Energy Research and Development Division

FINAL PROJECT REPORT

Demonstrating a Secure, Reliable, Low-Carbon Community Microgrid at the Blue Lake Rancheria

California Energy Commission

Gavin Newsom, Governor

January 2019 | CEC-500-2019-011

PREPARED BY:

Humboldt State University Sponsored Programs Foundation/Schatz Energy Research Center

Primary Authors:
David Carter
Jim Zoellick
Marc Marshall
Greg Chapman
Peter Lehman
Doug Saucedo
Charles Chamberlin
Steve Shoemaker
Jana Ganion
Pramod Singh

Schatz Energy Research Center
1 Harpst Street
Arcata, CA 95521
(707) 826-4345
www.schatzcenter.org

Contract Number: EPC-14-054

PREPARED FOR:
California Energy Commission

Jamie Patterson
Project Manager

Fernando Piña
Office Manager
ENERGY SYSTEMS RESEARCH OFFICE

Laurie ten Hope
Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Drew Bohan
Executive Director

ACKNOWLEDGEMENTS

The authors acknowledge the partners who made this project possible, demonstrating the vision and commitment necessary to bring it to successful completion.

Blue Lake Rancheria and Serraga Energy, LLC
The Blue Lake Rancheria was the site host. Key contributors included the Blue Lake Rancheria Tribal Government, Vice Chairperson Arla Ramsey, Tribal Council Member Jason Ramos, Jana Ganion, Mike Smith, and Robert Pollard, among others. They had an unfailing commitment to the success of the project and to moving low-carbon energy solutions forward. They provided substantial cost-share, managed risk during installation and commissioning, and provided key facilities and IT technical support as this first-of-its-kind microgrid was used.

California Energy Commission
The California Energy Commission provided primary funding to make this project possible, and Commission Agreement Manager Jamie Patterson provided strategic project stewardship.

Siemens Industry, Inc.
Siemens provided the microgrid management system for the project. Key contributors included Shashank Pande, Rima D'Costa and their entire team. This was the first deployment of the Spectrum Power™ Microgrid Management System at a customer site. The Siemens team demonstrated unwavering commitment to ensure that the control system met the requirements.

Tesla Motors, Inc.
Tesla provided the battery energy storage system. Ed McCullough and his colleagues provided critical technical expertise to successfully integrate their system in the research team's application.

Idaho National Laboratory
Idaho National Laboratory conducted hardware-in-the-loop, real-time digital simulation testing. Rob Hovsapian, Manish Mohanpurkar and the rest of the INL team provided valuable expertise for testing and de-risking the control system and providing a venue for operator training.

Pacific Gas and Electric Company
Pacific Gas and Electric Company (PG&E) is the local distribution utility, and it was a tremendous partner on this project. David Rubin, Martha Baeli, Mark Randazzo and team provided critical support during the funding application process, the purchase of PG&E infrastructure, and the interconnection of this cutting edge microgrid technology on its distribution system.

Robert Colburn Electric
Randy Cox and team at Colburn Electric provided electrical contracting services necessary for the successful design, installation, and commissioning of the microgrid system. Randy's knowledge of the Blue Lake Rancheria electrical infrastructure was critical to the project.

REC Solar and McKeever Energy and Electric
REC Solar designed the solar electric system, and McKeever Energy and Electric was the subcontractor that installed the array, with excellent workmanship in every detail.

GHD
GHD and Rick Gugianna provided expertise and electrical engineering services for the project.

Kernen Construction
Kernen Construction provided civil contracting services for the project.

PREFACE

The California Energy Commission's Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission, and distribution and transportation.

In 2012, the California Public Utilities Commission established the Electric Program Investment Charge (EPIC) to fund public investments in research to create and advance new energy solutions, foster regional innovation, and bring ideas from the lab to the marketplace. The California Energy Commission and the state's three largest investor-owned utilities – Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company – were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The Energy Commission is committed to ensuring public participation in its research and development programs which promote greater reliability, lower costs, and increased safety for the California electric ratepayer, and include:

- Providing societal benefits.
- Reducing greenhouse gas emissions in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and, finally, with clean conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Demonstrating a Secure, Reliable, Low-Carbon Community Microgrid at the Blue Lake Rancheria is the final report for the Blue Lake Rancheria Microgrid project (Grant Award Number EPC-14-054) conducted by the Humboldt State University Sponsored Programs Foundation/Schatz Energy Research Center. The information from this project contributes to Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

This project demonstrates a secure, reliable, low-carbon community microgrid at the Blue Lake Rancheria, a federally recognized tribal government and Native American community adjacent to Blue Lake (Humboldt County). The project shows the feasibility of integrating renewable energy with battery storage, a microgrid controller, and controllable loads into a single microgrid. The microgrid supports an American Red Cross evacuation center and a six-building campus. The project improved resiliency for the Blue Lake Rancheria Tribe and the surrounding region. The microgrid includes 420 kilowatts of solar photovoltaics, and a 500 kW/950 kilowatt-hour (kWh) battery energy storage system. The microgrid is connected to the Pacific Gas and Electric distribution grid at 12.5 kilovolts through a computer-controlled circuit breaker and is designed to operate autonomously. The project was completed on time and with only minor cost overruns (less than 1.5 percent of project cost). The project was recognized internationally including receipt of Federal Emergency Management Agency's 2017 Whole Community Preparedness Award and DistribuTECH's 2018 Project of the Year for DER Integration Award. Energy savings to the Blue Lake Rancheria was about $160,000 in 2017 and beginning in 2018 will increase to nearly $200,000 annually. In October 2017, a nearby fire caused a grid outage. The microgrid successfully islanded and kept the microgrid facilities from experiencing a blackout. The greenhouse gas emission reductions for 2017 are estimated to be 159 tons carbon dioxide equivalent (CO_2e) and are expected to reach 175tons CO_2e/year in 2018 and beyond.

Keywords: Microgrids, distributed energy resources, climate change mitigation, battery energy storage system, low-inertia, island-mode, microgrid controller, microgrid management system, resiliency, critical facility, load sharing, seamless islanding transition, droop control, PV curtailment, microgrid interconnection process

Please use the following citation for this report:

Carter, David, Jim Zoellick and Marc Marshall. Schatz Energy Research Center, Humboldt State University. 2019. *Demonstrating a Secure, Reliable, Low-Carbon Community Microgrid at the Blue Lake Rancheria*. California Energy Commission. Publication Number: CEC-500-2019–011.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Page

EXECUTIVE SUMMARY

Introduction

Climate change is humankind's largest environmental challenge, and the State of California has aggressive goals and strategies to address the problem. These initiatives include efforts to slow climate change (*mitigation)* and efforts to become more resilient to the impacts of climate change (*adaptation)*. An important mitigation measure is to increase the use of clean renewable electricity, like solar, to reduce greenhouse gas emissions from fossil fuels. Adaptive functions include providing emergency power for critical services during disasters, such as large storms, that are amplified by climate change.

Microgrid technology can help society mitigate and adapt to climate change. A microgrid is an independent electric grid with onsite energy generation or storage (or both) that can operate both while connected to and when disconnected or "islanded" from the larger utility grid. When islanded, the electrical power generation on the microgrid must exactly match the electrical loads on the microgrid.

Customers who install microgrid technology can reduce and stabilize their energy costs while gaining a reliable source of backup power in the event of a larger grid power outage. If the microgrid uses renewable generation sources, like solar or wind, it can also reduce the customer's greenhouse gas emissions. In addition, microgrids can use smart controls, energy storage, or controllable loads or both to provide demand response and other benefits to the larger electric grid.

Microgrids with integrated renewable energy and energy storage are a preferable alternative to stand-alone fossil-fueled generation for providing emergency power. Fuel supplies can be cut off in a disaster, but most renewable energy resources will remain viable. Microgrids capable of reliably integrating intermittent renewables are an emerging technology and require sophisticated control systems. While microgrid controller technology has matured beyond the research and development phase, systems must be demonstrated at a larger scale to prove capabilities and move the technology toward full commercialization. More microgrid systems must be designed, used, monitored, and evaluated to understand performance, costs, and benefits better, and to ease replication.

Humboldt County is a geographically isolated, region of California served by limited transmission infrastructure; power must be generated in the Humboldt area to meet local demand. Power interruptions/outages are frequent due to technical and natural factors. Past outages have lasted from several days (the 2005 New Year's storm) to several weeks (the December 1964 flood). Energy resilience is, therefore, a serious concern to the region and has been a focus of countywide energy and hazard mitigation planning. Local governments and community stakeholders have identified the need for expanding sources of backup energy generation at critical facilities like hospitals, disaster shelters, and police and fire stations. Microgrids are a technology that can serve this need.

Project Purpose

The project team designed, built, and demonstrated a microgrid that reduces energy costs and greenhouse gas emissions and provides robust backup power for a certified American Red Cross shelter and other critical infrastructure at the Blue Lake Rancheria, a federally recognized tribe and community located in Humboldt County.

The project advanced microgrid technology by demonstrating a new microgrid controller and integrating a set of equipment not previously been combined in a microgrid setting. In addition, the project demonstrated the ability to integrate solar electric power with battery energy storage, conventional generators, and dispatchable demand into a microgrid at the scale of a small administrative and commercial campus, with an added goal of relegating the existing fossil-fueled generators to a deep backup role where they rarely run. Another key goal of the project was to transfer the knowledge gained to a broad audience. By sharing project results via extensive outreach and knowledge transfer activities, the project sought to encourage replication of a scalable solution for similar critical infrastructure throughout California and beyond.

Project Approach

The Schatz Energy Research Center (SERC) at Humboldt State University led the project and the site host was the Blue Lake Rancheria tribe. SERC managed the project, coordinated the efforts of all subcontractors and vendors, and acted as the owner's engineer and technology integrator. As the owner's engineer, SERC protected the site host's interest by ensuring that all contractors met their contractual obligations and that their products met project specifications. As technology integrator, SERC ensured that all the used technologies functioned as a well-integrated system and all subcontractors and vendors worked efficiently and effectively as part of the project team.

The project team used an integrated design process to develop review packages at 50, 75, 90, and 100 percent levels of completeness. Each review package included design plans, specifications, an engineer's opinion of probable cost, and a concept of operations document. Maintaining consensus on these design documents kept the engineers focused on common outcomes and built stakeholder confidence during the buildup to a challenging construction schedule, governed by several Pacific Gas & Electric Company (PG&E) compliance milestones. The interconnection process required purchasing distribution circuitry by the Blue Lake Rancheria tribe, a service rearrangement from secondary to primary voltage service, pre-energization testing, a pre-parallel inspection, and two metering inspections.

Since the Blue Lake Rancheria microgrid incorporated existing facilities, electrical service was maintained with minimal outages during construction. To accomplish this, protection and foundational microgrid control programming was part of the protection relays at the point of common coupling with PG&E. This allowed the microgrid to become operational as soon as the cutover to the new primary service was completed by PG&E. The Siemens Microgrid Management System was integrated with those protection and foundational microgrid relay settings.

Extensive testing to de-risk the integrated microgrid control system took place at Idaho National Laboratories' smart grid test facility before live testing started at the project site. Live onsite testing of the microgrid management systems began with the foundational control programming in *automatic transfer switch mode*, which prohibited the MGMS from controlling the main breakers in the microgrid. As testing progressed, confidence grew and the foundational control program was removed from automatic transfer switch mode to allow the microgrid management system complete control of the microgrid. An extensive microgrid management system commissioning process verified the functionality described in the concept of operation documents. This led to full permission to operate from PG&E and a six-month period of full system operation and monitoring.

Project Results

The Blue Lake Rancheria microgrid successfully demonstrated a low-carbon microgrid that saved the site host money, reduced greenhouse gas emissions, and improved the energy resilience of onsite critical infrastructure and facilities. The project largely met the stated goals and objectives, was completed on schedule and on budget, won numerous national and international awards, and gained substantial public exposure. Lessons learned and benefits gained were documented, and extensive public outreach and subsequent activities ensure that this valuable information is being widely shared and used.

The system design, procurement, installation, and initial commissioning phases required about 24 months to achieve full operation, an impressive feat for a first-of-its-kind project of this magnitude and complexity. This was followed by another nine months of testing, observation, and ongoing commissioning to improve system operation.

The total project cost $6.3 million and included these components:

- A 420 kilowatt alternating current (kW_{AC}) solar electric system.
- A 500 kW/950 kWh battery energy storage system provided by Tesla Motors.
- A Siemens Spectrum Power™ microgrid management system.
- A Schweitzer Engineering Laboratories protective relay.
- An energy management system (EMS) for building control integration.
- Purchase of PG&E distribution system infrastructure and creation of a new point of common coupling.

An estimated 15 percent to 20 percent of project costs were associated with the first-of-its-kind, research and development nature of the project. During commissioning, savings attributable directly to the microgrid project were measured at $160,000 per year (a 25 percent cost savings), and savings are expected to reach about $200,000 per year with system improvements (completed as of this report). The solar electric system met 15 percent of the onsite load, and a greenhouse gas emissions reduction of 159 metric tons (MT) CO_{2e} was achieved. Future reductions in greenhouse gas emissions are expected to reach 175 MT CO_{2e} per year. The system responded to four unplanned outages and several additional planned outages over the first nine months of full operation. The system responded as designed in these situations and provided reliable backup power services.

The project was nominated for numerous awards and won the following awards for innovation and emergency preparedness achievements:

- FEMA's 2017 Whole Community Preparedness Award
- DistribuTECH's 2018 Project of the Year for DER Integration Award.

The project was also honored as a 2017 finalist in S&P Global Platts "Commercial Application of the Year" and a 2017 first runner-up as the Renewable Energy World and Power Engineering "Project of the Year." In addition to these awards, the project generated extensive media coverage and public outreach and education opportunities. The Blue Lake Rancheria Tribe and SERC conducted more than 150 tours and presentations during this project, and numerous groups have used this project as a model to plan new microgrid projects.

Key lessons learned from the BLRMG include the following:

- Microgrids offer many stacked benefits, including energy cost savings, reduced greenhouse gas emissions, and increased energy resilience.
- Effective system integration is critical to success, and this requires a contractually empowered technical integration team.
- Microgrid utility interconnection processes are especially complex, and establishing a collaborative relationship with the utility is essential in any microgrid project
- Involving knowledgeable IT and communications department staff is mandatory for microgrid success. Microgrid installation within a built environment will require some IT system upgrades and component replacements. In addition, the control system must account for network latency and control cycle times.
- After microgrid installation, IT staff must be cognizant that changes in network structure or hardware, as well as software upgrades to network infrastructure can disrupt communications between microgrid components, causing operational issues. Therefore, changes and upgrades to IT systems should be analyzed for impacts to the microgrid before and after implementation.
- Legacy equipment and systems create challenges when installing a microgrid over an existing built environment. Institutional knowledge of electrical infrastructure, and inclusion of electricians and others with prior site knowledge on the project team is crucial.
- Advanced protection relays can be used to provide foundational control capabilities that ensure a robust system. They can provide basic backup control features if the more sophisticated microgrid controller ceases to function. In addition, this foundational

control functionality is critical when deploying a microgrid in a live environment where nuisance power outages are not easily tolerated during commissioning and testing.

- Testing and commissioning a microgrid is a major component of the installation timeline. Hardware-in-the-loop testing is highly recommended to de-risk the system in a virtual environment before deploying the microgrid controller(s) on the live system at the project site. Due to the "first of its kind" nature, this project required approximately six months to complete on-site testing and commissioning before reaching full, steady-state operational status. If replicated, it is expected the time required for testing and commissioning could be reduced to one to two months. Once operational, careful monitoring of system performance for the first year was critical to verify functionality and fine-tune the controls.

Technology/Knowledge Transfer/Market Adoption

A tremendous amount of knowledge transfer and outreach has been conducted on the BLRMG leading to numerous follow-on projects. Tribal staff have delivered microgrid presentations and onsite tours to hundreds of stakeholder groups. As an example, tribal staff gave presentations at the U.S. Department of Energy's 2015 and 2017 National Tribal Energy Summits, the U.S. Environmental Protection Agency's Clean Power Plan training for tribal governments, the USDOE/WAPA Tribal Energy Webinar Series, other USDOE Office of Indian Energy meetings and workshops, and national FEMA webinars on whole community preparedness for tribes. Tribal staff also conducted onsite microgrid tours for more than 40 local and out-of-area tribes interested to learn about microgrids and, perhaps most importantly, to see a successful working project. Many of these tribes are considering microgrid projects of their own, with some already in development.

In addition, Blue Lake Rancheria and SERC staff gave tours to numerous academic and research institutions across the state. Examples include more than 20 California State University (CSU) energy managers, the CSU Chancellors Office, U.C. Berkeley, Lawrence Berkeley National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, and Sandia National Laboratory representatives. The project team has also provided onsite tours and information to community choice aggregators such as the Redwood Coast Energy Authority, the California Community Choice Aggregation Association, and to emergency preparedness agencies including California Office of Emergency Services, American Red Cross, Department of Homeland Security, FEMA, and others. Microgrid information and presentations were delivered at numerous national and international energy, engineering, climate, and education conferences. This high-profile outreach effort resulted in widespread education about the feasibility and value of microgrids.

This microgrid project was the first commercial use of the Siemens Spectrum Power™ Microgrid Management System. Siemens is now actively marketing and selling this product. They have a webpage that features the Blue Lake Rancheria microgrid via a multimedia presentation. In addition, Blue Lake Rancheria staff have presented at the Siemens Digital Grid Customer

Summit twice, and have hosted site visits with Siemens and potential microgrid clients. These efforts are leading to further sales and deployment of microgrid technology.

The Blue Lake Rancheria microgrid established the SERC as a leader in the design and use of microgrid technology, and a microgrid center of excellence. Since executing this project, SERC has worked on several follow-on microgrid designs and deployments. Two examples are the "Scaling Solar+ for Small and Medium Commercial Buildings" and the "Redwood Coast Airport Renewable Energy Microgrid" projects. Both microgrids are being used in Humboldt County, California. In addition, SERC has conducted microgrid planning and feasibility efforts for UC Santa Cruz, the community of Shelter Cove, Humboldt Transit Authority, the Bear River Band of the Rohnerville Rancheria, and the Yurok Tribe. Additional regional microgrid projects, such as the McKinleyville Community Services District and the Hoopa Valley Tribe, are building on the knowledge base, co-benefits, and lessons learned from the Blue Lack Rancheria microgrid.

Benefits to California

The Blue Lack Rancheria microgrid has resulted in substantial benefits to California ratepayers. The project successfully demonstrated that a renewable-based microgrid can reduce energy costs and greenhouse gas emissions while improving the resilience of critical facilities and infrastructure.

The project achieved substantial economic benefits for the site host and the region. With the Blue Lack Rancheria microgrid, the Blue Lake tribe reduced its energy costs in the microgrid campus between $160,000 – $200,000 per year, approximately a 25-30 percent reduction. The tribe has added four full-time positions within its IT and utility departments, a 10 percent increase in employment for the tribal government. Six local small businesses and contractors worked directly for the project. In total, approximately $9.5 million of induced and indirect economic benefits accrued to local, regional, and state economies.

Careful assessment of Blue Lack Rancheria microgrid system performance, costs, lessons learned, and benefits realized has dramatically increased the microgrid knowledge base locally and across the state. This project demonstrated a successful system that can be expanded at the host site. The Blue Lack Rancheria microgrid design is suitable for replication at other sites, especially where a high value is placed on resiliency. Energy cost savings, greenhouse gas emissions reductions, and resilience benefits can be replicated on a larger basis throughout the state. Parallel academic work associated with this project found there may be up to 1,200 technically and economically feasible sites throughout California with a cumulative hosting capacity of about 7,500 MW. The identified sites include data centers, military bases, hospitals and emergency refuge sites with peak loads greater than 1 MW. If these additional microgrid systems were installed, it is estimated that they could offset an annual electric load of about 5.2 billion kWh, reducing about 1.5 million metric tons of greenhouse gas emissions per year.

CHAPTER 1: Introduction

The Blue Lake Rancheria Microgrid (BLRMG) project demonstrated a secure, reliable, low-carbon community microgrid. With the project complete and operational, this report provides valuable engineering, energy, and financial information demonstrating the value of a microgrid solution for any distributed generation site or critical facility in the state, including hospitals, emergency operations centers, public safety facilities, office and residential complexes, schools, and universities, among others.

This report provides details about implementing the project including:

- Design Engineering (Chapter 2).
- Procurement (Chapter 3).
- Component Interfacing (Chapter 4).
- Construction (Chapter 5).
- Commissioning (Chapter 6).

Chapter 7, System Observation, provides details about the first year of operation, including data-driven results and conclusions. Chapter 8, Project Benefits, presents the outcomes of the project in terms of benefits to the Blue Lake Rancheria (BLR), the local community, and California's ratepayers. Chapter 9, Technology and Knowledge Transfer, summarizes the many ways in which the project team transferred knowledge gained to a diverse group of stakeholders. Chapter 10, Production Readiness, discusses outcomes of the project as they relate to the replicability of microgrids. Chapter 11, Conclusions and Recommendations, summarizes the major findings from the effort.

The remaining sections of this chapter provide introductions to the SERC and the BLR, a brief project description, a description of the purpose and need for the project, a presentation of the project objectives, a summary of the project benefits, and a description of the project team.

The Schatz Energy Research Center

The mission of the Schatz Energy Research Center is to promote using clean and renewable energy technologies that restore environmental and human health while increasing energy access worldwide. The SERC team accomplishes this by designing, demonstrating and deploying clean and renewable energy technologies, performing lab and field research, engaging in scientific and policy analysis, providing graduate fellowships and work opportunities for student engineers and scientists, and educating the public about clean and renewable energy. Located in Arcata, California, SERC is affiliated with Humboldt State University's Environmental Resources Engineering program and provides a rare opportunity for undergraduate and graduate engineering students to acquire hands-on experience with emerging energy technologies.

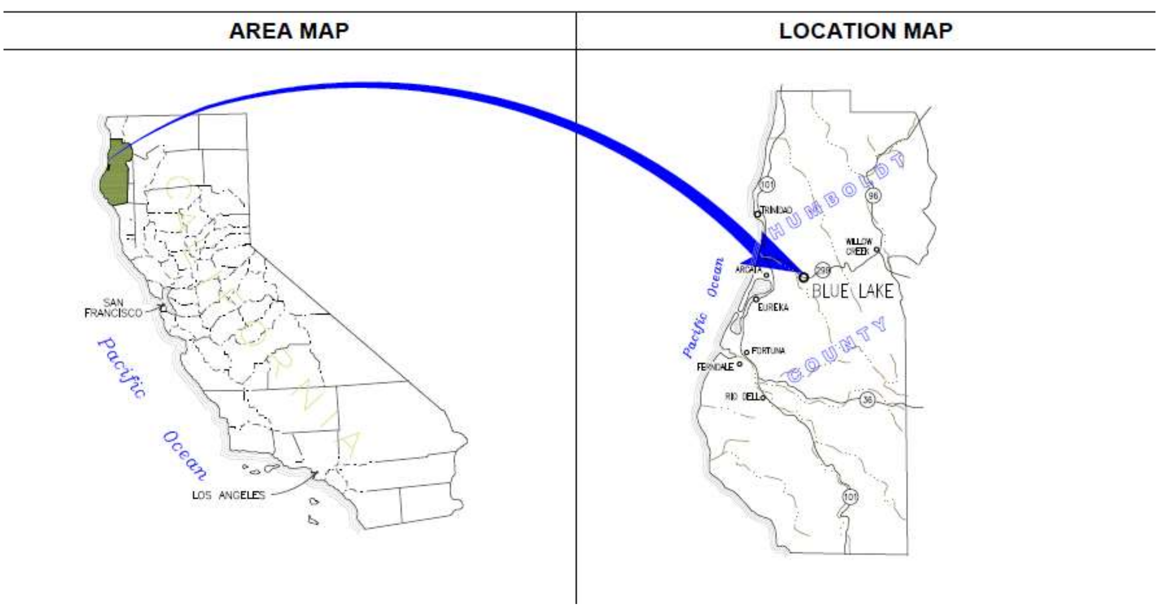
The Blue Lake Rancheria

The BLR, California is a federally recognized tribal government and community, located on about 100 acres of trust land spanning the Mad River, adjacent to the city of Blue Lake (Humboldt County) (Figure 1).

BLR has nearly 400 employees across government operations, economic enterprises, and 15 governmental departments, including a tribal utility authority. BLR's energy strategy is to reduce carbon emissions, energy costs, and price volatility while increasing resilience across energy and other lifeline sectors (water, food, communication/IT, and transportation). Named by the White House and the U.S. Department of Energy as a 2016 Climate Action Champion, BLR is a recognized national leader in the fields of sustainability, renewable energy, and climate action. The BLR's microgrid has received the following awards and nominations:

- Awarded the 2017 FEMA "Whole Community Preparedness" award
- Awarded the 2018 DistribuTECH "Project of the Year" award for Distributed Energy Resource Integration
- 2017 finalist, S&P Global Platts "Commercial Application of the Year"
- 2017 first runner-up, Renewable Energy World and Power Engineering "Project of the Year"

Figure 1: Vicinity Map for the Blue Lake Rancheria

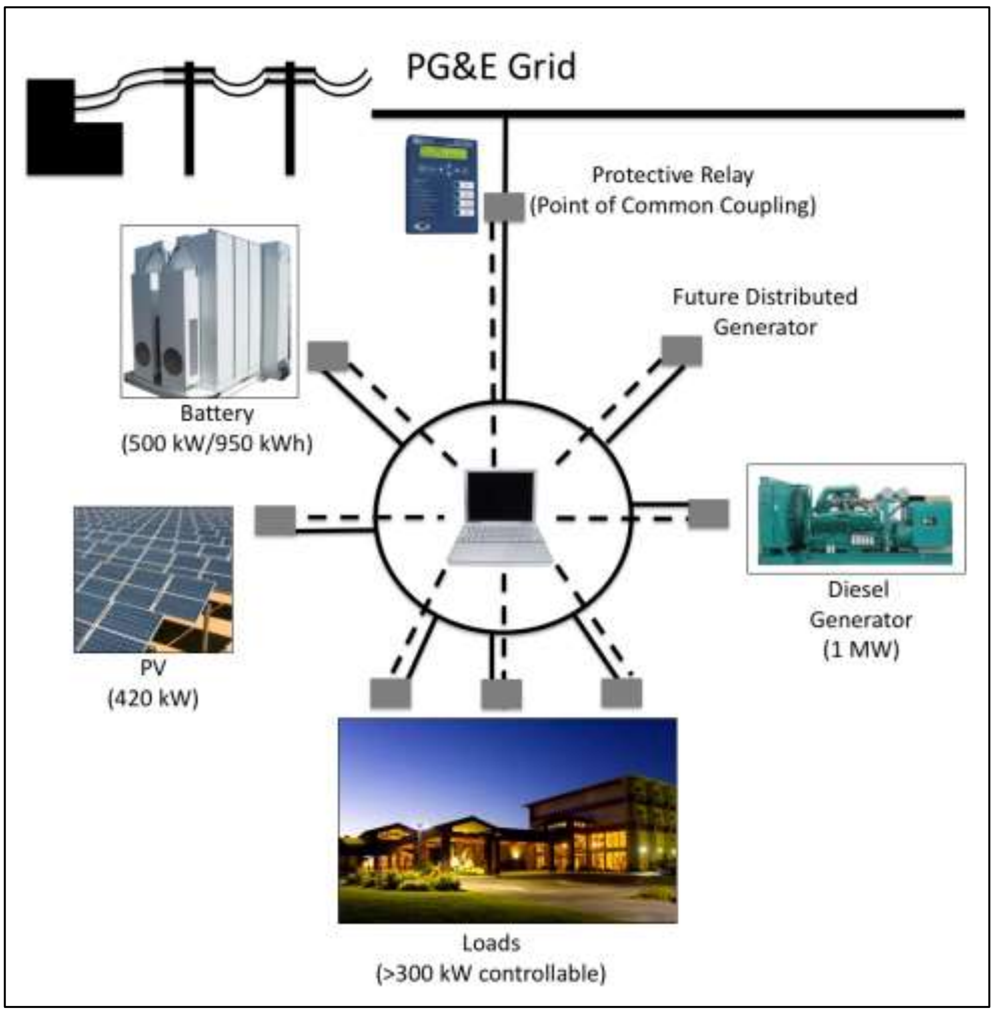


Source: Schatz Energy Research Center

Brief Project Description

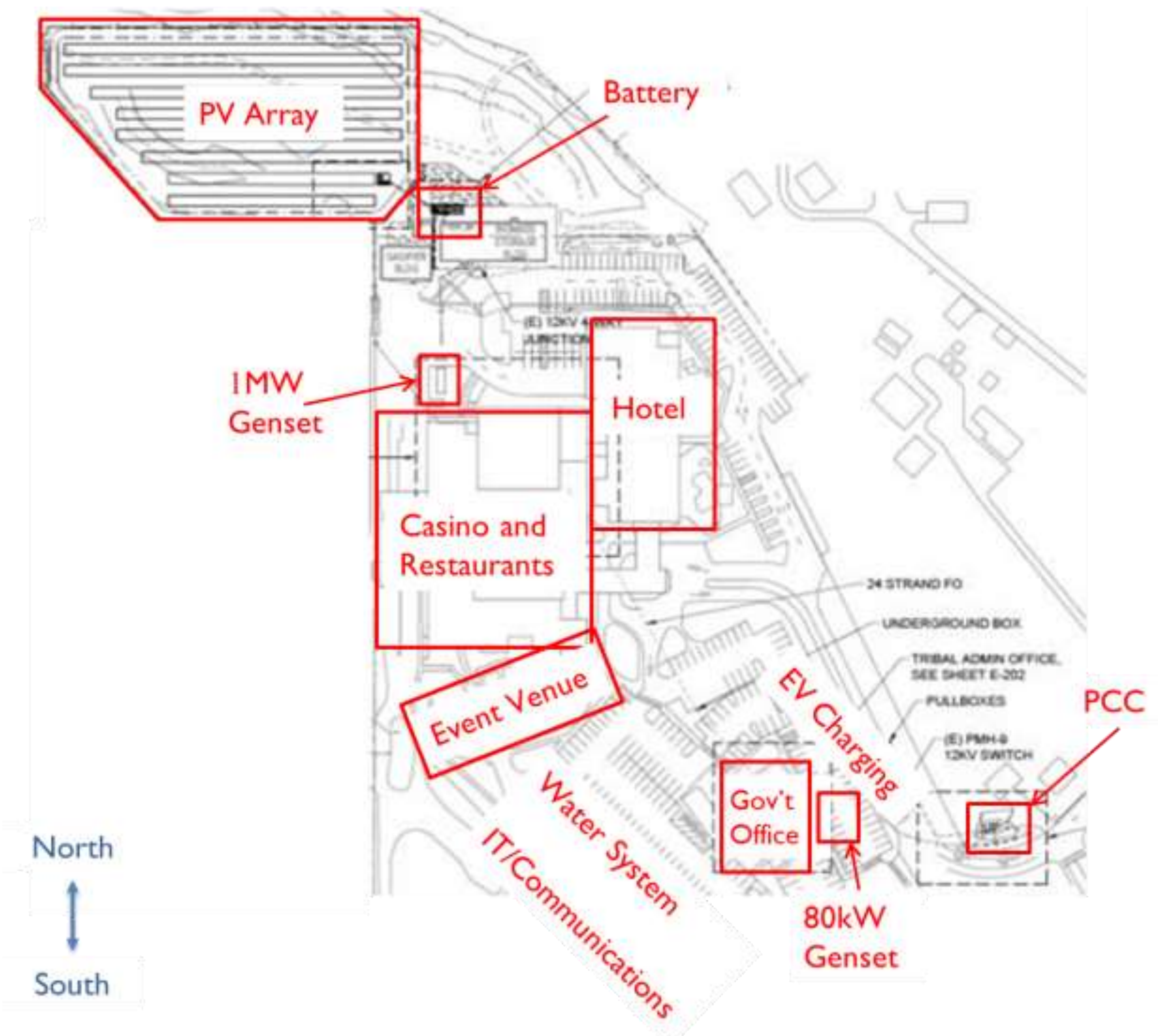
As shown in Figure 2, the BLRMG consists of a 420 kilowatt alternating current (kW_{AC}) photovoltaic (PV) array, a 500kW/950kilowatt-hour (kWh) battery energy storage system (BESS), a preexisting 1MW isochronous (constant frequency) generator set, and loads from a six-building campus and related infrastructure. The microgrid is connected to the Pacific Gas and Electric Company (PG&E) distribution grid at 12.5 kilovolts (kV) through a computer-controlled circuit breaker. The microgrid disconnects and operates in island-mode automatically if the PG&E grid experiences an outage, and automatically reconnects after the PG&E grid is restored. The microgrid is designed to operate autonomously, though extensive manual controls are also available. There are five levels of predesigned controllable loads, prioritized according to outage length and severity. Operators can shed these loads to prolong islanded operation in the event of extended outages, such as may occur following a major wildfire or earthquake. Figure 3 shows a site plan for the microgrid, and Figure 4 shows an overhead photo of the microgrid with the solar array featured prominently in the foreground.

Figure 2: Topology for Blue Lake Rancheria Microgrid



Source: Schatz Energy Research Center

Figure 3: Site Plan for the Blue Lake Rancheria Microgrid



Source: Schatz Energy Research Center

Figure 4: Overhead View of the Blue Lake Rancheria Microgrid

Source: Schatz Energy Research Center

Purpose and Need

This project sought to build a low-carbon microgrid for BLR, a Native American Tribe located in Northwestern California. The project integrated multiple sources of energy generation, some preexisting, with energy storage and controllable loads into a renewable-based microgrid capable of islanding (isolating itself from the grid) and providing power during a disaster or prolonged grid outage, while reducing greenhouse gas emissions and energy costs during business as usual operations.

Humboldt County is a natural-disaster-prone region of Northern California with most of the related power generation assets in the coastal tsunami zone and constrained transmission from the greater California electric grid. Energy resilience is a serious concern to the local community and has been a focus in recent communitywide energy and hazard mitigation planning (Zoellick, 2013; Tetra Tech, 2014). In these planning efforts, the community has emphasized the need to expand sources of backup energy generation at critical facilities like hospitals, disaster shelters, and police and fire stations.

Microgrids with integrated renewable energy and energy storage are an alternative to stand-alone fossil fueled generation for providing emergency power. Fuel supplies can be cut off in a disaster, but most renewable energy resources remain viable. Microgrids capable of reliably integrating intermittent renewables are an emerging technology and require sophisticated control systems. While microgrid controllers have made it past the research and development phase, they need to be demonstrated at scale to prove capabilities and move toward widespread commercialization.

Project Objectives

The objectives of this project were to:

- Install a microgrid capable of powering a certified American Red Cross disaster shelter at BLR in times of emergency.
- Integrate renewable solar PV, battery storage, generation, and controllable loads into the microgrid.
- Achieve renewable energy generation exceeding 17 percent of annual onsite energy consumption.
- Demonstrate the ability to island and supply uninterrupted electric power for at least seven days during a real or simulated grid outage.
- Demonstrate the ability of the microgrid to participate in one or more PG&E demand response programs.
- Achieve a reduction in annual electrical energy consumption from the grid of at least 680 MWh over one year of operation.
- Achieve at least 25 percent energy cost savings over one year of operation.
- Achieve a reduction in annual greenhouse gas emissions of at least 195 metric tons carbon dioxide equivalent (CO_2e) during one year of operation
- Make the knowledge gained from this project available to a broad audience.
- Develop a plan to help commercialize the microgrid technologies and strategies demonstrated under this agreement.

These objectives were largely met as discussed in Chapter 7, System Observation, and Chapter 8, Project Benefits.

Project Benefits

The BLRMG project has provided substantial benefits to the site host, to the region, to the California ratepayers, and to society as a whole. These benefits include lower energy costs, increased reliance on clean and renewable energy, reduced greenhouse gas emissions and criteria pollutants, job creation, greater electricity reliability and increased safety, all of which are described in Chapter 8, Project Benefits.

The BLRMG project has achieved technological advancements and overcome barriers associated with microgrid deployment. The project demonstrated a successful model of working cooperatively with the local utility (PG&E) to integrate distributed renewable energy resources into California's electricity grid. The project also successfully demonstrated the technical, financial, and regulatory feasibility of integrating renewable energy generation with battery storage, conventional/existing generators, emerging microgrid controller technology, and controllable loads into a single microgrid at the scale of a small commercial campus.

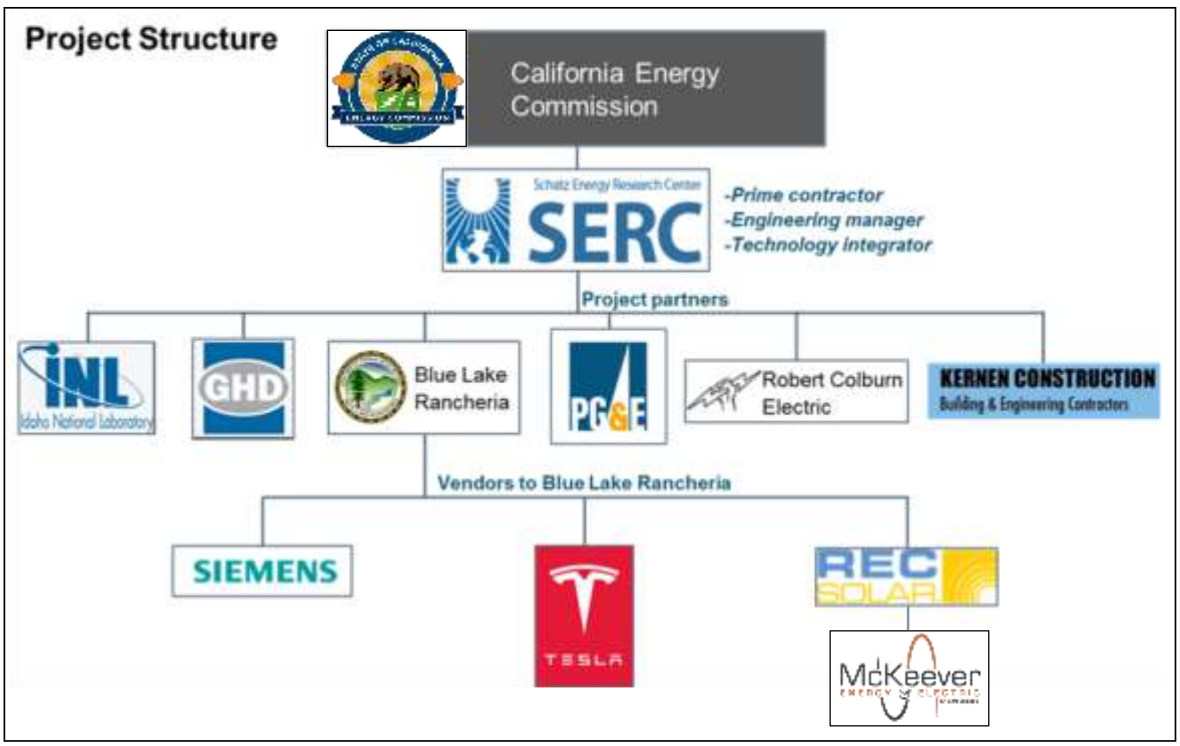
Beyond the direct benefits associated with this specific project, there is significant potential for much greater benefit to be realized via the increased deployment of microgrids throughout the state. The lessons learned and the significant outreach conducted as a part of this project will help move the deployment of microgrid technologies forward. Chapter 8 briefly examines the market potential for replication of projects like those that the one demonstrated here.

The BLRMG project has demonstrated beneficial impacts for the BLR community, the greater Humboldt County region, and California in terms of providing a functioning example of a secure, reliable, low-carbon community microgrid for a Native American tribe and a designated American Red Cross evacuation center.

Project Team

Figure 5 shows the organizational chart for the project.

Figure 5: Project Team Organizational Chart



Source: Schatz Energy Research Center

The project was led by the Schatz Energy Research Center. Major subcontractors and their prospective role were as follows:

- The BLR and Serraga Energy, LLC (Serraga)
    - The BLR is the site host and owner of the microgrid. Serraga is a project management firm for BLR that contributed significant match funding, supported the project with onsite facilities and IT technical teams and support, and conducted various technology and knowledge transfer plan activities.
- Pacific Gas and Electric (PG&E)
    - PG&E is the regional utility and was a critical project partner from the proposal stage through granting the project permission to operate after a complex interconnection process.
- Siemens
    - Siemens provided its Spectrum 7™ Microgrid Management System (MGMS), which provides the supervisory control and data acquisition (SCADA) functions for the microgrid. SCADA is a computer system for gathering and analyzing data to monitor and control equipment. Siemens also provided a power flow modeling study of the microgrid and significant engineering during hardware-in-the-loop testing and onsite testing and commissioning.
- Idaho National Laboratories (INL)
    - INL tested the microgrid controls and components in the Power and Energy Real-Time Simulation Lab with hardware-in-the-loop connectivity. This was a critical de-risking step to allow the microgrid control system to be tested in a simulated environment before being deployed and commissioned in a live environment. The hardware-in-the-loop test facility was also used to train microgrid operators.
- Robert Colburn Electric (RCE)
    - Colburn Electric was the main electrical contractor for the project, completing all electrical construction with the exception of the solar PV array. Colburn Electric has extensive experience with the electrical infrastructure at BLR and expertise in large and small electrical systems. This experience greatly improved the efficiency and outcomes of all microgrid deployment activities.
- REC Solar
    - REC Solar provided the turnkey solar PV array and hired a local electrical contractor, McKeever Energy & Electric, to install it.
- Tesla
    - Tesla provided the battery energy storage system (BESS) and engineering support to integrate the BESS into the microgrid.

- Kernen Construction
    - Kernen Construction provided all of the civil construction services, such as grading, trenching, and construction of concrete slabs necessary for the project.
- GHD
    - GHD provided electrical engineering support and acted as the electrical engineer of record for the project.

CHAPTER 2: Design and Engineering

Engineering Design Process

The engineering design process for the project used a hybrid design-build approach with engineers, contractors, and vendors working together to design the microgrid. The design process had five stages:

- 30% design completed during the proposal stage
- 50% design completed on January 8, 2016
- 90% design completed on May 2, 2016
- 95% design completed on June 15, 2016
- 100% design completed on September 15, 2016

At each stage, a package that contained engineering plans, a concept of operations document (CONOPS), and an engineer's opinion of probable cost was presented to stakeholders for review. The package communicated the design intent with progressing levels of detail at each stage. The CONOPS presented the latest understanding of microgrid use cases, control functions, operational parameters, and constraints. The engineer's opinion of probable costs served as a cost check to make sure that the microgrid could be implemented within the constraints of the fixed project budget. At each review stage, comments were collected, reviewed and discussed, and used to guide the design work toward the next milestone.

Due to the grant timeline, the project had to be constructed during one construction season (May through November 2016). This required an early start on many of the construction tasks. Consequently, the 90% design package included an early start package with 100% construction-ready designs for the PV array, network upgrades, and load-shed system. The 95% design package contained complete construction details for most aspects of the project, except some of the control system and network wiring diagrams and specifications. The 100% design package contained all the details required for construction of the complete system. Changes made to the design after the release of the 100% design package were captured and included in the as-built project documentation.

The roles of the various team members in the design process were as follows: SERC led the design and electric utility interconnection processes and acted as the lead technology integrator, construction manager, commissioning agent, civil engineer of record, and owner's engineer for the BLR and Serraga. GHD acted as the electrical engineer of record. Colburn Electric acted as a design advisor. In response to design specifications provided by SERC and Serraga, vendors designed specific components and subsystems. REC Solar designed the PV system, which included a single point of connection with the microgrid for power and communication. Tesla designed the battery energy storage system and provided design information for integrating its system into the microgrid. Johnson Controls designed the energy management system used for shedding load- in the microgrid. Eaton designed the point of common coupling switchgear based on plans and specifications provided by GHD. Siemens conducted a power flow study of the microgrid and provided the Spectrum Power™ Microgrid Management System (MGMS). Siemens also provided guidance to SERC, Tesla, Johnson Controls, and REC Solar throughout the design process to promote the integration of subsystems into the MGMS.

Microgrid Control Strategy and Design

Siemens was originally envisioned to handle the microgrid control strategy by using its MGMS. However, as the design progressed, it became clear that while the MGMS would ultimately act as the central microgrid controller, SERC would need to develop foundational aspects of the microgrid control system to promote reliable electrical service during construction and on-site commissioning. This was necessary to support the first use of the Spectrum 7 MGMS in a third-party, live microgrid environment. The CONOPS became the governing document for communicating the microgrid control strategy. SERC authored the CONOPS and used it to coordinate the design teams from Siemens, Tesla Energy, and Johnson Controls.

The microgrid control strategy has two modes:

1. MGMS mode
2. Automatic transfer switch (ATS) mode

The following sections provide a brief description of these two control modes. Figure 6 provides a simple single-line diagram of the BLRMG that will help orient the reader to the modes, design, and function of the microgrid.

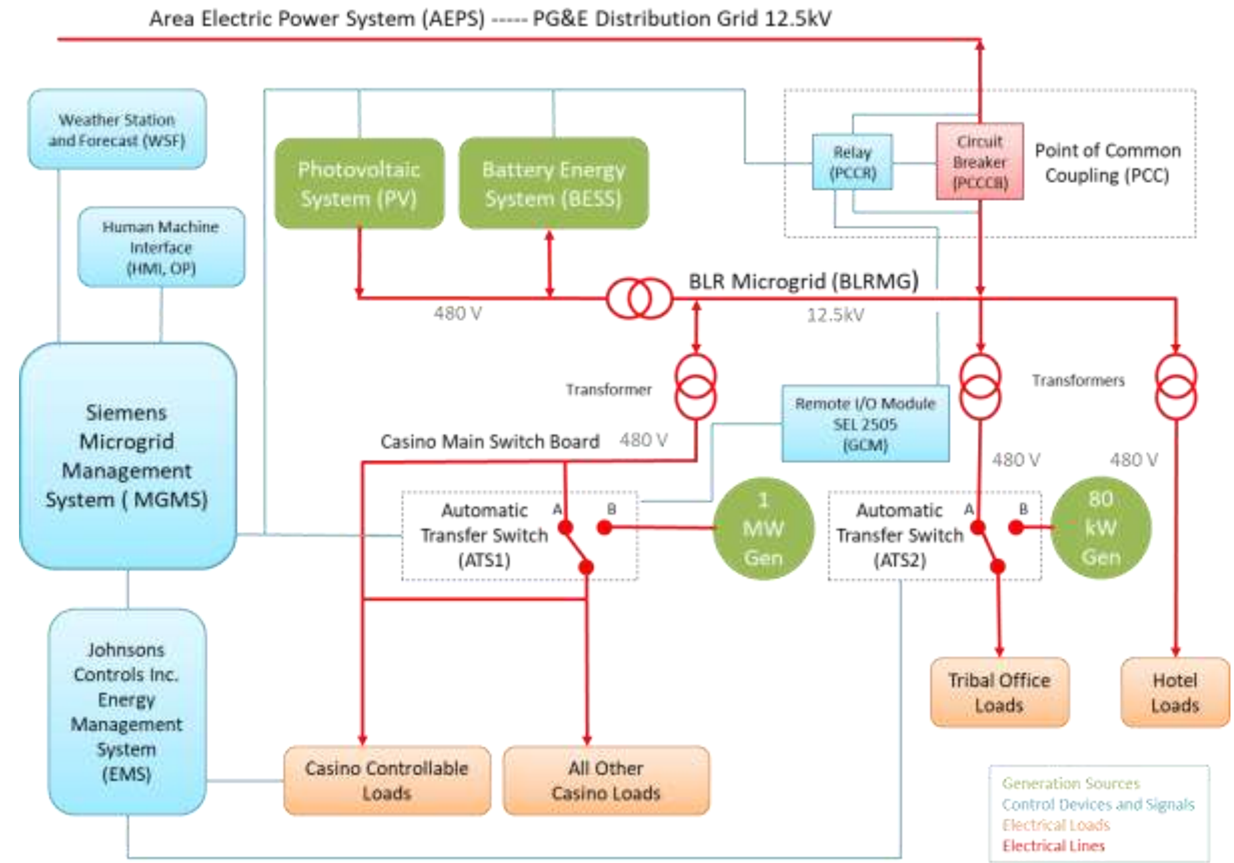
MGMS Mode

This is the normal control mode for the microgrid. The MGMS provides automated control in grid-connected and islanded modes and responds to PG&E grid status by automatically disconnecting and reconnecting to the utility grid as needed to keep the microgrid loads energized. In grid-connected state, a microgrid optimization module (MOM) in the MGMS automatically dispatches the battery to minimize cost via peak shaving and energy arbitrage (buying energy at a low price, and then selling it later for a higher price). When in an islanded state, the MGMS automatically maintains nominal voltage and frequency on the microgrid, determines which generation sources will serve the load, and manages load sharing between generation sources. In MGMS mode, the MGMS manages the transition to the islanded state using either the BESS or the 1-megawatt (MW) isochronous (constant frequency) generator (DG), depending on the net load at the time of the transfer.

The MGMS communicates with a Schweitzer Engineering Laboratories (SEL) 700GT+ relay (henceforth, “relay”) to start/stop and connect/disconnect the 1 MW DG during islanded operation and to trip/close the point of common coupling circuit breaker (PCCCB) between the microgrid and PG&E. The Tesla battery energy storage system (BESS) can also trip/close the

PCCCB using the relay for either seamless or break-before-make transitions. While the MGMS and the BESS can trip/close the PCCCB through the relay, both commands originate from the MGMS (the BESS will not request a trip/close action of the relay without receiving a command from the MGMS). Protective functions programmed into the relay by SERC prevent unsafe breaker close commands from being executed.

Figure 6: Simplified 1-Line Diagram of BLRMG



Source: Schatz Energy Research Center

ATS Mode

This is a fail-safe operational mode for use during construction and commissioning, or for any time the MGMS is offline. In this mode, basic automatic transfer switch functionality for the entire microgrid is provided by the SERC-programmed relay, and all commands from the MGMS and BESS are ignored. Direct manual control of the relay using push buttons on the device is also available in this mode.

Since the relay has been programmed with all the applicable protection settings required by PG&E Electric Rule 21 for interconnection of distributed generators, the relay will open the PCCCB on a grid fault regardless of what mode it is. In ATS mode, after the PCCCB opens on a grid fault, the relay black starts the microgrid with the DG. The BESS will go into standby (no AC power output), and the PV will reconnect with maximum power output capped at 50% (to prevent under loading or reverse-powering the DG). After the PG&E grid has been re-energized for 15 minutes, the relay will disconnect the DG and close the PCCCB. The PV will reconnect with no output limit five minutes later.

In either ATS or MGMS mode, operators can manually transfer between grid-connected and islanded states using the operator controls on the relay. If the operators island the microgrid using these relay push-button controls, then the only way to reconnect to PG&E is by also using the buttons. This is implemented as a safety feature for greater operator control during maintenance procedures.

Operators can switch between MGMS and ATS modes using buttons on the relay. In addition, the control system will automatically switch from MGMS mode to ATS mode if the microgrid 12.5 kV bus becomes de-energized for more than 15 seconds. This reliability feature provides backup foundational control functions in case there is a problem with the MGMS.

Load Shedding

The control system includes five levels of load shedding that can be used to reduce loads for prolonged islanded operations during emergencies. The load shedding control is accomplished through an interface between the MGMS and an energy management system (EMS) provided by Johnson Controls. Operators must manually engage a given load shed level through a dedicated screen on the MGMS console computer. The MGMS then sends a binary output command to the EMS, which, in turn, changes the operating state of various pieces of equipment to cause a reduction in microgrid loads. Table 1 shows the five load shed levels and the associated approximate load reductions.

Table 1: Load Shed Levels in the BLRMG Control System

Level	Description	Approximate Demand Reduction (kW)
1	Transfer Tribal Office Loads to preexisting backup generator	30
2	Rotating outage of 25 noncritical HVAC compressors	30
3	All 25 noncritical HVAC compressors	100
4	Gaming	100
5	Exhaust fans and noncritical HVAC Unit Fans	75

Source: Schatz Energy Research Center

Electrical Design

The electrical design was completed under the supervision and direction of licensed electrical engineers at GHD, Inc. and consisted of the following plan sheets:

- Electrical Legend & Abbreviations
- Overall Electrical Site Plan
- Casino Electrical Plan

- Tribal Admin Office Electrical Plan
- PV System Electrical Plan
- Battery System Electrical Plan
- PCC Switchgear Electrical Plan
- Electrical Details
- PCC Switchgear Single-Line Diagram
- Blue Lake Casino Single Line Diagram
- Tribal Office Single Line Diagram
- Electrical Three Line Diagram
- Electrical Network Diagram
- Miscellaneous Diagrams

The electrical design involved reconfiguring three secondary services serving six buildings on the BLR campus into one primary service at 12.5 kV, three phase. The PCCCB is housed in a new three-compartment outdoor electrical enclosure (PCC). The PCC contains a PG&E metering section, a 1,200-Ampere main breaker section, and a substation battery section. Redundant SEL 700GT+ protection relays and customer metering are included in the main breaker section. The PCC is energized via an underground primary service originating from a pole roughly 25 feet from the enclosure. An air switch on the pole provides a visible lockable disconnect for PG&E.

From the PCC, underground conductors connect to a pad-mounted S&C PMH-9 switch that serves as BLR is visible lockable disconnect. BLR can open this switch and manually operate the microgrid in the event that the PCC is offline.

