OCRACOKE ISLAND MICROGRID

SUMMARY OF USE CASES

MARCH 2018

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EXECUTIVE SUMMARY

In 2015, North Carolina Electric Membership Corporation (NCEMC) Innovation Energy Team presented a business case to the NCEMC senior staff that comprised of a plan to build a microgrid on Ocracoke Island. This would help NCEMC save on peak, improve reliability, and conduct research on this emerging technology. Detailed planning and construction of the microgrid started upon review and approval from the senior staff. The microgrid was commissioned in February 2017 and detailed testing and use cases evaluation started in June 2017.

This document details six use cases that demonstrate the lessons learned, the value of building a microgrid, and recommendations for NCEMC or distribution cooperatives considering the development of a microgrid.

The six use cases are:

1. Demand response and energy arbitrage
2. Ancillary services
3. Capacity firming and smoothing of renewable resources
4. Islanding and resiliency
5. Asset deferment
6. Power quality improvement

Both monetary and operational values were considered for this documentation.

Use cases focused on monetary value included demand response and energy arbitrage, asset deferment and ancillary services.

Operational use cases included capacity firming and renewable smoothing, islanding and resiliency, and power quality improvement. As more distributed energy resources (DER) are developed on cooperative systems, these use cases could bring significant operational value to the distribution cooperatives as they attempt to integrate more DERs on rural feeders.

Demand response and energy arbitrage

For Ocracoke, DR and asset deferment provided the easiest and largest economic benefits. The magnitude of these benefits is heavily dependent on the location and specific application of the microgrid or microgrid components. In the PJM market area, where the Ocracoke project is located, energy and demand prices are relatively low. The value of DR and energy arbitrage are approximately $36,000 and transmission savings are approximately $31,000 for the 2018/2019 planning year. Depending on the location of the microgrid, demand and transmission savings could be significantly higher.

Ancillary services

In addition to DR and asset deferment, ancillary services is a third revenue-producing use case. The battery could participate in PJM's ancillary services market (RegD Market). When tested against a PJM regulation signal using PJM testing criteria, the battery performed better than expected, achieving a composite score of 96 percent. (PJM will accept regulation resources with score as low as 75 percent percent.) ACES Power Marketing (APM) performed an economic analysis to determine what value the battery could bring to the NCEMC portfolio if it participated in the PJM RegD market. The assessed portfolio value came in lower than expected at $22,000 on an annual basis. The low prices are due in part to the market being flooded by battery technology providing regulation services. Unfortunately, combining the value from ancillary services, DR is not a viable option due to the operation requirements of having a resource that performs both functions. NCEMC will continue to follow developments in the PJM ancillary services market but it is unlikely that a recommendation will be made to pursue this service until market prices improve.

Capacity firming and smoothing of renewable resources

Batteries can firm up renewable capacity and smooth out fluctuations associated with renewables. This capability was tested under several different scenarios. Prior to testing, several related technical challenges were resolved, including

- Determining the correct power capacity or inverter size for a specific solar array
- Determining the correct set point (capacity) for the inverter,
- Evaluating the energy capacity (kWh storage) of the battery.
- Incorporating solar forecasting and programming the energy management system (EMS) to control the battery output needed to be included.

One testing scenario included matching the battery with existing solar arrays within the portfolio and holding a static set point for a fixed period. The second scenario involved programing a solar track with a schedule that varied from hour to hour, mimicking typical photovoltaic (PV) output under sunny conditions. The final evaluation scenario was experimenting with a rolling set point, which could alleviate the intermittent renewable output's pressure on regulating resources.

<u>Islanding and resiliency</u>

The islanding test resulted in limited success. It demonstrated that the resources of the microgrid had enough capacity to serve Ocracoke island load and support operations on the adjacent Cape Hatteras Island, but the microgrid was not able to successfully island from the main grid. Problems with the way the microgrid is interconnected with the 25kV system when it is isolated from the larger grid were revealed in the testing. A detailed explanation of the events during testing follows, and an evaluation of remedial actions is currently underway.

<u>Asset deferment</u>

It was found that deferring the purchase of transformers or other equipment has the potential to bring substantial value. Currently transmission/distribution capacity on Ocracoke has significant reserve margins before Tideland Electric Membership Corporation (Tideland EMC) would require any upgrades. Aggressive load growth scenarios were considered to evaluate the value of delaying the replacement of the 34.5/25 kV transformer for 5 years. That analysis produced a Net Present Value (NPV) savings on cash flow of approximately of $61,000 that would directly benefit Tideland EMC members.

<u>Power quality improvement</u>

Testing of this use case is still in progress. Solar inverters were programmed to provide VARs and proved that with slight modifications to the settings, solar inverters can function similar to a capacitor bank. This concept was tested further by managing the VAR control remotely from NCEMC's Integrated Operations Center (IOC). Limitations on communications to the solar inverter did not enable this remote operation. Modifications to the solar inverter should be completed by mid-January to allow testing of this functionality. NCEMC also considered testing this functionality with the energy storage inverters. Through research and collaboration with other users, NCEMC determined that reactive power production would be difficult to implement at this remote location given the time and effort required to successfully bring this feature to full operation. This test will be considered as a use case for other battery storage projects.

Key lessons learned from the Use Cases include:

1. Demand response – The maximum capacity that could be integrated over two full hours was 442 kW, not the 500 kW that was anticipated.
2. Ancillary services – The battery performed better than expected, but the market value of ancillary services is lower than expected.
3. Capacity firming/renewables – The battery is an excellent way to firm up solar capacity, but a reliable solar forecast and set points for capacity and energy are critical for success.
4. Islanding and resiliency – When designing the microgrid it is important to coordinate closely with all parties who have expertise about the local system.
5. Asset deferment – A microgrid composed of supply- and demand-side resources can extend the life of assets on both the transmission and distribution systems.
6. Power quality improvement – Solar inverters can be programed to solve issues on the distribution system.

This project has provided NCEMC staff and others with valuable lessons in the planning, development and testing of microgrids and the individual components that make up a microgrid. These lessons learned have already been applied to NCEMC's second microgrid at Butler Farms and will no doubt prove to be valuable to North Carolina's electric cooperatives and others as they endeavor to develop similar projects. A detailed description of all six-use cases follows.

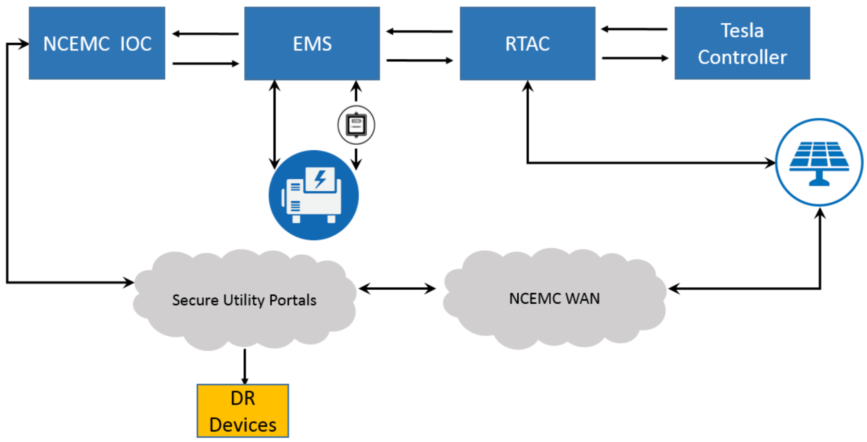
DEMAND RESPONSE AND ENERGY ARBITRAGE – USE CASE 1

BACKGROUND

DR and energy arbitrage are expected to be the most straightforward and most frequently implemented functions of the Ocracoke Microgrid. Situated in the PJM market area, the battery and demand response components of the microgrid are dispatched to take advantage of market opportunities in PJM. Use Case 1 evaluates actual performance and projects the potential savings of using the microgrid for DR and energy arbitrage.

To dispatch the battery, the Energy Operations staff accesses the controls through NCEMC's EMS. NCEMC utilizes a GE/Alstom EMS system. To enable this functionality, custom programming and EMS displays were developed and added to the system by NCEMC IT staff. The additional programming enables the user to select the rate of charge or discharge (1kW-500kW) and initiate the event. The EMS system converts these actions to commands and sends them to the Schweitzer (SEL) Real-Time Automation Controller (RTAC) that is linked to the Tesla battery controller. The

RTAC acts as the microgrid controller. The illustrations below include a control schematic for the microgrid as well as screen capture from the EMS display:



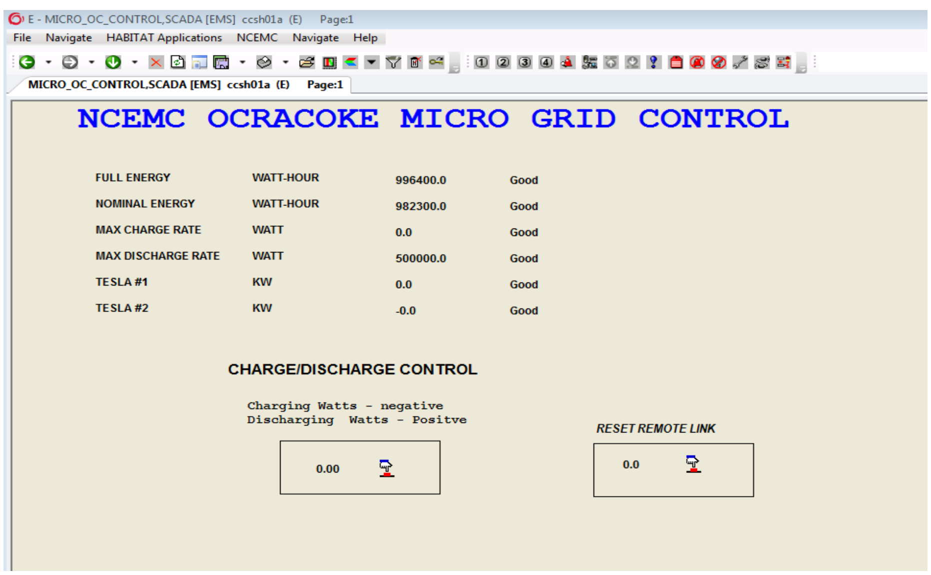


Figure 1: Microgrid battery controls as displayed in EMS

DEMAND RESPONSE

Demand savings from the Ocracoke Microgrid are realized in two parts. First, by lowering the NCEMC demand in the PJM footprint through battery discharge and DR deployment during the

PJM 5 coincident peaks (5-CPs), and second, by deploying the same strategy during the Dominion annual transmission peak known as the Network Service Peak Load (NSPL).

During a 5-CP or NSPL event, the battery, thermostats and water heaters are all dispatched to accompany any solar output the PV system is generating. One early lesson learned was that the battery was only able to hold a 500 kW discharge rate for 75 minutes before the output began to decline. Various tests revealed the optimal discharge rate for a constant two-hour discharge is 442 kWh. Discharging at 442 kW for 2 hours minimizes the risk of missing peak demand while maximizing output over 2 hour integration.

Preliminary PJM capacity market (RPM) settlement data was used to estimate what the annual future demand savings could be based on the dispatch of the battery, thermostats, water heaters and solar output during the 5-CPs. The PJM 5-CPs were set during the summer months and yielded a projected savings of $36,432 in 2018/2019.

The chart below shows estimates of the value of dispatching the microgrid during the annual 5-CPs (including full battery participation) over the next two years. The analysis predicts reduced savings in future years due to the decline in PJM's capacity clearing price. (Capacity prices shown decline nearly 50 percent in coming years). The degradation in capacity prices directly correlates to a reduction in savings to NCEMC of 39 percent.

PJM 5 CP Savings	Delivery Year 2018/2019		Delivery Year 2019/2020		Delivery Year 2020/2021	
	kWh	Savings	kWh	Savings	kWh	Savings
Battery	435	$ 29,051.10	442	$ 16,868.88	442	$ 14,344.17
Solar	8	$ 513.37	7	$ 251.98	7	$ 214.27
Thermostats	98	$ 6,556.77	125	$ 4,776.57	150	$ 4,874.02
Water Heaters	5	$ 311.11	14	$ 528.24	22	$ 708.32
Total	**545**	**$ 36,432.35**	**588**	**$ 22,425.67**	**621**	**$ 20,140.78**

Assumptions:
- Thermostat & Water Heater load drop based on performance from summer 2017
- Water Heater growth at 15 per year; TStat growth at 50 per year
- Solar is based off the average production during peak hours HE 16-18 from 6/2017-9/2017
- Battery drop is based on current dispatch parameters for load management (442 kWh)
- Final Zonal RPM Scaling is based off previous four year avg.
- Forecast Pool Req. Factor based off previous four year avg.
- Final Zonal Clearing Price are estimates based on the CP and Base auctions
- Factors and rates for each delivery year won't be known until the February before delivery year

Figure 2: three-year forward look at the estimated value of dispatching the microgrid during the annual 5-CPs

TRANSMISSION SAVINGS

While savings from microgrid dispatch during the 5-CP's is expected to decline over the next two years, the savings generated from dispatching the microgrid for the Dominion NSPL should continue to grow. The Network Integrated Transmission Service (NITS) rate, which determines NCEMC's transmission charges, is based on Dominion's annual revenue requirements, which are less susceptible to decreases. The annual Dominion NSPL calculation window is the 12-month period from November 1 until October 31 of the previous year.

