Business & Technology Report

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The Value of Battery Energy Storage for Electric Cooperatives

Five Emerging Use Cases

NRECA
America's Electric Cooperatives

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Executive Summary

Electric cooperatives have long made use of battery technology, notably for back-up power in substations. However, with advancements in technology and plummeting prices for lithium-ion batteries, the last several years have brought new energy storage opportunities for both electric utilities and electricity consumers. By all measures, battery energy storage is, and will continue to be, an increasingly important tool for electric cooperatives. Battery technology will inevitably be part of the solution for managing the grid impacts of variable power sources like solar and wind, and as an asset in the various approaches that cooperatives might take to increase system resiliency and operational efficiency.

While overall system costs for battery energy storage continue to fall, the threshold for “affordability” is highly dependent upon several factors, including the application and the need. Certain proponents of battery storage refer to the benefits of ‘value stacking’ in maximizing the return on investment in an energy storage system by utilizing the battery for multiple use cases. However, it is challenging to leverage use cases simultaneously, and calling on the battery energy storage system (BESS) more often than intended may shorten its useful life.

There is no replacement for the value of hands-on experience, and this report provides a deep and detailed dive into battery energy storage evaluation, operations, key use cases, and lessons learned from a variety of applications relevant to electric cooperative needs. This report, and the upcoming companion report on procuring a BESS, provide insights designed to inform the decision-making of cooperatives that choose to explore possible investments in and uses of battery energy storage.

Introduction

This report explores five battery energy storage use cases through the lens of electric cooperative projects. These projects are designed to provide real-world tests of applications that may be critical in helping electric cooperatives manage changing grid issues and consumer expectations.

The five use cases in this report include:

- **Behind-the-meter Peak Shaving:** MiEnergy and Dairyland Power Cooperative
- **Utility-Scale Peak Shaving:** Middle Tennessee Electric Membership Corporation
- **Transmission & Distribution Deferral (T&D Deferral):** Anza Electric Co-op and Arizona Electric Power Cooperative
- **Renewable Energy Integration:** Cordova Electric Cooperative
- **Microgrids:** North Carolina Electric Membership Corporation, Tideland Electric Membership Corporation, South River Electric Membership Corporation

The energy storage industry – specifically battery storage – is often characterized by custom, application-specific designs and value propositions. This relative lack of standardization in cost, applications and value inhibit batteries from being more widely deployed. This limits potential advantages of economies of scale and slows the maturity of the industry. The results of the projects profiled in this report are intended to increase the certainty of realizing value from battery applications by providing application-specific knowledge and lessons learned from deployments. It is hoped that this can help shape the pace, scale and nature of electric cooperative investment in battery energy storage.

What is Battery Energy Storage?

A battery energy storage system (BESS) typically consists of an electrochemical battery coupled to a bi-directional inverter. The inverter converts DC power from the BESS to AC power, allowing the BESS to discharge and supply power to the grid or load, and also can convert AC power from the grid to DC power, allowing the BESS to charge from the grid or an AC generation source.

The battery itself typically consists of small cells which are connected in series and parallel to provide the required capacity at a specified voltage. A battery management system (BMS) is used to optimize the operation of the cells in a manner that ensures adherence with the design specifications and desired performance requirements, and to provide detailed information and diagnostics about the operational conditions at a cell level in the battery. The primary types of batteries are *solid-state* and *flow batteries*. Solid state is used here to describe batteries with self-contained electrolyte and electrodes – similar to the common household battery. Flow batteries store energy in external electrolyte tanks and use pumps to transfer the material past the electrodes. Flow batteries are in theory a good fit for many utility-scale applications, but after years of research and demonstration, a commercial market has not yet developed. All batteries used in the projects studied in this report use solid state lithium-ion technologies.

Battery energy storage systems are typically described using both power capacity rating and total energy rating (or sometimes duration). For example, a battery might be specified as 2 MW / 8 MWh, or alternatively 2 MW / 4-hour. In this example, 2 MW refers to the maximum instantaneous power output from the battery, 8 MWh refers to the total amount of energy that is available from the battery, and 4-hour refers to the maximum number of hours for which the battery can provide its maximum instantaneous power output – which is 2 MW. The number of hours over which the rated total energy can be stored or discharged from a battery, can be varied based on the requirements of the use case. This means for example, that a 2 MW / 4-hour battery could also be used as a 1 MW / 8-hour battery if required, since in both cases, the total amount of energy stored or discharged does not exceed 8 MWh energy rating (2 MW x 4-hour or 1 MW x 8-hour).

Utility-scale batteries are usually monitored and controlled through a supervisory control and data acquisition (SCADA) system, although some applications (renewable smoothing, local VAR control) may be implemented using autonomous controllers located in the device itself.

Use Case #1: Peak Shaving – Behind-the-Meter

The electric meter is the traditional dividing line between the electric utility and the customer. The utility's responsibility ends at the consumption meter. On the customer side of the meter ("behind-the-meter" from the utility perspective), the customer has responsibility for how the power is distributed and used at the premises.

Utilities first breached this "barrier" more than 30 years ago with the installation of remotely controlled on-off switches for residential electric water heaters, air conditioners and heat pumps, with the goal of managing utility demand during peak periods. Remote management of loads was then extended to commercial and industrial customers. This has been expanded today through advanced metering into communication with controllable thermostats, a finer control of water heaters and two-way verification. All are variations on the same objective – active control technologies targeting existing loads in order to align demand on the customer side with the needs of the larger grid, whether it be reducing demand at peak times, or coordinating water heating or electric vehicle charging with ovenight wind or daytime solar production.

Behind-the-meter (BTM) battery energy storage is in the very early stages of customer adoption, primarily as a complimentary technology to a rooftop solar system. A residential battery system, paired with solar, has been characterized as potentially disruptive to the utility-customer relationship, with customers able to reduce dependency on the utility as solar and storage prices fall.

It is also possible that behind-the-meter storage can function as another customer-sited device in a utility-driven demand response program. Unlike an appliance that is simply turned on or off to affect demand, behind-the-meter storage can inject power to serve the household load and even deliver power into the grid if the capacity of the system exceeds the local load.

Historically, commercial and industrial rates, not residential, have included peak demand charges. But today, residential demand charges and time-of-use (TOU) rates for residential consumers are being more widely considered by electric cooperatives. BTM energy storage may provide residential consumers another tool with which to respond to a time-of-use rate or demand charge and reduce their electricity costs at peak periods. If these batteries can be controlled by the electric cooperative, it may also be a means to reduce peak demand system-wide, to the benefit of all the co-op's consumer-members.

Case Study – MiEnergy Cooperative

MiEnergy Cooperative is headquartered in Rushford, Minnesota. It is the product of a 2017 merger of neighboring cooperatives in southern Minnesota and northern Iowa. MiEnergy is one of four distribution cooperatives participating in a behind-the-meter residential battery energy storage project, in partnership with their G&T, Dairyland Power Cooperative, headquartered in La Crosse, Wisconsin. The other cooperatives in the pilot project (also members of Dairyland Power Cooperative) are Oakdale Electric Cooperative of Oakdale, Wisconsin, Jo-Carroll Energy of Elizabeth, Illinois and Richland Electric Cooperative of Richland Center, Wisconsin.

The pilot project, which commenced in 2018, tests the concept of harnessing member-sited – but externally monitored and controlled – batteries to simultaneously provide benefits on several levels:

- The member will gain a source of back-up power that can be used in the event of an outage;
- With the proper price signals, the member-sited batteries can be called upon to assist in peak shaving, reducing costs to the distribution cooperative;
- Paired with member-sited distributed generation (such as solar PV), energy can be stored and dispatched when its value to the grid is highest;
- The G&T cooperative can aggregate member-sited batteries and bid these resources into a wholesale market.

MiEnergy was the first of the four participating cooperatives to install battery storage systems at six member homes between November 2018 and March 2019. Four systems were installed in Iowa, supported by a grant from the Iowa Economic Development Authority, and two systems were installed in Minnesota. The cooperative has released a preliminary report on the results from the first six months of operation.

Oakdale Electric Cooperative plans to install a battery system at one residence and at a co-op owned exhibit center near its community solar array. Jo-Carroll Energy is installing battery systems at its two offices. Richland Electric Cooperative is installing systems at two residential locations.

Jo-Carroll Energy has already installed one battery in their warehouse and is planning on installing an additional system soon. The existing battery operates under a time-of-use (TOU) scenario, but in case of an emergency such as a loss of power, Jo-Carroll will use the battery for backup power so that it can continue to load trucks and carry out other operations as part of its business continuity plan.

The pilot project, which also receives technical and financial support from NRECA and NRTC, is designed to provide cooperatives with an opportunity for hands-on experience with a new technology – battery energy storage – placed in service on the member side of the meter. These behind-the-meter systems are remotely controlled and monitored by the cooperatives (including the G&T, Dairyland) and the battery manufacturer, under guidelines settled upon in consultation with the members hosting the systems. The goal is to provide economic and other tangible value to both the participating members and the cooperative.

MiEnergy's Project Goals and Expectations

In the long-term, MiEnergy wants to better manage its load profile and address the impact of renewable and distributed energy resources (DER) on its distribution grid. MiEnergy seeks ways to provide resiliency to a grid experiencing growth in distributed energy resources. By 2019, the cooperative had interconnected 531 DER, primarily solar, but also wind and manure digestors. MiEnergy seeks to answer the question, can a residential battery backup system add resiliency and counteract the impact of these intermittent sources of power? Taken to an extreme degree, can consumer-sited battery systems can help optimize the supply and demand of energy and allow the utility to operate with 100 percent renewable energy around the clock?

To achieve this resiliency, and to extract the maximum benefit from energy storage located on the member side of the meter, the cooperative is evaluating whether battery storage might become a tool for peak energy management, similar to the residential load controls placed on HVAC systems and water heaters over the past three decades.

The average pattern of electricity use at MiEnergy homes is similar to many cooperatives – a peak in the early morning, followed by a midday lull before peaking again late in the day. The electrical power production cycle of a solar photovoltaic (PV) system, on the other hand, peaks in the middle of the day in MiEnergy's territory. The power production of a residential solar system and electric use within the home do not match very well. The behind-the-meter pilot can help the cooperative determine if there are benefits to an optional time-of use-electric rate utilizing a battery to reduce use of the grid during times of peak demand.

Figure 1: MiEnergy staff and technicians in the home of an Iowa member participating in the behind-the-meter battery storage pilot project. The group flanks the Sonnen battery system.
(Courtesy of MiEnergy Cooperative)

Selecting A Battery Storage Technology

NRTC – the battery supplier for this project – selected Sonnen Batterie, a German-based manufacturer of lithium iron phosphate battery storage systems, used primarily for residential applications, as the vendor. This selection was based on pricing, responsiveness to queries, and level of project support offered by the battery vendor. BTM battery storage is more widely deployed in Europe, where energy policy mechanisms financially reward "self-consumption" of residential solar over sales of excess production into the grid. Sonnen began U.S. battery production and sales in 2015. NRTC negotiated discounted pricing and project support based on a ten-unit purchase.

Selecting MiEnergy's BTM Pilot Participants

With a strong interest in replicating a real-life test of using battery storage for consumer peak load management, MiEnergy determined that units should be installed in the homes of consumer-members, specifically consumer-members willing to work with the cooperative through the learning curve of a first-time technology deployment. The cooperative also intended to focus on homes with a solar PV system or another source of distributed energy already in place. The project was introduced at the co-op's annual meeting in 2018 and publicized in the MiEnergy member newsletter. The cooperative fielded many inquiries and eventually a list of 24 members willing to be considered for the project.

In narrowing the field to the final six pilot participants, the cooperative used the following criteria:

1. **Internet Connection:** A lack of internet availability, and specifically the ability to hardwire an ethernet connection to the unit, eliminated a number of interested members. This level of communication is required to allow Sonnen to check the current state of the battery, change the charge/discharge times, troubleshoot issues, and install software updates. It also gives the member the ability to view the state of the battery storage system in real time.

