PNNL-28941

Nantucket Island Energy Storage System Assessment

Final Report

August 2019

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Richland, Washington 99354

Executive Summary

Nantucket Island is located off the coast of Massachusetts, as highlighted in blue in Figure ES.1. It has a fairly small resident population of approximately 11,000. During summer months, however, the population on the island can swell to over 50,000. Currently, Nantucket's electricity is supplied by two submarine cables (as shown in Figure ES.2 by green and purple lines) with a combined capacity of 71 megawatts (MW) and two small on-island combustion turbine generators (CTG) with a combined capacity of 6 MW. In an N-1 contingency event where one of the transmission cable fails, electrical load on Nantucket Island could exceed the grid's capacity to serve that load. National Grid has taken steps to meet this challenge. The small CTGs will soon be replaced by a single, larger CTG with a temperature-dependent capacity that varies between 10 MW and 16 MW. National Grid is also adding a 6 MW / 48 MWh Tesla lithium-ion battery energy storage system (BESS). These investments will bring the total energy supply capacity on the island to approximately 91 MW on the days when the grid faces peak energy demand. The high energy to power ratio for the BESS will enable it to provide sufficient energy to ride through N-1 contingency events.

Figure ES.1. Nantucket, MA

Figure ES.2. Two Supply Cables connecting Massachusetts to Nantucket Island

These investments were taken after thoughtful consideration of all options, including the deployment of a third submarine transmission cable. In consultation with National Grid, Pacific Northwest National Laboratory (PNNL) has evaluated the financial implications of this investment decision. PNNL defined a set of services to be evaluated from an economic perspective based on its experience in conducting similar assessments for various utilities across the U.S. While the primary service provided by the BESS is responding to N-1 contingency events in order to defer investment in a third submarine transmission cable, there are additional local and market-based benefits that the BESS can also provide, including outage mitigation, volt-VAR operations (VVO)/conservation voltage reduction (CVR), capacity, frequency regulation, spinning reserves, and energy arbitrage.

Total 20-year lifecycle benefits of BESS plus CTG operations are estimated at $145.9 million, yielding a 1.55 return on investment (ROI) when compared to $93.9 million in revenue requirements and energy costs. The majority (75.0%) of the benefits are tied to deferring the investment in the third transmission cable for 13 years. An additional $18.8 million (12.9%) result from regulation services. Outage mitigation yields $12.3 million (8.4%) in benefits. Forward capacity market operations generate $4.1 million (2.8%) in total revenue. Spinning reserves are estimated to generate $1.2 million, or 0.8% of total benefits. Volt-VAR/CVR operations yield negligible benefits.

Table ES.1. Benefits vs. Revenue Requirements and Energy Costs – Base Case

Element	Benefits	Revenue Requirements and Energy Costs
Capacity	$4,060,124	
Regulation	$18,757,805	
Spin Reserves	$1,195,419	
Volt-VAR/CVR	$80,043	
Outage Mitigation	$12,313,206	
Transmission Deferral	$109,490,163	
Energy Costs		$657,898
Revenue Requirements		$93,264,355
Totals	$145,896,759	$93,922,253

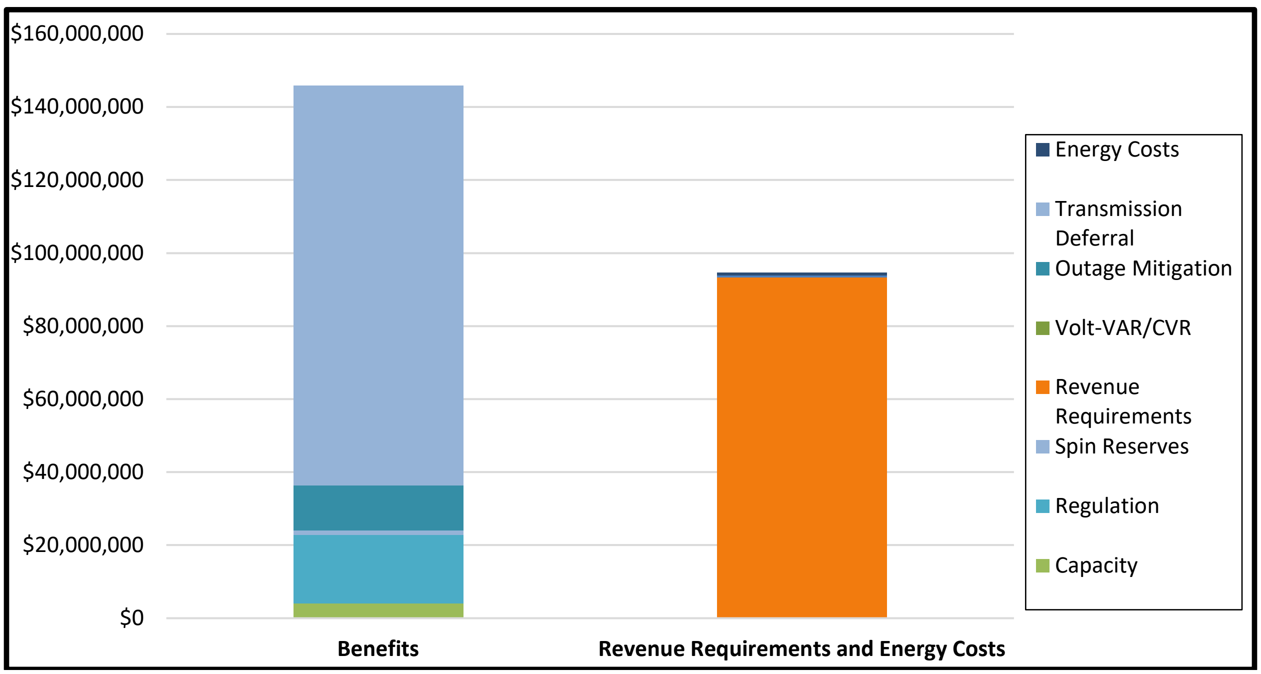


Figure ES.3. Benefits of Local and Market Operations (Base Case) vs. Revenue Requirements

This analysis includes the impacts of both the BESS and CTG because both are required to achieve the desired effect of deferring investment in the 3rd transmission supply cable for 13 years; however, we assume that only the BESS would participate in ISO-NE market operations due to the presence of emissions and noise constraints on CTG operations. To ensure that the BESS has sufficient reserves to respond to reserve, capacity, and outage events, we have assigned a 50% state of charge floor when the BESS is engaged in market operations. During N-1 contingency events, the BESS would be fully charged.

Even when limited to non-market operations, the value of the Nantucket Island BESS and CTG ($122 million) exceeds the $93.3 million in revenue requirements for the systems, yielding an ROI of 1.30. Over 90% of the local benefits result from deferring the investment in the third transmission cable. Deferral reduces the present value (PV) costs of that cable by $109.5 million. Based on a Nantucket Island load analysis conducted by PNNL, we estimate that the BESS will be required to cover four hours of an N-1 contingency event in 2019 and that the number of hours when National Grid will be operating in the N-1 contingency window on Nantucket Island will expand to 290 hours, or 3.3% of all hours, by 2033.