Over the last few years, the timing for the Dominion NSPL has fluctuated between winter and summer months. In 2017, the annual Dominion NSPL was set in January. The Ocracoke Microgrid was not commercially available until February and therefore did not operate to reducing the NCEMC demand. For purposes of this report, NSPL savings estimates for 2017 are based on having availability during that peak. The analysis calculated the savings associated with a peak occurring in either season, and put the potential savings estimate at approximately $31,000 in 2018 and $41,000 in 2020.

The analysis in Figure 3 below indicates that savings potential is greater during a winter NSPL than a summer NSPL. This is due to a stronger response from thermostats and water heaters in the winter season. The year-over-year increase in savings takes into account the projected increases in the NITS rate and continued growth in thermostat and water-heater program participation on the island.

Dominion NSPL- Winter	2018*		2019		2020	
	kWh	Savings	kWh	Savings	kWh	Savings
Battery	442	$ 23,706.06	442	$ 24,610.89	442	$ 25,577.26
Solar	1	$ 53.64	1	$ 56.13	1	$ 58.34
Thermostats	129	$ 6,970.57	206	$ 11,484.15	248	$ 14,322.11
Water Heaters	4	$ 214.56	14	$ 770.68	22	$ 1,263.02
Total	**576**	**$ 30,944.83**	**663**	**$ 36,921.85**	**713**	**$ 41,220.73**

Dominion NSPL- Summer	2019		2020	
	kWh	Savings	kWh	Savings
Battery	442	$ 24,610.89	442	$ 25,577.26
Solar	7	$ 367.63	7	$ 382.07
Thermostats	125	$ 6,968.79	150	$ 8,690.92
Water Heaters	14	$ 770.68	22	$ 1,263.02
Total	**588**	**$ 32,717.99**	**621**	**$ 35,913.26**

Assumptions:
- 2017 Winter number is based on if we had all resources
- Thermostat drop based on performance from Winter & Summer 2017
-Water Heater drop based on observed performance
- Water Heater growth at 15 per year; Thermostat growth at 50 per year
- Solar is based off the average production during peak Winter and Summer hours
- Battery drop is based on current dispatch parameters for load management
- NITS Rate is from LRFF & Transmission

Figure 3: two-year forward look at the estimated value of dispatching the microgrid during the annual NSPL

ENERGY ARBITRAGE

To capture energy arbitrage opportunities, the battery should be dispatched during high-priced peaking periods and charged during low cost off-peak times. Only solar output and battery discharges were used to capture energy arbitrage opportunities, as thermostats and water heaters were deployed for demand savings only. The battery, being a dispatchable resource, can be charged overnight while market prices are typically low and discharged during the peak hours when prices are higher. The battery is dispatched by APM with strategy guidance given by NCEMC. The solar panels are only able to capture value during daytime hours when the sun is shining.

During the first six months of operation, various arbitrage strategies were deployed to capture value from the PJM market, including 1-hour and 2-hour charge/discharge cycles, and discharging only when a minimum margin threshold was reached. The actual value realized from energy arbitrage over six months was approximately $2,500.

Further analysis was performed to determine how energy arbitrage could be optimized and to determine a realistic best-case scenario. Various strategies were considered, including a predetermined charge and discharge period taking advantage of perfect knowledge (prices and timing) for a whole year. The analysis compared a 1-hour vs. a 2-hour vs. a 3-hour charge/discharge cycle at varying charge/discharge rates, assuming the ability to capture the pricing difference in the PJM market existed in all cases. It also incorporated historical Real-Time Locational Marginal Pricing (LMP) data, selecting the hours that were consistently the strongest and weakest on a seasonal basis in order to establish a predetermined scheduled dispatch. The scenario that created the most savings in this realistic example was the two-hour charge/discharge cycle.

The analysis also revealed the optimal dispatch scenario produced approximately twice as much value as the projected savings scenario. It's important to note that optimal dispatch is not realistically achievable, as forecasting LMPs accurately has proven to be far more difficult than forecasting load due to unknown information such as PJM generation dispatch, transmission outages and congestion, which all impact pricing in the real-time markets. The table below illustrates the differences between the three scenarios:

Battery Savings	1 Hour	2 Hour	3 Hour
Projected	$ 3,269.70	$ 5,257.18	$ 4,903.52
Optimal	$ 7,373.20	$10,604.70	$ 9,279.77

Assumptions:
- Picked the best hour(s) to charge/discharge by looking at each season and how prices formed to set seasonal specific hours
- Used historical Dom Res Agg LMP data to generate dollar amounts
- 2016 Weekday LMPs only (261 days)
- Charge/ Discharge Rate for 1 hour = 500kWh
- Charge/Discharge Rate for 2 hour = 442 kWh
- Charge/Discharge Rate for 3 hour = 300 kWh

Figure 4: energy arbitrage estimated values

Another strategy analyzed potential savings from instituting a $15, $20 and $30 margin between charging and discharging the battery. These margin rates were paired with a one-hour charge/discharge cycle. This scenario assumed the more realistic seasonally scheduled dispatch using the same seasonal LMP values as the analysis above. The data proved that a $30 margin on a one-hour cycle would discharge the battery roughly 64 times a year with a savings of $2,011, approximately 62 percent of total projected revenue from the table above. By imposing a $30 minimum threshold margin, the analysis indicated that almost two-thirds of the best-case revenue could be captured with a 75 percent reduction in the number of dispatch cycles. The table below summarizes the savings estimates:

Margin Analysis	Projected Cycles	Savings	% of Total 1 Hour Revenue
$15 Margin	130	$2,700.04	83%
$20 Margin	93	$2,374.26	73%
$30 Margin	64	$2,011.45	62%

Figure 5: expected savings with various margins

CONCLUSION – USE CASE 1

The microgrid testing and analysis performed indicates the largest savings to NCEMC can be attained by decreasing NCEMC's demand for both capacity and transmission requirements.

Deploying a strategy to dispatch the microgrid to reduce NCEMC's demand at key times can save the portfolio approximately $60,000 annually if deployed during the PJM 5-CP's and the Dominion annual NSPL. Even though the estimated savings from deploying during the 5-CP's is expected to decrease, there is potential and likelihood for PJM capacity prices to increase in future years.

While the energy savings is not as large as the demand savings, it can still add value to the portfolio by capturing energy market price volatility by deploying a strategy to dispatch the microgrid battery for limited schedules with a specific margin goal for each dispatch. As opportunities present themselves, both Energy Operations and APM can utilize volatility to improve on this baseline. Adopting this strategy captures arbitrage savings while decreasing wear and tear on the battery, preserving it for future use and savings in both demand and energy markets.

NCEMC will continue to use the microgrid for demand reduction during the 5-CPs and the Dominion NSPL and look into ways to optimize the battery for energy arbitrage. Future energy arbitrage evaluation should include research to gain a better understanding of the impact of battery cycling, and to determine the optimal number of operations annually, to extend the life of the battery.

ANCILLARY SERVICES – USE CASE 2

BACKGROUND

Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." Microgrids, and more specifically batteries, have been cited as excellent resources to provide ancillary services to the grid. Use Case 2 is focused on testing the Ocracoke Microgrid's ability to provide ancillary services, specifically regulation in the form of PJM's "RegD" ancillary service.

PJM has two classifications for regulation service: traditional regulation service (RegA) typically provided by traditional combustion turbines, combined cycle or steam resources; and dynamic regulation (RegD) provided by batteries and flywheels. There are significant differences in these two types of resources. RegA resources are also known as "ramp limited" resources; they can provide a lot of energy but are limited in their ability to respond quickly. It can take several minutes for RegA resources to satisfy the regulation signal they have been assigned. The resources that supply RegD can move more quickly satisfying the RegD signal, sometimes within seconds. However, RegD resources are also known as "energy limited" resources because they are limited in their ability to provide large amounts of energy.

In 2012, PJM implemented rules to support fast-responding resources (RegD), as outlined in FERC Order 755[1]. Because these rule changes were favorable to battery storage, a flood of battery storage projects entered the PJM market Based on industry research, it appears that there is as much as three times more RegD resources in the PJM market than are actually needed. This oversupply of resources has caused prices for regulation services to drop by nearly 50 percent. The oversupply of fast-responding resources introduced additional burden to the grid, causing PJM to put a temporary cap on new RegD resources and implement changes in the business rules for RegD. The changes to the business rule require batteries to provide power over longer durations – more in line with RegA resources. The bottom line is that the oversupply of resources and the modification to the business rules are making the PJM market less favorable for new entrants. According to an APM Q2 2017 report, "Assessing the Regional Business Cases for Combined Solar + Battery Technology," the revenue stream for RegD is heading lower[2].

EVALUATION PROCESS

Implementation of PJM RegD service was based on the same communication and control architecture that was developed to integrate the battery into the EMS for DR functionality. However, additional EMS programming was required to accomplish the ancillary service function beyond DR. An additional interface on the EMS was added, enabling it to receive control signals from PJM and to provide feedback to its operation center in real time. NCEMC IT staff programmed these processes into the EMS so that a PJM self-test could be administered as the first step to evaluate the battery's response to RegD signals. A full PJM administrated test would require live regulation signals from PJM through NCEMC's current Intra Control Center Protocol (ICCP) link.

[1] Utility Dive Peter Maloney Sept 5, 2017 "is the bloom off the RegD rose for battery storage in PJM?"
[2] Second Quarter 2017 Solar Update Assessing the Regional Business Cases for Combined Solar + Battery Technology, APM and NRCO, page 13.

If NCEMC wanted to qualify the resource with PJM, there are a number of steps that need to be taken prior to the testing. The first step would be for NCEMC to interconnect the battery with PJM as a generator. As it is currently configured, the battery is behind the meter, and PJM does not recognize it as a resource on the PJM system. NCEMC would need to go through feasibility and system impact studies, as would any generator, in order qualify for RegD participation. Once the battery was accepted as a resource, NCEMC could request a PJM RegD test. To qualify, the battery would need to pass three consecutive 40-minute tests administered and scored by PJM. The performance score on all three tests would need to be 75 percent or higher.

NCEMC conducted a test of the battery based on PJM RegD self-test data. PJM provides a data file that is designed to mimic a typical PJM RegD signal; this signal provides set points every two seconds, either up or down. This test file was loaded into the EMS and the EMS dispatched the battery to satisfy the PJM RegD signal.

It is important to note that the EMS was not receiving live data from PJM; rather data was loaded directly into the EMS.

A flow diagram depicting these steps is below:

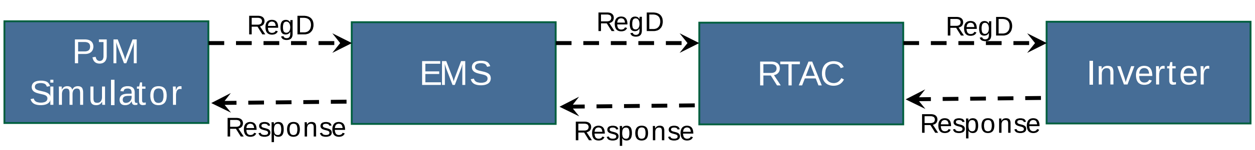


Figure 6: communication flows enabling RegD

For the test, the assumption was that NCEMC bid +/- 0.5 MW into the RegD market. Prior to initiating the test Operations/EMCT staff discharged the battery down to 50 percent capacity so that it could charge as well as discharge for the entire test period. The signals were then generated every two seconds and sent to the RTAC for a 1-hour test.

SELF-TEST RESULTS

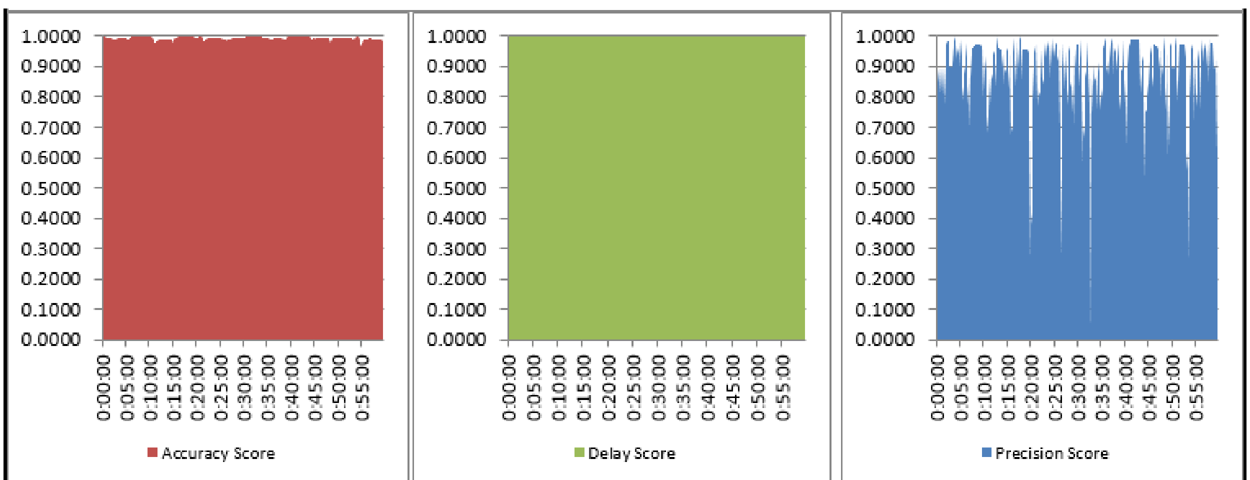
PJM qualifies RegD resources on a composite score based on three criteria:

- Accuracy
- Delay
- Precision

The Accuracy score is based on the correlation of the RegD output supplied by the resource and the control set point requested by PJM. PJM monitors the RegD supplied and RegD requested every five minutes during the 40-minute test(s). The Delay score is based on the time delay between the control signal request and the point of highest correlation from the accuracy test described above. PJM reviews the Delay over 5-minute windows during the test. Precision is the difference between the areas under the curves for the PJM generated control signal and the resource's response to that signal. For a test to be successful, PJM requires that the RegD resource perform at 75 percent or higher.

