utility infrastructure. The microgrid may involve integration of existing customer-owned equipment. Identifying the architectures, benefits, and services that can best be provided to the customer by the utility can help identify the appropriate bright line between utility-owned and operated and customer/third party operated microgrids. SDG&E's Borrego Springs is an example of a utility-owned and operated microgrid project. It was partly funded through the American Recovery and Reinvestment Act to help prove certain advanced technologies; in some situations, such as those evident in Borrego Springs, utility investments in microgrids to support the delivery of electricity and improve local reliability for their customers may be necessary and prudent. In these circumstances, state utility commissions will need to

---

[35] D.12-08-016 at 23 (August 8, 2012).

[36] The Commission has traditionally shied away from relying too heavily on fossil-fueled back-up generation. For example, the Demand Response Vision statement, adopted in D.03-06-032, stated that "the definition of demand response does <u>not</u> include or encourage switching to use of fossil-fueled emergency backup generation, but high-efficiency, clean distributed generation may be used to supply on-site loads."

determine the appropriate rate design and tariffs for customers of utility-owned and operated microgrids.

VII. Conclusion

Microgrids present a challenging, yet intriguing opportunity for utilities, customers, and developers and operators that upends the traditional means of providing and consuming electricity. The ability to provide electric service using this new technology in a safe and reliable manner will test all involved in its development and operation. Determining how to allow the utilities, customers, and developers to try out and use these innovative offerings is the job of the regulators; the ability of these innovations to occur safely and reliably, allowing the utility to prepare and work with developers fairly, and providing and creating appropriate and equitable policies and opportunities for rate recovery is imperative for regulators. This will not be easy, as wide-spread and successful implementations of microgrids will upset the century long view of “the electricity grid.” We should not shy away from this opportunity, but should embrace it thoroughly. In support of this, this paper had provided several key challenges, opportunities, and recommendations for regulators to consider.

1) The role of the electric utility will change. An option outlined in this paper is to consider the utility as a distribution system operator, akin an independent system operator on the transmission side.

2) There is a need to develop appropriate standards and requirements to ensure that microgrids interconnect and interact with the distribution grid in a reliable and safe manner.

3) In order to determine optimal locations for microgrid development, the Commission should undertake an effort to map the distribution grid in order to best identify these locations. This effort can be done in conjunction with the development of distribution grid planning efforts.

4) There is a national interest in successful development of microgrids; the Commission should be involved in these efforts to better understand the technical challenges with microgrids, and learn from these efforts to help support appropriate policies.

Microgrids are being investigated across the country as a solution to support greater reliability, resiliency, and security of supply, but microgrids can be much more. We need to take care not to pigeon-hole microgrids as only a set of technologies capable of keeping the lights on specific locations. Rather, microgrids can provide far more benefits, not only to the customers of the microgrid, but to the grid as a whole. Encouraging and realizing these benefits should be investigated and considered as beneficial to the state and its customers.