PROJECT RESILIENCY - OVERCOMING BARRIERS FOR REPEATABLE MICROGRIDS IN THE US

MASTER OF ENVIRONMENTAL MANAGEMENT

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Executive Summary

The recent blackouts which occurred in Texas and California, the result of extreme weather events inducing stress on the electric transmission grid, highlight the growing burden on the nation's transmission systems and necessitates a reimagining of the traditional grid structure. According to the U.S. Department of Energy's report on *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*, grid outages in the United States cost between $28 billion and $33 billion annually, a number which is increasing due to the impact of climate change on the frequency and intensity of severe weather events. Schneider Electric(SE), the corporate client for this project, believes that microgrids are a crucial component to strengthening grid resiliency, mitigating grid disturbances, allowing for faster recovery from blackout events, and accelerating the integration of distributed energy resources(DERs). This team has been tasked to analyze the barriers which hinder repeatable microgrid deployment in the United States and propose solutions in the form of a roadmap. This would facilitate widespread microgrid deployment through economies of scale and provide cost-effective energy solutions to small-scale manufacturing customers in the United States. Specifically, this project will focus on microgrids for small and medium manufacturing facilities in California and Massachusetts with less than 5 MW of peak facility load under an energy-as-a-service (EaaS) model.

The participation of microgrids in energy markets is crucial to developing a long-term business case beyond just the delivery of resilient energy solutions. This has been demonstrated effectively through energy modeling using HOMER Pro for microgrids. By keeping modelling inputs such as initial power purchase agreement(PPA) price, load served, and macroeconomic factors constant, this study demonstrates that the financial return profile is considerably stronger for simulations that have two-way energy market interactions in form of grid purchases and sellback, compared to simulations with just grid purchase of electricity. Based on these initial results, this paper identifies four key areas of focus for repeatable microgrids deployment.

First, irregularity in microgrid regulation presented the major regulatory challenge as deployment can be impeded at any legislative level: federal, state, or utility. Therefore, the creation of a consistent, nationwide regulatory environment to set basic standards for deployment and interconnection is necessary to reduce rework and additional costs. The second regulatory recommendation is the creation of a microgrid tariff regime which would compensate developers for the ancillary services microgrids provide to the main grid, such as frequency and voltage regulation, and electricity sales. Finally, the regulatory analysis proposes the establishment of a Microgrid Development Fund, wherein targeted public investment could be provided to reduce the financial risk of developing microgrids, enabling the grid to seize the resiliency and reliability benefits of microgrids. Such a public fund would operate as a revolving fund to provide financial assistance with low cost to developers, funded by carbon pricing regimes and legal settlement fees associated with regulatory non-compliance.

The second barrier addressed is the lengthy and expensive interconnection process, which can take up to 650 days to complete. To limit escalating project costs and shorten development timelines, information availability and clear communication are key. This can be achieved through creation of a centralized web portal with all applicable information which details the mandate for clear and established timelines, increase in capacity limits for the standard review process, etc. The use of a single communication platform to ensure clear and concise collaboration between utility and developer, alongside a cluster approach enables the study of multiple projects simultaneously to improve decision turnaround.

To address the environmental barriers surrounding microgrid deployment, Project Resiliency recommends partnering with architecture firms to create a blueprint for microgrid ready buildings to give SE the opportunity to reduce upfront costs for microgrid users and achieve greater repeatability through standardization of design.

Finally, risk mitigation strategies are proposed to address the financial barriers associated with technology, execution, and market risks. These risks cover challenges such as seamless integration of multiple technologies, developer and off-taker credit risk, and wholesale power price volatility. Risk mitigation can be achieved through a combination of operation strategies and prerequisites to financing agreements.

In conclusion, widespread microgrid deployment is achievable and presents SE with recommendations relating to the six, necessary components: reduction of retrofitting costs, standardization of the interconnection process, creation of a microgrid tariff and development fund, risk mitigation, energy market participation, and the mandate for a conducive regulatory environment.

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ABBREVIATIONS AND ACRONYMS

Term	***Abbreviation/Acronym***
Energy-as-a-service	EaaS
Power purchase agreement	PPA
Photovoltaic	PV
Schneider Electric	SE
Commercial and industrial	C&I
Combined heat and power	CHP
Distributed energy resource	DER
Federal Energy Regulatory Commission	FERC
Regional transmission organization	RTO
Independent system operator	ISO
Public Utility Regulatory Policies Act of 1978	PURPA
Pacific Gas & Electric	PG&E
Southern California Edison	SCE
California Public Utilities Commission	CPUC
California Solar Initiative	CSI
Self-Generation Incentive Program	SGIP
National Grid	NG
Massachusetts Department of Public Utilities	DPU
Solar Massachusetts Renewable Target	SMART
Emissions trading systems	ETS
Public Utility Commission	PUC
Renewable Portfolio Standards	RPS
National Electric Code	NEC
Investment Tax Credit	ITC
Discounted cashflow analysis	DCF

INTRODUCTION

As the electric power grid begins to adapt to renewable and distributed generation resources, the traditional utility grid struggles to meet the necessary flexibility and reliability to maintain resiliency. One proposed method of integrating more flexibility into the grid is through the implementation of microgrids. A microgrid is an electrical grid network which allows for electricity to be generated and stored on-site in a self-contained manner. Some of these smaller electricity networks can switch between operating while connected to the grid or independently in an “island” mode.[1] Microgrids respond to various stimuli from the grid, such as electricity rates or outages, and provide stability and financial benefits to facilities with installations.

Numerous factors have inhibited the growth of microgrids throughout the United States making repeatability of microgrid installations challenging. Repeatable deployment mandates standardization which enables scale for cost reduction. Most complicating factors can be categorized into the following broad areas: financial, regulatory, environmental, and technical. Capital costs for microgrids are still high despite the reduction in cost for some DER technologies, like solar photovoltaic (PV), due to improving technology and incentives/rebates.[2] The regulatory complications for microgrid implementation are a major hindrance to standardization, as they are location dependent. Although federal regulations remain the same throughout the United States, the policies of each individual state can result in divergent regulatory frameworks. Some utilities and authority holding jurisdictions have additional requirements for interconnection to ensure reliability and resiliency for their customers, further complicating the process of a microgrid. These requirements can, in certain locations, prevent microgrid owners from injecting energy into the grid, which reduces the financial benefit gained by the ability for microgrids to sell energy back to the grid during periods of excess generation. Microgrids may also be regulated as utilities if they meet certain criteria as laid out in national regulations, which can prevent microgrid installation within the service area of another utility.[2] This project seeks to explore these barriers and develop potential solutions for overcoming them to enable microgrids to be deployed swiftly and cost effectively.

The client for this project is SE, a large multinational energy and technology company with more than 137,000 employees which seeks to provide energy and automation digital solutions for efficiency and sustainability. SE would like to develop a potential roadmap for deploying microgrids across the United

States, which will incorporate onsite renewable resources, as well as ensure access to energy for their customers. SE already has developed large microgrids for facilities with significant energy demand, such as airports and university campuses through the AlphaStruxure joint venture with the Carlyle Group.[3] Thus, this project will focus on defining microgrids as exclusively island-able microgrids with less than 5 MW of peak facility load. Additionally, the target geographies under this project are California and Massachusetts, as these regions are potential target markets for microgrid deployment at the scale.

Importance of Microgrids

The US electricity grid is a very capital intensive and centralized network of generators connected by transmission and distribution infrastructure. Most of the transmission lines were built more than 50 years ago using 1950s technology.[4] Since large amounts of energy cannot be stored, the grid is designed and operated to produce electricity as it is consumed. Thus, US power markets are operated by a patchwork of grid operators that strive to match supply with demand in real time. Such an intricate network of electrical and mechanical equipment has limited resiliency, especially in the face of increasingly common extreme weather events such as hurricanes, storms, heatwaves etc. With such an asset intensive grid infrastructure, the grid operators have failed to keep up with the required network upgrades, resulting in an increasingly obsolete electricity grid. This results in grid blackouts and brownouts that costs Americans and the economy tens of billions of dollars each year and impacts public health.[5]

A study of national power outage data depicts an increase of 67% in major power outages due to weather related events over the past decade. While the frequency of these weather-related outages varies by region, the Northeast region (served by NYISO and ISO-NE) witnessed the greatest increase in outages.

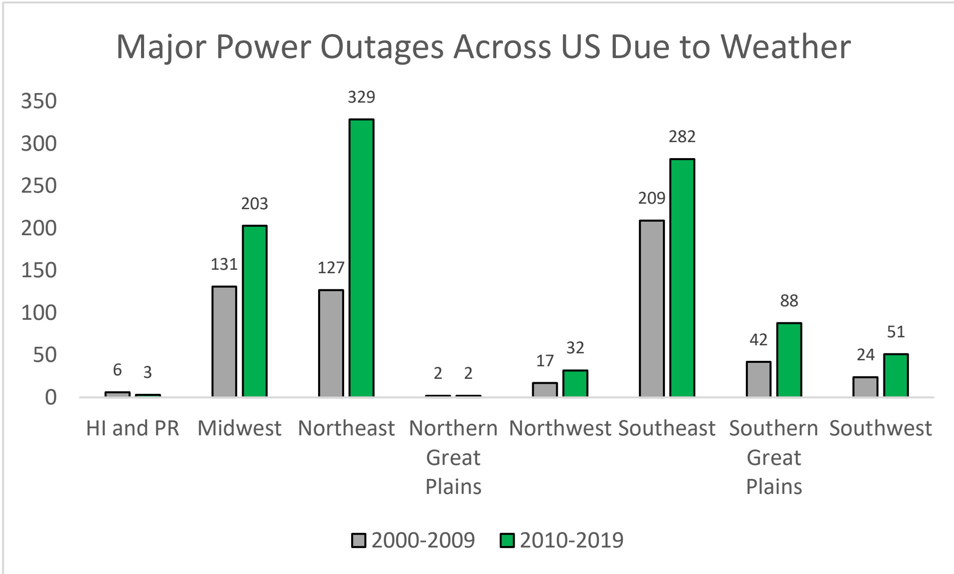

FIGURE 1 - INCREASING FREQUENCY OF WEATHER INDUCED POWER OUTAGES IN UNITED STATES

In addition, the cost of these disasters has increased overtime.[6] The graphs below show how climate induced natural disasters have risen in costs to the states of California and Massachusetts.[6]