The self-test administered by Operations and EMCT staff resulted in a composite score of approximately 96 percent. Each component score and a graphic illustrating the test results are below:

- Accuracy Score: 99.3 percent
- Delay Score: 100 percent
- Precision Score: 88.2 percent



Hourly Score	0.9930	Hourly Score	1.0000	Hourly Score	0.8821
Weight	0.3333	Weight	0.3333	Weight	0.3333
				Composite Score	0.9584

Figure 7: PJM RegD self test score summary

The scoring results were determined using a PJM-supplied Excel template. NCEMC requested that PJM review the data that NCEMC entered into the template to confirm that the calculations were completed correctly. PJM subsequently confirmed that the self-test was successful. An APM economic analysis noted that battery scores typically fall between 90-100 percent for the composite score, providing further support that the battery score on the self-test was as expected.

As noted above, the self-test was completed "behind the meter." Because of the direct link between the source data and the EMS, the delay score was 100 percent.

According to PJM, there is no way to determine what the actual delay score would be unless the battery was interconnected as a capacity resource in PJM. That score would depend on the unit's unique regulation signal to PJM control center. PJM expects some delay, and when scoring the actual test (and evaluate the performance of actual market resources), PJM compensates for communication delays by providing a 10-second margin for all resources.

To gain further confidence in the self-test despite the absence of a live signal, NCEMC evaluated several latency scenarios until the composite score fell to 75 percent. PJM completed the same evaluation and determined that delaying the response to 1 minute and 20 seconds dropped the composite score to slightly more than 75, which is still a passing score. Latency of that magnitude is highly unlikely; therefore, the team is confident that the Ocracoke battery would qualify in an actual test.

ECONOMIC ANALYSIS

To evaluate the potential value that the battery could provide to the portfolio through the RegD market, NCEMC engaged APM to analyze the value of PJM's regulation market if NCEMC chose to participate with the battery on Ocracoke. In order to calculate the potential value, APM made the following assumptions:

- Limiting battery operations to 300 cycles/year. (APM counts one cycle as moving from inactivity to inactivity while maintaining a minimum of 20 percent of charge.)
- Daily clearing based on 2016 regulation capacity factor (77 percent for 2016, down from 91 percent in 2015)
- Daily clearing prices using 2016 prices as a base, with scenarios based on lower expected prices

Given these assumptions, the APM analysis projected a range of annual values from approximately $11,000 to $36,000, with an expected value of approximately $22,000. The lower values for RegD reflect the dramatic drop in prices in recent years, a trend that APM expects to continue. APM attributes the drop in clearing prices to several factors. First, market energy prices are lower, leading to lower opportunity cost payments for regulation. Second, a large increase in battery storage capacity is displacing the need for natural gas for regulation (RegD displacing RegA). The majority of RegD resources are offered at $0/Effective MW and are price takers. Finally, PJM has improved their processes, requiring higher efficiencies from regulating units. The table below outlines the range of values from the APM report.

Range of Outcomes for PJM's Regulation Market				
Estimated Regulation Clearing Price ($/Effective MW)	**Performance Score**	**100% Regulation Capacity Factor (Clearing All hours)**	**77% Regulation Capacity Factor**	**65% Regulation Capacity Factor**
$5.00	96%	$16,819.20	$12,950.78	$10,932.48
$10.00	96%	$33,638.40	$25,901.57	$21,864.96
$14.00	96%	$47,093.76	$36,262.20	$30,610.94

Figure 8: estimated values of RegD

To maximize the value of the resource, we considered stacking DR with RegD services. This would require the battery to be interconnected with PJM as a resource. This arrangement would require that NCEMC manage the resource on a daily basis in the market, making it available or unavailable for RegD depending on the circumstances of each day. Unfortunately, this type of arrangement would not result in a net increase in revenue for NCEMC because as a DR resource, the battery's capacity would be added back into NCEMC's locational reliability requirements.

CONCLUSION AND RECOMMENDATION – USE CASE 2

After reviewing the self-test results and consulting with PJM, it is clear that the battery at Ocracoke can follow PJM RegD dispatch successfully. The only element not fully tested is the latency between the PJM Control Center and NCEMC's IOC. Without fully interconnecting with PJM, this latency cannot be tested; however, NCEMC's scenario analysis and follow up with PJM provide enough surety that the battery would qualify. We can conclude that Use Case 2 of ancillary services was thoroughly tested and the battery has passed the test.

It is important to note that the impact of RegD services on the long-term health of the battery has not been determined. Batteries have a limited number of cycles that they can undergo before the discharge/charge operations degrade the battery's performance. However, questions remain about how a cycle is defined. Pending work with N.C. State University on battery health should help provide a conclusive answer, but until that work is complete, NCEMC will continue to pose the question.

Considering the economic analysis completed by APM, the logistics of integrating the resource into the market, and the relative value of the resource for demand response and energy arbitrage behind the meter, it is clear that ancillary services would not be the optimal use for this asset. NCEMC recommends continuing to monitor PJM's market rules for ancillary services and working with N.C. State University on its battery health research project. As new information is learned, NCEMC will reassess any opportunities that could surface in the future.

CAPACITY FIRMING/SMOOTHING OF RENEWABLE RESOURCES – USE CASE 3

BACKGROUND

Renewable energy is growing fast, both nationally and locally. As of November 1, 2017, NCEMC has executed Power Purchase Agreements (PPAs) to interconnect 43MW of renewable projects, and an additional 108MW could be built in 2018. Integrating renewable energy into electric power systems reliably and efficiently is becoming an important issue for electric cooperatives and other utilities.

The intermittent nature of renewable sources, such as solar and wind, poses challenges to the traditional power grid, which is designed for controllable generation. For generation and transmission services, the variable output makes it harder for system operators to balance load and generation. For distribution services, the rapid change of power can cause reliability and power quality issues. Battery storage systems, if sized appropriately, provide a viable solution. Battery storage can smooth the renewable output, while excess renewable generation can charge the battery. Battery and variable renewable resources naturally work better together. In Use Case 3, the Ocracoke microgrid was used as a testbed to study the battery's capability of smoothing solar generation.

The first goal of this study was to provide a constant output or predefined schedule for a set period of time. This combination of battery and solar system can firm renewable power and make it easier to participate in a traditional or Regional Transmission Organizations (RTO)/Independent System Operators (ISO) power market that integrate resources on hourly values.

The second goal of this study is to alleviate the power output fluctuations from distributed renewable energy resources. When connected to the local distribution system, the fast change of solar output could affect system power flow and voltage regulation. Batteries can smooth out output fluctuations and improve system reliability and power quality at the local level.

With these two goals in mind, NCEMC designed and conducted several tests for PV generation smoothing using the Tesla batteries at the Ocracoke microgrid.

EVALUATION PROCESS

The core issue of solar generation smoothing is the interaction and coordination between battery storage system and PV generation. NCEMC tackled this issue from serval aspects.

1. Capacity sizing

Matching the capacity size between PV generation and the battery storage system is important for several reasons. First, the battery power capacity cannot be too small. The PV generation output is usually not controllable and can swing between zero and the maximum output very quickly. To compensate for these fluctuations, the battery system's controllable output range has to be greater than or equal to the capacity set point. At Ocracoke, the Tesla battery power output is -500kW to +500kW. Thus, it could accommodate PV generation with maximum output of 1MW if the capacity set point was 500kW. Second, the cost of battery systems are still relatively high. For the purposes of renewable smoothing, the smallest battery should be used to satisfy the desired set point. If the batteries are already on the site, as much PV generation as possible should be installed. Third, there is a control dead band in the microgrid controller and inverter. If the battery is too big, NCEMC will have limited ability to control the battery for small changes in PV generation. In the Ocracoke microgrid, the PV output rating is 15kW. That is only 1.5 percent of the battery's control range. The PV generation is too small for the battery.

Because it is not feasible to use the PV output at Ocracoke directly, NCEMC used two methods to design the renewable smoothing tests. In the first method, NCEMC selected two other solar sites in the NCEMC footprint whose outputs are below 1MW, but big enough for the existing microgrid battery. The sites we chose were QVC 1 at Edgecombe-Martin County EMC and Sunny Point at Brunswick EMC. The real-time data from these sites, in conjunction with battery data, was used as inputs to the tests. In the second method, NCEMC scaled up the solar output from Ocracoke to simulate the future solar expansion on the island. In our test case, a multiplier of 20 times the actual output data was used.

2. Set point

Set point is the desired summed output of the PV generation and battery storage system. To determine the set point, the PV output profile and battery capacity were analyzed. Because PV generation output can go from zero to the maximum quickly, the set point should be within a range that prevents the battery from exceeding its compensation capability. The maximum possible set point is equal to the maximum battery power output since PV output could be zero. The minimum possible set point is the maximum PV output minus the maximum battery power. Using the three test sites as examples, the set point ranges are as follows:

Site	Max PV output (kW)	Min Set point (kW)	Max Set point (kW)
QVC 1	800	300	500
Sunny Point	1,000	500	500
Ocracoke	300	-150	500

Figure 9: Set points for solar sites

Another point worth mentioning is the diurnal variation of PV maximum output. This gives us the capability to determine different set points at different times of day.

3. Energy volume considerations

A battery has limited energy capacity, meaning it can only generate or absorb a certain amount of energy before it must be charged or discharged. Because of the variable nature of solar output, there is uncertainty of PV generation. When using the battery to smooth the PV output, the stored energy in the battery could be depleted or saturated before the desired test ending time. NCEMC will need to carefully analyze the battery and PV generation from the standpoint of energy and plan its tests accordingly. To reduce the impact of the PV output uncertainty, PV output forecasting is needed. In this use case, we used PV output forecasting data from QVC 1, Sunny point and Ocracoke Solar to calculate the initial stored energy in the battery and expected length of operation.

4. Renewable forecasting

Solar output forecasting is required to determine the proper battery settings to ensure the testing periods are within the limitations of the battery's total energy characteristics. The method employed to forecast the integrated hourly solar output was a General Statistical Model (GSM). The statistical predictions were created using three factors: the month; the hourly irradiation; and the hourly forecast categories from clear to partial, moderate or heavy cloud coverage. This data was provided by Weatherbank, through its historical and forecast products, in combination with NCEMC's hourly-integrated solar output data to allow for this correlation into the GSM.

The GSM model requires a minimum amount of data to create reasonable results, which was a challenge for Sunny Point and Ocracoke. For the QVC1 site, the GSM produced statistically significant results based on the model variance capabilities within one standard deviation. For the Sunny Point site, there was not enough existing data to create statistically significant results, but NCEMC was still able to produce results that allowed for test requirements. For the Ocracoke Microgrid, there was also a lack of data, so recent history estimations were used.

5. Control Strategy

A negative feedback control loop with a compensator was used in the tests of this use case. It could effectively maintain the combined solar and battery output at a certain level by controlling the battery's output. This loop was implemented with the existing function in NCEMC EMS. This simple control function can also be applied to any advanced SCADA, PLC or other microgrid controller. Below is the control diagram.

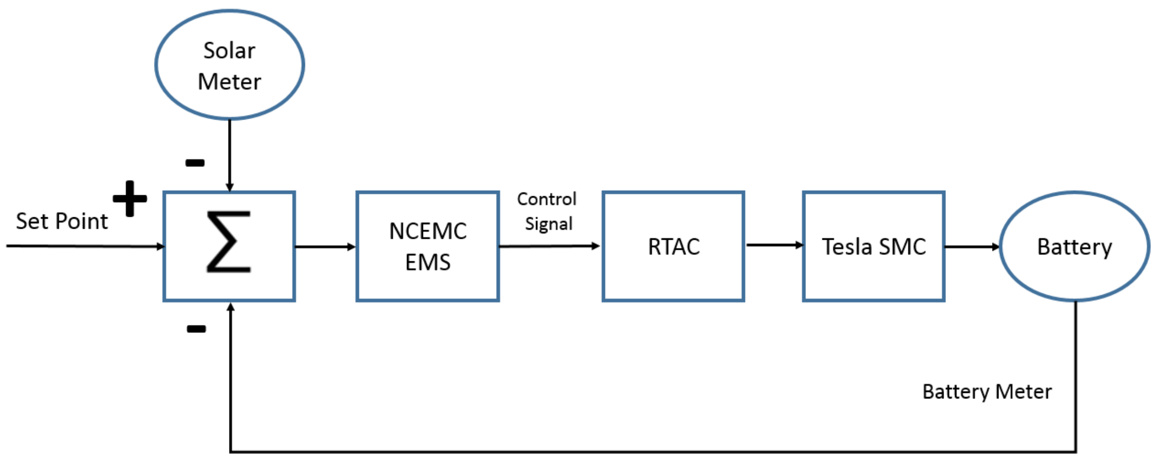


Figure 10: solar smoothing control function

In use case 3, NCEMC carefully studied each issue mentioned above and conducted multiple tests. The tests used real-time output from solar sites at different locations. We also set the set point at different levels to obtain in-depth knowledge of renewable smoothing. The sum of solar and battery output, which is defined as the primary meter, was used to evaluate the smoothing effect. We also captured the energy stored in the battery (remaining energy) in each test.