PNNL used its Battery Storage Evaluation Tool (BSET) to simulate operation of the BESS while engaged in local and market operations for a one-year period. Based on BSET operation algorithms, regulation service would dominate the application hours, with the BESS engaged in that service 7,900 hours each year. The BESS would provide VVO/CVR service 1,825 hours per year, spin reserves 388 hours per year, and would be available to provide capacity and outage mitigation as called upon. The annual hours of service noted above exceed the number of hours in a year (8,760) because some services can be provided simultaneously. Outage mitigation and transmission deferral provides tremendous value despite the fact that those services are concentrated in a very small number of hours each year – 5 and 145, respectively.

The Nantucket Island Distribution System was modeled using two open-source simulation programs: OpenDSS and GridLAB-D. Upon review of the system near Bunker Road, it became apparent that the BESS and CTG could not safely provide full power simultaneously. The following upgrades are suggested to mitigate this and other limitations:

1. There are two underground cable exits from Bunker Road, each rated 420 Amps in National Grid's CYMDIST network modeling tool. When both the BESS and CTG are at their maximum output, i.e., 6 and 13 MW respectively, a certain section in one of the cables exceeds that level (verified at maximum and minimum feeder load). If combined BESS/CTG output is de-rated by 2 MW, overloading vanishes. However, in order to have a full 19 MW export from Bunker Road, the conductors in an overloaded section identified in Section 2.2.1 of this report may need to be upgraded. It is useful to note that with 19 MW export, the limiting section carries 463 amps. During winter time, additional output may be available from the CTG. To reflect that situation, 21 MW export has been considered that increases the current flow to 513 amps.

2. The hospital has a second feeder service from 101L5, which mitigates an outage on the main service from 101L4. In the 2019 feeder map, there are also two load breaks that connect feeders 101L4 with 101L2. In case of an outage on 101L4 or outage of mainland cables, automatic switches in these locations can ensure timely supply to the hospital from the BESS/CTG. Hence, this upgrade seems to represent a potentially beneficial investment.

3. Load breaks on Pleasant Street and Hooper Farm Road connecting 101L4 with 101L2 are required.

4. In the existing feeder map, BESS/CTG can already supply the Town Offices. However, a recloser upstream of the Town Offices on 101L7 can make this supply more effective. Another possibility is to relocate the existing recloser 17/200154 to the other side of the Town Offices – i.e. on Orange Street.

5. Since the BESS and CTG are located on 101L7, an automatic switch on Orange Street, which connects 101L7 and 101L2, would be a beneficial investment. This is especially true

when an outage takes place on Orange Street and takes out 101L7 and 101L2. All of these new or upgraded switches could have SCADA for operational dispatch, which would reduce the outage durations compared to manual switching.

Outages were modeled under scenarios where the additional distribution-level investments outlined above enable full output of the BESS/CTG and 5- and 1-minute response times. When the systems are able to operate at full power and respond more rapidly, the value of lost load to customers on Nantucket Island could be reduced by as much as $240,000 annually. Thus, these investments would appear to be cost-effective.

This report concludes by presenting an illustrative rules-based control/coordination strategy, while elaborating on a few specific scenarios using simulation studies tied to N-2, N-1, and normal operating scenarios. We have identified several areas for potential future study, including the design and incorporation of a more optimal control approach based on optimization of the island network, development of a day-ahead load and price forecasting tool, and simulation and quantification of the benefits of a firm/non-firm transactive energy system under islanded conditions.

Acknowledgments

We are grateful to Jack Vaz, Joseph Henry, Terron Hill, David Bianco, Ben Carron, Babak Enayati, and Tim Martin of National Grid for the data, guidance, and insight each provided in support of this project. We are also grateful to Dr. Imre Gyuk, who is the Energy Storage Program Manager in the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy, for providing financial support and leadership on this and other related work at Pacific Northwest National Laboratory.

Acronyms and Abbreviations

ADMS	Advanced Distribution Management System
AGC	automatic generation control
ANSI	American National Standards Institute
ARIMA	autoregressive integrated moving average
ARMA	autoregressive moving average
ATRR	alternative technology regulation resource
BESS	battery energy storage system
BLS	U.S. Bureau of Labor Statistics
BOL	beginning of life
BSET	Battery Storage Evaluation Tool
C&I	commercial and industrial
CIM	common information model
CMI	customer minutes interrupted
CSF	continuous storage facility
CSO	capacity service obligation
CTG	combustion turbine generator
CVR	conservation voltage reduction
DALMP	day-ahead locational marginal price
DAM	day-ahead market
DARD	dispatchable asset-related demand
DER	distributed energy resources
EPS	electric power system
ESB	electric system bulletin
FCA	forward capacity auction
FCM	forward capacity market
FERC	Federal Energy Regulatory Commission
GBM	gradient boosting machine
IEEE	Institute of Electrical and Electronics Engineers
ISO	independent system operator
kV	kilovolt
kVAR	kilovolt-amperes reactive
kW	kilowatt
kWh	kilowatt-hours
O&M	operations and maintenance
LMP	locational marginal price
LTC	load tap changers

MVA	megavolt-amperes
MVAR	megavolt-amperes reactive
MW	megawatts
MWh	megawatt-hours
NEP	New England Power
O&M	operations and maintenance
PCC	point of common coupling
PCS	power conversion system
PNNL	Pacific Northwest National Laboratory
PV	photovoltaic or present value
RCP	regulation clearing prices
RCCP	regulation clearing capacity prices
RFM	random forest model
ROI	return on investment
RMSE	root mean square error
RSCP	regulation service clearing price
RTE	round-trip efficiency
RTLMP	real-time locational marginal price
RTM	real-time market
SCADA	supervisory control and data acquisition system
SCR	short circuit ratio
SLGF	single line-to-ground fault
SOC	state of charge
SOW	statement of work
STC	standard test conditions
VAR	volt-ampere reactive
VoLL	value of lost load
VVO	volt-Var optimization
WACC	weighted average cost of capital
XGBoost	eXtreme gradient boosting

Contents

Figures

Tables

1.0 Introduction

Nantucket Island, located off the mainland coast of Massachusetts, has a fairly small resident population of approximately 11,000. During summer months, however, the population on the island can swell to over 50,000 (Town and County of Nantucket 2018). Currently, Nantucket's electricity is supplied by two submarine supply cables with a combined capacity of 71 MW and two small on-island 3 megawatt (MW) combustion turbine generators (CTGs). The small CTGs will be replaced by a single, larger CTG with a capacity that varies between 10 MW and 16 MW. National Grid is also adding a 6 MW / 48 megawatt-hours (MWh) Tesla lithium-ion battery energy storage system (BESS). This brings the total energy supply capacity on the island to approximately 91 MW on the days when the grid faces peak energy demand.

These investments were taken after thoughtful consideration of all options, including the deployment of a third submarine transmission cable (National Grid 2016). This report represents the outcome of a collaborative effort between Pacific Northwest National Laboratory (PNNL) and National Grid. Tasks completed by PNNL include the following:

1. In consultation with National Grid, we defined a set of services to be evaluated from an economic perspective based on our experience in conducting similar assessments for various utilities across the U.S.
2. Simulated BESS and CTG operations for a year and estimated the economic benefits over the economic life of each technology. Benefits were defined for seven services stratified into two categories: local operations (transmission deferral, outage mitigation, volt-VAR/ conservation voltage reduction) and market operations (capacity, regulation, spinning reserve, arbitrage).
3. Converted and validated grid models for time-series power flow simulation based on National Grid's CYMDIST file and other data.
4. Evaluated BESS integration under various conditions, primarily by steady-state analysis, covering several design combinations.
5. Suggested protection settings for the BESS.
6. Evaluated the benefits of using more feeder sensors.
7. Defined the economic benefits of reconductoring and automated feeder switching investments to reduce the number and duration of customer outages.
8. Defined control strategies under N-1, N-2, and normal operating conditions.