From the PMH-9 switch, underground circuits feed four transformers on the BLR campus. The tribal office complex is fed through a 75 kVA, 12.5 kV, 208 V three-phase transformer. The casino, event center, two restaurants, emergency shelter, and associated buildings are fed by a single 1,000 kVA, 12.5 kV-480 V three-phase transformer. The hotel is fed by another 1,000 kVA, 12.5 kV-480 V three-phase transformer. The 420 kW_{AC} photovoltaic (PV) array and the BESS are AC coupled at 480 V and then connected to the microgrid through a dedicated 1,000 kVA, 12.5 kV-480 V three-phase transformer, which is connected to the 12.5 kV system via a pad-mounted four-point junction.

Two preexisting generator sets (DGs) were incorporated into the microgrid. An 80 kW DG was originally installed as a backup power supply for the tribal office, and the 1 MW DG was originally installed as a backup power supply for the casino and events center. Neither of these isochronous DGs was originally designed to parallel to PG&E and they were intended for backup power only.

Under this project, the 80 kW DG was configured to come on-line and energize the office load as a load shed action for the emergency use case. Now operators can transfer the office load to and from this DG at will from the MGMS human-machine interface (HMI). The 80 kW DG is not capable of paralleling with the microgrid or PG&E's grid.

Under the project, modifications were made to the ATS that connects the 1 MW DG to the microgrid such that the microgrid can parallel with this isochronous DG. An interlock in the microgrid control system prevents the 1 MW DG from ever paralleling with the PG&E grid. The 1 MW DG now serves as a backup power supply for the entire microgrid. If the reserve margin for BESS-only operation is not met when islanded on BESS and PV only, the MGMS can seamlessly bring the isochronous 1MW DG on-line and load share with the BESS and PV.

Electrical Studies

Table 2 shows the electrical studies completed during the design phase of the BLRMG project. These are briefly discussed below.

Table 2: Electrical Studies Completed During Design Phase

Study	Authors
Blue Lake Rancheria Microgrid Study	Siemens PTI (Power Technologies International)
Load Flow and Voltage Drop Study	GHD
Electrical Coordination Study	GHD
Short Circuit Study	GHD
Arc Flash Study	GHD

Source: Schatz Energy Research Center

Blue Lake Rancheria Microgrid Study

The B Microgrid Study was completed using the PSS SINCAL simulation software package. The research team performed steady state and stability analyses. The following four steady-state scenarios were analyzed:

1. Scenario 1: BLR is connected to the PG&E grid, and all internal renewable generation sources are offline.
2. Scenario 2: BLR is connected to the PG&E grid with all internal renewable generation sources in service with priority to be dispatched.
3. Scenario 3: BLR disconnected from the PG&E grid supplying its own load with internal generation sources.
4. Scenario 4: While BLR is operating as described in Scenario 3, a fault occurs, forcing the internal generation sources to supply the casino load only

The conclusion of the steady-state study was that all voltages and thermal loadings in the buses and line sections were maintained within normal criteria and no thermal or voltage violations were found.

The stability analysis was performed to evaluate the ability of the generation sources, especially the BESS, to start motor loads when disconnected from the PG&E grid. Two scenarios were considered; BESS at full state of energy (SOE) and BESS at minimum SOE. The results indicated that the BESS would not likely be able to start all the motor loads without support from the DG. The study estimated that the amount of motor load in the system was about 614kW, which is conservatively high.

The study identified the following potential issues:

- Effects of variations in the solar PV output during islanded operations
- Short circuit current that may not be adequate for fault detection during islanded operation without the DG on-line

Other Electrical Studies

The other studies shown in Table 2 were performed using SKM PowerTools. The Electrical Coordination Study included protective devices at the first level of connection, where power sources and main load switchboards connect to the microgrid. The Short Circuit Study determined the fault current at the main breaker of each Rancheria-owned service entrance (tribal office, hotel, and casino) connected to the microgrid. The Arc Flash Study determined the arc flash category rating at the main bus, where each major microgrid component is connected to the microgrid. This information was used to develop arc flash warning labels that were affixed to each associated electrical service panel, as appropriate.

Civil and Structural Design

The civil engineering design was completed under the supervision and direction of a licensed civil engineer at SERC and consisted of the following plan sheets:

- Civil Legend and Abbreviations
- Overall Civil Site Plan
- PCC Civil Site Plan
- BESS and PV Civil Site Plan
- PCC Sections- 1
- PCC Sections- 2
- PV Array Field Prep Plan
- Civil Details

Structural engineering was completed under the supervision and direction of a licensed civil engineer at SERC. Structural engineering was limited to equipment anchoring and concrete equipment pad design.

Network and Communications

Network and communications engineering was a joint effort among SERC, BLR, and GHD. SERC created a data flow diagram showing each device that has a role in the microgrid communications, control, and generation systems. The dataflow diagram showed the signal paths and characteristics between all devices. From this data flow diagram, SERC created a data flow table to add details such as IP addresses. Next, a network diagram was created by GHD and added to the electrical plan set. The data flow diagram, data flow table, and network diagram were created after the 50% design review and were revised at 90% and 95% level of detail. The 100% network diagram was used during construction to install the required components for inter device communication, monitoring, and control.

The research team also conducted a cybersecurity assessment as part of the network and communications design. BLR led the cybersecurity assessment, with support from the National Renewable Energy Laboratory. BLR Information Technology (IT) staff is trained in cybersecurity analysis and protection methods and made sure that the microgrid network and communications design met the stringent cybersecurity requirements for the facilities.

Concept of Operations Document

The Concept of Operations Document (CONOPS) was drafted early in the project, and the research team included the first revision in the 50% design review package. The CONOPS described the characteristics of the proposed microgrid from the point of view of the operators. The document was used to communicate to all stakeholders how the microgrid would operate.

As the lead system integrator, SERC created the CONOPS draft while working closely with BLR, Siemens, Tesla, Johnson Controls, GHD, REC Solar, and Colburn Electric to develop a common understanding of how the microgrid should operate. At the 50% review stage, all team members reviewed the CONOPS and provided comments. These comments highlighted areas where team members had different understandings of microgrid operational characteristics. Ultimately, equipment and software providers constrained what the microgrid could and could not do from a technical and contractual perspective (what their system is capable of and what their contract responsibilities are for the project). BLR and PG&E requirements defined what the microgrid capabilities needed to be from an owner preference and regulatory perspective. The CONOPS document was the primary tool used to balance the form and function of the microgrid within the technical, contractual, owner preference, and regulatory constraints. The CONOPS was revised 11 times to account for changes as stakeholder understanding deepened throughout the project. The final CONOPS was used in developing commissioning test plans and preparing the operations and maintenance manual for the project. Excerpts of the final CONOPS are attached as Appendix A.

Interconnection Process

The interconnection for the project had three parallel approval processes:

1. Purchase and sale agreement
2. Service rearrangement
3. Interconnection agreement

These three processes were executed in parallel, with certain aspects coordinated in series.

Purchase and Sale Agreement

To install the microgrid as designed, the BLR needed to purchase the end of the Blue Lake 1102 distribution circuit from PG&E, and this required CPUC approval of a purchase and sale agreement. This was difficult to plan and implement because it is not a common process, and CPUC approval is required, which was seen as a scheduling risk. The process began with PG&E taking an inventory of the assets that would be sold to BLR. PG&E then had to assign a value to these assets for the sale to occur. Asset sales like this are rare, and PG&E was careful in its analysis. Moreover, the software used to determine asset value was outdated, and PG&E had to expend extra effort to generate cost numbers. Once the value was determined, PG&E prepared a purchase and sale agreement and the required advice letter filing to the CPUC. The CPUC approval time was shorter than expected, and the sale was approved in September 2016.

Service Rearrangement

As the approval for the purchase and sale agreement was being sought, the project team proceeded with the service rearrangement. This work was considered "at risk" because if the CPUC did not approve the purchase and sale agreement, then the service rearrangement could not proceed. Fortunately, PG&E and BLR were very strong partners on this project, and the work proceeded despite this risk.

The service rearrangement involved designing, procuring, and testing the PCC switchgear. During the design phase, PG&E engineers reviewed the shop drawings from the manufacturer (Eaton) and provided comments. The design was finalized, the order was placed, and the switchgear was built and delivered. Once the switchgear was installed, the following steps had to be completed before the official onsite pre-energization test could be completed with PG&E:

1. Emmerson Reliability Services (ERS) was hired to come to the site and conduct site acceptance testing on the switchgear, which included checking all connections, insulation resistances, and other build-specific checklist items.
2. While ERS was onsite, it tested the protection relays and generated relay test reports.
3. The relay test reports were sent to PG&E to verify that the correct protection settings were programmed into the relay and the basic protection settings performed as expected under the test conditions.
4. The 48-volt DC battery system, which provides uninterruptable power for the protection relays, was commissioned and tested by SERC, and a test report was sent to PG&E.

Once these items were approved by PG&E, the pre-energization test (PET) was scheduled for October 6, 2016. On that day, ERS came back to the site, and PG&E sent an inspection team. The basic relay protection settings passed, but some control functions did not pass. Even though for the service rearrangement process PG&E was interested only in the protection settings, the fact that the control functions necessary for microgrid operation did not pass meant that a new test date had to be scheduled to verify correct protection and control settings before the switchgear was energized. Fortunately, PG&E was able to schedule the second PET for October 19, 2016.

The problem that led to the failed test was that each programming team focused solely on the settings that were specific to the team's responsibility and not the integrated settings file. The relay settings were initially programmed by engineers at Tesla Energy and then sent to GHD, where the protection settings were added before the settings were written to the relays. The relay settings for the BLRMG (and probably most microgrids) are more complicated than a typical protection relay settings file.

After the failed test, SERC took control of programming the relay settings files for microgrid protection and control. SERC relied on GHD engineers to verify that the protection settings were consistent with PG&E requirements, Tesla Energy verified that the BESS functionality was supported, and Siemens verified that the MGMS functionality was supported. ERS and PG&E inspectors came back to the site for the second PET, and this time, all relay settings passed.

With the pre-energization test passed, the cutover to the new primary service was scheduled for November 6, 2016. The cutover was accomplished on schedule, and this concluded the service rearrangement process. After the cutover, the BLR began operating as a basic microgrid with control provided by the protection relay settings, meaning the system ran in ATS mode.

Interconnection Agreement

The interconnection agreement process used all the information that was generated and provided to PG&E for the service rearrangement, plus additional information regarding controls, inverters, interlocks, synchronization, and so forth. This process involved approval of an interconnection application, a preparallel inspection (PPI), and, upon passing the PPI, obtaining permission to operate.

From PG&E's perspective, certain aspects of the system were rather routine. This included the PV array, which was commissioned in December 2016. Other aspects of the microgrid were more complicated, including the following:

- SERC requested that the ride-through settings for over-/undervoltage and frequency be set in the protection relays at the PCC, so the research team could relax the ride-through settings for the PV inverters. This could allow the PV inverters to ride through seamless transitions between grid-connected and islanded states.
- The details of the interlock between the DG tie breaker and the PCCCB had to be carefully reviewed to ensure that the DG would never be able to parallel with PG&E.
- The seamless transitions between grid connected and islanded states were of keen interest to PG&E, and the project team was not allowed to test them before the PPI.
- The microgrid design includes an 800 ampere (A), 480 V, three-phase, manually operated circuit breaker in series between the BESS and the PCCCB. PG&E pointed out that a synchronism check was needed on this circuit breaker since the BESS can be grid-forming, and technically, this breaker could be manually closed, connecting two out-of-phase AC sources. Providing a synchronization check at this breaker was outside the project budget, and SERC specified a Kirk Key interlock system to ensure that both BESS emergency stop switches have to be engaged whenever that circuit breaker is manually

closed. This ensures that the BESS is not energizing its side of the circuit breaker when the closure happens, thereby addressing the issue.

The research team spent January and February 2017 commissioning and testing the microgrid controls, first at the Real Time Digital Simulation Laboratory at Idaho National Laboratories and then onsite at BLR. Upon completion of that testing, the PPI was scheduled with PG&E for March 29, 2017. PG&E sent two inspectors to the site for two days of PPI testing. Everything passed except for the seamless transitions to and from grid-connected states.

These were the first attempts at the seamless transitions, and though they did not work, they failed safely. PG&E was impressed with the test results and granted the team conditional permission to operate for testing only. PG&E also allowed the team to proceed without another onsite PPI. Instead, the team was allowed to send event capture data from the relay once the seamless transitions were working. An additional requirement was for Tesla to prove that its inverters would not parallel with PG&E in grid-forming mode for more than two seconds.

The team kept working to perfect the controls and transitions and was able to provide the data PG&E requested in July 2017. PG&E reviewed the data, and on July 26, 2017, the project was granted full permission to operate with the full functionality described in the CONOPS document successfully implemented.

Engineering Plan Set

As discussed, the engineering plan set was an integral part of project development. The preliminary plan set was developed during the proposal stage of the project. During the initial months of the project, the design team added detail to the preliminary plan set and brought them up to a 50% level of completeness, making them ready for stakeholder review. Comments from the 50% design review process were incorporated, and details were added to create a 90% complete engineering plan set. The 90% set contained 100% level of detail on some aspects of the design and represented an early start package so that contractors could start work on May 15, 2016. This 90% complete set was also reviewed and commented on by all stakeholders. Again, comments were incorporated into a revised set, and detail was added to achieve a 95% level of completeness on July 5, 2016. The 100% design completeness level was achieved on September 15, 2016. Selected 100% design plan sheets are included in Appendix B.

Engineering Specifications

Engineering specifications for the project were produced differently than for a typical design-bid-build project, where a specification book is part of the bid package. Instead, the specifications were called out on the plans, and there was dialog between stakeholders about equipment specifications throughout the design process. In that way, vendor-specific requirements could be met to allow for rapid deployment of emerging technologies. A partial compilation of the key specifications used for this project is included in Appendix C.

Engineering Cost Estimates

The first engineering cost estimate was developed at the proposal stage using the preliminary design plans, and work was delineated into the following divisions:

- Civil Construction
- Electrical Construction and Commissioning - PV
- Electrical Construction and Commissioning - EMS
- Electrical Construction and Commissioning - BESS
- Electrical Construction and Commissioning - General

A team led by a licensed civil engineer at SERC prepared the preliminary design plans and an opinion of probable costs during the proposal stage. The preliminary design plans were then provided to contractors for each of the divisions listed above, and not-to-exceed pricing was requested. From here, a series of negotiations ensued to refine the design and finalize the costs for the proposal.

Additional significant project costs, such as procuring and commissioning the MGMS and the testing completed at INL, were not included in the initial engineer's opinion of probable construction costs and were accounted for as separate line items in the project budget.

After the project was award by the California Energy Commission, contracts between all partners and vendors were finalized using the costs agreed upon during the proposal stage. At this point, the contractor budgets became fixed. The risk in contracting large construction projects in this way is quite high. Normally, the standard method would be for engineers to develop the design to the 100% level of completeness before soliciting bids from contractors. This allows an accurate cost bid to be developed by the contractor and for the engineer to manage costs with good precision. In this case, a fixed price had to be agreed upon when the level of completeness for the design was about 30%. Many things change as the design develops, and it is very challenging to control costs and maintain project quality when the construction costs have to be agreed upon so early in the design process. Nevertheless, these were the conditions under which the project was developed.

To reduce these risks, the engineer's opinion of probable costs was revised at each design review stage (30%, 50%, 90%, and 100%), and contractors were asked to provide a statement of cost conformance indicating whether the design shown in the plan set could be built within the original project budget. In some cases, value engineering was required to keep the construction costs within budget.

In the end, there were cost overruns in the civil construction (about $40,000) and electrical construction and commissioning (about $50,000). These cost overruns were reconciled between Serraga and Kernen Construction for the civil work, and with Colburn Electric for the electrical work. Serraga's willingness to fund these cost overruns was a key factor in the success of this project. The total budget of the project was about $6.3 million,[1] and the overrun of roughly $90,000 is less than 1.5% of the total project cost. Given the first-of-its-kind nature of this project, to be significantly under a typical construction contingency of 10% is an achievement. PG&E and the private company partners of the project – particularly Siemens, Tesla, Colburn Electric, and Kernen Construction – provided in-kind work to ensure their budgets remained fixed for the project and that their technologies and work products were successfully integrated within budget constraints. Their willingness to work on integration issues outside the formal text of their contracts ultimately made the project successful.

1 It is estimated that approximately 15% to 20% of the project costs were associated with the first-of-its-kind, research nature of the project.

CHAPTER 3: Equipment Procurement and Testing

This chapter presents the processes that were followed to procure the equipment and services necessary for installing and commissioning the BLR microgrid.

Procurement Process

The procurement began during the proposal stage of the project, once the preliminary design had been completed. At that stage, the major microgrid components were shown on the preliminary design plan sheets with annotations to show who was responsible for procuring and installing each component. These plans were circulated among the project team members and used to gain agreement regarding which member was responsible for procuring and installing each component and the associated subsystems.

Once agreement was reached regarding the preliminary design plans, an overall scope of work was developed, along with a division of responsibilities (DOR) spreadsheet. These documents were used to add detail and deepen the understanding of how the project would be executed if funding was awarded.

After roles and responsibilities were clearly delineated, each of the project participants (subcontractors and vendors) was asked to provide a not-to-exceed budget for its part in procuring, installing, and testing the various components and supporting subsystems in the microgrid. The pricing gathered during this proposal stage then became the basis for the proposal budget that was submitted to the Energy Commission.

After the Energy Commission awarded the project and during the contracting phase, SERC used the overall scope of work, the preliminary design plans, the DOR spreadsheet, and the Energy Commission budget to develop detailed contracts with each of the subcontractors. These detailed contracts included terms and conditions, a partner-specific scope of work document, a budget, and a project schedule. The research team took care to ensure that the overall project scope of work would be completed by virtue of completing all the subcontracts issued under the project.

This process resulted in subcontracts with the entities listed in Table 3. Of the subcontractors listed, only Serraga and Robert Colburn Electric were responsible for equipment procurement. The remainder of this chapter explains how the major components and subsystems were procured under the project.

Table 3: BLRMG Project Subcontractors

Subcontractor	Role
Serraga Energy, LLC (Serraga)	Blue Lake Rancheria tribe's project development and management entity
Robert Colburn Electric (RCE)	Electrical contractor
GHD, Inc.	Electrical engineering
Kernen Construction	Civil/site work contractor
Idaho National Laboratories (INL)	Real-time digital simulation, hardware-in-the-loop testing of microgrid system

Source: Schatz Energy Research Center

Microgrid Management System

The Microgrid Management System (MGMS) was procured by Serraga from Siemens. A Serraga purchase order and a Siemens master services agreement were used to procure the Siemens Spectrum Power™ Microgrid Management System software and the necessary hardware including:

- Three servers (one for BLR, one for INL hardware-in-the-loop testing, and one for Siemens).
- One console computer for BLR.
- One GPS clock.
- Engineering support.
- Design/testing/commissioning/data analysis/operations support.
- Up to five display consoles.
- Spectrum Power™ Microgrid Management System License
- Warranty.

The MGMS was programmed and tested at Siemens' facility in Minnetonka, Minnesota, and then installed and tested at INL. After testing at INL, the MGMS was installed at BLR. Siemens engineers hosted trainings at the Minnetonka facility, supported hardware-in-the-loop testing at INL, then completed interfacing and commissioning onsite with support from SERC and Serraga. No contract change orders (CCO) resulted from procuring the MGMS for the project.

Battery Energy Storage System

Serraga procured the battery energy storage system (BESS) from Tesla. A Serraga purchase order and Tesla master battery purchase and sales agreement were used to procure the BESS, which included:

- Two 250 kW Dynapower inverters
- 10 Tesla Powerpack lithium ion battery modules.

- Two DC combiner panels.
- One Tesla site master controller.
- Engineering/installation support.
- Five-year warranty.
- Five-year operations and maintenance (O&M) contract.

The BESS was shipped to BLR and RCE completed the installation. Once the installation was complete, Tesla commissioned the system and worked with SERC and Siemens engineers to test the system onsite as part of the microgrid. No CCOs resulted from procuring the BESS for the project.

PV System

Serraga procured the turnkey PV system from REC Solar. An engineering, procurement, and construction contract was used to procure the turnkey PV system. REC Solar designed the PV system and hired local electrical contractor McKeever Energy & Electric (ME&E) to install it. ME&E hired a subcontractor, Humboldt Fencing Company, to install a fence around the PV array field.

Kernen Construction, working under a separate subcontract with SERC, prepared the PV array site, built the access roads, and placed the weed mat and aggregate base after the piles had been driven for the racking system. These activities were conducted in compliance with the storm water pollution prevention plan and permit for the site. RCE installed the circuit that connects the PV array to the BESS and to the microgrid. SERC coordinated the work to prevent conflicts from multiple contractors working on the same site. Several CCOs resulted from procuring the PV system and were paid for by Serraga. These CCOs stemmed from:

- The need for extra work to support the hardware-in-the-loop testing at INL.
- Additional instrumentation that was requested beyond that which is provided in the standard meteorological package.
- The data logger manufacturer having to develop a custom software driver for the revenue grade PV output meter that was specified.[2]
- The originally chosen inverter manufacturer not being able to meet the functionality and control specifications for islanding operations of the project, so another inverter had to be selected, resulting in a cost increase.

Point of Common Coupling Switchgear

RCE procured the point of common coupling (PCC) switchgear from Eaton. GHD produced the one-line and three-line diagrams of the microgrid, and RCE submitted these to Eaton. Eaton produced shop drawings that were reviewed by PG&E, SERC, and GHD. After approval of the

2 The power meters installed were all the same to simplify interfacing and the list of applicable meters was limited due to Tesla's approved meter list.

shop drawings, Eaton manufactured the PCC switchgear and shipped it to the site, and RCE installed it. More information about testing the PCC switchgear is provided in Chapters 2 and 6. No CCOs resulted from procuring the PCC switchgear for the project.

Energy Management System

Based on initial design engineering, adding an EMS for two of the largest electrical-load buildings (the event center, restaurants, and casino) was necessary to meet the load shed, PG&E distribution grid connectivity, and required MGMS functionality requirements for the project. The EMS provides load shed functionality for the BLRMG through an interface with the Siemens MGMS and was procured by Serraga from Johnson Controls, Inc. (JCI). A JCI proposal and customer order form was used, which included:

- An application data server.
- A network integration engine - Supervisory Controller, 1 Trunk Modbus, 1 Trunk MSTP BACnet.
- A network control engine.
- Three field-embedded controllers.
- Nine exhaust fan contactors.
- 25 wireless thermostats.
- Four wireless coordinators.
- Six uninterruptable power supplies.
- Engineering.
- Programming.
- Commissioning/checkout.
- Metasys software package.

RCE installed network and power wiring for the EMS components, and JCI installed its own hardware components. The installation and commissioning of the JCI system had several issues, which are ongoing as of this report. These include, but are not limited to, nuisance alarms for the loadshed watchdogs, and “AC rotate” programming was not functioning as designed. There was one CCO for two additional site visits, four remote phone support sessions, and two additional drawings, which JCI required for microgrid system integration. Serraga paid for this CCO.

Balance of Systems

The balance of systems (BOS) for the BLRMG can be categorized into two categories: civil and electrical.

Civil

SERC procured the BOS for civil works using a subcontract with Kernen Construction. Civil work items not mentioned above included trenching for power and communication circuits and constructing concrete pads for the PCC switchgear, BESS, and PV system point of connection (POC) switchgear. In addition, miscellaneous items were required, such as a drop inlet and drain pipe near the BESS pad and a 6-inch-diameter water main extension under the BESS pad to the vicinity of the PV array field for future use. A CCO was granted under the subcontract with Kernen Construction to account for changes in quantities of aggregate base and trenching that occurred between the proposal phase and the construction phase of the project. Serraga paid for the CCO.

Electrical

SERC procured the BOS for the electrical work by using a subcontract with RCE. Electrical work items not mentioned above include, but were not limited to:

- Landing the medium-voltage conductors in the PCC during the cutover to the new primary service.
- Installing low-voltage power and communication circuits between the PCC switchgear and the tribal office.
- Installing the 48 V battery system and charger in the PCC switchgear.
- Installing the BESS and PV coupling switchgear and boost transformer.
- Installing the medium-voltage connection between the boost transformer and a preexisting four-point junction on the microgrid.
- Installing a bus tie bridging the normal circuit breaker in the 1,600 amp automatic transfer switch in the Blue Lake Casino (BLC), which enabled the preexisting 1 MW isochronous DG to power the entire microgrid instead of just the BLC, as was the case.[3]
- Installing various power and communication circuits inside the tribal office and BLC to enable microgrid operations.
- Installing a new controller in the 1,600 amp ATS in the BLC (Eaton technician onsite to assist).
- Installing power meters on the 1 MW isochronous DG, the BLC load, the hotel load, the tribal office load, and the BESS and PV coupling switchgear.
- Providing site acceptance testing and relay testing on the PCC switchgear for the pre-energization tests (PET) and the preparallel inspection.

RCE has extensive institutional knowledge of the BLR campus and took responsibility for all the electrical construction except for work items falling under PG&E, REC Solar, and JCI's divisions

3 This procedure was done twice because the first attempt revealed that the ATS controller needed to be upgraded. Consequently, the procedure was reversed, rescheduled, and repeated.

of responsibility. A CCO was requested under the subcontract with RCE to account for the new controller for the 1,600-amp ATS in the BLC and an unplanned round of on-site relay testing to support the second PET prior to the cutover to the new primary service. Serraga paid the CCO.

Microgrid Controller Testing

As part of the procurement, the Siemens MGMS was installed and tested in a real-time digital simulation, hardware-in-the-loop environment at Idaho National Laboratory. This testing is summarized in Chapter 6, Commissioning, and is documented in detail in the INL report titled *Real-Time Modeling and Testing of Microgrid Management System for the Blue Lake Rancheria – Performance Assurance Report* (Mohanpurkar, Luo, Hovsapian, & Medam, 2017). This testing at INL was a critical de-risking step that allowed the MGMS to be deployed and commissioned in a live environment with minimal inconvenience to the site host. The INL testing also created a robust training opportunity where teams from SERC, Serraga, and BLR traveled to INL to learn how to operate the full system under test conditions, increasing knowledge and capacity before the system was live onsite.

CHAPTER 4: Microgrid System Interfacing

The BLRMG is composed of networked actors. These actors operate autonomously, semiautonomously, or under control of an autonomous actor. This chapter summarizes the control hierarchy and basic functions of the various actors.

Microgrid Control Hierarchy

The BLRMG actors contribute different control and monitoring features that operate at different control hierarchy levels. The control hierarchy is defined according to the four levels listed below:

- Supervisory actors
- Autonomous actors
- Semiautonomous actors
- Controlled actors

Supervisory actors include microgrid components that have primary objectives of monitoring microgrid states and providing commands to microgrid actors to maintain preferred operating conditions. Autonomous actors include components that perform functions independent of control from other components in the system. Semiautonomous actors can operate independent of outside commands and can operate under the guidance of external control. Controlled actors are those actors that will take actions only when given commands from external controllers.

The available features are categorized by the following terms:

- **Protection** – describes monitoring and control specific to the protection of microgrid components
- **Control** – the ability to command or enact a change in the state of the system
- **Communication** – specific to easing analog and digital communications between actors
- **Generation** – electric power delivery to the microgrid
- **Loads** – electric power consumption from the microgrid
- **Data acquisition** – monitoring and recording microgrid component states and environmental conditions
- **Forecasting** – prediction of future microgrid component states and environmental conditions

Table 4 lists the BLRMG actors, identifies the control hierarchy level for each actor, and lists the control features that are associated with each actor. Appendix D contains a listing of each of the actors grouped by control hierarchy, lists the features associated with each actor, and briefly summarizes the system interface for each actor.

Table 4: Control Hierarchy and Features for BLRMG Actors

Actor	Control Hierarchy	Features
SEL-700GT	Supervisory	Protection, Control, Data Acquisition
Siemens MGMS	Supervisory	Protection, Control, Data Acquisition, Forecasting
Environmental Forecasting and Monitoring System (EFMS)	Autonomous	Forecasting, Data Acquisition
Weather Station/PV Data Logger	Autonomous	Data Acquisition
Power Meters	Autonomous	Data Acquisition
GPS Clock	Autonomous	Data Acquisition
SMA PV Inverters	Semiautonomous	Generation, Control, Data Acquisition
SMA Cluster Controller	Semiautonomous	Control, Data Acquisition
Tesla Battery Energy Storage System (BESS)	Semiautonomous	Protection, Control, Generation, Load, Data Acquisition
ATC900/ATS1	Semiautonomous	Protection, Control
Gen1	Semiautonomous	Generation
ATS2	Semiautonomous	Control
Gen2	Semiautonomous	Generation
JCI - EMS	Semiautonomous	Loads, Control, Data Acquisition
PCC-CB	Controlled	Control
SEL-2505	Controlled	Communications

Source: Schatz Energy Research Center

CHAPTER 5: Construction

This chapter provides an overview of the construction management process and a description of the major construction and installation completed to build the BLRMG. Included at the end of the chapter is a section discussing the challenges encountered and variations adopted during the construction period.

Construction Management

In May 2016, an on-site meeting at BLR was held to kick off the construction of the BLRMG. The SERC management team met with the project subcontractors to discuss the construction schedule, discuss the on-site management and construction observation process, and review the engineering drawing plan set. A list of the subcontractors and their general scopes of work is presented below.

REC Solar – turnkey contractor for the complete photovoltaic system (PV)

- Supplier of PV system components (ground-mount rack system, solar modules, inverters, switchgear, monitoring system, balance of system components, and security fence)
- Design of the PV system and monitoring system
- Responsible party for installation and commissioning of the PV system

McKeever Energy & Electric, Inc. (ME&E) – local subcontractor hired by REC Solar

- Installation of the ground-mount rack system
- Installation of the complete PV system
- Assistance in PV system commissioning tasks

Humboldt Fence Co. – local fence company hired by ME&E

- Installation of the solar array field perimeter security fence

Robert Colburn Electric, Inc. - electrical contractor

- Installation and wiring of the battery energy storage system (BESS)
- Installation and wiring of the PV and BESS transformer switchgear and transformer
- Installation and wiring of the point of common coupling (PCC) switchgear

- Rerouting of 12.5 kV electrical lines during the primary cutover
- Reconfiguration of the casino 480 V bus tie
- Installation of Johnson Controls EMS hardware and associated breakers for load shedding
- Installation of communication wiring, including fiber optic and copper lines
- Installation of balance of system electrical system components

Kernen Construction – civil construction contractor

- Provide earthwork services (clearing, grubbing, grading, and trenching)
- Provide concrete construction services (concrete slab building for microgrid equipment)

During construction, SERC engineers provided on-site management and observation services and documented site work via daily photographs and reports. Serraga and BLR facilities and IT teams were engaged throughout the construction period to review and edit designs and drawings; conduct certain construction activities; support facilities, construction, and IT needs, as identified; conduct procurement; coordinate vendor deliveries and site access; authorize security passes to the subcontractors and vendors; and support various teams with onsite equipment and materials, as needed.

Construction Drawings

The civil and electrical construction engineering plan sets were released for construction and provided to the project subcontractors before commencing construction. All field changes were recorded so they could be documented in an as-built drawing set.

Environmental Review and Storm Water Pollution Prevention Plan

Before beginning construction operations, all required environmental reviews were conducted, including an environmental assessment (EA) by the Blue Lake Rancheria Environmental Programs Division, a cultural resources review by the Blue Lake Rancheria Tribal Historic Preservation Office, and a California Environmental Quality Act (CEQA) review conducted by the California Energy Commission. The EA resulted in a finding of no significant impact (FONSI). The EA/FONSI was published by the Energy Commission, along with the Commission's initial study (IS) and proposed negative declaration (ND), as a part of a notice of intent (NOI) to issue a negative declaration under CEQA. Public postings at five locations were made to promote a 30-day public review, and the NOI/IS/ND was transmitted to the State Clearinghouse for a 30-day state agency review. The original signed NOI was provided to the Humboldt County Clerk-Recorder for 30-day public review, and a copy of the IS/ND was provided to the Energy Commission librarian. There were no public comments received, and an ND was finalized in June 2015.

Pacific Watershed Associates of Arcata (Humboldt County) prepared a storm water pollution prevention plan (SWPPP) was for the BLR site. The SWPPP is an erosion control plan that identifies the best management practices to minimize onsite erosion and prevent sediment or pollutants from entering the stormwater system. Pacific Watershed Associates developed and integrated a SWPPP site map and erosion control plan into the engineering plan set of the project. The site map and plan identify specific locations within the construction area and list the construction activities that will occur in each area. Based on these activities, each area was assigned specific best management practices to address any potential erosion issues. All contractors were responsible for understanding the requirements and instructions provided in the engineering plan set.

Major Construction and Installation Work

The construction and installation period was about 10 months, from March 2016 to January 2017. The first construction activities occurred indoors and included the installation of the HVAC energy management system and preliminary electrical work required for the hotel and casino controllable loads. In April, the weather and ground conditions permitted earthwork to begin with the preparation of the solar array field. By early May, full-time outdoor construction and equipment installation had commenced. A monthly summary of the construction activities is presented at the end of the document.

Most of the construction involved installing three main components within the microgrid: the solar photovoltaic system, the battery energy storage system, and the point of common coupling. A brief description and key photos of the construction and installation activities for these three main components are provided below. Although not documented with photos, the additional balance of system electrical equipment was installed, and electrical power and communications lines were routed throughout the microgrid system.

Solar Photovoltaic System

The solar field is in the northwest portion of the BLR property just north of the City of Blue Lake Wastewater Treatment Plant. A site land survey was conducted to identify field boundaries, and erosion control measures were installed prior to earthwork operations. The construction crews used heavy equipment to clear, grub, and grade the two-acre site (Figure 7).

Figure 7: Solar Field Preparation

Clearing, grubbing, and grading are performed to prepare the solar array field.

Credit: SERC

Once the site was graded, the solar contractor tested the soil to inform the design of the ground-mounted racking system. The solar contractor surveyed the field and began construction of the ground-mounted rack system. A hydraulic pile-driver embedded more than 140 steel mounting and equipment posts to support the array structure (Figure 8).

Figure 8: PV Array Post Driving

Crew uses hydraulic pile-driver to set PV rack structural posts.

Credit: SERC

After the structural posts were set, the solar field was covered with a geotextile mat, and gravel was compacted on top (Figure 9). The trenched areas on the east end of the rows were left uncovered until the subgrade array wiring was completed.

Figure 9: Compacted Ground in the PV Array Field

Crew compacts gravel base in PV array field.

Credit: SERC

The next step was assembling the ground-mounted, galvanized steel racking system. A steel chord was attached to the top of each mounting post and supported by an upper and lower knee brace to achieve the specified array tilt of 20 degrees. Additional steel cording was added to the racking system to ensure seismic strength. Four horizontal purlins were then attached to the chords of adjacent posts to provide the frame for mounting the modules. Once erected, the mounting brackets were adjusted along the length of all eight rows to ensure the framing provided a level surface before attaching the modules. The PV array mounting structure is shown in Figure 10 and Figure 11.

Figure 10: PV Array Mounting Structure

The first assembled PV array mounting structure is shown before PV module installation.

Credit: SERC

Figure 11: Installation of PV Mounting Racks

Contractors install eight rows of PV array mounting racks.

Credit: SERC

Upon completion of the array, the solar contractor took on the arduous task of mounting 1,548 solar modules and wiring them in 86 strings of 18 modules each. Fourteen string inverters were mounted to the array at the east end of four alternating rows. The strings of modules were then wired to the inverters, with 2 inverters receiving seven strings of modules and the other 12 inverters receiving six strings of modules. This installation of the PV modules on the racking structures is shown in Figure 12 and the installation of the inverters is shown in Figure 13.

Figure 12: PV Module Installation

PV modules are installed on the array.

Credit: *SERC*

Figure 13: PV Inverter Installation

Solar contractor installs the SMA inverters.

Credit: *SERC*

On the southeast side of the array field, a concrete pad and Unistrut® rack was constructed to house the PV switchgear and monitoring system. The switchgear (AC subpanel, AC disconnect, and utility-owned net generation output meter) was mounted to the front side of the rack, and the PV monitoring system was mounted on the back side (Figure 14).

Figure 14: Installation of PV Switchgear

Solar contractor installs the switchgear for the PV array.

Credit: SERC

Equipment installation and final electrical and communications wiring were completed as designed, providing a clean and functional layout for the PV system. Figure 15 and Figure 16 show the completed inverter installation at the end of one row of PV modules and the switchgear installation, respectively.

Figure 15: Completed PV Inverter Installation

The completed installation of four PV inverters is shown at the end of one row of modules.

Credit: SERC

Figure 16: Completed PV Array and Switchgear

Completed PV system with PV switchgear in the foreground.

Credit: SERC

Battery Energy Storage System

The BESS procured from Tesla Energy was sited in an ideal location, about 150' southeast of the PV system and in direct line to a four-way, 12.5 kV microgrid junction box. A robust concrete pad was required to house the heavy equipment in the system (10n battery Powerpacks™, two DC combiners, two inverters, switchgear and a 12.5 kV transformer). Construction and electrical field crews cleared the area, installed the necessary subgrade electrical and communications conduits, and built the heavy-duty concrete pad. Figure 17, Figure 18, and Figure 19 show contractors laying conduit, pouring concrete, and finalizing the concrete slab for the battery energy storage system pad.

Figure 17: Laying Conduit in Preparation for Battery Storage System Pad

Field crew installs electrical conduits for battery energy storage system.

Credit: SERC

Figure 18: Concrete Pour for Battery Storage System Pad

Concrete is poured for battery energy storage system pad.

Credit: SERC

Figure 19: Completion of Battery Storage System Pad

The concrete pour for the battery energy storage system is smoothed and finished.

Credit: SERC

Once the pad was cured, the equipment was anchored to the pad and the electrical contractor began wiring the BESS battery packs, combiner boxes, and inverters. Figure 20, Figure 21, and Figure 22 show the installation and wiring of the battery storage system on the concrete pad.

Figure 20: Placing Battery Power Packs on Battery Storage System Pad

The crew places the last power pack on the concrete pad.

Credit: SERC

Figure 21: Wiring the Tesla Battery Powerpacks

The electrical contractor completes the wiring on the Tesla Powerpacks

Credit: SERC

Figure 22: Grounding the Battery Powerpacks

A site electrician grounds a BESS inverter to the grounding network embedded in the concrete pad.

Credit: SERC

The 480 V conductors for the BESS and PV systems were each wired through 800 A breakers, then combined and fed through a 1,500 A breaker and connected to a 1,000 kVA, 480 V : 12.5 kV transformer. This completed the BESS equipment pad installation. Figure 23 shows the wiring of the 1,000 kVA transformer, and Figure 24 shows the completed installation of all the battery Powerpacks and inverters, as well as the associated switchgear and step-up transformer.

Figure 23: Completed Connections in the Battery and PV System Step-Up Transformer

PV and BESS connections are shown on the primary side of the BESS-PV step-up transformer.

Credit: SERC

Figure 24: Completed Battery System, Switchgear and Transformer Installation

Completed BESS equipment pad installation.

Credit: SERC

Point of Common Coupling

As a new primary voltage customer, BLR was required to install switchgear at the PCC that separates the utility grid from the microgrid. The PCC switchgear assembly includes redundant protective relays that provide control and safety features. These relays prevent damage to the utility grid and/or microgrid equipment by prohibiting the connection of generators with improper synchronization or out-of-range electrical parameters.

Installation of PCC Switchgear

The PCC is located in a small area at the edge of the BLR property within 40’ of an existing PG&E utility pole and underground 12.5 kV electrical supply lines. Construction and electrical field crews cleared the area, installed the necessary subgrade electrical and communications conduits, and built the concrete equipment pad. Figure 25 shows the PCC equipment pad ready for a concrete pour, and Figure 26 shows the completed pad after the concrete pour.

Figure 25: Prepared Equipment Pad for Point of Common Coupling

The PCC pad is prepared with conduit, rebar, and forms and ready for the concrete pour.

Credit: SERC

Figure 26: Completed Equipment Pad for Point of Common Coupling

Completed PCC pad waiting for installation of the PCC enclosure.

Credit: SERC

Figure 27 shows the installed PCC switchgear enclosure. Once the PCC switchgear unit was positioned and securely mounted to the pad, the PCC breaker, PCC battery system, and communications systems were installed and wired. Figure 28 shows installation of the PCC breaker, and Figure 29 shows the redundant protective relays.

Figure 27: Point of Common Coupling Switchgear Enclosure

PCC enclosure mounted to concrete pad.

Credit: SERC

Figure 28: Installation of PCC Breaker

An electrical contractor installs the PCC breaker using the PCC breaker jack.

Credit: SERC

Figure 29: Protective Relays Installed in PCC Enclosure

Redundant Schweitzer Engineering Labs SEL-700GT+ protective relays are installed side-by-side in the PCC enclosure.

Credit: SERC

Primary Service Cutover

With the installation of the microgrid, BLR switched from a secondary voltage customer to a primary voltage (12.5 kV) customer. For this to occur, a primary service cutover was needed to reroute incoming utility power to the PCC unit. This critical construction required extensive planning.

The cutover began in the early morning hours of November 3, 2016, and was completed that evening and required a complete shutdown of the electrical service to the campus, which is typically in operation at all times. PG&E utility crews and project electrical crews were onsite for the event. The construction tasks that were performed during the cutover are listed below:

1. Once the grid power was de-energized, PG&E disconnected the 12.5 kV lines from the utility pole, and the conductors were pulled back through the existing conduit from the underground vault on the BLR property.
2. The utility pole and associated switchgear were then removed and replaced.
3. A new subgrade conduit was installed, and new 12.5 kV conductors were pulled from the utility pole to the utility-side bus in the PCC unit.
4. The main subgrade conduit was cut, and a new section of conduit from the PCC was installed, connecting the PCC to the site vault.
5. The 12.5 kV conductors were pulled from the site vault through the new conduit and connected to the microgrid side of the PCC switchgear.

PG&E managed all notifications and traffic-flow routes to enable safe activities. It also coordinated with all the communications entities that share the utility pole (e.g., AT&T) to synchronize the management of its lines during pole replacement. Figure 30 shows the PG&E linemen disconnecting the 12.5 kV lines that feed the BLR casino-hotel complex. Once these lines were disconnected, the rest of the work could be performed. Figure 31 shows the utility crew pulling back the 12.5 kV lines so they could be rerouted.

Figure 30: Disconnection of 12 kV Distribution Lines

PG&E linemen disconnect 12 kV lines.

Credit: SERC

Figure 31: Rerouting the 12 kV Distribution Lines

PG&E crews pull 12 kV conductors back from the underground vault.

Credit: SERC

Figure 32 shows the PG&E crew installing a new power pole, and in Figure 33 they connect 12.5 kV distribution lines to the utility side of the PCC.

Figure 32: Installation of a New Power Pole to Support the New Primary Service

PG&E crews install a new power pole.

Credit: SERC

Figure 33: Connection of 12.5 kV Distribution Lines to the Utility Side of the PCC

PG&E crew connects new 12 kV conductors to grid side of the PCC.

Credit: *SERC*

Figure 34 shows the PG&E crew intercepting the existing 12.5 kV line and installing a new conduit. In Figure 35 they pull the 12.5 kV from the vault to customer side of the PCC.

Figure 34: Installation of New Conduit

Crews intercept the existing 12 kV conduit and install new conduit between PCC and site vault.

Credit: SERC

Figure 35: Pulling Conductors From the Vault to the PCC

PG&E crews pull 12 kV conductors from vault to microgrid side of PCC.

Credit: SERC

Figure 36 shows the 12 kV conductors that come from the underground vault connected to the microgrid side of the PCC.

Figure 36: Conductors Connected to Microgrid Side of PCC

The 12.5 kV conductors from the underground vault are shown connected to the microgrid side of PCC.

Credit: SERC

Siemens Spectrum Power™ Microgrid Management System

The Siemens Microgrid Management System (MGMS) arrived onsite in the form of a rack server, a console computer with dual monitors, and a GPS clock. The BLR information technology IT department worked with Siemens engineers to install the rack server and GPS clock in the BLR IT core and to install the console computer in the main facilities office. The BLR IT department worked with SERC engineers to install the environmental forecasting and monitoring system onto a virtual server and link it to the Siemens MGMS. Once these components were installed, Siemens Engineers began point-to-point testing between the MGMS and all microgrid actors.

Figure 37 shows two SERC engineers working at the MGMS console during commissioning. Figure 38 shows the MGMS dashboard screen, and Figure 39 shows the MGMS one-line diagram, both on the MGMS console computer. Figure 40 shows the two public display screens that BLR installed in the lobby of the tribal office; these displays host the MGMS dashboard and single-line diagram console screens and are useful for tours, demonstrations, and education and outreach.

Figure 37: Working at the MGMS Console

SERC engineers work at the MGMS console computer during commissioning.

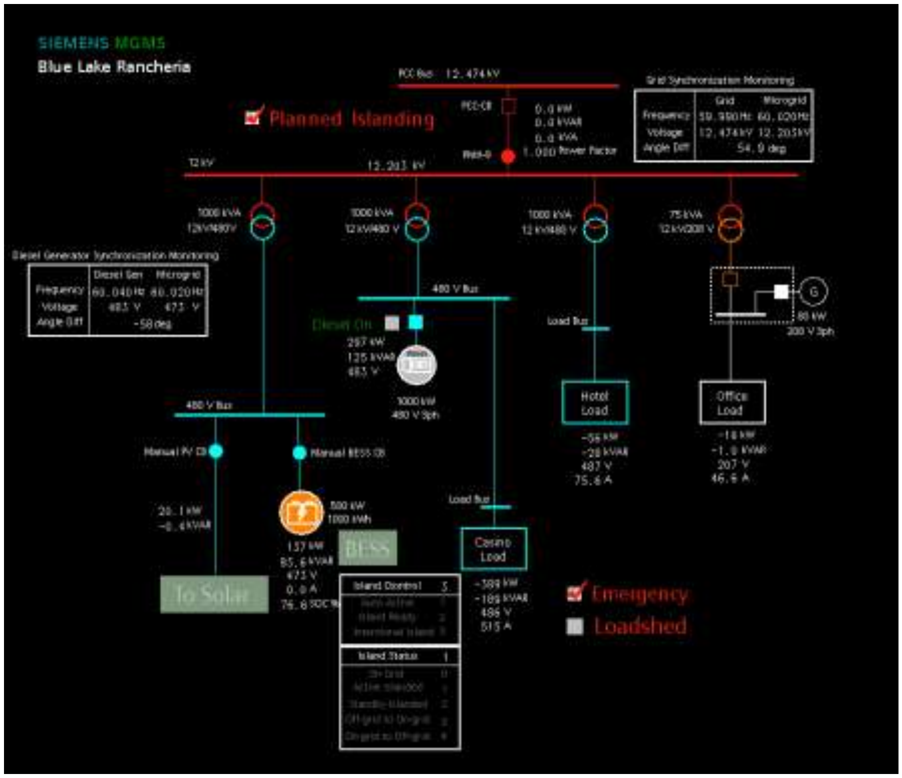
Credit: SERC

Figure 38: Siemens MGMS Dashboard Screen

The Siemens MGMS dashboard screen allows system monitoring and control.

Credit: SERC

Figure 39: Siemens MGMS One-Line Diagram Screen



The Siemens MGMS one-line allows system monitoring and control of system components.

Credit: SERC

Figure 40: Public Displays of the MGMS User Interface

BLR installed two large public display screens in its office lobby so visitors can observe the microgrid in action.

Credit: SERC

Challenges Encountered During Construction

Overall, the construction and installation phase of the BLRMG project went smoothly, with only one significant challenge and a couple of minor issues. The one key challenge during the process was a failed attempt to complete an electrical system bus tie in the casino main switchboard (MSB). The other issues were common construction problems, including a minor equipment defect and a subcontractor using an outdated design drawing when building one of the concrete equipment pads. Below is a brief description of these construction issues.

First Attempt to Install Casino MSB Bus Tie

As part of the BLRMG design, a new 480 V bus link was installed to connect the electrical system of the casino to the rest of the microgrid. The original configuration connected these two electrical sections through an automatic transfer switch (ATS1). This original configuration was wired so that on a loss of grid power, the switch would disconnect from the grid and connect the casino bus to the 1 MW backup DG. The new bus tie allowed the backup generator to be connected to the entire microgrid, not just to the casino. Installing this bus tie required a planned electrical outage of the entire facility, so extensive planning was required to minimize disruptions. Backup generators were brought in to power critical loads, additional security guards were employed, and work was started in the early morning hours to minimize inconveniences to personnel and customers. Figure 41 shows the bus tie work in the existing ATS1 transfer switch.

Figure 41: New Bus Tie Work in the Existing Automatic Transfer Switch

The bus tie work shown allowed the exiting 1 MW generator to be connected to the entire microgrid rather than just to the casino load bus, as had been the case previously.

Credit: SERC

The project electricians were able to reconfigure the bus work in a timely manner; however, during post work testing, the electricians discovered there was a problem with the ATS1 controller firmware. Unknown to the project team, the firmware did not have three key functions enabled (emergency inhibit, go to neutral, and go to emergency). These functions were needed to make the system work properly. This situation meant that a controller upgrade was required, so the project team decided to return the bus tie to its original configuration, restore site power, and attempt the bus tie later.

This oversight in the available functionality of the controller firmware was due to poor, aged documentation; poor communication between the manufacturer and the project team; and insufficient knowledge of the switch controller functions by members of the project team. This situation illustrated the challenges of installing a microgrid into an existing built environment, with generation and transmission components of varying vintages. On the positive side, the project team handled this stressful and costly situation with professionalism and competency. Each decision made during the reconfiguration and testing period was well thought out to ensure no equipment damage would occur and that no one was put in an unsafe situation. The project team regrouped and worked with the manufacturer to ensure the controller would work as desired. A second bus tie event was scheduled and successfully completed.

Other Minor Issues

BESS Inverter Product Defect

During an equipment inspection of the Dynapower inverters, the project team discovered that the coating on the inside of the enclosure was defective. The paint easily peeled off in large pieces and exposed the bare metal surface on the bottom of the enclosure. The equipment supplier was notified of the problem and readily acknowledged that there were issues with the priming process for some of its products. The defect was covered under warranty, and both inverters were replaced with acceptable units. There was a three-week pause in installation while replacement units were shipped; however, the replacement was conducted as quickly as possible, and the new units were defect-free.

Monthly Summary of Construction Activity

Table 5 provides a list of monthly construction activities that were carried out to install the BLRMG system. Installation work lasted about 11 months, starting in March 2016 and ending in January 2017.

Table 5: Monthly Summary of Construction Activity

Date	Construction/Installation Tasks
Mar-2016	Began installation of system hardware for controllable loads, including Johnson Controls EMS.
Apr-2016	Began site preparation for installation of PV array and other outdoor site work.
May-2016	Conducted site work to prepare for PV array installation, including site clearing, grubbing, grading, and compacting.
	Began installation of PV array structure.
May-2016 (cont.)	Began on-site management and observation during construction and began documenting site work via photographs and site reports.
	Prepared jigs for BESS layout. Worked on layout of BESS pad.
	Set up an automated camera to take photos of the site work over time.
Jun-2016	Dug trenches and laid conduit for PV array, battery, and point of common coupling.
	Worked on pulling power and communication wiring.
	Laid out and poured BESS concrete pad.
	Continued installation of PV array structure, began installing PV modules, and erected fence around PV array.
Jul-2016	Continued installation of PV array; completed mounting of all PV modules.
	Prepared and poured PV system concrete pad.
	Prepared and poured PCC concrete pad.
	Worked to install battery system. Laid out, set and anchored, and began wiring BESS equipment (Dynapower inverters, Tesla battery packs, Tesla combiner panels, transformer, and switchgear).
	Installed casino load meter and BESS meter.
	Identified paint peeling problem on Dynapower inverters; they were to be replaced.
Aug-2016	Continued installation of PV array and inverters.
	Began to install switchgear on PV system pad.
	Installed PCC switchgear on PCC pad.
	Installed JCI system components; established virtual server with required software application.
	Began to plan for facility outages during PG&E cutover (changing from secondary to primary voltage customer) and during key installation, testing and commissioning steps.
	Finished laying the weed barrier and gravel around the PV array.
	Received replacement Dynapower inverters (due to paint chipping/pealing on original units).
	Completed site visit and walk-through with electrical engineer.
Sep-2016	Continued installation of PV array and inverters.
	Continued installation of PV switchgear and metering and monitoring equipment on PV system pad.
	Completed wiring of BESS.
	Continued installation of communications networks, including fiber optic.

Date	Construction/Installation Tasks
Sep-2016 (cont.)	Continued to plan for facility outages during PG&E cutover and during key installation, testing, and commissioning steps.
	Installed battery backup system for PCC.
	Installed watchdog timer system and PCC battery alarm system.
	Worked with PG&E to schedule cutover date from secondary voltage service to primary voltage service to occur in late October or early November.
Oct-2016	Continued installation of PV array, inverters and equipment on PV system pad.
	Installed cluster controller for SMA inverters as part of PV array.
	Completed wiring of BESS; completed BESS installation checklist.
	Completed wiring of BESS/PV 1000 kVA transformer.
	Finished grounding in the BESS transformer.
	Completed megger testing of high-voltage cables. Following cable testing, landed three-phase cables on the BESS MSB breakers and the BESS transformer.
	Worked to complete Tesla precommissioning checklist.
	Completed fiber optic line to PCC battery alarm.
	Continued to plan for facility outages during PG&E cutover and during key installation, testing, and commissioning steps.
	Worked with PG&E to schedule cutover date from secondary voltage service to primary voltage service; scheduled for November 3.
	Prepared for PG&E cutover, including finalizing and testing protection relay settings.
	Conducted cutover activities from secondary voltage customer to primary voltage (12.5 kV) customer. PG&E installed new metering, PTs and CTs in PCC switchgear cabinet.
	Continued to work on installation and commissioning of the environmental forecasting and monitoring server at BLR (PV and weather forecasting function).
	Installed electrical warning signs at the PCC.
	Completed security fencing around the battery and PV installation.
Nov-2016	Continued to plan for facility outages during PG&E cutover and during key installation, testing, and commissioning steps.
	Prepared for PG&E cutover, including finalizing and testing protection relay settings.
Nov-2016 (cont.)	Completed PG&E cutover activities to change from secondary voltage to primary voltage (12.5 kV) customer.
	Completed the installation and commissioning of the environmental forecasting and monitoring server at BLR.
	Prepared for receipt and installation of MGMS at BLR.
	Prepared for bus tie installation on ATS1.
	Attempted to install ATS1 bus tie. Modifications are necessary. This will be completed next month.
	Completed connection of BESS and PV systems to 480 V to 12.5 kV transformer and connected 12.5 kV transformer to microgrid.
	Installed shunt trip breakers for gaming load shed.