2. **Conditioned Space:** The unit needs to be sited in a controlled environment where temperatures never fall below 41 degrees (Farenheit) or above 113 degrees. Temperatures higher or lower than the acceptable range will shorten the unit's 20-year life span. Battery systems also must be installed in close proximity to the member's electrical service panel.

3. **Adequate Spacing:** The battery unit is substantial – more than six feet high, more than two feet wide, and more than a foot deep. It requires an additional three feet on each side for ventilation, and space in front of the unit for service access. The units weigh 800 pounds, rests on the floor, and require wall supports.

4. **Electrical Service Panel:** The ideal configuration is a 200-amp service panel with an existing subpanel near the main service panel. For the duration of the project, the member had to agree to have an electrician remove circuits from the main service panel and transfer them to a critical load panel.

5. **Term of the Pilot Project:** Before installation, participating members signed an agreement that allowed the unit to stay in their houses for a minimum of five years, with an option of a second five-year term. After the pilot project concludes, members will have the option to purchase the units at market value or have them removed.

6. **Daily Control Periods:** One of the goals of this pilot project is to explore the possibility of allowing MiEnergy control of the battery during high demand times to reduce peak demand on the system. Members had to agree to allow MiEnergy to control the battery charge and discharge time periods at its discretion.

7. **Household Energy Use Profiles:** Applicants consumption varied from 263 kWh to 10,030 kWh per month. MiEnergy focused on households with 1,100 or fewer kWh per month in order to align demand with the capabilities of the residential battery storage system. Peak kW demand among applicants ranged from 6.56 to 45.6. The battery units contain 7 kW and 8 kW inverters, households

chosen to participate are all below that threshold to avoid overloading the inverter and tripping the breaker. For the same reason, residential air conditioning circuits were not included in the circuits supplied by the battery in an off-grid mode.

Of the six households enrolled in the MiEnergy pilot, four have solar PV systems, one has back-up natural gas generator, and one has no distributed generation on site. The homes with the smaller monthly electrical usage were assigned Sonnen 10 kWh battery systems, and the four larger homes were outfitted with Sonnen 16 kWh units.

Technology Specifications and Costs

- System Specification
  - Sonnen Batterie ECO 16kWh/8kW (AC) using Murata Lithium Ion Phosphate (LiFePO4) cells, Configurable in 2kWh increments
  - AC Roundtrip efficiency = 86 percent
  - Outback Radian inverters
  - 26” x 14” footprint; height varies with capacity; 16 kWh is 71” high
  - NEMA-12 indoor enclosure, 41 - 113°F
  - ≈16 manhour installation time
- Communications and Software
  - Serial, ethernet, Modbus, Z-Wave connectivity
  - Itron/SSN, Enbala, EnergyHub compatibility
  - Ability to aggregate multiple batteries into an effective peaking solution
- Warranty
  - Assembled in Atlanta
  - 70 percent capacity after 10 years / 10,000 cycles.
  - If a problem occurs, Sonnen replaces components at its expense
- Costs

  At the MiEnergy installations, the ECO 16 (16 kWh) units cost $19,672 and the ECO 10 (10 kWh) units cost $14,522. The ECO 16 units were purchased in conjunction with the other pilot cooperatives through NRTC. The ECO 10 units were purchased through Werner Electric. The average installation labor cost (using electricians) was $3,363. In total, the purchase price along with installation averaged $23,035 for the ECO 16 units and $17,885 for the ECO 10 units.

MiEnergy's Overall Findings After Initial Six-Month Test

A full description of the results of the various operating modes tested at MiEnergy in 2019 is available from the Iowa Economic Development Authority in its "Residential Battery Pilot Summary" released in February 2020. The experience from the pilot reinforced the belief that – in the long-term – customer-sited energy storage integrated into the utility network will be a viable and important part of electric cooperative operations, delivering benefits to the member and to the cooperative.

"I'm bullish on the future of battery storage," says Ted Kjos, vice president of marketing and external relations at MiEnergy. "We have seen that the technology is working. We have a good IT team that can handle the data, and we can use it as part of our load management. We're positive on it."

Among the takeaways from the initial test period:

- Remote communications with the battery system worked as intended. The cooperative was able to remotely control the charge and discharge of the battery system, and Sonnen was able to monitor the state of the units and run software updates.

- In one of the residences, the battery was set up on a 'whole home' basis, with the battery on the line side of the main service panel, and every load in the home served by the battery in the event of an outage. In the other five homes, the battery system was tied to a subpanel and delivered power to only part of the home. For the purposes of maximizing the peak load management potential of behind-the-meter battery storage, MiEnergy found that the whole home approach was much more dynamic. One of the downsides of the whole home approach was the inevitability of overloading the limits of the BTM system inverter, causing the breaker to trip. When this happened, the homeowner needed to shed some load within the home then manually turn the breaker back on.

- While load management with the battery system generally functioned as planned and was able to deliver on signals through different rate structures (such as a TOU rate or a peak alert rate), the return on investment to the owner of the battery system is too long when measured in years for payback. At the cost of the technology as purchased and installed, there is an estimated payback of 33 years on a TOU rate for the 10 kWh battery system, and 43 years for the 16 kWh system. "We're not moving forward at this time, not because it's too difficult or the technology doesn't work," says Kjos. "Currently cost is the big barrier."

Questions and Potential Barriers

The initial test period revealed several issues and questions surrounding the learning curve of purchasing, installing and operating a residential storage system as an asset that benefits both the homeowner and the utility. These include:

- **Efficiency loss.** MiEnergy was surprised to find that the efficiency losses calculated from the performance of the systems in its pilot were far higher than that described by the manufacturer. The battery units averaged an efficiency loss around 30 percent round trip in contrast to the advertised 7.5 percent efficiency loss. The cooperative reported the issue to Sonnen, which initially could not explain the discrepancy, though they suggested that the rates of charging and discharging the batteries may be a factor.

  - The lower efficiency led to an increased electricity use within the homes of the test participants. The 16 kWh battery system that initially discharged 15 kWh daily would have a loss of 4.5 kWh on a full charge/discharge cycle. This means during the AC/DC/AC conversion, only 10.5 kWh of the 15 kWh would be consumed in the home. The other 4.5 kWh would be lost during the conversion process. This would equate to 130 kWh monthly that would be seen through the service meter (purchased by the member), but never consumed in the household. MiEnergy saw the member usages increase by an overall 13 percent over a 6-month time frame.

  - The round-trip losses of the battery must be accounted for in the rate structures to ensure that the consumer does not end up paying for utility use. If these higher losses are the norm, it could negatively affect the feasibility of commercial deployments.

- **Size of the battery system.** Customers were surprised at the large size of the Sonnen battery following publicity about the Tesla PowerWall and viewing photos of its sleek, wall-mounted unit.

- **Rates and charges.** The value of these systems depends upon the rate structure, and the applicability of net metering and demand charges. “We’ve got to figure out the rate and how to handle the flow of energy back into the grid from the member’s installation,” says Kjos. “That’s critical to being able to move forward with integration with Dairyland Power on a formal load management program. Today our members with solar want net metering as opposed to using the excess solar power to charge the battery. So, it is important to develop the right price signal to allow us to use unit for load management.”

- **Operating modes.** The Sonnen battery has different modes of operation, some of which (like self-consumption) may not be applicable to some or most cooperatives in the U.S. Direct control of charge and discharge is possible through the Sonnen Application Programming Interface, but it will require integration.

- **Ownership.** There are still questions about whether it is better to have the battery owned by the consumer-member or the cooperative. Insurance and indemnification are parts of this discussion. Oakdale Electric Cooperative, another battery pilot participant, has started working with Federated Rural Electric Insurance Exchange to better define these issues.

- **Certifying the installer.** The Sonnen equipment must be installed by a company which has been specifically trained and certified in the installation of its product. Tesla has similar requirements, unique to its product. There is a cost for training, and the certification exam is difficult. Until there is sufficient demand, local companies may not feel the cost is justified, particularly if separate training programs are required by every battery manufacturer.

- **Business case**. As a result of the complexity of dealing with local contractors, some co-ops are considering either working more closely with local electrical contractors or going into the specialized electrical contracting business themselves.

- **Installation costs vary.** Depending on the service size and location of the unit, the installation cost can vary widely. A pre-purchase estimate from a certified Sonnen installer is suggested. Consumer-members are advised to get installation quotes from electricians before purchasing battery units.

- **Meters.** Installing bi-directional meters is needed to monitor the flow of electricity in order to compensate the consumer-member for any excess discharge that goes back onto the grid. The rate of compensation depends on state policy and the cooperative's policy.

- **Net metering.** With a 30 percent efficiency loss, the members in the MiEnergy pilot did not want the excess production of their solar to go into the battery. Financially, the member was better off selling all the excess back at the retail rate than to store the generation for later use.

- **Critical circuits versus whole home.** This will depend on what the consumer-member is looking for in the battery unit and how much they choose to spend. A smaller storage unit can realistically support critical loads only. With larger capacity, the goal would be to serve the entire home and educate the homeowner on how to control the load during an outage. From a cooperative's standpoint, the larger the capacity, the more significant the load management benefit. "Being able to use the storage on a whole house basis – that's the end goal for us from the technical side," says Kjos. "The storage industry is not there yet. We can't manage residential air conditioning with the current storage capacity. That's a huge load but if we can't control that, the load management potential is not being met. I think that will improve – the kW capacity will increase."

- **Understanding the state of charge.** Fully discharging the unit continuously will reduce the life expectancy of the unit.

- **Location of storage.** Cooperatives will want to standardize battery installations. This will be very difficult in a behind-the-meter scenario. Does it make the most sense to have the battery on the line side or load side of a production meter? Standardization requires more development and market maturity.

MiEnergy Assesses the Benefits of Behind-the-Meter Energy Storage

In addition to analyzing the positives and negatives of the initial stage of the pilot, MiEnergy evaluated the long-term potential of residential battery energy storage. Despite the challenges – including the need for significant reduction in cost – the cooperative believes that the technology will mature to provide value on both sides of the meter.

For consumer-members, BTM storage offers:

1. **Back-up power.** At this point the biggest benefit is electric resiliency. Today this can be achieved at a much lower price with a natural gas residential generator. The price gap will shrink as battery technology advances, along with increases in capacity and power.

2. **Flexibility in electric rates.** Cooperatives will continue to develop time-of-use rates, which will incentivize homeowners to find ways to use or purchase power at off-peak times. Residential demand charges will likely become more mainstream in the future. Behind-the-meter battery energy

storage can be used to take advantages of TOU rates and shave daily peaks which on a monthly basis reduce their demand payment.

3. **Maximizing use of 'green' energy.** A home-based solar PV system, coupled with battery storage, can help members significantly reduce their carbon footprint. This benefit decreases as wholesale power becomes increasingly less carbon-intensive. This is depicted in Figure 2.

4. **Lessening grid dependence.** Battery storage systems tied to a solar array will allow homeowners to become more self-reliant in energy production, while maintaining a tie to the grid.

For electric cooperatives, BTM storage offers:

1. **Reduction in peak demand.** The biggest benefit to the cooperatives comes in reducing the system peak demand. MiEnergy was able to control the BTM storage units to discharge in support of the home during a February peak alert. A system reduction of 24 kW was achieved by the six units. At scale (with widespread deployment) BTM storage would bring measurable benefit.

2. **Savings incentives for consumer-members.** While a utility-scale battery energy storage system will have a greater impact on peak load reduction, residential storage offers two levels of savings. The individual member can directly benefit through a TOU rate, capacity credit or power credits, in addition to sharing in the wholesale savings enjoyed by the entire membership. Most cooperatives will likely choose to have a blend of large-scale and small-scale storage systems.

3. **Opportunity for new services.** As the market for BTM energy storage matures, cooperatives may enjoy new business opportunities, including sales, installation and service of energy storage systems, independently or in partnership with a local contractor and/or a particular battery vendor.

4. **Increased member satisfaction.** "One of the things I appreciate about MiEnergy is their focus on both conservation and renewable energy," reported one of the pilot participants. "The Sonnen Battery pilot project is a great example of that focus. It makes the grid more resilient as members like us add solar to our homes and businesses. It also provided a nice backup on the rare occasion I lost grid power since it was installed."