The remainder of this report is dedicated to presenting the results associated with each of these completed tasks.

2.0 Distribution System Integration

This section presents the results associated with an extensive modeling and simulation of the Nantucket BESS. The focus of this work was to identify and mitigate negative system impacts of the BESS. Tasks associated with this analysis included:

- Converted and validated grid models for time-series power flow simulation based on National Grid's CYMDIST file and other data. The grid model was initially described in a model validation report on August 13, and then later manually updated with CTG, BESS and customer-owned photovoltaic (PV) installations. The fully updated model is described in section 2.1 of this report. This completes items 1 – 4 of Task 2 in our statement of work (SOW).
- Evaluated BESS integration under various conditions, primarily by steady-state analysis, and covering the design combinations shown in Table 2.1. This is described in section 2.2 and completes item 5 and 7 of Task 2.
- Suggested protection settings for the BESS. This work expanded into an add-on evaluation of the BESS transient model provided by Tesla (PNNL 2019). Settings are described in section 2.3, which completes item 6 of Task 2.
- Evaluate the benefits of using more feeder sensors, as originally proposed for the volt-VAR optimization (VVO)/ conservation voltage reduction (CVR) pilot project on Nantucket Island. This is described in section 2.4, which completes item 8 of Task 2.
- Evaluate the benefits of a firm/non-firm transactive energy system under islanded conditions to maximize service to critical loads. This is described in section 2.5, to be completed later in 2019 with completion of a peer-reviewed conference paper. It is not required for BESS commissioning or operation. This would complete item 9 of Task 2.

Table 2.1. Design Combinations of Candle Street Sources with CTG and BESS

	Under Sea Cables		Candle St	Bunker Rd	
	4605	4606	Bus Tie Bkr	CTG	BESS
Case1a			Open		
Case2a		Out	Open		
Case3a	Out		Open		
Case4a		Out	Closed		
Case5a	Out		Closed		
Case1b			Open		In
Case2b		Out	Open		In
Case3b	Out		Open		In
Case4b		Out	Closed		In
Case5b	Out		Closed		In
Case1bc			Open	In	In
Case2bc		Out	Open	In	In
Case3bc	Out		Open	In	In
Case4bc		Out	Closed	In	In
Case5bc	Out		Closed	In	In

2.1 Grid Model Conversion

PNNL conducted studies of the Nantucket Island BESS using two open-source simulation programs, OpenDSS (Dugan 2011) and GridLAB-D (Chassin 2014). These programs offer several features important to the research project:

- Include the 46-kV sub-transmission sources in the distribution model for contingency studies
- Smart inverter controls, BESS state-of-charge (SOC) modeling, automated scripting support, weather, and load behaviors depending on time and voltage
- Ability to modify the source code, if necessary

National Grid provided data from network modeling tools they use, i.e., CYMDIST and PSSE, and other relevant data. This was converted to OpenDSS and GridLAB-D via automated scripts (PNNL 2018), with all eight feeders included (101L1 through 101L8) and a manually constructed model of the 46-kV source:

- Candle Street Transformers 1 and 2
- 46-kV Cables 4605 and 4606
- Lothrop Ave and Merchant's Way 46-kV source impedances, including 8 mega volt-ampere reactive (MVAR) shunt reactors

Figure 2.1 shows an older town feeder map and the general scope of the study model. However, the seven feeders in Figure 2.1 will be reconfigured into eight feeders. The rest of this section describes the model conversion process, with comparisons to a CYMDIST and PSSE solution provided by National Grid.

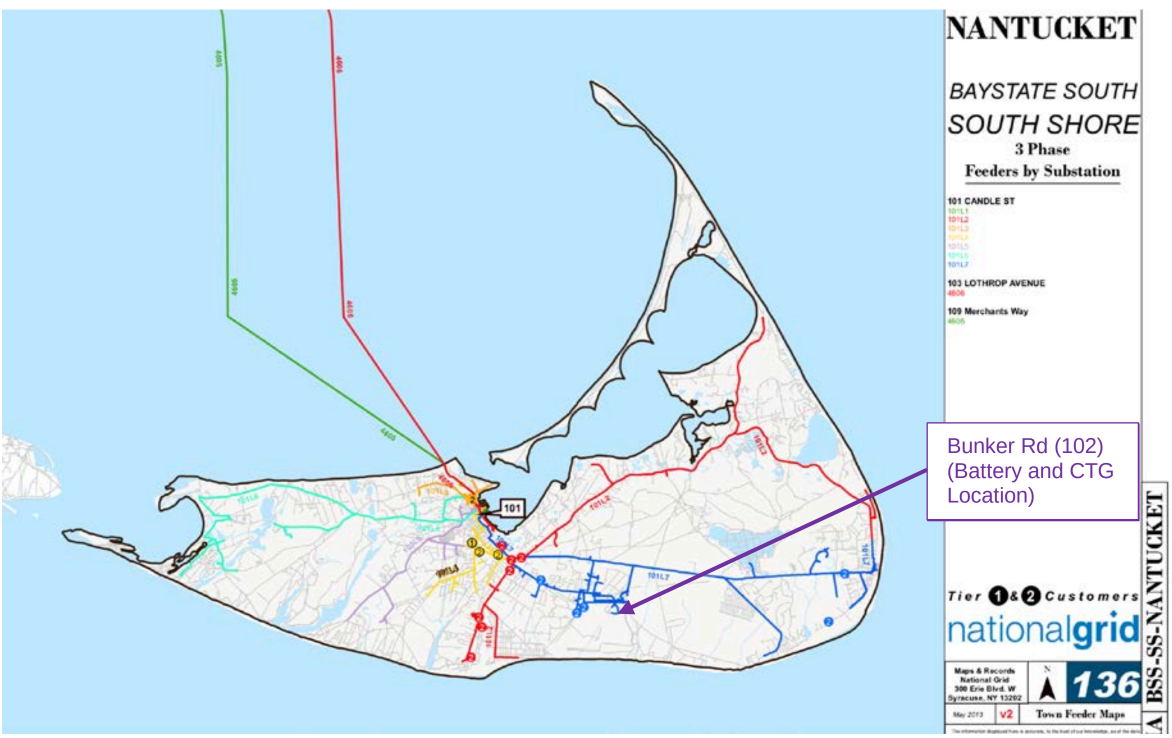


Figure 2.1. Town Feeder Map (13.2 KV) for Nantucket Island, with 46-kV Cables and Battery/CTG Location

2.1.1 Sub-transmission Model

Figure 2.2 shows a model of the 46-kV source and Candle Street transformers as manually constructed in OpenDSS, with unbalanced power flow solution feeding the full eight-feeder model at peak load, with all capacitor banks on. A similar solution was obtained in GridLAB-D, feeding the net nominal peak load of 21.81 + j1.69 MVA on Candle1 and 29.48 + j3.96 MVA on Candle2. Because of the delta/wye transformer connections at Candle Street, only the positive sequence impedances are significant at 46 kV and shown in Figure 2.2.