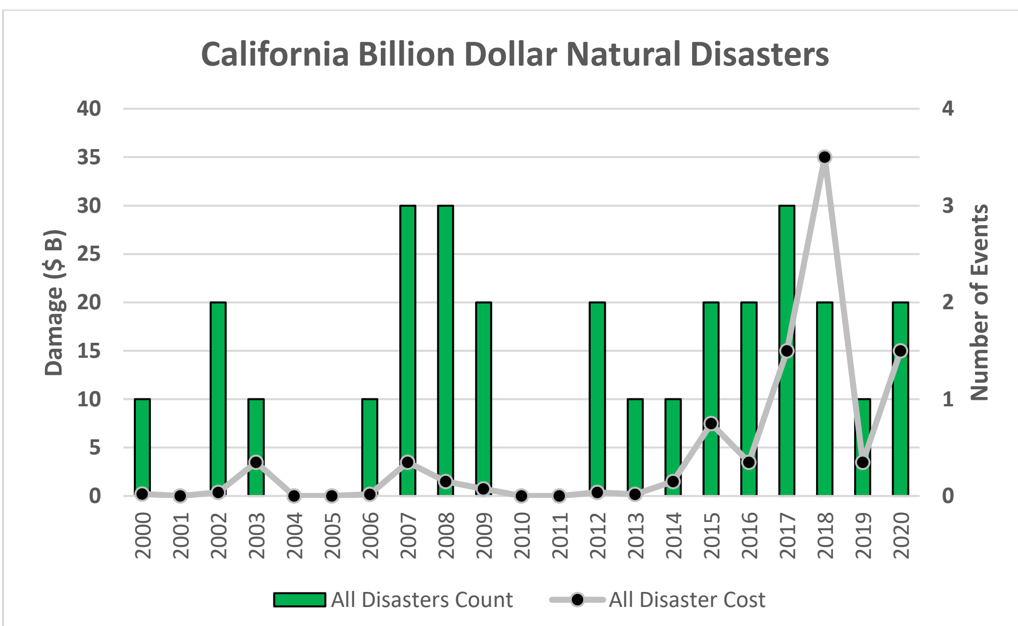

FIGURE 2 - RISING FREQUENCY OF NATURAL DISASTERS AND ASSOCIATED DAMAGES IN CALIFORNIA

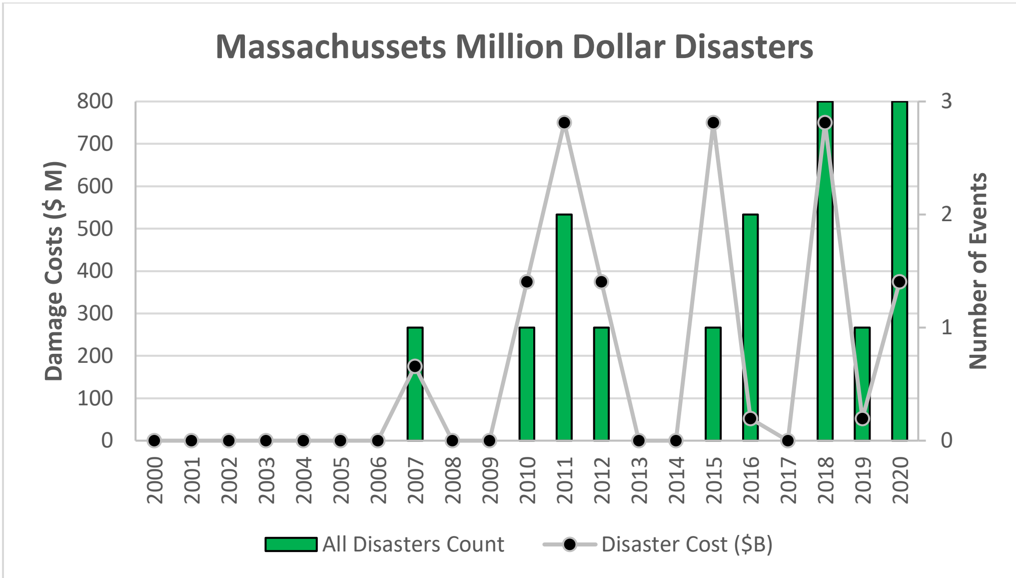

FIGURE 3 - RISING FREQUENCY OF NATURAL DISASTERS AND ASSOCIATED DAMAGES IN MASSACHUSETTS

As climate change and an outdated grid infrastructure poses threats to public health and safety, it is important to not ignore the cost of outages to businesses. According to the 2020 State of Commercial and Industrial Power Reliability Report, 50% of the respondents cited increasing reliance on reliable power supply going forward. Furthermore, at least 40% of respondents were paying a premium, or willing to pay a premium for guaranteed power supply in the face of extreme climate events.[7]

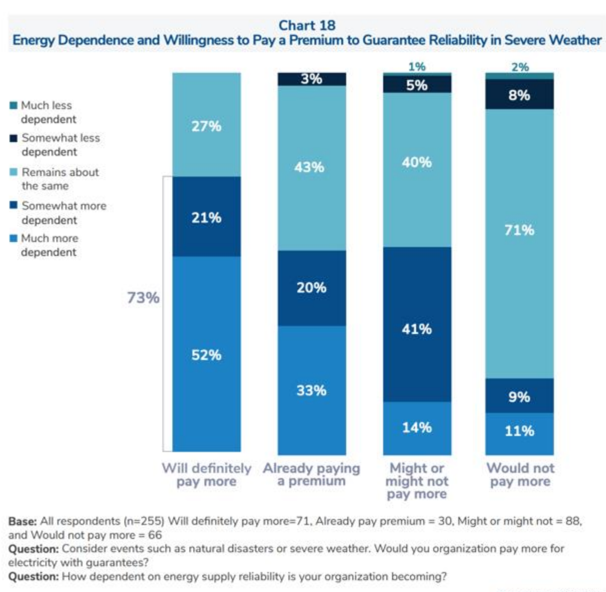

FIGURE 4 - MANUFACTURERS ARE WILLING AND ABLE TO PAY A PREMIUM FOR RELIABLE POWER IN SEVERE WEATHER.

As extreme weather events become more prevalent, utilities across the United States are faced with the dual task of incorporating renewable generation and building grid resilience for intensifying climate events. However as slow as this process may be, commercial and industrial (C&I) consumers of electricity need innovative solutions that address resiliency issues competitively and sustainably. The past decade has witnessed a steep decline in the price of solar and wind power generation, by 89% and 70% respectively.[8] Coupled with declining prices of energy storage systems, many C&I customers are increasingly turning to wind and solar with storage to replace traditional standby generators. Furthermore, the incorporation of smart-grid technologies such as sensors, machine-to-machine technologies can enhance grid stability and provide consumers with better information to manage their consumption. This supports better emergency decision-making in face of natural disasters such as snowstorms and wildfires.

In a bid to keep the lights on, microgrids have emerged as an increasingly attractive solution for many commercial and industrial customers. By combining one or more DERs such as solar PV and combined heat and power (CHP) with energy storage and sophisticated software and control systems, an industrial customer can ensure that its manufacturing facility can keep functioning by "islanding" from the grid in case of an outage. Furthermore, even in the case of a functioning grid, an advanced microgrid can create price efficiencies through peak shaving and load shifting to reduce energy bills.

Proposed Business Model: Energy-as-a-Service

A microgrid's upfront capital investment, complex operations and associated risks are a significant barrier to adoption. Inspired from the subscription-based model prevalent in the software industry, EaaS allows the manufacturer to secure microgrid benefits by contracting for it as a service and avoiding the risk of financing, owning, operating, and maintaining it altogether. Not only is the manufacturer able to free up capital for more pressing business needs but is also able to gain long-term visibility into energy costs by locking in fixed PPA rates and other terms. Furthermore, by opting for an industry leading microgrid solutions provider such as GreenStruxure, the manufacturer continues to derive value and cost savings over the life of the project.

The EaaS model is also more beneficial for the developer. While the microgrid may be designed and operated around the manufacturer as the anchor client, the developer can participate in external energy programs with the main grid. This allows it to monetize additional value streams and be able to provide the manufacturer even more competitive PPA terms.

Despite being a recent innovation within the microgrids industry, EaaS models have been very popular with energy customers. The key value proposition they offer is the flexibility in construction, operation, and services without the ordeal of managing a complex asset.

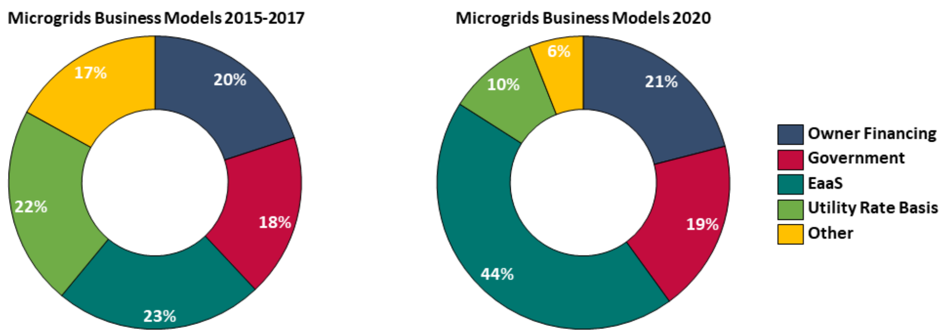

FIGURE 5 - EVOLUTION OF PREVALENT BUSINESS MODELS IN MICROGRID DEPLOYMENT (GUIDEHOUSE)

Figure 6 from Guidehouse (formerly Navigant Consulting) show that in just 3 years from 2017 to 2020, the share of new microgrids being deployed has almost doubled from 23% to 44%.[9] Another additional driver that will enable greater adoption is the ability to incorporate existing assets. Thus, if a manufacturer already has on-site generation in form of solar, energy storage or CHP, these assets can be integrated in the microgrid system. This avoids having to dispose of these generators as stranded assets. By reducing the capital investment for the developer, the asset owner can expect greater reduction in PPA costs.

Lastly, the customer can also benefit from flexible payment terms depending upon the needs. If the objective is to prioritize resiliency and performance, the customer can opt for a performance-based contract. If the user intends to use it only as a backup or secondary source of power, a traditional per kWh rate-based model might be desirable. Likewise, in the case the microgrid is used as the primary source of power, a flat rate subscription might be selected. The micro-grid energy as a service model prioritizes customers and thus can accelerate deployment across a wide variety of customer types including small and medium scale manufacturers. This in turn makes it the appropriate business model to deploy as its customer centric approach enables repeatability and standardization through turnkey solutions.

Regulatory Challenges

The largest initial barrier for microgrid deployment across the United States, is achieving regulatory compliance. For each proposed location, a regulatory analysis must be completed to ensure all applicable legislation is considered during project development. The customer profile was a 5MW medium sized manufacturing facility with the ability to island when required. Therefore, any regulations surrounding interconnection or grid-tied operation of those specific facility types were also included in the regulatory analysis. This section will begin by discussing the current state of microgrid regulation in Massachusetts and California, microgrid classification, interconnection requirements, and state incentives plus available funding for SE to consider when assessing the viability of microgrids. Recommendations to address these areas will follow.

Federal Regulations

The first step when analyzing the current state of microgrid regulation revolves around federal legislation for the project type. September 17, 2020 marked a substantial step forward in the integration of DERs on the national electric grid when the Federal Energy Regulatory Commission (FERC) approved the implementation of FERC Order No. 2222. Issued to focus on the *Participation of Distributed Energy Resource Aggregations in markets Operated by Regional Transmission Organizations and Independent System Operators*, it enables DERs to participate in the regional, organized, wholesale electricity markets through aggregation in order to work alongside traditional generating resources.[10] The minimum size DER facilities which falls under the Order No. 2222 rule are facilities which exceed 100 kW of generation capacity, which additionally limits any regional transmission organization (RTO)/independent system operator (ISO) from setting a minimum size requirement greater than 100 kW.[11] Although not yet in effect, FERC Order No. 2222 represents a concerted effort at the national level to modernize the electric grid of the future through promotion of competition in electric markets by removing the barriers preventing DERs from competing in capacity, energy, and ancillary services markets being operated by RTOs.[10] The next step of the process requires RTOs to revise tariffs and establish a market category for DERs above a certain size when aggregated to participate in the wholesale electricity market. Although the 5 MW facilities being considered for this analysis are far above the minimum participating size, regulatory support for grid integration will still apply to these facilities and allow for market participation.

Additionally, the Public Utility Regulatory Policies Act of 1978 (PURPA) established requirements for utilities obligating them to purchase the electricity output from qualifying facilities under 20 MW of installed capacity. To gain qualifying facility status, the net power production capacity of the site must be greater than 1 MW and must be applied via either self-certification or Commission certification.[12] While this regulation was implemented to enable more distributed, small generation resources, FERC rules enacted since have largely relieved these utility obligations in the majority of the country.[13] FERC rulings have been implemented to encourage the development of qualifying facilities but provide the states with greater flexibility to adapt the regulations to better fit a modern power grid infrastructure.[14] Although federal regulation does not present a challenge to widespread microgrid deployment for SE, FERC Order No. 2222 does not provide enough federal support. Therefore, SE should undertake efforts to implement the regulatory regulations discussed in this report to further the goal to create a conducive regulatory environment for widespread microgrid deployment.