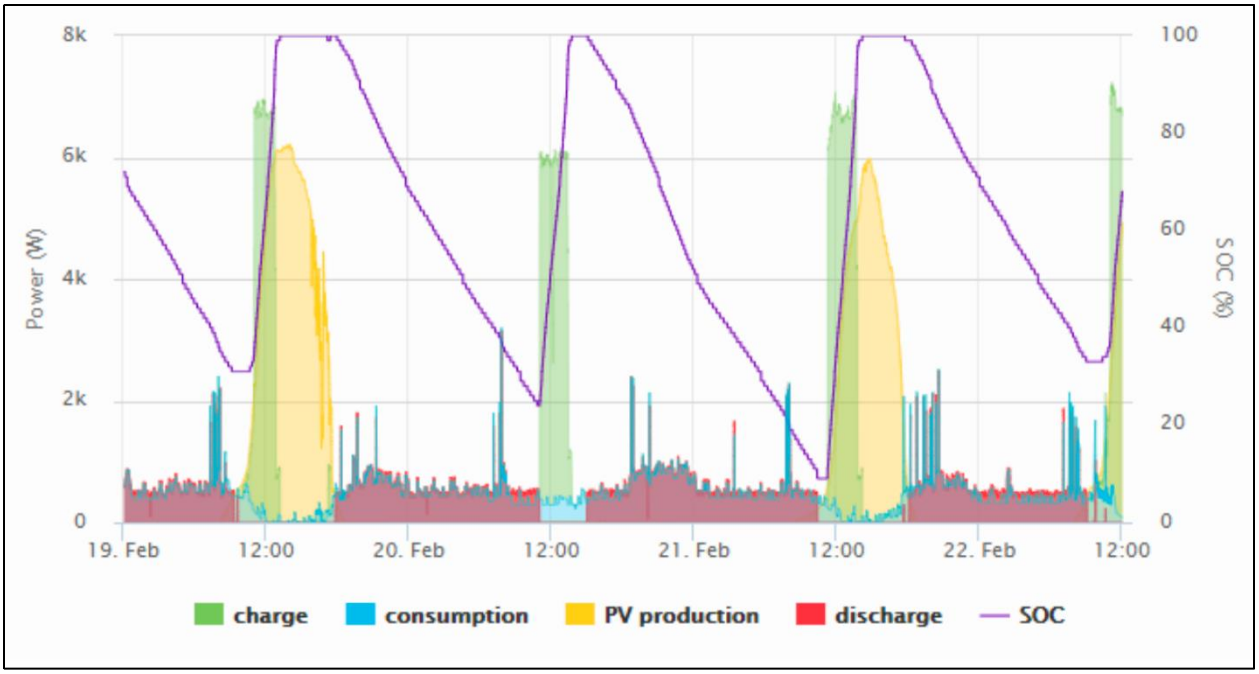

Figure 2: Charging batteries with on-site solar. In the graph above, the battery was set to charge when the solar was producing and to discharge when there was no solar. On February 19, solar output provided the majority of the charge, while on February 20, a day without sun, charge came from the grid. (Courtesy of MiEnergy Cooperative)

Next Steps for MiEnergy

Kent Whitcomb, V.P. of Member Services at MiEnergy, says that the pilot project has confirmed his view of the relevance of battery storage to electric cooperatives. "Everything is there technically – we can communicate with the batteries, we can control the output, and the member has access to it," he says. "Everything is there, except the price point."

Kjos adds that BTM storage "is not a technology that resides in the utility background but something available to the public. We have several certified Sonnen dealers in our area. They are not selling a lot of them yet, but they are out there."

Distributed resources like batteries and electric vehicles (EVs) "are the third leg of the stool," he says. "Members are buying EVs and they will buy batteries. We need to be ready to reach out to members and say 'hey, we can help you get more out of that resource, if you use it in a different way.'"

Can A Member-sited Battery Become an Asset of Value to a G&T?

One of MiEnergy's six residential battery systems is now tied in to Dairyland Power's load management dispatch center in La Crosse, Wisconsin. "As we look at the modernization of our load management platform, one of our goals is to integrate batteries [and other distributed resources] in the future," says Mitch Vanden Langenberg, Dairyland Power Cooperative's Supervisor of Load Management. The modest first step with one system has "proven that we can communicate to the battery system remotely and align a discharge event behind the member meter with a peak avoidance event at the G&T," he says. "But there is room for enhancing the sophistication of the way it is being done."

Because the Sonnen battery was not designed with load management as a feature, Vanden Langenberg and his team developed an algorithm that would calculate an optimal discharge rate based on various parameters including the current state of charge and event duration to be sent to the battery. "We know that we can accommodate this method for a single unit," he says, "but thinking about the scalability [to support a fleet of BTM systems] – that's a bigger challenge." Another challenge is sustaining reliable communications with a device located at rural residences "without being overly burdensome to the utility and the consumer from a cost or interoperability standpoint."

Vanden Langenberg also believes that these challenges are well worth solving. "The functionality does work, and there is a real demand offset taking place that is comparably quite significant," he says. It would take "anywhere from 7 to14 water heaters to provide the same 5 kW dispatchable demand reduction available from one behind-the-meter battery storage system. It is definitely a valuable asset."

Looking forward, Vanden Langenberg believes that Dairyland Power could aggregate the demand response value of a fleet of BTM batteries and monetize that as a registered resource bid into the MISO (Midcontinent Independent System Operator) market.

He notes two additional opportunities that could be harnessed by the distribution cooperative. One is the opportunity for sales and service – "a number of co-ops have taken steps to become solar installers – that business model could be extended to also become battery storage solution providers." He also points out that the advanced inverters that are part of the battery system have the capability to provide reactive power. "The advanced inverter features could be used for volt/VAR optimization on distribution feeders – especially those feeders seeing voltage problems increasing as a result of increasing penetration of distributed energy resources," Vanden Langenberg says. "If behind-the-meter assets are not leveraged for the capabilities that are inherently there – that's a missed opportunity."

Use Case #2: Peak Shaving – Utility Asset

To accurately reflect the cost of supplying electricity at various levels of consumption, electric rates typically include an energy charge (cents/kWh) and a demand charge ($/kW), both often time dependent. This two-part rate applies both to commercial consumer-member rates, as well as the rates that utilities pay to their suppliers. In the latter case, this may also include time-dependent demand charges for transmission services.

For distribution utilities, these energy and demand charges are incorporated into the rates they pay their suppliers. For generation utilities such as G&Ts, these rates are typically reflected in the cost of equipment that must be brought online to meet demand.

At distribution cooperatives, demand can be controlled with aggregated load management services, such as water heater or thermostat controls, or by offering voluntary incentives to customers to reduce demand during expensive peak periods.

Battery storage can act as loads when charged with low-cost off-peak energy, or with excess energy produced by a variable renewable resource like solar or wind. When discharging that lower cost or excess energy during times of peak demand, batteries act as generators.

In the behind-the-meter case study in this report, we examined how member-sited battery storage could be called upon by both the distribution and the G&T cooperative as another tool to manage system demand.

This case study looks at the same application through the use of a utility-scale, utility-sited battery energy storage system. The larger size of a utility-scale BESS, combined with the *relative* simplicity of access to and control of the system, offer some economic advantages when compared to the use of behind-the-meter storage for load control purposes.

Case study: Middle Tennessee Electric Membership Corporation

Middle Tennessee Electric Membership Corporation (MTE) is now the second largest electric distribution cooperative in the U.S. following its June 2020 merger with the municipally-owned Murfreesboro Electricity Department. MTE serves more than 600,000 people through approximately 307,000 member accounts across its nearly 2,200 square mile service area spanning eleven Tennessee counties south of metropolitan Nashville. The Tennessee Valley Authority (TVA) is the cooperative’s wholesale power supplier.

The cooperative is committed to taking a hands-on approach to increasing its understanding of emerging and distributed energy technologies, spurred in part by growing interest from its membership. In July 2019, MTE took its first step into the use of battery energy storage with the installation of a 1 MW / 2 MWh Tesla lithium-ion BESS adjacent to its Rockvale substation, not far from the cooperative’s corporate headquarters. The battery, which is owned by MTE, is utilized by the cooperative to help reduce peak demand on a heavily loaded feeder. The BESS is coupled with an existing Conservation Voltage Reduction (CVR) program to lower demand and reduce wholesale demand charges from TVA.

Project Selection, Construction and Commissioning

The site selection was straightforward. The Rockvale substation is on land owned by Middle Tennessee EMC, serves a feeder that sees high demand, and is in a highly visible location on a main road outside Murfreesboro, which serves the cooperative's goal of using the battery project to engage members.

Figure 3: The Tesla Battery Energy Storage System at MTE's Rockvale Substation
(Courtesy of Middle Tennessee Electric Membership Corporation)

After a review of battery providers to the small but rapidly growing utility market, MTE's senior management team selected Tesla for the battery system. The contract defines the length of the warranty (dependent upon battery use), and the responsibilities of MTE and Tesla in the site preparation, installation, commissioning and maintenance. Avery Ashby, project manager and senior engineer at MTE, says that the experience of working with a battery technology provider came with a few surprises and required adaptations from both partners. It revealed gaps in language, expectations and business approach, a challenge that has also been experienced by other cooperatives when acquiring battery storage. These occasional disconnects arise out of the differences in business models between electric cooperatives and battery vendors, and are similar to those experienced between cooperative utilities and solar developers in the not too distant past.

Middle Tennessee EMC prepared the site, choosing to locate the BESS on cooperatively owned land about 150 feet outside the substation on a gravel bed behind a fence, like the layout of the substation. The battery system is situated about 100 feet from the well-traveled Highway 99. MTE added a recloser upstream of the battery to provide an option for an emergency disconnect.

Operational Experience

MTE briefly considered pairing its first utility scale battery to a solar resource, but was unable to qualify for an additional solar allotment from TVA (MTE operates a 1 MW community solar project that required TVA approval). Its operational plans for the BESS were straightforward – charge the battery with off-peak power, then dispatch power from the battery during peak events to help reduce system peaks and the associated demand charges incurred from TVA. Ashby and his team proposed a simple charge/discharge system for the co-op's control center team, integrated along with the CVR mechanism and displayed in the SCADA system.

Coordinating the communications and control scheme with the Tesla software was not as easy as Ashby had expected. The cooperative had difficulty in finding a communications protocol that Tesla was familiar with that would allow the battery system to 'talk' with the utility control software. MTE and Tesla were able to communicate with a basic version of the Distribution Network Protocol (DNP), but limitations on the Tesla side made communications through the co-op's SCADA a challenge. A workable solution was found when Tesla was able to adapt protocols it uses with its industrial customers in order to meet the utility requirements.

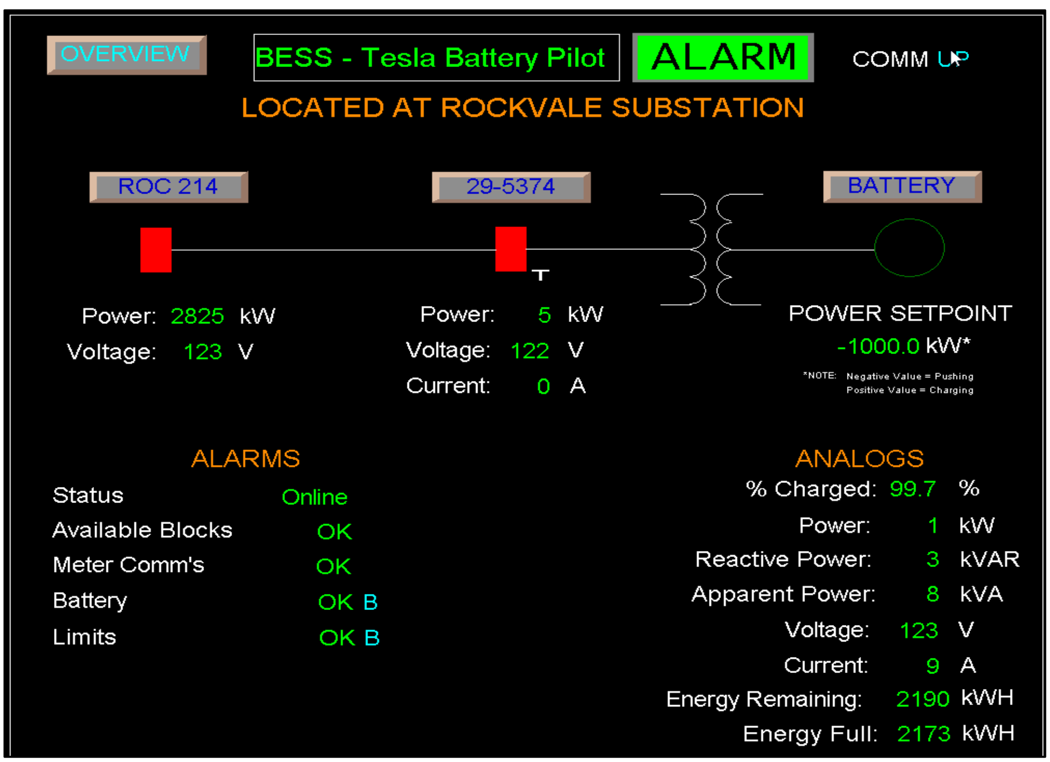

Figure 4: A Control Center Screen Displaying the State of the BESS
(Courtesy of Middle Tennessee Electric Membership Corporation)

In the first year of operation, the BESS has proved to be an effective tool in managing peak demand, though its overall impact on MTE's system demand of 1,400 MW is small. Still, Ashby says, "The concept is scalable, and I wish I had others [battery storage systems] available to dispatch."