Because of the unbalanced distribution system load, there is a noticeable phase voltage unbalance at Candle Street. Ganged substation load tap changers (LTC) would not correct this, but the National Grid CYMDIST models assume balanced source voltages. In order to balance the phase voltages, we added independent phase regulators with automatic controls on the low side of Candle Street transformers, shown in Figure 2.2. These regulators have tap steps of 0.625%, and within that tolerance, the phase voltages are balanced within the target of 1.025 per-unit at Candle1 and 1.030 per-unit at Candle2.

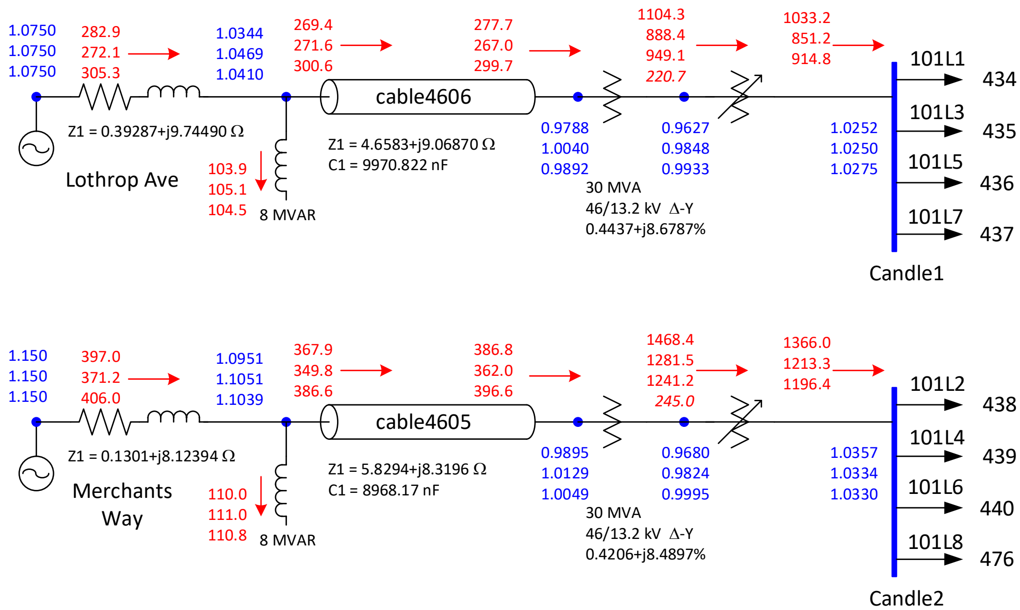


Figure 2.2. Sub-transmission Model and Unbalanced Load Flow Solution from OpenDSS at 51 MW Nominal Peak Load

In Figure 2.2, we note large voltage drops across the 46-kV cables, due to the combination of high cable resistance and high loading level. Nominal peak load in the model and this load flow solution is about 51.5 MW, vs. 44.7 MW in the 2017 hourly load data. Figure 2.3 shows the screen shot of a corresponding load flow solution in PSSE, provided by National Grid. The 46-kV system voltages are all below 1.05 per-unit, although the 13.2-kV bus voltages at Candle Street are both higher than 1.05 per-unit. The PSSE solution also included local (13.2-kV) generation, indicated by negative loads to the left in Figure 2.3. This generation was not running in the CYMDIST, OpenDSS, or GridLAB-D models. Therefore, net flow through the 46-kV cables was lower in the PSSE solution, but the voltage drop across the cables is still significant at 0.04 per-unit and 0.06 per-unit, compared to 0.06 per-unit and 0.09 per-unit in Figure 2.2. We conclude that the sub-transmission models behave consistently, even though they reflect different operating conditions.

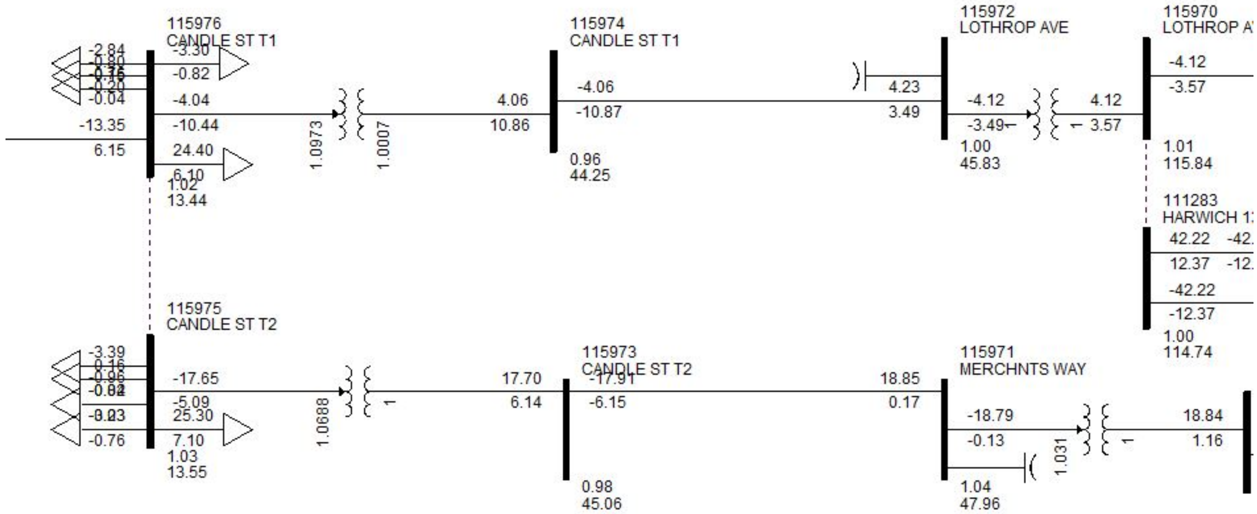


Figure 2.3. PSSE Load Flow with Local Generation Included

2.1.2 OpenDSS Model Conversion

The OpenDSS model was created from a Python script that reads the National Grid CYMDIST model file (SXST format) containing network data. Figure 2.4 shows the resulting voltage profile vs. distance from the source for all eight feeders, and Figure 2.5 shows the geographic layout of all eight feeders. (In order to create Figure 2.4 with scaling like CYMDIST, a new plotting option was added to OpenDSS on August 9; it may not be available to end users immediately). At 51.5 nominal peak load, there are some voltages below 114 V (0.95 per-unit). This doesn't happen at the 44.7-MW peak load level from 2017 hourly data. The Candle Street 13.2-kV bus is split, as in Figure 2.2. All feeder capacitor banks are on, and all regulators are active, as shown in Figure 2.5. Two of the feeders have three-phase line regulators, but the individual phases are not on the same poles; rather, they are spread out among several poles.