Date	Construction/Installation Tasks
	Installed warning signs for PCC and other switchgear.
	Final building permit issued.
Dec-2016	Installed final PV inverter completing the installation of the entire PV system.
	Continued to plan for facility outages during key installation, testing and commissioning steps.
	Installed MGMS at BLR.
	Prepared for and installed the bus tie. The bus tie will allow the 1 MW generator to back up the entire microgrid, including the Tribal office, casino and hotel.
	Installed Eaton ATC900 controller upgrade kit for the ATS1 transfer switch
	Installed JCI FieldServer
Jan-2017	Installed KirkKey system for PV/BESS breakers.

Source: Schatz Energy Research Center

CHAPTER 6: Commissioning

Overview of Commissioning Process

Goals and Strategy

Commissioning for the project had to be planned carefully to balance the need to test first-of-the-kind equipment in an operating facility with stringent uptime requirements.

The BLR's economic enterprises within the microgrid operate 24/7/365, so at all stages, a critical consideration was to maintain operations at the hotel, restaurants, and casino to avoid economic loss. The casino has a large number of gaming machines that, by Gaming Commission and applicable regulation and technical requirements, cannot be powered down without significant planning. These and other critical loads are backed up by uninterruptable power supplies, but other devices at the facility, including ventilation for the kitchens, are not, so unplanned power disruptions of more than a short duration would necessitate an evacuation of the facility at considerable cost.

As a result, the following enterprise operational constraints needed to be complied with during commissioning:

- No unplanned power outage of longer than 30 seconds could occur due to the substantial operational and economic impact it would cause.
- Brief planned power disruptions of 1 to 30 seconds during islanding and component commissioning needed to be planned to avoid times when they would disrupt facility operation due to heavy patron traffic or special events being hosted or both.
- Periods without available standby generation to power the facility in the event of utility grid failure had to be minimized.
- Facility shutdowns had to be kept to a minimum number and duration due to the extremely high economic cost and logistical requirements of these events.

To meet these goals, the commissioning was conducted in stages. Whenever possible, components were installed and tested to ensure functionality before efforts were made to integrate the overall system. In addition, foundational controls (such as the SEL relays) were designed to provide protection and backup functionality should one of the newly installed components fail; they were installed and tested early in commissioning to enable this protective functionality. The timing of each test was planned to coincide with periods of low traffic and when no event was in progress.

Components Requiring Testing During Commissioning

Table 6 outlines each component and subsystem that was tested, and the party or parties responsible for performing the test. SERC participated in, managed, and provided oversight of all commissioning tests.

Table 6: List of Components Commissioned

Component	Responsible Party
PV Array	REC Solar, McKeever Energy, Meteo Control
Battery Energy Storage System (BESS)	Tesla
Controllable Loads/EMS	Johnson Controls
SEL Relays and PCC	GHD, Tesla, SERC
ATS1 Modification and Bus Tie	Colburn Electric, SERC
Environmental Forecast and Monitoring System (EFMS)	SERC
Power Meters	Colburn Electric, SERC
PG&E Interconnect	PG&E, SERC
MGMS and SCADA	Siemens

Source: Schatz Energy Research Center

Partial Timeline of Commissioning Process

An abbreviated timeline of some milestones of the commissioning helps one understand the overall flow of commissioning.

1. October 7, 2016 – Initial pre-energization test (PET) attempted
2. October 19, 2016 – Second PET attempted and passed
3. October 24-31, 2016 – EFMS commissioning
4. November, 2016 – RTDS testing of MGMS begins at INL
5. November, 2016 – PV array commissioning begins
6. November 3, 2016 – Cutover: PCC energized and switched to primary service
7. November 8, 2016 – Bus tie installation attempted, failed
8. December 14, 2016 – Bus tie installed successfully
9. December 2016 – PV array allowed to generate; PV array commissioning complete
10. December 2016 – MGMS SCADA commissioning begins
11. December 2016 – Power meter commissioning complete
12. January 6, 2017 – Acceptance testing of BESS at Tesla Palo Alto facility
13. January 2017 – Weather station commissioning complete
14. January 2017 – MGMS SCADA commissioning complete

15. January 2017 – MGMS basic software functionality testing complete
16. February 2017 – Primary RTDS testing of MGMS at INL complete
17. February 2017 – Testing of advanced MGMS functionality and islanding begins
18. February 2017 – Testing of JCI load-shedding capability begins
19. March 2017 – Islanded testing of BESS begins; first low-inertia islanding test performed
20. March 29, 2017 – Relay witness testing portion of PPI complete
21. March 30, 2017 – Seamless transition testing portion of PPI attempted and failed
22. April 3, 2017 – Conditional PTO issued by PG&E
23. April 5, 2017 – Significant upset during testing; testing halted for analysis
24. June 2017 – JCI load-shedding capability commissioning complete
25. June 2017 – Supplemental round of RTDS testing completed; onsite testing resumed
26. July 2017 – All major outstanding BESS issues resolved; successful seamless transitions performed; BESS considered fully operational
27. July 2017 – All major outstanding MGMS issues resolved; microgrid considered fully operational
28. July 25, 2017 – Final islanding transition tests performed for PPI
29. July 28, 2017 – Final PTO received
30. December 2017 – Issues identified during ongoing operations, and development of mitigations begins
31. March-April 2018 – Final mitigations deployed

Subsystem Commissioning

PCC Switchgear and Foundational Microgrid Controls

Site acceptance testing of the PCC switchgear and foundational microgrid controls included visual and mechanical inspection and electrical testing of switchgear hardware, as well as functional testing of the primary and secondary SEL-700GT+ relays. The site acceptance testing also included functional testing of the custom foundational software that was written using Schweitzer Engineering Laboratories' AcSELerator Quickset® software. In addition, the backup switchgear power supply, 48 V_{DC} battery system, was tested and confirmed to meet PG&E's required specifications.

Basic Functionality Acceptance Testing

Basic functionality acceptance testing consisted of passing required PG&E pre-energization tests (PET), performed by Emerson Network Power – Electrical Reliability Services and observed by

PG&E. These tests confirmed basic safety functionality of the PCC relays control over the PCC and adherence to PG&E interconnect requirements.

Emerson ERS attempted initial PET testing October 7, 2016. This test was not passed due to issues in the relay software provided by Tesla and GHD.

SERC took over leadership of the PCC relay programming and modified the software. Emerson ERS retested basic functionality on October 19, 2016. All basic functionality tests were passed at that time, the results were documented by Emerson ERS, and the PET was passed.

Advanced Software Simulation Testing

To safely test scenarios that could not be tested on a live system without risking damage to hardware or operational disruption, the research team performed thorough hardware-in-the-loop testing of advanced SEL software functionality at Idaho National Laboratory (INL), and all software features were proven in a simulated environment.

Testing at INL began in November 2016 and concluded in February 2017. INL personnel testing under the direction and test plans of SERC, with SERC personnel onsite monitoring tests and Siemens supporting communication with the MGMS. Both MGMS control and fallback foundational features were tested. All tests were passed successfully in this simulated environment. Minor additional regression testing was performed in May 2017. All tests were again passed.

The research team also tested advanced SEL software functionality as part of the simulated BESS microgrid testing performed at Tesla's Palo Alto microgrid test facility. All tests performed were passed successfully.

Live Site Acceptance Testing

Advanced fallback software functionality is also known as ATS mode or fallback mode. It replicates the original functionality of ATS1 before installation of the bus tie. Once the bus tie was installed, this fallback functionality became a necessity for site operations during commissioning, MGMS maintenance, or MGMS failure. Critical fallback functions of the primary PCC relay were tested and confirmed.

SERC personnel performed initial testing of automatic fallback functionality of the PCC relay on the not-yet-energized PCC immediately before the cutover (the process of transitioning from the old system to the new system) in late October 2016 using simulated electrical inputs. All tests were passed at this time. The cutover was then performed on November 3, 2016. At this point the PCC was electrically connected, and service to the facility was converted from three secondary-voltage accounts to a primary account with the new PCC as the point of connection. Basic PCC relay functionality performed as expected for the next two months.

The second phase of live site acceptance testing, which required successful testing of fallback automatic operation features, was performed during successful installation of the bus tie on December 14, 2016. This allowed the 1 MW DG to fully energize the microgrid in an islanded state. All tests were passed, and the system ran in this mode without incident for the next several months during MGMS commissioning, including several real-world PG&E outages.

Testing of SCADA control by Siemens and Tesla began in February 2017 and continued for several months during MGMS and BESS commissioning. During this period minor issues with PCC Relay communication were identified and resolved. Final SCADA testing was performed during June and July 2017. At the end of that period all Siemens MGMS and Tesla BESS control signal tests had been successfully passed. In addition, PCC Relay functionality that is necessary for full microgrid operation was tested under control of the Siemens MGMS and Tesla.

Additional testing observed by PG&E personnel was performed as part of the July 2017 PPI islanding tests. This included testing of seamless transitions disconnecting from and reconnecting to the PG&E grid. All tests were passed.

PG&E Permission to Operate

Ultimately and finally, to pass site acceptance testing, the custom code for the PCC Relays was required to pass inspection by PG&E's interconnect group, and PCC functionality was required to pass the PG&E pre-parallel inspection. The Relay foundational software that was written using AcSELerator Quickset® software and includes relay protection settings was provided to PG&E for their review and approval. All PCC Relay acceptance testing and commissioning was complete when PG&E issued final permission to operate (PTO) on July 28, 2017.

Modifications to Existing 1 MW Isochronous Generator and Transfer Switch

Site acceptance testing of ATS1 (the 1 MW DG point of connection) control was performed as part of a bus tie operation in which the grid-source breaker of ATS1 was bridged to enable full microgrid islanding functionality. Testing was overseen by Colburn Electric personnel, a GHD engineer, and SERC personnel, assisted by BLR and Serraga personnel.

The initial attempt at installation of the bus tie and ATS1 testing was on November 8, 2016. This attempt failed because necessary functionality in the ATS1 controller that was expected to be present was not enabled in the actual device. Consequently, the bus tie was removed and a plan was developed to replace the ATS1 controller to provide the necessary functionality.

The controller was replaced with an upgraded model and a second attempt was made to install the bus tie on December 14, 2016. All tests were performed during the installation process and completed successfully.

Note that these two attempts, approximately 18 hours each, were the only points during the project where the BLR economic enterprises in the microgrid were not supplied with power and open for business. ATS1 commissioning was considered complete in December, 2016.

PV System

Site acceptance testing and commissioning of the PV system was conducted by REC Solar. The process consisted of the following steps:

- Pre-commissioning tests and check procedures
    - DC String Megger Test Report
    - DC Combiner Box Feeder Megger Test Report
    - DC Feeder Megger Test Report

    - AC Feeder Megger Test Report
    - String V_{oc} & Polarity Test Report
    - Planning Checklist - Array Combiner Pre-Commissioning Check
    - Planning Checklist - Remote PV Tie Pre-Commissioning Check
    - Planning Checklist - DC Disconnect Pre-Commissioning Check
    - Planning Checklist - Inverter Pre-Commissioning Check
    - Planning Checklist - AC Disconnect Pre-Commissioning Check
    - Planning Checklist - AC Switchgear/Switchboard Pre-Commissioning Check
    - Planning Checklist - Transformer Pre-Commissioning Check
    - Planning Checklist - Transformer (Medium Voltage) Pre-Commissioning Check
    - Planning Checklist - Point of Connection Check
    - Pre-Commissioning Checklist
- Pre-commissioning meeting where the pre-commissioning test results were reviewed and the decision was made as to whether or not to proceed to the commissioning stage.
    - The decision was made to proceed and commissioning occurred during the week of December 12, 2016.
- Commissioning checklist
- System performance tests
    - String performance test
    - Combiner box string performance test
    - Inverter performance test
- Testing and commissioning report

Once the PV system was commissioned by REC Solar, Siemens conducted point-to-point testing with the 14 SMA Sunny Tripower 30000TL-US PV inverters to establish the necessary communications and controls links to the MGMS. Over the course of the following months SERC engineers made several adjustments to the inverter settings for microgrid operation. These adjustments included:

- Relaxing the ride-through settings for over and under voltage and frequency to allow the inverter to stay online during seamless transitions. Since the requirements of PG&E's Electric Rule 21 were met in the Relay settings at the PCC, PG&E agreed that these settings could be relaxed.
- Setting the fallback output level to 50% if the inverters lose communication with the Siemens MGMS. Each inverter has a different delay time before they will fall back to 50% with the interval between each set to 30 seconds. This causes the PV array to gradually fallback to a reduced output if the Siemens MGMS goes offline or if there is a network failure. This is an important feature to minimize the likelihood that an export violation may occur (exporting more than 100 kW is not allowed by PG&E) or that the 1 MW DG will be exposed to reverse power in island-mode.

Battery Energy Storage System

Acceptance testing of the Tesla Battery Energy Storage was performed by Tesla, with observation by SERC and onsite assistance provided by electrical contractor Colburn Electric, BLR, Serraga, and SERC.

General Testing

Tesla provided an installation checklist to electrical contractor Colburn Electric and the BESS passed checklist testing in late 2016.

Initial acceptance testing of interaction between PCC Relay, Tesla controller, and BESS Dynapower inverter, and BESS functionality with a 30 kW load in a test-bed microgrid was performed at Tesla's Palo Alto headquarters on January 6, 2017. Tesla personnel performed all tests and SERC personnel observed and documented that the Tesla controller and Dynapower inverter passed the six test sequences.

Grid-Connected Testing

Grid connected import and export testing (charge and discharge of the BESS) was performed on the live system during January 2017. Using onsite metering, SERC confirmed that the BESS imported and exported energy as commanded. Grid connected commissioning was considered complete after communication issues with the BESS power meter were resolved in June 2017.

Islanding

During islanding testing on the live microgrid in March 2017, the BESS was allowed to carry the full microgrid load in an islanded state. The microgrid ran islanded with only BESS providing power for approximately 10 minutes without incident.

Load-sharing between the DG and BESS was tested beginning February 2017 and proceeded through July 2017. All load sharing acceptance tests were passed successfully by July 2017.

Final low-inertia islanding testing on the live microgrid was performed in July 2017, with both BESS and PV inverters observed running in low-inertia islanded mode and sharing the site load for a period of over one hour without significant issue. This test did expose a minor bug in BESS voltage regulation while islanded. Tesla continued to work on the non-critical voltage regulation issue while in low-inertia mode as part of their firmware development process. During on-site testing in January 2018 performed by SERC with remote support from Tesla, the issue was not observed and was considered resolved by a Tesla firmware update.

Load-sharing functionality commissioning was considered complete at the end of July 2017.

Commissioning of all islanding functionality was considered complete in January 2018.

Seamless Disconnect and Reconnect

Seamless disconnect and reconnect functionality was initially attempted as part of the PG&E pre-parallel inspection (PPI) on March 30, 2017. This initial attempt failed to successfully island the microgrid due to issues involving interaction between the Tesla BESS control system and the BESS Dynapower inverters. This was Tesla's first multi-inverter installation in a microgrid and their first attempt at a seamless transition with a multi-inverter arrangement on a live microgrid system. Nonetheless, conditional permission to operate was received from PG&E, and this enabled testing on microgrid transitions to proceed.

Over the next two months Tesla, with support from SERC and Siemens, tested and resolved islanding and transition issues involving the BESS SMC firmware and Dynapower inverters. The first successful seamless islanding transition was performed on June 6, 2017, and a successful seamless reconnect was performed near the end of June 2017.

A final test of seamless disconnect and seamless reconnect was performed by SERC with Tesla supporting on July 25, 2017. During this test, the BESS successfully disconnected the microgrid from PG&E without disruption to microgrid voltage or current, operated in low-inertia islanded mode, and reconnected to PG&E without disruption to voltage or current. Data from these tests was provided to PG&E and accepted, and final permission to operate was issued based on these successful tests on July 28, 2017.

Event captures logged by the SEL-700GT+ PCC relay during the seamless transitions are presented in Chapter 7: System Observation. Voltage and frequency on the microgrid did not deviate significantly when disconnecting from or reconnecting to the PG&E grid. Commissioning of seamless transitions was completed in July 2017.

Controllable Loads

Controllable loads are managed through a JCI EMS installed as part of the project; the EMS accepts commands from the Siemens MGMS and initiates load shed or load restore actions based on this. Site acceptance testing of controllable loads was performed by JCI in conjunction with Siemens and SERC.

Commissioning of load shedding began in February 2017. A set of operational tests were initiated by SERC through the MGMS, with results confirmed by direct observation of physical devices, SCADA feedback, and site load.

The initial round of tests in early 2017 uncovered a number of issues with JCI EMS programming for all tests attempted. Fixes were deployed by JCI, and all tests required for full microgrid functionality were passed in June 2017. Nuisance error messages on the JCI EMS related to a minor wireless coordinator failure, softstart, and loadshed watchdogs have been ongoing and not resolved satisfactorily by JCI. Further testing and monitoring of the JCI EMS system has revealed that the “AC Rotate” programming is incorrect, and will need to be addressed. These issues do not affect microgrid functionality.

Environmental Forecasting and Monitoring Server

The Environmental Forecasting and Monitoring Server (EFMS) is a server-based set of scripts designed by SERC that collects real-time weather data, weather forecast data, and solar forecast data from internet sources, integrates that forecast data into a PV production and weather forecast for the site, and provides that forecast data to the MGMS for use in the optimization algorithm.

Onsite commissioning of internal features of the EFMS was performed the week of October 24, 2016. All features not involving the MGMS were tested as functional at that time.

Initial MGMS commissioning efforts used manually ingested EFMS data starting in late 2016. Commissioning of the MGMS integrated with the EFMS was completed at the end of June 2017 and confirmed as working by SERC personnel who observed forecast data being ingested successfully into the MGMS based on an automated schedule. Weather and solar forecasting is a key component of microgrid installations with PV generation, and another area of emerging software technology.

Power Metering

Seven Acuvim II power meters were installed in the microgrid and are used for SCADA monitoring. These meters were installed by electrical contractors Colburn Electric and McKeever Electric and configured by SERC. Testing on electrical connectivity and data accuracy were carried out by SERC in late 2016 and completed in December 2016. All tests were passed at that time. MGMS SCADA testing was carried out by Siemens, with SERC providing onsite support, beginning in December 2016. MGMS SCADA testing was completed in early January, 2017. Tesla BESS SCADA commissioning began in January 2017. Communication issues with the meter were uncovered during these tests and resolved by Tesla's software team and wiring modifications in June 2017. All commissioning of the power meters was completed in June 2017.

Microgrid Management System Commissioning

The process of commissioning the MGMS was lengthy and involved both hardware-in-the-loop Real Time Digital Simulation (RTDS) testing at Idaho National Laboratory (INL) and onsite testing of the live microgrid at the BLR.

Testing and debugging of the MGMS began on the RTDS in October 2016. On-site testing as part of commissioning began in February 2017 and continued through July 2017. In July 2017 the MGMS passed all tests necessary to allow full automated operation of the microgrid. However, non-critical issues with the MGMS optimization routine continued after July 2017 and Siemens continued efforts to fix these problems through the remainder of 2017 and early 2018.

MGMS Testing at Idaho National Laboratory

Extensive testing on the MGMS was performed at INL using an RTDS simulation of the microgrid. This simulation employed the MGMS along with a PV array, SMA PV inverter and SEL-700GT+ relay as hardware-in-the-loop (HIL) components interacting with the following simulated components: utility grid, BESS, DG, and load. Commissioning and tests were performed by INL staff with SERC personnel onsite providing support and Siemens personnel providing support remotely. Initial commissioning and testing work at INL started in October 2016 and was completed in February 2017.

Additional testing was performed in the first half of 2017 in response to issues discovered during commissioning of the MGMS on the live microgrid. This testing was necessary to confirm that issues were fixed and that the fixes had not caused regressions. This follow up testing at INL was critical to minimize the risk of equipment damage or disruption of operations at Blue Lake Casino. These tests were completed and passed in early June 2017.

The testing phase at INL was also used to train SERC, Serraga, and BLR personnel on the microgrid system operations. INL and SERC created an operator training curriculum for a multi-day training session.

Onsite MGMS Testing and Commissioning

SCADA Points Testing

SCADA commissioning for MGMS communication with onsite devices began in November 2016 and was completed in January 2017. Siemens performed work both onsite at the microgrid and remotely; SERC personnel observed commissioning and provided onsite support when Siemens personnel were working remotely; BLR IT personnel provided support onsite.

Due in part to stringent cybersecurity requirements of the BLR IT infrastructure, which all SCADA relies on, minor issues continued to be discovered or develop due to network infrastructure changes throughout 2017. Minor intermittent network issues involving PV inverter communication continue to be addressed as of May 2018, with issues expected to be fully resolved by mid-2018.

Basic MGMS Software Functionality Testing

Initial commissioning of MGMS software functionality was performed on an RTDS at INL as described previously, and on a server installed at the microgrid site with the ability to control critical infrastructure components disabled or selectively enabled, thereby allowing testing to proceed safely. Siemens performed initial commissioning both onsite and remotely, supported by SERC, BLR, Serraga, and INL personnel.

Onsite commissioning of basic software functionality began in parallel to offsite RTDS testing in late 2016 and proceeded through February 2017. Functionality of HMI controls was verified as part of SCADA commissioning. Basic software functionality testing was considered complete by the end of January, 2017, allowing testing of advanced software controls to commence.

Detailed Testing of MGMS Logic and Functions

Full commissioning of MGMS logic and software control functions began in early February 2017. All tests were performed by SERC operating onsite, supported by Serraga and BLR staff, with Siemens providing support remotely. Step-by-step plans for each test were developed, which included timing, expected results at each stage of the test, possible modes of failure, and corrective action to take if unexpected behavior or anticipated failures occurred.

Due to the necessity to perform these tests on a live facility open for business 24/7, tests were scheduled with economic enterprise management for times of lowest traffic and when no hosted events were in progress that might be disrupted by brief power disturbances. When necessary due to a failed test and during periods between tests, MGMS control was disabled using the PCC Relay foundational control scheme to allow reliable fallback operation.

Test results were observed and logged by SERC using visual inspection of the facility (e.g. fan or HVAC equipment states, visible power disruptions during transitions), observing SCADA data on MGMS human-machine interface (HMI), and observing HMI data on other devices (PCC Relay, power meters, EMS, BESS SMC, etc.). Siemens and Tesla also provided confirmation of behavior by logging and analyzing backend data streams in their respective products.

It should be noted that SERC, BLR, and Serraga staff coordinated on design, deployment, and ongoing operation of cyber-secure remote access by sub-contractors and vendors to their respective equipment and data. This communications-enabling work and infrastructure became a larger scope than anticipated at the beginning of the project.

Certain initial tests in February 2017 were not successful and based on data collected during these failures Siemens began implementing bug fixes and logic modifications necessary to account for component interactions that were not anticipated during development and were not exposed during RTDS simulations.

Commissioning progressed during the first half of 2017 with a process of attempting a test, identifying failures or unexpected behaviors if they occurred, implementing fixes based on any issues identified, then re-running the failed test. Periodically, previously-passed tests would be re-run to detect any regressions caused by changes implemented.

By the end of March 2017 tests sufficient to allow the seamless transitions required for the PPI had been passed, and the seamless disconnect and reconnect witness testing part of the PPI was attempted on March 30, 2017. This test failed due to BESS control issues as noted in the BESS section of this memo.

Conditional permission to operate was, however, received at that time, allowing further MGMS tests to be executed in parallel to BESS commissioning.

On April 5, 2017, a significant race-condition bug was exposed, resulting in unexpected behavior (repeated cycling of ATS1 during an islanding attempt) that had not been anticipated as possible and for which mitigation had not been planned. This caused onsite testing to halt while the cause of the incident was analyzed, mitigation developed, and the revised MGMS logic re-tested at INL's RTDS facility to verify that the issue had been addressed.

RTDS testing was completed in early June 2017, and onsite testing was resumed. All tests had been passed as of late July 2017, and PTO was issued by PG&E on July 28, 2017.

The microgrid was allowed to run in fully automated mode under control of the MGMS from this point onward and MGMS was considered fully operational. It is important to note that during the period between installation of the bus tie in December 2016 and the completion of commissioning in July 2017, critical infrastructure functionality was handled by the PCC Relay foundational control algorithms with MGMS control locked out. This allowed the facility to continue to operate normally, including responding to unplanned PG&E grid disturbances, during the commissioning period.

Analysis of data collected in the remainder of 2017 uncovered optimization issues with BESS and PV dispatch that necessitated modification by Siemens, and certain cosmetic user interface (UI) issues were also identified as necessitating Siemens modifications. Implementation and internal testing of these modifications is ongoing at Siemens as of January 2018, with deployment and completion of commissioning anticipated for February 2018.

Interconnection Acceptance Testing

PG&E interconnection acceptance testing consisted of three main inspections:

- A pre-energization test (PET), which was required to proceed with energization of the PCC and cutover from secondary to primary service
- PCC Relay witness testing as part of the pre-parallel inspection (PPI), which was required to begin testing of BESS islanding features and to obtain conditional permission to operate
- Testing of seamless transitions to and from and islanding state with the BESS as part of the PPI, which was required to obtain final permission to operate

These inspections served as major checkpoints in the overall commissioning process, both by providing an externally verified test of integrated microgrid components and by providing utility permission to operate increasingly advanced microgrid features to allow commissioning to proceed.

In addition to these inspections, a major step in the commissioning of the microgrid was the cutover of service, during which the PCC was energized and the site was converted from three secondary voltage accounts to a single primary voltage account serving the entire microgrid.

Pre-Energization Test

The PET of the non-energized PCC was first attempted on October 7, 2016. The test was conducted by Emerson ERS with PG&E witnessing the results. SERC personnel, the GHD project engineer, Colburn Electric personnel, and BLR and Serraga personnel were also onsite to support the test. This test was not passed due to PCC Relay programming issues as noted in Service Rearrangement.

After resolving the issues, a second PET was scheduled and performed on October 19, 2016. The test was again performed by Emerson ERS with PG&E witnessing. This test was successfully passed. Based on the result of the PET, PG&E granted permission to energize the PCC and proceed with the cutover of site power to primary voltage service.

Cutover

The cutover was performed on November 3, 2016 by a PG&E line crew and Colburn Electric personnel. Suddenlink and AT&T personnel were also involved, due to their wires being present on the pole that was replaced as part of the cutover. PG&E managed the majority of the pre-cutover planning and logistics, including coordination with AT&T and Suddenlink, and traffic control. SERC personnel were onsite documenting and supporting the procedure. BLR and Serraga personnel coordinated traffic flows to the property and other site logistics and support. The cutover was completed on schedule late in the day and no unexpected issues occurred.

Initial Pre-Parallel Inspection

The pre-parallel inspection was performed on March 29 and March 30, 2017. PCC Relay witness testing was performed on March 29 by Emerson ERS, with PG&E personnel witnessing and SERC personnel present to assist in demonstrating functionality. PCC response to grid disturbances and PCC Relay/ATS1 interlock functionality was tested, and all tests passed.

Islanding testing observation was performed on March 30, during which seamless disconnect and seamless reconnect operations with the BESS were attempted for the first time. Both tests failed due to issues with Tesla controls. However, due to the successful PCC Relay witness testing, a Conditional Permission to Operate for Test Purposes Only letter was received from PG&E on April 3. This allowed for live testing of BESS transition functionality with the PG&E grid to resolve issues.

Completion of Pre-Parallel Inspection and Permission to Operate

The initial conditional permission to operate (PTO) was for a period of 30 calendar days. This was insufficient to resolve all issues with the seamless transitions, so extensions were requested by SERC and granted by PG&E three times.

Due to the success of the PCC Relay witness testing portion of the PPI and the extensive amount of high-resolution data captured by the PCC Relays, MGMS, and internal BESS logging, PG&E determined that it was not necessary for their personnel to witness the re-test of seamless transition features if appropriate captured data was provided to them. Seamless disconnect and reconnect functionality was tested successfully on July 25, 2017, with SERC operating the microgrid onsite and Tesla supporting remotely. Data on inverter states captured by the BESS and waveform data from the PCC Relays was provided to PG&E, and final permission to operate was issued by PG&E based on these tests on July 28, 2017.

Chapter 7:
System Observation

This chapter presents operational results for the BLRMG that were observed during the 2017 calendar year. The PV system became fully operational in December 2016, and the BESS and MGMS became fully operational in July of 2017. As noted previously and below, during 2016, 2017, and continuing into 2018, there were significant installation and commissioning activities and issues which constrained system performance, including significant solar curtailment, system testing, system communications issues, and other conditions that impaired performance and reduced benefits (e.g., solar power output and cost reductions). These performance metrics will improve when the system is fully "dialed in" and operating optimally.

The following sections describe the data acquisition capabilities of the system and the availability of data. This is followed by the performance of various subsystems, including the foundational control system, PV system, the BESS, the MGMS and the fully integrated microgrid system. This includes assessments of system operational functionality, system performance, system efficiency, and electricity costs.

Description of Data Acquisition Capabilities

Introduction

Primary data acquisition for the system is performed by the MGMS, which pulls data from various microgrid sensors and logs the collected data with a Historian database component. The microgrid also has three secondary data acquisition systems provided by third parties, including weather and PV data, inverter data, and utility data. Much of these third-party data are read from the same sensors that MGMS uses, but they are processed and archived using third-party systems.

Onsite Sensors Used for Monitoring

Table 7 summarizes the sensors used to collect data. Exact accuracy varies by sensor; most are specified as accurate to within 2% full scale by the manufacturer, and none are specified as worse than 5%. Only primary data points used for monitoring and analysis are listed; many additional performance and status values used for real-time control and monitoring are available, and some are logged.

MGMS Data Acquisition Subsystem

The MGMS data acquisition (DAQ) subsystem consists of a network SCADA subsystem with one remote terminal unit (RTU) per networked sensor device. Each device is polled asynchronously over the site's IP network by the DAQ subsystem, and collected data are scaled into final values per the specifications of the sensor manufacturer. Exact data poll rates vary depending on network traffic and sensor responsiveness, but parameters are nominally updated every 1-10 seconds. Data that cannot be refreshed within a reasonable period of time due to network issues or an unresponsive sensor device are flagged as not updated. Data read from networked sensors are used for real-time control by the MGMS and are also provided to Historian for logging.

Table 7: List of Key Sensors

Sensor	Primary Data Collected	Units	Accuracy (Full Scale unless specified)	Collection/Logging Mechanism
Acuvim IIR Power Meters (7) • PCC Utility • BESS • PV Inverters (combined) • Casino Load • Hotel Load • Tribal Office Load • 1 MW Generator	Real Power	kW	0.7%	MGMS/Historian
	Apparent Power	kVA	0.7%	
	Reactive Power	kvar	0.7%	
	Frequency	Hz	0.02%	
	Voltage	V	0.2%	
	Total Energy	kWh	0.7%	Acuvim IIR Internal
PCC Utility Meter *(PG&E Installed Device)*	Energy	kWh	<2%	PG&E Use/Billing Data/PG&E Inter-Act data portal
PCC SEL-700GT+ Relay	Utility Voltage	kV	1%	MGMS/Historian
	Microgrid 12.5 kV Bus Voltage	kV	1%	
	1 MW Generator Voltage	V	1%	
	PCC Interchange Current	A	1%	
	Utility Frequency	Hz	±0.01Hz	
	Microgrid 12.5 kV Bus Frequency	Hz	±0.01Hz	
	PCC Breaker State	Boolean	N/A	
	ATS1 Breaker State	Boolean	N/A	
	Utility Voltage Waveform	kV	1%	SEL-700GT+ Internal Event Logging (*triggered by breaker event*)
	Utility Current Waveform	A	1%	
	Microgrid 12.5 kV Bus Voltage Waveform	kV	1%	
	1 MW Generator Voltage Waveform	V	1%	
	PCC Breaker State	Boolean	N/A	
	ATS1 Breaker State	Boolean	N/A	
	All Internal Variables Used by Relay	Boolean	N/A	
PV Inverters (14)	AC Real Power Output	kW	Not specified	MGMS/Historian

Sensor	Primary Data Collected	Units	Accuracy (Full Scale unless specified)	Collection/Logging Mechanism
		kW	Not specified	Meteo Control Portal
		kW	Not specified	SMA Portal
BESS SMC *(Some SMC Inverter power measurements are read from BESS Acuvim IIR meter)*	BESS Inverter Real Power Output	kW	Not specified	MGMS/Historian *(Note that some data is also logged internally by SMC, but is only accessible by Tesla for troubleshooting purposes)*
	BESS Inverter Apparent Power Output	kVA	Not specified	
	BESS Inverter Reactive Power Output	kvar	Not specified	
	BESS State of Charge	%	Not specified	
	BESS Total Available Capacity	kWh	Not specified	
	BESS State	N/A	Not specified	
Weather Sensors *(Read and scaled by Meteo Control Data Collection Device)*	Ambient Air Temperature	°C	±0.3 °K	MGMS/Historian and Meteo Control Portal
	Ambient Air Humidity	% RH	2%	
	PV Module Temperature (single point)	°C	1%	
	Plane-of-array Insolation (thermopile)	W/m2	<2%	
	Plane-of-array Insolation (PV reference cell)	W/m2	0.3%	
Building HVAC Data *(Collected and relayed by Johnson Controls Building EMS)*	Ventilation Fan State (Boolean: on/off)	Boolean	N/A	MGMS/Historian and Johnson Controls EMS
	HVAC Unit Block Thermostat State (Boolean: reduced setpoint/standard setpoint)	Boolean	N/A	
	Tribal Office Generator Breaker State (Boolean: microgrid/generator)	Boolean	N/A	

Sensor	Primary Data Collected	Units	Accuracy (Full Scale unless specified)	Collection/Logging Mechanism
	Gaming Load Shed Shunt-Trip Breaker Output State (Boolean: no trip/trip)	Boolean	N/A	

Source: Schatz Energy Research Center

MGMS Historian Data Archiving Method

The Historian subsystem runs as an independent process on the MGMS server. Historian uses an Oracle database to asynchronously log all relevant data collected from hardware sensors. Data point quality is also logged; if a point is not updated due to SCADA issues, it is flagged as such. Each data value is logged based on the data poll rate of the associated sensor and a new point is only logged when the value has changed significantly since the last logged point. As a result, data rates for each point and from point to point vary depending on response time of the network and sensor, and the variability of the data being collected. For example, PCC Real Power is recorded approximately once per second. PCC Breaker State, in contrast, only has a new point written when the breaker state changes, so it can go months between data points being recorded.

All data are logged at the described rate (considered “raw data”) to the Oracle Database and maintained for a period of six months. Once this period of raw data archiving has passed, the data are post-processed into 5-minute interval data and moved to a long-term archive. Data can be queried from the database in both raw format (all points, at whatever interval that point was recorded at) and interval format (processed internally by the database to specified intervals). SERC performed periodic raw data dumps from the Historian database to process and analyze the raw data.

Third-Party Datalogging

Three third-party data sources are also available as part of the microgrid system, and these were also utilized during commissioning and analysis.

Meteo Control

A Meteo Control blue’Log X network datalogger was installed by REC Solar as part of the PV performance monitoring system. The blue’Log X reads and scales outdoor weather and environmental sensor data via serial or direct sensor connections. It also monitors the AC power output of all 14 PV inverters via network communication with the inverters and total energy produced by the array via network communication with the PV meter. Environmental sensor data are relayed via the network to the MGMS. Environmental and PV inverter output data are also uploaded to the cloud-based Meteo Control portal and logged on a 15-minute interval.

SMA

An SMA Cluster Controller present in the system communicates with the PV inverters via a network connection. The Cluster Controller uploads basic PV inverter performance data to

SMA's cloud-based Sunny Portal where they are logged. This data source was not used for commissioning or analysis during the project.

PG&E

PG&E collects energy use data from the standard utility meter located at the PCC as part of normal time-of-use and demand billing. Cumulative energy use data on a 15-minute interval are logged and available to the customer via PG&E's Inter-Act data portal. These data were used for performance analysis during some parts of commissioning and were used as an accuracy check on Historian data for later periods.

SERC Data Management

SERC determined which data points of those collected were of value in analyzing the performance of the microgrid and performed downloads of raw (maximum time resolution) data for those points from Historian beginning in July 2017. These data were reformatted into a format that is easily ingested by data analysis software and stored on a secure internal server at SERC. Raw data will be stored indefinitely. SERC also downloaded 15-minute interval PV performance data from the Meteo Control web-portal and 15-minute interval load data from the PG&E Inter-Act site for all of 2017.

Data Processing Procedure

Data processing was performed on the raw MGMS historian data, supplemented by Meteo Control PV data and PG&E billing data for periods lacking Historian data. Processing was performed with the R statistics package, with visualization and analysis also performed using Microsoft Excel. Some data were also pre-processed with a custom piece of software created by SERC to remove points stored during communication loss, and to sort and sum large datasets.

Data Availability During Project Implementation

The data sources described in Data Acquisition Capabilities were commissioned and began recording data as follows.

Meteo Control

The Meteo Control online portal first began recording data on December 21, 2016. Remaining communication issues were resolved in early January, and accurate data are available in the Meteo Control portal from February 2017 onward, with the exception of PV array temperature data. PV array temperature data were corrupted until May of 2016 at which time the problem was resolved. Access to the portal was provided to the project team at the start of March 2017.

PG&E Billing Data

PG&E billing data are available for the microgrid primary service account beginning at the time of the cutover from three secondary voltage accounts to a single primary voltage account on November 3, 2016. Standard billing data available to the project include monthly energy use and peak demand data, as well as 15-minute interval energy use data.

PG&E billing data dating back several years were available to the project for the three secondary accounts that existed prior to the microgrid creation. Data available include a mix of monthly energy use totals and peak 15-minute interval demand values, as well as 15-minute interval energy use data.

MGMS Historian

Initial data collection using the MGMS and Historian began during commissioning in December 2016, and most SCADA issues were resolved in January 2017. While much of the initial data were incomplete and/or inaccurate due to the commissioning process, early data did allow for monitoring, analysis and direct observation of the system during commissioning. All communication issues were resolved and fully accurate data was available to the MGMS and operators beginning in March 2017.

Historian configuration issues during the later phases of commissioning resulted in raw data for the period prior to July 5, 2017 not being preserved. Correct Historian functionality was implemented at that time, and raw data from that point onward were downloaded and preserved by SERC for analysis of system performance.

Primary commissioning of the microgrid was considered complete on July 28, 2017, and a period of real-world, unattended performance observation began at that time. Data from that period through December 2017 were analyzed in January 2018 and used to identify opportunities for improvement in the MGMS optimization routines. These data were also used for analysis in this report.

A secondary commissioning period of MGMS optimization improvement began in January 2018 and was nearing complete at the end of February 2018. Beginning in March 2018 collected data are expected to reflect final microgrid functionality.

Foundational Microgrid Control System Observations

The foundational microgrid control system was developed to enable the microgrid to maintain safe and reliable operation during the commissioning period and in the case of failure of the advanced controls. The foundation is based on custom SEL-700GT+ relay programming designed to replicate the functionality of an ATS, to prevent any inappropriate commands sent by advanced components (MGMS and BESS) from being executed, to provide a lockout/fallback mode in which advanced commands are ignored, and to revert to ATS functionality in the event the advanced controls fail to energize the microgrid within a reasonable period of time after a power loss.

Additionally, the PV inverters are configured such that if there is a network or MGMS failure and no commands are received from the MGMS, the inverters will revert to a safe output level that has minimal risk of producing enough power during an islanding event to reverse-power the 1 MW DG. The BESS has similar fallback functionality when on grid and will revert to zero activity if the MGMS has not updated status within an acceptable timeout period.

As described below, the full range of foundational control features was assessed. This was accomplished by observing proper system behavior throughout the commissioning period, as well as forcing tests of fallback functionality where needed as part of the commissioning process.

Pre-MGMS Commissioning Functionality

At the point the bus tie was installed in December 2016, the MGMS was not yet online or commissioned, so all standby generation ATS functionality was by necessity handled by the foundational control system.

During this period, several unplanned utility outages occurred due to weather and wildfire events. In all cases, direct observation during the event and review of available data afterward indicated that the fallback control scheme successfully opened the PCC breaker, started the 1 MW DG, and energized the microgrid using the 1 MW DG once voltage on the generator was stable. The amount of time without power during one of these unplanned outages was approximately 6-8 seconds. According to Blue Lake Casino personnel, this blackout duration is similar to their previous experience with the original ATS prior to the installation of the bus tie and PCC.

When grid power was restored after each of these unplanned outage events, the foundational control system correctly disconnected the 1 MW DG and immediately reconnected to utility power at the PCC. This behavior was observed by onsite personnel and verified in subsequent review of the data. Casino Personnel indicated that the time without power during these re-transfer events, approximately 1 second, was at least as fast as with the original ATS.

Reliability and Safety Functionality During Commissioning

During commissioning of the Siemens MGMS and Tesla BESS, control of the PCC breaker and ATS breaker was periodically provided to the MGMS and BESS during tests. During this period the foundational control system was observed by SERC personnel to correctly execute safe commands, and only safe commands, sent by the MGMS and BESS.

Between such tests, the lockout feature in the foundational control was utilized. This feature disabled all response to commands received from the MGMS or BESS while monitored tests were not in progress. This functionality was observed functioning correctly several times during commissioning by SERC personnel, both during intentional tests and during commissioning operations when commands were sent but not executed due to the lockout feature being active.

MGMS and BESS control were manually disabled while SERC personnel were not onsite during this commissioning phase. During these periods the successful execution of the lockout feature allowed BLR personnel to trust that the system would maintain basic ATS functionality, and that unintentional operator actions or software bugs would not result in power disruptions.

PV Fallback Functionality

Due to the magnitude of the onsite load relative to the size of the PV array, there is a significant risk of reverse power on the 1 MW DG during a utility outage on a sunny day. The MGMS prevents this by curtailing PV output and managing BESS charge/discharge settings. If there is an MGMS or network failure, the PV inverter fallback functionality will provide the needed protection and prohibit reverse power on the generator.

During the commissioning period, the PV fallback functionality was observed to perform as designed. When the PV fallback functionality was implemented and finished testing, which occurred partway through the MGMS commissioning process in early 2017, the PV system was observed by SERC personnel to correctly reduce output power in a controlled, stepped fashion. This occurred as designed over a period of several minutes after communication ceased. This was observed during both a simulated loss of communication and intentional disabling of the MGMS SCADA subsystem.

Successful implementation of this functionality allowed all PV subarrays to be enabled during the later portion of the commissioning period, with fallback functionality handling curtailment during periods when MGMS control was not enabled. Expected and safe behavior was observed throughout the period.

BESS Fallback Functionality

During the commissioning period, the BESS loss-of-communication fallback functionality was observed to function as designed. During on-grid operation, the BESS controller was configured to set power output to zero in the event a communication was not received from the MGMS for a period of approximately one minute. This functionality was used to ensure that the BESS would not become stuck in an undesirable state in the event of a network communication loss or MGMS failure. This functionality was tested and observed numerous times during the commissioning period.

PCC Fallback Functionality

The foundational control system was designed to automatically revert to the lockout/fallback mode in the event the microgrid is de-energized for 15 continuous seconds. This would remove control from the MGMS in the event a software or communication failure caused the MGMS to fail to energize the microgrid during an islanding event. During the commissioning process this PCC fallback functionality was observed by SERC personnel to operate as expected during a small number of tests in which incorrect settings, software bugs, or operator error failed to energize the microgrid in a timely fashion.

PV System Observations

This section describes the performance of the photovoltaic (PV) system within the BLRMG for the year 2017, compares that performance to the expected performance, and discusses a variety of PV system losses.

The array was designed by REC Solar and construction began in May 2016 with completion of the array commissioning in December 2016. The as-built array faces due south and has a slope of 20˚. It incorporates 1,548 Solar World SW 325 XL Mono modules arranged in 86 series strings of 18 modules each. The modules are rated at 315 W at STC (1000 W/m^2, 25˚C) and at 296 W at 1000 W/m^2 and 46˚C). At the maximum power point, the array is rated at 503.1 kW$_{DC}$. The array is divided into 14 subarrays with each subarray connected to a 30 kW$_{AC}$ Sunny Tripower 30000TL-US-10 inverter.

Table 8 summarizes the layout of the array by subarray. The inverters for subarrays 1 and 2 each serve 7 strings, while all other inverters serve 6 strings. The total AC power rating for the array is 420 kW. Since the maximum inverter output is 30 kW which is lower than the rating for the DC input (correcting for the inverter efficiency), this limits the power production from each subarray (i.e., clipping occurs). This is more important for subarrays 1 and 2, which are expected to reach this inverter limit at a plane-of-array (POA) irradiance of about 820 W/m^2. REC Solar estimates clipping losses to be about 0.5% on an annual basis.

Table 8: PV Array Layout by Subarray

Subarray	Parallel Strings per Subarray	Maximum Power Point Output (1000 W/m2, 46°C) (kW$_{DC}$)	Maximum Inverter Output (kW$_{AC}$)
1 & 2	7	37.3	30.0
3, 4, …14	6	31.9	30.0
Total Array	86	457.7	420.0

Source: Schatz Energy Research Center

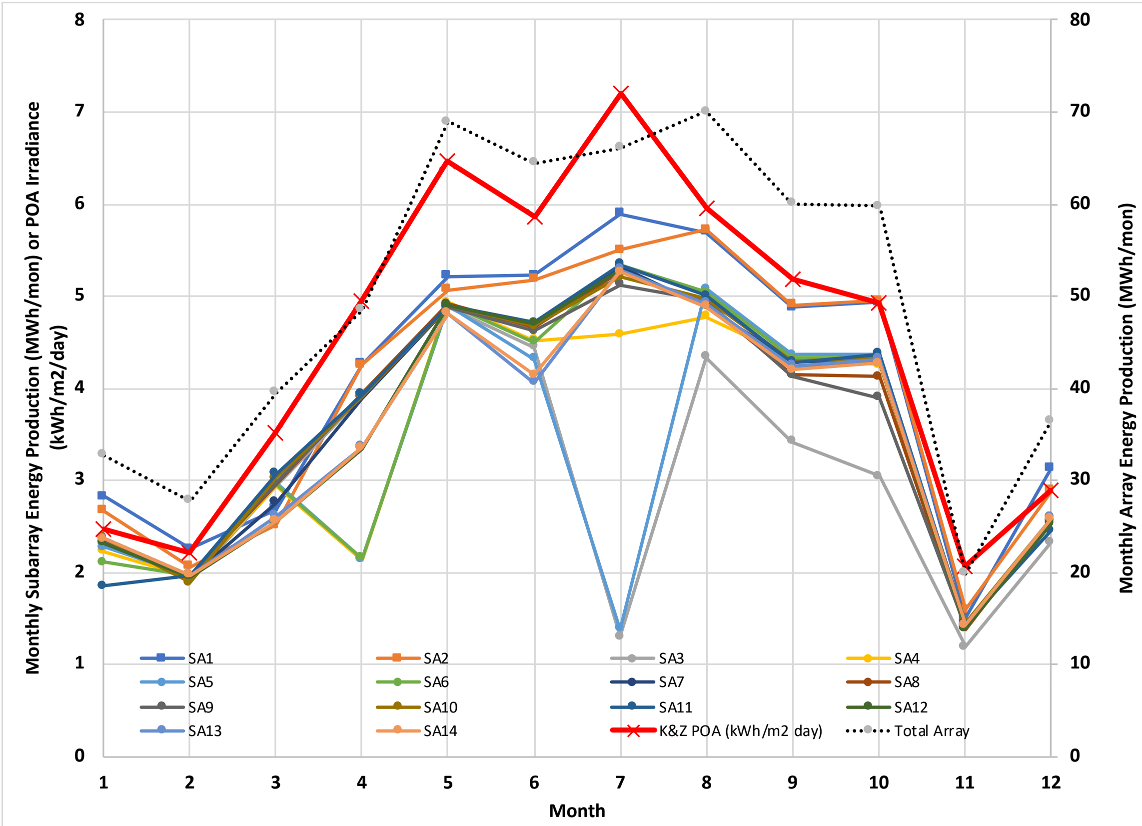
Each of the 14 inverters reports power production and a bank of instruments measures ambient conditions, including POA irradiance (using a Kipp & Zonen SMP10 pyranometer) and module temperature (using a PT1000 adhesive sensor). These parameters are reported to the MGMS via the Meteo Control datalogging system. The analysis in this section is based on a dataset containing these 14 power outputs, the POA irradiance, and the module temperature for 15-min intervals for all of 2017.

PV System Performance Over One Year of Operation

Starting with the 2017 observations at 15-min intervals, the team excluded all observations with POA irradiance less than or equal to zero and then summed the energy output from each subarray by month and also determined the monthly average POA irradiance. Table E.1 in Appendix E summarizes these results. In 2017 the total array produced 594 MWh of AC power with 66% of the energy production in the period May through September, 25% from January through April, and the remaining 9% in November and December. The annual average POA irradiance was 4.5 kWh/m^2/day, which is in the range expected for coastal Humboldt County.

Based on the results in Table E.1, Figure 42 shows the monthly subarray and total array energy production and the monthly average POA irradiance by month for 2017. As expected, the total array energy production approximately followed the monthly average POA irradiance values, being lowest in the late fall and winter and peaking in the late spring and summer. Subarrays 1 and 2 have somewhat higher energy production due to their having 7 strings of modules rather than the 6 strings that the remaining 12 subarrays have.

Figure 42: Monthly Subarray and Total Array Energy Production and Monthly Average POA Irradiance for 2017



Source: Schatz Energy Research Center

As can also be seen in Figure 42, the performance of some subarrays is substantially below the others in many months. Most notably, subarrays 3 and 5 produced only 1.3 to 1.4 MWh in July while all of the others yielded at least 4.5 MWh. Loss mechanisms include intentional interventions that capped the inverter outputs as part of the system development and commissioning process, programmed curtailments of inverter outputs to avoid exceeding the limit on export to the grid, inadvertent curtailments due to interruptions in communication between the inverters and the control system, array soiling, and other mechanisms. These losses in performance are discussed in depth in the PV System Losses section below.

Table E.2 in Appendix E presents the annual and monthly-observed capacity factors for each PV subarray and for the total array for 2017. The capacity factors were calculated based on the observed energy production and the 30 kW_{AC} rating of each inverter. For the array as a whole, the annual capacity factor for 2017 was 16%. As expected, higher capacity factors were recorded for May through August, with lower values for January through March and November and December. The capacity factors for subarrays 3 and 5 were notably low in July since those subarrays were intentionally disconnected from June 30 through July 24.

Expected Versus Observed System Performance

The PV array design that was originally envisioned and described in the project proposal was developed in October 2014 by REC Solar. Based on NREL Solar Prospector radiation data for Blue Lake, CA, that design was estimated to produce 680 MWh per year. In December 2016 using HelioScope software (Folsom Labs, 2016) REC Solar estimated the as-built design would produce 647 MWh per year based on typical meteorological year (TMY3) data for the Arcata Airport. The recorded array production for 2017 was 594 MWh, which is about 8% below the expected performance.

Table 9 compares the REC Solar projections and their assumed POA irradiance to the actual array performance and the actual POA irradiance for 2017. Since the REC Solar projections were based on TMY data and the observed performance reflects the actual POA irradiance for 2017 and the two sets of monthly irradiance values were not the same, some of the difference between the projected and the actual is likely due to the difference in POA irradiance. To correct for this, the actual performance was adjusted to match the TMY irradiance using Equation 1:

Equation 1: $$\left(\text{adjusted } \frac{\text{MWh}}{\text{month}}\right) = \left(\text{actual} \frac{\text{MWH}}{\text{month}}\right) \cdot \frac{\left(\text{TMY } \frac{\text{kWh}}{\text{m}^2\text{day}}\right)}{\left(\text{actual } \frac{\text{kWh}}{\text{m}^2\text{day}}\right)}$$

Since the actual 2017 irradiance was 3.6% less than the annual TMY irradiance, the adjustment generally reduced 2017 monthly energy production figures, with the adjusted annual energy production being 11% below the projected value. On a monthly basis, the adjusted 2017 production exceeded the projected production in three months (January, February, and December) and was below the projections for the remaining months. In July, the adjusted production was 27% lower than the projection while in April and November it was at least 20% lower. The reasons for these substantial differences are discussed in greater detail in the PV System Losses section.