How MTE Uses the Battery System

Initiating use of the BESS is in the hands of the cooperative's control center, which typically deploys it three to five times a month.

MTE has chosen the simplest form of control – direct control as opposed to site control. Under site control, MTE could employ a more dynamic use of the battery, utilizing feedback from meter data to vary the discharge to flatten the peak load at the Rockvale substation. But the primary goal of the battery project is to manage the overall system peak and lower the demand charge. "Since our BESS is less than 0.1 percent of our system peak, there wasn't much to gain by actively controlling it," says Ashby. "It would be different if we had a fleet of battery systems sufficient to meet 10 percent of our system peak."

Under direct control, the operators fully discharge the battery during a system peak event, in sync with the use of CVR. This means a relatively small number of deep discharges that do not come close to violating the terms of the 15-year warranty schedule, which allows an average of up to 180 discharges per year. To help extend battery life, MTE recharges the battery at a low rate, though the recharge may be accelerated if the control center anticipates a "double hump" peak event.

The initial bumps in the relationship with Tesla have smoothed out. "Now that we're up and going, Tesla is phenomenal," says Ashby. The remote Tesla staff call before updating firmware on the BESS (in order to avoid disrupting operations on a peak day) and have volunteered to update the software on MTE inverters when Tesla perceives a need.

Lessons Learned and Other Observations

- While installing a battery energy system is not among the cooperative's 'core competencies', and in the future MTE may well use a third party on the installation of additional battery systems, "I'm glad we did it ourselves this time," Ashby says. "We have C&I customers who will want to have this in the future, so it's best to be in the position where we have a hands-on understanding of the technology. If we understand how it delivers value, we can share that with our members, and we'll all be better off."

- The lack of direct assistance from the vendor in the on-site commissioning came as a surprise. "I was a little put-off when, in response to a question, Tesla would point me to a page in the manual," Ashby says. He was also surprised to find that the company offered no training programs for a project like the one at MTE. "They said that if we were to order a similar project today, the battery system we'd get would be very different, because the technology is evolving so quickly."

- Tesla reacted differently to the prospect of the cooperative integrating behind-the-meter (BTM) Powerwall systems located at member sites as dispatchable assets managed through its SCADA in the future. Tesla noted that the BTM products were strictly controlled, requiring purchase through authorized dealers that have undergone a rigorous training program. "The idea that we had just installed a Power Pack system on our own did not seem to matter," says Ashby.

- The project has MTE envisioning the addition of battery storage as a part of designing new substations. "It should be able to be incorporated into our facility like it's another transformer."

- Ashby credits the project with "reenergizing our engineering program", and sparking renewed interest among the cooperative Board, senior staff and control center operators in the approach to and value of peak demand management.

- Member interest in the battery project has been high. "The system has the flashy look of all Tesla products and people pull in and want to know what we are doing," says Ashby. "It's my number one job to stop whatever I'm doing and talk with them. It's like the reaction we get with our cooperative solar field. More than just demand reduction, this is a huge win for us in engaging members and demonstrating that we really are their trusted energy provider. It gives you an impact that you won't get from reading a brochure."

Economic Justification

The primary rationale for investing in the project is as a working demonstration of the ability of the BESS to help reduce peak demand, as well as a tool for member education. Nevertheless, MTE is tracking the return on its investment and estimates that the demand savings may cover the BESS investment in between 8 and 12 years.

What Can Other Cooperatives learn From This Project

- **Battery storage is a useful peak demand tool.** Distribution co-ops have been managing peaks (shaping loads) for many years through programs such as direct load control and other incentives on the consumer-member side. Battery energy storage adds a promising tool on the utility-side of the meter. It delivers the expected value and complements existing programs like MTE's conservation voltage reduction.

- **Review your wholesale power contract.** There is a potential legal complication with battery storage, depending upon the terms of a cooperative's contract with its wholesale supplier, as it delivers energy to the grid. In the case of MTE, Ashby says that there are no issues with TVA, as the battery is charged with energy from the TVA supply.

- **Adding a BESS to your utility infrastructure is not yet 'plug-and-play'.** Installing a utility-scale BESS on the cooperative premise remains a customized process, with both the vendor and the cooperative arriving at the project with different sets of expectations and procedures.

Use Case #3: Transmission & Distribution System Deferral

When the load served by a specific feeder or substation grows beyond the capacity of its components, the system will require an upgrade to transformers, conductors and associated equipment.

In some cases, the peak load is present for only a short duration and limited to few times per year. In these situations, a dispatchable energy storage system such as a battery can provide energy sufficient to reduce the load to levels that do not cause overloads on the feeder or substation components, and the upgrade can then be postponed, resulting in savings to the utility. This is commonly termed a *transmission and distribution (T&D) infrastructure deferral*.

Case study: Anza Electric Cooperative and Arizona Electric Power Cooperative (AEPCO) G&T

Anza Electric Cooperative (Anza EC) is a distribution cooperative headquartered in Anza, California and serves nearly 550 square miles of high desert in Riverside County. The co-op brings power to more than 5,000 metered loads, 92 percent of which are residential. Anza EC is a member of Arizona Electric Power Cooperative (AEPCO), a generation and transmission (G&T) cooperative headquartered in Benson, Arizona. AEPCO provides wholesale power to its six member cooperatives in Arizona, New Mexico and California, as well as several other utilities. AEPCO owns both a 605 MW coal- and natural gas-fired power station (Plant Apache) and a 20 MW solar photovoltaic (PV) power plant (Apache Solar). Anza EC, which must meet California renewable energy goals, contracts for a 5 MW segment from the Apache Solar plant. In 2017, Anza EC installed an AEPCO-owned 2 MW-AC solar photovoltaic (PV) system next to its headquarters and is planning a 1.4 MW-AC expansion.

The Need for T&D deferral and the Case for Battery Energy Storage as a Solution

Anza EC receives its wholesale power from AEPCO over a single radial 34.5 kV transmission line owned by Southern California Edison (SCE). The distribution cooperative's summer peak, pushed by residential growth and increased demand for air-conditioning, has been spiking closer to the capacity of the transmission line in recent years. Peak demand will likely exceed the capacity of the existing transmission line by the mid to late 2020s, according to Barry Brown, AEPCO's executive director of engineering and transmission maintenance.

The primary goal of the Anza EC energy storage project is to keep the cooperative's total peak load below the capacity of the single radial transmission feeder serving the utility. The peak typically occurs only on a few summer afternoons. Another goal is to provide a source of back-up power to critical loads in the event of a transmission line outage. The transmission line crosses U.S. Forest Service land, and a 2018 wildfire caused a ten-day outage. Annually, three-quarters of the co-op's outages originate from the transmission line.

Anza considered deployment of energy storage, and evaluated it against other alternatives to reduce peak load and/or upgrade transmission capacity. These alternatives included:

- **Traditional infrastructure investment**. AEPCO was able to reconductor and upgrade the capacity of the feeder from 14 MW to 19 MW in 2018. Despite this upgrade, recent load growth trends have indicated that peak demand on the feeder will likely reach this increased capacity before the end of the current decade. Further upgrades to the transmission line to keep pace with the anticipated growth would cost an estimated $21 million.

- **Lessen transmission congestion through use of local solar generation.** The 2 MW of PV installed next to the Anza EC headquarters may have a positive effect on the local load profile, given that at least a portion of the solar output will overlap the period of peak demand. But, solar output cannot be guaranteed and would not meet demand peaks that occur after sunset. Solar could be part of the solution, if stored and dispatched in a "solar plus storage" BESS configuration (see Use Case #5 for more detail on battery storage for peak shaving and resiliency).

- **Installation of a natural gas peaking generator.** This is not a viable option due to California's strict air-quality rules.

Upon analysis of the above alternatives, it was determined that installing energy storage will reduce peak demand, thus deferring further upgrades of the transmission line. Further, energy storage can also enable optimal utilization of the solar generation at Anza and can enable the formation of a microgrid and supply critical load, thus increasing resilience.

Anza EC Battery Energy Storage Project Design and Description

The energy storage system is adjacent to the Tony Lappos substation, which is located next to Anza EC's headquarters. Combined with the on-site solar, it forms the heart of a microgrid, supplying power to a restricted number of essential circuits during an outage. The system began commercial operations in December 2020. The battery will be interconnected to the 34.5 kV transmission line at the same point as the existing and new PV arrays.

The BESS chosen for the Anza EC installation is a 2 MW (4 MWh) lithium-ion solid state battery from Samsung. The BESS project will also include the additional 1.4 MW-AC PV array and a microgrid controller.

ENGIE North America is the Engineering Procurement, Construction (EPC) contractor for the project (AEPCO initially worked with SoCore Energy of Chicago, which was purchased by ENGIE in the early days of the development of the project). ENGIE is directly handling the set-up of the controller and buildout of the other components of the microgrid, and is subcontracting the installation of the battery system and the second phase of the solar array. CoBank provided the third-party financing.

Figure 5: Anza Electric Battery Energy Storage
(Courtesy of Anza Electric Cooperative)

Research Component

Anza and AEPCO worked with Sandia National Labs (Sandia) and with NRECA's Business and Technology Strategies department to study the economics of the proposed system and to develop the technical requirements for the energy storage and microgrid controller procurement. The assistance provided by Sandia was funded by the Energy Storage Program at the U.S. Department of Energy.

Figure 6: Site Detail
(Courtesy of Anza Electric Cooperative)

Co-op Business Model Considerations and Decisions

Similar to the existing Anza EC's solar PV facilities, AEPCO will own and operate the battery. Anza EC will realize the value streams of the battery through a Power Purchase Agreement with AEPCO. Under this arrangement, the battery will be able to provide value to Anza EC, as well as to AEPCO's system as a whole, because it will be optimized to defer AEPCO's infrastructure investments.

The third-party financing through CoBank utilized for the project tapped the federal Investment Tax Credits (ITC) available for combined solar and storage projects. In keeping with the ITC rules, the BESS will be charged from the solar arrays, not the grid.

Once operational, AEPCO will monitor the performance of the BESS to ascertain that, in the event of outages, it safely and successfully serves a critical circuit of the Anza EC system in island mode, with microgrid operations suspended once the external grid is restored.

Economic Justification

The Sandia economic analysis and the NRECA development of specifications for a microgrid were started in 2018 and completed in 2019. The economic analysis identified the solar-plus-storage microgrid as the most cost-effective answer to Anza EC's issues with resiliency and transmission constraints. Further, the project's value includes its demonstration of energy storage as a 'learning lab' for cooperatives, resulting in valuable lessons learned.

Additional Uses Cases for This BESS

In addition to deferring infrastructure upgrades by lowering peak demand, the project will also contribute to greater resiliency, by providing a back-up power system that can be utilized in the case of service disruptions on the single transmission line serving the cooperative.