The OpenDSS model has been provided to National Grid, comprising several files:

- *101L?_network.dss* – eight files containing lines, capacitors and regulators for each feeder
- *101L?_loads.dss* – eight files containing nominal peak loads for each feeder
- *Nantucket_catalog.dss* – converted items from the CYMDIST equipment database
- *Nantucket_master.dss* – this is the file to run the whole model
- *Candle_Street.sub* – manually created file of the 46-kV system and substation, see Figure 2.2
- *Candle_Street_N-2.sub* – variant with no connection to the mainland
- *Nantucket.edits* – manually created adjustments to the model, included by *Nantucket_master.dss*
- *PV_Generators.ds* – 1,540 kW in customer-owned PV at 54 sites
- *DGs.dss* – interconnection transformers and generators for CTG and BESS

- *Nantucket_faults.dss* – calculates the system impedances at all points on the distribution system
- *Fault_Test.dss* – calculates the Candle Street source impedances

Any of these files with a *.dss are created automatically from the Python script and should not be edited. Any such edits would be lost if the script runs again. Instead, changes should be made to Candle_Street.sub and Nantucket.edits. In order to run the converted model successfully, these changes were needed in Nantucket.edits:

- Change fuse 22_9535 rating to 40
- Change fuse 13_374 rating to 25
- Change fuse 35_4315 to 100
- Change P129-Polpis capacitor to 1200 kilo volt-ampere reactive (kVAR)
- Changes to regulator control VT ratios and setpoints as noted in the file
- Changes to capacitor control voltage setpoints as noted in the file
- Manually close fuses or switches 85_4816, 89_4547, 81_4502, 64_2115, 31_1366, 31_7022, 31_1332, 149_3870, 148_3855, 147_4229, 200060, 8_7440 and 2000066.
- Open up three-phase segments that were fed single-phase: 67406440, 67406440-1, 67406440-2 and 67406440-3.

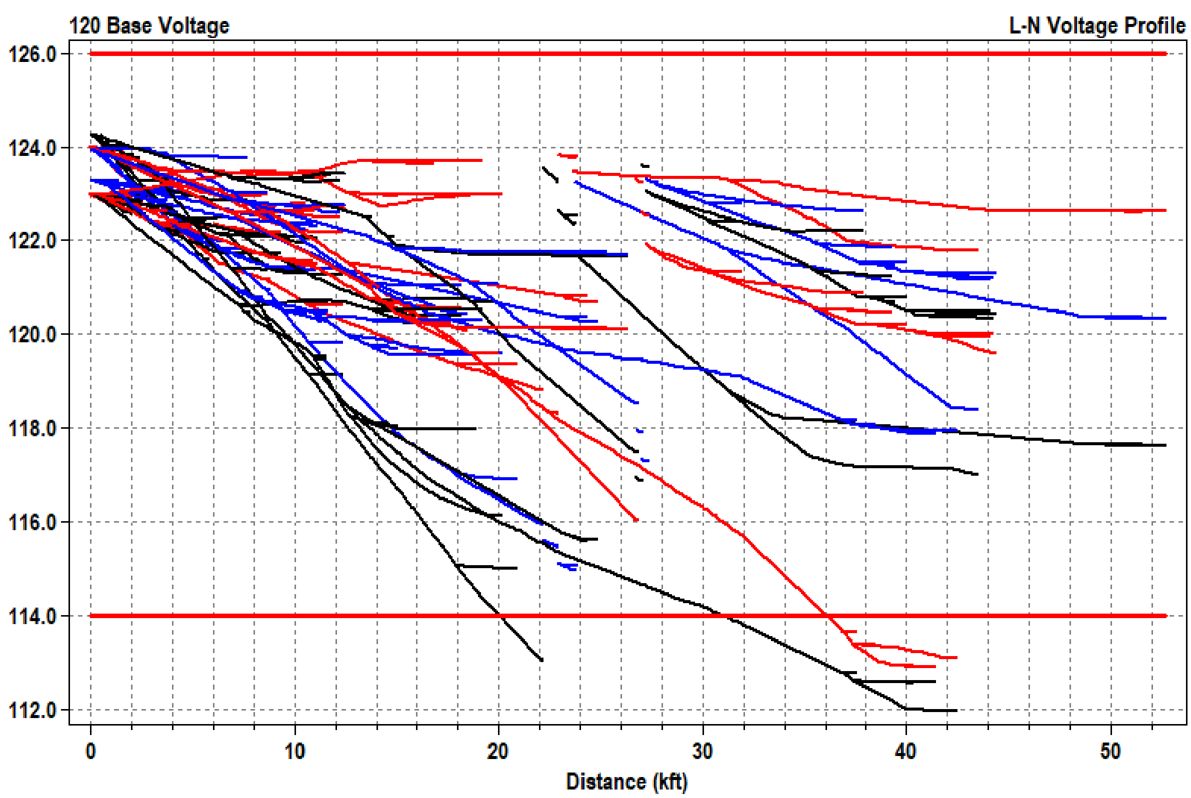


Figure 2.4. OpenDSS Voltage Profile of All Feeders at Peak Load

The model conversion process creates new OpenDSS internal buses for items like fuses, reclosers, switches, and regulators. Therefore, some of bus names don't match. Synchronous generators and roll-on generators at Bunker Road were not active in the CYMDIST load flow solution, and they were not included in the OpenDSS model. In nearly all cases, a CYMDIST section ID is identical to its "to node" ID; there are some exceptions that had to be identified and mapped. Even accounting for these, some discrepancies in the energized buses were found (see *Missing_Nodes.map* included with the model on Box). Buses with non-zero voltage in the OpenDSS model, not found in the CYMDIST peak load flow solution:

```
132145964, // deenergized in CYMDIST
132145964-1, // deenergized in CYMDIST
132143435, // deenergized in CYMDIST
132143435-1, // deenergized in CYMDIST
24454210, // deenergized in CYMDIST
24454210-1, // deenergized in CYMDIST
132145338, // deenergized in CYMDIST
132145338-1, // deenergized in CYMDIST
132145867, // deenergized in CYMDIST
132145867-1, // deenergized in CYMDIST
132145482, // deenergized in CYMDIST
132145482-1, // deenergized in CYMDIST
32225443, // deenergized in CYMDIST
32225443-1, // deenergized in CYMDIST
24455859-3, // deenergized in CYMDIST
24565574, // deenergized in CYMDIST
```

Figure 2.5. Magnitude-Weighted Currents in OpenDSS with Regulators (▼), Reclosers (■) and Capacitors (**I**)

Buses with non-zero voltage in the CYMDIST load flow solution, apparently de-energized in the SXST and OpenDSS:

```
159621059,,,// 500_Cu cable (open)
159621059-1,,,// 500_Cu cable (open)
159621059-2,,,// 500_Cu cable (open)
172334803,,,// 2_SAL cable (open)
172334872,,,// 2_SAL cable (open)
217037012,,,// 2_Cu cable (not in SXST)
217037012-1,,,// 2_Cu cable (not in SXST)
217037012-2,,,// 2_Cu cable (not in SXST)
217037012-3,,,// 2_Cu cable (not in SXST)
217037012-4,,,// 2_Cu cable (not in SXST)
24455007,,,// 4/0 Cu overhead (not in SXST)
24563557-1,,,// Fuse (open)
24563687-1,,,// Fuse (open)
24563695-1,,,// Fuse (open)
24565574-1,,,// Loadbreak (open)
24567838-1,,,// Fuse (open)
24597896-1,,,// 2_Cu cable, unloaded
24598179-1,,,// Fuse (deenergized)
32192428-1,,,// Fuse (deenergized)
32200114-1,,,// Fuse (deenergized)
430151498,,,// Fuse (deenergized)
55746331,,,// Fuse (deenergized)
67406440,,,// single-phased segments opened
67406440-1,,,// single-phased segments opened
67406440-2,,,// single-phased segments opened
67406440-3,,,// single-phased segments opened
67406440-4,,,// single-phased segments opened
```

Based on these discrepancies in the energized buses, along with mismatches in total feeder lengths, it's possible that there are differences between the SXST input data, and the CYMDIST peak load flow solution.