Table 9: Expected Versus Observed PV System Performance

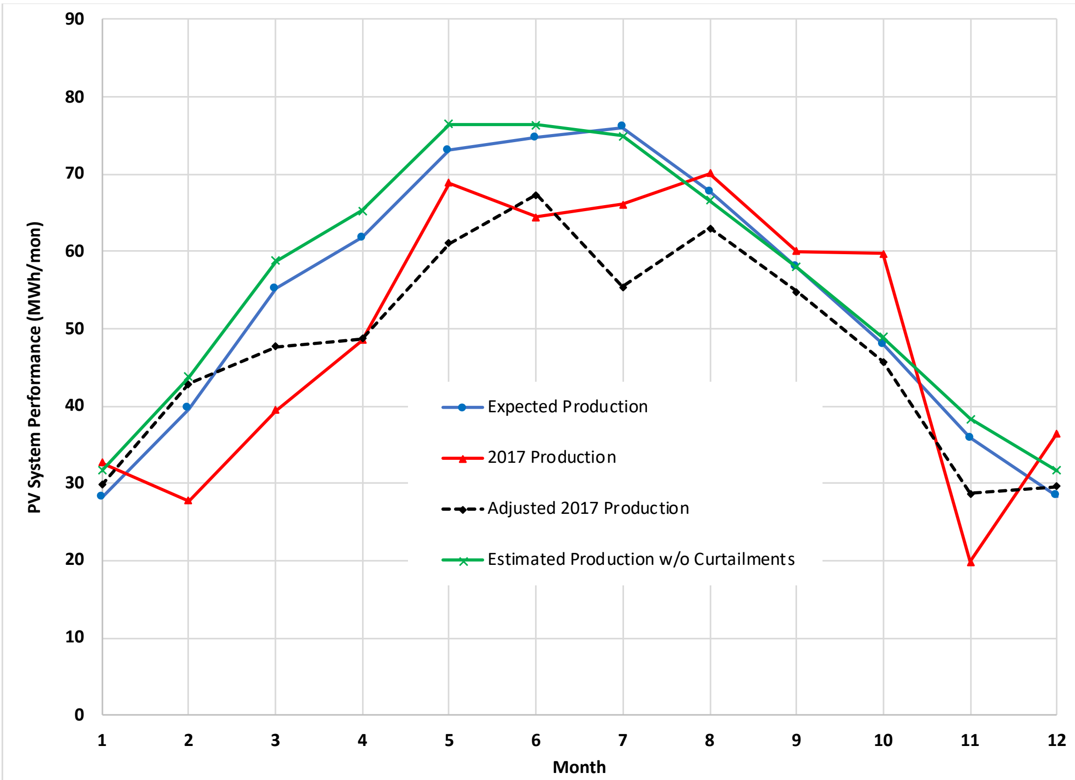
Month	TMY POA (kWh/ m^2/day) (1)	Expected AC Energy Production (MWh/mo.) (1)	2017 Actual POA (kWh/ m^2/day)	2017 Actual AC Energy Production (MWh/mo.)	Adjusted 2017 AC Energy Production (MWh/mo.) (2)	% Difference (Adj. 2017 - Exp.) (3)
Jan	2.25	28.2	2.47	32.7	29.8	5.9%
Feb	3.42	39.7	2.21	27.8	42.9	8.1%
Mar	4.25	55.2	3.51	39.5	47.7	-13.6%
Apr	4.98	61.8	4.95	48.5	48.8	-21.1%
May	5.74	73.1	6.47	68.9	61.1	-16.4%
Jun	6.12	74.8	5.86	64.5	67.3	-9.9%
Jul	6.04	76.1	7.20	66.1	55.4	-27.2%
Aug	5.36	67.7	5.96	70.1	63.1	-6.9%
Sep	4.74	58.0	5.19	60.0	54.8	-5.4%
Oct	3.77	48.0	4.92	59.7	45.8	-4.6%
Nov	2.97	35.9	2.06	19.9	28.7	-20.1%
Dec	2.35	28.4	2.89	36.5	29.6	4.3%
Year	4.33	646.9	4.49	594.2	575.1	-11.1%

Notes: 1. (Meichtry, 2016)
2. Adjusted to match TMY POA values used in HelioScope run (Adj = Actual/POA_2017*POA_TMY)
3. % Diff = (Adj 2017 - Exp.)/Exp

Source: Schatz Energy Research Center

Figure 43 presents the observed and the projected array performance by month for 2017. The 2017 monthly energy production exceeded the projected production in five months (January, August, September, October, and December) and fell below the projected production in the other seven months (February, March, April, May, June, July, and November).

Figure 43: Expected Versus Observed System Performance with Adjustments for POA Irradiance



Source: Schatz Energy Research Center

PV System Losses

A wide variety of causes may explain the differences between the projected and the observed PV system performance, including:

1) Intentional and programmed curtailments

    a) intentional interventions that capped power output from one or more inverter as part of the system development or testing process,

    b) programmed curtailments of inverter outputs to avoid exceeding the limit on export to the grid,

2) Inadvertent curtailments due to interruptions in communication between the inverters and the control system (i.e., “glitches”),

3) Array soiling

4) Other system losses

In this section energy production losses from of these four causes are estimated for 2017.

Losses Due to Intentional and Programmed Curtailments and Communication Glitches

PV system curtailment includes intentional interventions that capped the inverter power output as part of the system development and testing process, and programmed curtailments of inverter power output to avoid exceeding the limit on power export to the grid. Examples of curtailments due to intentional interventions include disconnecting subarrays 3 and 5 from June 30 through July 24 and limiting the output of all inverters to 19.8 kW from April 4 through June 11.

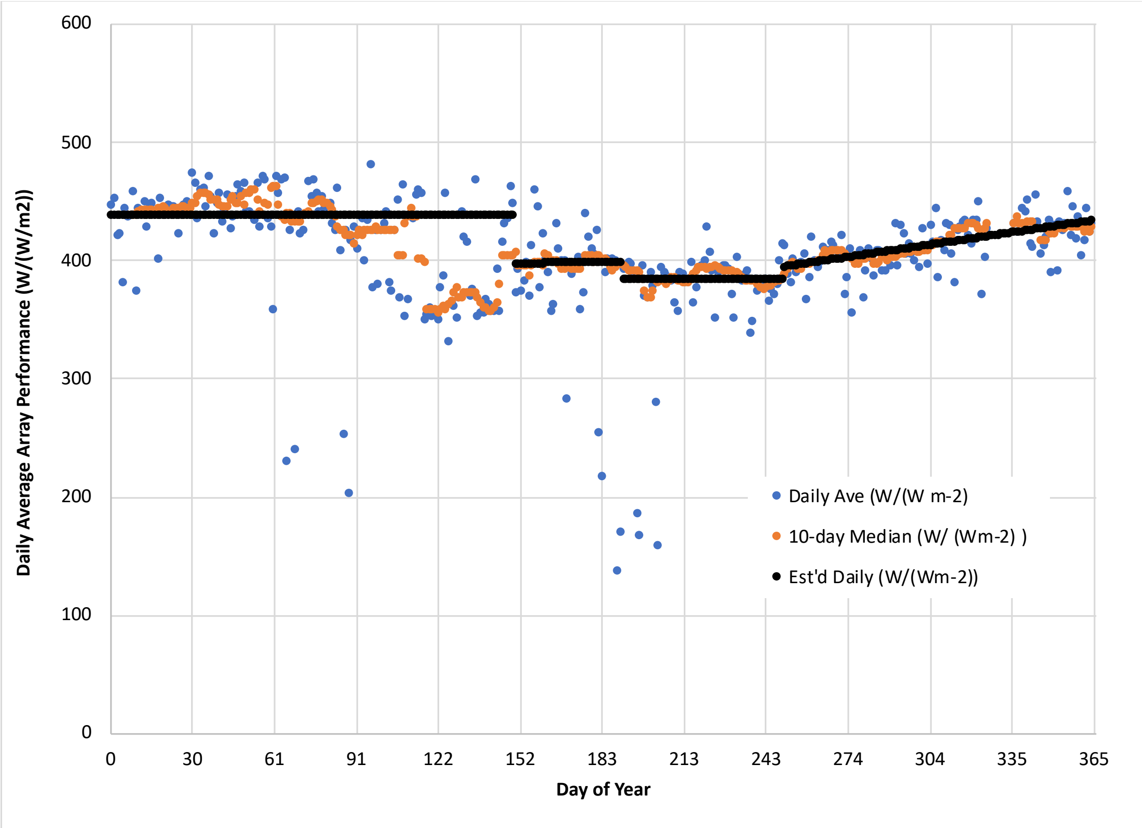
Communication glitches occur when there are interruptions in communication between the inverters and the control system. If the interruption persists for longer than 15 min, the inverter limits it maximum output to 50% of its rating, or 15 kW.

Since these curtailments substantially reduced the performance of many of the subarrays during 2017, the team estimated what the array performance might have been in the absence of these curtailments based on the median performance of the module strings that make up the array and the POA irradiance measurements. For each daytime data point in 2017, the energy produced per string was calculated for each subarray (note that subarrays 1 and 2 had 7 strings each and subarrays 3 through 14 had 6 strings each). Then the median output per string was determined and used to estimate the array output in the absence of curtailments.

Table E.3 in Appendix E presents, for each subarray for each month, the percentage differences between the observed 2017 energy production and the estimated monthly energy production based on the median string. The highlighted cells are extreme outliers as defined by NIST (2018). The most notable outliers are subarrays 3 and 5 for July which produced about 75% less than the median and subarrays 4, 5, and 6 for April which produced approximately 40% less than the median. In both cases, the differences are attributable to intentional curtailments.

Since in some periods, curtailments reduced or zeroed the power output by more than half (more than 7) of the subarrays, the team also estimated the array power energy production in the absence of any curtailments based on the POA irradiance. Using the array power estimated from the median spring output for each daytime data point in 2017, the ratio of the estimated output to the measured POA irradiance was calculated. This yielded an index of performance or efficiency for the array. The team computed the daily average of these values, which are plotted versus day of year in Figure 44. Based on a 10-day moving median of the performance measure, a piece-wise linear function was fit to characterize the time pattern. That piece-wise function was used to estimate the array output from the measured POA irradiance values. The larger of the estimates based on the median string and on the POA irradiance was used as the estimated array output in the absence of curtailments of any kind. The output of each subarray was constrained by the 30 kW inverter output limit.

Figure 44: Daily Average Array Performance Versus Day of Year



Source: Schatz Energy Research Center

After adjusting to the TMY POA irradiance, the estimated output in the absence of curtailments was compared to the projected output. Table summarizes these results.

Table 10: Comparison of Estimated Array Energy Production without Curtailments to Projected and Adjusted Observed Production

Month	Projected AC Energy Production (MWh/mo.) (1)	Adjusted 2017 Actual AC Energy Production (MWh/mo.)	Estimated AC Energy Production without Curtailments or Glitches (MWh/mo.) (2)	Estimated AC Energy Losses Due to Curtailments (MWh/mo.)	% Losses Due to Curtailments (3)
Jan	28.2	29.8	31.7	1.9	5.9%
Feb	39.7	42.9	43.8	0.9	2.1%
Mar	55.2	47.7	58.8	11.1	18.8%
Apr	61.8	48.8	65.3	16.5	25.3%
May	73.1	61.1	76.5	15.4	20.2%
Jun	74.8	67.3	76.4	9.0	11.8%
Jul	76.1	55.4	74.9	19.5	26.1%
Aug	67.7	63.1	66.6	3.5	5.3%
Sep	58.0	54.8	58.0	3.2	5.5%
Oct	48.0	45.8	48.9	3.1	6.3%
Nov	35.9	28.7	38.4	9.7	25.3%
Dec	28.4	29.6	31.7	2.0	6.4%
Year	646.9	575.1	671.0	95.9	14.3%

Notes 1) (Meichtry, 2016)

2) Estimated from median string and POA irradiance and adjusted to match TMY POA values used in HelioScope run

3) % losses due to Curtailments = (Est’d Losses)/(Est’d Prod. w/o curtailments)

Source: Schatz Energy Research Center

Figure 43 presents the estimated output in the absence of curtailments plotted versus month. Compared to the project energy production of the as-built array of 647 MWh, the estimated array production in the absence of curtailments of all kinds was 671 MWh (about 4% higher). Referring back to Figure 43, the annual pattern of the projected energy production and the estimated output in the absence of curtailments are strikingly similar.

Comparing the estimated array production in the absence of curtailments to the observed 2017 array production as adjusted to the TMY irradiance values, there was about a 14% annual loss due to curtailments, with the largest losses occurring in July, November, and April. These and the other large losses coincide with one or more weeks of intentional curtailments of the outputs of some or all of the subarrays.

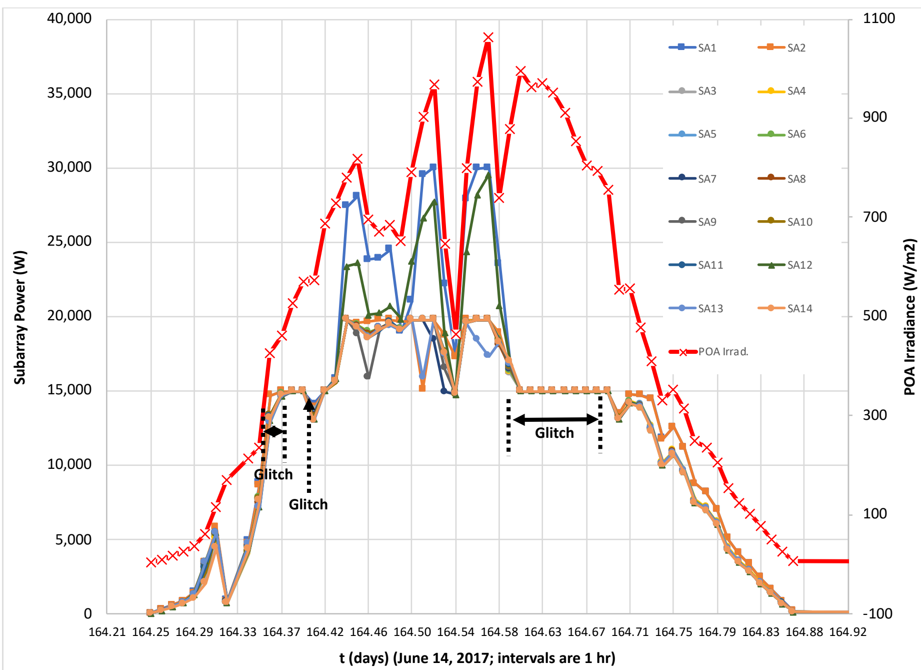
We also estimated the magnitude of lost energy production due to the 30 kW limit on inverter output (i.e., clipping) by comparing the estimated array production in the absence of curtailments to that estimate without the inverter limit. For 2017, clipping would have caused only a 0.7% loss in energy production or about 5 MWh. As expected subarrays 1 and 2 (with 7 strings instead of the 6 strings serving each of the other 12 inverters) would have experienced the largest clipping losses, reaching 2.5%. Almost 75% of the clipping losses were in April and May due to a combination of more favorable sun angles and weather.

Losses Due to Communication Interruptions

Communication glitches occur when there are interruptions in communication between the inverters and the control system. If the interruption persists for longer than 3-5 min, the inverter is programmed to limit its maximum output to 50% of its rating (15 kW). Figure 45 shows an example day (i.e., June 14, 2017) when during three different periods the output of all 14 subarrays was limited to 15 kW even though the POA irradiance was substantially above 500 W/m^2.

We estimated the energy production lost due to communication glitches by comparing each subarray power output to the expected output based on the POA irradiance values (i.e., estimated as described above in the section on Losses Due to Intentional and Programmed Curtailments and Communication Glitches). If the expected output was at least 15 kW and the actual subarray output was within 0.1 kW of 15 kW, then the subarray was assumed to be limited to 15 kW due to a communication interruption or glitch. The amount of lost energy production was estimated as the difference between the expected output and the actual. Table E.4 in Appendix E summarizes the MWh of energy lost by subarray and by month for 2017. For the array as a whole, it was estimated that 0.927 MWh of production were lost in 2017 due to communication glitches. This represents only about 1% of the 92.9 MWh lost due to all types of curtailments.

Figure 45: Example of Reduction in Array Output Due to Communication Glitch (June 14, 2017)



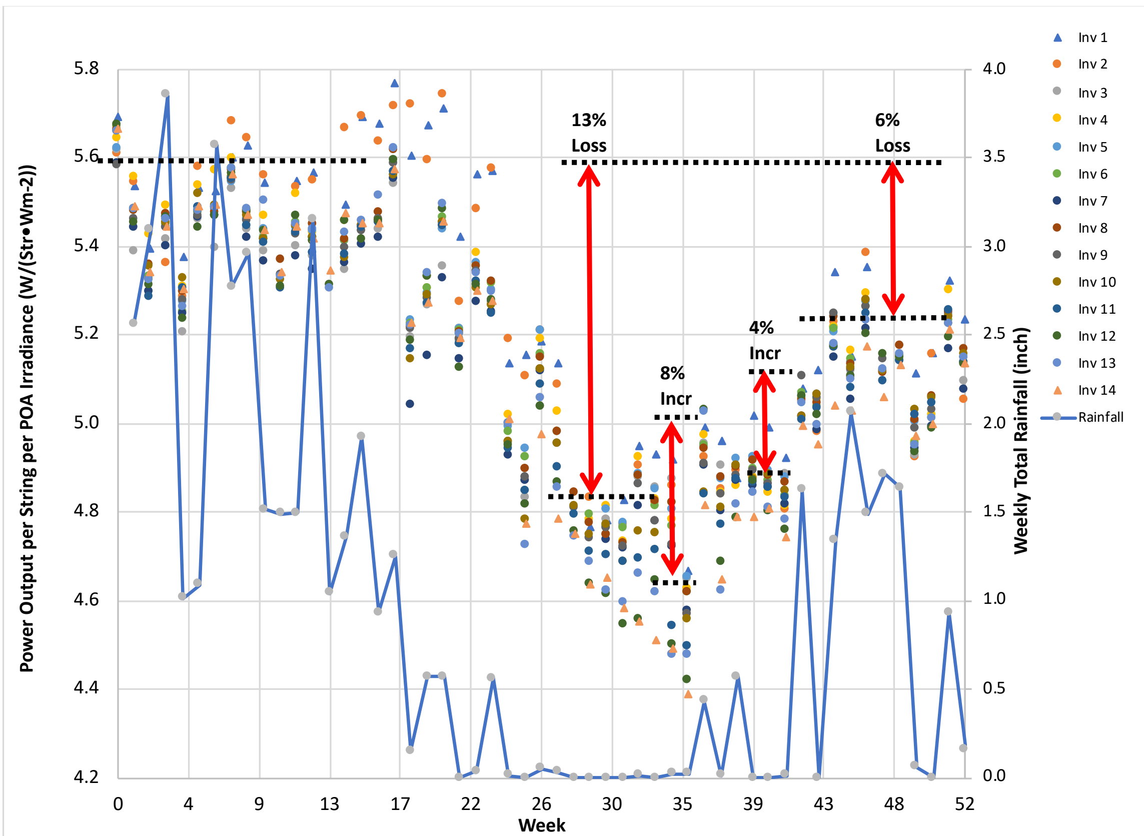
Source: Schatz Energy Research Center

Losses Due to PV Array Soiling

PV array soiling is the result of the accumulation of dust and other particles on the surface of the modules, which both reduces the transparency of the glazing and increases the reflectivity from the surface. This has the effect of decreasing the amount of solar irradiance reaching the PV cells, which reduces the module power output. During the late spring and summer of 2017 Northern California in general and the Blue Lake, CA area specifically experienced elevated dust fall rates due to the smoke plumes from extensive wildfires to the north and northeast of the area.

We estimate the impact of the PV array soiling using the ratio of the actual subarray outputs to the measured POA irradiance, yielding a performance index for each subarray (correcting for the number of module strings making up each subarray) for each daytime observation. The weekly averages of these index values (in W per string per W/m²), were computed which are plotted versus week of the 2017 year in Figure 46. Note that the modules had been in place for over three months before the start of 2017 and so may have accumulated some soiling already. In addition, this analysis does not take into account the effect of soiling on the pyranometer readings. If the actual POA irradiance was larger than the recorded values due to soiling, then the reductions in array output due to soiling would be even larger.

Figure 46: PV Array Soiling and Recovery Due to Rainfall



Source: Schatz Energy Research Center

In Figure 46, the performance index is approximately constant (averaging 5.56 W/(string·W/m²)) for the first four months, but then begins to steadily decline over May, June, and July, reaching an average of 4.75 W/(string·W/m²) in August. This represents a 13% loss, which is attributed to soiling. This decline occurred over a period matching the presence of smoke from wildfires in combination with the decline of rainfall associated with the area's Mediterranean climate pattern.

The return of rainfall in September (0.43 inch in week 36 following 12 weeks with no more than 0.02 inch per week) reduced array soiling, producing an 8% increase in the performance index. An additional 4% increase in the index followed week 42 that accumulated 1.62 inches. Note that these rainfall measurements are for the National Weather Service station in Woodley Island, Eureka and not for Blue Lake.

By the end of 2017, the performance index was still 6% below its value from the start of the year, indicating that the rainfall had not removed all of the accumulated soiling. In an effort to reduce the losses due to soiling, SERC developed the following recommendations:

1) The pyranometer dome should be cleaned at least every week, although daily cleaning would be desirable. After the first scheduled cleaning, the subsequent pyranometer readings should be carefully compared to the readings just prior to cleaning to assess the impact of spoiling on the readings. The best conditions for comparisons would include several clear days of sunshine.

2) The reference cell installed in the array field should be cleaned at the same time that the modules in the array field are cleaned to provide a direct basis for assessing the impact of soiling by comparison to the pyranometer readings. This was also a suggestion from REC Solar.

3) A protocol for cleaning the modules in the array field should be developed that would seek to minimize the associated labor costs while effectively removing soiling. It should be noted that several best practices solar PV array O&M manuals suggest that if panels have >15% slope, they should not require periodic scheduled cleaning, except for exceptional soiling events such as ash fallout from a wildfire. It would be useful to first implement the draft protocol on a single or a few of the 14 subarrays (i.e., conduct a pilot study), and then compare the performance of those test subarrays based on the differences between just before the cleaning and just following.

After the cleaning protocol is finalized, all of the modules in the array field should be cleaned whenever the effect of soiling reaches a target threshold, e.g., a 5% reduction in the performance index.

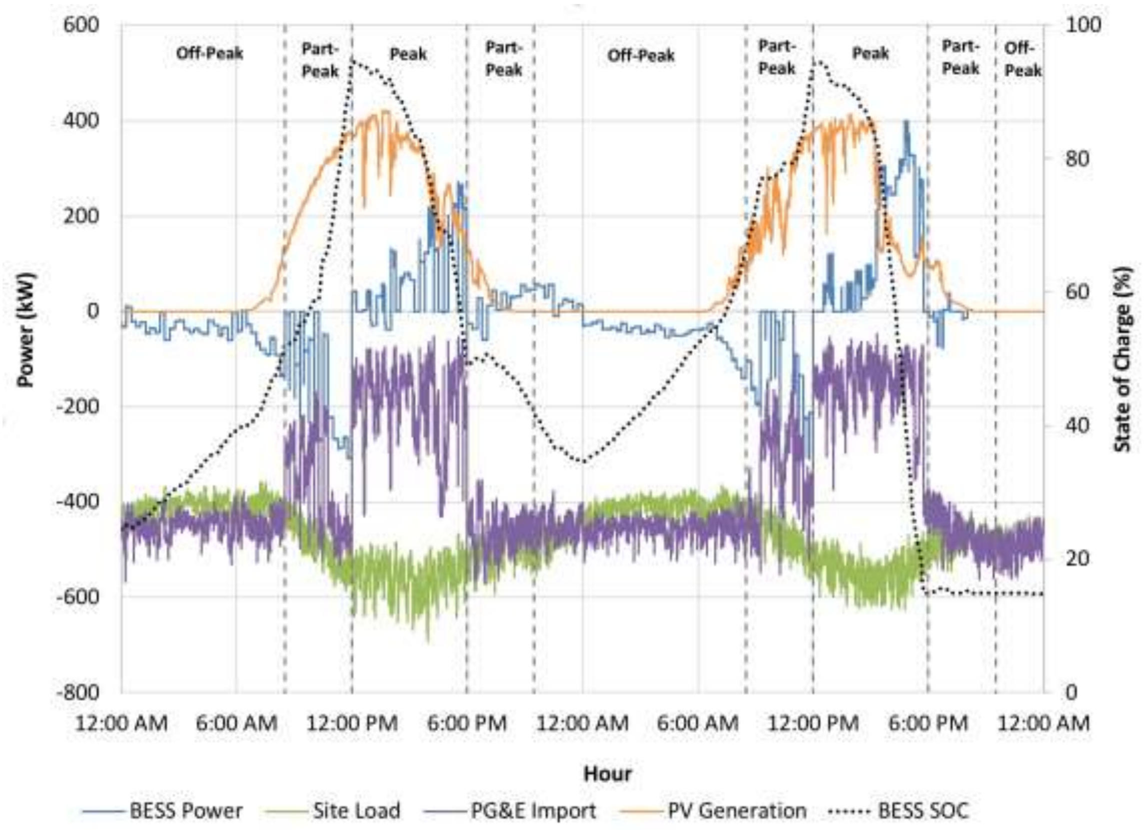
Battery System Observations

Figure 47 illustrates typical power flow characteristics for the microgrid over a two-day period in the summer. During this period the charge and discharge decisions for the BESS primarily depend on the PG&E import rate tariff and the electricity generation from the PV array. Starting at 12 midnight the site load is entirely met using PG&E imports and the BESS is slowly being charged. As PV generation picks up and the peak rate period approaches, BESS charging is accelerated. At 12 noon, when the summer peak prices take effect, the BESS is rapidly switched to discharge mode and the BESS and PV meet the majority of the onsite load, with the margin made up using PG&E imports.

In order to ensure that the 100 kW export limit is not exceeded, the control system aims to maintain roughly a 100 kW import from PG&E. Analysis has shown that this 100 kW import threshold is set optimally – i.e., if it were reduced, there would be numerous situations where the system would island to prevent the export limit from being exceeded.

Once the sun goes down and the rates drop into the off-peak period, PG&E imports are once again used to meet the onsite load and the BESS begins recharging. Then the cycle repeats itself the following day.

Figure 47: Representative BESS Two-Day Power Cycling



Note: BESS power is negative when charging and positive when discharging. Site load and PG&E import are both shown as negative.

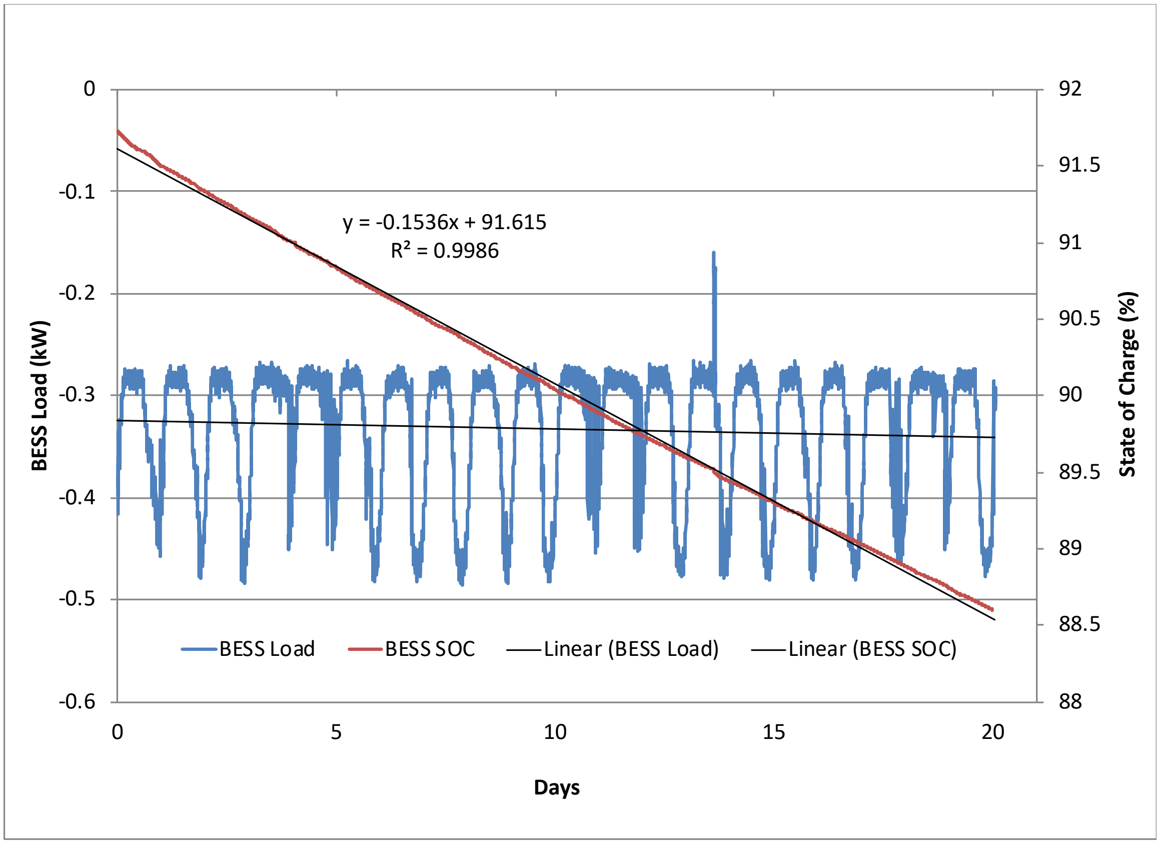
Source: Schatz Energy Research Center

In the rest of this section the performance of the BESS is evaluated according to several performance characteristics. This evaluation is based on data that were collected during operation of the BESS in the pre- and post-commissioning period of 2017.

BESS Parasitic Load

The parasitic/standby load of the BESS support electronics (including inverters, SMC, DC/DC converters, and other devices active when the BESS is not producing or consuming power) was calculated based on a 21-day period in July 2017 during which the BESS was powered on but neither charged nor discharged, shown in Figure 48.

Figure 48: BESS Parasitic Load During Extended Standby Period



Source: Schatz Energy Research Center

Observed parasitic load is cyclic with a daily pattern, varying between approximately 180 W and 486 W (excluding a brief maintenance window), with an average load of 332 W. This compares favorably to the Tesla-specified standby energy consumption of 167 W, and DC system standby energy consumption of 250 W at STC.

Self-discharge of the BESS battery pack was also analyzed over the same period. Using a linear regression, self-discharge is calculated at 0.15% of total battery capacity per day, with an R^2 of 0.9986.

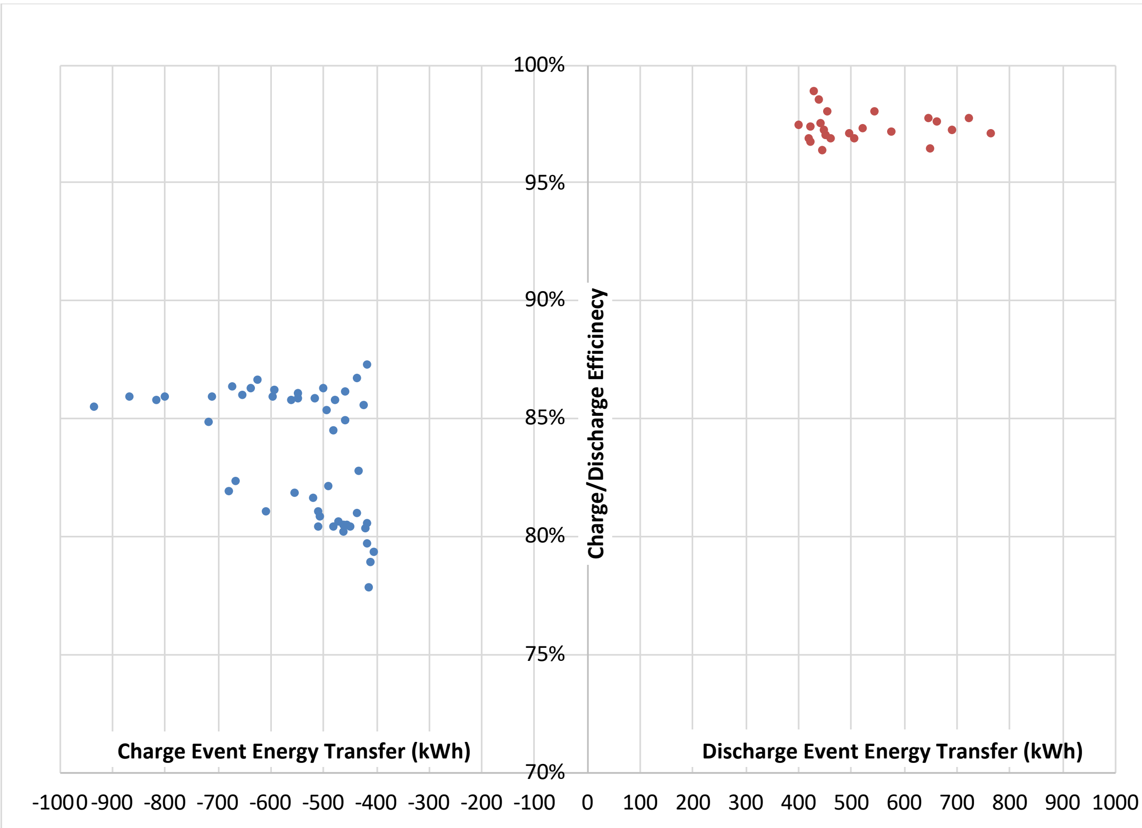
Charge/Discharge Efficiency

BESS charge and discharge efficiency were calculated by examining all significant charge and discharge events in the August through December 2017 post-commissioning period, defined as events in which the BESS state of charge changed by greater than 30% of its total capacity. Energy consumed or produced was measured at the BESS meter, and state-of-charge is based on BESS indicated SOC.

Figure 49 shows the charge/discharge efficiency versus power flow for these events. For the 48 significant charge events observed, the average charge efficiency was calculated at 83.4% (standard deviation 2.8%). For the 23 significant discharge events observed, average discharge efficiency was calculated at 97.3% (standard deviation 0.6%). Accounting for the calculated parasitic load and self-discharge discussed above over the length of the event, the charge efficiency is 83.9% (standard deviation 2.5%) and the discharge efficiency is 97.6% (standard deviation 0.6%).

This results in a roundtrip efficiency of 81.1%, or 81.8% when parasitic load and self-discharge are factored out. In comparison, analyzing the six largest well-defined round-trip charge-discharge cycles that occurred in the observation period, mean roundtrip efficiency was calculated at 80.9%, or 81.6% with parasitic load and self-discharge factored out. This is very close to Tesla's specified 81.5% roundtrip efficiency.

Figure 49: BESS Charge/Discharge Efficiency Versus Energy Transfer



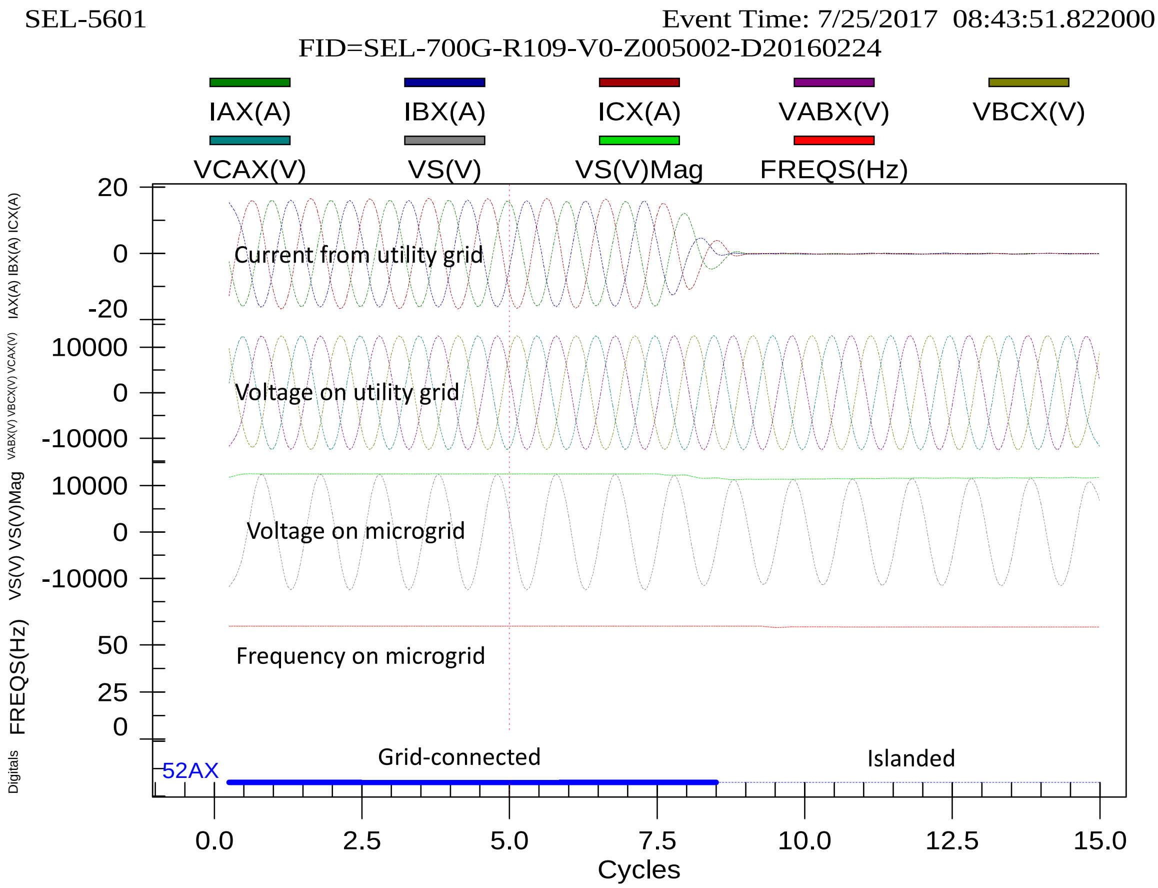
Source: Schatz Energy Research Center

Seamless Transitions

Due to the relative size of the onsite load and BESS inverters, seamless transitions were only performed during tests for which the load-shed capability of the microgrid had been used to reduce site load sufficiently to allow the BESS inverters to carry it without risk of overloading the inverters. Figure 50 and Figure 51 show SEL event captures from the PCC Relay of the disconnect and reconnect portion, respectively, of one such test. During the disconnect, utility current through the PCC can be seen dropping to zero when the utility breaker (indicated by 52AX due to Tesla-specified PCC Relay programming) is opened, while voltage and frequency on the microgrid remain stable. During the reconnect, utility current can be seen increasing from zero when the utility breaker is closed, while voltage and frequency on the microgrid remain stable.

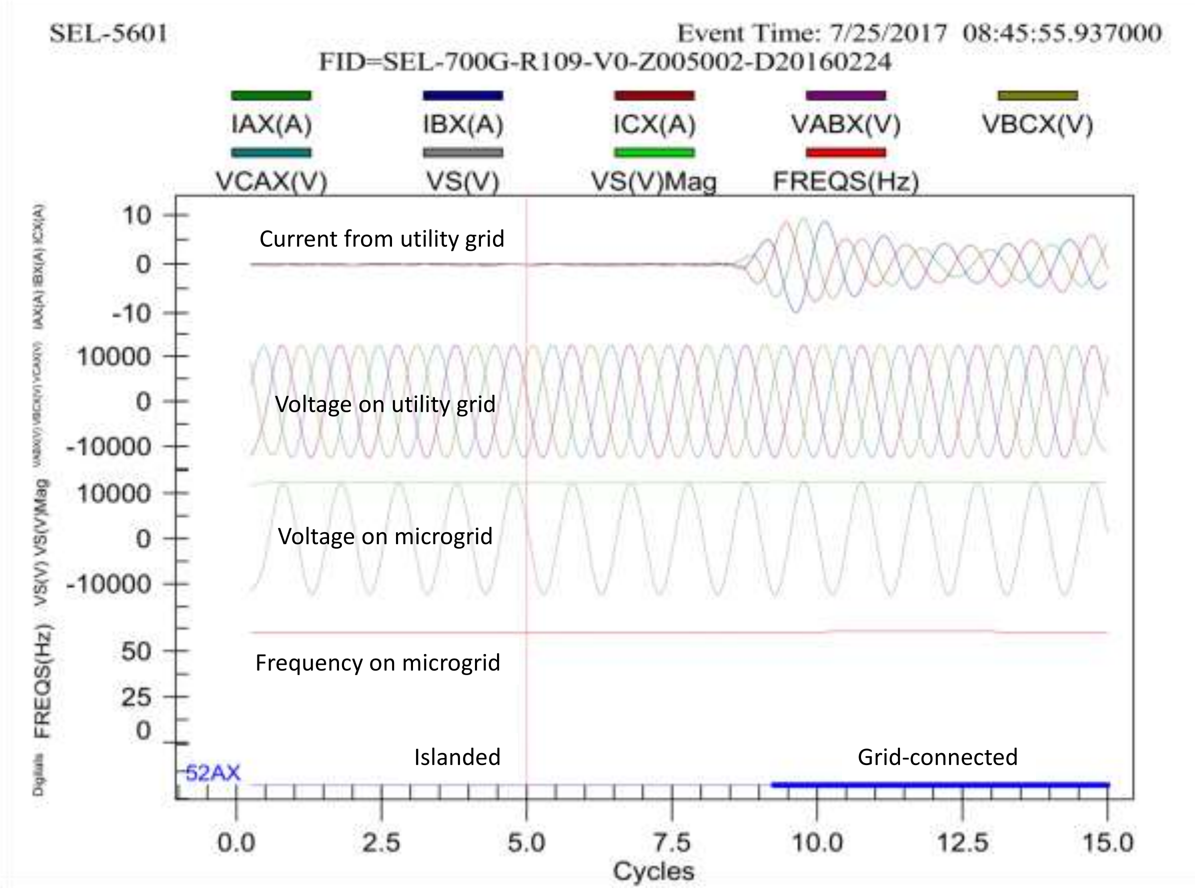
As would be expected based on these event captures, there was no noticeable disruption in power observed onsite during these transitions. The PCC current during reconnect shown in this event capture is significantly less than the current at disconnect (site load was similar at both times) indicating that proper synchronization had been achieved at the time of breaker closure. PV inverters were producing power during both of these events and did not trip offline; this is discussed later in the Low Inertia Islanding section.

Figure 50: Seamless Disconnect from Utility Grid



Source: Schatz Energy Research Center

Figure 51: Seamless Reconnect to Utility Grid

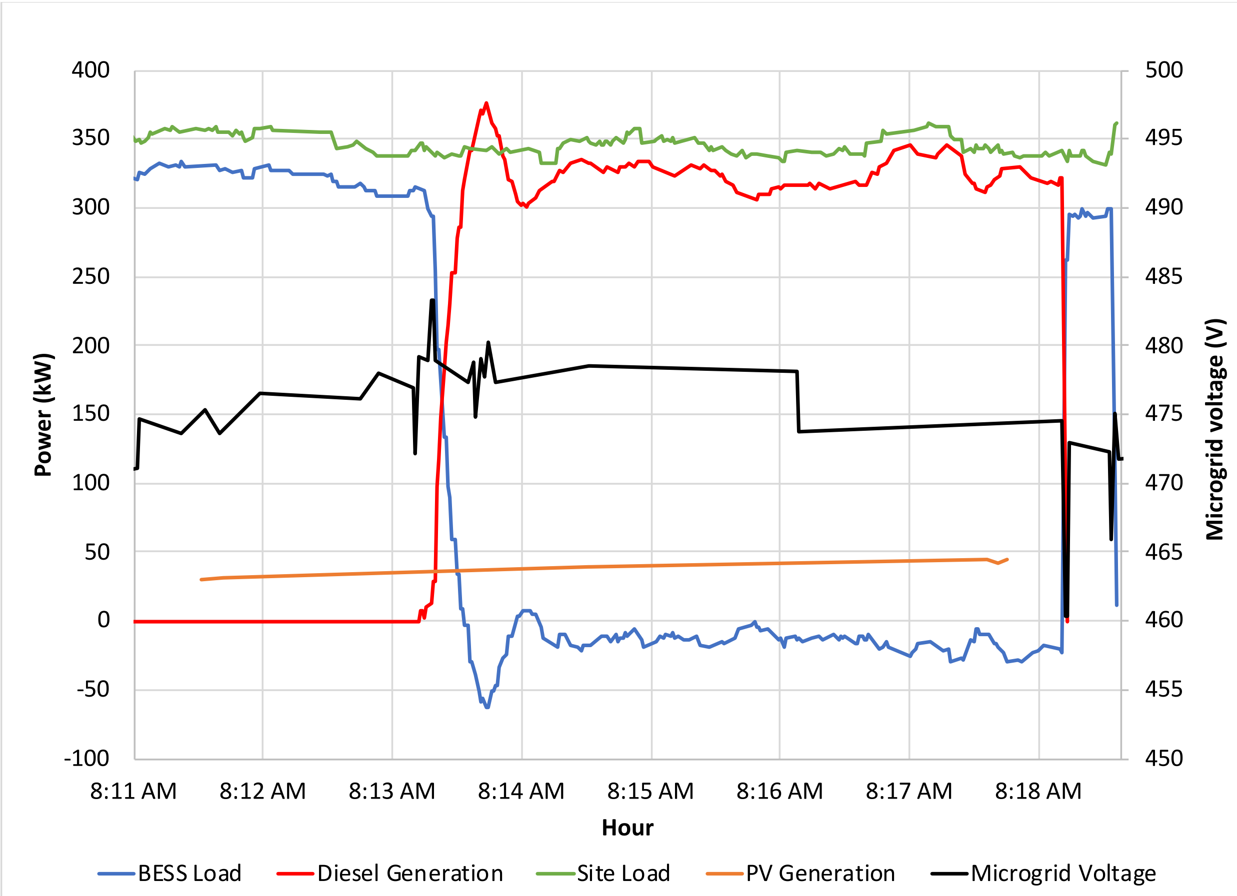


Source: Schatz Energy Research Center

Because of the previously discussed limitations, a seamless connection of the 1 MW DG to the islanded microgrid during a low-inertia islanding event was only possible during testing. Figure 52 shows a test demonstrating this functionality. As shown, the 1 MW DG was successfully synchronized and connected to the BESS without disrupting site load or causing a voltage deviation, as measured at the 480 V BESS meter. Generator loading was positive at all times and brought to within standard operating range within 20 seconds of connection.

Toward the end of the test, the DG was seamlessly disconnected, returning the microgrid to a low-inertia islanding state. Voltage again remained within acceptable ranges (<5% deviation from nominal) at all times. The test concluded with a seamless transition back to grid power.

Figure 52: Seamless Connection of Generator



Source: Schatz Energy Research Center

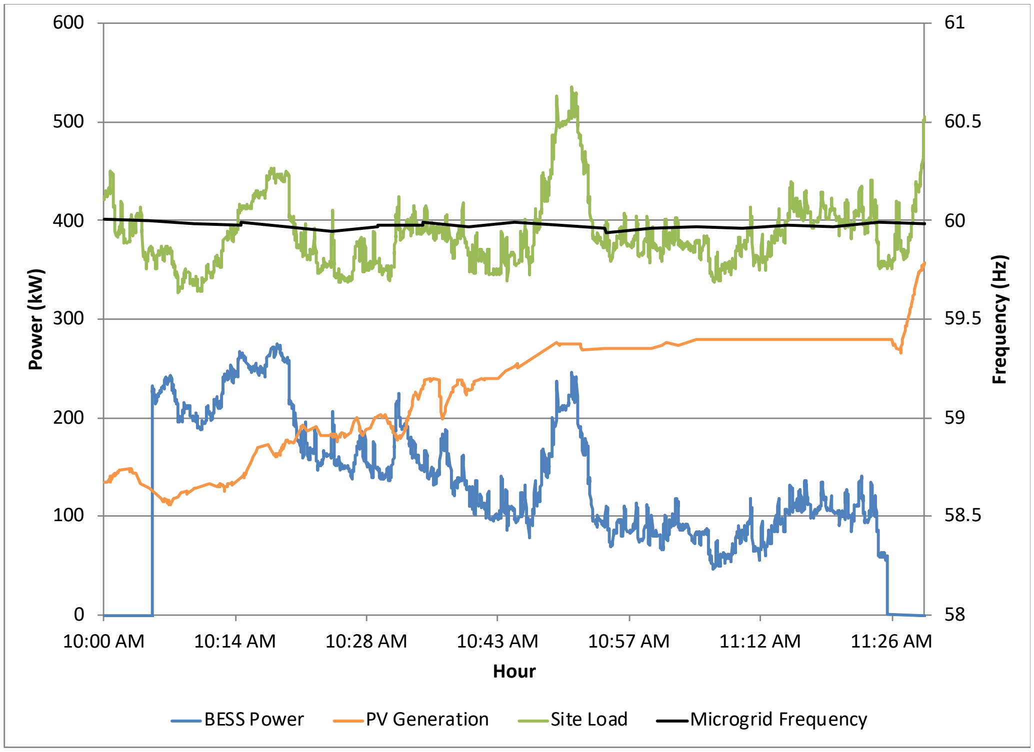
Low-Inertia Islanding

As noted above, low-inertia islanding was only performed during commissioning tests, when load shed had been used to reduce site load. Figure 53 and Figure 54 show the longest such test performed, lasting 1 hour 20 minutes.

During the low-inertia islanding period, microgrid frequency was maintained between 59.94Hz and 60.01Hz (<0.1% deviation from nominal), demonstrating both effective islanding capability of the BESS and effective frequency control by the MGMS in response to load variations >150 kW. Microgrid voltage during this period, as measured at the BESS 480 V meter, was maintained between 456 V and 485 V (<5% deviation from nominal), again demonstrating stable islanding capability and effective voltage control by the MGMS in response to load variations >100 kvar. BESS SOC was 86.9% at the start of this test and had reached 67.0% at the end, an approximate drop in SOC of 15% per hour.

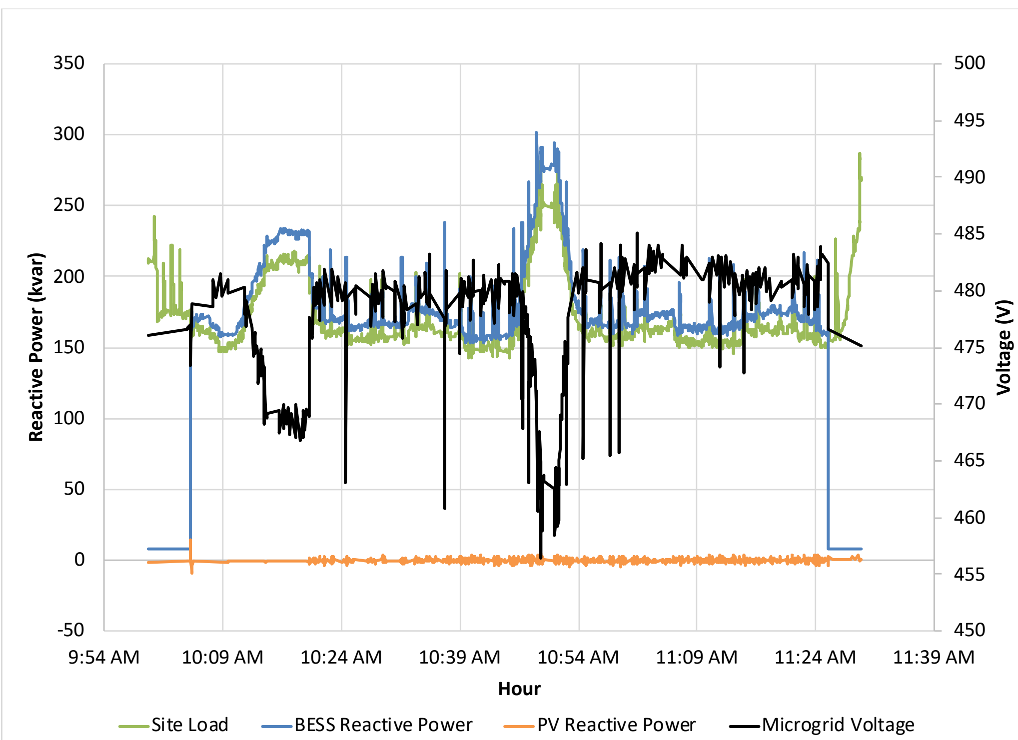
Note that site reactive power in Figure 54 is calculated from the sum of the Hotel, Casino, and Tribal Office power meters, resulting in a slight offset from the reactive power measured at the BESS, which was supplying all onsite reactive power during that period. PV var output is approximately zero; this was expected as the PV inverter settings specified a unity power factor.