State & Utility Regulations: California

Regulations

Project Resiliency will be analyzing the regulatory environment for microgrid implementation in California, specifically within Pacific Gas & Electric (PG&E) and Southern California Edison (SCE). The state of California has operated as a deregulated electricity market since 1996, including the ability for customers to purchase electricity and other services from electric service providers instead of PG&E or SCE.[15][16] When planning a microgrid installation in California, there are additional regulatory requirements to consider which are associated with energy efficiency and apply to the study facilities, rather than exclusively microgrid requirements. Although they will not be within the scope of this report, compliance with these regulations should be addressed. The California Energy Commission published the updated 2019 Building Energy Efficiency Standards for Residential and Nonresidential Buildings, which should be the primary reference in these endeavors. Within this report, exceptions are established to building code standards for facilities which incorporate solar PV energy generation, which has the potential to affect target facilities.

California is closer to widespread integration of microgrid facilities than many other regions in the United States, with the California Public Utility Commission (CPUC) formally recognizing microgrids and dictating electric utilities must have a standardized interconnection process.[17] Senate Bill No. 1339 in California was created to ensure customers are able to explore the benefits of investing in DERs, specifically through microgrids, for resiliency and usage management. For the purpose of these regulations, the bill classifies a microgrid as:

> "'Microgrid' means an interconnected system of loads and energy resources, including, but not limited to, distributed energy resources, energy storage, demand response tools, or other management, forecasting, and analytical tools, appropriately sized to meet customer needs, within a clearly defined electrical boundary that can act as a single, controllable entity, and can connect to, disconnect from, or run in parallel with, larger portions of the electrical grid, or can be managed and isolated to withstand larger disturbances and maintain electrical supply to connected critical infrastructure."[17]

Therefore, the two facility types being studied here, manufacturing facilities and commercial office buildings, will qualify under Senate Bill No. 1339. The bill requires that there be microgrid service standards in place and methods are developed to reduce the barriers of entry for microgrid deployment.[17] However, according to the Public Utilities Code of California, a microgrid installation will be unable to span any public street as it constitutes a barrier over which the owner of the property must be common and the same entity generating the electricity.[18] This represents a limiting factor for SE's implementation of the microgrid as a service business model in California, as they would not fulfill the property owner requirement and, therefore, would be unable to span any public street. Although this problem will not affect the majority of microgrid projects, especially under this project, it may impact larger manufacturing facilities which span a large area intersected by streets. This rule was designed to protect the authorized utility from competition, but functions to restrict the potential distribution of locally generated power.[19]

Similarly, the first stage of the interconnection process represents a potential area of concern for SE, as the distribution provider conducts an impact study to assess the vulnerability of the transmission section.[20] If the infrastructure is found lacking for the proposed installed capacity, SE will be responsible for covering the cost of the infrastructure upgrades necessary. As part of the information gathering stage for this project, the team spoke with James Strange, Esq., an Associate General Counsel at the Center for Sustainable Energy, regarding his work to support reduction of barriers to microgrid implementation.[21] Strange explained that the primary reason microgrid project fail, is due to this requirement of transmission system upgrades when necessary. The cost to upgrade can equal the total expense of the rest of the project making upgrades cost-prohibitive for those seeking to install microgrids.[22] The interconnection application for PG&E has the potential to take more than one year if the maximum time allotted is utilized for each step of the process. Even without the potential queued wait time, there are more than 450 business days over which this process may occur. Additionally, for the necessary detailed interconnection study on a 5 MW facility, the cost will range from approximately $14,725 – $19,825.

Despite the challenges associated with the implementation of a microgrid within PG&E, they are supportive of microgrid development through legislation and lobbying efforts. As part of compliance with CPUC regulations, PG&E looked to procure distributed generation enabled microgrid services with online dates between June 1, 2020 and September 1, 2020.[23] They have also lobbied for numerous proposals designed to reduce the number of customers affected by power outages through implementation of cost-effective microgrids.[24] Overall, developing a microgrid at a site within the PG&E jurisdiction will mandate compliance with a variety of strict regulations at the federal, state, and utility level. However, Project Resiliency still considers pursuit of microgrid development in PG&E to be the correct choice from a regulatory standpoint.

As another utility governed by the CPUC, SCE is mandated to follow the same Electric Rule 21 requirements as PG&E.[25] SCE also mandates that any facility connected to their transmission grid be compliant with their Electrical Service Requirements, regardless of facility type.[26] Although SCE has a different version of Electric Rule 21, the differences, as applicable to this project's customer profile, are largely insubstantial, aside from what is subsequently discussed.[27] The application process for interconnection with SCE includes a commissioning test where SCE ensures that the requirements for the National Electric Code (NEC) and Electric Rule 21 are being met.[25] There is also an additional expense of $800 for reviewing the application of any facility which has an installed capacity greater than 1 MW.[25] SCE is interested in increasing the resiliency of the grid through the usage of microgrids to "keep the lights on" during any type of proactive power outage instituted by the utility.[28] Taking these factors and the interest of the utility regarding microgrids into account, the pursuit of microgrid development within SCE jurisdiction to be viable from a regulatory standpoint.

Incentives and Funding

California has been associated with clean energy initiatives and solar energy generation for some time and had adopted different solar initiatives to help fund solar generation methods. One of the more successful programs was the California Solar Initiative (CSI) which commenced in 2006 as a part of a wider effort to integrate solar.[29] Due to the significant price drops in the equipment prices associated with solar energy generation, the CPUC determined that direct solar incentives were no longer necessary, and the program closed on December 31, 2016.[29] However, a subprogram of the CSI, the Thermal Program/Solar Water Heating, provides rebates to utility customers which install solar thermal systems to replace water-heating systems that are normally powered by electricity or natural gas.[30] Depending on the utilization SE develops for any installed solar generation resources, a facility would be able to achieve qualification under the CSI-Thermal program and receive a rebate.[31] On a utility scale, PG&E does not currently offer any solar generation incentives under which a 5MW microgrid facility would qualify. However, CPUC has created the Self-Generation Incentive Program (SGIP), which provides funding for qualifying businesses seeking to increase resiliency by installing an energy storage system.[32] Qualification for this program would depend on the geographical location of the facility in question, as it must be located within a Tier 2 or Tier 3 fire risk area or have already had power shut down during at least two Public Safety Power Shutoffs.[32]

State & Utility Regulations: Massachusetts

Regulations

The second region which will be analyzed is the state of Massachusetts, specifically within National Grid (NG) and Eversource. The current regulatory environment surrounding microgrids and DERs is far less developed in Massachusetts than California. Like California, Massachusetts has been a deregulated energy market for many years, tracing all the way back to legislation passed in 1997.[33][34] Massachusetts designed the framework to allow competitive producers to supply the electrical power to customers who have chosen that specific power producer. As with California, there are non-microgrid related regulations with which any facility connected to the electric power grid must comply. Every non-temporary building must abide by the regulations established in the Ninth Edition of the MA State Building Code, which is adapted from the International Code Council’s building requirements including the following: International Building Code, International Residential Code, International Existing Building Code, International Mechanical Code, International Energy Conservation Code, and portions of the International

Fire Code.[35] However, the largest area of regulatory concern in Massachusetts is established at a statewide scale, rather than by either selected utility.

According to the net metering regulations for the state of Massachusetts, no facility which uses wind, solar, or anaerobic digestion technology may be larger than 2 MW of installed capacity for a private facility.[36] As installations of more than 2 MW are less common for non-microgrid DERs, Massachusetts has not created regulations enabling the integration of these larger resources. Despite having the net metering regulations, Massachusetts does not have any regulations regarding the deployment of microgrids as a part of their electric utility grid. They recognize microgrids and their potential as a part of building a modern, stable electric power grid.[37] However, they have not yet implemented any regulations, as they will be included as a portion of the Department of Public Utilities (DPU) Grid Modernization Plan.[37] Situationally, in Massachusetts, larger generators may establish power purchase agreements with the applicable utility or interconnect with the transmission level of the power grid.[38] The latter is a much more time intensive process and should only be considered by larger generators, as it may constitute substantial outside review.[38]

NG specifically outlines a timeline for the interconnection of smaller facilities into the power grid under their jurisdiction. In the NG Interconnection Tariff, the total maximum days for completion of the standard process for complex projects is greater than 200 business days.[39] Despite not having existing regulations regarding microgrids, NG has demonstrated its interest in incorporating the burgeoning technology into achieving compliance with the DPU Grid Modernization Plan.[40] In contrast, Eversource transferred more than $400 million in grid improvements into their rate cause sector, making their grid modernization plan focused more on the time variance of electricity rates and cybersecurity, with a small focus on research and development.[40] Eversource looks to be relying on additions and substitutions to their existing grid structure, rather than innovating and modernizing the grid to accommodate new technologies.[40] However, Eversource is seeking to implement microgrids in New Hampshire, in a rather innovative way, in which the utility would own the microgrid coupled with energy storage to increase the resiliency of the surrounding grid.[41] This microgrid would be powered by a 7.1 MWH battery on the utility side of the meter, as they are the owner of the energy storage system.[41] Despite both utilities targeted by Project Resiliency within Massachusetts demonstrating interest in the utilization of microgrids to solve a variety of issues facing the grid, it cannot be recommended that SE pursue microgrid development within Massachusetts at this time. The statewide regulations and lack of widespread, proposed regulatory support from utilities would make the development of 5 MW microgrid installations challenging under the current and near future landscapes.

Incentives and Funding

Massachusetts has implemented incentive and funding programs which are potentially applicable to the facilities included in the customer profile analyzed. The Solar Massachusetts Renewable Target (SMART) is designed to create a sustainable solar incentive program to promote solar development in Massachusetts in the long-term.[42] The SMART program sets the maximum capacity of Solar Tariff Generation Units on a single parcel of land at 5 MW, which includes units that generate electricity using solar PV technology.[43] The SMART program establishes a variety of incentive levels which could be pursued by SE, depending on the microgrid configuration selected for each project. The other primary solar funding opportunity found in Massachusetts is the Municipal Light Plant Solar Rebate program, created by the Department of Energy Resources. However, the MLP Solar Rebate program would be inaccessible to SE on this project's facilities, as the maximum installation size to participate in the program is 25 kW DC generation.[44] All other solar incentive programs found in the state of Massachusetts are applicable primarily to residential homeowners and, thus, the facilities considered in this study do not qualify.

Regulatory Recommendations

This project is designed to evaluate the barriers for widespread deployment of microgrids with less than 5 MW of installed capacity and propose solutions for navigating around these barriers. As such, the first and primary recommendation is to lobby members of the Massachusetts state government and DPU to institute legislation allowing for interconnection of DERs and microgrids with up to 5 MW of installed capacity. Without such a regulation in place, the proposed sizing for Project Resiliency will be unable to deploy within the state of Massachusetts, regardless of which utility (NG or Eversource) territory the project is developed within. Aside from this recommendation allowing Project Resiliency's target microgrid facilities to be deployed in Massachusetts, the primary barrier we see to microgrid implementation in both Massachusetts and California is the cost of upgrading the transmission system being the responsibility of the microgrid developer. Alongside other financial challenges associated with microgrid development, which are discussed in the forthcoming Financial Risks section, the Project Resiliency team proposes a regulatory solution to address these issues. However, before the potential solution is discussed, the concept of carbon pricing and the effect it will have on this proposed solution must be introduced.

Carbon pricing has gained momentum in recent years to encourage cleaner energy sources by putting a price on the carbon emissions of traditional, fossil-fuel burning power plants. Increasing the price of traditional generation will incentivize corporations to seek cleaner methods of generation and clean up the generation assets they already utilize. Generally, there are two methods of introducing a carbon pricing system: emissions trading systems (ETS) and carbon taxes.[45] ETS, also known as cap-and-trade systems, work as traded emissions allowances where corporations are able to sell emissions allowances if they do not utilize all their allowed emissions. Carbon taxes work in a more direct way, putting a direct price on the amount of carbon emissions associated with the generation method used. This is usually accomplished through imposing a tax rate on the carbon content of the fossil fuel used in generation.[45] There is substantial momentum building from a regulatory side towards instituting carbon pricing. President Joe Biden has stated he will institute "an enforcement mechanism to achieve net-zero emissions no later than 2050".[46] With the aforementioned growth in momentum and Biden's "enforcement mechanism" promise, it is not unreasonable to predict the United States will see some method of carbon pricing in the near future. Under the scenario where a carbon tax is instituted in the United States, a unique opportunity for microgrids presents itself.