Test #1

In test #1, we used data from QVC 1 as the solar input. At this time of year, the maximum output of QVC 1 is approximately 800kW. As discussed, this size matched the battery at Ocracoke microgrid. The goal was to maintain primary meter output at a constant value of 450kW. To capture the highest solar generating period, NCEMC planned an 8AM to 6PM test. Based on PV forecasting, we set the initial energy at 450kWh. Figure 10 shows the solar and battery contribution to the schedule, and solar production and primary meter output during the test. The smoothing effect in this test is clearly demonstrated. The standard deviation of the primary meter output is only 1.4, while the solar output's standard deviation is 142. The constant output in this test achieved the two goals set forth in this use case: provide capacity firming and/or alleviate power fluctuations. The total energy required from the schedule was 4,613 kWh and the combination of battery and solar delivered 4,509 kWh. The delta was 104 kWh over the 10-hour schedule, which is approximately a 2 percent of imbalance. Due to a prolonged ramp schedule, the first hour had a large imbalance of 93 kWh or more than 20 percent.

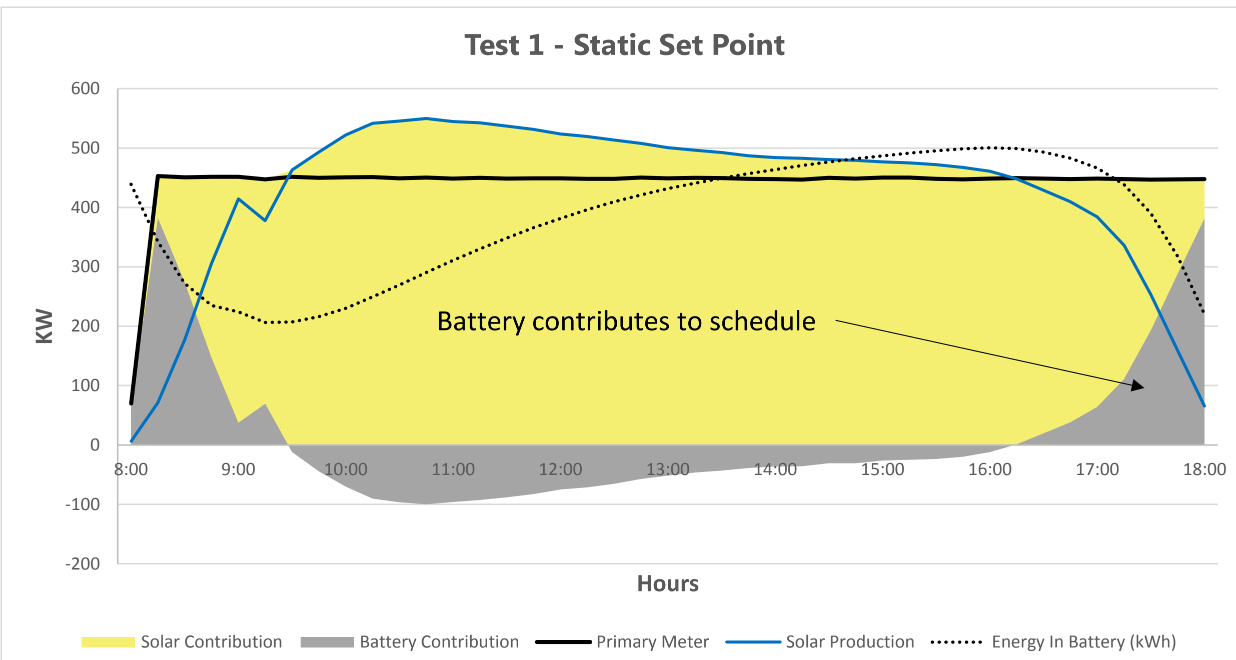


Figure 11: results of test 1

Test #2

Test #2 also used QVC 1 as the solar input. The difference from test #1 was the way the set point was specified. In this test, NCEMC tried to track the scheduled values that varied from hour to hour. Using different set points gives flexibility to provide committed capacity to the system operator or power market. It can also extend the battery usage time because PV output is highly dependent on the time of day. Below are the set points we specified in this test.

Hour	HE9	HE10	HE11
Set point	250	400	500
Solar Std. Dev.	130.28	36.45	8.29
Primary Meter Std. Dev.	31.62	72.66	49.02
Imbalance	-12.64	-38.41	-22.80

Figure 12: Test 2 results

Figure 11 shows the solar and primary meter output of this test. The outputs were maintained at the scheduled level for almost the full hour. However, a delay was seen when reaching the new set point, which led to higher standard deviations and underperformance of output.

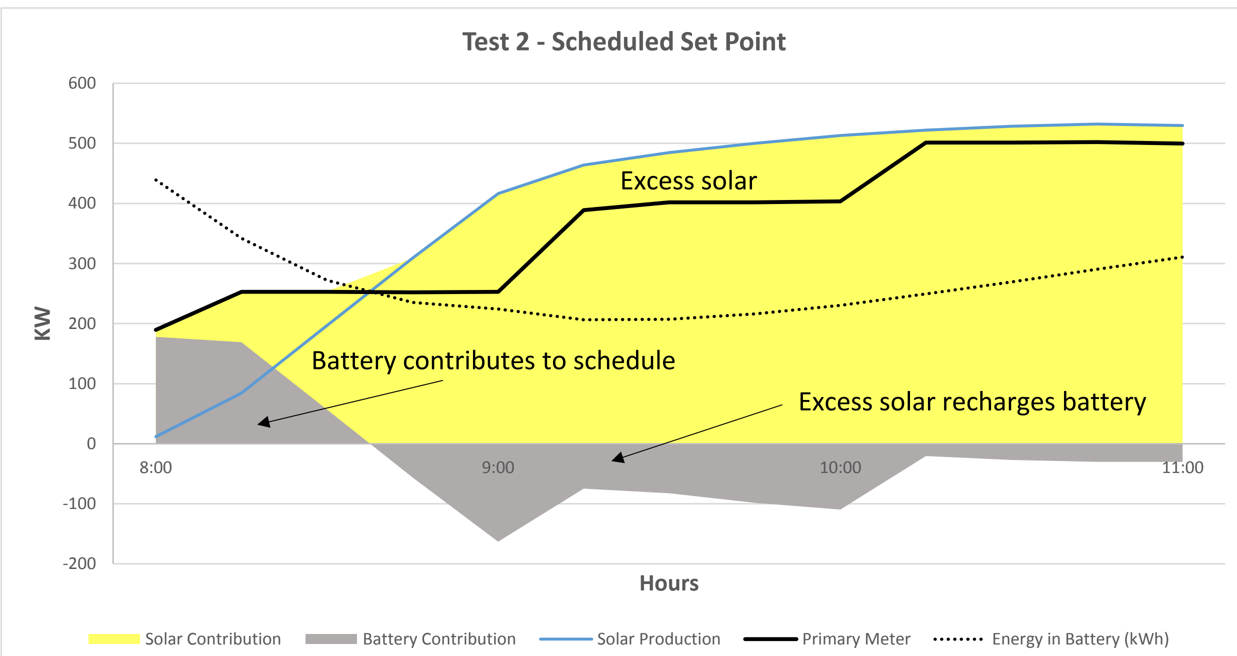


Figure 13: test 2 result

Test #3

Test #3 used Ocracoke solar data as the input. Here, PV generation is located on site with the battery as part of the microgrid. Because the solar rating is too small, it was scaled up for the test with a multiplier, which can amplify the fluctuations of the solar output. For the overall test, the smoothing effect was reasonable, with the standard deviation from solar output to primary output reduced to 14.43 from 71.92. Hour to hour, fluctuations were more pronounced, with imbalances ranging from 14 to -8 percent, as illustrated in Figure 12. NCEMC noted that primary meter output fell at around 9:30AM, which was also when the battery switched from discharging mode to charging mode. This explains the imbalance of -12.6 kWh. It appears the battery's smoothing capability degraded when the output was near 0kW. This phenomenon was also observed in other tests.

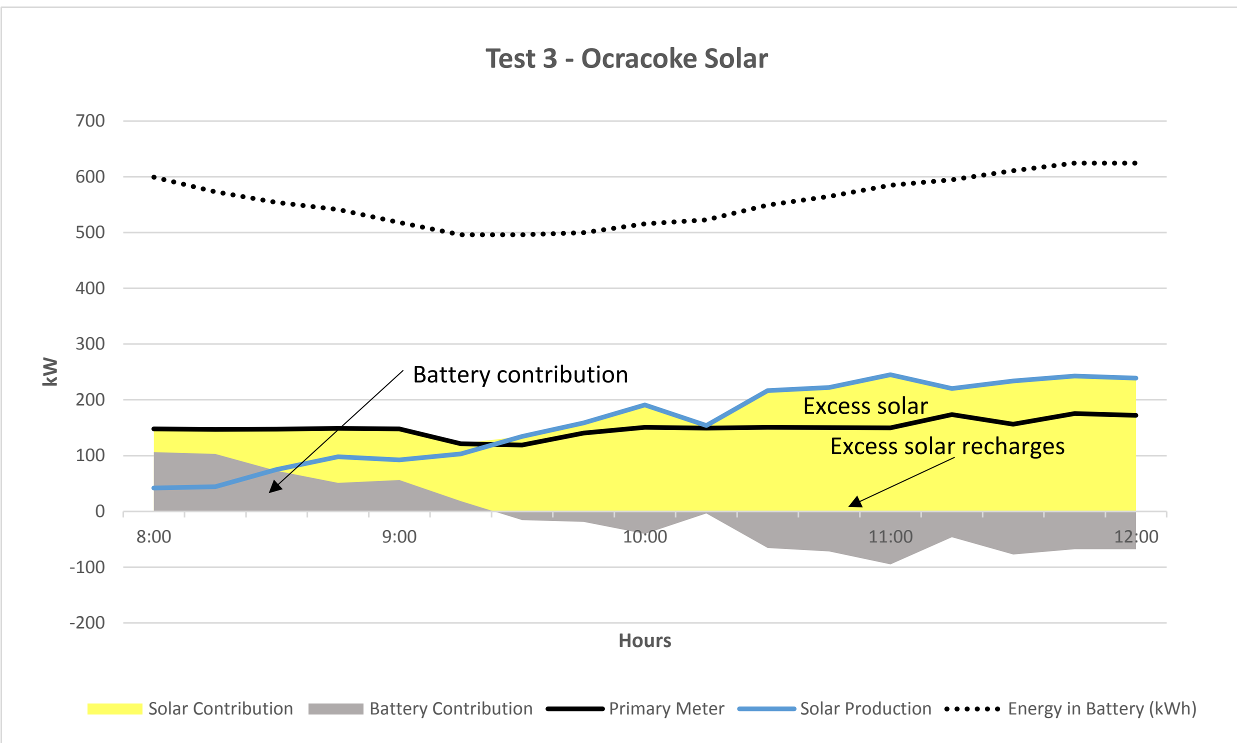


Figure 14: test 3 result

Test #4

Test #4 used Sunny Point at Brunswick EMC as the solar input. Based on PV forecasting, the following parameters were set for the test.

Set point = 500kW

Initial Energy = 520kWH

Length of operation = 4 hours

Results of the test are shown in Figure 13. There was a steep drop of primary meter output around 1:15PM, which resulted in large standard deviations of 253.58 for solar output and 108.67 for the primary. This occurred because the solar output on that day was lower than forecasted, and the battery was depleted before the test could be completed. This led to an imbalance of nearly 225 kWh in the last hour. This result demonstrates the importance of coordination among renewable forecasting, energy set point and expected length of operation. The other hours had minor imbalance. Based on these results, NCEMC recommends adding an initial energy "buffer" to account for forecasting errors.