Figure 53: Low-Inertia Islanding Event Real Power Balancing



Source: Schatz Energy Research Center

Figure 54: Low-Inertia Islanding Event Reactive Power Balancing



Source: Schatz Energy Research Center

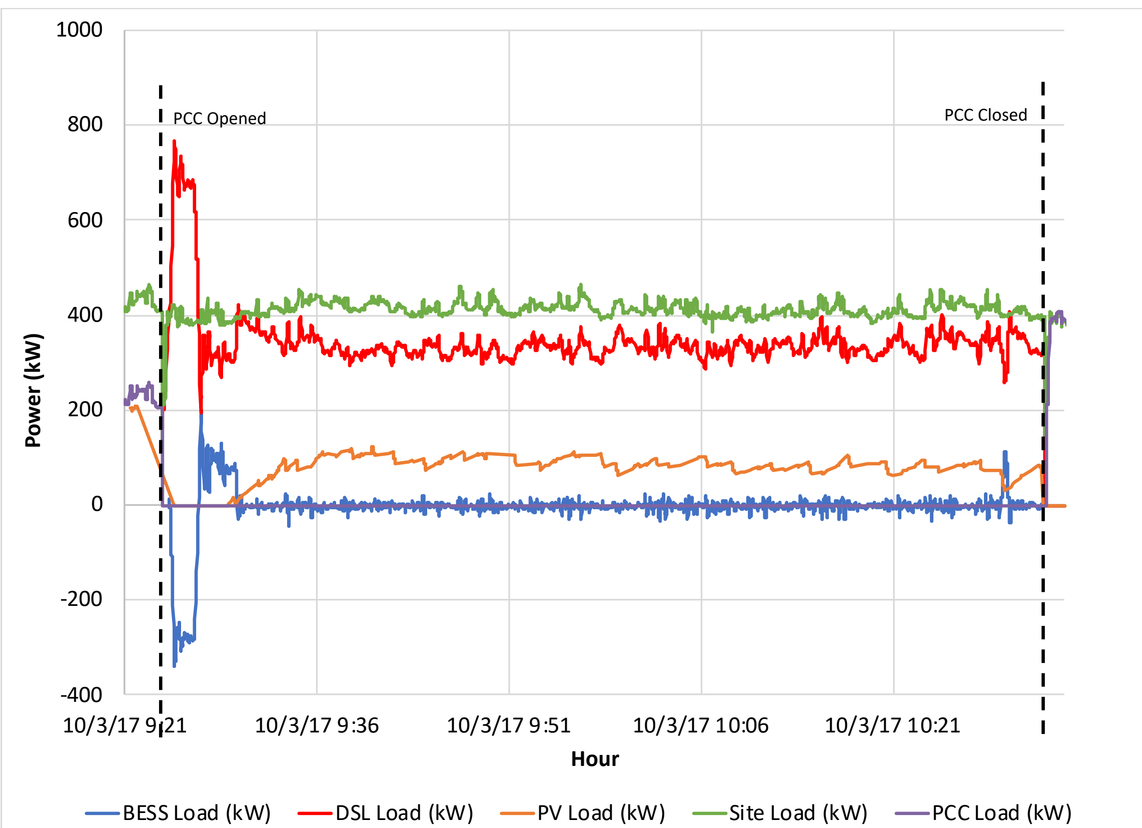
Load-Sharing with Generator

Load sharing with the generator was observed three times during the post-commissioning observation period, twice during PG&E outages and once during a planned islanding event. Figure 55 and Figure 56 show selected data from the planned islanding event. Because all islanding events during the post-commissioning period occurred during periods of low insolation, only modest amounts of BESS load sharing were observed, but behavior was as expected.

For the event shown in Figure 55, the 1 MW DG is kept appropriately loaded (>300 kW) during the islanding period. After a brief (~2 minute) initial period during which the MGMS optimizer is calculating appropriate load balance, the BESS is dispatched to carry approximately 100 kW of site load until the PV array has come back online after the disruption caused by the disconnect event. Toward the end of the islanding period, PV output is reduced by a cloud, and the BESS can be observed increasing power output to compensate. Once the load balancing has stabilized, the BESS is never charged by the DG.

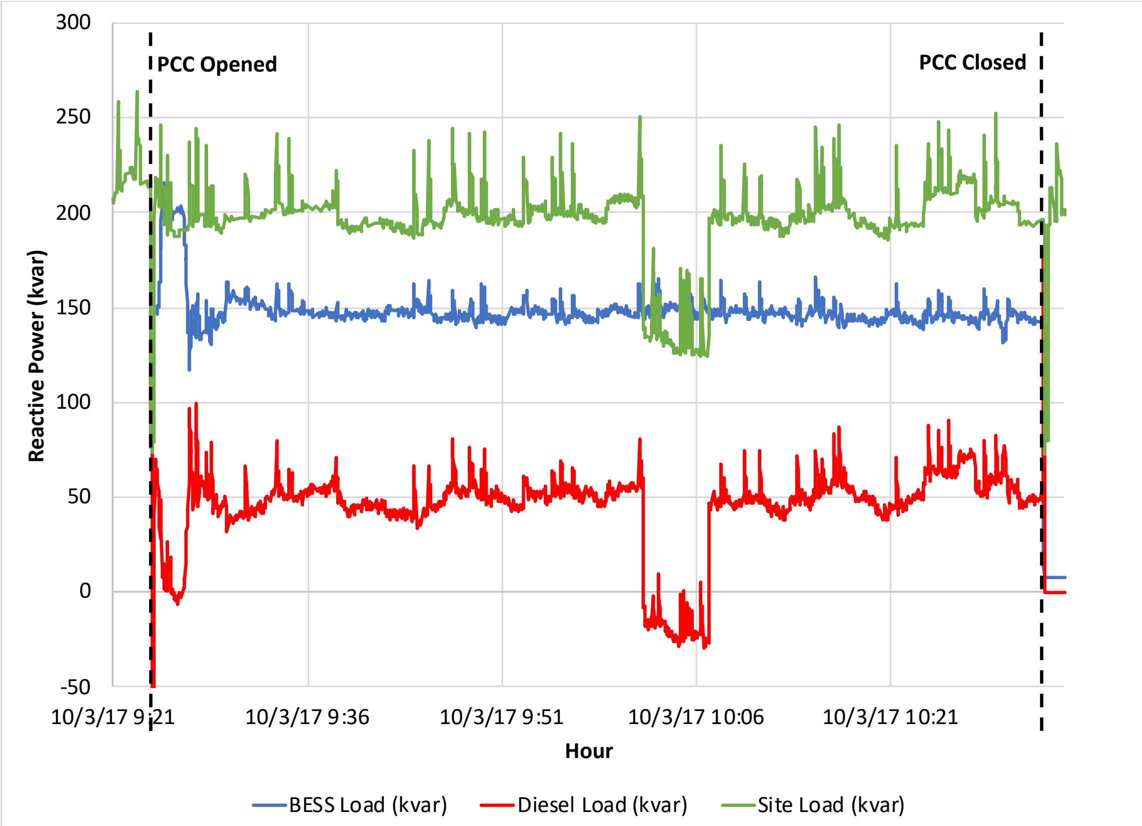
During the same event, the BESS can be seen carrying approximately 75% of the site reactive power load, based on its target voltage setting, significantly reducing reactive power load on the DG. During commissioning tests performed on sunny days, the BESS was observed absorbing excess PV energy, enabling the DG to maintain a healthy load of >300 kW without necessitating PV curtailment.

Figure 55: Load-Sharing with Generator Real Power Balancing



Source: Schatz Energy Research Center

Figure 56: Load-Sharing with Generator Reactive Power Balancing



Source: Schatz Energy Research Center

MGMS and Fully Integrated Microgrid Observations

Observation of MGMS functionality and overall automated, integrated microgrid system behavior began with the official completion of MGMS commissioning on July 28, 2017. The microgrid was allowed to run without user intervention through the remainder of 2017, operating under normal conditions under automatic control of the MGMS. Data were collected during this period and analyzed. According to informal interviews with BLR and Serraga personnel tasked with monitoring and operating the microgrid, staff indicated that the microgrid ran smoothly and without any intervention during this period.

Certain microgrid features, in particular low-inertia mode islanding functionality, could not be tested under normal operating conditions due to insufficient size of the battery inverters relative to the site load on the microgrid. For example, in low inertia mode if both elevators in the hotel move upwards simultaneously with moderate weight in each, the BESS inverters will very likely trip on an overcurrent condition unless the net microgrid load is unusually low at the time. As a result, observation of this functionality is based on tests performed in the final stage of the BESS commissioning process and afterward. This functionality is planned to become available under automatic control when an upgrade of the BESS capacity[4] is completed in 2018.

One of the significant measures of success of the MGMS and integrated microgrid system is its ability to operate within specified limits under sometimes rapidly changing conditions. Notable challenges in this area include:

- Maintaining appropriate loading (neither too high nor too low) on the 1 MW DG while in islanded mode, which is necessary for DG health.
- Preventing reverse power conditions on the 1 MW DG when in islanded mode, critical to both generator health and microgrid operation during islanding events, as a significant reverse-power event will cause the 1 MW DG's safety features to disconnect it, likely causing a significant blackout on the microgrid.
- Allowing an export to the utility grid of no more than 100 kW per the interconnection agreement. A violation of greater than two seconds results in an unplanned disconnect from utility power.

Affecting these operational limits is the variable and unpredictable nature of PV output, which without mitigation can increase or decrease by large amounts in a matter of seconds due to cloud cover, and the variable nature of the site load, which can change by tens of kW in less than a second due to operation of the hotel's elevators and cycling of HVAC systems.

Basic Islanding Functionality

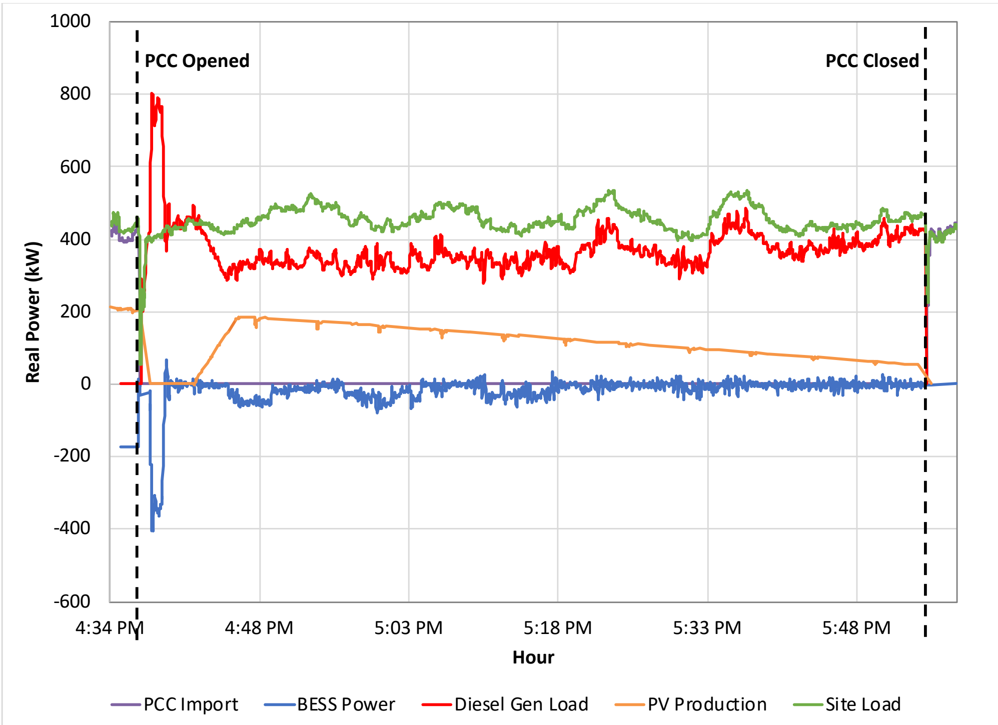
There have been four unplanned grid power outages that affected BLR between July 2017 and March 2018. These outages resulted in islanding events ranging from 15 to 79 minutes in length. In each event, the microgrid was observed to behave as expected: the PCC was automatically disconnected from PG&E by the PCC Relay and the 1 MW DG was started by the MGMS and connected to energize the microgrid. During the islanding event, PV curtailment and smoothing occurred as designed and load-sharing with the BESS was managed such that the 1 MW DG was not over- or under-loaded. Fifteen minutes after PG&E stability was restored, the 1 MW DG was disconnected and the microgrid was re-energized using utility power. No operator intervention was necessary at any time.

Additionally, one planned islanding event was performed by BLR personnel during the observation period to support maintenance on an internal component. BLR personnel were able to use the MGMS HMI to successfully initiate the islanding event and perform a reconnect to the grid without additional onsite support. System performance during this period was as expected.

Shown below in Figure 57 and Figure 58 are plots of a representative PG&E disruption on October 8, 2017 local time.

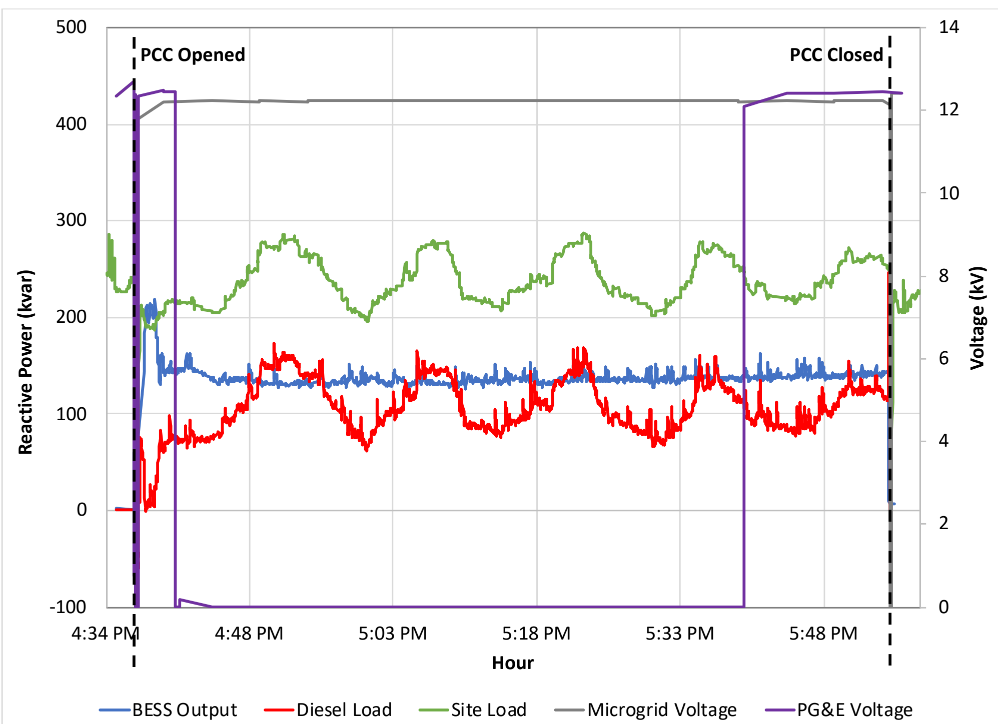
[4] Plans are to essentially double the kW and kWh ratings on the BESS.

Figure 57: Unplanned Islanding Event Real Power Balancing



Source: Schatz Energy Research Center

Figure 58: Unplanned Islanding Event Reactive Power Balancing



Source: Schatz Energy Research Center

Figure 57 illustrates successful energization of the microgrid using the 1 MW DG and BESS approximately 10 seconds after the initial outage. Five minutes after the microgrid is energized the PV inverters come online, increase smoothly in output due to the smoothing algorithm, and share load with the battery for the remainder of the power outage as insolation gradually decreases due to the sun going down. Early in the outage the BESS can be observed absorbing some PV power to maintain a healthy load of approximately 300 kW on the DG, allowing maximum PV output without curtailment. At the end of the outage, the PV inverters trip off due to the break-before-make transition and load is transferred to PG&E in approximately two seconds.

Figure 58 illustrates load-sharing of reactive power load between the BESS and DG, with the BESS outputting a roughly constant 150 kvar based on voltage setpoints and the DG providing the remainder, from 60 kvar to 170 kvar. Voltage on the 12.5 kV microgrid bus is stable throughout the islanding period.

Figure 58 also illustrates the anatomy of the grid outage and islanding decisions with the PG&E grid voltage shown. There is an initial power outage (approximately 30 seconds including a brief recloser burn-off attempt), power is restored for slightly under 4 minutes, then fails again for approximately 1 hour. The microgrid remains islanded throughout this unstable period. At 5:40 PM grid power is restored successfully, at which point the MGMS waits 15 minutes before transferring back to grid power.

Low-Inertia Islanding Functionality

The MGMS did not automatically attempt low-inertia islanding during any of the observed outages. This was expected and correct behavior due to BESS inverter capacity relative to the onsite loads. Several successful low-inertia islanding tests with site load reduced using load-shed capability of the microgrid were, however, conducted. The longest such low-inertia islanding test, with significant PV load sharing, was performed in July 2017 as part of the commissioning process for the BESS (see Figure 53 and Figure 54 in Battery System Observations: Low Inertia Islanding section).

As noted previously, microgrid voltage and frequency remain within acceptable limits throughout the test (<0.1% frequency deviation from nominal, <5% voltage deviation from nominal), and due to successful application of the seamless transition function are not disrupted while either disconnecting from or reconnecting to the grid.

As the sun rises during this test PV inverter output initially increases steadily, with a corresponding decrease in BESS output. Approximately halfway through the test stability curtailment begins limiting the output of the array to 275 kW. After the seamless transition back to the grid, the PV inverter output can be seen increasing steadily due to the output smoothing algorithm.

Regarding the system's ability to automatically initiate low-inertia islanding without operator preparation, observations showed that the original analysis of utility bill demand data, which showed a potential concurrent peak of 794 kW based on 15-minute-interval averages, did not capture short-duration increases in load, which were observed to be common in the microgrid. In particular, elevator operation and HVAC/refrigeration equipment start-up routinely cause significant short-duration increases in load. Analyzing 5s resolution data gathered in August 2017 shows an additional load from various equipment can be as much as 151 kW above the 15-minute average. When added to the potential concurrent peak of 794 kW reported in utility demand monitoring, this results in an actual potential peak as high as 945 kW. Actual demand peak may be even higher than this on a shorter timescale. Additionally, the utility bill demand data only reflects real power; the electrical loads of the facility have a significant reactive power component, with measured peaks during a 3-hour observation period of at least 375 kVAR and coinciding with the short-duration real-power peaks noted above. The combination of these two factors mean that the microgrid campus is likely to experience peak VA demand of at least 1016 kVA.

Because the BESS as-installed has a hard limit of 500 kVA output, above which it will immediately shut off due to DC system limitations, real power alone does not accurately reflect the necessary capacity to serve the onsite load.

Seamless Transition Functionality

Because of the size mismatch between the BESS inverters and the site load, seamless transitions were only attempted during commissioning tests when the site load was manually reduced using load-shed capability and the hotel elevators were disabled to minimize sudden reactive power spikes. There was no need for a planned islanding event during the normal-operation observation period. Therefore, seamless disconnect and reconnect operations were observed during commissioning tests, as discussed in the Commissioning chapter of this report. Refer to Figure 53 and Figure 54 for an example of a seamless islanding event. Note that the PV array does not trip off due to grid loss at the start and end of the islanding event. Figure 50 and Figure 51 illustrate the seamless transitions at the waveform level.

For the same reason that low-inertia islanding was only attempted during testing, a seamless connection of the 1 MW DG to the islanded microgrid running in low-inertia mode was only attempted during commissioning tests. As discussed in Battery System Observation: Seamless Transitions, this test was successful, with the foundational control system and the MGMS commands interacting to connect the 1 MW DG seamlessly to the BESS-energized islanded microgrid and sufficiently loading it once connected. Figure 52 illustrates a seamless DG reconnect event. This is discussed further in Chapter 6: Commissioning.

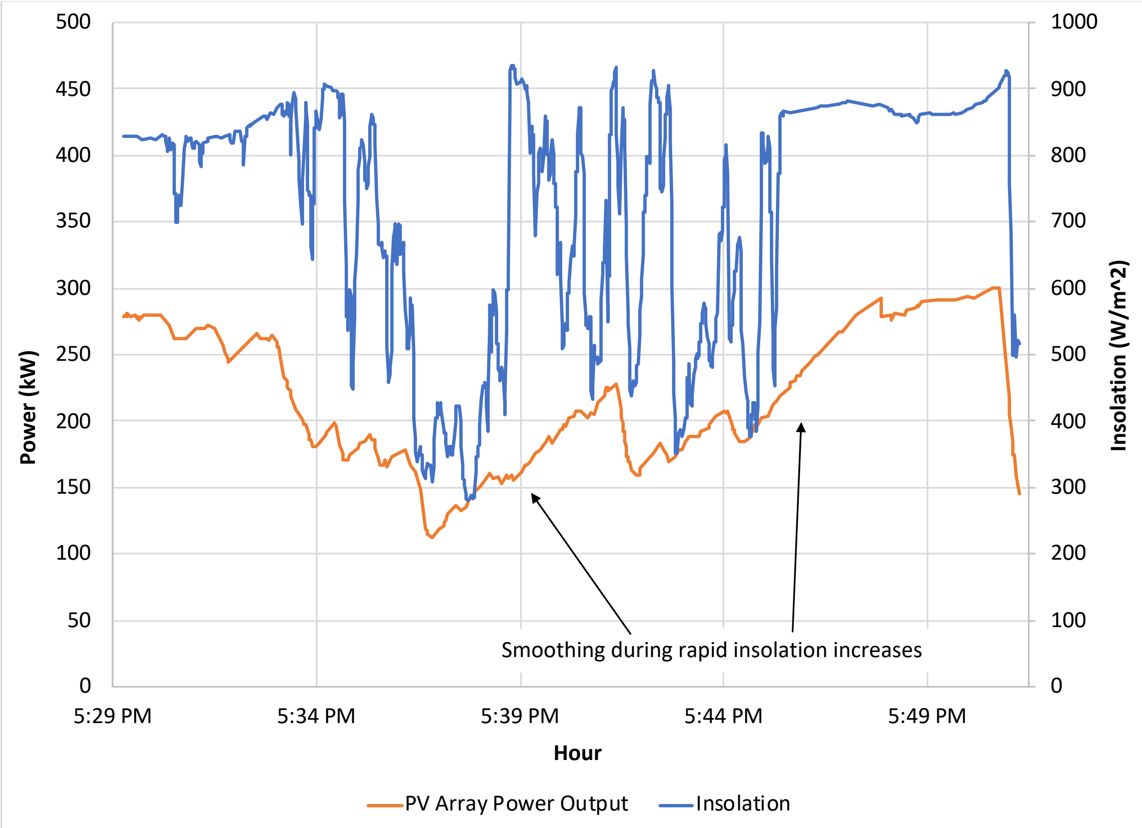
Post-Commissioning Success at Maintaining Operational Limits

Keeping the system within the specified utility export limit of 100 kW was the most significant stability requirement in grid-connected operation, as a violation of this limit for more than 2 seconds results in an immediate unplanned disconnect from utility power per the interconnect agreement and protection relay settings. To achieve this, abrupt increases in PV output are smoothed programmatically to give the system sufficient time to appropriately adjust BESS charge or charging rates. Relative ramp rates of various SCADA parameters were coordinated, and target limits were set to account for the very abrupt load changes that result from hotel elevator use.

A minimum 100 kW utility import target has been set for the microgrid control system to achieve the desired result. During the observation period of August through December, the maximum observed export was 94 kW, and as such there was no point at which the system disconnected from the grid due to an export limit violation.

The PV smoothing algorithm implemented in the MGMS, which prevented rapid increases in the output of the PV array when a passing cloud resulted in a rapid increase of insolation over a short period of time, was observed to perform as designed at all times. A representative period of rapid insolation fluctuations due to erratic cloud cover along with smoothing of PV array output is shown in Figure 59.

Figure 59: PV Smoothing Example



Source: Schatz Energy Research Center

Assessment of Overall System Performance

Microgrid Impact on Net Site Load

The site load at BLR can be characterized by a number of parameters, including annual energy consumption, average power demand, peak power demand, and load factor.[5] The net site load is referred to as the portion of the onsite load that is met using imported electricity from PG&E at the 12.5 kV level. In contrast, the gross site load is the total onsite load measured at the 480 V level. The difference between net and gross is due to onsite generation from the PV system and additional load due to BESS and transformer inefficiencies.

To evaluate the impacts of the BLRMG system on the larger utility grid, the net site load for 2017 is assessed with and without the microgrid. Between January 1, 2017 and July 6, 2017, the team did not have access to MGMS Historian data due to a data-archiving problem. Consequently, for this period PG&E interval data and Meteo Control PV generation data were used to determine the onsite load. It was assumed the onsite load was the sum of these two sources. Since there was no export of energy to the PG&E grid, this should be accurate. The other source of error is added site load due to BESS inefficiencies. However, the BESS mainly sat idle during this period and is expected to have had little impact on the site load. For the period

[5] Load factor is the electricity consumed during a period in kWh divided by the product of the peak load for the period times the number of hours in the period.

from July 6, 2017 through December 21, 2017 Historian data was assessed. This provided direct measurements of PV generation, BESS charge and discharge energy, PG&E imports, and onsite loads.

The team did not expect the microgrid to have any significant impact on the gross onsite load. To assess this, 2017 site load data was compared with 2015 site load data, and no substantial change in load characteristics were noted.

Table 11 provides net site load characteristics for the year 2017 with and without the microgrid, and Figure 60 compares the load duration curve for these two scenarios.

Table 11: Comparison of Load Characteristics

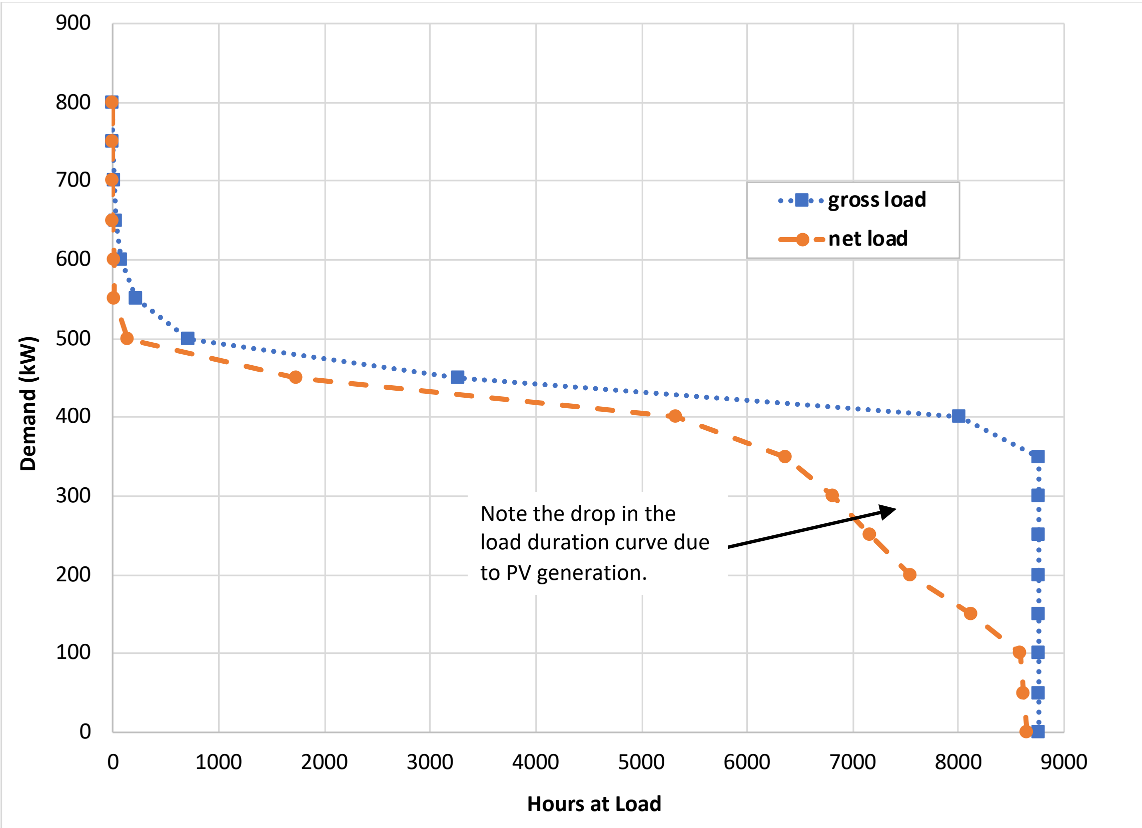
Load Characteristic	2017 Gross Site Load	2017 Net Site Load	Microgrid Savings	% Decrease Due to Microgrid
Annual energy use (MWh)	3,810	3,240	570	15%
Average demand (kW)	435	370	65	15%
Peak demand (kW)	754	625	129	17%
Load factor	0.58	0.59	N/A	N/A

Source: Schatz Energy Research Center

The reduction in imported electrical energy is a function of the PV output and any added load incurred due to BESS inefficiencies. As already noted, the PV array generated 594 MWh, and when adjusted to a TMY year and eliminating curtailment and communication glitch losses (as is expected moving forward), the PV array is expected to produce about 670 MWh per year. The losses due to BESS inefficiencies amounted to approximately 20 MWh in 2017 (active only from July through December); it is uncertain how these losses will change in a more typical operational year, but the observed six-month period is expected to be representative of ongoing operations, which would result in losses of approximately 40 MWh per year.

Using the observed BESS losses for 2017, the actual decrease in net site load was 574 MWh (approximately 563 MWh after assumed PV transformer loss of 2%) and the expected decrease moving forward should be about 630 MWh (617 MWh after 2% transformer loss). This should result in about a 16% decrease in the amount of energy imported from PG&E. The reduction in average power demand over the 2017 year as seen by the PG&E system was estimated at 65 kW (15%), and the reduction in peak demand was 129 kW (17%).

Figure 60: Load Duration Curve – Gross vs. Net Site Load



Source: Schatz Energy Research Center

Cost Savings

Assessing the cost savings from the BLRMG is a complex process due to the number of factors that affect electricity bills. The BLR facility receives electric service under the E-19 Medium General Demand-Metered TOU Service. The installation of the microgrid required a switch from secondary voltage service to primary voltage service. This was necessary because to form the microgrid, BLR purchased a portion of PG&E's distribution infrastructure and began receiving service at 12.5 kV. Primary voltage rates are lower than secondary voltage rates, and therefore this switch resulted in financial benefits to BLR that are not strictly due to the operation of the microgrid. Additionally, in May of 2017, BLR switched their generation service from PG&E to a new Community Choice Aggregation Program under the Redwood Coast Energy Authority (RCEA), and this led to further savings. BLR also has the ongoing opportunity to increase their savings by enrolling in Option R rates (favorable to solar customers) and/or participating in demand response programs. Finally, as this report has detailed, there were PV system losses due to curtailment and communication issues. Correcting those losses will lead to additional savings, and those additional cost savings will also be assessed.

This analysis does not model the savings that were actually realized in 2017, but rather models the savings that would result based on 2017 consumption and the most up-to-date electricity rates from RCEA and PG&E, which were implemented in March of 2018.

Data and Methodology for Cost Savings Estimations

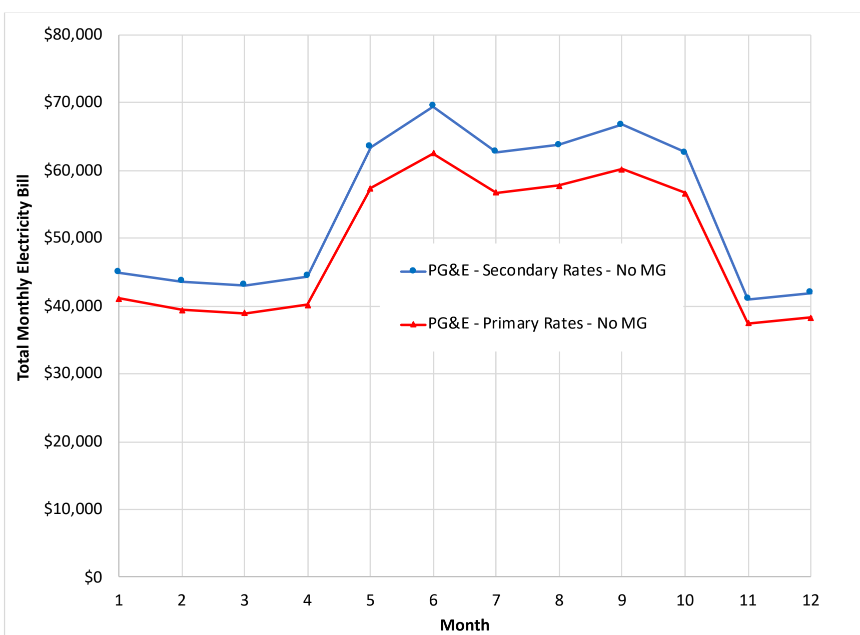
To understand how the microgrid saves BLR money, this section itemizes each of these steps by moving chronologically through both the rate changes and the microgrid installation. These calculations are based on the observed 2017 consumption. Each relevant rate structure is applied to these consumption numbers, and monthly and annual savings are calculated. First, the team assessed the impacts of switching from secondary to primary voltage service; next the impact of switching to RCEA generation rates was assessed; and lastly the impacts due solely to the installation of the microgrid were assessed. There were some issues with microgrid operation over the last year (such as unnecessary PV curtailment and PV inverter communication glitches). These performance issues are examined and their impact is assessed in the section on PV System Observations. These issues have since been resolved; therefore, the team also estimated the increased microgrid cost savings BLR can expect going forward.

The cost calculations were checked against actual 2017 bills where applicable. For the months there are accurate PG&E bills, the average difference between the actual and calculated bills was about 1%. This deviation is not surprising given the small issues that can arise in billing. BLR's 2017 electricity bills had substantial omissions and subsequent corrections that had to be made by PG&E and RCEA. The rates used for the following analyses were effective as of March 1, 2018 for all PG&E rates and March 15, 2018 for all RCEA rates.

Secondary Rates to Primary Rates Under PG&E

Before installing the microgrid, BLR received bundled electricity service from PG&E via three secondary voltage accounts. To install the microgrid, BLR combined the secondary service infrastructure from the Hotel, Casino and Tribal Office into one primary service. This switch resulted in cost savings for BLR. Figure 61 illustrates those savings by taking the measured 2017 load, without the microgrid, and applying PG&E E-19 Secondary Rates and E-19 Primary Rates. This switch results in about $61,000 in annual savings for BLR, which amounts to about a 9% drop in annual costs.

Figure 61: Estimated Non-Microgrid Monthly Bills - Secondary vs. Primary PG&E Rates

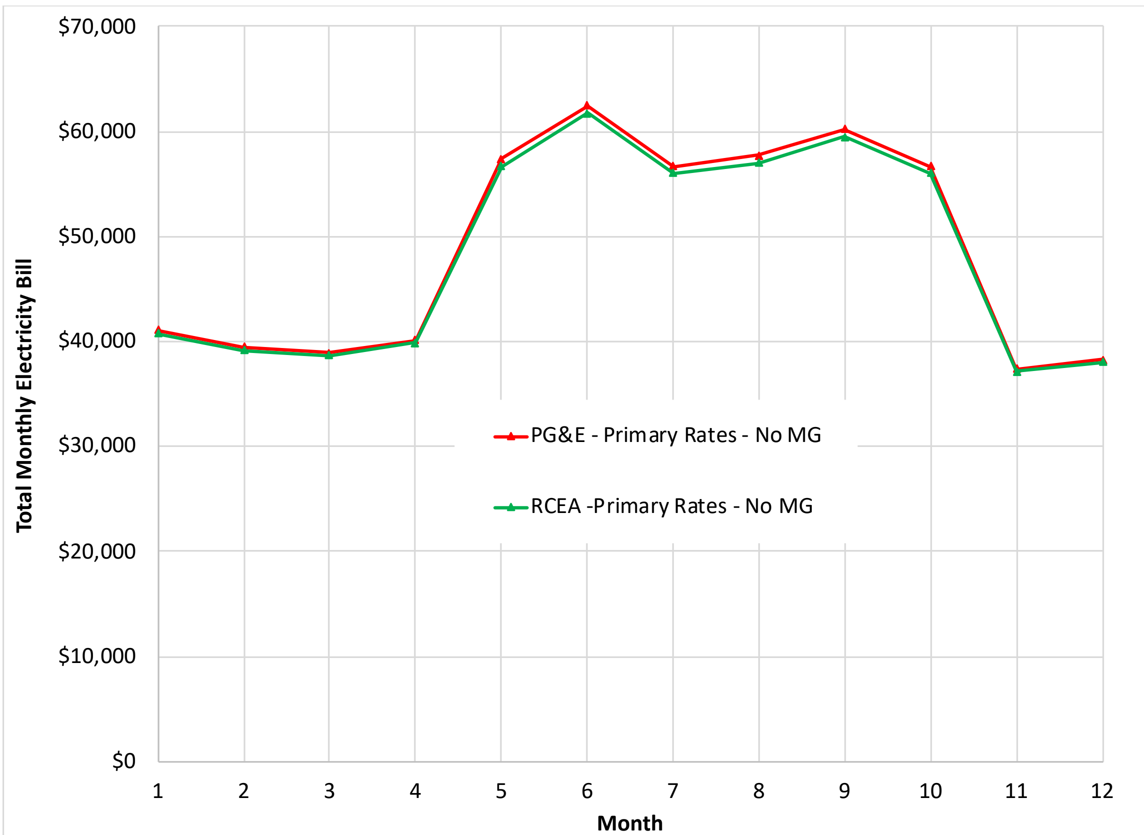


Source: Schatz Energy Research Center

PG&E Generation Rates to RCEA Generation Rates

In May of 2017, the entire BLR site was switched from PG&E to RCEA for electricity generation service. Although this switch occurred mid-year, the team estimated the annual savings associated with this rate change. Figure 62 shows the savings associated with the switch from PG&E to RCEA rates in a non-microgrid scenario. The difference is about $6,000 per year, which amounts to roughly an additional 1% drop in annual costs.

Figure 62: Estimated Non-Microgrid Monthly Bills - PG&E Primary vs. RCEA Primary Rates

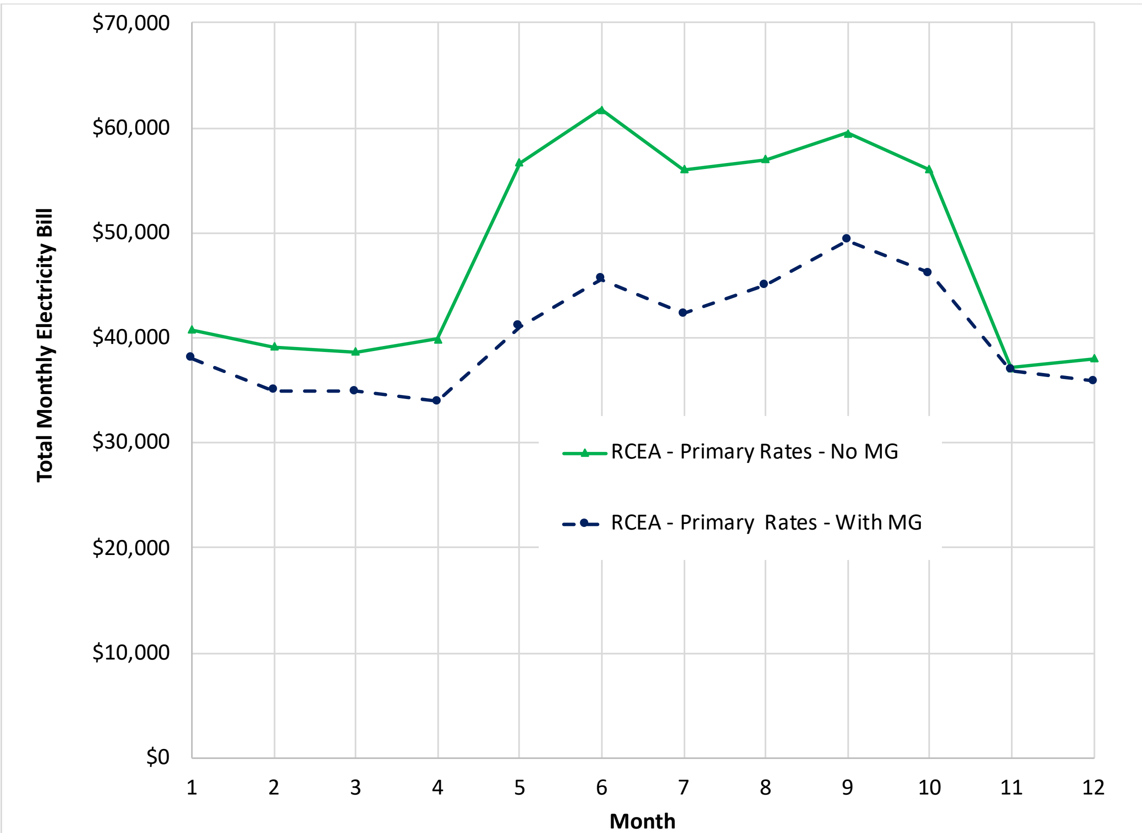


Source: Schatz Energy Research Center

Installation of the Microgrid – RCEA Rates

In order to model savings directly attributable to the microgrid, monthly costs were compared using 2017 load data without the microgrid to 2017 load data with the microgrid, both under RCEA primary service rates (current as of March 2018). Figure 63 illustrates the results. The annual savings were about $97,000 annually, with an average of about $13,000 in the summer months (May - October) and $3,000 in the winter (November – April). This amounts to about a 17% drop in annual costs.

Figure 63: Estimated Monthly Bills with and without Microgrid - RCEA Primary Rates

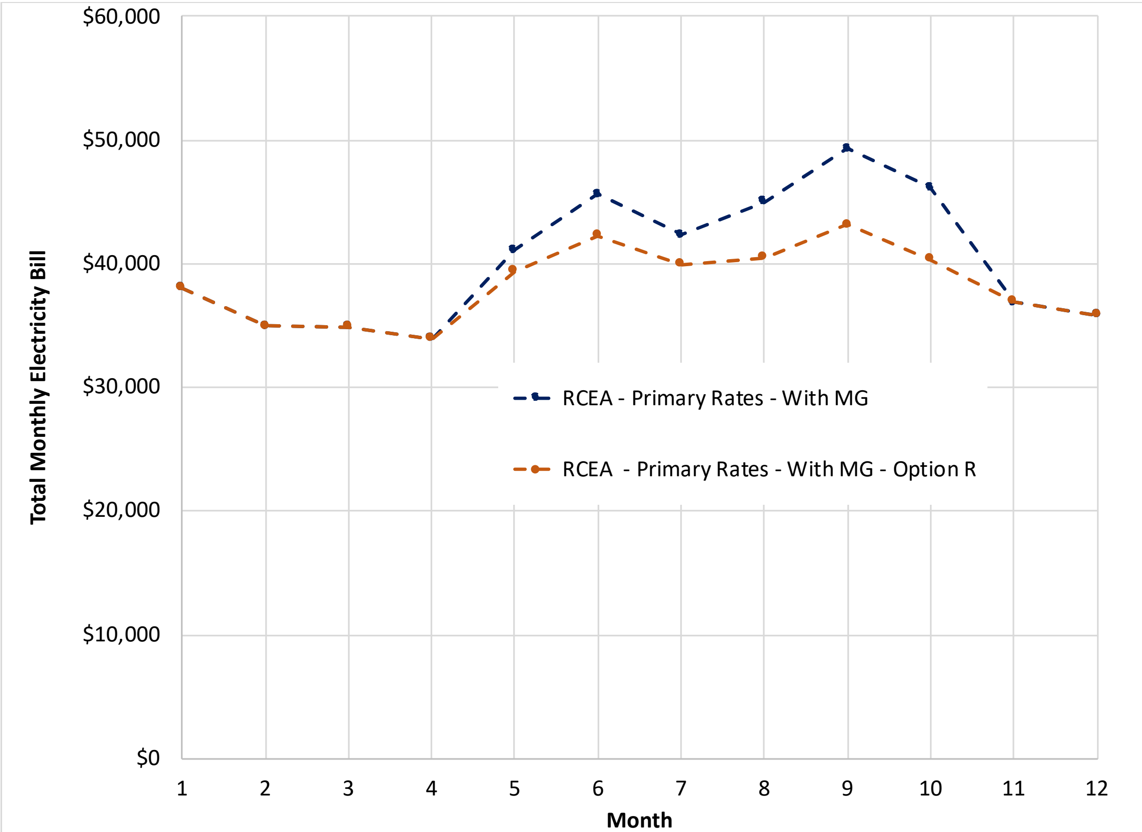


Source: Schatz Energy Research Center

Additional Savings Potential - Option R

Both PG&E and RCEA offer an Option R rate for solar customers. Option R shifts some of the monetary burden from demand charges to energy charges. Since solar PV is more effective at lowering energy charges than demand charges, Option R provides financial benefits to solar customers. BLR has not yet enrolled in Option R rates. Figure 64 shows the same 2017 consumption with the microgrid under a standard RCEA E-19 Primary Rate and an Option R RCEA E-19 Primary Rate. The annual savings under Option R is about $24,000, which is an additional 5% drop in annual costs. Switching to Option R saves an average of $4,000 per month during the summer and *costs* an average of $7 per month more in winter. This is due to the fact that Option R is only beneficial in the months with higher demand charges (the summer).

Figure 64: Estimated Monthly Bills with and without Option R - RCEA Primary Rates



Source: Schatz Energy Research Center

Additional Savings Potential – Demand Response

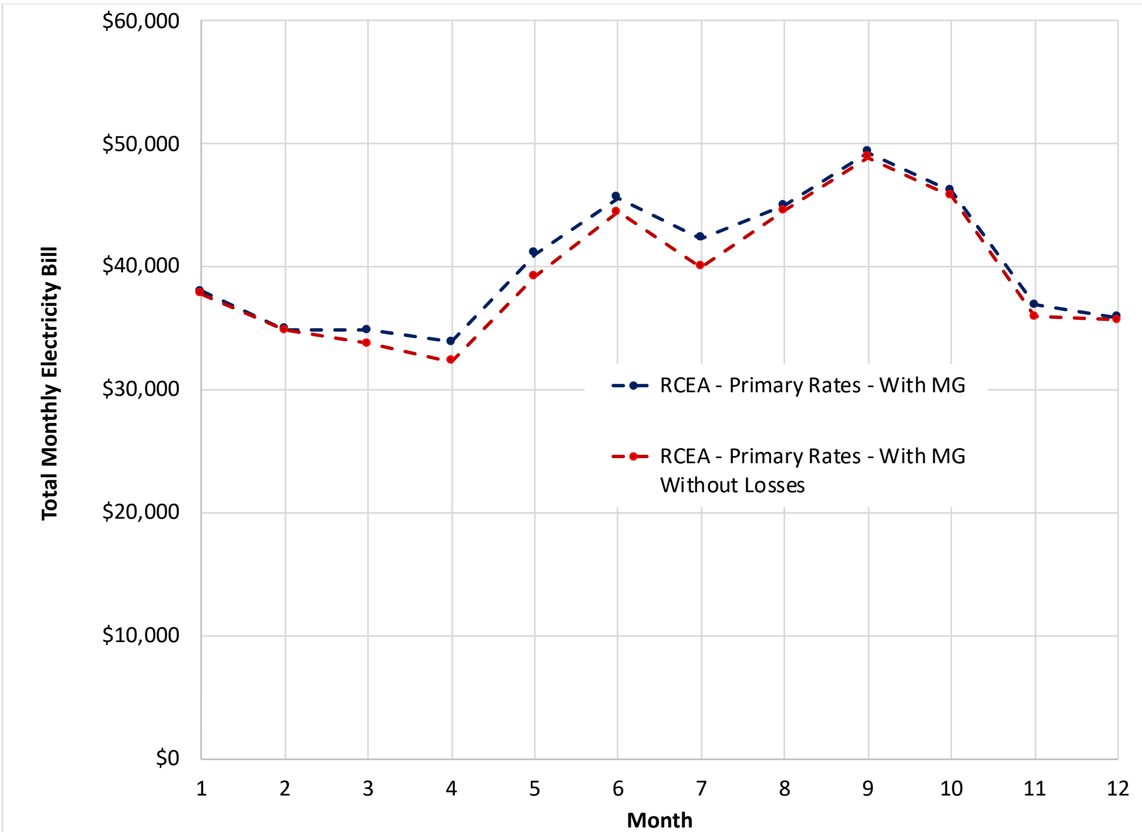
As a CCA customer, BLR is still eligible for several PG&E-run Demand Response Programs. The Base Interruptible Program (BIP), which they have previously participated in, offers incentives to customers who voluntarily lower their load when asked. As it stands, the battery system is not large enough for BLR to shed their entire load and go into island mode. However, they can shed part of their load via planned battery management. This should allow them to participate in programs such as BIP. In addition, BLR plans to expand its battery capacity, and this could allow complete facility load shed by transferring to low-inertia island mode. Additionally, the Redwood Coast Energy Authority is developing a demand response program via their CCA program and is looking at the BLRMG facility as a tentative pilot participant.

Additional Savings – Curtailment and Communication Issues

The earlier sections of this report outlined how the PV system lost about 96,000 kWh in 2017 due to curtailments and about 900 kWh due to communication glitches. When those energy savings are broken out into peak, part-peak, and off-peak hours (assuming the same proportions that the 2017 PV production data showed) and multiplied by the current RCEA Primary Rates, they result in roughly $10,000 in lost value to BLR. These savings should be realized in the coming years. It is critical to note that these are only the savings in energy charges; fixing these issues would also likely lower demand charges. That savings potential is not modeled here, though it is expected that it may surpass the savings in energy charges.

Figure 65 shows the additional expected cost savings due to resolution of PV curtailment and communication issues.

Figure 65: Estimated Monthly Bills with and without Curtailment and Communication Losses, RCEA Primary Rates

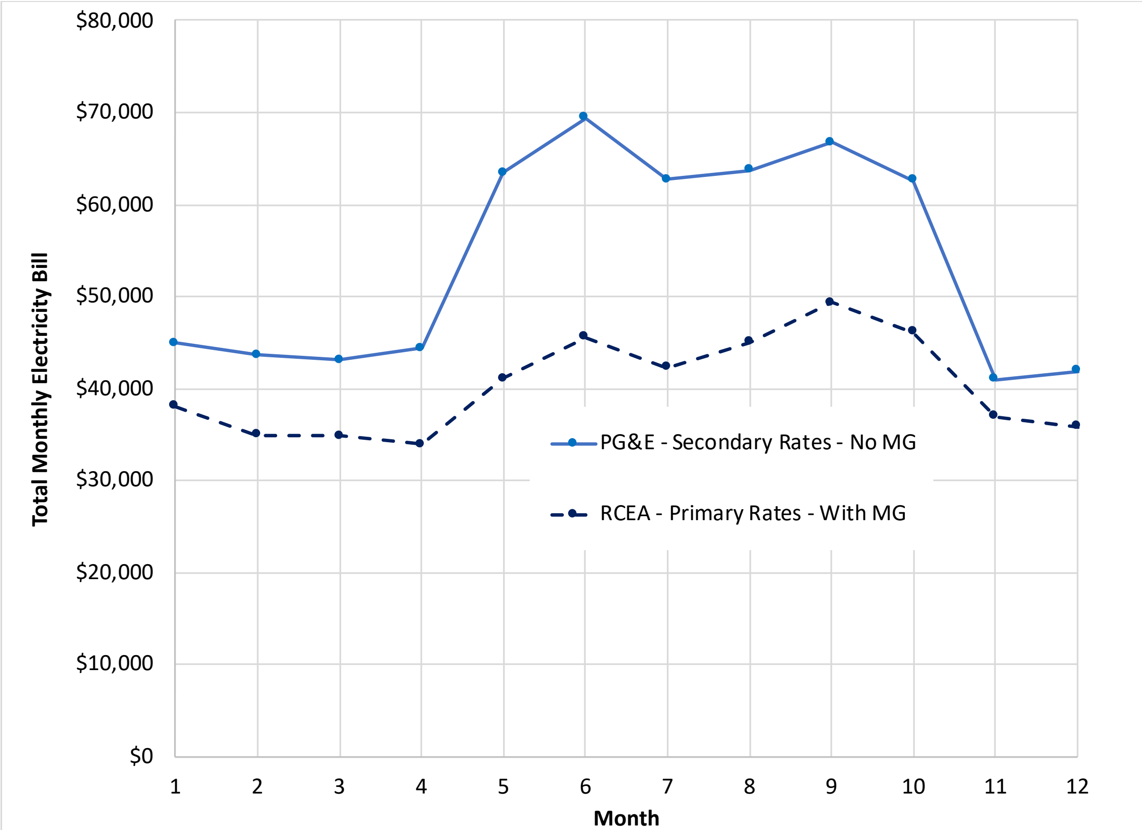


Source: Schatz Energy Research Center

Summary – Savings Due to Microgrid Installation

Working chronologically, the difference between what BLR was paying before and after the microgrid is the difference between PG&E secondary rates without the microgrid to RCEA primary rates with the microgrid; this amounts to an estimated $164,000 annual savings during 2017, which was a year filled with commissioning activities that impacted actual savings. About $61,000 is due to the switch from secondary to primary service, $6,000 due to the switch to RCEA, and the remaining $97,000 due to the microgrid. Figure 66 shows the monthly cumulative savings associated with the switch from PG&E secondary rates before the microgrid to RCEA primary rates after the microgrid. Note that the total annual savings could reach $198,000 or more without the PV curtailment and communication glitches and with a switch to the Option R rate.