There are already examples of the government utilizing funds generated by regulatory penalties for clean and sustainable energy development, such as the Petroleum Violation Escrow Account, which serve as an inspiration for the proposed solution.[47] Under the scenario where a carbon tax is implemented in the United States, there are two sources through which funding could be acquired to assist with the development of microgrids. First, a direct percentage of the financial return garnered by the carbon tax being moved into a fund specifically designed to assist in microgrid financing through reduced out-of-pocket developer costs. Second, any penalties incurred as a result of non-compliance with the carbon tax regulations could also be moved into the same fund to add another financing source for this microgrid development fund. A development fund created using the returns of carbon tax legislation at either the state or federal level would provide market access for small or new microgrid developers which may lack funding to participate currently.

There are already funds available to microgrids through Green Banks, competitive microgrid grants, and incentives at the state and federal level assisting in the deployment of DERs. However, these funds are particularly lacking at the early stages of microgrid development where initial site evaluation costs are incurred.[48] These initial costs are sunk costs for the microgrid developer, for which they will not receive reimbursement regardless of project continuation status. However, with targeted investment and incentives available to the developer, the financial risk of undertaking these sunk costs would be significantly reduced. Instituting a carbon tax funded microgrid development fund to assist with the early stage, sunk costs associated with microgrid development and developer market entry have great potential to assist in the widespread development of microgrids. Additionally, these funds could be utilized to offset the grid improvement costs often incurred through the utility, further reducing potential financial concerns for microgrid developers. Utility access to these funds would be granted to utilities with proven and approved microgrid projects seeking the funding to offset the costs of upgrading their transmission system to enable microgrid interconnection. This would prevent the necessity for a waiting period as funds were transferred from the fund to the developer and then to the utility to offset these upgrade expenses. Even if the fund only covered a portion of the improvement costs, the barrier represented by these costs substantially easier for SE to navigate during their microgrid deployment process.

The other recommendation proposed compounds with the creation of this development fund through the implementation of a microgrid specific tariff similar to the proposed tariff developing in Hawaii. Hawaii is in the legislative process of creating a specific tariff for microgrid owners which would pay for a variety of services provided by microgrids, such as capacity, demand response, and a source of distributed and renewable energy generation.[49][50] The creation of such a tariff combined with the development fund would greatly reduce the financial risk and provide regulatory backing for the development of new microgrid resources if implemented at either the state or federal level.

The two primary regulatory recommendations proposed would provide a societal benefit as well if implemented by SE through the microgrid deployment at the factory target facility in this study. More than four percent of all individuals working in production occupations within the United States are classified as below the poverty line, which amounts to more than 390,000 people nationwide as of 2016.[51] The financial insecurity associated with work in production facilities, such as this project’s target factory facility, disproportionately impacts members of minority communities.[51] The increased reliability and resiliency provided to these production facilities through SE’s microgrid installation would ensure these facilities stayed operational and continued to provide the necessary income for these impoverished individuals. Individuals living below the poverty line are highly dependent on reliable income, as they lack the financial security to provide for themselves or their families with accumulated resources. Ensuring these facilities remained operational through the implementation of a microgrid would not only provide financial benefit to the facility operator but would also provide a societal benefit to those individuals working within SE’s microgrid powered facilities.

TECHNICAL CHALLENGES

A grid-tied island able microgrid provides the dual benefit of working in conjunction with the grid alongside isolating and operating independently in case of a power outage. It also offers the option of net energy metering and thus the two-way transmission of electricity between microgrid and the main grid is like that of other DERs.[52] This requires an interconnection between the microgrid and the macrogrid. The interconnection can enhance the reliability of the grid and provide monetary compensation to the project developers. The microgrid consists of on-site generation, particularly a renewable energy resource such as solar PV, energy storage and local load. For a grid-tied island able microgrid, unless new regulation is approved, the interconnection process is like that of any DER. While this poses limitations to fully utilizing the benefits of microgrids, such as frequency regulation and demand response by islanding, it is the best practice available.

State-level Public Utility Commissions (PUCs) establish interconnection standards that developers and utilities must adhere to. Thus, the standards and regulations vary by state and the procedures vary by utility. For this report, current regulations in place by the California Public Utilities Commission (CPUC) and the Department of Public Utilities of Massachusetts (DPU) are studied and best practices from across the United States are recommended. Similarly, current procedures from PG&E, SCE, NG and Eversource will be analyzed and best practices from utilities across the United States will be recommended.

Clear and transparent interconnection requirements make the process more efficient for both the developer and the utility while maintaining the safety, reliability, and the power quality of the electric power system. There are two distinct pieces to streamlining this process – utility partnership and additional steps to the interconnection itself.

INTERCONNECTION APPLICATION

There has been an enormous increase in the demand for renewable energy due to a combination of state and federal policies, the growing voluntary green power purchase markets, and the improving economics of renewable energy development. As of today, thirty states, Washington DC, and three territories have adopted Renewable Portfolio Standards (RPS) while seven states and one territory have set renewable energy goals.[53] It is estimated that an additional 100,000 MW of renewable generating capacity will need to be added to the grid to satisfy these requirements by 2035.[54] Each project that adds more renewable capacity to the grid goes through the interconnection process. Standardizing this process will result in streamlined efforts which are less time consuming for both the utilities and the developers.

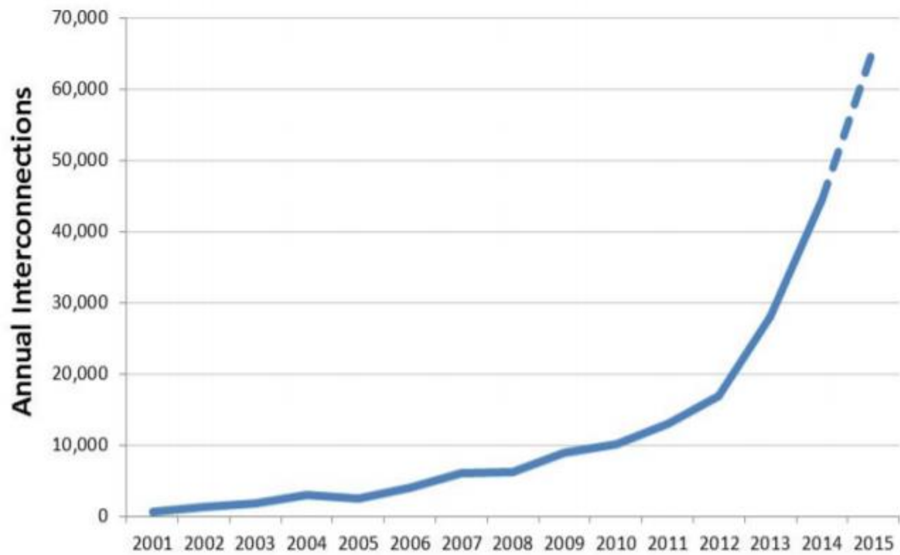

FIGURE 6 - INCREASE IN PG&E INTERCONNECTION REQUESTS ANNUALLY

The interconnection process can be a major cost for any DER project. Streamlining the process can lead to reduction in many soft costs for the developer, while accelerating the interconnection timeline. Based on the size and location of the project, the project needs to go through a maximum of three detailed studies: the feasibility study, the system impact study, and the facilities study. Each of these studies add an additional financial cost on the microgrid developer in addition to the significant waiting time involved in being part of an interconnection queue. Standardizing and making this process transparent can help developers plan their project finances and timelines with greater certainty.

As the number of interconnections increase, there is greater pressure on utilities to restructure and improve their interconnection processes. The Energy Policy Act of 2005 requires state regulatory commissions and certain non-regulated utilities to consider adopting interconnection procedures based on the IEEE 1547 Standard and current best practices. This had a major impact on raising awareness about the need for interconnection standards. 42 states currently have interconnections standards in place but with more than 190 investor-owned utilities, 2000 publicly owned utilities and 870 cooperatives in the United States, microgrid developers face widely varying interconnection fees and requirements.[55] The next section focuses on understanding what the best policies and recommendations are on how to standardize these requirements. Figure 7 shows the number of days it takes for application approval in several states across the United States. [56]

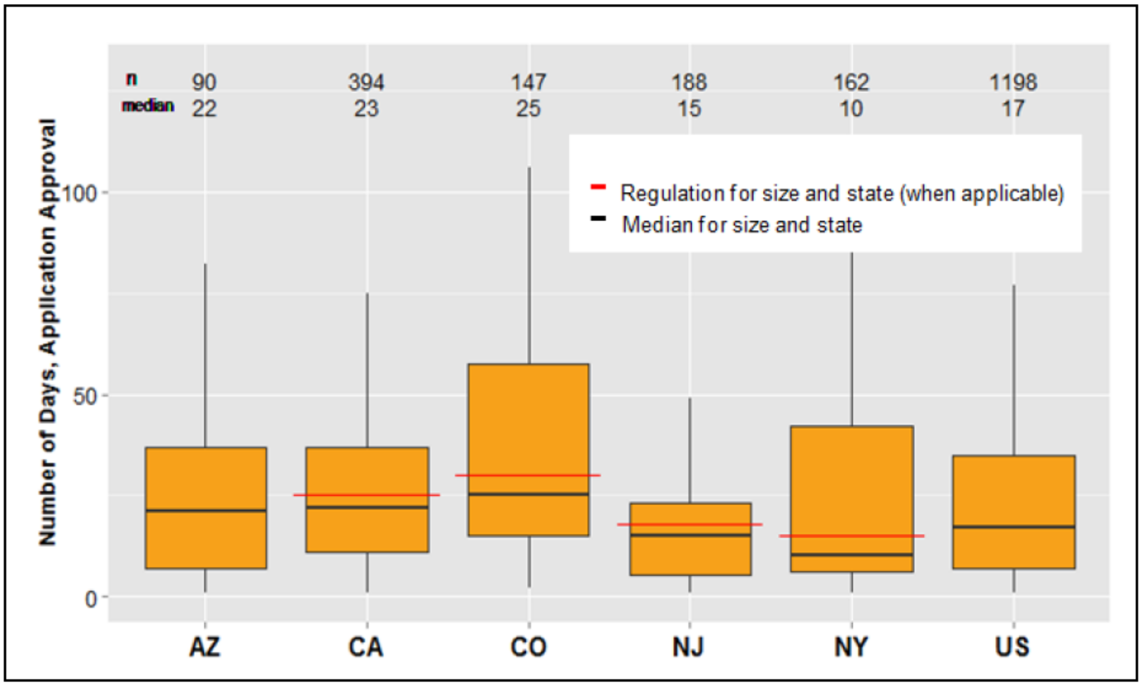

FIGURE 7 - APPLICATION REVIEW AND APPROVAL DAYS FOR FIVE STATES AND FULL US SAMPLE (10 TO 50 KW)

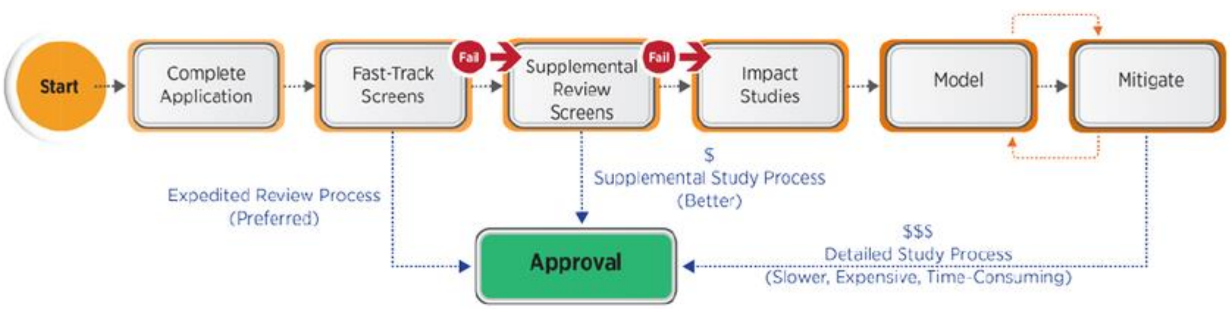

FIGURE 8 - COMPLETE SGIP INTERCONNECTION PROCESS

The Small Generator Interconnection Process (SGIP) process is divided into three levels of review:

Level 1 – A “Simplified Screening Process” for certified inverter-based systems less than 10kW

Level 2 – “Fast Track Process” for eligible generators no larger than 2MW

Level 3 – “Study Process” for all other systems 20 MW or less.