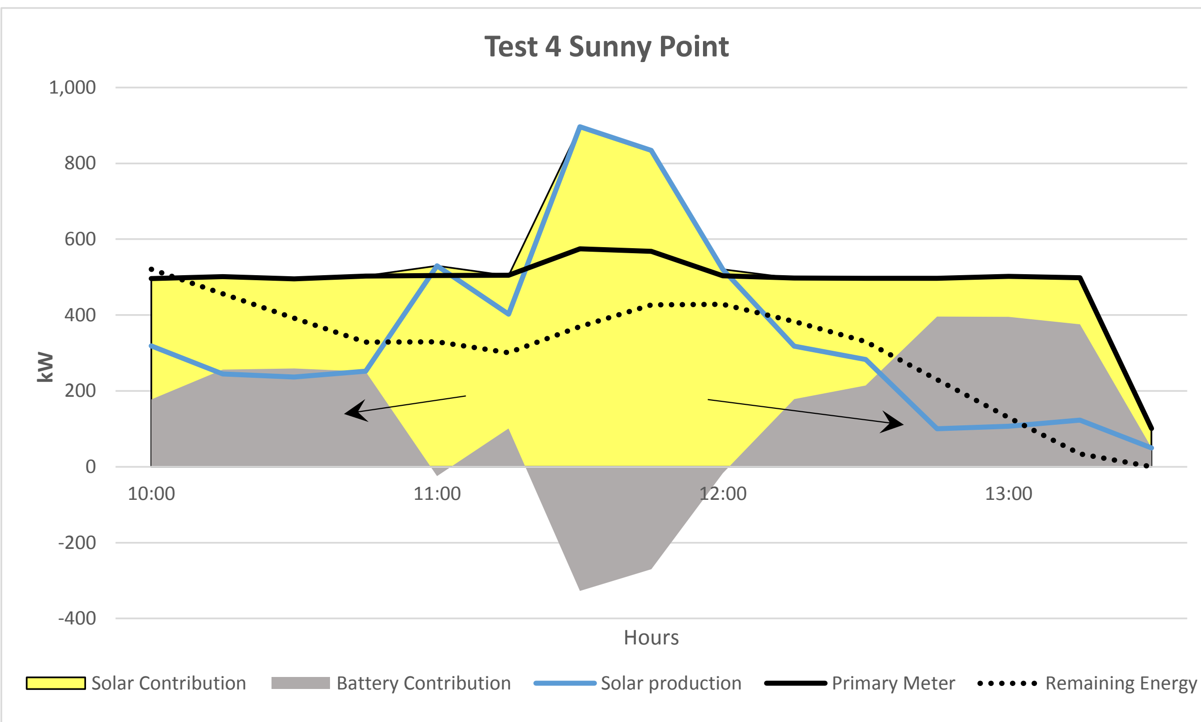


Figure 15: test 4 result

Test #5

Test #5 again used Sunny Point as the solar input source. This test experimented with a "rolling set point" based on a rolling average. The formula is set point = ((old set point – old set point/N) + (new solar output + basepoint))/N. N is the number of samples. The purpose of a rolling set point method is to alleviate the intermittent renewable output's pressure on the regulating generation source. This is particularly useful when the microgrid is in an island mode. Compared to a constant set point, the usable time of battery using a rolling set point could be much longer. The test results are shown in Figure 14. The primary meter can follow the solar output very well; however, because the day was very sunny the smoothing effect is not obvious from this test.

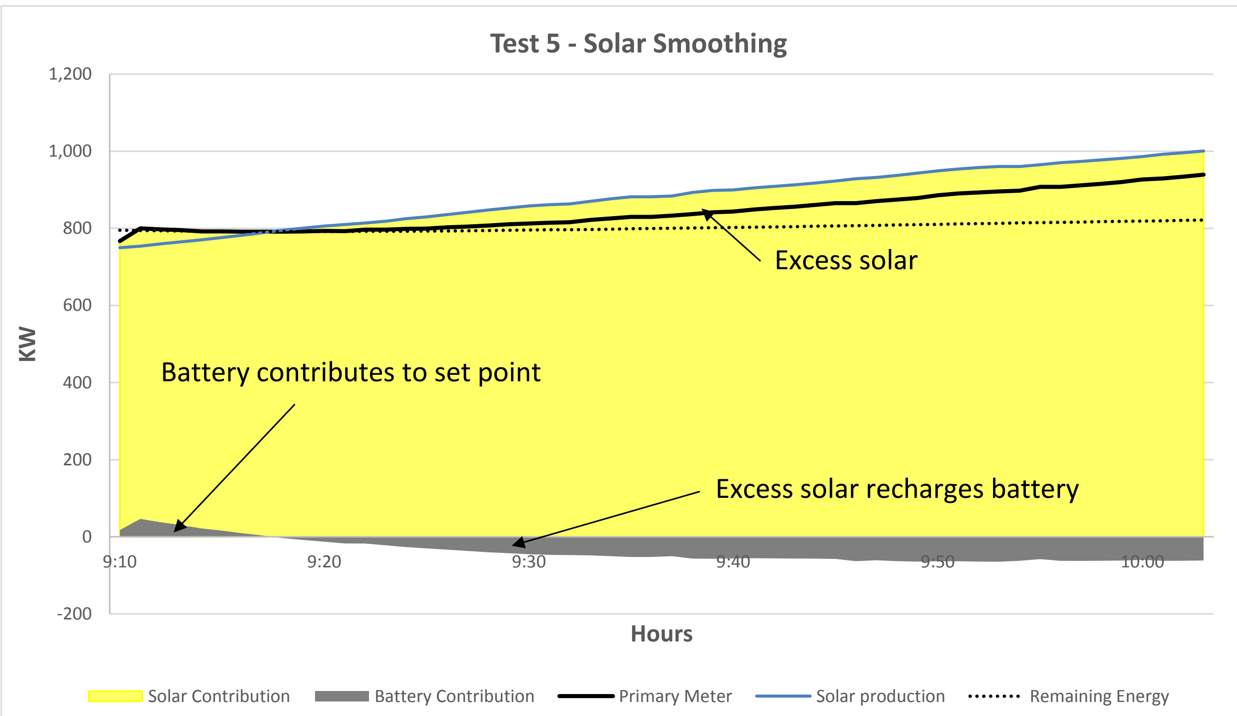


Figure 16: test 5 result

LESSONS LEARNED AND FUTURE STUDIES

From the tests that were conducted, NCEMC learned several valuable lessons and obtained insights for future studies.

1. Renewable Forecasting

There has been much discussion in recent years about NCEMC preparing for solar forecasting. The microgrid use case testing provided a starting point for this effort. While the GSM was used in the tests to provide results, an initial idea was to use the Nostradamus forecasting software that currently provides load forecasts for each load area. Both methods are recognized as accepted industry practice; however, NCEMC expects that when properly applied, Nostradamus should result in better output than the GSM.

Solar forecasting is difficult due to a lack of irradiance and cloud-cover forecast accuracy. Government and private efforts are being led to improve forecasting of clouds and irradiance at specific geographical locations. Multiple studies have concluded that this will be the key to improved solar forecasting. Unfortunately, this capability is in its infancy and will require giant leaps of scientific understanding and terrestrial equipment to improve.

It is important to note that the variance of results of solar forecast outputs will be significantly higher than typical load forecasting expectations. Based on its experience, NCEMC expects clear day forecasts will be more reliable, and with smaller variances, than cloudy day forecasts. As a final lesson, the variance of solar output highlights the importance of the combination of energy storage with solar to create reliable and predictable outputs. Additionally, NCEMC plans to fully utilizing APM's renewable forecasting services going forward.

2. Rolling set point

From test #5, limited benefits were observed from using the rolling set point method due to a lack of intermittency during the test. Additional testing will need to be completed at Ocracoke or NCEMC's other microgrid locations. Additionally, the implementation of this method was more complicated than fixed set point and may need to be refined prior to retesting. NCEMC cannot recommend using this method in its current form.

3. Future studies

Two areas should be considered for future studies. The first is adding local load to the combined system to determine how well a solar and battery combination could serve load. The second is to implement the control function on the local battery controller instead of on the centralized EMS. NCEMC anticipates this could produce better performance because of the faster response time.

4. Initial energy reserve

To avoid depleting the battery of energy during solar smoothing operations, an algorithm for solar forecasting error should be developed. This should include a conservative cushion, reserving contingency energy for deviations in solar output.

CONCLUSION – USE CASE 3

We conducted multiple tests related to the renewable smoothing in this use case. These tests demonstrated batteries at Ocracoke could be used to smooth the PV output in different situations. The batteries or microgrid can help renewable resources to penetrate into traditional power grids at system and local levels. This use case provides valuable experience and lessons for the renewable smoothing problem.

ISLANDING AND RESILIENCY - USE CASE 4

BACKGROUND

A core function of microgrids is to provide resiliency and backup for the load(s) it serves. One reason Ocracoke was chosen as the location for NCEMC's first microgrid is its physical and electrical location on a barrier island at the end of radial transmission line. There are times, during storms, system maintenance or other events, when Hatteras and Ocracoke islands become isolated from the larger grid. In these cases, power must be provided locally until normal operations return. Use Case 4 will test the microgrid's ability to support grid operations when connected to Cape Hatteras, as well as its ability to support Ocracoke when the island is isolated from transmission service from Cape Hatteras in a true "island mode." The components of the larger Hatteras/Ocracoke system are illustrated in the graphic below.

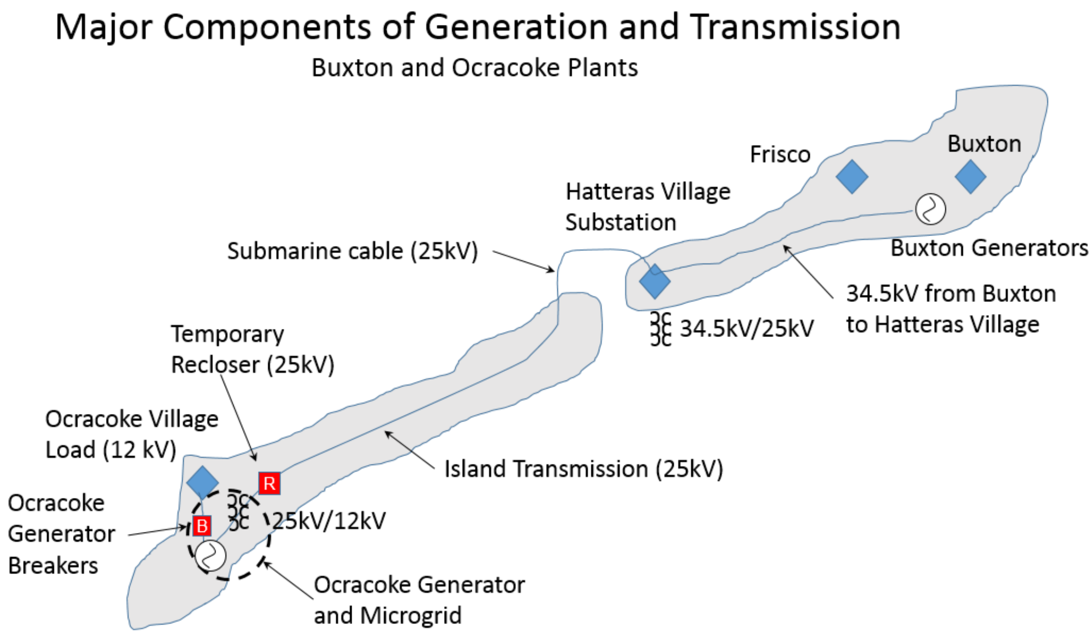


Figure 17: major components of Hatteras / Ocracoke system

There is a 3 MW diesel generator on Ocracoke Island. This generator was installed more than 25 years ago for peak shaving and to support grid operations during severe weather events. Since commissioning, load has grown on the island. Peak demand during the summer season surpasses 5.5 MW, which is almost twice the capacity of the generator. During storm emergencies, tourists are typically evacuated from the island, reducing load to less than 3 MW. As mentioned above, the generator capacity is 3 MW and if the loads during an outage event are greater than 3 MW for an extended period of time, Tideland EMC must implement load reduction measures on its distribution circuits to ensure that the generator does not exceed its capacity when the carrying isolated village load.

The original islanding concept for the Ocracoke Island microgrid was to support the existing generator with new technology that would enable the generator to serve the entire island under an evacuation scenario. In addition to the existing 3 MW generator, 500 kW of batteries were installed, along with 15 kW of solar, which brought supply on the island to more than 3,500 kW. Along with this increased supply, Tideland EMC added smart thermostats and water-heater controls in an effort to add another 300kW - 500 kW of demand response. In theory, the combination of increased supply and reduced demand would enable Tideland EMC to keep all circuits energized during an evacuation or maintenance event when loads were reduced. Below is a diagram illustrating the microgrid components.

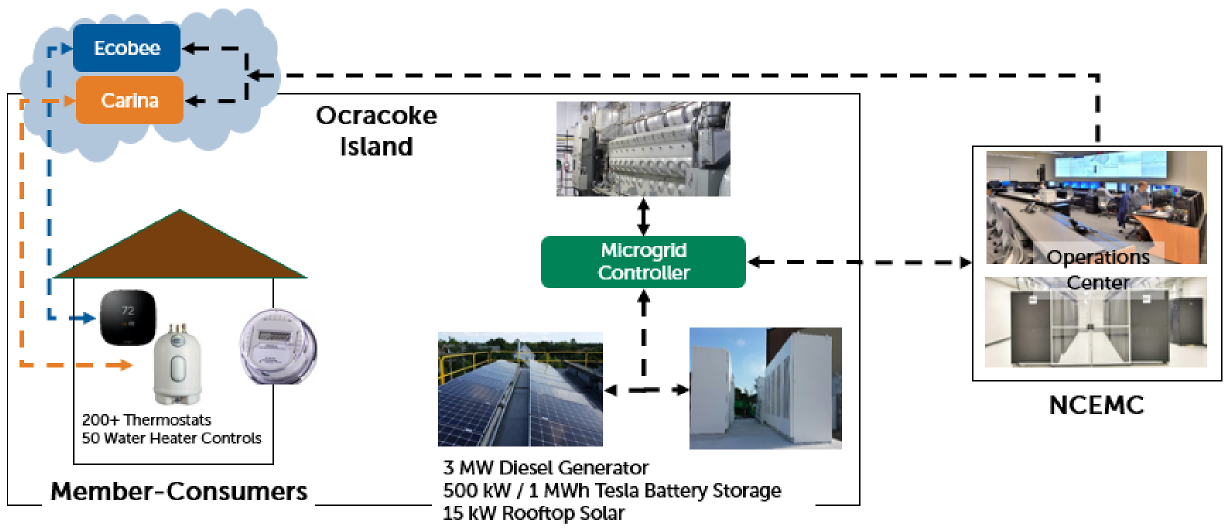


Figure 18: Ocracoke microgrid and components

EVALUATION

To evaluate the microgrid's ability to island and provide resiliency, two scenarios were tested. The first tested the microgrid's ability to serve the load of Ocracoke Island and the larger island grid when connected to transmission from Hatteras Island. The second was a true "islanded" scenario in which Ocracoke Village was isolated from the larger grid. As mentioned above, Ocracoke Village has been islanded previously, and the diesel generator serves the village load at 12 kV. The Village load is electrically "downstream" from the generator at 12kV. Due to space and clearance limitations, the microgrid was interconnected on the 25 kV side of the diesel generator. The true islanding test would include the diesel generator, the battery and solar supporting the generator. NCEMC would also remotely dispatch DR resources of water heaters and thermostats.