Figure 66: Monthly Bills - PG&E Secondary without Microgrid to RCEA Primary with Microgrid

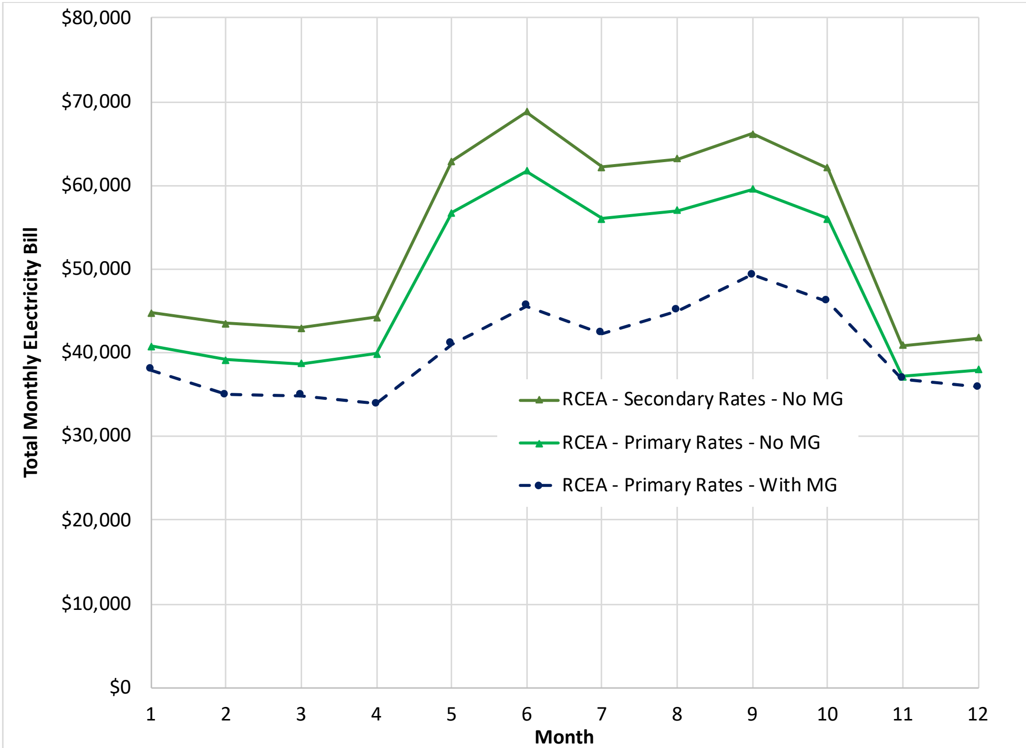


Source: Schatz Energy Research Center

However, this does not take into account the fact that, in a world in which BLR never installed the microgrid, they still likely would have switched to RCEA rates for generation but never installed the primary service. Therefore, the more likely assessment of savings is the difference between RCEA Secondary Rates without the microgrid to RCEA Primary Rates with it. Figure 67 shows the estimated monthly bills under these three successive scenarios: RCEA secondary rates without the microgrid, RCEA primary rates without the microgrid, and RCEA primary rates with the microgrid.

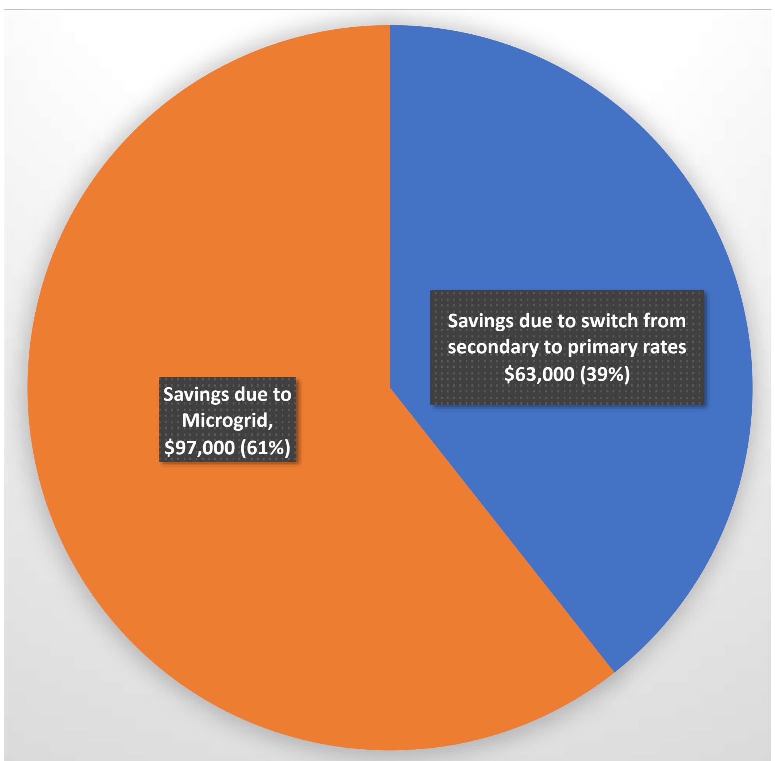
These two transitions – the switch from secondary to primary rates under RCEA and the addition of the microgrid – results in annual savings of about $160,000, a 25% drop in the annual cost of electricity for the BLR facilities served by the microgrid. As shown in Figure 68, approximately $97,000 is due to the microgrid and about $63,000 is due to the rate change from primary to secondary.

Figure 67: Monthly Bills, Secondary & Primary without Microgrid and Primary with Microgrid



Source: Schatz Energy Research Center

Figure 68: Annual Savings from Rate Switch and Microgrid



Source: Schatz Energy Research Center

Figure 69 shows the monthly savings between the RCEA E-19 Secondary Rate without the microgrid and the RCEA E-19 Primary Rate with the microgrid and breaks these savings out into three categories. "Other Charges" consist of non-bypassable charges such as nuclear decommissioning, public purpose programs, and others, and are assessed on a per-kWh basis. The microgrid usually provides a higher savings value via demand charges, especially over the summer. About 42% of annual savings come from demand charges, with 37% and 21% in energy and other charges, respectively. It is important to note that both energy charges and other charges are assessed on a per-kWh basis, while demand charges are assessed on a per-kW basis. The negative savings in November and December are likely due to the fact that when the battery charges from the grid, it can sometimes raise the maximum recorded demand.

Figure 69: Cumulative Monthly Microgrid Savings by Charge Type, RCEA Rates

Source: Schatz Energy Research Center

There are many options for improved savings that can be realized in the near future, including ameliorating curtailment and communication issues, participating in Demand Response and Option R Programs, and further optimizing dispatch of the BESS.

Assumptions and Potential Errors

There are numerous small uncertainties inherent in modeling the electric bill savings that occurred during 2017. Because it is not possible to know what the power factor would have been in a non-microgrid scenario, the Power Factor Adjustment Charge was not included in this analysis. This charge was only $0.00005/kWh/% (usually amounting to between $10 and $70 on bills of this size), so its omission should not greatly affect the outcome. Again, it is important to note that this analysis does not model the savings that were actually realized in 2017, but rather models the savings that would result based on 2017 consumption and the most up-to-date electricity rates from RCEA and PG&E, which were implemented in March of 2018.

Reliability Successes

As noted in the Basic Islanding Functionality section above, during the observation period the system's response to an unplanned grid outage was similar to the Casino's ATS prior to the microgrid installation. The facility was not without power for more than ten seconds during the initiation of an unplanned islanding event, and transfer from an islanding state to an on-grid state resulted in power disruptions on the order of 1-2 seconds. Both are similar to pre-microgrid ATS performance.

Disaster Relief Islanding Performance

During the observation period no serious outages occurred necessitating disaster-relief operation of the microgrid and/or islanding for extended periods of time without use of generators. However, an analysis of potential islanding capability during such an event was performed based on observed data.

Real-world PV output for August 2017 and for late November through December 2017 were used as representative summer and winter months, respectively. During the summer, the minimum energy produced by the PV array during one day was 671 kWh; every other day the PV array produced over 1100 kWh, with an average of 2294 kWh. During the winter, on the worst day the PV produced only 24 kWh, and such days were common; average PV generation was 926 kWh.

Based on these representative months, the round-trip BESS efficiency calculated previously, a maximum BESS SOC of 95%, and some simplifying assumptions, during the summer months the system is capable of islanding using only PV and BESS throughout 93% of days with an average site load of 50 kW or less. The remaining 7% of days would experience some time without power due to a lack of stored and available solar energy. With an average load of less than 38 kW, the system is capable of islanding indefinitely during the summer months. It is expected that 38 kW should be more than sufficient to provide power to the American Red Cross portion of the facility, including water infrastructure, if all loads other than IT infrastructure necessary to operation of the microgrid were shed.

Using the same assumptions in a representative winter month, a 50 kW load would result in some time without power on slightly more than 50% of days. Due to periods of several days with virtually no insolation, load would need to be reduced to an unrealistically low 8 kW to run indefinitely. This indicates that backup generation would be critical for providing essential emergency services in the winter months.

The planned increase in BESS storage capacity to approximately 2 MWh will improve these numbers. During the summer the system would be able to island indefinitely with an average site load of 58 kW or less; 90% continuous uptime could be achieved at an average load of

68 kW. During winter the average load necessary for indefinite uptime would be slightly improved to approximately 11 kW, while >80% full-uptime days could be achieved with an average load of 19 kW, and 50% uptime achieved with a more realistic average load of 56 kW.

For perspective, the hotel has an average load of 43.5 kW during summer months and an average load of 52 kW during winter.

In most real-world situations, the 1 MW DG would be available to provide supplemental power when sufficient PV and stored energy to carry the onsite loads is not available. Load-sharing with the PV and stored BESS energy would reduce fuel consumption during an extended outage, either prolonging the amount of time the facility could remain powered using only onsite stored fuel or minimizing the amount of fuel that would have to be imported to continue operations.

It should also be noted that on October 8, 2017 a fire started about a quarter mile from the BLR. This caused power on the PG&E grid to go out from 4:37 PM until 5:55 PM. Just under 1,900 customers were without power according to PG&E. The BLRMG detected the outage, islanded and kept the microgrid facilities from experiencing a blackout. At 5:55 PM the microgrid automatically reconnected to the grid when grid power was restored. This was all done automatically and transparently as part of the standard operation of the microgrid. The fire burned about 25 acres.

Chapter 8: Project Benefits

Project Benefits Overview

The BLR Microgrid Project has produced a myriad of benefits. These include benefits to the BLR as the end-use customer in the form of cost savings, improved reliability, and improved resilience; benefits to the local community in terms of resilience and disaster preparedness; benefits to the utility rate payers in terms of more renewables on the grid, which are deployed with smart controls that can benefit rather than strain the local distribution system; and benefits to society at large in the form of greenhouse gas emission reductions and further development, demonstration, and deployment of smart grid distributed energy systems along with sharing of knowledge and lessons learned. Direct project benefits (energy savings, cost savings, emissions reductions) are quantified and non-energy benefits are discussed.

In the latter sections of this chapter, the project goals and expectations are compared with observed results, followed by discussion regarding opportunities for statewide replication of similar projects and the resulting impacts that could have.

Direct Project Benefits

Energy Savings

In Chapter 7, it is estimated the total net energy savings associated with the BLR project as the difference in the energy demand on the PG&E grid for the year 2017. Without the microgrid, BLR is estimated to have used an additional 563 MWh of utility power. As also noted in Chapter 7, there were numerous system losses experienced in 2017, while the system was being used and commissioned (curtailment losses and communication glitches). Without these losses in a typical weather year, the team expects the microgrid system will save 617 MWh/yr.

Cost Savings

In Chapter 7, a detailed assessment of the cost savings associated with the BLRMG is provided. Total 2017 savings were estimated at $164,000. The savings directly attributable to the microgrid were about $160,000, with about 61% of this due to the microgrid system and 39% from the change from secondary to primary voltage rates. In addition, it is estimated that an additional $34,000 per year can be accrued with operational improvements that have already been implemented, as well as with a switch to the Option R rate. Total costs savings could therefore amount to nearly $200,000 per year.

Emissions Reductions

Greenhouse Gasses

The greenhouse gas emission reductions associated with the BLRMG project are directly proportional to the energy savings. Per the Energy Commission, an emissions factor of 0.283 metric tons/MWh (California Energy Commission, 2014) was used. The actual 2017 emissions reduction is estimated to be 159 metric tons CO_2e, and by resolving the system loss issues mentioned the team expects this to reach 175 metric tons CO_2e per year.

Non-Energy Benefits

Reliability

According to the California Electric Reliability Investor-Owned Utilities Performance Review 2006-2015, the Humboldt County region suffers the longest and some of the most frequent power outages when compared to other regions in California (Kurtovich, 2016). BLR has experienced frequent outages, including several events that lasted for multiple days. Further, as documented in the *PG&E Annual Electric Distribution Reliability Report 2016 Final,* multiple areas near BLR are among PG&E's poorest-performing electrical lines (PG&E, 2017).

Adding to tenuous electricity infrastructure concerns are the annual landslides that close main road access to/from the region for weeks or months at a time, impeding supplies of fuel and other essentials. In 2017, simultaneous landslides across California Highways 101 and 299 closed those roads and constricted fuel shipments to the BLR's fuel station by 60% for over a week. Disruptions to surface transportation routes threaten the availability for use of generators throughout the North Coast.

BLR has had backup power since 2002 via generators that powered two buildings within the Tribe's main campus of critical infrastructure. With the microgrid, the Tribe has significantly improved electric reliability in the event of an outage, now supplying power to all six buildings in the main campus and supporting related critical infrastructure (water, wastewater, electric vehicle charging stations, communications/IT, lighting, surveillance and security systems, etc.). In addition, with the microgrid's power generation backbone of solar PV and battery storage, the Tribe has reduced its reliance on fossil-fueled generation for a source of emergency power, mitigating the demonstrated unreliability of fossil fuel supplies to the region. By relegating the generators to deep back-up and using solar energy in both business-as-usual and emergency situations, the Tribe has reduced greenhouse gas and criteria pollutant emissions and improved reliability and resilience.

Public Safety

The microgrid supports several aspects of public safety at the BLR, and by improving the energy lifeline sector, the microgrid increases resilience across other sectors, including water, food, transportation, and communication/IT. The low-carbon power supplied through the microgrid allows the operation of a certified American Red Cross emergency shelter, which is operational in times of regional need. The microgrid supports the activities of the Tribe's many public safety divisions including Tribal Police, Office of Emergency Services, Wildland Fire Department, and Department of Energy and Technologies (the Tribe's utility).

Through automated and manual load shed scenarios, the Tribe can reduce power needs throughout its campus, and the microgrid can supply 'life, health, and safety level power' for as long as needed. As discussed above in the Disaster Relief Islanding Performance section, the team estimates the microgrid could provide power for critical emergency services almost indefinitely in the summer months, and in the winter months would likely double run-times through load sharing with the back-up generator.

Job Creation

Due to the savings created by the microgrid, the Tribe's energy efficiency measures, and other sustainability efforts, the Tribe has increased its employment by 10% during the course of this project. These new clean energy jobs are in the operations and maintenance of the microgrid and its sub-components, across facilities and IT roles.

Market Potential

This project has received acclaim for its successful implementation and performance. As a result, the Tribe and SERC have conducted over 150 tours and presentations during the course of this project. Please see Chapter 9 for a full discussion of the Technology and Knowledge transfer activities. These activities help communicate the benefits and lessons learned to move microgrid technology forward in the market. Almost all members of the project team are engaged with and supporting several developing microgrid projects throughout California.

Economic Development

The Tribe has reported that its microgrid, and particularly solar photovoltaic power with battery storage, has provided several economic benefits, including dramatically lower costs of energy ($150,000 to $200,000 per year), increased job creation (10%), and manageable operations and maintenance. The microgrid supports the tribal government offices and functions, and also improves resilience for the Tribe's economic enterprises. Regionally this project supported at least six small businesses and contractors, including several veteran- and minority-owned companies through the design and construction phase. Using a conservatively-estimated labor income multiplier of 1.5 (Center for Strategic Economic Research, 2014), the BLRMG project created an estimated $9,450,000 of induced and indirect economic benefit to the local, regional, and state economies.

Microgrids present an opportunity to improve economics and governance with robust low-carbon power. By developing distributed energy resources, microgrids keep energy expenditures circulating within the local region, and can transfer energy savings into new jobs. Microgrids also provide new opportunities for economic development strategies between local governments and investor owned utilities, to solve energy access issues, improve reliability, and transition to the decarbonized, somewhat decentralized grid of the near future as rapidly as possible.

Project Performance

Comparison of Project Expectations and Actual Performance

In this section the performance of the BLRMG is compared to initial project expectations and the fulfillment of project goals and objectives is assessed. Table 12 provides a set of project goals and objectives stated at the beginning of the project along with observed results.

Table 12: Comparison of Project Goals and Results

Metric	Project Goal	Result	Comments
Install microgrid capable of powering BLR Red Cross shelter in times of emergency	Yes	Yes	This has been demonstrated
Annual renewable energy generation as a % of onsite load	17%	15%	We expect this to rise to about 16% following the correction of loss mechanisms (PV curtailment & communication glitches)
Demonstrate ability to island with uninterrupted power for ⩾7 days	Yes	Yes	An assessment based on actual system performance indicates the system could island for extended periods
Demonstrate ability of microgrid to participate in demand response	Yes	Yes	While BLR is not currently participating in DR programs, the project demonstrated the ability to reduce net site load by discharging the BESS
Reduction in annual electrical energy consumption	680 MWh	563 MWh	We expect about 620 MWh per year moving forward due to reduction of system losses
BLR energy cost savings	25%	25%	Cost savings goal was met & there are opportunities for further savings, expect up to 31% or greater savings
GHG emissions reduction (CO_2e)	130 MT	159 MT	Goal was exceeded and should go up as system losses are reduced
Make knowledge gained available to broad audience	Yes	Yes	Extensive outreach was performed, numerous awards were received, knowledge transfer was robust and continues
Develop plan for commercializing microgrid technologies and strategies	Yes	Yes	Chapter 10: Production Readiness lays out a clear strategy to allow for replication; numerous follow-on projects are in the works

Source: Schatz Energy Research Center

As can be seen in Table 12, most project goals were met or exceeded, and even when they were not attained, substantial benefits accrued. The inability to meet the annual electricity reduction goal is largely due to the parasitic load of the BESS, which was not accounted for in the original goal setting process.

Potential Statewide Microgrid System Benefits

In this section the team examined the broader benefits available from microgrids and considered the opportunity for large-scale market use and the resulting societal benefit that could be generated. This section draws heavily on the Master's Thesis of Pramod Singh, a former graduate student at Humboldt State University in the Energy, Technology and Policy Program. Mr. Singh's studies centered around the microgrid at BLR, and his full Master's Thesis can be accessed online via the Humboldt Digital Scholar service provided by Humboldt State University. (Singh, 2017)

Classifying the Possible Benefits of Microgrids

The benefits of a microgrid can accrue to the project owner, the electric utility, and society. The potential benefits provided by microgrids can be classified into four broad categories: energy, economic, environmental, and emergency (Figure 70).

Figure 70: Microgrid Benefits to Different Stakeholders Under Different Operating Modes

Benefit Description	Grid-connected			Islanded		
Benefit Type / Benefit to	Owner	Utility	Society	Owner	Utility	Society
Energy						
Demand charge reduction	● S					
Deferred T&D investment		○ S				
Deferred capacity requirement		○ S				
Energy cost reduction	● S			● S		
Demand response support	● S	● S		● S	● S	
Grid ancillary services		○ S				
Economic						
Increased reliability				● S		● S
Local jobs creation			● G			
Environmental						
Reduced emissions			● S			● S
Emergency						
Shelter service			● S			● S

● Savings that will be realized in BLR project
○ Plausible savings, but not realized in BLR project
G Technology and Site neutral
S Technology and Site dependent

Source: Singh 2017

The benefits are listed under two typical modes of operation: 1) grid-connected mode in which the microgrid and macrogrid are running in parallel and are synchronized, and 2) island mode, where the microgrid is disconnected from the macrogrid and is working autonomously due to a planned or unplanned outage of the macrogrid. Some of the benefits listed in Figure 70 have been demonstrated and others are yet to be established.

Assessing the Potential of Microgrids in California

Extrapolating the benefits of the BLRMG to estimate the cumulative benefits of microgrids in California is an uncertain process. Estimations need to be made about the load size of many large facilities, and very few microgrids were implemented and had their performance rigorously documented. However, academic work was done to estimate the potential of microgrids throughout the state. This analysis will very briefly summarize the work of Pramod Singh at Humboldt State University, who estimated 1,188 sites in California (with a total capacity of 7,450 MW) to be technically and economically viable for microgrid development (Singh, 2017).

Microgrid potential was estimated by: 1) identifying California sites with a minimum demand of 250 kW and a maximum demand of 20 MW (this was deemed necessary to support a microgrid) and 2) determining the microgrid capacity that would best serve those customers. Potential sites were separated into categories: cities, hospitals, military bases, universities, tribal areas, utilities, American Red Cross centers, data centers, and airports. The electricity consumption for these sites was estimated using the U.S. Census, the U.S. Geological Survey, and other authoritative sources. Benefits were distributed into six categories and expressed in dollar amounts: demand reduction, energy reduction, energy arbitrage, demand response, improved reliability, and emissions reduction. The dollar value of the emissions reduction was calculated using the most recent data from the California Air Resources (\$12/metric ton of CO_2e). The value of electric reliability was calculated using a statewide average developed by the California Public Utilities Commission. It is important to note that sites at which a microgrid would primarily be used for emergency medical purposes (hospitals, emergency refuge centers) are assumed to be completely economically viable because a life saved outweighs any costs.

Singh's thesis found that, based on the load profiles of California end-users, there are about 2,171 technically feasible sites that could host 7,825 MW of microgrid generation; this is about 9.8% of the installed generation capacity in California (Singh, 2017). All of California's data centers, emergency refuge sites, and defense sites (military bases) were found to be technically viable for microgrid development.

To select out the microgrid sites that were economically feasible, Singh required the following:

1) A simple payback of 10 years or less. A U.S. customer survey revealed that this was the timeframe that customers set as the cutoff payback period for a self-generation project (Hedman & Hampson, 2010),

2) A levelized cost of energy from the microgrid not more than 1.1 times the rate the customer currently pays for electricity, and

3) A benefit-cost ratio greater than 1. The present value in dollars of the previously listed benefits were quantified and weighed against the present value of the cost of microgrid installation.

When applied to the technically feasible sites, this analysis resulted in 1,188 economically feasible sites with a cumulative hosting capacity of 7,450 MW. Most of the economically feasible sites were larger, and it was determined that customers with peak loads over 1 MW were more likely to be economically viable.

The greenhouse gas emissions benefits that would result from the installation of the estimated viable microgrids would depend on 1) the capacity factor of the microgrids (different customers have dramatically different load requirements and therefore would run their microgrids in unique ways) and 2) the emissions factor of the grid electricity that the microgrid is displacing. The BLRMG, with a total solar + storage nameplate rating of 920 kW, offset roughly 617,000 kWh of annual load (without curtailments or communication issues), which is about 8% of what the microgrid would put out if it ran at full capacity for the full 8,760 hours in each year (not feasible given that the battery needs to charge from either the solar or the grid, but useful for this calculation). If that percentage is extrapolated to Singh's estimated potential microgrid capacity, the result is an estimated annual load offset of about 5.2 billion kWh. Assuming an emissions factor of 0.283 metric tons/MWh, the installation of this statewide microgrid capacity would result in about 1.5 million metric tons of GHG offset per year.

Chapter 9: Technology and Knowledge Transfer

Project Fact Sheet

As part of the technology and knowledge transfer activities, a project fact sheet was developed and disseminated. The final project fact sheet can be found in Appendix F.

Presentation Materials

Presentation materials were also prepared to share the knowledge gained and lessons learned from the project. The presentation was adjusted as needed to serve the audience.

Technology and Knowledge Transfer Plan

The purpose of the Technology/Knowledge Transfer Plan was to develop a plan to make the knowledge gained, experimental results, and lessons learned available to the public and key decision makers.

Microgrids are a new technology area that is still in development. The technology offerings, codes and standards, regulatory requirements, utility interconnection requirements, rate tariffs, and arrangements, and market opportunities are still evolving. Early microgrid projects, such as the BLRMGproject, are important undertakings to learn about the technology and its related support systems and to test out new ideas to see what works. Then, to maximize the value of early demonstration projects like the BLRMG project, it is important to broadly share the lessons learned with other stakeholders so they can build on the knowledge gained. That is the purpose of this technology and knowledge transfer plan.

This technology and knowledge transfer plan aimed to reach the following audiences:

1. Tribal nations
2. Electric utilities
3. Regulatory agencies
4. Public entities and local governments
5. Industry
6. Academia
7. Emergency service planning and implementation personnel
8. End users (commercial, industrial and institutional electricity users)
9. Distributed energy practitioners, engineers and consultants
10. Sustainable energy and climate mitigation advocates

The types of information to be shared with stakeholders included the following:

1. Description of the BLRMG system design and the technologies that were deployed

2. Project performance and project benefits

3. Lessons learned

Education, outreach and knowledge transfer activities were to include:

1. In-person and remote participation in workshops, conferences, webinars and other knowledge transfer activities, including:

    a. Presentations at professional energy conferences, workshops and/or webinars

    b. Presentations at tribal energy and tribal leadership events

    c. Presentations/outreach at emergency planning events/venues

    d. Participation in workshops, conferences and meetings as a representative of the project

2. Preparation, publication and distribution of project documents, including:

    a. Project fact sheets and presentations

    b. Technical journal articles

    c. Project press releases

    d. Project videos and outreach materials

3. Outreach to interested potential end-users and stakeholders

    a. Project kick-off and ribbon cutting ceremonies and outreach events

    b. Site tours

    c. Outreach, discussions and consulting to entities interested microgrid deployment

4. Educational outreach

    a. Engagement of university engineering students to learn about and contribute to project activities

    b. Outreach to K-12 students, with a specific focus encouraging STEM students

Education, outreach and knowledge transfer activities were tracked and recorded throughout the project period.

Technology and Knowledge Transfer Activities

This report documents the efforts and accomplishments regarding project outreach efforts to publicize the project and share knowledge, experimental results and lessons learned. A Technology/Knowledge Transfer Plan was previously developed; this report documents the results associated with the implementation of that plan.

The SERC, the BLR Tribe and other project partners have worked to disseminate project results and lessons learned from this project to many interested stakeholders. This has included participation in conferences, workshops and webinars, onsite tours of the microgrid facility at BLR, and presentations to many interested parties. In addition, there have been press releases and multimedia efforts to publicize the project. BLR has conducted significant outreach activities, including hosting tours and providing information and guidance to stakeholders seeking to build their own microgrids. To support these educational efforts, the Tribe has contributed staff time, meeting spaces, catering, supplies, teleconferencing, and other resources. Project partners California Energy Commission, Siemens, PG&E, Tesla, and stakeholders such as the California Department of Water Resources have put substantial effort and resources into developing multimedia presentations that feature the co-benefits of the BLRMG project.

Stakeholder Engagement

This project has generated tremendous publicity and stakeholder interest. To illustrate the widespread interest in microgrids, the following list document the stakeholder groups who have toured onsite and/or received presentations/consulting regarding the BLRMG (*not a complete list*).

Tribal Nations

- Spokane Tribe
- Bear River Band of the Rohnerville Rancheria
- Karuk Tribe
- Hoopa Valley Tribe
- Yurok Tribe
- Trinidad Rancheria
- Crow Nation
- Navajo Nation
- Mesa Grande Band of Mission Indians
- Rosebud Sioux Tribe
- San Pasqual Band of Mission Indians
- Soboba Band of Luiseno Indians
- Association of Village Council Presidents, Alaska (56 Tribes)
- Cherokee Nation
- Eastern Band of Cherokee Indians
- North Coast Tribal Chairmen's Association (15 Tribes)
- U.S. Department of Energy, Indian Country Energy and Infrastructure Working Group
    - Confederated Tribes of the Warm Springs Reservation of Oregon
    - Ewiiaapaayp Band of Kumeyaay Indians
    - Gila River Indian Community

- Ho-Chunk Nation
    - Mandan, Hidatsa & Arikara (MHA) Nation
    - Mississippi Band of Choctaw Indians
    - Osage Nation
    - Seminole Tribe of Florida
    - Seneca Nation of Indians
    - Tanana Chiefs Conference, Alaska (20+ Tribes)
    - The Confederated Salish and Kootenai Tribes of the Flathead Nation
- U.S. Department of Energy, National Tribal Energy Summit, 2015 (~100 Tribes)
- U.S. Department of Energy, National Tribal Energy Summit, 2017 (~100 Tribes)
- U.S. Department of Energy, Western Area Power Administration, National Tribal Webinars (3) (~100-150 Attendees each webinar)
- National Indian Gaming Association (~50 Tribes)
- Oklahoma Indian Gaming Association (~30 Tribes)

Public Entities

- Federal Emergency Management Agency
- U.S. Department of Energy
- National Laboratories (4)
- Bureau of Indian Affairs
- State of California Emergency Management Agency
- State of California Governor's Office
- Utility and Special Districts (4)

Industry

- Silicon Valley Leadership Group (400 member companies)
- DistribuTECH Conferences (2) (13,569 attendees; 78 countries; 326 utilities)
- Private Companies (10)

Academia

- California State University System (20+ Energy Managers Representing 23 CSU Campuses)
- Humboldt State University (STEM Students)
- California State University Chancellor's Office (Research Division)
- Humboldt County Office of Education (HISI Program; STEM Students)
- McKinleyville High School
- Arcata High School

Month-by-Month Outreach Activities

A record was kept of the month-by-month BLRMG project outreach activities. Outreach activities started in September of 2015 and continued through February of 2018, with additional events planned for March and April of 2018 and beyond. Appendix G provides a listing of the monthly outreach activities covering the duration of the project period.

Outreach Materials

To support the outreach activities associated with this project the following outreach materials have been prepared:

- Project Fact Sheet (Appendix F)
- Project Presentation – Note that this presentation is representative of the many project presentations that have been delivered over the course of the project.
- Project journal article for peer reviewed journal (in process as of February 2018)
- Press releases – Press releases associated with key milestones in the project were disseminated (e.g., receipt of grant award, flip-the-switch celebration denoting the official start-up of the microgrid, DistribuTECH 2018 Project of the Year for Distributed Energy Resources award received, etc.).
- PG&E Corporate Responsibility and Sustainability Report 2016, "Collaborating on a Low-Carbon Microgrid" video, http://www.pgecorp.com/corp_responsibility/reports/2016/index.jsp
- Siemens Featured Multimedia Stories
  Project kick-off - August 24, 2015:
  http://siemensusa.synapticdigital.com/featured-multimedia-stories/siemens--blue-lake-rancheria--and-humboldt-state-university-partner-to-install-low-carbon-microgrid-/s/9531215a-b1c8-4bee-a5da-c7b1dfe15ad9
  BLRMG goes live - April 27, 2017:
  http://siemensusa.synapticdigital.com/featured-multimedia-stories/blue-lake-rancheria-native-american-reservation-microgrid-goes-live/s/64bc14d8-b74a-4951-8a5b-9e1f48a07f9b

Sampling of Project Press & Publicity

At key junctures in the project there were flurries of press and publicity. Below is a sampling of the publicity associated with the press release for the project kick-off in September 2015.

Full Broadcast Coverage Review

Microgrid Knowledge "Is the Low-Carbon Microgrid Next?"

Electric Light & Power "Siemens, partners to install microgrid at Native American Reservation"

P&L syndicated to Penn Energy "Siemens, partners to install microgrid at Native American Reservation"

POWERGRID Magazine Tweet https://twitter.com/powergridmag/status/635949837536653312?refsrc=email&s=11

Utility Dive "Siemens to construct islanding microgrid on northern California reservation"

Greentech Lead "Siemens to help build microgrid in Native American reservation"

Smart Cities Council "Siemens partners on low-carbon microgrid for Native American reservation"

Cogeneration & On-Site Power Magazine "Siemens behind microgrid for Native American reservation"

Energy Business Review "Siemens and partners to install low-carbon microgrid on Native American Reservation"

Smart Grid Today (subscription only) **"Siemens to build microgrid for American Indian reservation"**

Energy Manager Today "Siemens to Install Microgrid on Native American Reservation"

North American Clean Energy "Siemens, Blue Lake Rancheria, and Humboldt State University Partner to Install Low-Carbon Microgrid on Native American Reservation"

Indianz.com "Blue Lake Rancheria breaks ground on 'microgrid' energy system"

Follow-on Consulting Activities

In addition to the outreach activities listed above, this project has led to numerous microgrid consulting opportunities for SERC and others on the project team. While these additional consulting opportunities are not part of the direct activities associated with this project, they have served the purpose of promoting the replication of similar microgrids. As a result of this project, microgrid feasibility analyses and preliminary design work has been conducted for and/or discussed with the following entities:

- Shelter Cove Resort Improvement District #1
- University of California at Santa Cruz
- Humboldt Transit Authority
- McKinleyville Community Services District

- Hoopa Tribe
- Yurok Tribe
- Bear River Tribe
- Karuk Tribe
- Redwood Coast Energy Authority and County of Humboldt for the ACV Airport Microgrid

Chapter 10: Production Readiness

The production readiness of microgrids is a complex topic because microgrids are a complex blend of carefully integrated systems with components from multiple manufacturers and unique characteristics due to inevitable differences between sites. This chapter attempts to relate the experience of implementing the BLRMG to the concept of microgrid production readiness and replicability in general.

For the purposes of this chapter, a microgrid is defined as per the U.S. Department of Energy Microgrid Exchange Group definition:

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

Note that the last sentence of this definition is sometimes left out, which allows the possibility that the microgrid will never island. This changes the character of a "microgrid" significantly and, as stated previously, the full definition will be used in this chapter.

Single-facility microgrids, sometimes referred to as nano-grids, are not discussed further in this chapter.[6] A multi-facility, single-customer microgrid is the most common type because it is because it is easier to implement than a multi-customer microgrid.[7] Multi-facility, multi-customer microgrids require a high degree of participation by the utility and are administratively complex unless all of the generation within the microgrid boundary is owned by the utility.

This chapter focuses on production readiness, from a technical perspective, for multi-facility microgrids. Since the focus is technical rather than administrative, the findings are generally applicable to both single-customer and multi-customer cases.

Required Elements for Microgrid Readiness

This section contains a narrative to describe the types of elements that are required for multi-facility microgrid readiness. These elements are then listed at the bottom of the section.

For a given site to be considered "microgrid ready" there must be one or more locations where a switching device can be installed along the boundary of the microgrid and the area electric power system (AEPS) so that the microgrid can be completely disconnected from the AEPS. It is important to note that most AEPSs are configured as a series of radial circuits energized at the substation. One can think of these radial circuits like the spokes on a bicycle wheel and they are not normally connected to each other. However, there can be locations on each circuit where portions of one circuit can be connected to another circuit using a switch on a utility pole. This

[6] SERC and the Blue Lake Rancheria are currently partnering on a single-facility microgrid for the Tribe's fuel station and convenience store, under CEC EPIC GFO-16-309, entitled "Scaling Solar+ for Small and Medium Commercial Buildings," estimated to be in operation in 2019.

[7] The BLRMG is a multi-facility single-customer microgrid.

enables the utility to minimize the amount of time that customers are without power due to distribution line damage, by isolating the part of the grid that has the fault and energizing the rest while repairs are undertaken. One can think of microgrids as being easier to deploy at the ends of radial feeders with complexity generally increasing with proximity to the substation and density of the built environment. Of course, implementing a microgrid on a utility's radial feeder requires the participation of the utility operating that feeder.

The BLRMG is located at the end of a distribution circuit, part of which was purchased by BLR to create the microgrid. For this type of microgrid, only one point of common coupling (PCC) with the AEPS is needed. A single-PCC microgrid is easier to implement than a multiple-PCC microgrid, but multiple-PCC microgrids are possible provided the other required elements are present. With more PCCs the controls and protection engineering challenges become more complex. Typical microgrids would have at most two PCCs.

If the boundary between microgrid and the AEPS can be created with one or two PCCs then the next qualifier to check is whether there is enough area to install the amount of generation and/or energy storage that will be needed to allow the microgrid to operate in island-mode. This can be an iterative process of determining the net microgrid loads (i.e. loads minus existing generation within the proposed microgrid boundary), peak loads, and the available area where new generation, storage, switching, and controls can be sited. This step typically involves modeling to determine optimal generation/storage component sizing and type, which feeds into a preliminary site plan (to scale) to determine the area requirements. The generation and/or storage component sizing should account for the desired island-mode run-time capability.

Once the area requirements have been determined and the preliminary site plan is done, the project proponent needs to determine if it is feasible to gain site control (e.g., by ownership and/or agreements) over the area required for new generation, storage, switching, and controls. If the answer is yes, then overall permitting requirements (e.g., utility interconnection agreements, easements, SWPPP), and environmental (e.g., CEQA, NEPA) and cultural resources studies should begin, to determine if there are permitting issues, project impacts, and/or cultural resources that have a high likelihood of preventing the use of the site and/or that will incur significant project costs. Detailed discussion of environmental and cultural reviews is outside the scope of this Production Readiness section, however relevant activities conducted for the BLRMG are included in the Environmental Review and Storm Water Pollution Prevention Plan sub-section above. Once these areas are reviewed, the site can be considered microgrid ready in a preliminary technical sense. From this point, the design team can begin to work out the details needed to gain utility approval, construct, commission, and operate the microgrid.

With the PCC locations(s) identified, net and peak loads characterized, initial permitting, environmental, and cultural resources reviews completed, and the preliminary generation/storage components sized, a preliminary one-line diagram and controls narrative should be created. These documents will show the electrical connections between the distribution circuit, the microgrid circuit, the microgrid loads, and the generation/storage components. This preliminary one-line diagram can be simple, showing the microgrid circuit from the PCC to the loads, the generation units, batteries, and transformers with line-level circuit breakers and disconnects. Also include the microgrid controller and indicate which components will be controlled: circuit breakers, generation units, storage batteries, etc.

A microgrid site host should also contact their utility representative very early project development to introduce the project and let them know more information will be forthcoming. This allows the utility and the project team to exchange contextual, high-level information so that the utility can become familiar with the project prior to delving into technical and process requirements. The utility can be a resource for internal utility expertise and administrative and technical contacts for interconnection activities.

With the preliminary one-line diagram created, a brief control narrative should be created that describes how the microgrid controller will manage transitioning to and from island-mode to meet utility requirements. If utility requirements are not clear, working with the utility to gain understanding combined with a conservative approach founded in sound electrical engineering practice becomes especially important.

Since microgrids by definition will interact with the AEPS, utility participation is a requirement. Electric utilities are so expert at providing safe and reliable power that society tends to take that for granted. A major reason the U.S. electric power system is safe and reliable is because utilities have strict requirements and protocols for how the AEPS is built and operated. When a microgrid is proposed, the utility must evaluate the project with the same diligence as they would any project on their grid. If the microgrid is proposed by a third party, then the utility will have a rigorous approval process that the project proponent will have to follow to demonstrate that the high bar set by the utility can be met by the third-party design team.

Since microgrids are relatively new, some utilities may not have a standard interconnection process in place. This could stop or delay the project. Therefore, a good approach is, after the preliminary site plan, one-line diagram, and controls narrative have been created, to contact the utility's interconnection or grid integration department to obtain interconnection process information and gauge the utility's areas of support or concern. It can be difficult to arrange an informal meeting with the right people at the utility to discuss the documentation described in this section and the project proponent may be routed through a formal process. For best results, let the utility steer the process and follow the required steps. As the process progresses you will gain access to people who will help you to meet the requirements. Project teams should be prepared to redesign or limit functionality to meet utility requirements since there can be significant budgetary impacts for unconventional projects. Some projects may have to fund special power-flow studies and/or upgrades to the distribution system.

To summarize, the basic elements needed for preliminary microgrid readiness include:

- A defined boundary between the microgrid and the AEPS with PCC location(s) identified
- Generation/storage components have been sized to meet net microgrid loads and provide the required island-mode run-time capability
- An initial study of permitting, environmental review requirements, and cultural resources survey(s)
- A preliminary scaled site plan showing the area requirements for the generation/storage components and controls has been created
- A preliminary one-line diagram of the microgrid
- A brief controls narrative
- A site control plan demonstrating that it will be practical to obtain site control for the required generation/storage components has been created
- The utility has been made aware of the project, has been provided with the preliminary documentation above, and has not said no to the project

With these basic elements in place the project proponent will be in good position to begin working out the details needed to successfully implement the microgrid. The remainder of this chapter discusses other key considerations concerning the replicability of microgrids.

Integrating Existing Equipment into a Microgrid

Since microgrids are typically implemented with existing facilities, there will likely be pre-existing equipment to account for in the microgrid design. Examples include existing backup generators, energy management systems, photovoltaic (PV) arrays, wind turbines, electric vehicle (EV) chargers, and the like. Since these pre-existing systems will have been installed with a load-serving purpose that is uniquely related to the role that the AEPS has in serving the same loads, the way that these components operate in the microgrid will have to be carefully evaluated. For example, if an existing backup generator for a facility is not allowed to parallel with the AEPS but designers want that generator to be able to support all microgrid loads in island-mode, then modifications will need to be made to add that functionality without violating the agreement with the utility that the unit shall never parallel with the AEPS. Another example would be a pre-existing rooftop solar PV array with inverters that have ride-through settings and active anti-islanding. Depending on the size of the PV array relative to the microgrid loads and other onsite generation and storage components, its output may need to be curtailed during island-mode, which would require an interface with the microgrid controller. It is also important to understand the functionality, settings, and intelligence of existing equipment controls, and whether those controls can communicate with an advanced microgrid control system, or whether additional components and/or upgrades will be needed.

Pre-existing intermittent renewable energy resources like wind and solar PV present unique challenges because there will be times when fluctuations in their output align with intermittent load fluctuations in exactly the wrong direction, which can cause large swings in net load on a time scale that is too small for the microgrid controller to respond to. Because this can lead to instability during island-mode, it is important that each pre-existing generation and/or storage asset be evaluated individually and a specific integration plan be devised for each.

One purpose of microgrids is to increase electrical resiliency, which means keeping microgrid loads energized when the AEPS has an outage. Microgrid loads are intermittent and load profiles will vary from microgrid to microgrid. The AEPS is designed to handle load intermittency and any conceivable load profile due to conservative design and interconnection practices, and the presence of large generation sources (power plants). A microgrid operating in island-mode becomes disconnected from these large generation sources and relies on smaller generation and storage components within the microgrid to keep loads energized. As mentioned previously, the compounded intermittencies of wind, solar PV, and loads can create controls challenges that are masked when connected to the AEPS and pronounced when in island-mode.

Controlling pre-existing loads can be another tool available to designers for maintaining stability and extending run time in island-mode. To incorporate controllable loads into the microgrid, an energy audit should be conducted to characterize microgrid loads and, using the results, a list of non-critical loads that can be shed can be identified and prioritized. Using that list, a control plan can be developed to allow the microgrid controller to use controllable loads as well as controllable generation to maintain stability and extend run time in island-mode.

Using New Generation Sources within a Microgrid

A microgrid must balance loads and generation to operate in island-mode. Additionally, at least one generation source that is sized to meet microgrid loads (peak kVA plus a peaking factor for inrush current) must be able to act in “grid-forming” mode. This means that the generator must be able to regulate voltage and frequency while generating current. If more than one generation source is capable of being grid-forming then reliability is increased but so is the controls complexity, because load sharing between two grid forming generators requires careful coordination.

Load sharing between two grid-forming sources is typically accomplished using “droop control.” With this method, real power load is shared between the sources proportionally based on variations in system frequency (for a given difference in system frequency from nominal [60 hertz] the generator will respond by adjusting its output by some percentage of its real power capacity to bring the system frequency back to nominal). Similarly, the reactive power load is shared between the sources proportionally based on variations in system voltage. The response of a given grid-forming generator is typically configurable using a droop equation and coordination between two grid-forming sources involves determining the appropriate parameter setpoints to be used in each controller’s droop equations. Special care must be taken to ensure that any circuit breaker or switch that could connect two grid-forming sources on the microgrid has a synchronization check to prevent the two sources from being connected out of phase, which can cause equipment damage, fire, injury or death.

Any generation sources that are not grid-forming are, thereby, “grid following.” Grid-following generation sources will automatically disconnect from the AEPS or the microgrid if the voltage or frequency of the circuit they are connected to deviates beyond specified setpoints for a specified duration. The source will remain disconnected until stable power is detected on the circuit they are connected to, usually after a period of five minutes based on current standards. At that point they will synchronize to the AEPS or microgrid and begin to operate as a current source, provided the sun is shining (solar PV), or the wind is blowing (wind turbine), or a fuel supply is present (microturbine or other). Generally speaking, grid-following generation sources are relatively easy to integrate into a microgrid, with some notable exceptions.

As mentioned previously, intermittent, inverter based renewable energy generation sources such as solar PV and wind generators create microgrid controls challenges when operating in island-mode. Output from a solar PV array can change dramatically on a time scale of seconds on a partly cloudy day. The controls must be able to manage a case where the solar PV output spikes at the same time as major loads are turned off. This case could result in the net load going from a positive state to a negative state very rapidly. Depending on the generation sources that are online, the speed of the microgrid controller, and communication network latency, this case could result in a reverse power condition at a generator that is not designed for reverse power.

To minimize this risk, the solar PV inverters can be controlled using a configurable ramp rate. This is an advanced feature that was not available for the BLRMG project so the Siemens MGMS was programmed to provide ramp rate control for the PV inverters. Ramp rate control dampens the output spike from the solar PV system when the clouds move away rapidly exposing the PV modules to solar insolation. Rather than outputting the maximum power possible, the inverters slowly increase the power to whatever the maximum is based on solar insolation. This allows the control system time to adjust and make adjustments to the dispatch schedules for the generation sources that are online to keep them all within their optimal operating range. An analogous scenario can be used for wind generation.

Baseload generation sources such as microturbines and fuel cells can be configured to be either grid-forming or grid-following. Microturbines have better load-following characteristics and better turn-down capabilities and are therefore better suited as a grid-forming generator in a microgrid application. Fuel cells are best used as base-load, grid-following generators because their performance and longevity is better if they can be kept at constant output and temperature.

Using the Microgrid Controller

There are typically four different levels in a microgrid control system.

1. Component controllers
2. Optimization controller
3. Real-time controller
4. Protection and coordination controller

The component controllers are provided by the manufacturers of generation and storage devices such as inverters, batteries and generator controllers. Optimization and real time controllers are often packaged together and provided by the same manufacturer. The protection and coordination controller is typically a set of redundant protection relays. In some cases, items 2, 3, and 4 can be provided by the same manufacturer in one integrated controller.

Deploying the microgrid control system requires great care. This is because constructing a microgrid around existing facilities requires major electrical reconfiguration work at the PCC(s). This requires shutdowns, which are disruptive to facility occupants and enterprises. Planned outages are generally more tolerated than unplanned outages and the impacts and duration of unplanned outages can be unpredictable. Important questions to consider are:

- How will the microgrid control system be tested before it is deployed on a live system?
- What is the best construction sequence to minimize cumulative outage duration?
- What are the best initial settings in the component level controllers for interim operations before the entire microgrid control system becomes operational?
- How should the microgrid control system respond to PCC switching as a result of AEPS outages?
- How should the microgrid control system respond to the re-energization of the AEPS after an outage?

Based on the experience of implementing the BLRMG, a microgrid controller deployment plan based on the following outline is offered for consideration:

1. Test the microgrid control system in a digital simulation environment with control hardware in the loop. This is a critical step and its importance cannot be overemphasized for de-risking the system before operating in a live setting.
2. For the main grid-forming generation source’s controller, program it to start when the microgrid circuit becomes de-energized. The circuit breaker that connects this

generation source to the microgrid circuit should be controllable by the protection and coordination controller, which also controls the PCC circuit breaker.

3. Set the component level controllers for the remaining generation sources to operate in grid-following mode with voltage and frequency ride-through settings as per utility requirements and active anti-islanding turned on.
4. Program the protection and coordination controller(s) with the protection settings required under your interconnection agreement and program an automated foundational microgrid controller into this level.
    a. The foundational microgrid control system should respond to AEPS faults as per utility requirements and coordinate the switching of the main grid-forming generation source's tie-breaker with the PCC breaker(s) to safely form the microgrid when the PCC is open, provided that the PCC did not open due to a fault that is internal to the microgrid.
    b. The foundational microgrid control system should respond to the AEPS becoming re-energized with a coordinated reconnection of the microgrid to the AEPS.
    c. The foundational microgrid control system should have two modes:
        i. Mode 1: Switching commands that are sent by any other external controller (i.e. component level, optimization level, or real-time level controllers) are ignored.
        ii. Mode 2: Switching commands for external controllers are processed and acted upon if protection settings allow.

    If the foundational control system is operating in Mode 2 and for any reason the microgrid circuit becomes de-energized for an unexpectedly long period, then it should automatically switch to Mode 1 and energize the microgrid with the main grid-forming generator.
5. With the PCC and the foundational control system operational, the optimization and real-time controllers can be deployed and tested on the live system with the foundational control system being in Mode 1 until these controllers have been tested successfully for all functions that do not require switching of the PCC or main generation source tie breakers. At that point the foundational control system can be switched to Mode 2 and live testing can continue with the optimization and real time controllers being allowed to attempt switching of the PCC and main tie breakers for applicable control sequences.

Once the optimization and real time controllers are proven, a final step is to coordinate ramp rates and component-level controller settings so that components will revert to a safe operating state if the optimization and/or real time controllers go offline. The final state should be optimal economic performance if all controllers are online, commissioned well, and meeting the design intent, with fail-safe operation at the component-level controllers if the optimization and/or real time controllers are offline.

Critical Processes, Equipment and Expertise

Developing a microgrid is a complex process that involves several key processes, technologically advanced equipment, and specialized expertise. Information relevant to these topics was provided previously in this chapter. This section summarizes several key aspects that cannot be overemphasized when considering developing a microgrid.

Based on the experience of the BLRMG project, the most critical process for implementation is technology integration. With multiple contractors and vendors involved in implementing the project, there is a tendency for each entity to be narrowly focused on their scope of work, schedule, and budget. This creates risks because the work items and technical systems being provided must be able to interact with the overall integrated system for the design intent of the microgrid to be realized. Care must be taken to avoid gaps in the divisions of responsibility between contractors and vendors, which will become more apparent in the latter stages of the project as budgetary and schedule pressures increase. To retire as much of this risk as possible, the prime contractor should consider selecting a qualified technical integrator to assist in setting up a contractual framework to empower the project's integration team. This will ensure when uncertainty arises about the division of responsibilities, there is a licensed engineer with responsible charge of the work that can provide direction in a fair manner that is reinforced by contracts that were carefully negotiated at the beginning of the project. Other critical processes include:

- Interconnection process with the utility
    - Take the necessary time to fully understand this process at the very beginning of the project and account for the various steps and necessary review periods in the master project schedule
    - Pre-Energization Testing (PET) will be required for any new switchgear at the PCC
    - A Pre-Parallel Inspection (PPI) will be required prior to obtaining Permission to Operate (PTO) from the utility
- Engineering design process
    - Include development and review of the following at the 50%, 75%, and 90% level of completeness
        - An integrated plan set showing design plans for each system in one plan set. Every piece of hardware should be included with divisions of responsibility for procurement and installation noted on the plan sheets.
        - A Concept of Operations document written in lay-person's terms that outlines the goals and objectives of the microgrid, defines the use cases for the microgrid and describes the control actions that will be active to support each use case, specifies the actors that have a role in the control system and describes how they will influence the operational characteristics of the integrated system, and describes each control function that will used to meet the design intent.
        - An engineer's opinion of probable costs, which is used at each design review stage to check to make sure that the estimated construction cost of the system is still within the project budget. If not, a value engineering

step can be included in the work to achieve the next level of design completeness milestone.

- Hardware-in-the-loop testing in a digital simulation environment
  - A digital blueprint of the microgrid should be created in a suitable real-time digital simulator.
  - All four levels of microgrid controllers listed above should be included whenever possible. If it is not practical to integrate a certain component level controller, a simulated model may be used as a substitute but the amount of risk that can be retired through this critical process will be reduced in that case.
  - Hardware-in-the-loop testing system can be used to train microgrid operators.
- Deploy a fully tested foundational microgrid controller implemented in the protection and coordination hardware at the time that the PCC construction occurs
  - This control system will include all of the protection requirements that the utility requires at the PCC as well as control functions to transfer the microgrid loads between the AEPS and the main grid-forming generator in the microgrid and back in response to outages on the AEPS or operator commands for planned islanding events.
- Commissioning
  - This process will involve making sure that all of the interfaces between the various actors in the microgrid are functioning and that the four levels of control listed above are coordinated and functioning to meet the design intent of the microgrid.
- System Observation
  - After commissioning, the system should be observed for at least one year with data analysis conducted at regular intervals. Due to the complexity of the integrated system there will likely be deviations from expected behavior that will require effort to diagnose. The project team should plan for this observation period by making sure there is budget for data analysis and diagnostics and by making sure that warranty documentation supports any fixes that are deemed necessary.

In addition to these critical processes there are several critical pieces of equipment that are necessary for the microgrid to function safely, reliably, and optimally from an economic perspective. The list of critical equipment includes:

- Advanced protection relays that can be programmed to provide basic control, coordination, and protection for the microgrid
- A grid-forming generator that is capable of black starting the entire microgrid and that can:
  - Generate enough current to handle reactive load spikes and inrush current from starting large motors

    - Generate enough fault current to maintain the selectivity of fault interruption devices on the main circuits in the microgrid

- A microgrid controller that provides real-time control of generation sources and storage in the microgrid on a time scale of milliseconds to seconds to enforce constraints within the control scheme
- A microgrid controller that provides optimal dispatch of generation sources and storage to minimize operational costs and maximize economic benefits
- Component level controllers (for example smart inverters) that provide adequate control and protection functions to enable fail-safe operation in the event that communication with the real time or optimization controller is lost

Key expertise for implementing microgrids includes:

- A project management team who can lead the implementation team to keep the project on schedule and under budget, and ensure environmental and permitting processes are closely managed
- A licensed engineer to act as the lead technical integrator with responsible charge over the integration process and who has been empowered through contracts to direct work as needed
- A controls expert who can program advanced protection relays with control functions necessary for microgrid operation, participate in the development of the real-time and optimization control programming, and who can coordinate the settings of the component level controllers
- A licensed electrical engineer who has responsible charge over the electrical design of the microgrid and who can develop a power flow model of the microgrid to evaluate stability under various conditions
- A protection engineer who can program protection relays, complete short circuit coordination studies, and who has responsible charge over the selectivity of the fault interruption systems in grid-connected and islanded modes
- An energy modeler who can verify the optimal component sizing and consult with the controls team to ensure that the necessary functions are in place to achieve optimal economic performance
- Utility interconnection engineers who can evaluate the proposed project to clarify requirements and ultimately inspect and approve of the project
- A licensed electrical contractor with experience with medium-voltage systems
- A network technology expert who can design the communications network needed for microgrid control and data acquisition
- A cyber security expert who can evaluate the design plans, identify any vulnerabilities, and recommend mitigation measures to harden the microgrid again cyberattack
- A testing team with facilities to conduct hardware-in-the-loop testing of controls in a digital simulation environment so that the microgrid control system can be tested before being deployed on a live system

- A construction management team to document construction and help mediate any disputes that arise
- A commissioning agent who is responsible for testing all of the functionality included in the final Concept of Operations document, which should contain a common understanding among all project participants as to how the system should operate upon completion
- A data analysis specialist who can efficiently analyze large operational data sets during the system observation period and provide summary reports to the project management team

The information provided in this section is not intended to be exhaustive but should provide a sense of the types of processes, equipment, and skills needed to successfully implement a microgrid.