2.1.3 GridLAB-D Model Conversion

The GridLAB-D model was created automatically from the OpenDSS model by exporting OpenDSS into Common Information Model (CIM) format, and then exporting CIM to GridLAB-D (PNNL 2018). More of the work reported in this section was based on OpenDSS because it has more functions to simulate smart inverters, protection, harmonics, and reliability events on the distribution system. However, GridLAB-D has more functions to simulate responsive loads under N-2 contingencies, as discussed in Section 2.5. Therefore, we used both tools in their areas of strength. The GridLAB-D model is posted to Box in four files:

- nantucket_run.glm – invoke "gridlabd nantucket_run.glm" to run the whole model including 46-kV source
- test.glm – the feeder loads and feeder network components, included by nantucket_run.glm
- nantucket_base.glm – direct output of the conversion from CIM. However, manual edits were necessary and the CIM export should not be done again

- make_fbs.py – a script that creates test.glm from nantucket_base.glm by “python make_fbs.py”
  - Swaps the “from” and “to” nodes as necessary to support the forward-backward sweep (FBS) load flow solution algorithm
  - Scales the nominal peak loads, where 1.19048 corresponds to the nominal peak and 1.0 corresponds to the 2017 hourly data peak

In future practice, load scaling changes should be made through re-running make_fbs.py, and the BESS should be added to nantucket_run.glm.

In order to run the GridLAB-D model successfully, it was necessary to employ FBS for the extra diagnostics provided. It then became evident that GridLAB-D could not solve a system with bypassed individual phase regulators, as appear in Figure 2.5. To work around this limitation, the two downstream individual phase regulators on each feeder were moved to the phase location nearest the source. This change was made manually to nantucket_base.glm, so the CIM export should not be run again. Other changes were noted in this process:

- Modify all node and component names to begin with a letter
- New CIM exported capacitor attribute nominal_voltage, set equal to cap_nominal_voltage
- Change CIM export to ensure line-to-line voltage is written for transformer_configuration
- Verify ohmic values on CIM export of phase impedance (Zabc) matrices
- Change CIM export to write capacitance [nF] values for Zabc matrices
- New CIM export of shunt reactors as constant-kVAR loads
- Some opened lines in OpenDSS were not opened in the CIM export to GridLAB-D

Most of these are to be addressed with code changes to the conversion tools (PNNL 2018) at a later time.

2.1.4 Summary of Feeder Model Comparisons

Table 2.2 compares the model sizes and summary solution statistics for each program at nominal peak load. The source voltages at Candle 1 and Candle 2, in both OpenDSS and GridLAB-D, are within a tap step of the source voltages in CYMDIST. However, the total load on the Candle 2 transformer is nearly phase-balanced in CYMDIST, but not in OpenDSS or GridLAB-D. This difference could partially explain the larger voltage drops observed on some of those feeders in OpenDSS and GridLAB-D. Furthermore, the distribution of load among the eight feeders is different in CYMDIST than in OpenDSS or GridLAB-D.

Figure 2.6 shows the distribution of sorted node voltage magnitude errors between OpenDSS and CYMDIST, and between GridLAB-D and CYMDIST. Note that the sorting order is different between OpenDSS and GridLAB-D. These errors are based on CYMDIST phase voltage magnitudes reported in tenths of a kilovolt (kV), which corresponds to a range of 0.0139 per-unit. About 88% of the OpenDSS voltage magnitude errors are less than this tolerance. The errors in GridLAB-D are larger, possibly because the individual phase voltage regulators had to be moved into a banked location in order to solve the loadflow; nodes between the banked location and the actual location would have larger errors because those intermediate nodes were regulated in GridLAB-D but not in CYMDIST or OpenDSS.

Figure 2.7 shows the phase current magnitude differences between OpenDSS and CYMDIST, and between GridLAB-D and CYMDIST. Only line section phase currents were included, and the sorting order is different between the two traces. However, the distributions of current magnitude errors are nearly the same in both cases. Some of those errors are large, up to 70 A. Together with other observations, this may indicate some different switching arrangements, or load phase assignments, between the two models (CYMDIST vs. OpenDSS/GridLAB-D).

Table 2.2. Comparison of Voltage Range, Feeder Loads and Taps

Quantity	CYMDIST	OpenDSS	GridLAB-D
Nodes (i.e. phase at a bus)	12,314	12,666	12,636
Links (i.e. phases in a line)	11,029	11,626	11,626
Candle 1 Bus Voltage [pu]	1.025	1.026	1.027
Candle 2 Bus Voltage [pu]	1.030	1.034	1.032
Min Feeder Voltage [pu]	0.9617	0.9304	0.9254
Max Feeder Voltage [pu]	1.0333	1.0356	1.0556
Candle 1 Phase A Load [kVA]	7918.4 +j642.0	8020.2 +j917.5	8018.4 +j971.4
Candle 1 Phase B Load [kVA]	6984.2 +j317.3	6642.2 +j307.6	6641.4 +j366.9
Candle 1 Phase C Load [kVA]	7197.2 +j431.5	7148.7 +j462.5	7147.9 +j521.0
Candle 2 Phase A Load [kVA]	9720.7+j1018.1	10643.9+j1718.9	10618.8+j1719.6
Candle 2 Phase B Load [kVA]	9971.9 +j988.4	9480.3+j1197.0	9471.4+j1262.1
Candle 2 Phase C Load [kVA]	9720.0 +j988.1	9359.6+j1046.7	9331.5+j1117.1
101L1 (434) Net Load [kVA]	3554.1+j1482.7	3980.4+j1383.7	3984.3+j1418.2
101L2 (438) Net Load [kVA]	8184.7 +j318.4	7764.4 +j747.8	7714.4 +j612.5
101L3 (435) Net Load [kVA]	6541.0 +j586.7	6043.5 +j295.7	6042.2 +j319.2
101L4 (439) Net Load [kVA]	7003.1+j1392.8	7116.8+j1581.1	7123.1+j1603.7
101L5 (436) Net Load [kVA]	5323.0 +j197.4	5101.7 +j151.1	5102.2 +j172.1
101L6 (440) Net Load [kVA]	5613.7 +j682.6	5967.9 +j602.0	6018.7 +j712.1
101L7 (437) Net Load [kVA]	6681.7 -j876.0	6670.3 -j120.7	6679.0 -j50.1
101L8 (476) Net Load [kVA]	8611.1 +j600.8	8616.0+j1049.1	8565.5+j1170.6
Candle 1 Taps	n/a	11, 7, 6	11, 7, 6
Candle 2 Taps	n/a	12, 9, 6	11, 8, 5
Reg 81-89 Taps (101L2)	Unknown	16, 8, 12	16, 8, 12
Reg 147-149 Taps (101L8)	Unknown	10, 11, 9	10, 11, 9

We conclude that in spite of the differences noted in load flow solutions, both the OpenDSS and GridLAB-D models are adequate for this BESS evaluation project. The BESS would be connected at or near bus 314 in the model.