Test # 1

The grid-connected test was completed on June 21, 2017 at approximately 08:00. Though it was peak tourist season, this time was chosen because load forecasts indicated that the diesel, batteries and solar resources would provide enough generation to serve Ocracoke and supplement loads on Hatteras Island. The test ran for approximately 1 hour and 10 minutes. The integrated energy production during the test was diesel at 3.1 MWh, batteries at 494 kWh, and solar at approximately 2 kWh. The island load integrated at 2.7 MW, making the net export to Hatteras Island approximately 900 kWh. Figure 16 below illustrates the microgrid status and island load during the test.

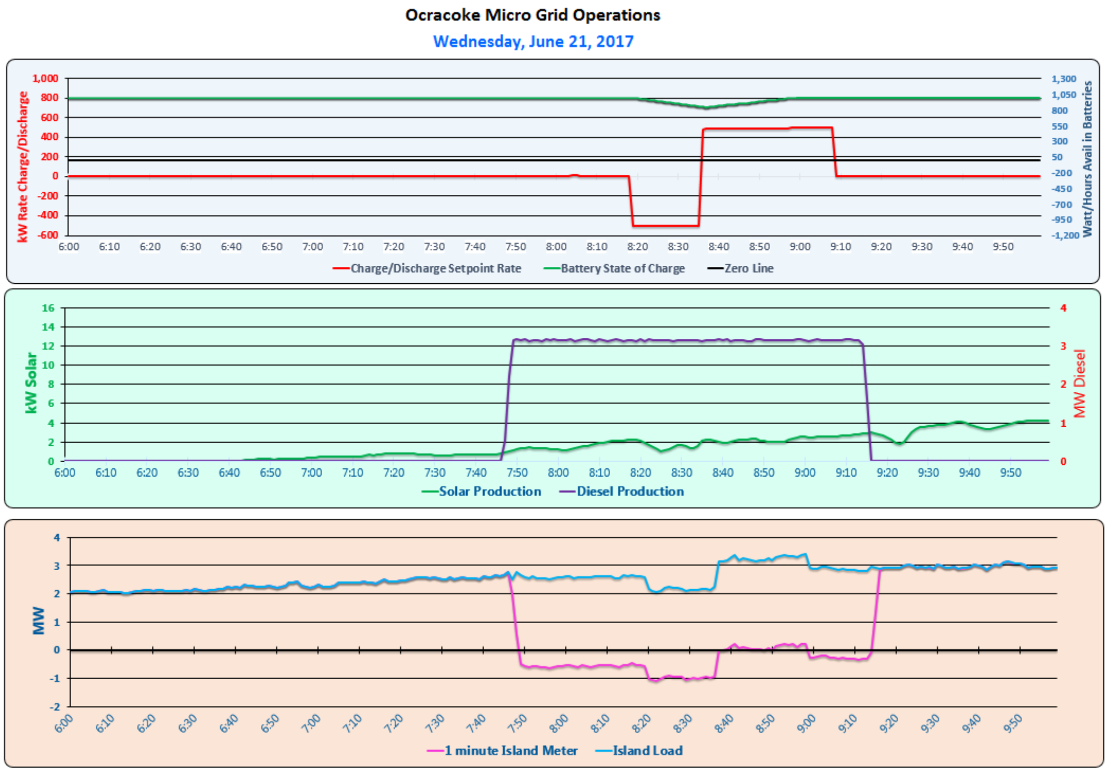


Figure 19: microgrid status and island load

Test # 2

The full island test was scheduled for the morning of August 3, 2017. This was again during peak tourist season, but the mid-week, morning loads were forecasted to be at ideal levels for the microgrid test. Unfortunately, a week before the scheduled test, work on the Bonner Bridge replacement caused an outage to both Hatteras and Ocracoke islands. This incident provided an unexpected opportunity to test all of the components of the microgrid; unfortunately, due to a forced outage of the diesel generator on Ocracoke, we were not able to test as we had hoped. Details of that experience will be included in the lessons learned following this section.

The full islanding test was rescheduled for October 25, 2017. Several steps were required before we could run the islanding test, including:

- Development and review of microgrid switching orders with Tideland EMC, Plant Operations and Energy Operations

- Installation of a temporary recloser that would allow uninterrupted transition from grid power to islanded power for Tideland EMC end-use consumers
- Forecasting of island loads to select the optimal time for the test
- Determination of how to re-synchronize all phases of distribution with the larger grid, and to transition back to grid power with no interruption to Tideland EMC members

Once preliminary steps were complete, the test was confirmed and implemented on October 25, 2017. The plan included scheduling the water heater and thermostat controls to switch off before the test and return to service afterward. The generator, battery and solar would serve the remaining island load during the test. Depending on load levels, Operations would use the battery to support the generator by discharging when load levels were rising or charge the battery as loads were dropping.

At approximately 11:50, the test was initiated. NCEMC planned to separate from the grid and switch to the microgrid at 12:00. Prior to 12:00, with island load at 1.7 MW, the generator was synchronized to the grid and all microgrid components were online and ready to serve. A one-line diagram of the key components and their status at this point is included below.

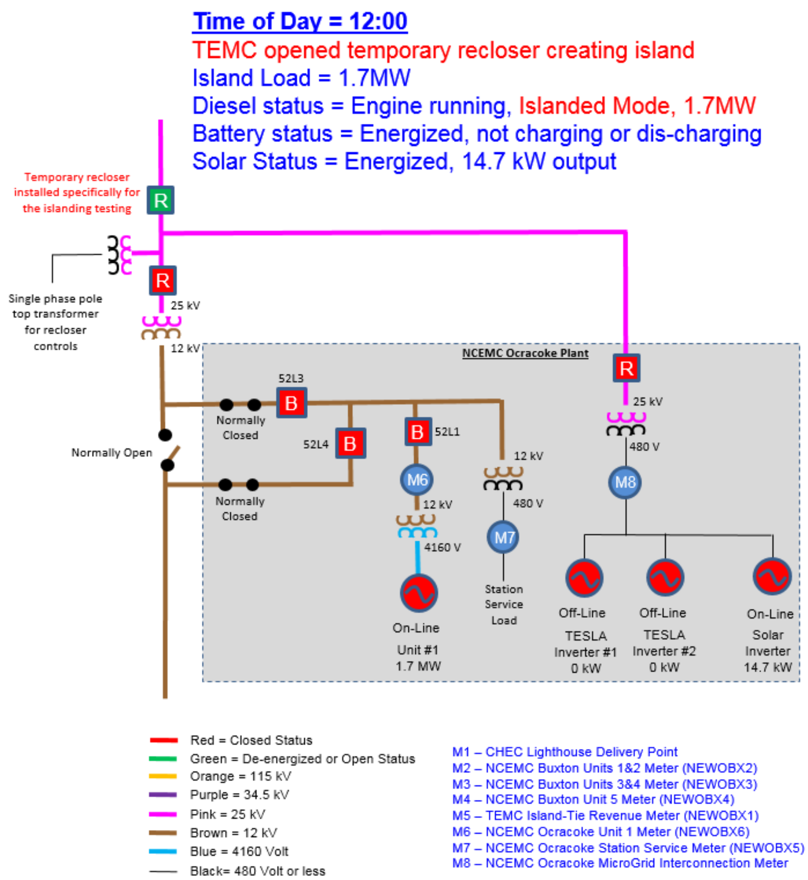


Figure 20: Islanding test #1

Shortly after the island load was switched to the microgrid, the 25kV system experienced high voltage that caused a lighting arrestor to fail. This failure caused a momentary drop in voltage that caused the microgrid recloser to open and generator protection devices to activate, which left the Village without power. After a brief safety check and assessment of the generator, the diesel was restarted and the Ocracoke Village load was picked up. The diesel was serving the Ocracoke Village load on the 12 kV system; the 25 kV system was de-energized. Tideland EMC removed the remaining lightning arrestors on the 25 kV system and allowed NCEMC to resume the test. A one-line diagram of key components and their status prior to continuing the test is included below.

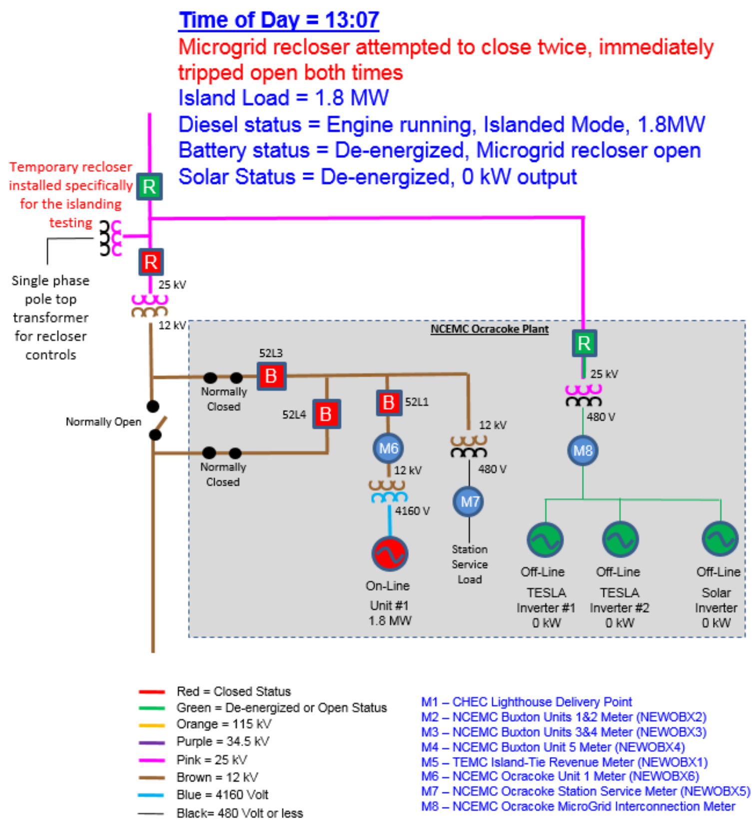


Figure 21: Islanding test #2

While the diesel was still serving the Ocracoke Village load, the 52-L3 circuit breaker was closed energizing the 25kV system. Shortly after, the microgrid recloser attempted to close twice (incorporating the battery and solar as part of the resource mix) but immediately opened both times which prevented the battery and solar from coming on-line. The microgrid recloser was placed in manual mode to prevent it from trying to bring the microgrid online. At almost the same time, the circuit breaker (52-L1) for the generator operated, which took the generator off-line and dropped the Ocracoke Village load for a second time. The test was aborted, and grid power was restored to the island.

These protection devices operated as designed in protecting the generator and microgrid. The unsuccessful islanding test, and the events that resulted in the microgrid's inability to participate in the test, triggered an investigation. The preliminary analysis of events indicated that in both cases the protection devices operated due to high voltage on the island. Initially it was unclear what caused the high voltage. Subsequent meetings between Power Services (Engineering, Procurement, and Construction firm), Tideland EMC and NCEMC Engineering staff revealed that multiple issues could have contributed, including a 25 kV grounding reference issue and/or generator control issues. Further study is required before this test can be attempted again.

NCEMC met with Tideland EMC and Power Services to evaluate data gathered during the events. The problems appear to be limited to the 25kV system. Some issues discussed included VAR flows, generator control logic for power factor, and a ground reference issue with the Delta-Wye 25 kV transformer. Several solutions have been proposed. The first will be for Power Services to get the Tideland EMC WindMil model for Ocracoke and recreate the scenario in a modeling environment. By operating this model in various scenarios, Power Services should be able to determine the cause of the generator trip and recommend the solutions to correct the problems.

LESSONS LEARNED AND NEXT STEPS – USE CASE 4

One lesson learned is that when developing the project, NCEMC could have better coordinated with Tideland EMC, Power Services and Tideland EMC's consulting engineer. Having assistance and expertise from these resources who are knowledgeable about the 25 kV network could have yielded additional design concepts that may have avoided the unit trip on the islanding test.

Proving the value of remote DR dispatch was also a valuable lesson learned. When the transmission cable was cut, loads on Hatteras and Ocracoke were well beyond the generating capacity of the units on the islands (3 MW on Ocracoke and 15 MW on Hatteras). As part of the cooperative's power restoration efforts, there was a public appeal to turn off air conditioning units and water heaters. With the cooperative's permission, NCEMC Operations was able to control thermostats and water heaters from the Integrated Operations Center (IOC) in Raleigh.