Anza EC is also evaluating whether the energy storage system can be used for traditional peak shaving or even for energy arbitrage, since the co-op is charged for energy based on the locational marginal price at its delivery point. If there are significant differences between peak and off-peak energy prices, the battery can be "cycled" to charge from the grid during off-peak periods at low prices, and discharge power during peak periods, thus reducing the amount of power needed to be bought at high energy prices.

Lessons Learned: What Can other Cooperatives Learn from this Project?

Kevin Short, general manager of Anza EC, and Barry Brown of AEPCO agree that the project is a great example of a mutually beneficial collaboration between a G&T cooperative and one of its distribution members, applying a non-traditional solution to a traditional problem. According to Short, AEPCO's expert handling of the relationship with SCE and its transmission line "is one of the best reasons to sing the praises of the all-requirements contract"

Brown says the experience gained through the Anza project provides short- and long-term value for the G&T. “We’ve had interest in adding battery storage to our Apache Solar station for reliability and ancillary services, and we have another member preparing to add battery energy storage after Anza,” he says.

Brown and Short identified some of the key challenges encountered once the project was initiated:

- **Lack of EPC expertise in utility battery storage and microgrids.** Brown says that in 2018 it was “difficult to find a list of qualified EPC contractors ready to take on this project. A lot of companies said they were interested when we first issued a request for information, but when it came time to submit a bid most of them backed out.” There was a critical shortcoming in demonstrated expertise in developing dependable automated dispatch of the BESS in case of a system outage. “It was not easy to find people who knew what they were doing when it came to program the logic in the microgrid controls.”

- **Project Delays.** “I’d advise a co-op to take their original estimates for time taken to complete the project and double them – and even then, that might not be enough,” says Brown. Trying to execute the final stages of the project during the outbreak of the coronavirus pandemic did not help, notes Short, but he says that obtaining a variety of permits from state and county offices was a burden from the outset. “In retrospect, I’d have chosen a different property for the project, for that reason,” he says. The co-op fronts a state highway, which brought in oversight from both jurisdictions. Then he says a “ditch alongside the road” triggered a ‘waters of the U.S.’ (WOTUS) rule review from the U.S. Army Corps of Engineers. A time-consuming and expensive process eventually determined that there was no federal oversight required.

Other project takeaways:

- One decision that has proven to be a positive amidst the permitting difficulties was AEPCO’s decision to apply for a conditional use permit for the entire site at the beginning of the process. This permit covered both the solar PV build-out in phases one and two, as well as the addition of the battery energy storage system.

- Refining the logic and automated controls in the microgrid to both meet the requirements of the distribution cooperative and be set up for dispatch from AEPCO’s control center in Benson, Arizona, was the most complex challenge of the project.

- A few recent updates at Anza will likely change the operation of the battery system and microgrid. These include:
    - Additional upgrades from SCE to its area transmission network are expected to reduce outages.
    - The rapid load growth at Anza has eased in the past two years.
    - Through close monitoring, Anza found that it is getting sufficient production from the existing 2 MW of solar – and 1 MW of net-metered solar supplied to the grid from member-owned systems – to offset more of the 6:30 pm system peak load than originally anticipated.

Use Case #4: Renewable Energy Integration

Renewable energy offers attractive characteristics - little or no fuel cost, low operating costs, and low or no emissions. But as with all generation resources, there are drawbacks. For electric utilities, the most critical drawback is the variable and often non-dispatchable nature of most renewable generation. As renewable resources like solar and wind become cost-competitive with new fossil fuel generation, the need to address the variability becomes significant.

Unlike traditional generators, the variability of output from renewables affects integration with the larger energy system. For example, if a solar array or wind turbine experiences a sudden unanticipated drop in output, another generation source must be online to pick up the slack or load should be correspondingly reduced in the same timescale, to avoid system disturbances that if left unchecked, could result in a brownout or a blackout. And, rapid changes in system output, especiaslly from solar, can cause local voltage imbalances, resulting in flicker and other problems that may affect power quality.

Such intermittent availability must be managed, and in the case of solar and wind, improved forecasting through computer modelling is one such tool that can diminish the impact of variability. However, a battery storage system, dispatchable by its very natue, holds particular promise in easing the integration of renewables onto the electrical grid.It can provide short term benefits such as improved voltage regulation, and it can shift power from times of excess generation to delivery at times of higher demand.

Case study: Cordova Electric Cooperative

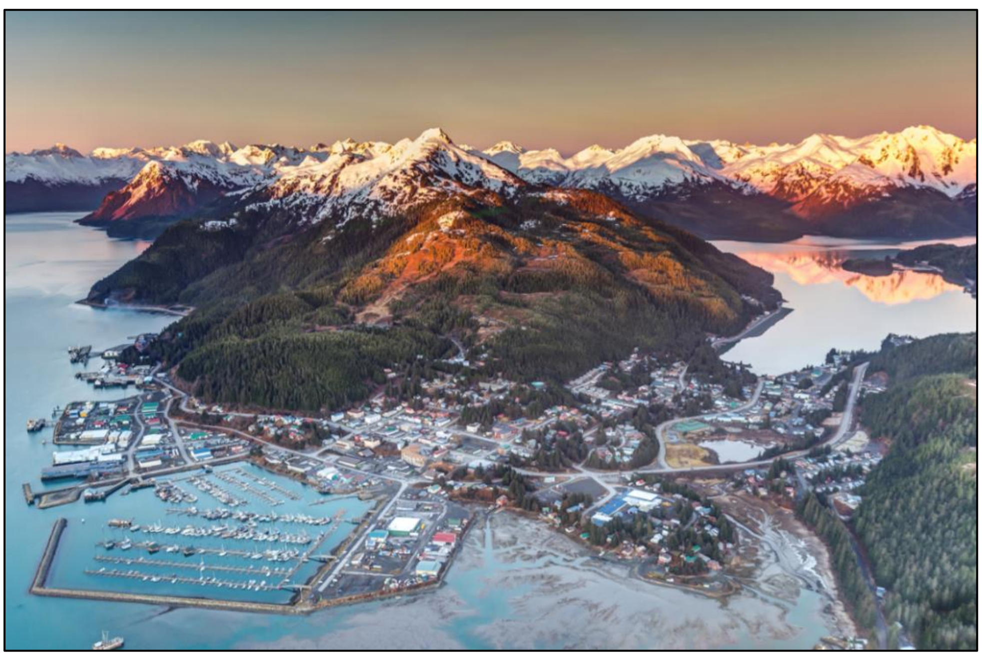

Figure 7: Cordova, Alaska
(Courtesy of Cordova Electric Cooperative)

Cordova Electric Cooperative (Cordova EC) serves 1,500 consumer-member accounts in and around the town of Cordova in the southeastern part of Alaska (Figure 7). It is in effect an "island" utility without connection to a larger electric grid. Its location along the rugged coastline of the Prince William Sound cuts the community off (Figure 8), not only from the Alaska highway system, but also from the state's main "Railbelt" electrical grid to the northwest.

The area has more than 200 days of precipitation per year, providing significant renewable electric generation in the form of run-of-river hydroelectric power. Hydropower provides more than 75 percent of the cooperative's annual energy needs, and costs approximately six cents per kWh. Diesel-powered generation provides the remaining energy and acts as a spinning reserve to help manage the variability of the hydropower. But it is very costly: depending upon the price of fuel, diesel power is delivered at between 40 to 60 cents per kWh.

Optimizing its hydroelectric generation, and improving the efficiency of its diesel generators, is critically important to maintaining affordable power to the Cordova EC members. After evaluating options, the solution chosen was the installation of battery energy storage to provide both spinning reserve and a dispatchable power source that can replace some of the power provided by the diesel generators.

The battery energy storage has been deployed with strong modelling, engineering, integration, and optimization support through the U.S. Department of Energy's Energy (DOE) Storage Research Program directed by Dr. Imre Gyuk. DOE sponsored a multi-partner research effort initiated in 2015 at Cordova EC. The Battery Energy Storage system has been very successful to date, and it is being included as a grid element for improving Cordova EC's system resilience through the RADIANCE project; a DOE Grid Modernization Laboratory Consortium project that includes NRECA's Business and Technologies Strategies department, Sandia National Laboratory, Pacific Northwest National Laboratory, Idaho National Laboratory, Alaska Village Electric Cooperative, and the Alaska Center for Energy and Power. The RADIANCE project at Cordova studies how deployments of emerging technologies, such as micro-phasor measurement units (micro-PMUs – a device that measures phase angles between voltages which can be compared at different points in the network to assess grid stability and performance parameters) and battery energy storage systems, can add efficiencies and capabilities to a utility's electric grid to improve resilience. The RADIANCE project has also identified potential cybersecurity vulnerabilities and developed future requirements for enhancing cybersecurity in grid operations.

Figure 8: Location of Cordova Electric Cooperative (Courtesy of Cordova Electric Cooperative)

The Need for Renewable Integration and the Case for Battery Storage

Cordova EC supplies power to its members using two run-of-river hydro-electric plants (1.25 MW Humpback Creek plant and 6 MW Power Creek plant) along with the Orca Diesel Plant (a 10.8 MW plant with five generators ranging from 1 to 4 MW). With run-of-river hydro systems like those at Cordova, the power that can be generated depends upon the amount of water flowing in the river, since there are no dams to store water. The output is variable; at times of high rainfall, the hydroelectric potential exceeds the cooperative's load, while during the deep freezes of winter, it may fall short requiring more generation from diesel power plants.

Cordova EC's loads are primarily residential, but the cooperative also serves some light commercial and industrial fish processing plants. Because the fish processing plants can cause a 10 to 15 percent surge in demand in a matter of seconds, spinning reserves (in the form of deflected/unused hydro capacity) was also incorporated into Cordova's run-of-river hydro plants, by foregoing power that could be generated, in order to create supply flexibility. These spinning reserves were historically kept at as much as 750 kW in the summer and 300 kW in the winter. Even though these load spikes can be of short duration, they can rapidly consume the system's hydro spinning reserve, causing the automatic startup of a diesel generator. Because the diesel generators must be run at a minimum output of 400 kW, the cooperative was forced to spill an additional 400 kW of hydro generation (beyond the spinning reserves) by deflecting water away from the turbines, sending almost 1,150 kWh of potential low-cost hourly renewable generation down the river during the summer season. With a battery system in place, it can operate instead of a hydro or diesel generator for spinning reserves of up to 1,000 kW, both supplying and absorbing power to maintain grid frequency. As long as demand is low, a diesel generator will only kick in when the system load exceeds the total available hydro capacity and the state of charge (SOC) of the battery drops to a set point of 30 percent. The generator will then both supply power to meet the grid's needs while also recharging the battery. Once the SOC of the battery reaches 70 percent, the generator will shut down and act as spinning reserve, as long as the battery state of charge stays above 30 percent.

Cordova EC Energy Storage Project Design and Description

The cooperative chose battery energy storage over flywheels and supercapacitors as the technology best suited to minimize the operation of the high cost diesel generator, maximize the use of its low-cost renewable resource, and provide additional benefits such as increased system resilience. The 1 MW / 1 MWh lithium-ion battery energy system was installed in June 2019 at a substation that connects Cordova EC's four primary feeders and is located three blocks from critical loads, including the town hospital. The project includes 'next generation monitoring' through the use of the micro-PMUs, which will allow the cooperative to quickly identify and respond to sudden changes in demand while maintaining grid reliability and stability. The BESS will also be used as one solution to avoid excess diesel generator startups, and it is also being assessed as a solution for providing emergency power supply to the community hospital.

When choosing their BESS, Cordova EC chose to go with well-established suppliers with strong track records. The SAFT USA battery is integrated with an advanced inverter from ABB, and the whole system was shipped to the site in a single modular container. Similar SAFT-ABB systems have been deployed elsewhere in Alaska and have operated successfully in the state's cold weather arctic regions and in coastal rainforest conditions in Cordova's case.

The turnaround from initiating the ordering process to full, autonomous operations of the BESS was one year. The final procurement was made in October 2018 and the BESS was 'hot commissioned' and operational on June 7. It was in autonomous operation by Thanksgiving.