Key Cost Considerations

Microgrids are capital intensive to implement. Certain components are commercially mature from both an economic and technical perspective, such as solar PV systems, natural gas and other fossil-fueled generators, and advanced protection relays. Battery energy storage systems are often essential to microgrid operability because they are able to absorb as well as generate energy in quantities that are useful in supporting microgrid operation in island-mode. Battery storage is still relatively expensive in 2018, but capital costs are declining steadily. Other components such as microturbines and high temperature fuel cells are available but less common and therefore can be more expensive. On an individual basis, procuring each of these types of assets and installing them at a facility with a connection to the AEPS is relatively straightforward, and in isolation the “soft costs” (i.e., engineering, permitting, testing, construction management, commissioning, etc.) of each are in line with a typical public works project. However, for a microgrid project, some combination of these assets must be deployed in an integrated system and a dynamic PCC with the AEPS must be managed as well, which is likely to create significant design, engineering, commissioning, and utility interconnection requirements that can add considerably to the cost.

Key cost considerations for microgrid deployment are:

1. The soft costs for the expertise needed during design, testing, interconnection, construction, and commissioning of the microgrid
2. The interconnection costs with the utility, including potential service reconfigurations
3. The microgrid controller system costs covering the four level of controls described above

These three cost considerations generally amount to a significant fraction of the overall project cost and should be evaluated early during the project budgeting phase. Estimating the amount of effort that should be budgeted for items one and two is difficult and can vary widely from project to project. From a cost management perspective, an experienced design team and a utility that has a clear interconnection process and experience with microgrids are two desirable attributes for any microgrid project.

Thoughts on Replicability

Regarding replicability of microgrids in California and general, a primary consideration is the perspective of the utility on any proposed project. Any type of microgrid will always require utility participation, and the utility will always be the expert in the room when it comes to safely and reliably operating an electricity grid. When a microgrid project is proposed, the utility has the ultimate authority to either approve or deny the project. If a project fails to meet the utility's requirements, it may be unable to obtain permission to operate regardless of whether construction has been completed.

Single-customer microgrids with a single PCC (i.e. a campus), that are well-designed according to utility requirements, should be able to obtain unconditional permission to operate from the utility. There may be restrictions on the types of transfers that are allowed (break-before-make or seamless) and/or the amount of power that is allowed to be exported from the microgrid to the AEPS. However, these are points of discussion that can be addressed using sound engineering design practices and clear communication to obtain mutual agreement.

Multi-customer microgrids will likely require that the utility's distribution circuit be modified and special cost recovery methods and tariffs will probably apply. It is easier to standardize these types of microgrids from a technical perspective, especially if the generation and storage assets are owned by the utility, because the protection and control hardware and software for switching on medium voltage circuits is mature. The more complicated aspects are the contractual and financial details that will govern cost recovery and the creation of special tariffs. The current ACV Airport Renewable Microgrid (which at the time of this report writing has received a Notice of Proposed Award under the CEC EPIC grant program) will demonstrate the business case and replicability for multi-customer microgrids on utility distribution circuits[8] in Pacific Gas & Electric's service territory.

Need for Standardization

Standardization of equipment, communication protocols, control sequences, interconnection pathways, and primary circuit switching protocols in the context of microgrid deployment is an admirable and elusive goal. There are industry efforts to pursue standards that, if adopted by enough manufacturers, could make it easier to integrate component-level controllers and optimization, and real-time controllers. The SunSpec Alliance is one example of such an effort (SunSpec Alliance, 2018).

The BLRMG project did not benefit from any such standardization. Most of the interfaces and much of the control software required custom development. This required significant effort by highly skilled engineers to develop and test the interfaces and software. These "soft costs" increased the overall project cost and timeline considerably. At present and for the near future, it is likely that teams working to develop a microgrid project will have a similar experience.

In an ideal scenario, a set of microgrid interface and communication standards would exist that component manufacturers would adopt to allow devices from different manufacturers to communicate with each other over a secure TCP/IP network with reduced customization requirements by the engineers deploying the equipment.

One approach is to try to implement a microgrid using hardware and software from a single vendor. There are several large companies that are capable of providing this type of umbrella

[8] More information on the ACV Airport Renewable Microgrid project is available at www.schatzcenter.org.

solution. However, there are pros and cons with this approach. On the plus side, one experienced firm can provide the components for much of the control system and, in some cases, the generation sources and energy storage systems as well. Experienced engineers from that same company can design, test, and commission the equipment. Custom interfacing and controls work is minimized.

However, with this approach the microgrid design, functionality, and innovative characteristics could become somewhat limited by what the "umbrella" company sees as the "best" way to implement a microgrid. Also, being able to fully grasp the operational characteristics of the completed microgrid during the sales period with a large company offering a turnkey microgrid could be challenging. Once the sale has been made, the selected company will implement the project and along the way details about how the system will be deployed and operate will become clear to the owner. There is a risk that the owner's expectations will not be met and options to remedy the situation may be limited.

Need for Plug-and-Play Architecture

The phrase 'plug-and-play' describes a case where a "child" device can be plugged into a "parent" device for the first time and after a brief communication period, the child device works perfectly the first time it is used. One example of this is when a keyboard (child) is plugged into a computer (parent) for the first time. The child device is designed with a standardized interface protocol, and as long as the port that it is plugged into complies with this protocol and the operating system on the computer has a standardized discovery mechanism for this protocol, meeting the plug-and-play standards, the child's driver will be installed on the parent and it will operate as designed.

While it is conceivable that an analogous system could be implement to speed deployment of microgrids with components from multiple manufacturers, the practicalities of such an endeavor are daunting. The types of components that could be deployed in a microgrid are many (e.g. inverters, automatic transfer switches, protection relays, internal combustion engine generators, microturbines, fuel cells, battery energy storage systems, energy management systems, meters, etc.), with potentially multiple manufacturers involved. From this perspective alone, it appears unlikely that standards to enable plug-and-play operation for multi-manufacturer microgrids will ever be widely adopted. It is much more likely that single-manufacturer microgrids may achieve plug-and-play functionality as competition drives down cost for turnkey microgrid solutions.

One note of caution regarding the concept of plug-and-play solutions for microgrids is that there could be significant risk in allowing any component that is connected to the microgrid circuit to operate as a plug-and-play device. For safety, any device that is connected to the microgrid circuit should be carefully configured to operate within the constraints of the site-specific control system by the engineering team. These components need to operate in a coordinated fashion with other grid-connected components.

Some grid-following components that are connected to the microgrid circuits such as solar PV inverters are essentially plug-and-play. Solar PV inverters are a good example of how grid-following generation sources can be designed to be plug-and-play because their initial settings are fail-safe and can be customized during commissioning as needed for microgrid duty. Also, components that are not directly connected to and have no direct influence on the microgrid circuit (i.e. power meters, weather station instrumentation, data loggers, etc.) could be made plug-and-play, which could definitely reduce microgrid deployment time.

Chapter 11: Conclusions and Recommendations

Conclusions

The BLRMG was highly successful. The project was completed on time with no safety incidents or equipment damage and only minor cost overruns (less than 1.5% of total project cost). The project was recognized internationally including the following awards and nominations, among others:

- FEMA's 2017 Whole Community Preparedness Award
- DistribuTECH 2018 Project of the Year for DER Integration
- 2017 Finalist for the S&G Platts Global Energy Award in the Commercial Application of the Year
- 2017 First Runner Up for Renewable Energy World and Power Engineering's Projects of the Year Awards

The design intent of the project was met and full functionality was achieved, including:

- A secure, reliable, low-carbon community microgrid was deployed for BLR, which is a certified American Red Cross Evacuation Shelter
    - This provides critical resiliency for the Tribe and for the surrounding community in this disaster-prone region.
- Automated transitions from grid connected to islanded states in response to the state of the area electric power system (AEPS)
    - With and without the Siemens Microgrid Management System online.
- Planned islanding with seamless transitions to and from AEPS-connected state
    - The 14 solar PV inverters do not trip off during these transitions.
- Five levels of programmed load shed to extend islanded run-time during emergencies
- Voltage and frequency regulation in island-mode with only the solar PV and BESS inverters forming the microgrid (low-inertia mode)
    - Demonstrating stable operation with a high percentage of renewable energy online relative to loads.
- Automated and seamless connection of the pre-existing 1 MW isochronous DG to the islanded microgrid if the state of energy in the Tesla BESS decreases to 15%
    - This enables long-term islanding in emergency situations.
- Load sharing management between the BESS and the isochronous DG in island-mode

- Ramp control on the solar PV inverters to dampen the otherwise rapid increase in output that can occur on partly cloudy days
- Optimized economic performance including:
  - Import limit for demand charge management (i.e. peak shaving)
  - 24-hour optimal generation dispatch schedule created every 15 minutes to minimize costs given the electric rate schedule, short-term load forecast, and solar PV output forecast.
- Foundational microgrid control system implemented in the protection relays that provide safe and reliable microgrid operation when the Siemens Spectrum 7™ is offline
- An appropriate balance between automated functionality and manual control capability was achieved (i.e. a trained electrical grid operator is not required)

The BLR Tribe supports academic, government, public and private industry groups and students visiting the microgrid site to tour and learn about solar energy, battery storage, distributed energy resource integration, demand response, energy arbitrage, peak shaving, low-inertia microgrid operation with high penetration rates of intermittent renewable energy, how to integrate pre-existing equipment into a microgrid, overall resilience, sustainability, and climate action strategies, and other project and knowledge transfer topics.

The telemetry and data recording system on the microgrid are extensive and the project represents a valuable resource to the State of California and the United States for studying grid dynamics and smart-grid strategies under a variety of real world scenarios on a live system. Committed partners such as SERC, PG&E, Siemens, and Tesla are providing ongoing support for the microgrid, which enables growth as the technology improves. An example of this is BLR's plan to double the size of the battery energy storage system so that the microgrid can operate without the 1 MW isochronous DG, except under prolonged outages that may occur after a major disaster (e.g., a Cascadia Subduction Zone earthquake and/or tsunami).

The economic benefit to BLR for 2017 was approximately $164,000 and this is expected to increase to approximately $198,000 in subsequent years due to improved system performance resulting from modifications to the microgrid controller made as a result of system observations conducted in 2017. The environmental benefits from the project include offsetting approximately 160 to 175 metric tons of CO_2e per year.

Lessons Learned

Some of the key lessons learned include:

- Implementing a microgrid project requires a contractually empowered technical integration team.
- A microgrid control system has four levels of control:
  - Component controllers,
  - Optimization controller,
  - Real-time controller, and
  - Protection and coordination controller.

- Advanced protection relays have control capabilities that can be utilized to make sure that the protection and coordination controller is at the top of the control hierarchy, which aids with construction sequencing and avoids significant risk when deploying the optimization and real time controllers.
- The electric utility is a critical partner in any microgrid project. Microgrid interconnection processes are especially complex and establishing a collaborative relationship with the utility is essential.
- Network latency and control cycle times must be accounted for, especially when solar output is large relative to loads.
- Hardware in the loop testing in a real time digital simulation environment is valuable for de-risking and providing a venue for operator training.
- During live testing, use detailed test plans with contingencies for all failure modes.
- Include electricians with prior knowledge of the microgrid site on your project team.
- IT upgrades can disrupt communications between microgrid components causing operational issues, so ensuring system/site wide IT coordination is important.
- Make sure to account for large reactive loads during design.
    - During the proposal stage the BLRMG design team did not have information about the magnitude of potential transient peak loads associated with two moderately loaded elevators in the hotel that can start upwards at the same time. This led to the battery energy storage system being undersized for low-inertia microgrid operations unless at least one elevator is locked out. In 2018, BLR, SERC, Tesla, and Siemens will implement a project to double the size of the BESS to eliminate this problem, which will significantly reduce the usage of the 1 MW DG onsite.
- Seamless transitions between grid connected and islanded states require the right equipment, specialized expertise, and careful execution. However, if they can be accomplished occupants of facilities served by the microgrid will appreciate them.
- Implementing a microgrid over an existing built environment is challenging.
- Owner/operator capacity should determine system complexity and the appropriate level of automation.
- After commissioning, closely monitor system performance to verify functionality and expected results.
- Involvement of the IT and communications department is critical to project success.
- Do not underestimate the amount of time it will take to commission the microgrid control system.

Recommendations

Chapters 2, 3, 4, 5, and 6 provide detail as to how the BLRMG project was implemented and can serve as a resource to other project teams working on implementing similar projects. Chapter 10, Production Readiness Plan, addresses key considerations regarding how to replicate microgrids in a general sense. The top five recommendations for project developers coming out of this project are as follows:

1. Engage and empower a qualified technical integration team in the early stages of project development.
2. Engage and cultivate a cooperative relationship with the electrical utility that the microgrid will connect to as early in the project development process as possible.
3. Use advanced protection relays at the point of common coupling with the utility to create a foundational microgrid control system that is at the top of the microgrid control hierarchy.
4. The site host should be prepared to accept risks associated with both planned and unplanned electricity outages, potential equipment damage, and cost overruns.
5. Ensure that there is enough budget after initial commissioning for a system observation period (ideally at least 12 months) during which data analysis results will lead to opportunities to improve system performance, sometimes dramatically.

Suggestions for Further Research

The following is a set of research topics that the authors think are worth further research:

- DC coupled PV-battery systems for microgrids.
- Optimization schemes for microgrids.
- Utilization of thermal storage in a microgrid.
- Front-of-the-meter multi-customer microgrids integrated into a distribution utility's control network.
- Simplified microgrid control – how simple and low-cost can you make a microgrid control system and still serve basic microgrid needs?
- Deployment of microgrid controllers that can provide seamless transitions during unplanned outages, like an uninterruptible power supply.
- Grid distribution services that can be provided by microgrids.
- Stacked value of microgrids and detailed assessment of the value proposition/business case.
- Transactional structures allowing entities on a microgrid to exchange value, such as experimental tariffs and blockchain-based systems.
- Exploration of distributed rather than centralized smart grid control architectures.
- Control and protection strategies for low-inertia operation of inverter-based microgrids with high penetrations of renewable energy.
- Workforce development and STEM education programs relevant to the microgrid space, including developing, possibly through public/private partnerships, microgrid centers of excellence which would support field study on live systems, and coordination with hardware-in-the-loop microgrid test laboratories.

GLOSSARY

Term	Definition
1 MW DG	The 1 MW isochronous (constant frequency) generator located at the casino that was used as backup power for the Casino and some Hotel loads prior to the project.
ATS	Automatic transfer switch; device used to automatically transfer from utility power to backup power in the event of a utility grid outage.
ATS1	The 1600-amp automatic transfer switch located in the Casino that was used to connect the 1 MW generator to the Casino during power outages prior to the project.
ATS2	The automatic transfer switch located at the Tribal Office that connects the 80 kW generator at the Tribal Office to the building for standby backup power.
BESS	Battery energy storage system; in the context of this project, specifically refers to the Tesla Powerpack 1 500 kW / 950 kWh battery energy storage system the project utilized.
BLC	Blue Lake Casino
BLR	Blue Lake Rancheria; project partner and site host.
BLRMG	Blue Lake Rancheria microgrid
CB	Circuit breaker
CONOPS	Concept of operations document
CPUC	California Public Utilities Commission
DG	Distributed generator
EFMS	Environmental Forecasting and Monitoring Server
EMS	Energy management system
EPIC	Electric Program Investment Charge
ERS	Emmerson Reliability Services; project subcontractor.
Gen1	Used in project documentation to refer to the onsite isochronous (constant frequency) 1 MW generator.
Gen2	Used in project documentation to refer to the 80 kW generator used for backup of the Tribal Office.
GHD	GHD Pty Ltd; project partner.
HIL	Hardware-in-the-loop; simulated testing that integrates digital simulation with actual hardware components, usually necessitating real-time digital simulation.
Historian	A subsystem of the Siemens Microgrid Management System that stores collected data for later analysis.
HMI	Human-machine interface
INL	Idaho National Laboratory; project partner.
IT	Information technology
JCI	Johnson Controls, Inc.; project vendor.
ME&E	McKeever Energy and Electric; project subcontractor.

Term	Definition
MGMS	Microgrid Management System; the central microgrid control system developed by Siemens AG.
MOM	Microgrid Optimization Module; a subsystem of the Siemens Microgrid Management System that optimizes energy dispatch.
MSB	Main switchboard
PCC	Point of common coupling; the point at which a microgrid is connected to the wider utility grid.
PCC Relay	In the context of this document, primarily used to refer to the primary SEL-700GT+ PCC breaker control and protection relay located in the PCC.
PCCCB	Point of common coupling circuit breaker; the circuit breaker used to disconnect the microgrid from the wider utility grid.
PET	Pre-energization test
POA	Plane of array; the plane that corresponds to the angle and azimuth that the modules in a PV array are mounted at.
PPI	Pre-parallel inspection
PTO	Permission to operate
PV	Photovoltaic
RCE	Robert Colburn Engineering; project partner.
RTDS	Real-Time Digital Simulation; a digital simulation system that operates in real time, often including hardware-in-the-loop components.
SCADA	Supervisory control and data acquisition
SEL	Schweitzer Engineering Laboratories, Inc.; project vendor.
SEL-700GT+	Specific model of protection relay device, manufactured by SEL, Inc., used to monitor and control the point of common coupling breaker and for foundational control.
SERC	Schatz Energy Research Center; project prime contractor.
Smart Grid	Smart Grid is the thoughtful integration of intelligent technologies and innovative services that produce a more efficient, sustainable, economic, and secure electrical supply for California communities.
SMC	System management controller; the local controller of the Tesla battery energy storage system.
SOC	State of charge; the amount of energy stored in the battery system (synonym of SOE).
SOE	State of energy; the amount of energy stored in the battery system (synonym of SOC).
SWPPP	Storm water pollution prevention plan
UPS	Uninterruptable power supply; device capable of powering attached loads from stored energy (usually batteries) for a short period of time after normal input power is interrupted, and of transferring quickly enough that connected loads are not affected by the transfer.

REFERENCES

California Energy Commission. (2014, July). Attachment 12 - References for Energy End-Use, Electricity Demand and GHG Emissions Reference Calculations. *PON-14-301, EPIC Grant Program.*

Center for Strategic Economic Research. (2014). *Economic Contributions of Pacific Gas and Electric Company.* Prepared for Pacific Gas and Electric Comany, San Francisco, CA.

Hedman, B., & Hampson, A. (2010). *Effect of a 30 Percent Investment Tax Credit on the Economic Market Potential for Combined Heat and Power.* ICF International.

Kurtovich, M. (2016). *California Electric Reliability Investor-Owned Utilities Performance Review 2006-2015.* Califoria Public Utilities Commission, Policy and Planning Division.

Meichtry, B. (2016, December 6). HelioScope Annual Production Report, Blue Lake Rancheria, REV-H (SMA 30TL-14inv) As Built (copy). REC Solar.

Mohanpurkar, M., Luo, Y., Hovsapian, R., & Medam, A. (2017). *Real-time Modeling and Testing of Microgrid Management System for the Blue Lake Rancheria - Performance Assurance Report.* Idaho National Laboratory.

PG&E. (2017). *2016 Annual Electric Reliability Report (Per Decision 16-01-008).* Pacific Gas and Electric Company .

Singh, P. (2017). *Technical and Economic Potential of Microgrids in California.* Humboldt State University, Environmental Systems - Energy, Technology, and Policy Option. Arcata, CA: Humboldt Digital Scholar Service (https://digitalcommons.humboldt.edu/etd/33).

SunSpec Alliance. (2018, March 22). Retrieved from SunSpec Alliance Web site: https://sunspec.org/

Tetra Tech. (2014). *Humboldt Operational Area Hazard Mitigation Plan Update.* County of Humboldt, Department of Public Works.

Zoellick, J. (2013). *Humboldt County as a Renewabel Energy Secure Community, Analysis and Strategic Planning.* California Energy Commission.

APPENDIX A:
Concept of Operations Excerpt

Blue Lake Rancheria Microgrid Concept of Operations

Revision History

Number	Date	Author(s)	Description
[0]	January 8, 2016	D. Carter, D.Saucedo	50% review draft
[1]	January 15, 2016	D. Carter	Minor edits and formatting changes and attached appendices
[2]	January 26, 2016	G. Chapman	50% review comments/edits
[3]	February 8, 2016	D. Carter	Addressed additional developments since 50% review and resolved some comments that were unresolved in version [2].
[4]	February 29, 2016	D. Saucedo	Revised functions based on new information needed to develop the RTDS test plan and reorganized function numbering.
[5]	April 17, 2016	P. Singh	Updates to BESS SoE settings, BESS capability function, Demand Response function
[6]	April 27, 2016	D. Saucedo	Update functions for 90% design level. Remove fuel cell related content due to the decision not to include fuel cell in microgrid project.
[7]	May 19, 2016	D.Carter	Remove fuel cell related content due to decision by SERC not to include fuel cell in microgrid project. Remove function 8 because seamless transition from islanded to grid connected state is not possible with current Dynapower Inverter control cards. Various updates to other functions. Final review and edits prior to release for 90% review.
[8]	September 8, 2016	D. Saucedo	The document was reconstructed from the 90% review comments due to a MS Word error and possible corruption of the original file.
[9]	October 18, 2016	D. Saucedo	Update to Function 10.
[10]	October 31, 2016	D. Saucedo	Update controllable load estimates per Pramod Singh's update.
[11]	December 15, 2017	D. Carter	Revisions to reflect operational results

1. Introduction

This document that was revised several times before it was finalized after commissioning of the project in 2017. The revision block on the title page provides information on past revisions. Past revisions are archived and the current version reflects the common understanding between Tribal Leaders and the technical team as of the date indicated.

Purpose

The primary purpose of this document is to communicate details to all stakeholders regarding how the Blue Lake Rancheria Microgrid (BLRMG) will operate in order to coordinate the work of the technical team and solicit feedback from Tribal Leaders at various review milestones. Additionally, this document seeks to clarify design decisions that have been made and to describe how the microgrid will operate as a result of those decisions. Finally, this document also serves as the basis for the test plan that was executed by INL during the de-risking process and by others in the technical team as part of the commissioning process.

Objectives

Four objectives were identified for the BLRMG project. These objectives include the following considerations:

- **Emergency**: high reliability during a prolonged outage of the Area Electric Power System (AEPS),
- **Environment**: low carbon intensity for the energy services delivered,
- **Economy**: low monetary expense in delivering energy services, and
- **Showcase:** the ability to perform advanced features for demonstration and research.

Specific goals have been identified for each of the objectives in the BLRMG design.

- Install a microgrid capable of powering the nationally recognized American Red Cross disaster shelter on BLR land in times of emergency;
- Achieve renewable energy generation exceeding 15 percent of onsite annual energy production;
- Demonstrate the ability to island and supply uninterrupted electric power for at least 7 days during a real or simulated grid outage;
- Demonstrate the ability of the microgrid to participate in one or more PG&E demand response programs;
- Achieve a reduction in annual electrical energy consumption from the grid of at least 680MWh over year 1 of operation;
- Achieve at least 25 percent energy cost savings over year 1 of operation;
- Achieve a reduction in annual greenhouse gas emissions of at least 130 metric tons CO_2e over year 1 of operation;
- Make the knowledge gained from the project available to a broad audience;
- Develop a plan for commercializing the microgrid technologies and strategies demonstrated under this project.

Each Use Case addresses one or more of the objectives as noted in Section 4 – Use Cases.

Organization

This document is organized around four major categories of information that relate to how the microgrid will operate:

1. **Actors**: These are the major components (hardware and software) that make up the microgrid.
2. **Controllable Loads**: There are 5 prioritized levels of controllable loads that can be selected by microgrid operators from one of the human-machine interfaces (HMI) for the MGMS.
3. **Use Cases**: These are the scenarios that the microgrid is designed to address.
4. **Functions:** These are the detailed sequences that the microgrid control system will execute using the Actors, in order to meet the intent of the Use Cases.

The Actors section is presented first providing a simplified overview of the microgrid architecture and the Actors that impact how the microgrid operates. The Controllable Loads section is presented next to summarize the loads that can be controlled to help manage the microgrid under various use cases. The Use Case section then follows providing a high level overview of the Use Cases for the microgrid. The document ends with the Functions section.

2. Actors

Actors are the major components (hardware and software) that make up the microgrid. The BLRMG consists of actors with various roles and functionalities. In general there are generation sources, loads, electrical circuits, sensors, actuator, and control elements.

Figure 1 shows a simplified diagram of the microgrid with the major actors shown.

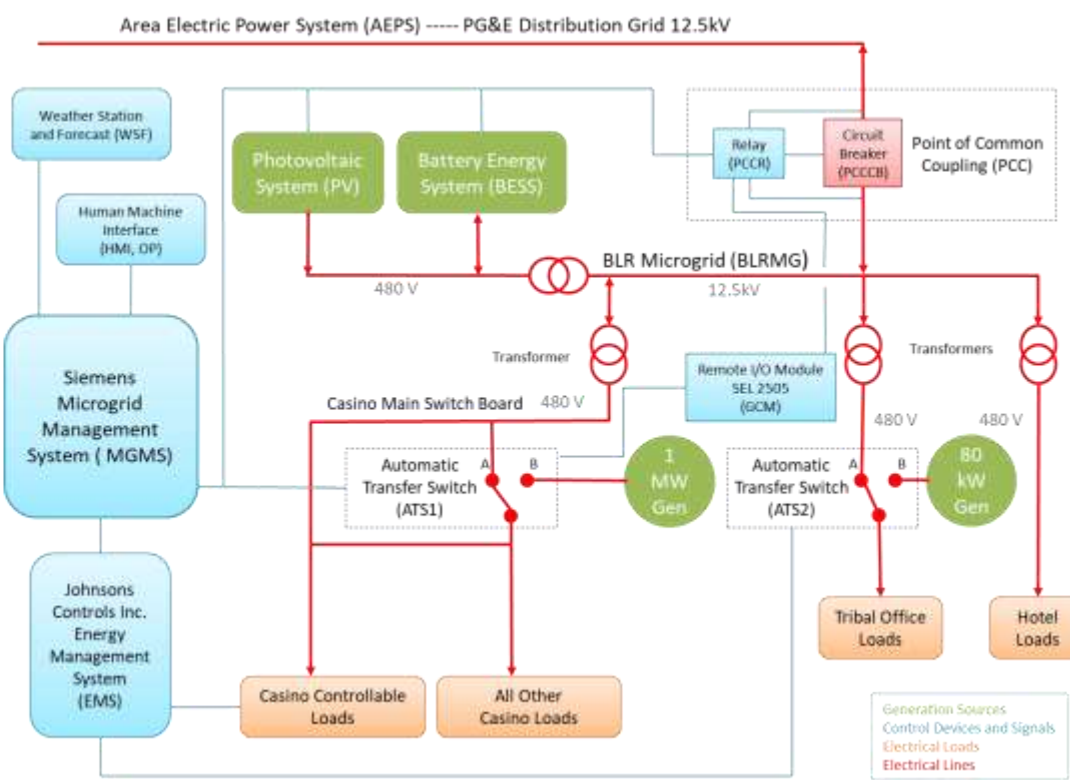


Figure 1: Simplified Diagram of the Microgrid

Table 1 below lists the major Actors and provides a brief description of their role in the microgrid control functions.

Table 1 – Actors participating in the BLRMG

Actor Name	Acronym	Actor Type	Actor Description
Area Electric Power System	AEPS	System	The PG&E distribution grid that normally supplies the BLRMG with electricity at 12.5 kV through their point of common coupling (PCC).
Human Machine Interfaces	HMI	Device	Computer screens on the network that allow operators to view and/or control the way that the MG operates.
Microgrid Management System	MGMS	System	The Siemens control system for the BLRMG.
1 Megawatt Diesel Generator	Gen1	Device	The pre-existing 1 Megawatt Diesel Generator.
Photovoltaic System	PV	System	A photovoltaic generating system with 14, 30 kW inverters (nameplate capacity of 420 kW AC).
Battery Energy Storage System	BESS	System	Tesla Energy battery system with 950 kWh and 500kW maximum output capacity. The BESS is capable of operating in grid forming or grid following mode.
Gen1 Automatic Transfer Switch	ATS1	Device	ATS1 connects and disconnects Gen1 to and from the BLRMG.
Generator Coordination Module	GCM	Device	A SEL- 2505 remote I/O unit at ATS1 that controls the starting and connecting functions of Gen1 and ATS1.
80 kilowatt Automatic Transfer Switch	ATS2	Device	ATS2 positions to supply power from either the AEPS or the BLRMG or connect to the 80 kW generator for emergency power and to allow the office to be a controllable load for load shed purposes.
Point of Common Coupling Relay	PCCR	Device	A SEL-700GT+ protection relay at the PCC that monitors and controls the PCCCB, ATS1, and Gen1. The PCCR also acts as the “islanding controller” for the BESS.
Point of Common Coupling Circuit Breaker	PCCCB	Device	A circuit breaker that physically connects and disconnects the BLRMG from the AEPS.
Energy Management System	EMS	System	A system by Johnson Controls Inc. that controls 25 HVAC units, 9 exhaust fans, three contactors in the casino, and ATS2.
80 kW Diesel Generator Office	Gen2	Device	An 80 kW diesel generator which operates as a back-up power system for the Tribal office.
Environmental Forecasting and Monitoring Server	EFMS	System	Provides temperature, humidity, and solar electricity generation forecast data for the MGMS.
Human Operator	OP	Human	Human decision maker overseeing BLRMG operations.
Distribution Infrastructure	DI	System	The conductors, transformers, and other components involved with distribution of power at the BLRMG.
Network Infrastructure	NI	System	The network, switches, and other components that facilitate communications between actors.
Electric Power Meters	EPM	Device	An array of electric power meters are used to monitor generation and load power characteristics.
GPS Clock	Clock	Device	Global Position System Clock used to maintain time synchronization of the MGMS.

3. Controllable Loads

Controllable loads are non-critical loads that can be regulated to extend service to critical loads on the microgrid. Upon manual input from operators at an HMI, the MGMS can command five different load shed events to be executed by the Johnson Controls Inc. EMS. Tribal leaders have determined priority of controllable loads. These loads are listed below from lowest priority to highest priority:

1. Tribal Office
2. Rotating outage of all non-critical AC units
3. All non-critical AC units
4. Gaming
5. Exhaust Fans and non- critical HVAC unit fans in Casino

These are the only loads that can be shed through the MGMS HMI. Figure 2 below shows an early version of the load shed interface.

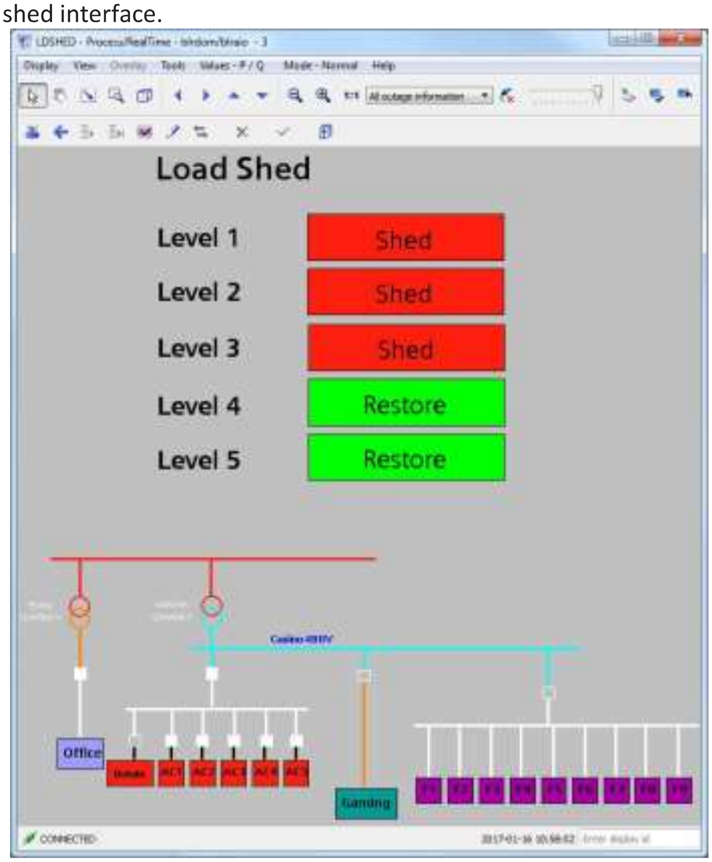


Figure 2: Controllable Loads Interface

Figure 2 shows that each load can be turned on or off using a button on the HMI. Below the buttons, a one line diagram shows the states of virtual circuit breakers that show the state of each load (connected or disconnected). Solid filled virtual circuit breakers represent closed states (load not shed) while open virtual circuit breakers represent an open state (load is shed). This is a simplified representation of what actually occurs within the software and hardware systems that make up the control system. The load groups shown in Figure 2 are described below and are available to operators when the microgrid is in islanded operation and operating under Use Case No. 3: Emergency. However, operators may also trigger these load shed events while grid connected after declaring an emergency by checking a box in the HMI. The primary intent of the controllable loads is to increase the amount of time the BLRMG can operate in an islanded state. This section presents the load shed concept and a subsequent section, **Error! Reference source not found.**, provides further details.

Level 1: Tribal Office

Load Group 1 can be activated by an operator initiated command via the MGMS HMI, which will transfer the office to its backup generator. The generator will pick up the entire office load thereby removing this load from the microgrid.

Controls Description

- Upon a PG&E grid outage the MGMS will initiate a blackstart using either Function 8 or 12, which are described in a subsequent section. Within approximately 6 seconds the microgrid will become energized. ATS2 will not start and pick up the Tribal Office load because the Time Delay Engine Start (TDES) is set to 20 seconds and by that time the BLRMG will be energized by either Gen1 or the BESS.
- When Gen2 and ATS2 are used to operate the office as a controllable load, the operator selects Level 1 from the load shed menu on the HMI. The MGMS will toggle a binary register in the interface between the MGMS and the EMS and the EMS will send a signal to ATS2 causing Gen2 to start and then ATS2 will transfer the office load to Gen2. When the MGMS receives confirmation from the EMS that the load shed was successful the button in the HMI will change from red to green and the text on the button will change from “Shed” to “Restore”.
- At the end of the load shed event the operator clicks on the “Restore” button on the MGMS HMI. Upon this command, the MGMS will toggle a binary register in the interface between the MGMS and the EMS, the EMS will then signal ATS2 to transfer the office load back to the microgrid.

Level 2: Rotating outage of AC compressors in Casino

When load shed Level 2 is initiated by an operator, the MGMS toggles a binary register in the interface between the MGMS and the EMS. The virtual circuit breaker above the “Rotate” function in Figure 2 will become solid to show that the AC Rotate function is active. The EMS then manages a rotating outage among five disaggregated groups of AC compressors as shown in Figure 2, so as to deliver a continuous load shed resource to the MGMS. The EMS does this by rotating through the five disaggregated groups of AC compressors. The thermostats controlling the compressors will be switched to unoccupied state for a 20 minute time period. This time period is adjustable by operators from within the EMS. During this time the EMS will monitor temperatures and switch to a different compressor group if a high temp set-point is reached in any of the zones impacted. During the switch between each compressor group the EMS will put the next group in line prior into an unoccupied state prior to putting the group that is currently being used in the rotation back into the occupied state, in order to maintain the load reduction on the microgrid. This rolling outage loop will cycle in the EMS until operators click on the “Restore” button for Level 2 in the MGMS HMI. Upon this command, the MGMS will again toggle the binary register in the interface between the MGMS and the EMS. The EMS will then put the thermostats for the active AC compressor group in the rotating outage back into the occupied state.

Level 3: All Non-Critical AC compressors in Casino shed simultaneously

When the operator selects Level 3 from the load shed menu on the HMI, the MGMS will toggle a binary register in the interface between the MGMS and the EMS. The EMS will switch the thermostats in all five groups into an unoccupied state sequentially. This will deliver a load shed resource of approximately 375kW (nameplate) to the MGMS. When the operator decides to stop using Level 2 load shed and clicks the “Restore” button, the MGMS will signal the EMS to restore all thermostats to occupied state in Load Group 2. Upon this command, the MGMS will toggle a binary register in the interface between the MGMS and the EMS. This will cause the EMS to put the thermostats for the five AC compressor groups in Level 2 back into the occupied state.

Level 4: Gaming

When the operator selects Level 4 from the load shed menu on the HMI, the MGMS will toggle a binary register in the interface between the MGMS and the EMS. The EMS will de-energize various gaming machines throughout the casino by sending a control pulse which will open shunt trip breakers shutting off power to five electrical panels in the Casino. Table 2 below shows the panels involved in this load group.

Table 2: Panels used in Controllable Load Group 3

Panel to be De-energized	Location and Size of Shunt-Trip Breaker
CHFD-1, CHFD-2	CHA, 100 Amp, 480 Volt
CLB-1, CLB-2	CLA, 225 Amp, 208 Volt
CLF-2	CLF-1, 100 Amp, 208 Volt

When the operator decides to stop using Load Group 4 they will need to manually reset the breakers shown in Table 2. This procedure is as follows:

Step 1: The Operator will put the 150kVA Liebert UPS system in bypass mode
Step 2: The Operator will manually reset the shunt trip breakers
Step 3: The Operator will take the 150kVA Liebert UPS system out of bypass mode
Step 4: The Operator will click on a confirmation box in the MGMS HMI
Step 5: The Operator will click on a restore button in the MGMS HMI

Level 5: Exhaust Fans and HVAC unit fans in Casino

When the operator selects Level 5 from the load shed menu on the HMI, the MGMS will toggle a binary register in the interface between the MGMS and the EMS. The EMS will de-energize the ventilation fans associated with AC compressor groups 1-5 shown in Figure 2 as well as nine large exhaust fans in the casino in a pre-programmed sequence with a time delay between each fan shut-down event. This time delay is adjustable through the EMS. When the operator decides to stop using Level 5 they will click on a "Restore" button on the HMI. Upon this command, the MGMS will open the virtual circuit breaker in the interface between the MGMS and the EMS and the EMS will re-energize all exhaust fans in Load Group 4 in a sequence.

The controllable loads are not automatically controlled or included in the MGMS optimization algorithms, which means that the decision as to whether or not to shed a given load is entirely up to the operator and no guidance will be provided by MGMS regarding when or how much load to shed. Adding controllable loads to the MGMS optimization is possible and, if desired, could be implemented under a subsequent project.

Table 3 below shows the nameplate ratings and the average load reductions for each load shed level.

Table 3 – Nameplate rating and estimated average of controllable load groups and cumulative load control.

Load Level		Name Plate Rating [kW]	Estimated Average Load [kW]
1	Tribal Office	50	12
2	Casino AC compressors- Rotate	75	37
3	Casino AC compressors- All	375	185
4	Gaming	90	65
5	Exhaust fans and HVAC unit fans	170	76

4. Use Cases

The BLR MGMS is designed to address various primary use cases, or operational scenarios, that may occur at any given time during operations. These Use Cases are summarized in Table 4.

Table 4 – Use Cases, System State, Trigger, and Objectives met

No.	Name	System State	Condition	Objectives			
				Emergency	Environment	Economy	Showcase
1	Blue Sky Operations	Connected	Normal Operations		X	X	X
2	Demand Response	Connected or Islanded	Economic Decision		X	X	X
3	Nuisance Outage	Islanded	AEPS Outage	X	X	X	X
4	Emergency Operations	Connected or Islanded	AEPS Outage > 8 hrs or Operator Preference	X	X	X	X

Referring to Table 4 above, the BLRMG is designed to meet the objectives shown for each of four operating modes, referred to herein as use cases. Figure 3 below shows how the various use cases relate to each other.

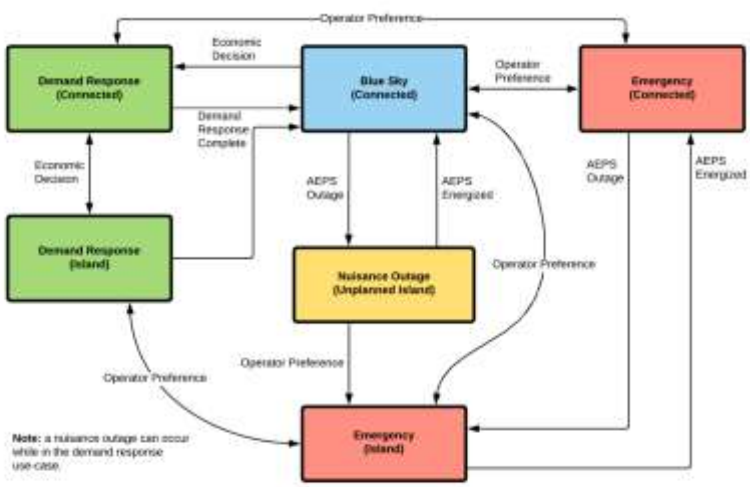


Figure 3 – Use-case state-flow diagram

Transitions between the Blue Sky and Nuisance Outage use cases are automated. Note that the Demand Response Use Case is also used for planned islanding for maintenance purposes. The remainder of this section describes the four use cases.

Use Case 1: Blue Sky

The Blue Sky use case represents normal operations when the system is connected to the AEPS and none of the other use cases are active. The PV system is connected and generating electricity depending on solar insolation levels. The BESS will be operating according to a schedule determined by the microgrid optimization module in the MGMS. Under the Blue Sky Use Case the MGMS will operate the battery to effect peak shaving and energy arbitrage as needed to optimize the objective function. PV may be curtailed during the Blue Sky use case if the export limit of 100 kW is being approached and the battery state of charge is full.

Sequence of Events

Every 15 minutes the MGMS runs the Microgrid Optimization Module (MOM), which results in a battery dispatch schedule for the next 24 hours, in 15 minute increments. To generate the dispatch schedule, the MOM uses the following types of inputs and constraints:

- A 15 minute load forecast results generated by a short term load forecast program that is part of the Siemens MGMS;
- a 15 minute PV system output forecasts generate by a separate program called the Environmental Forecasting and Monitoring Server (EFMS);
- the applicable PG&E rate schedule to determine how to operate the battery to minimize total costs for the subsequent 24 hours;
- a cost curve for operating the BESS;
- an import constraint entered manually into the MGMS for peak shaving; and
- a constraint that specifies that the state of charge (SOC) of the BESS must be the same at the end of the schedule as it was at the beginning of the schedule.

The schedule generated by the optimization is an attempt to minimize operational costs over the next 24 hours. Additional details are provided in subsequent sections where control functions are described in more detail.

Cost curves developed by SERC will be used in the optimization to capture the costs of operating the battery. The optimization does not use a cost curve for the PV system.

Use Case 2: Demand Response

Under the Demand Response Use Case, the microgrid will either reduce the power flow from the PG&E grid or enter a planned islanded state in response to a request from PG&E. The decision to participate in demand response (DR) events is based on favorable economic returns as determined by operators outside the MGMS. BLR does not currently participates in any demand response programs but they may elect to do so in the future. The two types of DR programs that are currently available are described below.

1. **Base Interruptible Program (BIP):** Under the BIP, customer declares a Firm Service Level (in kW) which becomes a cap for maximum import from PG&E during the DR event. Once enrolled in the program, it becomes compulsory for the customer to participate and the customer has to pay penalty if it exceeds the FSL during a DR event. BIP is a **reliability based** DR program initiated during the system emergencies. The notice to participate in a BIP program could be as short as 30 minutes.
2. **Demand Bidding Program (DBP):** Under the DBP, customer participates in a day ahead bidding process and the bids are cleared by PG&E. Successful bids receive further information regarding participation. However, failing to provide DR during the event attracts no penalty and thus the program is voluntary in nature. DBP is a **price responsive** DR program which is initiated whenever system operator foresees abnormal increase in power prices.

Sequence of Events

Planning: Timing and Duration of DR event will be known beforehand so operators can schedule the DR event.

Start: The operator determines if it is necessary to island in order to meet the demand response commitment. If the decision is not to island then the operator uses the import limit function to participate in the demand response event. In response, MGMS will dispatch the battery to reduce the BLRMG demand.

If the decision is to island, then the operator manually islands the microgrid by running a control sequence through the MGMS HMI.

> Note that the operator must also check the "Planned Island" checkbox in the HMI before or within 15 minutes after running the sequence. Otherwise, the MGMS will automatically connect the IEPS with the AEPS fifteen minutes after the PCCCB opens.

Once in islanded mode the MGMS balances loads and generation on the microgrid using a variety of Functions that are explained in Section 5 of this document. At the end of the demand response event, the operator initiates a reconnection sequence using Function 9.

Use Case 3: Nuisance Outage

The Nuisance Outage Use Case addresses short duration PG&E grid outages, which are relatively common in the project area.

Sequence of Events

The Point of Common Coupling Relay (PCCR) detects a deviation in power quality or a fault on the AEPS and opens the Point of Common Coupling Circuit Breaker (PCCCB). This causes the MGMS to initiate a

Schatz Energy Research Center

black start[1] of the IEPS. The decision to black start the microgrid with the BESS or Gen1 is made automatically by the MGMS and depends on the capability of the BESS to form the IEPS on its own at the time of the outage. The MGMS assesses the capability of the BESS to support the IEPS without Gen1 as per Function 4 below. A user specified time period for the expected duration of a nuisance outage is taken into account in the BESS capability assessment. If the BESS can sustain the IEPS for the specified time without Gen1 then the MGMS initiates a Black Start with the BESS. If not, the MGMS initiates a Black Start with Gen 1. After the black start, islanded operation for Use Case No. 2 begins.

The MGMS balances loads and generation on the IEPS and the PCCR monitors the AEPS power quality. After the power quality on the AEPS has been within specified limits continuously for 15 minutes, the PCCR sets a binary register telling the MGMS that it is ok to reconnect the IEPS to the AEPS. The MGMS then initiates a reconnection sequence that includes sending a close command to the PCCR. The PCCR responds by closing the PCCCB, provided that all the conditions and requirements for the closure are satisfied (i.e. dead IEPS bus and live AEPS, or synchronization between IEPS and AEPS).

If the AEPS outage persists and the projected time for restoration of service is lengthy then authorized operators may elect to enter Use Case 3: Emergency by selecting a button on the HMI, which enables load shedding. Operators may then elect to utilize load shedding to reduce diesel consumption during islanded operation and/or extend the duration of IEPS operation.

Use Case 4: Emergency

This use case is intended to address the situation where an extended AEPS outage occurs due to extreme weather, a large earthquake, a tsunami, or other natural event that seriously impacts the AEPS. Under this type of scenario, the microgrid can operate under Use Case No. 4: Emergency. Note that operators may enter the Emergency Use Case though the MGMS HMI when the BLRMG is connected to the AEPS or islanded.

Sequence of Events

The sequence of events typically begins identically to Use Case No. 2: Nuisance Outage. However, operators may elect to enter this use case proactively if they have reason to believe that a long AEPS is likely to occur. The operator puts the MGMS into emergency mode by checking a box through the HMI, which makes the load shed options described in Section 3 available to operators.

As with Use Case No. 2, the MGMS balances loads and generation on the microgrid using a variety of Functions that are explained in Section 5 of this document. When the PG&E grid is restored, the MGMS waits for the operator to initiate a reconnection sequence in the HMI before sending a close command to the PCCR. The PCCR will close the PCCCB if all of the protection requirements are met.

[1] Black Start means energizing the microgrid after an AEPS outage where power is momentarily lost to the entire microgrid except those loads that are backed up by uninterruptable power supplies.

5. Functions

The following section describes the control Functions used by MGMS to control the BLRMG. The Functions are described in relation to the Actors and Use Cases described in Sections 2 and 4, respectively.

A given Function may be used across numerous use cases. The association of Function to Use Cases is provided in Table 5.

Table 5 – Function assocation with Use Cases

Index	Use Case	Function																		
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
1	Blue Sky	X	X	X	X	X	X	X											X	X
2	Demand Response	X	X	X	X	X			X	X	X	X	X	X	X	X	X	X		X
3	Nuisance Outage	X	X	X	X	X			X	X		X	X	X	X	X	X	X		X
4	Emergency Outage	X	X	X	X	X			X	X		X	X	X	X	X	X	X	X	X

Table 6 – Function names and description

#	Function Name	Description
0	Optimal Dispatch	Dispatch of generation resources for optimal returns based on projected load, renewable power, and battery resources.
1	Weather Forecast	MGMS obtains a 24 hour weather forecast from online services.
2	Load Forecast	MGMS uses weather forecast and historical data to predict the power profile demanded by the BLRMG on a 15 minute basis over 24 hours.
3	PV Forecast	MGMS uses weather forecast and historical data to predict PV generation capacity over the next 24 hours.
4	BESS Capability Assessment	Calculated every two seconds in MGMS, this function estimates the battery capability to sustain the microgrid without 1MW Generator.
5	Site Import Control	MGMS signals BESS to meet specified site import set point
6	Site Export Control	MGMS will use BESS, curtail PV, or curtail FC to keep export to PG&E below 100kW
7	Soft Start	JCI EMS self-senses an outage and controls inductive loads. The MGMS then signals to the EMS when to bring back inductive loads in order.
8	Black Start with BESS	Using Function 4, MGMS has determined BESS can form microgrid and uses this function for blackstart
9	Seamless Transition to Island with BESS	For planned islanding, the BESS switches from grid-following to grid-forming operation while opening the PCCCB in a seamless transition.
10	Reconnect to AEPS from BESS IEPS	Make before break using SEL 700GT+ at PCC for active synchronization of BESS to AEPS
11	Connect Gen1 to BESS formed IEPS	Gen1 is brought online to support BESS in IEPS
12	Disconnect Gen1 from IEPS	Gen1 is brought offline because it is not needed to support IEPS
13	Black Start with Gen1	Using Function 4 MGMS has determined BESS can't form microgrid and uses this function for blackstart
14	Reconnect to AEPS seamlessly using BESS	Make-before-break reconnection of the IEPS to the AEPS using a BESS formed IEPS to reconnect.
15	Reconnect to AEPS from Gen1 IEPS	Break before make reconnection of IEPS to AEPS. MGMS sends reconnect command when Gen1 is grid forming. Short outage on microgrid as generator disconnects before PCCCB closes.
16	Gen1 Governance	MGMS will curtail PV, use BESS, or add or shed controllable loads to keep 1MW generator within operational limit set points.
17	Load Control	Five levels of load control are available to the MGMS. Manual input from operator required.
18	Curtail PV	MGMS curtails PV through Modbus communications with inverters.

Actors that participate in each of the function is also an important consideration. Participation in a function requires that an actor changes state or communicates a status as part of the function execution (Table 7).