There were almost 400 thermostats and 40 water heaters on Hatteras and Ocracoke islands that were controlled during the emergency period. As additional mobile generation became available, NCEMC was able to release specific air conditioning units and water heaters for normal operation. The specificity of returning the units to service was based on electrical location and whether the circuit had adequate capacity to carry the air conditioning and water heater load. The loss of transmission service allowed NCEMC to test the benefits of precise remote control of DR resources.

The battery on Ocracoke also assisted with generator operations on Hatteras Island. During emergency conditions, typically all diesels are operated with a single unit contingency. There is 15 MW of generation on Hatteras Island and during emergencies, each unit is run up to 80 percent of its capacity to serve a total load of 12 MW. This type of operation allows all load to stay on if a single unit trips off-line (the remaining four units can carry the 12 MW). Cape Hatteras Electric Cooperative (CHEC) manages this reduced supply by rotating blackouts with the feeders that service load. Having the battery available allowed an additional 500 kW of load to be served for short periods – load that otherwise would have been dropped. This combination of 500 kW battery and single unit contingency operation also allowed Plant Operations to optimize engine run times by starting engines later in the day and turning them off sooner in the evening when load levels dropped. This optimization saved approximately 3 hours of engine run time each day during emergency operations. The combination of DR resources (on both Ocracoke and Hatteras islands) and additional supply resources (the battery and solar) will enable improved operations during emergency events.

NCEMC expects to schedule a follow-up islanding test in the spring 2018. Before the test, NCEMC will need to determine the cause of the high voltage that triggered the protection devices to activate. NCEMC, Tideland EMC and Power Services are working to find solutions. The power flows resulting from back feeding the 25kV side of the wye-delta connected transformer caused abnormally high voltages during the test. These flows were confirmed during subsequent modeling runs after the event, and the initial conclusion is that the delta-wye configuration of the transformer does not have an adequate ground reference to stabilize voltages on the delta configured side of the transformer when operated in this mode.

Power Services is expected to complete initial modeling by mid-December and should have a recommendation for a solution(s) shortly after that. Once the solution(s) is in place a re-test will be scheduled. After testing, NCEMC will produce an addendum to this report explaining the findings of the model runs, the steps taken to correct the problem(s), the overall performance of the microgrid and any new lessons learned.

ASSET DEFERMENT – USE CASE 5

BACKGROUND

An often cited benefits of storage and microgrids is the potential for deferring or avoiding upgrades to transmission or distribution equipment. Use Case 5 will evaluate the use of microgrid components as a means to defer the costs associated with the procurement and construction of system equipment. Asset deferral or life extension would be accomplished by adding a microgrid or storage asset electrically “downstream” from the affected equipment. The microgrid could be deployed to relieve some portion of the asset's load carrying capacity during extreme peaking periods. The asset could be a transformer, conductor or other equipment that is approaching its maximum rating and/or expected life.

EVALUATION PROCESS

Because the Ocracoke microgrid is located "upstream" from Tideland EMC's distribution system on the island, this case considers how much relief the microgrid could provide to Tideland EMC's transmission system from Hatteras Village. The evaluation examined historical loads and projected future growth. Economic analysis was conducted to determine if and how much relief could be provided to the critical assets serving Ocracoke Island. These findings can be extrapolated to determine the relative value of microgrid components for distribution level voltages and associated equipment.

In this example, a peak load level of 6.475 MW was observed on the system in July 2016. This load level is consistent with normal load growth on the island and represents a good starting point for examining the prospect of future load growth increases. Part of the microgrid project involved installing equipment to provide demand response during peak periods. This equipment consists of ecobee thermostats and water heater controls. These devices are centrally controlled from NCEMC using a web portal, and will add an additional 300 kW of demand response. As participation grows, it is conceivable that the non-generator components of the microgrid may approach 1 MW of total load relief capability.

A one-line diagram in Figure 19 shows the local distribution system and the microgrid components at Ocracoke Island.

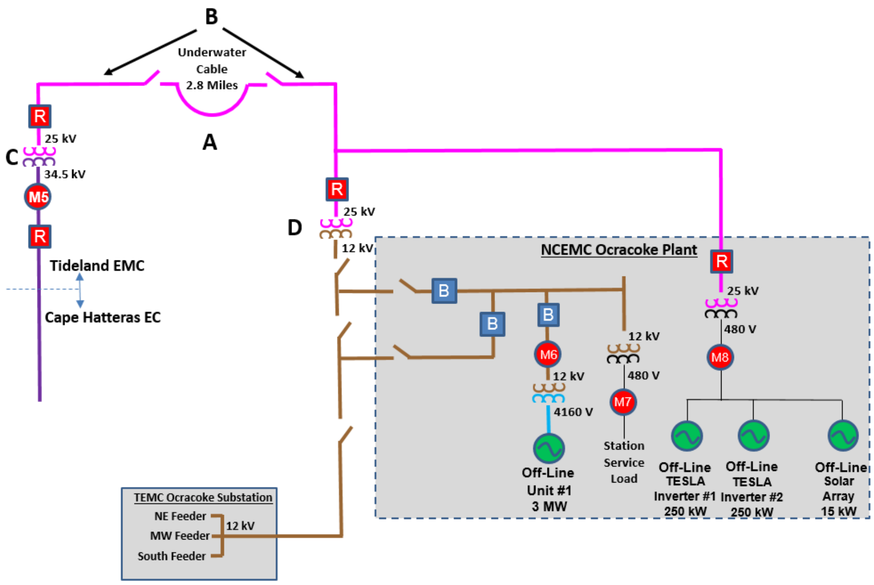


Figure 22: local distribution system and microgrid components

Three major system elements in the bulk service to Ocracoke Island from CHEC have the potential for significant capital cost deferment. They include:

- The 2.8 mile #2/0 AWG CU underwater cable through Cape Hatteras Inlet. Estimated rating: 10-12.7 MVA **(A)**
- 15 miles of 394.5 Kcmil AL overhead conductor from the Hatteras substation to the cable riser and down Ocracoke Island to the Ocracoke substation. Estimated rating: 22-25 MVA **(B)**
- A 7.5/9.375 MVA, 34.5/25 kV step down transformer at Tideland EMC's Hatteras substation. Base rating: 7.5 MVA **(C)**
- Another 7.5/9.375 MVA, 25/12.5 kV step down transformer also located at Tideland EMC's Ocracoke substation. Due to physical space and clearance requirements, the microgrid was electrically located upstream from this transformer, meaning it is unable to help reduce the loading for this device. **(D)**

Although the carrying capacity of the #2/0 cable and overhead conductor is well above the current peak load level, if the island had fewer growth limitations it would eventually come into play as a candidate for deferment. The calculated full power capability of the cable is 12.7 MVA. However, operating the cable at its full rating is not considered good utility practice as it stresses the cable insulation. Therefore, a safety margin has been included in our analysis, which limits the rating to 10 MVA.

Due to the relative proportional cost of major equipment items such as transformers as a percentage of the overall system investment and a high emphasis on reliability, co-op planners typically use the base rating of a transformer as the starting point for an upgrade in capacity. Since the base rating of 7.5 MVA on the 34.5/25 kV step down transformer is much closer to the peak load level, it represents an excellent opportunity for deferment under severe load growth conditions. In other words, once the peak load on Ocracoke Island reaches the 7.5 MVA threshold, Tideland EMC would likely include upgrading this transformer and the 25/12.5 kV Ocracoke Sub unit in its next work plan. The microgrid resources are interconnected on the 25 kV side, but NCEMC will also look at what the deferment case would be if the battery could be connected at 12.5 kV. As mentioned above, this was not part of the project due to clearance and space limitations. Postponing the investment in the 34.5/25 kV Hatteras substation transformer would either save the cooperative capital for that planning year or allow it to deploy that capital for some other purpose.

NCEMC examined what might happen if Ocracoke Island experienced a significant jump in load growth. Under a 1.5-2 percent per year severe growth scenario (net above any DR contribution from thermostats and water heater controls), load would reach the base rating of the transformer by 2021, as illustrated in Figure 20 below (solid line). Assuming the battery is deployed during the peak hour over the next few years, the load + battery capacity would not reach the base rating until the year 2026 (dotted line), deferring the transformer upgrade for five years.

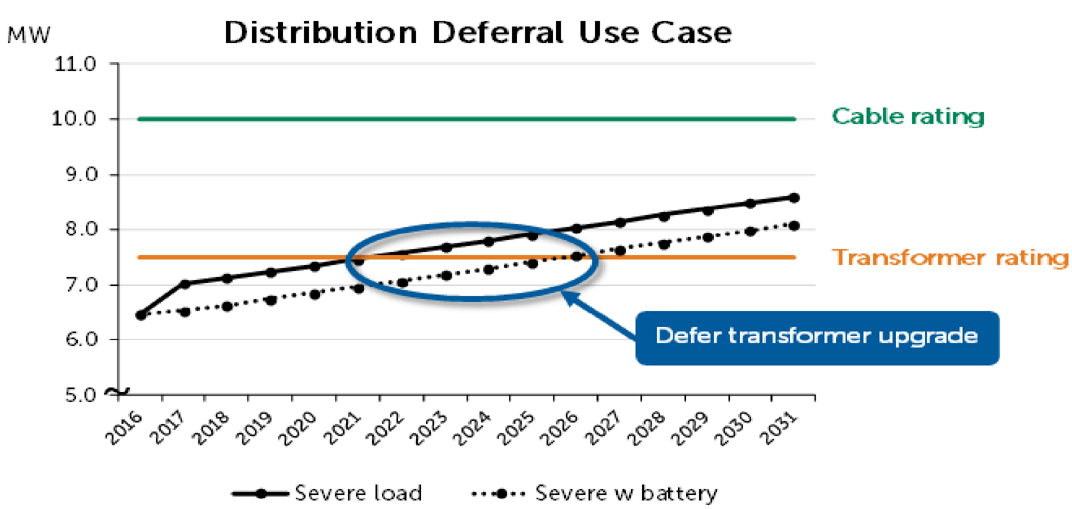


Figure 23: transformer deferral timeline

The associated cost savings is estimated to be approximately $125,000, calculated as follows:

$250,000 (estimated upgrade cost of new transformer) **X**
10 percent (5 percent depreciation + 1 percent tax/insurance + 4 percent interest/financing, O&M) **X**
5 years = $125,000 in cost savings. With a NPV of $60,502.

This assumes that the battery is available and operating during the peak hour, and that load does not dramatically increase beyond the battery capacity in a given year. It may also be possible to increase savings by including other assets such as voltage regulators or station equipment that is coincidentally also nearing a similar ratings limit.

If we had been able to connect all of the microgrid components on the load (12.5 kV) side of the 25/12.5 kV transformer, the net 5 year savings would include both transformers (almost double the $125,000 amount),

Component	Base Capital Cost	Carrying Cost (10%)	Years	Total Savings
34.5/25kV Transformer	$250,000	$25,000	5	$125,000
25/12.5kV Transformer	$200,000	$20,000	5	$100,000
Total				$225,000

Figure 24: transformer deferral savings

With an efficient deployment of the ecobee thermostats and water-heater controls to further reduce the peak load, there is the potential to defer upgrading the 25/12.5 kV transformer, or even both transformers, for an additional year.

CONCLUSION – USE CASE 5

Using a microgrid and its components for asset deferment would truly be a value added case since use as a deferment tool would likely be a secondary function. (Typically, a microgrid would be installed for other reasons.) This benefit could provide 2-4 years of relief for assets (or longer with a slower load growth rate), which would allow the cooperative to redeploy its capital in other areas or postpone construction costs associated with system upgrades.

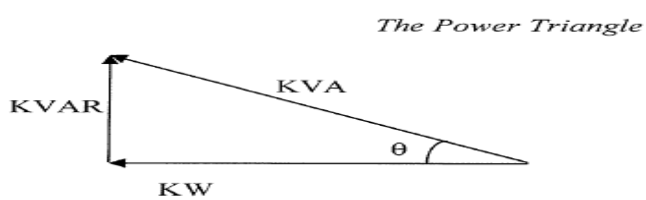
Depending on components and the project's intent, microgrids could be designed and constructed to be re-deployable to another location once asset upgrades are completed. Then, the microgrid could assist or defer upgrades in another area of the system. This model could be replicated for other distribution circuits with reliability, capacity or power quality issues.

Analysis showed that the closer the microgrid components are electrically located to the end-user load (i.e. at the 12.5kV distribution point), the more cost-effective their ability to defer upstream transmission and distribution assets becomes since more assets can be included in the deferment case.

POWER QUALITY IMPROVEMENT - USE CASE 6

BACKGROUND: THE POWER TRIANGLE

The *power triangle* (see figure 22 below) is one of the most fundamental concepts of electrical power system engineering, and represents an important point of reference when discussing the interaction between generation and load for a wide variety of system conditions. The basic idea is that there is a phase angle (ϴ) between the voltage and current, and the cosine of this angle is referred to as the power factor. When the power factor is lagging, it is an inductive circuit, and when it is leading, a capacitive circuit. An ideal state for an efficient power system is when the phase angle is close to zero, known as unity power factor.



$$P.F. = \frac{KW}{KVA} = \cos\theta$$

$$\frac{KVAR}{KVA} = \sin\theta$$

$$KVA = \sqrt{KW^2 + KVAR^2} = KV * I * \sqrt{3}$$

Figure 25: The power triangle

Electrical power networks often have loads that are highly inductive (lagging), such as motors. Even very resistive loads, such as lights, will contribute some inductive nature to the grid. In the past, this lagging component was counterbalanced by large generating plants that had the capability to produce a significant amount of positive (leading) reactive power (VARS) as part of their generating configuration. VARS could also be provided to the grid by capacitor banks located near load. This VAR input is important to support a healthy voltage on the grid and minimize losses as electricity is delivered to load. As large coal and nuclear plants have been retired, the need for VAR production on the grid has become more critical.