Figure 9: CEC Employees and ABB technician Installing and commissioning the BESS at Cordova.
(Courtesy of Cordova Electric Cooperative)

Economic Justification

An initial feasibility and sizing study for the proposed battery system by the Alaska Center for Energy and Power in 2016 indicated that energy storage would reduce the need for diesel generation as spinning reserve and help improve diesel generator efficiency. Refined feasibility assessments in 2018 had projected payback time on the investment to be longer than the initial analysis suggested. Since operation commenced, however, the system has exceeded the expectations of the 2018 assessment, generating greater savings which may result in a payback period close to those initially projected in 2016. The cooperative is working through operational refinements and Clay Koplin, CEO of the Cordova EC, is confident that control and operational refinements will produce even greater efficiencies and expanded use cases.

Figure 10: CEC BESS Ribbon Cutting Ceremony (6/7/19)
left to right: Denis Silva, SAFT; Dr. Imre Gyuk, DOE; U.S. Senator Lisa Murkowski
(Courtesy of Cordova Electric Cooperative)

Operational Experience

Koplin says “the battery buys us an extra 500 kw to 1 MW of power for our system. However, that use must be judicious in order to extend the life of the battery system.” Cordova EC is working to find the “sweet spot” in how the BESS is utilized, to maximize the many ways it can improve the efficiency and resiliency of the cooperative’s isolated grid, while doing so in ways that extends the life and cost-effectiveness of the battery system.

Koplin notes that batteries incur a “calendar aging” a degradation of as much as 2 percent a year even without use. When in use “what ages batteries the fastest is the depth of discharge. In our case, if we utilize the battery to supply as much stored power as possible through deep discharges, we’ll see a rapid loss in the life of the system.” If the Cordova system is utilized primarily for energy arbitrage – completely discharging and recharging the battery to deliver the lowest cost kWh – it may be able to cycle [from 100 percent SOC to complete discharge] 5,000 times, delivering a total of 5 GWh of energy, before it reaches the end of its useful life. However, if the BESS is used judiciously in a grid balancing mode, with discharges and charge cycles of just 5 percent of SOC, the battery will deliver one million cycles, or 30 GWh, over its life. Utilization for frequency regulation – which requires many small charge and discharge cycles – can take place at the same time as bulk charging or discharging. “The trick is to optimize the setpoints for the larger SOC swings in order to preserve battery life, while maximizing savings in diesel fuel,” says Koplin.

Additional Use Cases for Battery Storage at Cordova Electric

The primary energy storage use case focuses on increasing the efficiency and effectiveness of Cordova EC’s critical renewable energy resource by reducing reliance on diesel-powered generators. Cordova expects to increase its use of hydroelectric power to meet its demand from a previous high of 78 percent to closer to 85 percent in the future.

Use of the battery is changing the dispatch of the cooperative’s diesel generators, resulting in the use of fewer, more highly loaded gensets, while avoiding burning tens of thousands of gallons of expensive diesel fuel a year. This will also reduce diesel generator maintenance costs, which are typically based on a “per-operating-hour” basis rather than on specific electrical production.

The BESS also contributes to the resiliency of the cooperative’s grid. Without connection to the Alaskan Railbelt electric grid, there is no outside resource to call on if the cooperative’s generation fleet or its distribution system experiences problems. The local area is subject to harsh weather conditions, including flooding, excessive snow, avalanches and earthquakes. The cooperative’s distribution system is 100 percent underground. While this provides reliability benefits, it also limits the ability to add automatic switches and other gear commonly considered for increased resilience. The advanced distribution monitoring coupled with the battery energy storage can help keep the system stable in the face of weather-related outages, with the battery storage able to provide power to critical infrastructure, such as the hospital.

Additional Observations from The First Six Months of Operation

- Integration of battery storage into a microgrid is costly and complex.
- The cost of removal, recycling, replacing a full battery set is expected to be 60 percent of the initial package cost.
- Factory warranties and required annual maintenance are expensive.
- Control algorithms are complex.
- Significant improvements can be expected through careful monitoring and iterative optimizations

What Can Other Cooperatives Learn from This Project?

Cordova Electric Cooperative is one of just a handful of electric cooperatives that functions without a connection to an external grid. Yet within its operational footprint, this Alaska co-op faces many of the same challenges today that will be increasingly face electric co-ops nationwide – the need to integrate renewable energy efficiently, to cope with fast-changing demand, and generally maximize the use of existing resources. Cordova EC provides a window into the potential role for battery energy storage as a means of meeting these challenges.

Koplin says that “once you have a battery in place, you can back up solar, wind, or any other resource. Depending upon the resource, you may need to program different ramp rates. That’s just electronics.”

The BESS project at Cordova provides a deeper understanding of how advanced control technologies might be deployed at a small utility, and evidence of what can be expected in terms of a return on investment in a more complex set of operating components.

Use Case #5: Microgrids

Case Study: North Carolina's Electric Cooperatives

Battery energy storage is often a key component of a microgrid, an integrated energy system prominently featured in models for a decentralized distribution grid. The electric cooperatives of North Carolina, in partnership with North Carolina Electric Membership Corporation (NCEMC), the state's generation and transmission cooperative, have undertaken a comprehensive program to test and deploy microgrids in a variety of locations, sizes and configurations. Designed to operate whether connected or disconnected from the traditional grid, microgrids provide a suite of benefits, from peak shaving and the integration of renewables to ancillary services that can be monetized in a regulated market. Testing the microgrid's ability to operate in "island mode" and provide value by keeping power flowing to consumer-members during a grid outage is a key strategy in North Carolina's electric cooperatives' microgrid deployment.

The U.S. Department of Energy's definition of a microgrid is ''*a group of interconnected loads and distributed energy resources 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 grid-connected or island-mode.*"

As risks for power outages due to severe weather, cyber-attacks, and other causes persist, electric utilities are seeking new solutions to both respond to and prevent power outages. A microgrid, which can operate independently from the utility grid, has the potential to quickly restore power to critical services. A typical microgrid design draws from one or more sources of distributed generation, coupled with energy storage and a controller to manage the components, which provides a grid signal that allows distributed generation to continue operating during an outage. Active load control and other smart grid features optimize the resiliency value of the microgrid.

North Carolina's electric cooperatives' focus on microgrids is a product of their Innovative Energy initiative launched in 2015 to actively assess and deploy emerging technologies. As of July 2020, NCEMC and its distribution cooperatives are partnering in the development and operation of five microgrids. This case study will focus on the first two microgrids developed by NCEMC, the Ocracoke Island project with Tideland Electric Membership Corporation (Tideland EMC), and the Butler Farms project with South River Electric Membership Corporation (South River EMC). Each project was initially proposed in 2015, saw test operations commence in late 2017 (Ocracoke) and early 2018 (Butler Farms), and are now fully operational assets.

NCEMC's experience with its first two microgrids provides valuable insights for electric cooperatives across the country. The North Carolina projects demonstrate the multiple values that can be expected from microgrids and battery energy storage over the long term, but also reveal the setbacks that may be encountered in the short term, primarily in working through the painstaking technical issues of what are essentially unique, custom-designed energy systems. In short, at this time, microgrids do not operate problem-free "out of the box," and instead require custom design at each unique location and application, as well as fine-tuning of the controls that allow the various components to operate in concert, efficiently and effectively.

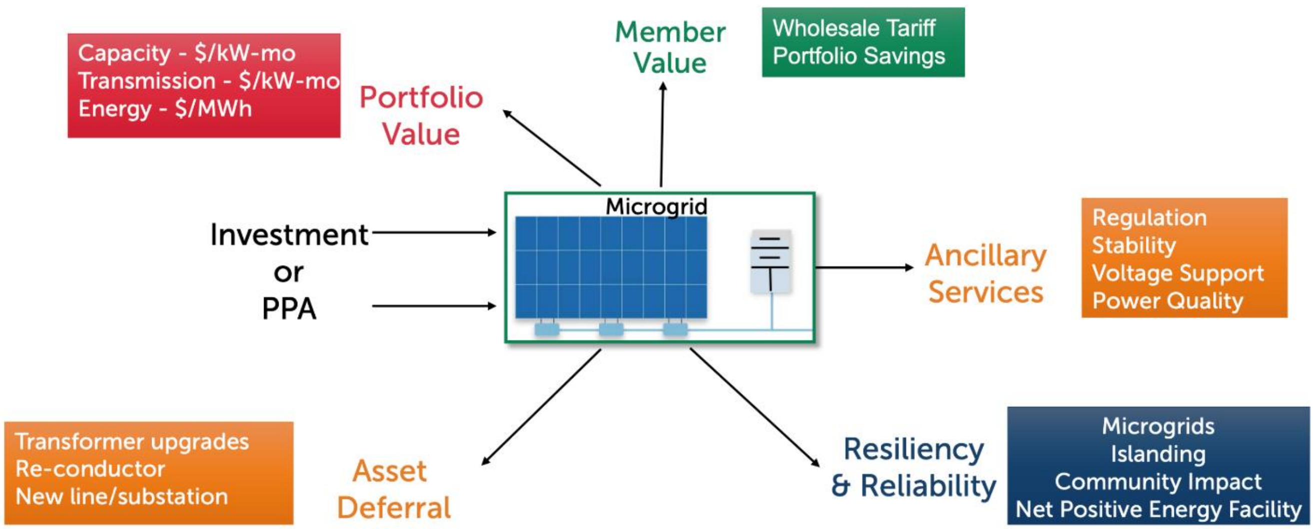

Figure 11: Microgrid Value Streams Identified By NCEMC
(Courtesy of North Carolina Electric Membership Corporation)

Ocracoke Island Microgrid

Ocracoke Island is a barrier island, part of North Carolina's Outer Banks. The island, which is only accessible by ferry, boat or private plane, is served by Tideland EMC, a cooperative with more than 22,000 meters and headquartered in the mainland town of Pantego.

Ocracoke is the last island on the transmission line. Electricity arrives at Tideland EMC via a single 25 kV sub-transmission line that connects through Cape Hatteras Electric Cooperative's infrastructure on neighboring Hatteras Island and eventually to a Dominion Energy substation. Because Ocracoke is at the end of the line, its power supply is impacted by any physical disruption along the feeder. As a barrier island, it is also vulnerable to impacts from severe weather.

John Lemire, NCEMC's director of grid management, recalls speaking with Tideland EMC's engineer in 2015 about the concern over service reliability to the hurricane-prone Outer Banks barrier islands. "He said to us that it sure would be nice to add another diesel generator to the back-up power resources on Ocracoke," said Lemire. But, they quickly realized permitting a new diesel generator would be problematic. "We wondered, 'Is there something else?' That was the genesis of the Ocracoke microgrid." Tideland EMC is focused on service and recognized there was an opportunity to harness innovation that could provide a variety of benefits to members.

Figure 12: Ocracoke Island
(Courtesy of North Carolina Electric Membership Corporation)

Figure 13: Ocracoke Microgrid Site
(Courtesy of North Carolina Electric Membership Corporation)

Designed for resiliency, the Ocracoke microgrid became the first “living laboratory” for the G&T to test microgrids as a dynamic asset for back-up power during an outage. NCEMC also used the Ocracoke project to assess five other use cases of economic and operational benefits. These benefits started with those specific to the island. Other benefits were system-wide, in a scenario where the G&T could bid the assets of the microgrid and its battery energy storage system (BESS) into the regional PJM wholesale market while connected to and synchronous to the greater grid.

Ocracoke Microgrid Project Design and Description

NCEMC contracted with PowerSecure as the engineering, procurement and construction (EPC) company to develop the microgrid at Ocracoke (Figure 14). The installation commenced in June 2016 and the microgrid was energized in December 2016.