For the first two levels, the project goes through 10 technical screens. The entire process is outlined in Figure 9 with a comparison of the time and cost involved in each process. Along with the 10 technical screens, the utilities that follow the FERC SGIP standards also need to specify a timeline for the process and the cost of each study. Customers are also required to obtain liability insurance sufficient to insure the generation facility, the interconnection equipment, and the characteristics of the system to which the interconnection is being made.

In general, the trend with changes to the SGIP can be characterized as refining the time that each review stage for the FGIP can take and the addition of more generation sources to the applicable DER list. This is a step in the right direction and microgrids for small and medium sized industries can easily be incorporated into this standard. In order 792 and 792-A confirmed in 2013 and 2014 the following new rules were added to the SGIP standard:

- Allowing customers to access a pre-application report.
- Revising the timelines for the fast-track report and a subsequent supplemental study if the fast-track determination is negative.
- New technical standards for the supplemental screens.
- Allowing energy storage to qualify for interconnection under SGIP.

Utility Partnerships

Utility partnerships are a key component to reducing some of the complications that arise with interconnection applications. As state and municipal governments move towards more ambitious goals for GHG emissions, utilities have certain mandates that they are required to meet. One such mandate is a Renewable Portfolio Standard that required a certain percentage of generation for the state to come from renewable standards. Similarly, as severe weather events become more common, the trend of utilities needing to meet reliability requirements are also increasing. Microgrids can help utilities meet these goals and so, creates the perfect opportunity for Schneider Electric to partner with utilities.

One way these partnerships can work out is something that is becoming more common with utility scale solar projects, is that the Renewable Energy Credits (RECs) from a project can be used by the utility to meet any state mandates that they have to comply with. This creates a win-win scenario where Schneider Electric is able to lobby for greater streamlining of the interconnection process, or even asking for reviewing interconnection processes quicker for projects that the utility can use to meet renewable mandates through Renewable Energy Credits (RECs)

Additionally, microgrids can help with other ancillary services, such as frequency regulation and demand response, sometimes better than other distributed energy resources because of its unique ability to island from the grid when needed. In areas of the grid where there is particular concern about reliability, microgrids can offer peak load shedding and modulation of frequency. Creating a partnership with the utility to help during outages can also allow the utility to fast-track interconnection processes for these projects.

STREAMLINING THE PROCESS

The responsibility of implementing interconnection standards falls on the utility that owns the grid. Hence, there are great variations in how a developer can apply for an interconnection request. Having an unclear workflow is one of the biggest constraints and can be an issue for both the utility and the project developer. PG&E with the help of NREL recently revamped its interconnection workflow to streamlines processes and decrease soft costs.[57] Figure 9 shows the time it takes to complete different stages of the interconnection process, and it is clear from the figure that the application stage takes the most amount of time. This section takes a page from their book and discusses best practices that utilities can adopt to ensure that the interconnection timeline is shortened.

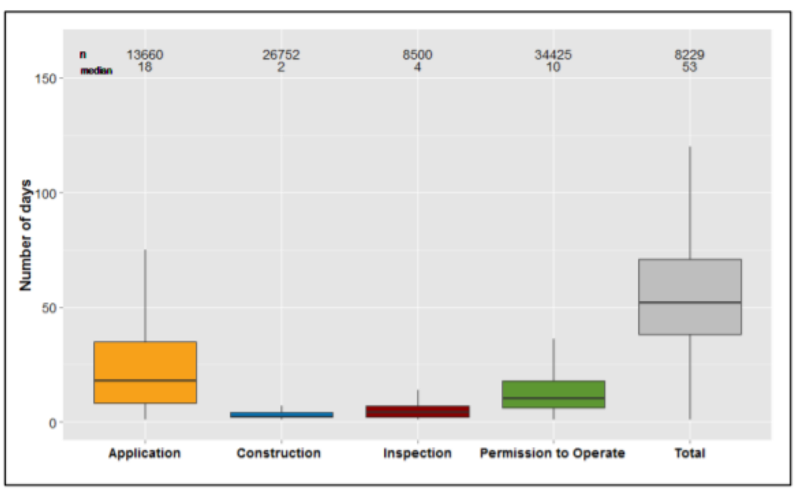

FIGURE 9 - AVERAGE TIME FOR EACH STEP OF THE INTERCONNECTION PROCESS

i) Central Webpage:

One of the key issues raised by many developers is the lack of clarity regarding the process outline for interconnection. A central webpage on the utility website with all required information and links can be a good resource for developers to understand requirements, time frames and costs for the interconnection requirements.

ii) Single platform for application

PG&E uses a utility-wide, single platform to manage and track interconnection application status and progress. The platform brings together all the different departments working on interconnections on one page and allows clarity into where each application is in the process. Developers can also use this platform to get access to data that might otherwise need to be separately requested, which makes it easier for them to take key decisions regarding the project.

iii) Online application

While the single entity-wide platform might be a longer stretch and require greater coordination, a good starting point is online application forms. This method allows the developer to have a clear understanding of what information the utility needs and save time by automatically emailing or uploading the form for the utility.

iv) Electronic Signatures and Online Payment Methods

The back and forth that results from needing physical signatures and checks for payments can unnecessarily increase application approval time and make it difficult for both the utility and the developer to track progress. Which the introduction of electronic signature platforms and online paying methods, both tracking and time management becomes easier.

v) Automatic Email Replies and Online Communication Platform

In addition to online payment and signature platforms, there are several reasons why the developer and utility would need to go back and forth in exchange of information. PG&E's online platform connects each email to a centralized platform where the utility and developer both can keep track of all the emails exchanged for each application and have a centralized communication platform.

vi) Online System to Track and Manage Applications

Many regulations now require PUCs to keep the interconnection queue online and publicly available so developers can keep track of how far in the process their application is. Most of the PUCs across the US, particularly the two reviewed for this report in CA and MA, have online queues for interconnection requests that are publicly available.

vii) Pre-application reports

This step really helps manage the interconnection requests by reducing the number of incomplete applications or projects that are not technically feasible to not become a part of the interconnection queue. The pre-application report can be requested from the utility, usually with an upfront cost. According to California Rule 21, once the pre-application report has been requested, the utility has 10 days to provide the report. The report includes information such as the total queue and available capacity at the location, the line voltage, distance of proposed point of interconnection to the substation, peak and minimum load data, and number of phases available at site and lastly, maps of the distribution system to identify areas where capacity is available.

viii) Hosting-Capacity Maps Publicly Available

Many regulations are also requesting utilities provide an online, publicly available hosting capacity map that shows the capacity available for interconnection at each distribution line. This information is usually the first consideration for developers when deciding the size and location of the project. It is also the first screen of any interconnection review process so the information could help ensure only the most viable project options are put forward to the utility, reducing the total screening time and reducing soft costs for the microgrid project.

Summary Table

TABLE 1 - SUMMARY OF RECOMMENDATIONS

	Recommendation	PG&E	SCE	NG	Eversource
Application	Central Webpage	Yes (https://www.pge.com/en_US/large-business/services/alternatives-to-pge/electric-generation-interconnection.page)	Yes, but difficult to navigate (https://www.sce.com/business/generating-your-own-power/Grid-Interconnections)	In place but outdated (https://www9.nationalgridus.com/narragansett/business/energyeff/4_interconnection-process.asp)	Yes - (https://www.eversource.com/content/ema-c/about/about-us/doing-business-with-us/builders-contractors/interconnections/massachusetts/application-to-interconnect)
	Online System to Track and Manage Applications	Yes - Customer Connection Online	No	No	
	Electronic Signature on Application	Yes, through online platform	Yes, with the option of attaching a digital copy of the bill for smaller interconnections	-	-
	Automatic Email Reply when Application received	Yes	Yes	-	-
	Pre-application Reports	Yes	No	Optional for systems 5MW or less, required for greater systems.	
	Hosting-Capacity Maps	Available	-	-	Available
	Information about Queues Publicly Available	Yes	Yes	Yes	Yes
	Online Application Forms	Yes		Yes	
	Cluster Approach	Yes	Yes		
Review	Application Timeframe in Place	Yes - Depending on generation size	Yes - Depending on generation size	Yes - 10 business days	Yes - 10 business days
	Simplified Track	10kW or less	10kW or less	-	-
	Fast Track Eligibility Limit	- 2MW on a 12kV line - 3MW on a 21 kV line - 5MW on higher voltage line	2MW	2MW	2MW
	Construction Upgrade Requirements	Fast Track connections can proceed without a full study. Distribution or Network Upgrades require a full study.	Fast Track connections can proceed without a full study. Distribution or Network Upgrades require a full study.	No Fast-Track option for construction upgrades	No Fast-Track option for construction upgrades

	Recommendation	PG&E	SCE	NG	Eversource
Standards Followed	Size-based tracks	Yes	Yes	Yes	-
	Technical Standards	IEEE 1547	IEEE 1547	IEEE 1547	IEEE 1547
	Inverter Standards	UL 1741	UL 1741	UL 1741	UL 1741
	Application Standards	Rule 21	Rule 21	FERC SGIP	-

Risks Assessment

In addition to resiliency, microgrids have numerous other benefits. They add to additional renewable energy capacity on the grid, enabling organizations to meet sustainability and carbon reduction objectives more quickly. Moreover, by opting for microgrids EaaS, manufacturers can lock-in long term stable energy prices. This has the added advantage as lower priced and uninterrupted energy enables manufacturers to remain competitive over the long run.

However, microgrid projects would not be without their risks. Identifying the scope and probability of investment risk is important to get investors onboard. For a thorough project road map, it is essential to develop a detailed risk analysis.