Traditional PV inverters were configured to maximize their real power output (kW), which meant that they produced very little, if any VAR output. Utilities and other independent power producers have recently worked with inverter manufacturers to make use of newer *smart inverters*, which include the capability to both absorb from and provide reactive power to the grid. This is possible because, with the exception of peak solar conditions when the solar output is close to the inverter rating, the PV inverter is running below its rated output current. This means that during this time, unused capacity of the solar inverter is available to produce reactive power, or VARS. Since the inverters are equipped with real-time control capability, they can also be deployed very quickly to respond to system conditions.

INVERTER REACTIVE POWER CAPABILITY

The initial configuration of the PV inverter for the Ocracoke microgrid was at full active power output (i.e. unity power factor). This is the typical default setting value for commissioning a new system. While a new set point could have been entered during this process, NCEMC elected to keep this setting in the interest of getting the system on line as soon as possible.

The SMA Sunny Tripower series inverter used at Ocracoke has several options for reactive power commands. One mode of operation is to put the inverter in Power Factor Control mode. This mode will control the system to output a specified amount of VARS to keep a power factor. NCEMC made this change as part of the use case development on August 30, 2017, and the system continued to produce power output at a 95 percent leading (positive) power factor until October 25, 2017. During the initial test, NCEMC observed a maximum output of 15.95 KW / 2.39 kVAR was observed (see data below).

A Direct VAR control mode is also available, which would allow the user to establish a leading or lagging value VAR set point. This value would need to be within the rated output of the inverter, ranging from full leading to full reactive output (no real power). NCEMC did not test this control mode, as portal control capability was not established before suffering a loss of the inverter during the islanding test on October 25, 2017. Therefore, this control mode has not been tested.

NCEMC has also confirmed that the Tesla inverters used for the project have the theoretical capability to produce reactive power to the grid. However, through research and collaboration with other users, NCEMC determined that reactive power production would be difficult to implement at this remote location given the time and effort required to successfully bring this feature to full operation. Tesla has since developed new generations of smart inverters with expanded capabilities, including this function. Given the fact that NCEMC was also unable to find anyone who had successfully implemented and used this particular feature on the type of inverter installed as part of our project, NCEMC elected not to pursue this option further due to complexity and scheduling/resource commitments already allocated to other activities.

NCEMC has also had a valuable opportunity to discuss installations with other entities working on battery installations through EPRI membership, and discovered that using larger batteries in a reactive power mode may introduce other problems such as “ringing” from harmonics on distribution feeders with switched capacitor banks. Affected entities have observed this problem to be especially notable during periods of low feeder load.

INVERTER CONTROL AND CAPABILITY CONSIDERATIONS

A key part of the use case evaluation for power quality experimentation is the need for fast and accurate control of the inverter. This accomplishes two functions. First, it allows the user to quickly change control modes and values in order to respond to changing system conditions. Second, it allows the introduction of automated responses to system condition inputs from a remote location, similar to the way a switched capacitor back or voltage regulator might behave. In order to accomplish this task, NCEMC identified the need to establish connectivity between the solar inverter and the Sunny Portal dashboard application. This application is already in use on the community solar installations, and NCEMC started the process to link the Ocracoke microgrid solar inverter to the portal.

In performing the preliminary groundwork, NCEMC learned that the telecommunication connection must be established in such a way that the internet accessible portal does not create a cybersecurity risk with the operational network at the plant. This task is not yet complete, but NCEMC’s Innovative Energy team and NCEMC IT staff are working to establish a prototype method for creating this connection in a safe and secure way. Sufficient bandwidth of 10 MB or more is needed to bring a wider variety of operational data back to the operations center and establish a high-speed connection to the site.

TESTING AND EVALUATION PROCESS

Set power factor at 95 percent (leading = positive value)

Values shown below are representative of test values observed

Date	Ocracoke Solar kW	Ocracoke Solar KVAR	Ocracoke Solar Voltage
9/7/2017 10:35	8.51	2.39	495.70
9/7/2017 10:36	8.97	2.39	496.39
9/7/2017 10:37	9.54	2.39	497.26
9/7/2017 10:38	8.66	2.39	496.91
9/7/2017 10:39	9.27	2.39	497.43
9/7/2017 10:40	9.03	2.39	497.78
9/7/2017 10:41	9.16	2.39	497.43
9/7/2017 10:42	9.77	2.39	499.68
9/7/2017 10:43	9.01	2.39	499.16
9/7/2017 10:44	8.90	2.39	499.34
9/7/2017 10:45	8.66	2.39	498.99

Figure 26: power factor test values

The data screen shown below shows a typical screen shot of what the Sunny Portal. NCEMC will have this connection installed soon at the Ocracoke microgrid, once the solar inverter is replaced. An additional follow-up action item is to adjust the VAR output and have Tideland EMC monitor its feeder voltages to get an idea of the corresponding voltage support capability of the inverter.

Figure 27: Sunny portal

ECONOMIC VALUE CASE

Although the potential direct value from this use case is not the same as the demand and energy arbitrage cases, there are still a variety of additional value propositions to be gained through using the VAR capabilities of the solar inverter.

An immediate benefit from the added VARS on the system is in the resulting system efficiency, improving the power factor and deriving savings from the reduced losses (especially during peak conditions). The voltage improvement will also reduce wear and tear on voltage regulators, allowing them to change taps less frequently and prolong their useable life span.

Since the VAR output of the solar inverter can be adjusted all the way to a full reactive setting, this capability could even replace the need to install a new capacitor bank if the operational case is workable. A new 25kV three phase, 50kVAR capacitor bank would cost approximately $3,100 plus installation and ongoing O&M.

CONCLUSION – USE CASE 6

Changing the active and reactive power state in the Ocracoke solar inverter proved surprisingly easy to do, and mainly consisted of establishing a connection to the inverter with the correct configuration software. Once the inverter is repaired and the Sunny Portal activated, NCEMC is planning to test the ability to remotely change the configuration. A successful test will opens up the possibility of automating the ability to respond to system configurations when reactive support is needed.

Even with limited testing opportunities, NCEMC was able to demonstrate the capability to use a wide variety of possible reactive output settings. This feature will only improve with the latest versions of inverters, and can easily be done remotely with a good and secure communications link to the device. The ability to change settings quickly will also add value in the form of voltage support, especially at locations where the batteries are paired with large amounts of solar generation.

The Power Quality Improvement use case also contains multiple value streams that may be easily combined with other use opportunities. In addition to the value of lower system losses and less wear and tear on system equipment such as voltage regulators, the VAR capability of a solar inverter can also replicate a capacitor or reactor. An additional value also flows through as a reduction to the cost of reactive support in PJM market ($/kVARh) used to serve load. In the control areas where lagging power factor penalties are applied to transmission bills, this capability could be used to offset the penalties if the generation is not being used for demand reduction (such as during a morning winter peak hour when solar output is not available).

CONCLUSION

The Ocracoke microgrid has provided NCEMC and North Carolina's Electric Cooperatives an excellent laboratory to develop, test, research and understand the capabilities and values associated with a utility-scale microgrid and its components. NCEMC staff has tested six use cases for economics and operational benefits at the microgrid. Testing is complete for four of the six use cases. Test data revealed economic and operational values that can be replicated for specific applications on other cooperatives systems. Further evaluation and problem-solving is underway to resolve issues that prevented completion of tests of the islanding and power quality use cases. Those use cases will be reevaluated and a supplemental report will be published to explain the findings.

GLOSSARY OF TERMS

APM- Aces Power Marketing provides wholesale electricity and natural gas trading services to its member/owners, which operate in the eastern, southern, and Midwestern US.

Ancillary Services- Those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. PJM operates three markets for ancillary services: 1) Regulation: Corrects short term changes in electricity that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired frequency, 2) Synchronized Reserve and 3) Non Synchronized Reserve. These services allow for fast response to match generation with load, synchronized being fastest to respond, and non-synchronized taking longer to come on line when needed.

Asset Deferment- The ability to defer or avoid the need to upgrade electrical transmission and distribution equipment or extend the life of existing transmission and distribution equipment.

Capacity Firming- The variable, intermittent power output from a renewable power generation plant, such as wind or solar, can be maintained at a committed level for a period of time.

Coincident Peak- The energy demand of an entity that coincides with the electric utility's peak system demand

Demand Response (DR) - Changes in electric usage by end use customers from their normal consumption patterns in response to changes in the price of electricity over time, or incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Energy Arbitrage- The ability to fill up batteries (or other storage) with cheap power from night time resources, abundant wind, or solar and using that stored energy rather than peak priced energy.

EMS- An energy management system (EMS) is a system of computer aided tools used by operators of electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system.

GSM- General Statistical Model (GSM) is a class of mathematical model, which embodies a set of assumptions concerning the generation of some sample data, and similar data from a larger population. A statistical model represents, often in considerably idealized form, the data-generation process.

Inverter- A power inverter is an electronic device or circuitry that changes direct current (DC) to alternating (AC). The input voltage, output voltage and frequency, and overall power handling depend on the design of the specific device or circuitry.

Islanding/Island Mode- Is the condition in which a distributed generator (DG) continues to power a location even though electrical grid power is no longer present. An intentional islanding design is called a microgrid. In case of an outage, a microgrid controller disconnects the local circuit from the grid on a dedicated switch and forces the distributed (DG) to power the entire "islanded" local load.

IOC- Integrated Operations Center (NCEMC)

ISO- Independent System Operator, like the RTO, the ISO coordinates, controls and monitors the operation of the electrical power system, typically in a single state or small geographic area.

LMP- Locational Marginal Pricing is the price for electric energy at each load zone. LMP takes into account the effect of actual operating conditions on the transmission system in determining the price of electricity at different locations in the PJM region. LMP reflects the value of the energy at the specific location and time it is delivered.

PJM- Is a RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. As a neutral, independent third party, PJM operates a competitive wholesale electricity market and manages the high voltage electricity grid to ensure reliability for more than 65 million people.

PJM Capacity Price- A utility or electric supplier can meet their resource requirements for customer demand and reserves either with generation capacity they own, contract for, through demand response, or capacity purchased through PJM capacity markets. The PJM Capacity Price is the cost of energy capacity contracted by the utility via PJM.

PLC- A programmable logic controller (PLC) is an industrial computer control system that continuously monitors the state of input devices and makes decisions based upon a custom program to control the state of output devices.

Power Factor- An electrical or electronic device's power factor is the ratio of the power it draws from the main power supply and the power it actually consumes.

NPV-Net Present Value (NPV) is the difference between the present value of cash inflows and the present value of cash outflows. NPV is used in capital budgeting to analyze the profitability of a projected investment or project.

Microgrid- A localized group of electricity sources and loads that normally operates connected to and synchronous with traditional centralized electrical grid, but can also disconnect to "island mode"-and function autonomously as physical and/or economic conditions dictate.

NITS Rate- Network Integration Transmission Services: Zonal NITS rates are based on a FERC formula filing that takes account for all dollars spent on transmission projects and maintenance for a particular utility.

NSPL-Network Service Peak Load. A load's contribution to the zone's metered annual peal load.

Reactive Power- Reactive power exists in an AC circuit when the current and voltage are not in phase.

Recloser- Is a circuit breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault. Reclosers are used on overhead distribution systems to detect and interrupt momentary faults.

Reg A- An automated generator control signal sent by PJM to a resource owner every two seconds.

Reg D- Fast regulation, automated generator control signal sent by PJM to a resource owner. It increases the "utilization" of energy storage devices

Renewable Smoothing- Integration of renewable energy resources to a power system can cause power fluctuations due to their intermittent nature. One way to reduce these effects is to smooth power production using energy storage systems (batteries).

Resiliency- Resilience, stemming from the root, resilio, meaning to leap or spring back, is concerning the ability of a system to recover and, in some cases, transform from adversity. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.

RPM- Reliable Pricing Model PJM's capacity market (RPM), ensures long term grid reliability by securing the appropriate amount of power supply resources needed to meet predicted energy demand in the future.

RTAC-Real Time Automation Controller

RTO- Regional Transmission Organization is an electrical power transmission system operator (TSO) which coordinates, controls and monitors a large multi-state electric grid.

Smart Demand Response (DR) Device- Smart control devices installed in member homes and/or businesses that will efficiently and in a real time manner, limit or reduce the kW demand upon the grid when a control signal is sent by the utility, and ideally not impact the consumer comfort or experience.

Smoothing-See Renewable Smoothing

Solar Track- To physically track or follow the path of the sun to collect the sun's energy with maximum efficiency.

Standard Deviation- In statistics, the standard deviation is a measure that is used to quantify the amount of variation or dispersion of a set of data values. A low standard of deviation indicates that the data points tend to be close to the mean (expected value) of the data set, while a high standard deviation indicates that the data points are spread out over a wider range of values.

Sunny Portal- A web based tool for solar facilities that tracks production and other key solar site data in a graphical and user friendly format.

Tesla SMC (Site Master Controller) - An additional charging cable that is 120v, instead of their standard 220v charging cable.

VAR- Is a unit by which reactive power is expressed in an AC electric power system.