The bulk of the microgrid's generation comes from an existing 3 MW diesel generator that has provided standby generation to Ocracoke Island for 25 years. Since the installation of the diesel generation, the peak load on Ocracoke has grown to more than 5.5 MW. Even with the reduced local loads that result during evacuations that are standard during a serious weather event, Tideland EMC needed to be able to supply more power than can be obtained from the diesel generation alone. As a result, three new components were added to the site:

- A 62-panel, 15 kW solar array on the roof of the diesel generator plant
- A 500 kW / 1 MWh Tesla PowerPack battery bank
- A microgrid controller hosted on a Schweitzer Electric (SEL) Real-Time Automation Controller

In addition, the cooperative added load management assets at member homes to reduce peak demand:

- 200 Wi-Fi connected thermostats
- 50 water heater controls

The smart thermostats and water-heater controls add 300-500 kW of demand response. In theory, the combination of increased supply and reduced demand allows Tideland EMC to keep all circuits energized during a storm evacuation or maintenance event.

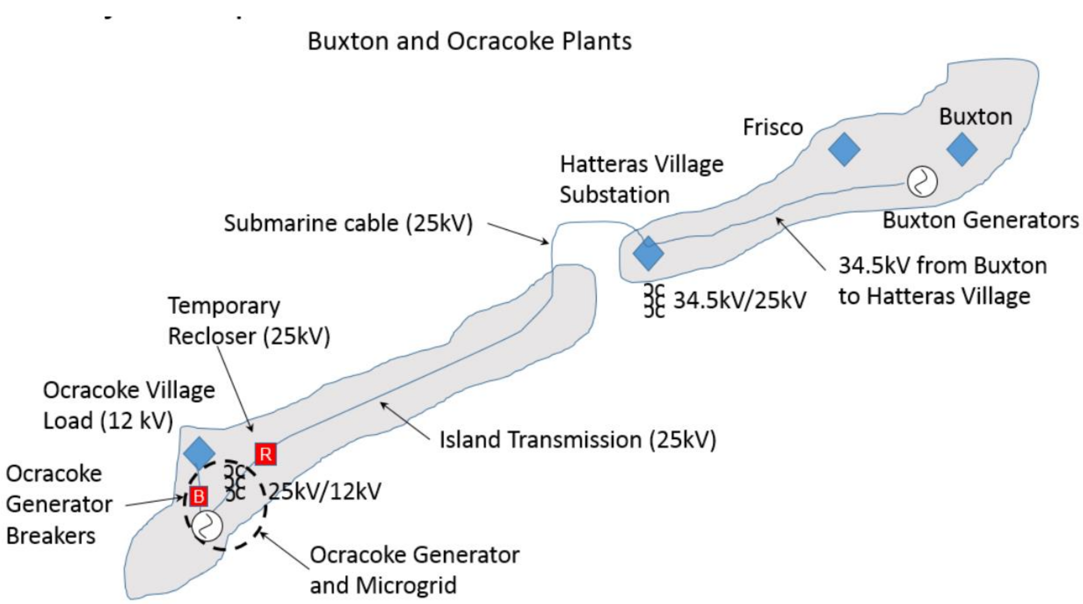

Figure 14: Ocracoke Microgrid Design
(Courtesy of North Carolina Electric Membership Corporation)

The microgrid was originally installed upstream from the island's load on a 25 kV circuit and directly connected to the substation where the sub-transmission voltage is stepped down to 12 kV distribution level. This upstream location was initially selected due to space limitations, cost and ease of installation. The microgrid was later moved downstream on the 12 kV load circuits to optimize benefits to the system. More detail on this is provided in the section below.

The microgrid is controlled via NCEMC's Integrated Operations Center using a combination of telecom data circuit, ethernet and fiber. NCEMC can monitor system and equipment voltages, power outputs and the status of reclosers. The G&T can also control the output of the battery, as well as the water heaters and thermostats. The Tesla Master Controller is on a different network, which allows Tesla to access the BESS for remote troubleshooting and data retrieval. It is behind a firewall to prevent potential security weaknesses from propagating to the microgrid system.

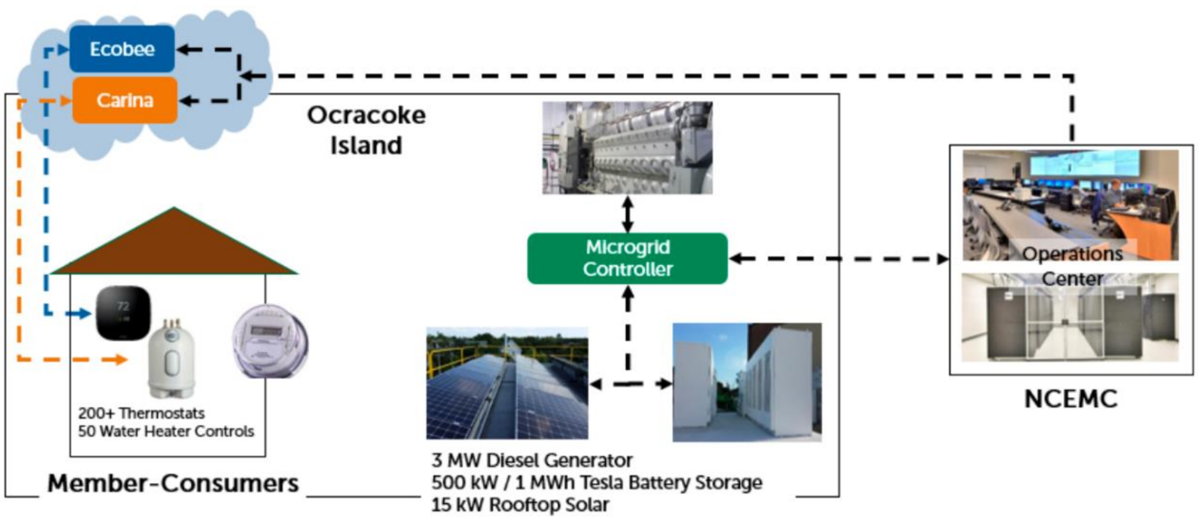

Figure 15: Ocracoke Microgrid
(Courtesy of North Carolina Electric Membership Corporation)

Testing the Potential Values of the Ocracoke Microgrid

Beginning in 2017, NCEMC used the Ocracoke microgrid as a research laboratory, running a series of virtual and real-world tests of the microgrid's ability to deliver any or all of the following potential values:

- Distribution system upgrade deferral
- Demand response and energy arbitrage (for peak shaving)
- Ancillary services (in regulated market)
- Island operation (resiliency)
- Smoothing impact of renewable energy integration
- Power quality

> *A detailed report on NCEMC's tests of these use cases can be found on NRECA's cooperative.com website: NCEMC Microgrid Implementation Report (2018).*

The first three potential values are primarily economic, while the next three are primarily operational. All three economic values of the microgrid showed the potential for savings, primarily as deployed within the PJM market area, however relatively low energy and demand prices in the 2018-2019 evaluation year made the prospect for savings from energy arbitrage and ancillary services quite modest. Over-saturation of new energy storage bidding into the PJM market depressed the return on ancillary services. In addition, "stacking" ancillary services and demand response uses is technically impractical. Asset deferral showed the most promising economic return by delaying the replacement of a 34.5/25 kV transformer for at least five years.

The initial tests of the three operational values, while positive and proving the test concepts, are not being implemented at this time. In theory, the inverters on the solar array and the battery storage can supplement or replace capacitors in the function of providing power quality through the injection of reactive power or VAR (volt-ampere reactive) into the grid. However, communicating with the inverters to test this value in this remote location was difficult. Smoothing renewables through a combination of identifying and controlling set points on the solar inverter and using solar forecasting and a finely programmed energy management system for the solar and storage outputs proved technically possible but not currently feasible for the small size of the on-site solar PV array. Lessons learned from these operational tests are being applied in other parts of the system with other resources.

In initial tests of the islanding operation of the microgrid, serious problems with over-voltage occurred. Part of the issue lay in the connection of the Ocracoke microgrid to the 25 kV sub-transmission system. During the first test of islanding, high voltage on the 25 kV side caused the failure of a lightning arrestor, a drop in voltage and a loss of all generation to the village when the microgrid recloser opened. After safety checks, the islanding operation began with the diesel generation serving the village load. However, a similar over-voltage occurred when attempting to add the battery and solar, and the test was aborted.

The project team, including NCEMC, Tideland EMC and Power Secure, spent several weeks analyzing the issue. Eventually, the key problem was identified as a lack of an adequate ground reference in order to stabilize voltages on the delta-configured (25 kV side) transformer when operated in the islanded mode. NCEMC relocated the microgrid assets to the 12 kV distribution side, which has solved the over-voltage issue.

The Ocracoke microgrid performed well in a real-world event, when Hurricane Dorian roared into the Outer Banks in the fall of 2019 (Figure 15). The main transmission feeder that runs down the chain of islands went out, and Ocracoke saw historical flooding damage, which initially limited access to the microgrid enclosure. After an inspection of the BESS components, which sit on a four-foot raised concrete platform in anticipation of high waters, the microgrid was partially energized, bringing power back to parts of the island hours before grid service was restored.

Figure 15: Hurricane Dorian
(Courtesy of North Carolina Electric Membership Corporation)

Butler Farm Microgrid

For its second microgrid project, NCEMC shifted its focus from a utility-controlled environment, to testing the feasibility of working with assets on the member-consumer side of the meter. NCEMC partnered with a sustainability focused hog farm, Butler Farms and Bioenergy, operated by Tom Butler in Lillington, N.C., and the local distribution cooperative South River EMC. Ten years ago, Tom Butler began capturing biogas in an anaerobic digester from hog waste in covered lagoons and using the biogas to power a 180 kW generator. With the addition of a 23 kW grid-tied PV array and a 100 kW diesel generator, Butler Farms provided a suite of generation sources for a microgrid.

Butler Farms Microgrid Project Design and Description

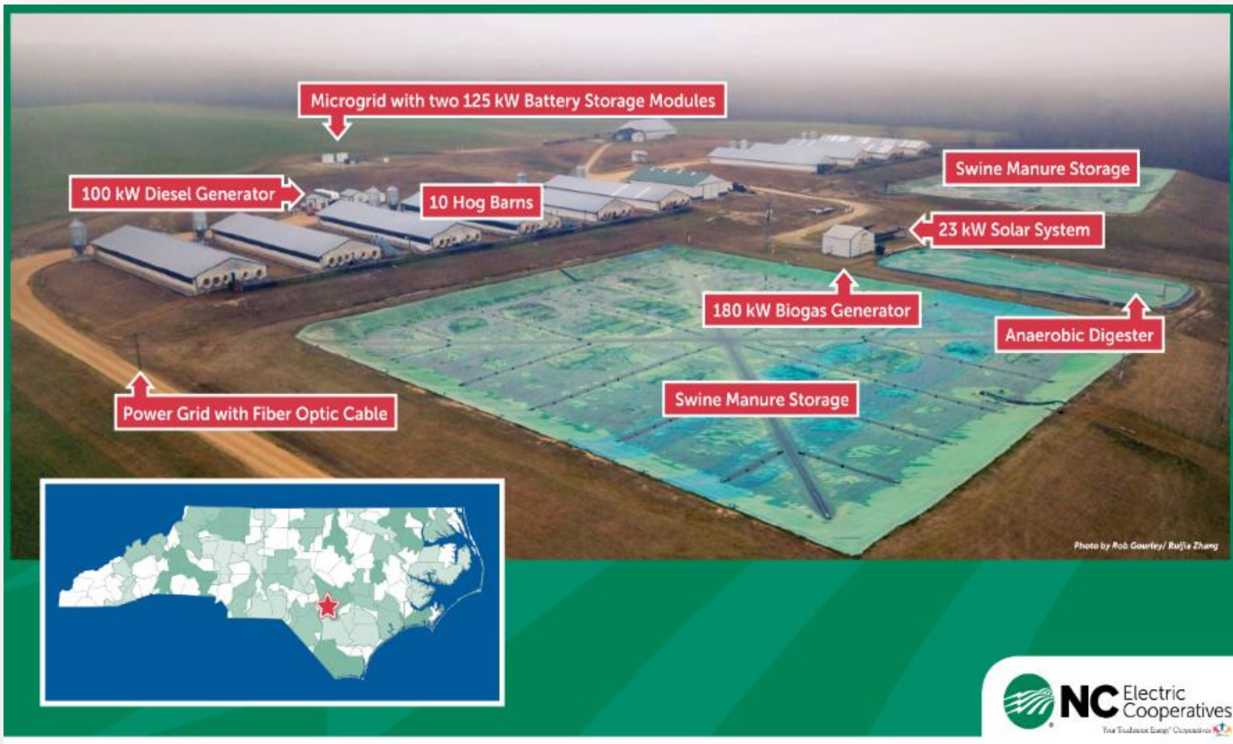

Figure 16: Butler Farms Microgrid, Tied into South River EMC System
(Courtesy of North Carolina Electric Membership Corporation)

NCEMC again contracted with PowerSecure as the EPC. PowerSecure assembled the microgrid on a turnkey contract utilizing the following resources:

Existing generation on the site (owned by Butler Farms):

- 180 kW methane-powered electric generator
- 23 kW solar PV array
- 100 kW diesel generator

Additional microgrid components:

- Two Samsung lithium-ion batteries each rated at 125 kW / 372.5 kWh
- Microgrid controller
- Reclosers on the distribution feeder

South River EMC owns the solar and biogas meters, as well as three reclosers (the microgrid recloser and two distribution line reclosers). The distribution cooperative also installed fiber communication for the microgrid.