The next sub-sections highlight the individual feeder footprints as converted to OpenDSS. They also compare the individual feeder voltage profiles vs. distance from OpenDSS and CYMDIST. Some of the feeder profile total distances do not match between the models, again indicating that the SXST input data and the CYMDIST load flow solution may not match.

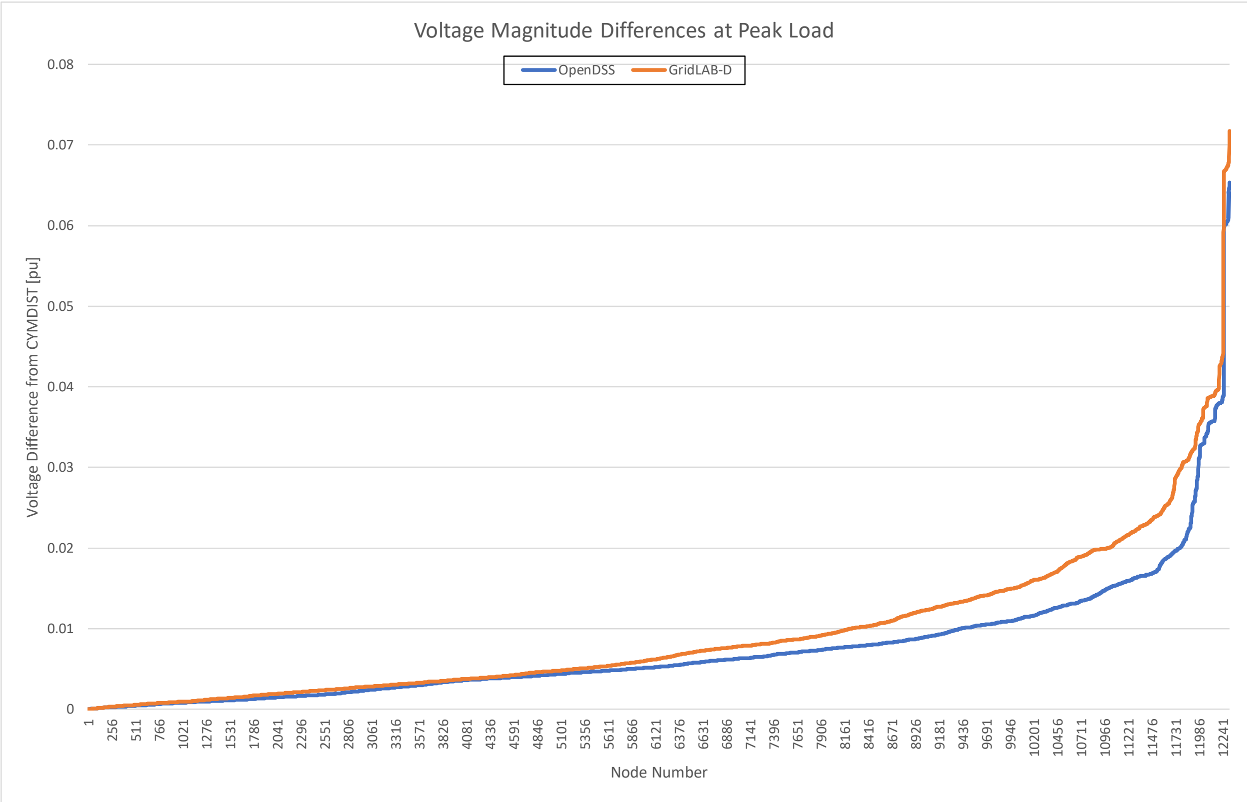


Figure 2.6. Node Voltage Differences between CYMDIST, OpenDSS, and GridLAB-D

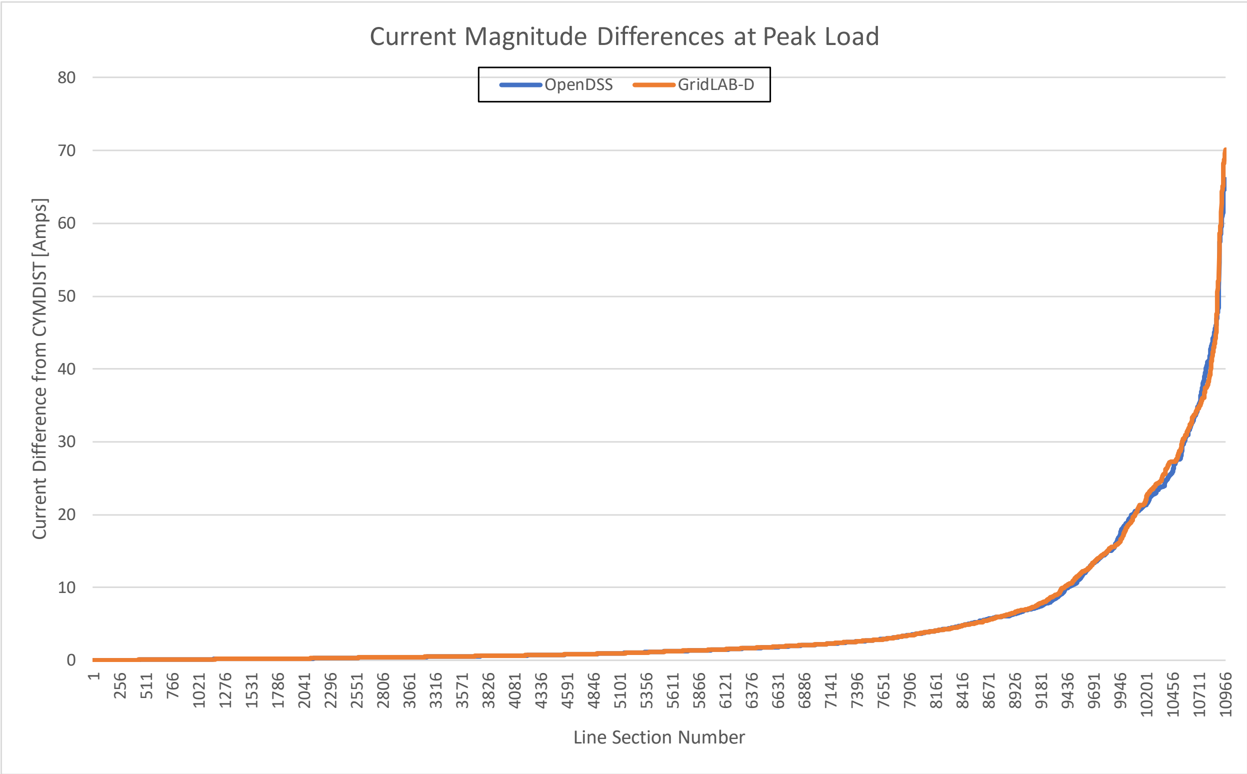


Figure 2.7. Line Section Current Differences between CYMDIST, OpenDSS, and GridLAB-D

2.1.5 Feeder 101L1 Comparison

This feeder has no capacitor banks or line regulators, so the voltage profile is flat. The furthest bus converted to OpenDSS is 24599177. The CYMDIST voltage profile was not provided, so we could not compare that result to OpenDSS output.