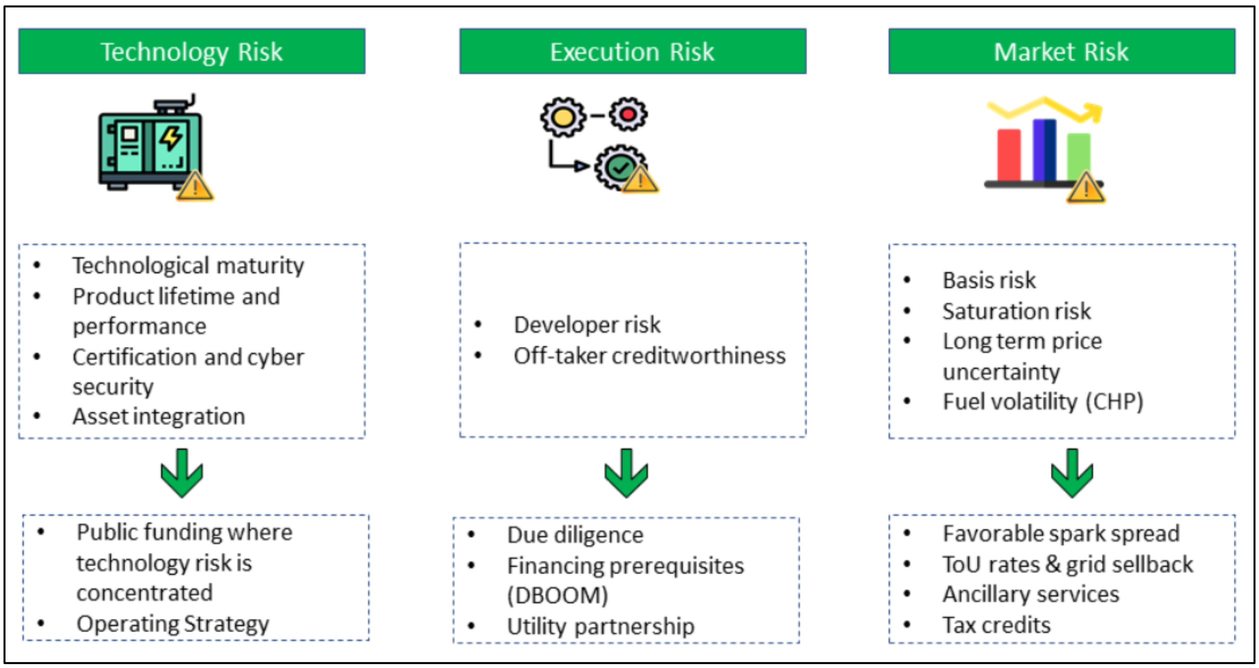

FIGURE 10 - FINANCIAL RISK ASSESSMENT

Technology Risk

Financial institutions are typically attracted by low-risk ventures, or ventures with well understood risks and higher returns. Some of the key technological risks that are associated with a third party microgrid include the following:

i) **Technology Maturity:**

Incorporating proven technologies is paramount to mitigating risk. For instance, solar PV, lithium-ion battery storage, and CHP are technologies with demonstrated success as compared to more recent technologies such as concentrated solar power.

ii) **Product Lifetime, Performance Degradation, and Implications on Revenue:**

To be able to estimate financial returns, a project developer needs to be able to forecast generation and thus revenues into the future through the project lifetime. Therefore, technologies in use must have defined lifetimes that come with warranty coverage and have been tested before installation. Performance degradation over equipment life is another major factor. The ability to quantify incremental loss in the power generation capacity of an asset is crucial to forecast revenues and estimate depreciation.

iii) **Product Certification and Cyber Security:**

Not only is product standardization key to mitigating risk, but it is also important to improve the repeatability of packaged microgrids solutions. For instance, a microgrid solution that includes UL-1703 certified solar panels and a CHP plant that meets the NFPA 70 NEC standards demonstrates that component technologies are meticulously designed, rigorously tested, and meet relevant industry and safety standards. Similarly, a microgrid also requires advanced controls that not only function seamlessly with the utility grid, but also protect generation assets and customer facilities against potential cyber threat. SE's EcoStruxure™ Microgrid Advisor is one such Energy Management System that has cybersecurity features that enable compliance with standards such as IEEE 1686.

iv) **Asset Integration:**

Unlike a large, centralized powerplant, a microgrid provides local energy supply to meet localized energy needs. This often entails the integration of multiple technologies such as multiple generation types, distribution automation switches, controllers, and advanced software. While these technologies may all be proven within a traditional performance context, operating in a microgrid requires collective operations. This means that the entire microgrid system bears the technology risk if even one component cannot operate in tandem.

Risk Mitigation

The use of proven technologies can alleviate investor concerns and result in better financing terms for a microgrid project. As microgrids are a combination of various technologies, it will take time for them to gain market and investors' trust. By appropriate structuring of financial agreements and operational strategy, much of the risk associated with multiple technologies can be addressed.[58]

i) **Financial Agreement:**

Funding can be secured on component basis. Commercial banks can finance microgrids based on individual generation assets, such as the CHP Plant or batteries for energy storage. However, grants and public funding can be used to finance the components of the microgrid where the "technology risk" is concentrated- such as the distribution switches, advanced controls, and energy management systems. Alternately, these could be used to troubleshoot technical issues that may arise during early operations.

ii) **Operation Strategy:**

In the proposed microgrid solution package, CHP has been incorporated as it is a reliable and proven technology that has a constant generation profile. However, if it must modulate its output constantly to meet load alongside intermittent PV generation, the equipment lifetime will be reduced drastically and affect power quality as well. To mitigate such technology risks, it would be ideal to allow CHP to provide baseload generation, with the macrogrid balancing the load profile alongside PV generation. In the absence of the macrogrid, the microgrid can operate in the islanding mode, energy storage can serve as an intermediate resource to balance the load profile alongside solar PV, thus ensuring CHP continues to operate without any technological risk.

EXECUTION RISK

Forecasting returns is important for a financier. However, even more important is that the project delivers the promised returns. The risks associated with project execution can be further divided into:

i) **Developer Risk:**

A microgrid developer's track record on project execution shows the execution capabilities they bring to the table. The risk is higher if the developer is not experienced in seamlessly navigating the regulatory landscape or the many project development stages. Additional considerations include the inherent financial strength of the developer, which can be gauged by the balance sheet or market capitalization in case of a public company.

ii) **Off-taker credit worthiness**:

A key concern is whether the customer can make timely payments for the energy procured through the microgrid EaaS model. As part of due diligence, the developer should study the off-taker's history of utility payments for electricity and/or fuel supply in the case of on-site power generation.

Risk Mitigation

Through due diligence on the developer and customer, the risk profile of the parties can be reduced significantly. Certain instruments can be built into financing agreements to secure investments from financial institutions from unforeseen circumstances that may impact project execution.

i) **Financial Agreement:**

A funding prerequisite to provide operations and maintenance support can convince financiers that the developer will be a reliable partner throughout project lifetime, which can span up to 20 years. A design-build-own-operate-model (DBOOM) on the developer's end can translate to an EaaS model for a customer, while mitigating execution risks for the financier.

Another funding pre-requisite can be asking the developer to post a letter of credit to cover its part of execution risk such as not building the microgrid on agreed schedule or the failure to achieve performance standards. Likewise, to ensure credit worthiness on their end, the financier can request business credit reports and trade references that reflect the financial health of the off taker.

ii) **Business Strategy:**

A major value proposition of microgrids is the ability to interact with and provide services to the centralized grid. The repeatability of microgrids going to be impacted by the ease of interconnection. A rapid and streamlined interconnection process would not only speed up deployment, but also reduce challenges to the monetization of additional value streams such as the ability to bid into capacity markets, demand response programs, and ancillary service markets. Bringing the local utility on as a project partner can address many of the associated challenges and unlock greater project value. This will further improve investor confidence in the project.

MARKET RISKS

To maintain competitiveness, a manufacturer will look carefully at both the energy prices it is paying and those being paid by other manufacturers opting for cogeneration and/or grid off-take. Thus, the market risk is encapsulated by uncertainty of wholesale electricity settlement price. The customer may enjoy energy cost savings when the market electricity prices rise, such as in the case of extreme weather events. However, there remains the risk that for certain time-periods the prices may fall below contracted PPA prices for electricity produced via microgrid. If this risk materializes for extended periods of time, it may render a PPA financially infeasible. This would put the manufacturer at a competitive disadvantage.

While it is impossible to know exactly what electricity prices will look like in the future, it is generally assumed that prices rise due to inflationary pressures.[59] With increasing frequency and severity of adverse climate events, such as the 2020 wildfires in California and the more recent snowstorms in Texas, foreseen prices through EaaS model hedges against extreme price volatility. However, electricity prices may also decrease due to technological advancements, grid modernization, or regulatory changes.

Furthermore, market risk includes saturation risk – which is pronounced in markets with high renewable penetration. With zero marginal price of solar and wind energy, an overabundance of these resources can lower market prices.[58]

For the microgrid solution in consideration, the integration of CHP assets poses a different kind of market risk. Fuel price volatility must be accounted for given that CHP accounts a significant portion of onsite generation. Fuel delivery infrastructure can be impacted by weather events that impact the macrogrid.

For instance, the rolling blackouts in Texas in February also saw severe shortages of natural gas due to shutdown gas processing facilities.

Thus, PPA performance and customer savings are impacted by market price variability which in turn depends on a host of factors including technology, regulation, and renewables penetration.

<u>Risk Mitigation</u>

In the face of these risks, smart investors would require the microgrid operator to mitigate these by diversifying revenue streams. For a microgrid project to be "bankable", it should be connected to the grid to be able to provide services that it may monetize. To do so, the developer needs to study potential markets and identify the presence of certain attributes that may mitigate risks.

i) Favorable Spark Spread:

A spark spread is the difference between the price of electricity purchased and electricity produced. Thus, it is useful for measuring the gross profitability of generators. Markets with high electricity prices, low natural gas prices, and abundant renewable resources result in favorable spark spread for microgrids. Figure 11a depicts the ratio of electricity prices to natural gas prices in California from 2009 -2017 while 11b shows the spark spread across the same period. Generally, a ratio of 2.5 results in a favorable spark spread.[60] For optimal spark spread, location selected should ideally have high locational marginal pricing and distribution level gas connection (to avoid higher retail price of gas)

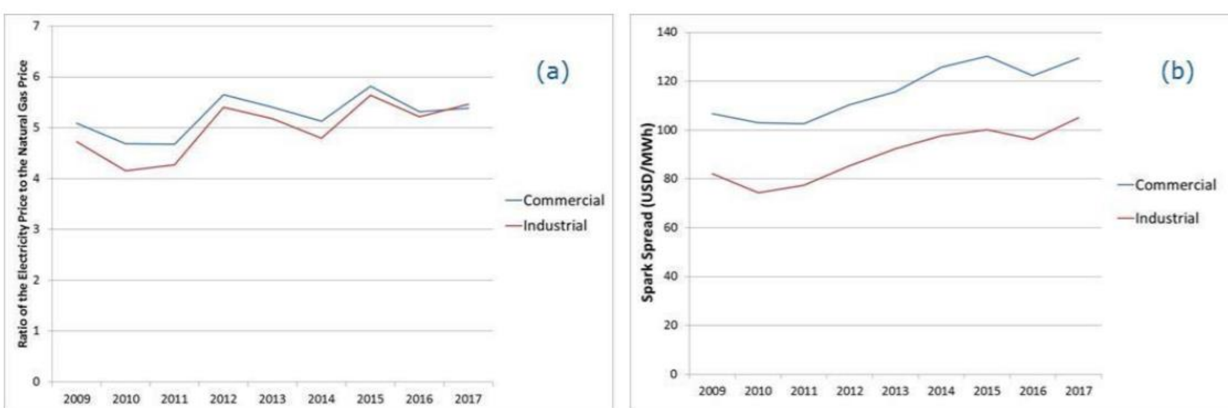

FIGURE 11 - RATIO OF ELECTRICITY PRICES (A) AND CORRESPONDING SPARK SPREAD (B) IN CALIFORNIA 2009 – 2017

i) **Peak Pricing:**

A main driver of microgrid is to reduce electricity bills through demand charge reduction. For many manufacturers, a major portion of electricity service charge is composed of demand charges accrued during peak pricing. A microgrid with an advanced energy management system, such as the EcoStruxure™ Microgrid Advisor optimizes operations through predictive algorithms. Similarly, varying retail electricity rates can provide for energy arbitrage opportunities through thermal and electric energy storage and net-metering in case of excess generation.

ii) **Ancillary Services:**

In deregulated electricity markets, such as regions under the jurisdiction of CAISO and ISO New England, there are established markets for ancillary services that provide value for services such as voltage control and frequency regulation. With increasing renewables penetration in these markets, these value streams are going to less variable and condition dependent. Eventually these will be promising revenue streams that can provide developers with established value streams to monetize.

iii) **Tax Credits**

Tax credits such as the investment tax credits (ITC) for solar projects beginning construction through 2022 provide opportunities for investors to buy tax equity in the project in return for utilizing these tax credits.[61] This can result in significant tax savings for these investors, and thus serve as an attractive proposition for financing.

AGGREGATION FOR SCALE

As of now, the microgrid industry is fragmented with multiple developers striving to secure both equity and debt financing on a project-by-project basis. Larger developers such as SE have been able to finance these projects through their own capital, or secure project finance at low capital costs.[58] However, readily available, and low-cost debt financing through institutional financiers, such as pension funds, mutual funds, and insurance funds, who are willing to take on the risks of microgrid projects will lead to a greater scale and rapid industry growth.