Table 7 – Function Association with BLRMG Actors

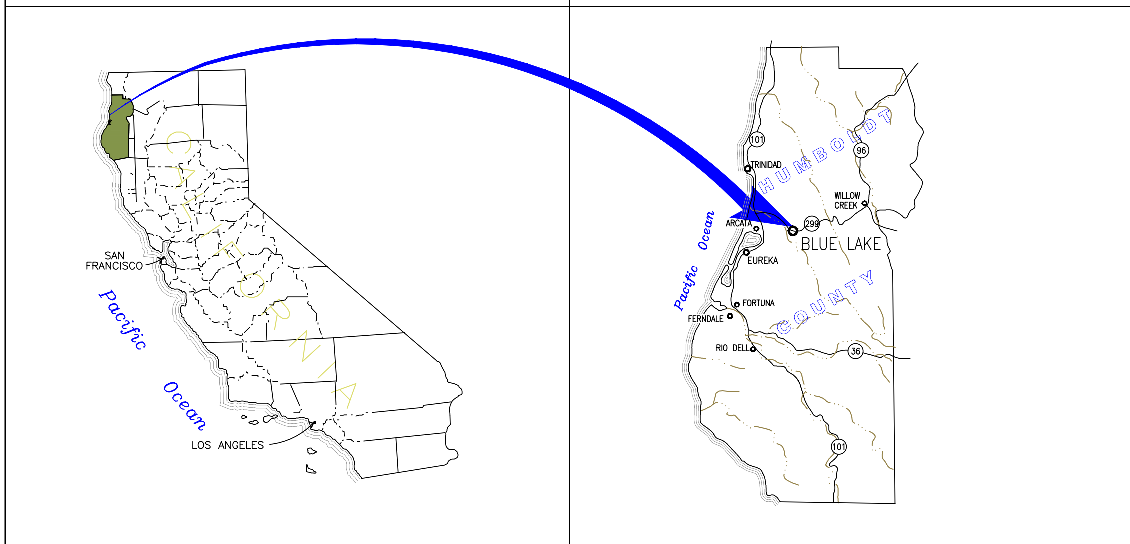
Actors	Functions																		
	0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
Blue Lake Rancheria Microgrid (BLRMG)	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Area Electric Power System (AEPS)	X					X	X			X	X				X	X	X		
Human Machine Interface (HMI)										X								X	
Microgrid Management System (MGMS)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
1 Megawatt Diesel Generator (Gen1)												X	X	X	X	X	X		X
Photovoltaic System (PV)	X			X	X	X	X			X							X		X
Battery Energy Storage System (BESS)	X				X	X	X		X	X	X	X	X			X	X		X
1 Megawatt Automatic Transfer Switch (ATS1)												X	X	X	X	X			X
Generator Synchronization Controller (GCM)												X	X	X	X				
80 kilowatt Automatic Transfer Switch (ATS2)																		X	
Point of Common Coupling Circuit Breaker (PCCCB)										X	X			X	X	X			
Point of Common Coupling Relay (PCCR)					X					X	X		X	X	X	X			
Energy Management System (EMS)					X			X						X	X	X	X	X	
Environmental Forecasting and Monitoring Server (EFMS)	X	X	X	X															
Human Operator (OP)						X	X			X								X	
Distribution Infrastructure (DI)	X				X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Network Infrastructure (NI)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Electric Power Meters		X				X	X												

APPENDIX B:
Listing of Engineering Plan Sheets

SECURE, RELIABLE, LOW-CARBON COMMUNITY MICROGRID AT THE BLUE LAKE RANCHERIA PHASE 1

JUNE 2016

AREA MAP	LOCATION MAP



APPROVALS

SCHATZ ENERGY RESEARCH CENTER PETER LEHMAN, PRINCIPAL INVESTIGATOR	SIGNED	DATE
ELECTRICAL ENGINEER: RICK GUGGIANA, PE, GHD INC.	SIGNED	DATE
BLUE LAKE RANCHERIA JANA GANION	SIGNED	DATE
CIVIL ENGINEER: DAVID CARTER, PE, SERC	SIGNED	6/15/2016 DATE

HUMBOLDT STATE UNIVERSITY

STAMP

BAR IS ONE INCH ON ORIGINAL DRAWING
0 1"

SCHATZ ENERGY RESEARCH CENTER

REV	DATE	DESCRIPTION
4	6/15/2016	PARTIAL RELEASE FOR CONSTRUCTION
3	5/9/2016	90% DESIGN REVIEW
2	1/8/2016	50% DESIGN REVIEW
1	10/9/2015	TECHNICAL TEAM KICKOFF PACKAGE

SECURE, RELIABLE, LOW-CARBON COMMUNITY MICROGRID AT THE BLUE LAKE RANCHERIA

COVER SHEET

PROJ NO: 74837-2
DRWN: DC CHK: –

G-001

SHEET G-001 OF XX

Sheet List Table

Sheet Number	Sheet Title
GENERAL	
G-001	TITLE
G-002	SHEET LIST
G-003	GENERAL AND CIVIL NOTES
G-004	PG&E-INFRASTRUCTURE-PURCHASE-PLAN
ENVIRONMENTAL	
1 OF 1	SWPPP SITE MAP AND EROSION CONTROL PLAN
CIVIL	
C-001	CIVIL LEGEND AND ABBREVIATIONS
C-101	OVERALL CIVIL SITE PLAN
C-201	PCC CIVIL SITE PLAN
C-202	BESS AND PV CIVIL SITE PLAN
C-301	PCC SECTIONS-1
C-302	PCC-SECTIONS-2
C-401	PV ARRAY FIELD PREP PLAN
C-601	CIVIL DETAILS
ELECTRICAL	
E-001	ELECTRICAL LEGEND & ABBREVIATIONS
E-101	OVERALL ELECTRICAL SITE PLAN
E-201	CASINO ELECTRICAL PLAN
E-202	TRIBAL ADMIN OFFICE ELECTRICAL PLAN
E-203	PV SYSTEM CELL ELECTRICAL PLAN
E-204	BATTERY SYSTEM ELECTRICAL PLAN
E-205	PCC SWITCHGEAR ELECTRICAL PLAN
E-501	ELECTRICAL DETAILS
E-601	PCC SWITCHGEAR SINGLE-LINE DIAGRAM
E-602	BLUE LAKE CASINO SINGLE-LINE DIAGRAM
E-603	TRIBAL OFFICE SINGLE-LINE DIAGRAM
E-604	ELECTRICAL THREE-LINE DIAGRAM
E-605	ELECTRICAL NETWORK DIAGRAM
E-606	MISCELLANEOUS DIAGRAMS-1

Sheet List Table

Sheet Number	Sheet Title
PV SYSTEM	
PV-100	GENERAL NOTES
PV-201	RACEWAY LAYOUT
PV-401	EQUIPMENT ENLARGED VIEWS
PV-501	CONSTRUCTION DETAILS
PV-601	SINGLE LINE DIAGRAM
PV-701	EQUIPMENT PLACARDS AND STICKERS
PV-702	EQUIPMENT SPECIFICATIONS
CONTROLLABLE LOADS	
CL-0	CONTROLLABLE LOADS PLAN
CL-1	JOHNSON CONTROLS COVER SHEET
SL-1-1	LEGEND
NR-1-1	NETWORK RISER
GD-1-1	NIE INSTALLATION GUIDE
GD-2-1	NCE INSTALLATION GUIDE
GD-3-1	FEC.IOM INSTALLATION GUIDE
SEQOPS	MAIN SEQUENCE OF OPERATION
AC-1-1	RTU FLOW LAYOUT
CC-1-1	FEC CONTROL OF CONTACTORS CHFD, CLB & CLF
CC-1-2	FEC CONTROL OF CONTACTORS POINT SCHED
EF-1-1	EF FLOW LAYOUT
EF-1-2	EXHAUST FANS POINT SCHEDS
EF-1-3	EXHAUST FANS WIRING DETAILS
GN-1-1	CASINO GENERATOR, ATS
GN-1-2	CASINO GENERATOR, ATS POINT SCHED
GN-2-1	TRIBAL OFFICE GENERATOR, ATS
GN-2-2	TRIBAL OFFICE GEN, ATS POINT SCHED
JS-1-1	JCI-SIEMENS INTEGRATION

HUMBOLDT STATE UNIVERSITY
Sponsored Programs Foundation

REGISTERED PROFESSIONAL ENGINEER
DAVID JOHN CARTER
C74837
STATE OF CALIFORNIA

STAMP

BAR IS ONE INCH ON ORIGINAL DRAWING
0 1"

SCHATZ ENERGY RESEARCH CENTER

REV	DATE	DESCRIPTION
4	6/15/2016	RELEASED FOR CONSTRUCTION
3	5/9/2016	90% DESIGN REVIEW
2	1/8/2016	50% DESIGN REVIEW
1	10/9/2015	TECHNICAL TEAM KICKOFF PACKAGE

SECURE, RELIABLE, LOW-CARBON
COMMUNITY MICROGRID AT THE
BLUE LAKE RANCHERIA

--
SHEET LIST
--

PROJ NO: 74837-2
DRWN: DC CHK: --

G-002

SHEET G-002 OF XX

APPENDIX C:
Major Component Specification List

Equipment	Acronym	Description	Quantity	Make	Model	Vendor	Key Specifications	Existing (E) vs. New (N)	Procured (Y/N)
PCC Switchgear Unit		metal-encloser, 3 cabinet	1	Eaton	MEB	Eaton	main bus: 15 kV, 600 A	N	Y
	PCCB	vacuum circuit breakers	2	Eaton	150-VCP-W 500	Eaton	15 kV rms, 1200 A, control 48 Vdc	N	Y
PCC Battery System		utility style, 6 Vdc batteries	8	Enersys	PowerSafe 3CC-03M	Sierra Utility	50 Ah capacity	N	Y
		float battery charger	1	Enersys	AT10.1	Sierra Utility	120 VAC, 6 A, 48VDC output	N	Y
PCC Relay	PCCR	Point of common coupling relay	2	SEL	SEL-700GT	Schweitzer Engineering Laboratories		N	Y
1 MW Diesel Generator	Gen1	Casino Diesel Generator	1	Cummins	Model KTA38-G1	-	1 MW	E	N
Gen1 Automatic Transfer Switch	ATS1	Automatic Transfer Switch Controller	1	Eaton	ATC-900	Eaton	120 Vac control power, 120-600Vac 1 or 3 phase application, programmable	N	Y
	ATS1	Automatic transfer switch	1	Cutler-Hammer	ATVISPB31600XKU	-	3-pole, 4-wire, 1600 A, 480 V, 60 Hz	E	N
	RGC	Remote generator controller I/O module	1	SEL	SEL-2505	Schweitzer Engineering Laboratories	Mirrored Bits®communication via fiber optic	N	Y
80 kW Diesel Generator	Gen2	Tribal office Diesel Generator	1	Cummins	Model DGDA-5750375	-	80 kW	E	N
Gen2 Automatic Transfer Switch	ATS2	Power Command Transfer Switch	1	Cummins	OTPCC-5750376	-	Opr V 208, Max AC V 600, 400 AC Amps, 1 or 3 phase	E	N
BESS/PV Switchgear		metal enclosures		Culter-Hammer		WBCo Electric Service	480Y/277V, 3 phase, 3000A, 65k AIC	N	Y
		AC power circuit breakers	3	Cutler-Hammer		WBCo Electric Service	600 VAC, (1) 1500A, (2) 800A	N	Y
Pad-mounted Transformer		Step-up transformer for BESS and PV System	1	Eaton	Cooper Power Series	Campton Electric	1000 kV A, 480V to 12.5kV, 3000 A, 3-phase	N	Y
Battery Energy Storage System	BESS	bi-directional inverter	2	Dynapower	MPS-250	Tesla	250 kW continuous	N	Y
		Powerpack battery system	2	Tesla		Tesla	500kWh energy, 2 hr @ 250 kW cont. net discharge, or 4 hr @ 125 kW cont. net discharge	N	Y
Photovoltaic System	PV	photovoltaic module	1,548	SolarWorld	Sunmodule SW 325 XL	REC Solar	325 Wp	N	Y
	PV	three-phase inverter	14	SMA	Sunny Tripower 30TL-US	REC Solar	30 kW	N	Y
	PV	AC subpanel w/ breakers	1	Eaton		REC Solar	800A/600V (1) 700A/3p main, (14) 50A/3p PV	N	Y
	PV	AC disconnect	1	Square D		REC Solar	800A/600V	N	Y
	PV	Net generation output meter socket	1	Cooper B Line		REC Solar	800A/600V	N	Y
	PV	Monitoring system	1	Meteo Control	blue'Log X-3000	REC Solar	irradance sensor, pyranometer, hygro thermo sensor and module temperature sensor	N	Y
Microgrid Management Control System	MGMS	custom industrial controller	1	Siemens	Spectrum Power™ MGMS	Siemens		N	Y
Energy Management System	EMS	JCI EMS system, allows control of non-critical HVAC loads, Gen2/ATS2, Twilight gaming load	1	Johnson Controls	Metasys®	Johnson Controls		N	Y
Switchgear		Pad mounted switchgear	1	S&C Electric Co.	PMH-9	-	25 kV, 600A	E	N
Pad-mounted Transformer		Distribution transformer	1	ABB		-	12.5 kV to 480V, 1000 kVA, 3ph	E	Y
Pad-mounted Transformer		Distribution transformer	1	Howard Industries		-	12.5 kV to 480V, 1000 kVA, 3ph	E	Y
Pad-mounted Transformer		Distribution transformer	1	ABB		-	12.5 kV to 208V, 75 kVA	E	Y
Electric Power Meters	Meters	Power and Energy Meters	7	Acuvim	IIR	Accuenergy		N	Y

APPENDIX D:
Listing of Microgrid Actors

Supervisory Actors

Supervisory actors provide protection, control, data acquisition and forecasting functionality. Supervisory actors within the BLRMG include the SEL-700GT protection relay and the Siemens' MGMS.

SEL-700GT Protection Relay

Two SEL-700GT protection relays are used to provide basic protection between the BLRMG and the utility. The primary relay provides basic protection and a high level of supervisory control. The secondary relay only provides basic protection in case the primary relay fails.

Features

The SEL-700GT protection relay forms the basis for the BLRMG protection logic for the PCC-CB, Gen1, and ATS1 control. The SEL-700GT has been programmed to provide:

- Protection
    - Ensures BLRMG is disconnected from the utility when a voltage or frequency disturbance is detected
    - Ensures Gen1 cannot be connected to the microgrid through ATS1 when the PCC-CB is closed
    - Ensures BLRMG cannot reconnect to the utility when Gen1 is connected to the microgrid
    - Ensures Siemens MGMS cannot command PCC-CB, Gen1, or ATS1 when the MGMS is flagged as unresponsive by the SEL-700GT

- Control
    - If the MGMS is flagged as unresponsive, when grid power fails, the SEL relay will start Gen1 and close ATS1.
    - If the MGMS is flagged as unresponsive when the utility is energized, the SEL relay will monitor utility side stability for 15 minutes before disconnecting Gen1 and closing the PCC-CB.

System Interface

The SEL-700GT relays are located at the PCC. The primary relay has data connections with several actors including:

- SEL-2505
- BESS Site-Master-Controller
- Siemens MGMS
- Utility Bus
- Microgrid Bus

Communications used between the SEL-700GT and other actors include:

- Mirrored-bits data link
- Modbus TCP
- DNP3
- Analog sensors

Siemens MGMS

The Siemens Microgrid Management System (MGMS) is a Supervisory Control and Data Acquisition (SCADA) platform. The MGMS is based on Siemens Spectrum 7 software suite.

Features

The MGMS allows for operator control and autonomous control that is optimized for a forecasted planning horizon.

- Protection
    - Generation monitoring and interlocks
    - Export limit control/PV curtailment
    - Import limit control

- Control
    - Optimal generation dispatch
    - Frequency and voltage regulation in islanded mode (when grid is formed by BESS)
    - Load sharing in islanded mode (when BESS in parallel with Gen1)
    - Manual operator control
    - Load shed capability
    - Development of event sequences

- Data Acquisition
    - Historian
        - Weather
        - Generation
        - Loads
        - Actor States

- Forecasting
    - Near-term load forecasting
    - PV generation forecasting

System Interface

The MGMS is hosted on BLR's servers and is accessible by authorized operators from multiple terminals located on the BLR campus. The MGMS has networked connections with nearly all actors within the microgrid including:

- MGMS HMI for operator monitoring and control
- Tribal office, casino, and hotel load meters
- EFMS
- SMA PV inverters
- Weather station via PV system data logger

- PV System output meter
- JCI EMS
- Gen1 meter
- BESS output meter
- BESS Site Master Controller
- SEL-700GT relay
- Main site meter (PCC)
- GPS clock
- Switchboard watchdog

The communication protocols involved include:

- DNP3
- Modbus TCP
- other

Autonomous Actors

Autonomous actors provide actions for the microgrid without having to accept external commands to perform the actions. In the case of the BLRMG, these actors are primarily concerned with forecasting and data acquisition.

Environmental Forecasting and Monitoring System (EFMS)

The EFMS is tasked with providing weather and PV generation forecasts every hour.

Features

- Forecasting - PV generation by inverter and forecasted weather are provided on a 15-minute sampling interval once per hour.
- Data Acquisition - Observations and forecasted data from multiple sources are compiled into a database hosted on the EFMS.

System Interface

The EFMS uses two networked connections. A connection to the internet is used for forecasted data from Weather Underground and Solar Anywhere to populate the weather and PV generation forecasts. It is planned that weather observations will also be sent to Weather Underground to improve weather forecasting.

EFMS also provides two networked directories to the MGMS. The MGMS can access forecasted data and report weather observations via these directories.

Weather Station/PV Data Logger

The weather station/PV data logger is part of the PV data logging system.

Features

The weather station/PV data logger's role is data acquisition. Ambient temperature, humidity, plane-of-array irradiance, and generation data (power, current, voltage) for each of the PV inverters are logged.

System Interface

These data are reported to REC Solar through an internet connection and are also provided to the Siemens MGMS through a local network connection.

Power Meters

Several power meters are located throughout the BLRMG. These meters include: casino meter, hotel meter, tribal office meter, Gen1 meter, BESS output meter, PV meter and main site meter at the PCC.

Features

The power meters are used to collect power flow and quality data (voltage, current, power, frequency, power factor) on the BLRMG.

System Interface

All meters connect to the BLR network and communicate with other devices on the network via Modbus TCP.

GPS Clock

The GPS clock serves to keep the Siemens MGMS system clock calibrated to the international time standard. It also provides a uniform time reference to other devices on the network with an internal clock.

Features

The GPS clock receives and reports the international time standard to calibrate the Siemens MGMS clock.

System Interface

The GPS clock is interfaced to the Siemens MGMS and other devices through NTP.

Semi-Autonomous Actors

Semi-autonomous actors are capable of making independent control decisions, but are also subject to external commands. The SMA solar inverters and Tesla battery system provide semi-autonomous services.

SMA PV Inverters

The SMA PV inverters are capable of acting autonomously by detecting and responding to the available DC power from the PV arrays, as well as to the state of the AC electric grid. If the AC voltage or frequency is out of range the inverters will disconnect from the AC bus. The PV inverters are also capable of accepting commands from the Siemens MGMS for additional control options.

Features

- Protection - The inverters have the following protection features and they will disconnect from the AC bus if the AC power characteristics are too far out of range. The activation set points associated with each of these protection features are adjustable. Because the BLRMG utilizes SEL-700GT protection relays and these relays provide over- and under- voltage and frequency protection, the corresponding PV inverter protection settings have been relaxed from the IEEE 1547-2003 standards.

    - Anti-Islanding
    - Over-current
    - Over/under voltage and frequency
    - DC reverse polarity
    - Ground fault
- Generation
    - The SMA PV inverters are grid-following with maximum power point (MPP) tracking capabilities. When sufficient solar radiation is available to the PV modules and the inverters are connected to a live grid, the PV inverters will seek to maximize the power output for the given conditions.
- Control
    - Power Output Curtailment – Control signals are sent from the MGMS to the PV inverters to curtail output power when necessary for grid stability purposes.
- Data Acquisition

System Interface

The SMA PV Inverters are networked to the Siemens MGMS and the SMA Cluster Controller. The MGMS sends commands to the inverters and receives status values from the inverters using Modbus TCP. Two-way communications between the SMA Cluster Controller and the inverters use Speedwire. Speedwire is a wired, Ethernet based fieldbus for the implementation of powerful communication networks in decentralized large-scale PV power plants.

SMA Cluster Controller

The SMA cluster controller provides a centralized interface for the distributed PV power plant.

Features

The cluster controller is a central control and communications hub for all 14 of the PV inverters. In addition to control and communications, the cluster controller also facilitates data acquisition.

- Control
    - Configuration of operating parameters depending on inverter capabilities and user permissions.
- Communications
    - Distribution of commands to the PV inverters
- Data Acquisition
    - Reporting of system performance data to Sunny Portal via Internet

System Interface

The SMA cluster controller is connected to the BLR network and can be accessed directly with a web browser to monitor or modify PV inverter parameters. The SMA Cluster Controller communicates with the 14 SMA PV inverters via Speedwire.

TESLA BESS

The BESS consists of a Site Master Controller (SMC), two four-quadrant inverters, and ten battery energy storage modules. The SMC is the main control unit for the BESS; it accepts external commands and controls inverter output and battery charging. The SMC also provides autonomous features and protection for the battery and the microgrid.

Features

The primary features of the BESS system are:

- Control
    - The SMC is capable of requesting changes in the PCC-CB state through requests routed to the SEL relay.
    - The SMC can switch the BESS between grid-following and grid-forming operating modes.
- Generation
    - The battery can be discharged to provide real and reactive power to the microgrid.
- Load
    - The battery can be charged to add real and reactive load to the microgrid.
- Protection
    - Overcurrent protection
    - Ground fault protection
    - Over/under voltage
    - Over/under frequency

System Interface

Tesla's SMC is the main network interface between the BESS and other actors within the BLRMG. Networked connections include:

- BESS output meter
- Siemens MGMS
- SEL-700GT

The communication protocols involved include Modbus TCP and others.

ATC900/ATS1

The ATC900 is primarily concerned with the connection/disconnection of the 1 MW generator. ATS1 is the automatic transfer switch (ATS) for Gen1 under control of the ATC900.

Features

- Protection (synchronization check for Gen1)
- Control of 1 MW generator
    - Connection to microgrid
    - Disconnection from microgrid
    - Weekly exercise of Gen1

System Interface

The ATC900/ATS1 communicates with several actors within the BLRMG through digital input/output.

- SEL-2505 commands connection and disconnection of ATS1 through relay output signals to ATC900 and receives ATS position signals via digital input signals from ATS1.
- 1 MW Generator receives Start/Stop commands from ATC900 through digital input/output and directly from SEL-2505.

Gen1

The 1 MW generator is an isochronous generator. This class of generator operates autonomously; its controls ensure the generator operates near 60Hz by adjusting its power output. This set point is not adjustable. Gen1 primarily receives start and stop commands from the SEL-2505, and provides a fault signal through the SEL-2505.

Features

- Generation
    - Gen1 delivers real and reactive power to meet the microgrid power demands and maintain a stable voltage and frequency. The power output of Gen1 cannot be directly controlled.
    - Gen1 has an internal automatic cooldown period of 5 minutes during which it will continue to run in an idle state after any time it is commanded to stop.

System Interface

Gen1 is interfaced with and controlled by the SEL-2505 through digital input/output signals.

ATS2

ATS2 is the automatic transfer switch (ATS) for Gen2, which serves the Tribal office as a backup power source. The office loads can be connected to either the microgrid or to Gen2 to receive power. Gen2 cannot be connected to the rest of the microgrid.

Features

- Control
    - Connects the office loads to either Gen2 or to the microgrid
    - Starts/stops Gen2

System Interface

The ATS2 transfer switch has its own controller that can receive signals from the MGMS via relay input/output from the JCI EMS.

Gen2

The 80 kW generator located at the tribal office is used in combination with ATS2 to isolate the tribal office from the rest of the microgrid while continuing to provide electric power service.

Features

- Generation
    - Gen2 delivers real and reactive power to meet the power demands of the tribal office circuit and to maintain a stable voltage and frequency. The power output of Gen2 cannot be directly controlled.

System Interface

Gen2 is interfaced to ATS2 through digital input/output signals. ATS2 provides start/stop signals. No signal feedback is provided to ATS2.

JCI-EMS

The JCI EMS is responsible for actuating casino load control and serves as an intermediary to control Gen2.

Features

- Control
    - Gen2 through ATS2
    - Casino controllable loads (non-critical HVAC, non-critical ventilation, Twilight Room gaming)
- Data Acquisition
    - Casino climate control zone temperatures and compressor status
    - Casino controllable load status
    - PCC battery alarm

System Interface

The JCI EMS has a network connection with the MGMS that requires the use of a protocol converter. The MGMS sends and receives DNP3 and Modbus TCP data over the network, whereas the JCI EMS receives and sends BACnet via the network. A protocol converter is used to convert Modbus TCP to BACnet for commands sent from the MGMS, and the operational data reported by the EMS is converted from BACnet to Modbus TCP.

The JCI EMS also uses digital I/O, analog inputs, and mesh wireless communication to communicate with various field devices. This includes relays to control HVAC and ventilation fan loads and ATS2, thermostats to monitor zone temperatures, and digital signals to indicate circuit breaker positions, compressor status and PCC battery alarm status.

Controlled Actors

Controlled actors are components that only act upon the command of a supervisory actor. The controlled actors respond to commands and report back their status to supervisory controllers.

SEL-2505

The SEL-2505 is a communications module that receives and transmits information between the SEL-700GT, ATC900, ATS1, and Gen1.

Features

The SEL-2505 is a communications interface between the SEL-700GT located at the PCC and the ATC900/ATS1 and Gen1. It provides for communication of commands and status between components.

System Interface

The SEL-2505 mirrors data between the SEL-700GT and devices associated with Gen1. The SEL-2505 communicates with the SEL-700GT via fiber optic line and with the ATC900, ATS1, and Gen1 via digital input/outputs.

PCC-CB

The PCC-CB is a physical circuit breaker located at the point of common coupling.

Features

- Control
    - The PCC-CB is controlled by the SEL-700GT. When the PCC-CB is closed the microgrid operates in parallel with the PG&E grid. When the PCC-CB is open the microgrid operates in island mode.

System Interface

The PCC-CB is controlled by the SEL-700GT, which uses relay outputs to actuate the PCC-CB.

APPENDIX E:
PV Array Performance

Table E.1: Observed PV Array Performance in 2017 by Month and Subarray

Sub-Array	Units	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1	MWh	2.83	2.25	2.68	4.27	5.21	5.23	5.90	5.69	4.87	4.93	1.50	3.14	48.50
2	MWh	2.66	2.07	2.51	4.25	5.07	5.18	5.50	5.72	4.91	4.95	1.59	2.88	47.29
3	MWh	2.31	1.92	2.94	3.91	4.88	4.45	1.30	4.34	3.42	3.05	1.19	2.33	36.03
4	MWh	2.23	1.96	2.93	2.13	4.93	4.52	4.58	4.78	4.33	4.26	1.41	2.57	40.62
5	MWh	2.27	1.97	2.97	2.14	4.90	4.32	1.38	5.08	4.36	4.37	1.44	2.56	37.77
6	MWh	2.11	1.96	2.95	2.15	4.92	4.50	5.33	5.04	4.33	4.33	1.42	2.56	41.61
7	MWh	2.32	1.95	2.76	3.90	4.87	4.69	5.32	4.88	4.29	4.28	1.41	2.53	43.20
8	MWh	2.37	1.97	2.96	3.94	4.92	4.66	5.26	4.91	4.15	4.13	1.39	2.59	43.24
9	MWh	2.36	1.97	2.97	3.92	4.88	4.62	5.12	4.95	4.13	3.89	1.40	2.57	42.78
10	MWh	2.37	1.89	3.02	3.92	4.90	4.67	5.21	4.97	4.29	4.34	1.45	2.59	43.61
11	MWh	1.85	1.96	3.07	3.93	4.90	4.71	5.34	5.01	4.28	4.37	1.44	2.46	43.32
12	MWh	2.32	1.95	2.55	3.35	4.90	4.70	5.28	4.90	4.24	4.27	1.40	2.53	42.38
13	MWh	2.36	1.97	2.61	3.37	4.81	4.06	5.29	4.92	4.25	4.32	1.43	2.59	41.99
14	MWh	2.37	1.97	2.55	3.35	4.81	4.14	5.26	4.89	4.19	4.27	1.43	2.58	41.82
Total	MWh	32.72	27.76	39.47	48.52	68.90	64.46	66.07	70.08	60.04	59.74	19.89	36.49	594.15
POA Irradiance	kWh /m2/day	2.47	2.21	3.51	4.95	6.47	5.86	7.20	5.96	5.19	4.92	2.06	2.89	4.49

Source: Schatz Energy Research Center

Table E.2. PV Capacity Factors* by Subarray and Month for 2017

Sub-Array	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1	12.7%	11.2%	12.0%	19.8%	23.4%	24.2%	26.4%	25.5%	22.6%	22.1%	6.9%	14.1%	18.5%
2	11.9%	10.2%	11.2%	19.7%	22.7%	24.0%	24.6%	25.6%	22.7%	22.2%	7.4%	12.9%	18.0%
3	10.3%	9.5%	13.2%	18.1%	21.9%	20.6%	5.8%	19.4%	15.8%	13.7%	5.5%	10.4%	13.7%
4	10.0%	9.7%	13.1%	9.9%	22.1%	20.9%	20.5%	21.4%	20.1%	19.1%	6.5%	11.5%	15.5%
5	10.2%	9.8%	13.3%	9.9%	22.0%	20.0%	6.2%	22.8%	20.2%	19.6%	6.7%	11.5%	14.4%
6	9.4%	9.7%	13.2%	10.0%	22.0%	20.9%	23.9%	22.6%	20.1%	19.4%	6.6%	11.5%	15.8%
7	10.4%	9.7%	12.4%	18.0%	21.8%	21.7%	23.8%	21.9%	19.9%	19.2%	6.5%	11.4%	16.4%
8	10.6%	9.8%	13.3%	18.2%	22.0%	21.6%	23.6%	22.0%	19.2%	18.5%	6.4%	11.6%	16.5%
9	10.6%	9.7%	13.3%	18.1%	21.9%	21.4%	22.9%	22.2%	19.1%	17.4%	6.5%	11.5%	16.3%
10	10.6%	9.4%	13.5%	18.1%	21.9%	21.6%	23.3%	22.3%	19.9%	19.4%	6.7%	11.6%	16.6%
11	8.3%	9.7%	13.7%	18.2%	21.9%	21.8%	23.9%	22.4%	19.8%	19.6%	6.6%	11.0%	16.5%
12	10.4%	9.7%	11.4%	15.5%	22.0%	21.8%	23.6%	22.0%	19.6%	19.1%	6.5%	11.3%	16.1%
13	10.6%	9.8%	11.7%	15.6%	21.6%	18.8%	23.7%	22.0%	19.7%	19.3%	6.6%	11.6%	16.0%
14	10.6%	9.8%	11.4%	15.5%	21.6%	19.2%	23.6%	21.9%	19.4%	19.1%	6.6%	11.6%	15.9%
Total Array	10.5%	9.8%	12.6%	16.0%	22.1%	21.3%	21.1%	22.4%	19.9%	19.1%	6.6%	11.7%	16.1%

* Capacity Factor = (Actual kWh Produced)/(days_per_month*24*30kW)

Source: Schatz Energy Research Center

Table E.3. Percentage Difference in Subarray Energy Production with Respect to Estimated Production. (Note: Highlighted Cells Are Extreme Outliers*)

Sub-Array	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1	4.5%	-1.5%	-21.6%	0.2%	-8.6%	-0.8%	-3.4%	-0.6%	-1.5%	-1.1%	-8.7%	4.8%	-0.8%
2	-1.5%	-9.7%	-26.8%	-0.2%	-11.1%	-1.7%	-9.9%	0.0%	-0.9%	-0.6%	-3.1%	-3.7%	-3.3%
3	-0.6%	-2.1%	0.2%	7.1%	-0.1%	-1.4%	-75.1%	-11.7%	-19.4%	-28.6%	-15.7%	-9.3%	-14.0%
4	-3.9%	-0.2%	-0.2%	-41.6%	0.8%	0.2%	-12.4%	-2.6%	2.1%	-0.3%	0.2%	0.1%	-3.1%
5	-1.9%	0.4%	1.2%	-41.2%	0.2%	-4.3%	-73.7%	3.5%	2.8%	2.3%	2.2%	0.0%	-9.9%
6	-9.0%	0.2%	0.5%	-41.1%	0.6%	-0.2%	1.9%	2.7%	2.1%	1.4%	1.1%	-0.2%	-0.7%
7	0.1%	-0.3%	-6.1%	6.8%	-0.3%	3.8%	1.7%	-0.5%	1.1%	0.3%	-0.2%	-1.2%	3.1%
8	2.2%	0.6%	0.8%	8.0%	0.6%	3.3%	0.5%	0.0%	-2.2%	-3.3%	-1.5%	0.9%	3.2%
9	1.7%	0.3%	1.3%	7.4%	-0.2%	2.4%	-2.1%	0.9%	-2.6%	-8.9%	-0.4%	0.0%	2.1%
10	2.3%	-3.8%	3.0%	7.3%	0.1%	3.5%	-0.5%	1.3%	1.1%	1.5%	3.1%	1.1%	4.1%
11	-20.2%	0.3%	4.5%	7.7%	0.2%	4.3%	2.1%	2.0%	1.0%	2.4%	2.0%	-4.1%	3.4%
12	-0.1%	-0.5%	-13.1%	-8.3%	0.3%	4.2%	0.9%	-0.1%	-0.1%	0.0%	-0.9%	-1.3%	1.1%
13	2.0%	0.4%	-11.0%	-7.7%	-1.6%	-10.0%	1.1%	0.2%	0.1%	1.1%	1.7%	1.1%	0.2%
14	2.1%	0.6%	-13.0%	-8.1%	-1.6%	-8.2%	0.6%	-0.4%	-1.1%	0.0%	1.2%	0.7%	-0.2%

* NIST (2018) Extreme outliers are identified as being less than (median - 3*interquartile range).

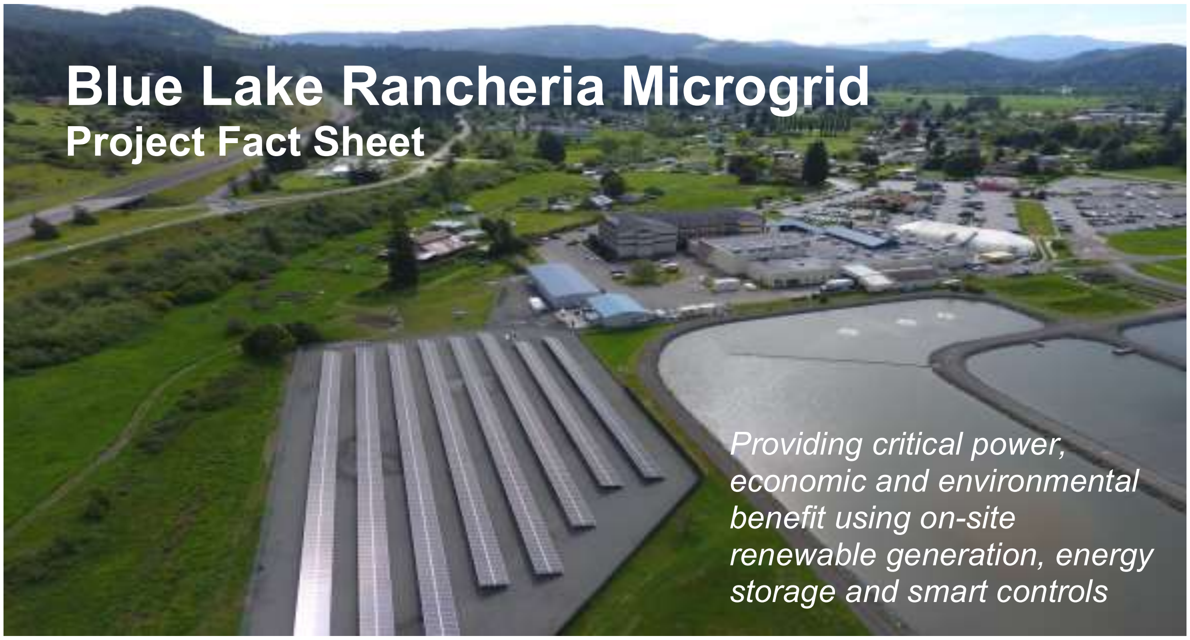
Source: Schatz Energy Research Center

Table E.4. MWh of Energy Production Lost to Communication Glitches in 2017 by Subarray and Month

Month	SA1	SA2	SA3	SA4	SA5	SA6	SA7	SA8	SA9	SA10	SA11	SA12	SA13	SA14	Array
Jan	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
Feb	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
Mar	0.002	0.000	0.004	0.004	0.007	0.000	0.007	0.000	0.004	0.000	0.004	0.000	0.000	0.000	0.032
Apr	0.003	0.003	0.000	0.003	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.002	0.000	0.000	0.015
May	0.000	0.001	0.001	0.002	0.000	0.001	0.002	0.001	0.000	0.002	0.001	0.001	0.001	0.000	0.014
Jun	0.076	0.074	0.047	0.049	0.049	0.048	0.048	0.049	0.049	0.052	0.049	0.047	0.048	0.047	0.730
Jul	0.018	0.010	0.001	0.005	0.000	0.003	0.001	0.001	0.002	0.008	0.001	0.000	0.001	0.001	0.049
Aug	0.003	0.009	0.003	0.000	0.000	0.001	0.000	0.002	0.001	0.002	0.000	0.000	0.000	0.003	0.026
Sep	0.011	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.001	0.000	0.000	0.000	0.000	0.000	0.018
Oct	0.002	0.000	0.000	0.001	0.001	0.000	0.000	0.001	0.007	0.000	0.002	0.002	0.004	0.000	0.020
Nov	0.001	0.002	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.008
Dec	0.000	0.005	0.001	0.001	0.000	0.001	0.002	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.012
Yr	0.116	0.106	0.058	0.066	0.058	0.053	0.061	0.058	0.066	0.066	0.058	0.053	0.054	0.052	0.927

Source: Schatz Energy Research Center

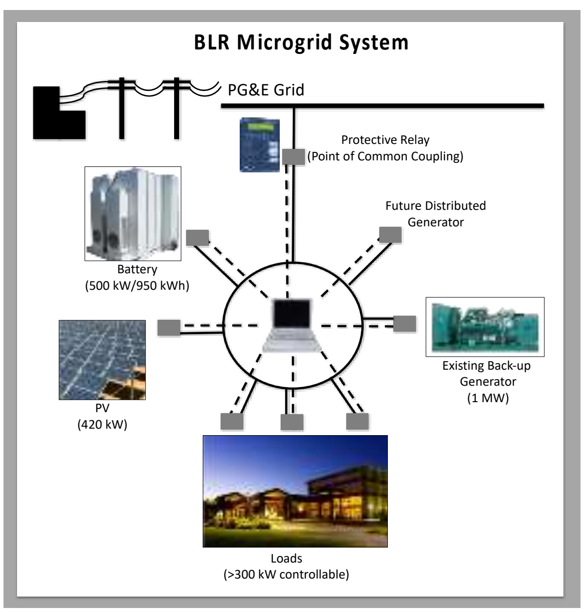
APPENDIX F:
Final Project Fact Sheet



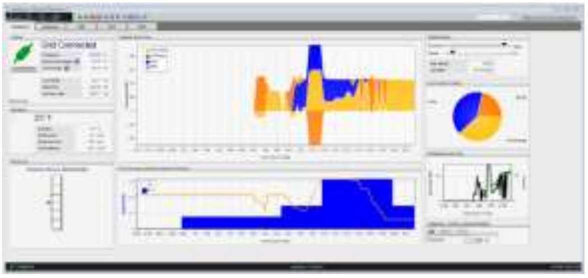
Credit: Blue Lake Rancheria

The Issue
Humboldt County is a natural disaster-prone region of California with a majority of power generation assets in the coastal tsunami zone and constrained transmission from the greater California electric grid. Energy resiliency is a serious concern to the local community, and planning efforts have emphasized a need to expand sources of longer-term backup energy generation at critical facilities.

The Project
Microgrids that deploy renewable power generators and energy storage can increase a community's resilience while also reducing its carbon footprint, providing both climate change adaptation and mitigation benefits. The Blue Lake Rancheria (BLR) Low-Carbon Community Microgrid Project has demonstrated a robust, renewable-based microgrid system that provides critical power during emergencies (including power to a nationally-recognized Red Cross evacuation center), as well as economic and environmental benefits during blue sky conditions.



Component Specifications	
PV System	420 kW, Solar World 325 XL Mono PV modules, SMA TP 30-TL-US-10 inverters
Battery Storage	500 kW / 950 kWh, Tesla Powerpack system w/ Dynapower 250 kW inverters
Microgrid Controller	Siemens Spectrum Power™ MGMS
PCC Protective Relay	Schweitzer Engineering Laboratories SEL-700GT+



System Operation

Blue Sky Conditions

The BLR microgrid runs in parallel with the utility grid. The solar electric generator provides on-site power to offset energy use from the grid, with a special focus on reducing power purchases during high priced periods. Battery storage is used to further offset peak power purchases and reduce peak demand charges. The microgrid can be placed in island mode to respond to demand response events.

Grid-Outage Scenario

When an electric grid outage occurs, the microgrid goes into island mode, continuing to provide power for on-site loads. For short duration outages, the battery can form the grid, with support from the solar generator. In the event of a long duration outage and a low battery state-of-charge, an existing 1 MW back-up generator will form the grid with support from the solar generator. As needed, non-critical loads will be shed to maintain microgrid stability. Planned seamless transitions to and from the grid are possible.

Project Highlights

- Saved $160,000 in 2017, a 25% electricity cost savings; $190,000 of savings are expected in 2018.
- On-site PV power met 15% of the total load and reduced greenhouse gas emissions by 158 metric tons CO_2e; due to operational improvements, a reduction of 170 metric tons CO_2e is expected in 2018.
- Provided reliable, unattended back-up power during numerous grid outages.
- Demonstrated seamless island and seamless reconnection capabilities.
- Demonstrated a foundational control system that provides critical redundancy and allowed for a smooth installation and commissioning period.
- Increased the resilience of a nationally recognized Red Cross evacuation center and demonstrated the ability to island for extended periods.
- Increased Tribal employment by 10% and provided induced and indirect economic benefits.
- Generated extensive media, public outreach and education opportunities. Received FEMA's 2017 Whole Community Preparedness Award and DistribuTECH's 2018 Project of the Year for DER Integration Award.
- Project completed on time and on budget.

Project Specifics

Contractor:	Schatz Energy Research Center, Humboldt State University
Partners:	Blue Lake Rancheria, PG&E, Siemens, Tesla Motors, REC Solar, Idaho National Laboratory, GHD
Funding:	$5,000,000 - Energy Commission Agreement EPC-14-054 $1,318,000 - Match funding from project team
Timeline:	July 2015 – March 2018
Energy Commission Agreement Number: EPC-14-054	
Contact: Dave Carter, P.E., email: serc@humboldt.edu	

APPENDIX G:
Monthly Outreach Activities

September 2015

- A microgrid project groundbreaking celebration event was held. Attendees included California Energy Commissioner Karen Douglas, U.S. Congressman Jared Huffman, Humboldt State University President Lisa Rossbacher, U.S. Department of Energy Director of Indian Energy Chris Deschene, PG&E Regional Manager Carl Schoenhofer, Siemens Director of Energy Automation Patrick Wilkinson, and many others (regional leaders, community members, industry colleagues, and regional/industry media outlets). The event generated uniformly positive publicity for microgrids and project partners.
- Jana Ganion conducted a presentation on this microgrid project at the U.S. Department of Energy's National Tribal Energy Summit in Washington D.C. Many tribal governments and communities are interested in and/or implementing microgrids with distributed generation renewable power sources, and the project was well-received.
- U.S. Department of Energy Commercial-scale Renewable Energy Development and Finance Workshop, at the National Renewable Energy Laboratory, Golden, CO, September 1, 2015

October 2015

- Jana Ganion conducted a presentation on this microgrid project at the U.S. Environmental Protection Agency within a training on the Clean Power Plan (CPP) for tribal governments. Because tribal governments are interested in and/or implementing microgrids with distributed generation renewable power sources that qualify for potential economic support under the CPP, the information was useful and timely.

November 2015

- Jana Ganion conducted presentations on this microgrid project at the following events/forums:
    - Silicon Valley Leadership Group, "Grid of the Future Summit," November 12, 2015, Santa Clara, CA
    - U.S. Department of Energy/Western Area Power Administration, 2015 DOE Tribal Renewable Energy Webinar Series: "EPA's Clean Power Plan: What Tribes Need to Know"
    - Climate Action Champion Program Case Study and End-of-Year Report

January 2016

- Jana Ganion reported on the project at the U.S. Department of Energy, Office of Indian Energy, Indian Country Energy and Infrastructure Working Group Quarterly Meeting in Seminole, Florida.
- SERC/BLR/Serraga staff drafted, revised and completed the Project Fact Sheet.

February 2016

- Jana Ganion reported on the project at the U.S. Department of Energy, Office of Indian Energy, Renewable Energy Project Development and Finance Workshop, Feb. 9–11, 2016, in Palm Springs, CA.
- Serraga/BLR staff presented on microgrid support of EV infrastructure at Clean Cities Symposium in Eureka, CA, 2/25/16.

March 2016

- Serraga/BLR staff presented on the project to two regional Northern California tribal governments who are interested in pursuing microgrids.

April 2016

- Serraga/BLR staff presented on the microgrid project to one regional Northern California tribal government interested in pursuing microgrids
- SERC/Serraga/BLR staff conducted microgrid tours to ~12 STEM students from Hoopa High School; and Humboldt State University Environmental Engineering students (~28 students).

May 2016

- Jana Ganion presented on the Microgrid Project at the U.S. Department of Energy Indian Energy Webinar Series, national webinar, May 4, 2016.
- Jana Ganion presented on the Microgrid Project at the U.S. Department of Energy Quadrennial Energy Review public stakeholder meeting in Los Angeles, CA, May 10, 2016.
- Serraga/BLR staff presented on the microgrid project to two regional Northern California tribal governments interested in pursuing microgrids.
- BLRMG project was also featured on the USDOE Office of Indian Energy blog

June 2016

- Serraga/BLR staff presented on the microgrid project to three regional Northern California tribal governments interested in pursuing microgrids.
- SERC/Serraga/BLR staff submitted a white paper on the microgrid project, and was accepted for presentation at 2016 ACEEE Conference 8/26/16.
- Jana Ganion assisted National Renewable Energy Laboratory communications team and REC Solar to write/edit an article for *Solar Today* publication covering the microgrid.

August 2016

- Serraga/BLR staff hosted 4 Native American Tribes (Quinault Nation, Bear River Band of Rohnerville Rancheria and others) and toured microgrid sites.
- Serraga/BLR staff hosted PG&E onsite to shoot a video documentary of the microgrid and other energy projects at BLR.
- SERC/Serraga/BLR staff gave a presentation on the microgrid at the annual ACEEE Conference on Friday 8/26/16.

September 2016

- Serraga/BLR staff hosted three Native American Tribes on tours of microgrid.
- SERC/Serraga/BLR staff presented the microgrid project at a nationwide Department of Energy-sponsored webinar: "Strategic Partnerships for Clean Energy and Economic Development" 9/28/16.

- SERC staff presented at the California Energy Commission Microgrid Workshop on September 6, 2016 in Sacramento, CA – "Demonstrating a Secure, Reliable, Low-Carbon Community Microgrid at the Blue Lake Rancheria."

October 2016

- Serraga/BLR staff hosted two Native American Tribes on tours of microgrid sites.
- Serraga/BLR staff presented a microgrid project update at the quarterly meeting of the U.S. Department of Energy, Office of Indian Energy Indian Country Energy and Infrastructure Working Group in North Dakota (10/4/16).

November 2016

- SERC/Serraga/BLR staff conducted tours of microgrid sites by high school students interested in STEM, with a particular focus on engineering.
- SERC/Serraga/BLR staff conducted tour of microgrid sites by California State University Chancellor's Office Team.
- Serraga/BLR staff presentation and discussion regarding microgrid project at the invitation-only Business Roundtable discussion on clean energy, communications, and other technologies, hosted by the U.S. Department of Energy, Office of Indian Energy; in San Francisco (11/30/16).

December 2016

- Held a tribal 'flip the switch' ceremony for the Blue Lake Rancheria Tribal Council to start up the solar array.
- Serraga/BLR staff created a presentation and brochure overview of microgrid project for attending the DistribuTECH annual conference in January 2017.

January 2017

- Serraga/BLR staff attended DistribuTECH 2017 conference in San Diego Jan. 31 and Feb. 1, 2017 to present on microgrid project.

February 2017

- Serraga/BLR staff consulted with three tribal governments in California on microgrid project development and replication of the BLRMG project.
- Serraga/BLR staff explored participation in Client Spotlight for REC Solar.

March 2017

- Serraga/BLR staff consulted with Alaska Native Communities and Alaska tribal governments on microgrid project development and replication of the BLRMG project as a part of the DOE Office of Indian Energy ICEIWG Quarterly Meeting 3/1-3/5/17, in Anchorage, AK.
- Serraga/BLR staff consulted with two other tribal governments in California on microgrid project development and replication of the BLRMG project.

April 2017

- Serraga/BLR staff presented on the microgrid project at Siemens Digital Grid Customer Summit 4/4/17.

- SERC/Serraga/BLR staff held a microgrid commissioning celebration event and project presentation 4/27/17.
- Serraga/BLR staff attended U.S. Department of Energy Tribal Energy Summit in Washington D.C. and presented on microgrid benefits and lessons learned 4/30/17.

May 2017

- Serraga/BLR staff presented on the microgrid project at the U.S. Department of Energy Tribal Energy Summit in Washington D.C. 5/1-5/4/17. Jana Ganion spoke at the plenary and two sessions.
- Serraga/BLR staff hosted five tribes onsite for tours of the microgrid infrastructure (Bear River Band of Rohnerville Rancheria, Karuk Tribe, Trinidad Rancheria, Tolowa Nation, Elk Valley Tribe).
- Serraga/BLR staff presented information on the microgrid project at regional Soroptimist meeting in Eureka, CA.
- SERC/BLR conducted a tour of the microgrid for the Redwood Coast Energy Authority, a local Joint Powers Authority and Community Choice Aggregator.

June 2017

- Serraga/BLR staff conducted outreach to four other tribal governments on microgrid replication project feasibility, including Spokane Tribe, and the Rosebud Sioux Tribe.
- Serraga/BLR staff conducted microgrid presentation and tour for California State University government affairs leadership and private industry stakeholders looking to replicate the project at their sites.
- Serraga/BLR staff presented information on the microgrid project at regional Mad River Rotary meeting in McKinleyville, CA.
- SERC/BLR staff hosted a visit from Siemens with a potential microgrid client. The team demonstrated and discussed the BLRMG.

July 2017

- Serraga/BLR staff conducted outreach to tribal governments and other entities on microgrid replication project feasibility, including Mesa Grande and GRID Alternatives.
- Serraga/BLR staff presented on the microgrid benefits to 40+ Tribal nations that attended the Oklahoma Indian Gaming Association conference in Oklahoma City, July 24-26, 2017.

August 2017

- Serraga/BLR staff conducted outreach to tribal governments and other entities on microgrid replication and project feasibility, including:
    - A regional federal/state/tribal emergency preparedness meeting on August 9, 2017 hosted by FEMA and CalEMA at Blue Lake Rancheria (give presentation and conducted tour of microgrid for ~60 attendees)
    - Microgrid presentation at Mad River Rotary Club meeting August 3, 2017, McKinleyville, CA.
    - Conducted Karuk Tribe microgrid tour on August 18, 2017.

September 2017

- SERC/Serraga/BLR staff conducted outreach to tribal governments and other entities on microgrid replication and project feasibility, including:
    - Humboldt State University Engineering under-graduate and graduate student tour of microgrid ~60 students, September 1, 2017
    - Presentation on microgrid to ~100 tribes at National Indian Gaming Association Mid-Year Conference September 20, 2017
    - Microgrid presentation to ~50 tribes at the U.S. Department of Energy Indian Country Energy and Infrastructure Working Group quarterly meeting, Washington D.C. September 21, 2017
    - Microgrid presentation to ~15 tribes at the North Coast Tribal Chairmen's Association, monthly meeting September 27, 2017, at Blue Lake Rancheria.
    - Tour of microgrid by 20+ Energy Managers from across the California State University system, September 13, 2017 at Blue Lake Rancheria.
- This microgrid project was selected as a 2017 finalist for the S&G Global Platts "Global Energy Award," in the "Commercial Application of the Year" category. The project was also nominated for the 2017 Renewable Energy World / Power Engineering's "International Renewable Project of the Year."
- Due to the resilience created with the microgrid, Blue Lake Rancheria was recognized by FEMA with a 2017 John D. Solomon "Whole Community Preparedness Award" https://www.ready.gov/awards

October 2017

- SERC/Serraga/BLR staff conducted outreach to tribal governments and other entities on microgrid replication and project feasibility, including:
    - Humboldt State University Advancement Foundation tour of microgrid, October 4, 2017.
    - Presented on the microgrid project at the American Solar Energy Society (ASES) Annual Conference, October 11, 2017, Denver, CO.
    - Hosted the Paskenta Band of Nomlaki Indians for a microgrid tour October 12, 2017.
    - Conducted multiple tours of microgrid by industry colleagues
        - Bioenergy 2020+ 10/16/17
        - PECO 10/19/17
        - GRID Alternatives 10/27/17
- This microgrid project was selected as a *finalist* for the 2017 Renewable Energy World / Power Engineering's "International Renewable Project of the Year."

November 2017

- Serraga/BLR staff conducted tour of microgrid for CA. Department of Water Resources, Nov. 8, 2017
- Serraga/BLR staff conducted tour of microgrid for Yurok Tribe, Nov. 15, 2017.
- Serraga/BLR staff presented on microgrid project during a national FEMA webinar on emergency preparedness, Nov. 29, 2017 – achieved 90% approval rating by attendees.

December 2017

- SERC/Serraga/BLR staff conducted outreach to utilities, industry professionals, tribal governments and other entities on microgrid replication and project feasibility, including:
    - Power-Gen International Conference, Las Vegas, December 5, 2017 – the microgrid project did not win Project of the Year, but did place as 1st Runner Up (i.e., second place) in a very competitive field.
    - S&P Global Platts Conference, New York City, December 7, 2017

January 2018

- SERC/Serraga/BLR staff conducted outreach to utilities, industry professionals, tribal governments and other entities on microgrid replication and project feasibility, including:
    - DistribuTech 2018 Conference, San Antonio, TX January 22-25, 2018; speak on the project during microgrid track panel discussion.
- The microgrid project was selected as the winner of the "DistribuTECH 2018 Project of the Year for Distributed Energy Resources" Award.

February 2018

- California Energy Commission 2018 EPIC Symposium, Sacramento, CA, Feb. 7, 2018. Jana Ganion spoke on microgrid project during panel discussion, "Improving Power System Resilience for Disaster Recovery."
- SERC/Serraga/BLR staff conducted tour of microgrid site for U.C. Berkeley representatives, Lawrence Berkeley National Laboratory, California Public Utilities Commission representatives, Industry stakeholders, and others.

March 2018

- SERC/Serraga/BLR staff conduct tour of microgrid site for McKinleyville High School STEM students (~70 students).

Planned for April 2018 and Beyond….

- SERC/Serraga/BLR staff to speak on project at *Sustainable Futures Speaker Series* at Humboldt State University (4/12/18).
- SERC/Serraga/BLR staff will continue to conduct ongoing tours of microgrid site for tribal, university/academia/research, industry, government, public/private, and other stakeholders.