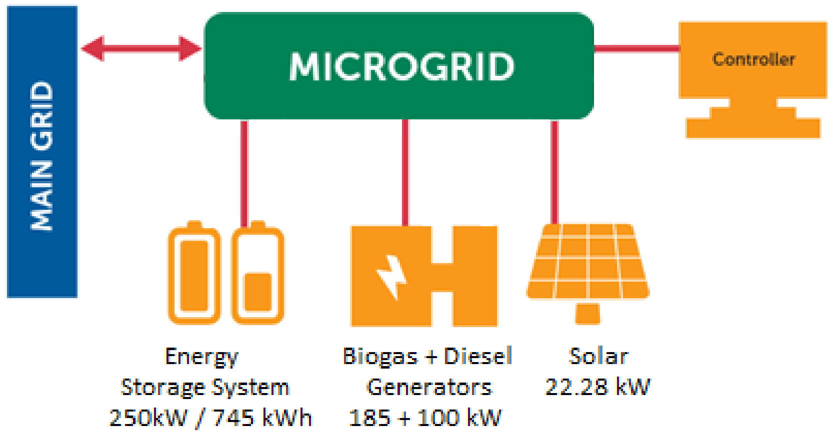

Figure 17: Butler Farms Microgrid Configuration
(Diagram Courtesy of North Carolina Electric Membership Corporation)

Similar to Ocracoke, the primary use case for the Butler Farms Microgrid is resilience, providing a local source of power for the farm and nearby community that can be energized during a grid outage. A secondary use of the microgrid is to provide other services (such as peak shaving) while in grid-tied mode.

NCEMC tested the operation of the microgrid in three stages:

- Phase 1 (February 2018) – the microgrid is commissioned though the farm, but not isolated in island mode (a simulation was run through the controller).
- Phase 2 (June 2018) – the microgrid isolated in island mode powers the farm as well as a segmented section of the nearby distribution grid (28 houses).
- Phase 3 (February 2020) – the microgrid incorporates the full suite of Butler Farm generation resources (biogas and diesel generators, PV array) both in island mode and in grid-connected mode.

However, as with Ocracoke, the early testing at Butler Farms experienced a failure. Due to other work underway at the farm, NCEMC did not start with a "hard" commissioning (cutting power to the farm and operating the microgrid in island mode), but instead simulated an outage on the controller. In September 2018, during the first live event where the microgrid was expected to island the farm in response to an outage on a nearby feeder, an alarm prevented the transition from taking place. Eventually, the failure to operate in island mode was traced back to the design of an older recloser that predated the system's smart sensors. When this recloser detected a loss of alternating current (AC) power, the recloser opened and generated the alarm that would not clear until AC power was restored. This recloser combined all alarms into a single alarm point. The microgrid would attempt to reset the alarm point prior to forming the island, and when it could not reset the alarm, the microgrid would stay shut down and power could not be supplied from the microgrid. Once NCEMC and South River figured out this issue, a team quickly redesigned the system alarm to only alert for a critical component failure of the recloser and successfully tested the islanding capability.

The microgrid passed its first real world test in May 2019 when a falling tree took out a 12 kV feeder serving the farm. In this instance, the microgrid recognized the outage and transitioned to island mode to maintain power at the farm during the 20-minute outage.

Lessons Learned: What Other Cooperatives Can Learn From NCEMC's First Two Microgrid Projects

- **Microgrids can achieve technical success – but projects are highly customized.** The cooperatives and their partners worked through unexpected technical challenges in smoothly integrating a stand-alone energy system into a traditionally designed distribution grid environment. Customization is not only required in design, but also in problem solving. "Our approach to microgrids is not to expect a cookie cutter approach," says Lemire. "We need to discover efficiencies, and eventually standardize the design and construction as much as possible."

- **The controller is the heart of the microgrid – and it takes time to optimize its function.** In the Butler Farms project, there are three levels of controls to synchronize. The primary level is at the devices, such as the solar and biogas generation inverters. The second level is an overall site controller. The third is the utility control level, which includes SCADA and the distributed energy resources management system (DERMS). "Microgrids are complex – make sure you reach a good steady state before you move forward," says Lemire.

  Two years into the project, enhancements to the Ocracoke controller now allow a higher level of automation and efficiency in the function of the microgrid, evidenced by its ability to monitor and respond to grid conditions and optimize the use of the diesel generation, saving fuel.

- **Clarifying roles and responsibilities is critical.** A multi-party project like Butler Farms involves various levels of ownership, as well as lease, operating and interconnection agreements. "We've made a concerted effort to document who controls and maintains equipment and promote an understanding of the roles and responsibilities of all parties," says Lemire. We have also spent a lot of time ensuring that the regulatory construct of the service has been maintained. Power directly serving the farm and homes within the microgrid boundary is provide by South River EMC, while power delivered from the batteries during island mode is billed by NCEMC to South River EMC.

- **The focus is still on optimizing the technology, not making a return – yet.** The Ocracoke and Butler Farms projects have demonstrated that microgrids can be a tool to meet needs, and that cooperatives can leverage the suite of benefits that have been predicted in the research environment. "Microgrids have contributed benefits to our systems that impact our members, and it is critical that we learn to effectively integrate innovative technologies as our industry evolves," says Lemire.

- **NCEMC has not settled on a preferred technology or business model.** In its five microgrid projects that are in construction or operational, NCEMC has utilized different EPCs, controllers and battery energy storage systems (including Tesla, Samsung and NEC), as well as different ownership options. One constant is that economic returns are shared with the entities that invest in the projects. Many of those benefits are directed to the local partners. For example, demand response savings are shared by the G&T with the membership as a whole. Each project is carefully constructed to preserve the regulatory construct between the distribution cooperative and NCEMC.

- **Secure, high speed communications is critical.** NCEMC and its member cooperatives are supplying fiber communications to each microgrid site. Communications from the site controllers are handled through NCEMC's private Verizon cloud system, allowing microgrid functionality in the event that external communication is lost.

- **The Advanced Grid Management concept is becoming a reality.** NCEMC is in the early stages of managing its growing fleet of microgrids through its DERMS platform. In aggregate, the microgrids and other DER and DR resources can also be used to provide reliability services upstream to the Transmission Operator for grid reliability events of economic benefit to the power supply portfolio.

- **It is an opportunity to highlight innovation in member service and technology leadership.** NCEMC's microgrid projects have won numerous awards and have been featured in both cooperative and industry publications. Partnering with members like Tom Butler makes a difference. "He's a great guy and is such an effective advocate for the co-op, the project and the cause," says Lemire. "He really understands the microgrid concept, the renewable concept and the value of using local resources to provide power when it otherwise is not available."

What's Next: The New Generation of Microgrids Are Developing Organically With New Uses

NCEMC has completed one additional microgrid, and two more microgrids are nearing completion and due online in 2021. These projects expand the use cases for the utilization of battery energy storage, including serving as an opportunity to encourage electrification of a variety of end-uses by both commercial and residential members, deferring on-site use of fossil energy.

There are already some early takeaways from the development of these new microgrid projects:

- NCEMC's investment in microgrids gives distribution cooperatives a new means to engage with commercial members and provide alternative provisions for onsite energy use that are a "win-win" for the end-consumers and the cooperatives.

    - A microgrid was recently completed at a sustainable housing development named Heron's Nest, where the builder had planned to outfit each home with rooftop solar and electric tankless water heater appliances. Tankless water heaters contribute to rapid demand spikes and are unsuitable for load management. NCEMC and the local co-op, Brunswick Electric Membership Corporation, convinced the developer to install high efficiency electric water heaters with tanks instead, along with smart thermostats, water heater controls and a plan to save homeowners money through an off-peak load management program. The developer also added a community solar garden and battery energy storage. Details include:

        - Developer installed a 230 kW / 255 kWh battery storage and 62 kW solar PV

        - Homeowners own rooftop solar PV and EV ready plugs, as well as smart thermostats and water heater controls
        - NCEMC partnered with Open Access Technology International (OATI) to install their GridMind microgrid controller
        - Resiliency services to be provided through a mix of solar generation, battery storage and demand side assets managed by NCEMC
        - Heron's Nest was awarded the 2020 Grid Integration Power Player of the Year Award by the Smart Energy Power Alliance

    - At Eagle Chase, a housing community being built on the lines of Wake Electric Membership corporation (Wake EMC), the developers planned to install propane generators at each home for back-up power. Wake EMC and NCEMC countered with an offer to provide the same outage resiliency through a centralized propane generation facility owned and operated by the co-op. This alleviates the cost of owning and maintaining individual generators by the homeowners, who instead pay a resiliency fee collected by the homeowners' association and paid to the cooperative. This project recently won the Research Triangle Cleantech Cluster Cleantech Community Award.

Other details on the two new microgrids under construction in 2021:

- Eagle Chase, a community designed with resiliency as a prominent feature:
    - Served by Wake EMC
    - One 300 kW propane generator with switchgear provided by Wake EMC
    - 500 kW / 1 MWh Tesla PowerPack battery and microgrid controller provided by NCEMC

- Rose Acre Farms, large egg production facility with sustainability and resiliency goals:
    - Served by Tideland EMC
    - Existing diesel generation (25 - 250 kW units)
    - 2 MW solar provided by NCEMC (offsets about one-third of the facility's power)
    - 2.5 MW / 5 MWh Tesla Megapack battery provided by NCEMC
    - Microgrid controller and other infrastructure provided by NCEMC

Conclusion

Battery storage is a flexible technology that can provide multiple value streams. It has great potential to benefit electric cooperatives and their consumer-members by potentially reducing costs, improving reliability and resiliency, helping to integrate increasing amounts of renewable energy, and providing new services to G&T cooperatives, distribution cooperatives, and consumer-members.

The projects discussed in this report highlight five use cases for battery energy storage. These use cases could have the potential to provide benefits if implemented at other electric cooperatives. However, it is important to stress that electric cooperatives' service territories and their characteristics vary widely throughout the country, and each electric cooperative should explore battery projects and the applicable use cases based on their unique circumstances.

In the future, batteries will likely become more common across the country including at electric cooperatives as prices continue to decline, standardization of projects increase, business models and use cases are further developed, and co-ops gain expertise in this emerging arena. As additional projects are deployed NRECA will continue to highlight successful projects in order to foster learning within the electric cooperative community.

Additional Resources:

- *Battery Energy Storage Overview*, NRECA, NRUCFC, CoBank, NRTC, May 2020
- *Electrical Energy Storage—A Lexicon.* Technology Advisory. 2016
- *When It Comes to Battery Storage Systems, Co-ops Should Focus on a Primary Application. TechSurveillance*. 2017
- DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA. July 2013
- Pinney, D. *Energy Storage Cost-Benefit Analysis with White River Valley EC.* NRECA. 2018
- *NCEMC Microgrid Implementation Report – Ocracoke Island Microgrid Project* (2018)
- *Ocracoke Island Microgrid – Summary of Use Cases* (March 2018)
- *NCEMC Microgrid Implementation Report — Butler Farms Microgrid Project* (2019)

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