The greatest challenge in attracting these investors today is the small deal size. A single microgrid project does not provide the returns these investors seek due to high transaction costs they incur.[58] However, bundling multiple projects into a similar portfolio will likely lead to success in securing financing. Project portfolios of standardized microgrids not only hedges against the performance risk of any one project, but also help prove the bankability of the microgrids by reducing technical and regulatory complexities involved with individual projects. This will ensure greater adoption of microgrids across small and medium sized manufacturers.

From a financier's perspective, portfolio aggregation can lead to the development of microgrids as an asset-class like other renewable energy projects. This will lead to structured approach in valuing microgrids and a uniform methodology to finance them. In turn, this will drive repeatable deployment at scale.

Repeatability and Scale: What's Next?

For a large developer or company such as SE, portfolio aggregation unlocks new possibilities – such as the opportunity to unbundle different risks that are present within a project portfolio. For instance, by launching a Yieldco company, SE can separate the low risk of operating microgrids from the higher risk of developing microgrid projects.[58] Like Yieldcos operated by renewable energy developers, the Yieldco in this case would buy completed and operational microgrid project portfolios from SE through raising capital from public markets. With lower operational risks and contracted revenue streams through EaaS model, the Yieldco can offer generous dividends to public investors. With a shorter long-term capital investment cycle, SE can recycle the capital back into new microgrid projects. In the future, Yieldco will also offer SE the opportunity to make a successful exit from the market. For instance, in August 2018, NRG Energy sold its stake in NRG Yield (now Clearway Energy, Inc) to the Global Infrastructure Partners.[62]

MICROGRID SOLUTIONS

Energy market participation is key to ensuring financial reliability of a microgrid project. To fully understand the difference the ability to participate makes, a microgrid for a 5MW manufacturing facility was modelled using HomerPro. HomerPro allows flexibility in accessing several grid integration modes which significantly affected project finances, as discussed in the financial results below. Three difference scenarios assessed were:

1. **No Grid Sellback** - Standalone microgrid that only allows purchases from the grid.
2. **Grid Sellback at Peak Demand** - Microgrid with two-way interaction with the macrogrid and sells excess electricity back during peak demand.
3. **Continuous Grid Sellback** - Microgrid is unrestricted in its interaction with the macrogrid and can simultaneously purchase/sell to the grid depending on economics.

The model assumed a 5MW peak load manufacturing facility in California. The microgrid was design with a combination of a CHP, a Solar PV and Storage. Figure 13 shows a schematic of the complete microgrid from HOMERPro. The component size and specific function of each component is discussed below:

1. **Combined Heat and Power** – Two CHPs, each with a capacity of 1.25kW were chosen to provide the base load for the project when islanding from the grid was needed.
2. **Generic Flat Plate PV** – The model was set to keep the PV project size between 500kW and 1000kW. The optimized size of the PV system was kept at 500kW by HOMERPro. Since this is the cheapest form of electricity production, the PV was used to sell electricity back to the grid at times when grid prices were relatively higher and to meet any additional load after the base generation.
3. **Storage** – A 100kWh Lithium-Ion battery was also added to meet any fluctuations in load during grid islanding.

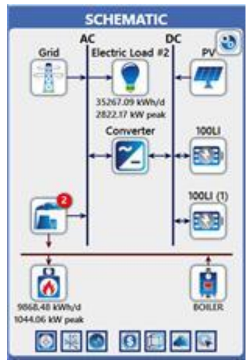

FIGURE 12 - MODEL **SCHEMATIC HOMER PRO**

Time of Use Rates

The model considered time of use rates based on the rates for small industrial and manufacturing facilities as defined by the Southern California Edison. The rates were divided based on:

1. Seasons:
   - i. Summer: June, July, August
   - ii. Winter: November, December, January
   - iii. Spring/Fall: March, April, May, September, October, November
2. Weekdays and Weekends
3. Peak and Off-peak hours.

Figures 13, 14 and 15 show the rates and their incorporation in the three scenarios modeled. The shaded areas refer to no sellback option.

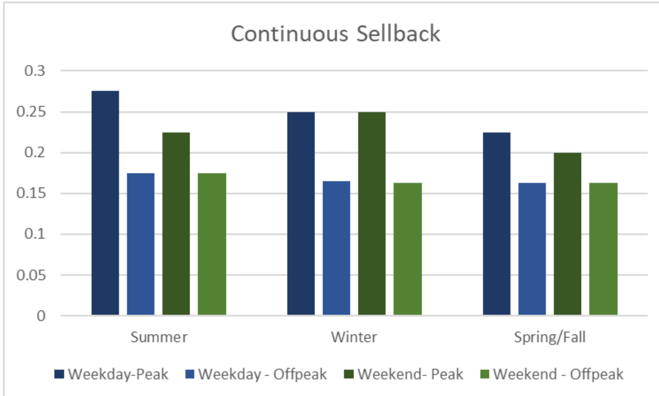

FIGURE 13 - CONTINOUS SELLBACK RATES

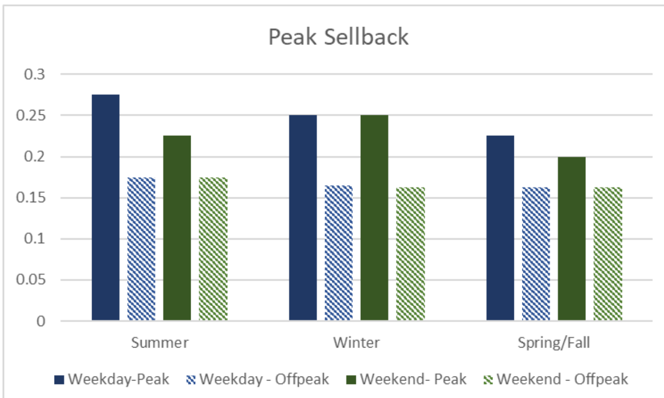

FIGURE 14 - PEAK SELLBACK RATES

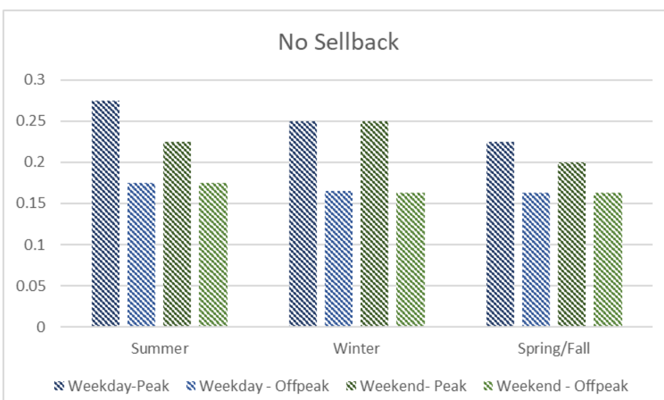

FIGURE 15 - NO SELLBACK RATES

Reliability

Monetization of the reliability that is offered by the microgrid is a key value stream for the project. To do this, an average, conservative number of 4 outages per year. This was then multiplied by the cost of a single outage for a manufacturing facility calculated by the US Department of Commerce , which values in at $72,000.[63] This calculation led to the total cost of resiliency for one year, equaling $288,000 annually. This value was compared to the cost of electricity purchased from the grid found by the model, leading to a 1.25 price escalation factor that was incorporated into each of the Time of Use rates. The graphs shown above incorporate this escalation factor in the rate values.

The results and cash flows for each of the three scenarios are discussed in the financial analysis section below.

FINANCIAL ANALYSIS

To have a better sense of project economics with grid integration, the HOMER Pro modelling software was used to design a microgrid for a manufacturing facility in California that met the specifications of the customer profile. The model output has been used to conduct a discounted cashflow analysis (DCF) to determine the optimum financial return profile for microgrids. The various operating models considered are:

- No grid sell-back
- Grid sellback only at peak demand
- Continuous grid sellback

These operating strategies have been considered against the backdrop of two business models:

- CHP asset purchase by GreenStruxure (in addition to all other necessary capital expenditures)
- Targeting customers with legacy CHP investments and thus foregoing capital investment in CHP assets

For a fair comparison, the following assumptions regarding modeling inputs have been kept constant:

TABLE 2 - FINANCIAL ANALYSIS INPUTS

Modeling Inputs	
Initial PPA Price ($/kWh)	0.08
Depreciation Schedule	10 Years MACRS
Project Lifetime	25 years
ITC (%)	26%
Tax Rate (%)	21%
Discount Rate (%)	7.0%
Inflation	2.0%

RESULTS

The following tables details the results from the DCF analysis of the various operating modes under the two business models of with and without CHP purchases. From the results, it can be surmised that from an NPV and IRR perspective, microgrids with energy market participation have a much better financial return profile than microgrids that do not sell back electricity to the grid. Likewise, foregoing capital investments in CHP also results in better financial outcomes.

TABLE 3 - FINANCIAL ANALYSIS RESULTS FOR CHP PURCHASE MODEL

Financial Analysis - CHP Purchase			Results	
S. No	**Scenario Name**	**Description**	**NPV**	**IRR**
1	No Grid Sellback	Standalone microgrid that only allows purchases from the grid	$406,197	7.5%
2	Grid Sellback at Peak Demand	Microgrid with two-way interaction with the macrogrid and sells excess electricity back during peak demand	$3,098,037	11.1%
3	Continuous Grid Sellback	Microgrid is unrestricted in its interaction with the macrogrid and can simultaneously purchase/sell to the grid depending on economics	$4,105,838	11.9%

TABLE 4 - FINANCIAL ANALYSIS RESULTS FOR NO CHP PURCHASE MODEL

Financial Analysis - No CHP Purchase			Results	
S. No	**Scenario Name**	**Description**	**NPV**	**IRR**
1	No Grid Sellback	Standalone microgrid that only allows purchases from the grid	$2,929,534	14.2%
2	Grid Sellback at Peak Demand	Microgrid with two-way interaction with the macrogrid and sells excess electricity back during peak demand	$5,630,366	21.9%
3	Continuous Grid Sellback	Microgrid is unrestricted in its interaction with the macrogrid and can simultaneously purchase/sell to the grid depending on economics	$6,637,595	20.9%

Furthermore, an analysis of cashflow profile over the project lifetime also shows that going forward, EaaS model unlocks the greatest value for both GreenStruxure and off-taker when the customer (manufacturing facility) already has CHP assets onsite. This allows the microgrid to participate in energy markets through sellback or similar method that allows additional revenue streams. As the figures below show, energy market participation and reduced capital investment result in shorter payback periods in addition to better rates of return and net present values. This is crucial from a project portfolio perspective as it improves cashflow over the lifetime of the project instead of just at project closure.

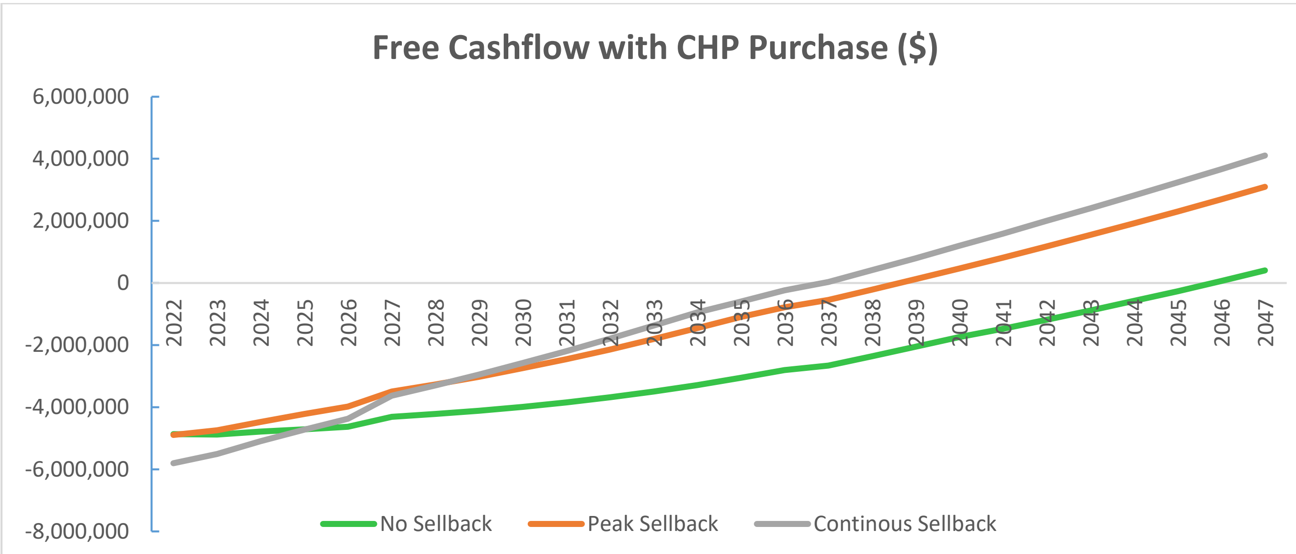

FIGURE 16 - CASHFLOW FOR CHP PURCHASE MODEL

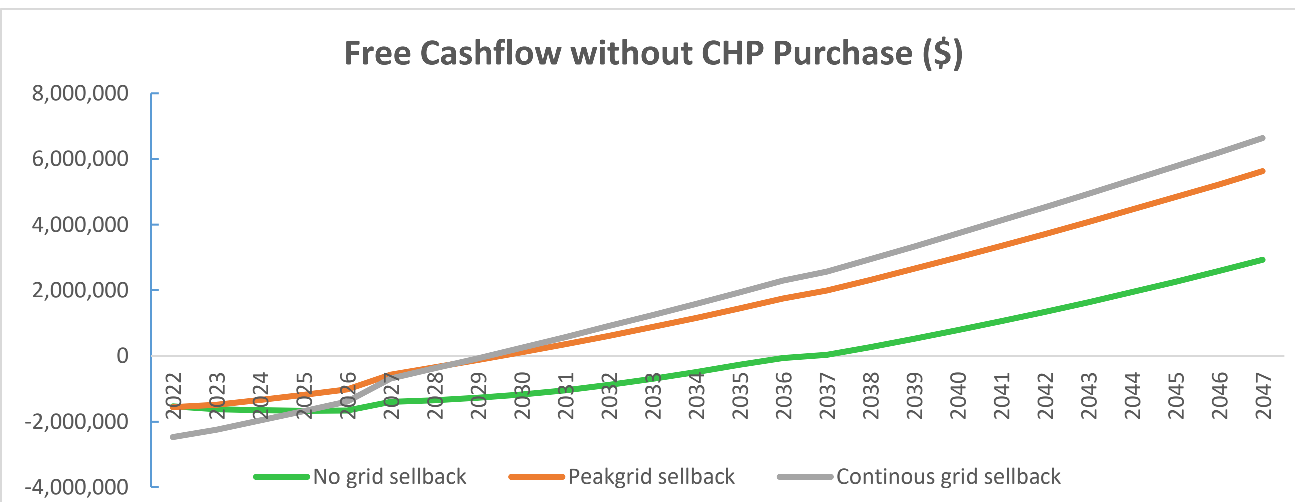

FIGURE 17 - CASHFLOW FOR NO CHP PURCHASE MODEL

ENVIRONMENTAL CHALLENGES

A reason why many medium and small industries deter from installing microgrids on their properties, even with obvious cost and reliability benefits, are the large upfront costs associated with making the retrofits to the already existing buildings. Thinking long term and making the necessary changes while the building is in the design or construction phase is a cost-saving strategy that creates the environment needed to deploy repeatable microgrids in the future. SE, as a market leader for microgrids in the US, can partner with design and construction firms to create the blueprint for these "Microgrid Ready Building". The technical and implementation experience of the SE's team coupled with expertise in building design from architectural firms will bring together the right set of skills to build and grow is area. While solar-ready buildings are tried and tested, microgrid ready buildings are a relatively new concept that SE can lead and develop.

Along with a reduction in retrofitting costs, creating this outline can develop building codes, as has happened with solar ready building mandates, which provide clear definitions and checklists , particularly for buildings in areas which are susceptible to greater reliability issues such as California or Texas. SE can also use these blueprints to develop Certifications that offer visibility about the building and its features. They can also be integrated into existing certifications, like LEED or EPA Energy Star, that would provide many revenue-based benefits to the owners and tenants of these buildings. Additionally, the concept of microgrid-ready buildings can lead to new markets as the concept is adopted by more states that might not have as clear or strong state-level policies for islanding. This is a natural response to developing a checklist, as was seen in Louisiana which saw an uptake in solar ready buildings lead to the state expanding its renewable energy goals. Lastly, creating this blueprint is also the first step in establishing state-wide mandates, like the ones in California for solar, that require all new buildings under a certain category to be microgrid ready. This initiative could be helpful in urban areas that are growing rapidly and manufacturing facilities and hospitals in areas where grid reliability has known to be a problem.

Defining a microgrid ready building requires breaking out the building stages into three main categories: the construction phase, the technical requirements, and the regulatory landscape. This report provides a top-level analysis on the areas that each of these sections should cover below.

i) **Construction Phase:**

a. *Onsite Generation*: The construction phase of a building can be divided into the vertical and horizontal construction. During the horizontal construction phase, which is focused on getting the ground ready before construction, a microgrid ready building will focus on having the right space to have on-site generation. Having clarity on the type of generation is important because maximizing efficiency would require looking at specific aspects of the area. For example, with solar it is important to make sure there are no sources of shading nearby and no expectancy of buildings being put up in the future that can cause shading.

b. *Energy Efficiency Buildings*: During the vertical construction phase, energy efficiency of the building is key. Building orientation, passive design structure and using energy efficient equipment help reduce the overall load that the onsite generation will have to be designed for.

c. *Spacing and Orientation*: Focusing on the safety and efficient use of the building is also important. There are some design decisions that can be easily implemented if made during the construction phase of the building as opposed to later in its lifetime when the microgrid is going to be deployed. An example of such a decision is keeping onsite generation that might have emissions away from areas where they could directly affect people, like parking garages. Similarly, if the onsite generation is planned to be solar, then making sure the glare from the solar does not affect roads and cars nearby.

ii) **Technical Requirements:**

a. *Islanding Capability:* The key feature of a microgrid that differentiates it from other DERs is its ability to island during a grid outage. To implement this, the electrical paneling of the building needs to incorporate electrically operated switchboards, relays and protection systems, and motor operated breakers. All these equipment ensure islanding can take place safely without having to physically make the switch between electric systems.

b. *Cabinet Space:* When a microgrid is installed, a separate PLC and control system also needs to be added to the electric cabinet space. When planning the electric cabinet and wiring cable designs, it is important to leave space for any equipment that will need to be installed with the microgrid later.

c. *Load Design*: When designing the load characteristics of a microgrid, the facility load is usually divided into critical, interruptible, and shed able. These provide an order of priority for which loads need to be met first. Dividing loads according to these classifications and from the beginning can help plan the electric wiring accordingly for the building and make the microgrid design in the future much easier.

iii) Regulatory Landscape:

a. *Zoning and Permitting:* Before beginning construction on site for a micro-grid ready building, it is important to understand the zoning and permitting laws of the region to be aware of any issues that might arise with installing a microgrid in the future. One common issue could be the permitting required to install on-site generation on the facility.

b. *Interconnection:* As discussed previously, the interconnection process can be time consuming and cost heavy. Understanding the grid congestion situation and the requirements for interconnection can allow better planning for the microgrid in the future.

c. *State and Utility Landscape:* Lastly, awareness about key positions the state or utility have regarding matters that could affect microgrid deployment are essential. For example, does the state have an emission reduction mandate on commercial or industrial entities? Or does is the state expected to roll out EV requirements for manufacturing industries? This outlook allows building owners and developers to have an outlook on potential changes to the system.

CONCLUSION

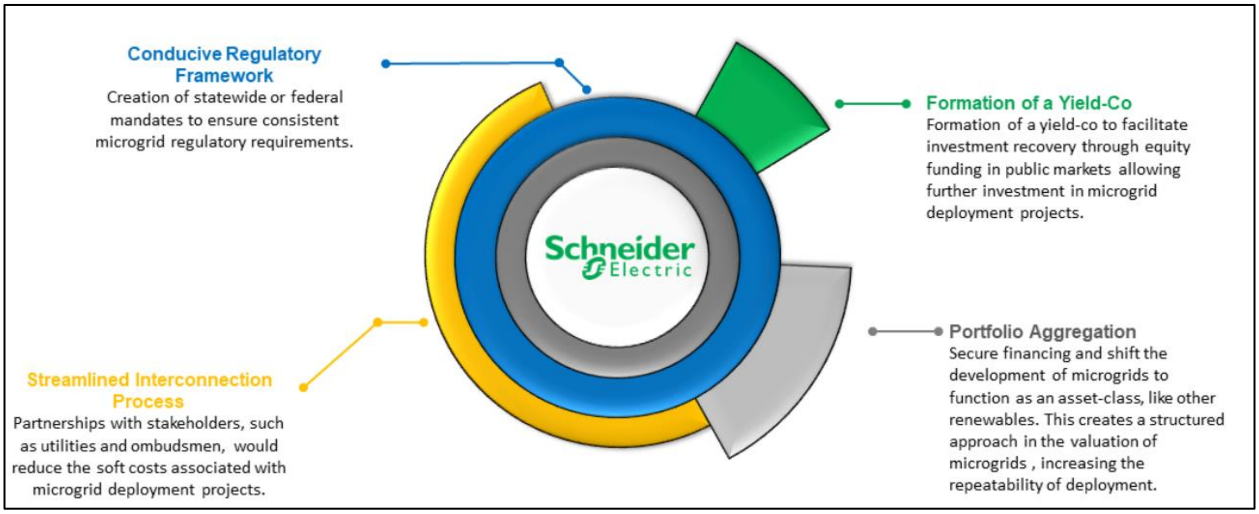

FIGURE 18 - RECOMMENDED AREAS OF FOCUS

The goal of this project was to propose solutions to overcome the barriers preventing widespread, repeatable deployment of microgrids in the form of a roadmap provided to SE's Microgrid Competency Center. Our team has determined that microgrids need to be able to seamlessly interact with the macrogrid to see the necessary increase in repeatability and decrease in costs necessary to promote nationwide deployment. Such an accomplishment would allow for the electric power grid to benefit from increased resiliency and reliability provided by interconnected microgrid facilities. We believe that the actions proposed by this report can be summarized into four primary action areas within which SE can direct their focus moving forward: a conducive regulatory framework, streamlined interconnection processes, portfolio aggregation, and the formation of Yieldcos.

First, the creation of a conducive regulatory framework can be achieved through consistent, overarching microgrid legislation and the implementation of microgrid-ready-facility standards. The regulatory framework can be accomplished through lobbying efforts and closely working with state and federal authorities. A conducive regulatory framework will lead to a reduction in additional costs for microgrid developers, in turn increasing project viability, decreasing project risk, and improving repeatability. Second, streamlining the interconnection process requires forming partnerships with new or existing utilities and stakeholders in order to reduce the soft costs associated with microgrid development. As with the creation of a conducive regulatory environment, this will increase the repeatability of microgrid development projects. Third, the aggregation of similar microgrid projects into larger project portfolios improves the chances of securing financing and allows microgrids to function as an asset-class. Aggregation will lead to a more structured microgrid valuation method, decreasing uncertainty and increasing repeatability of deployment strategies. Fourth, utilizing a Yieldco to facilitate investment recovery through equity funding in public markets allows SE to further invest into microgrid deployment projects. The best approach to these goals requires adopting a combination of these strategies simultaneously in order to result in the greatest opportunity to improve the repeatability of microgrid deployment projects throughout the United States while simultaneously improving the financial return of undertaken projects.

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