Figure 2.8. 101L1 Footprint (red) in OpenDSS Model

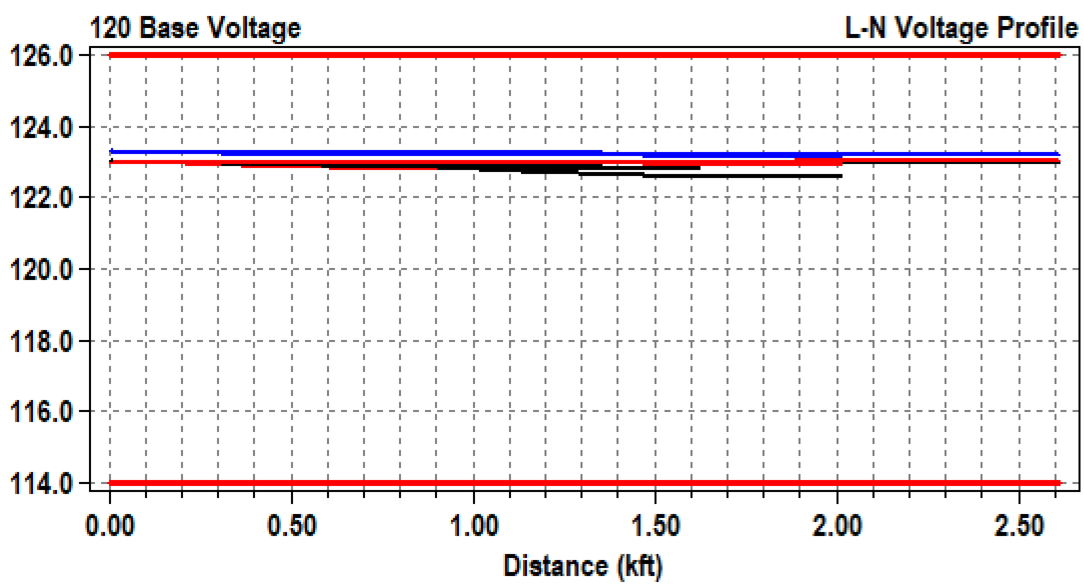


Figure 2.9. OpenDSS Voltage Profile of 101L1 at Peak Load

2.1.6 Feeder 101L2 Comparison

This feeder has capacitor banks on at Polpis (600 kVAR) and Commercial (1200 kVAR), plus one set of line regulators. The furthest converted OpenDSS bus is 24635828-5.

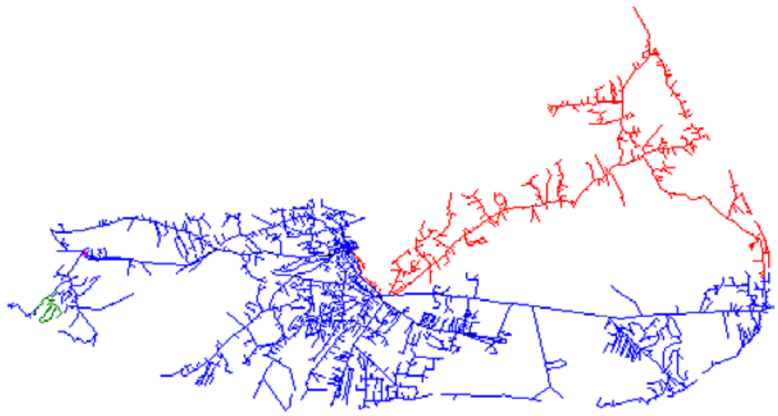


Figure 2.10. 101L2 Footprint (red) in OpenDSS Model

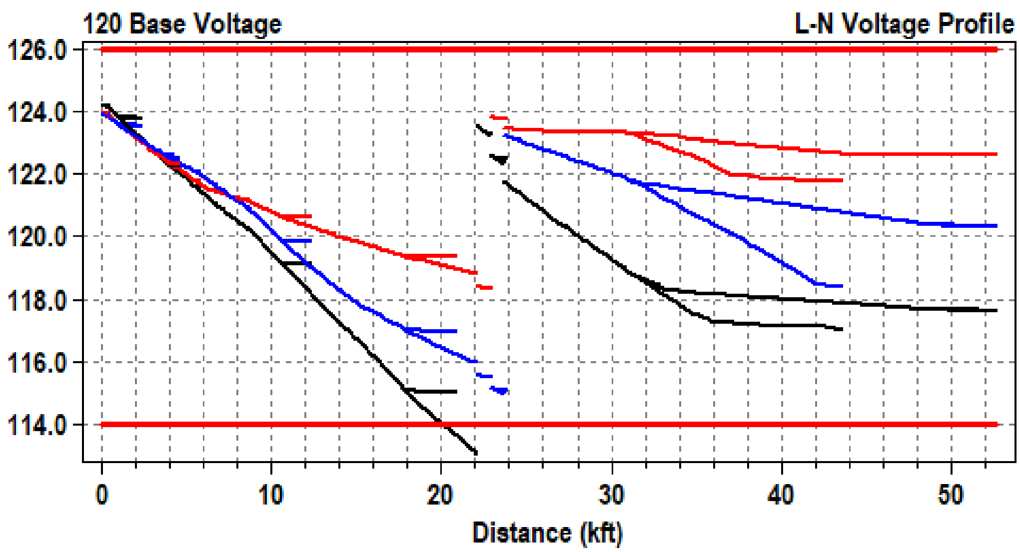


Figure 2.11. OpenDSS Voltage Profile of 101L2 at Peak Load

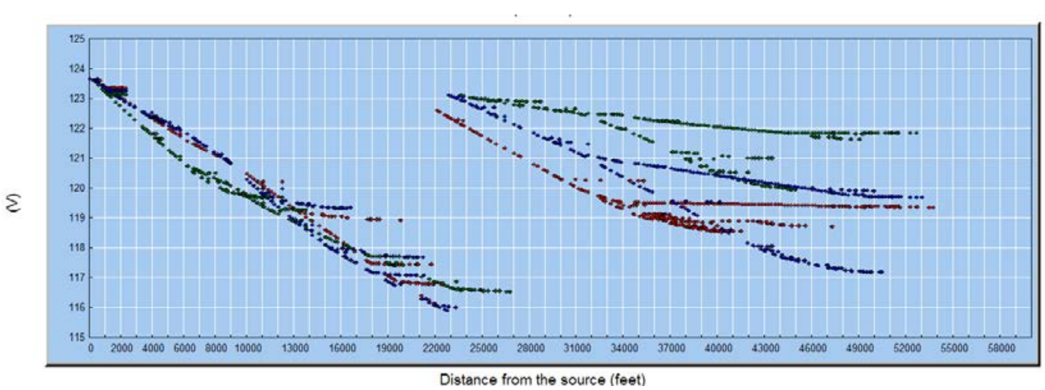


Figure 2.12. CYMDIST Voltage Profile of 101L2 at Peak Load, to 54 kft, 116.0-123.7 V

2.1.7 Feeder 101L3 Comparison

This feeder has capacitor banks on at Cliff (600 kVAR) and Easton (1200 kVAR), but no line regulators. The furthest converted OpenDSS bus is 68766000.

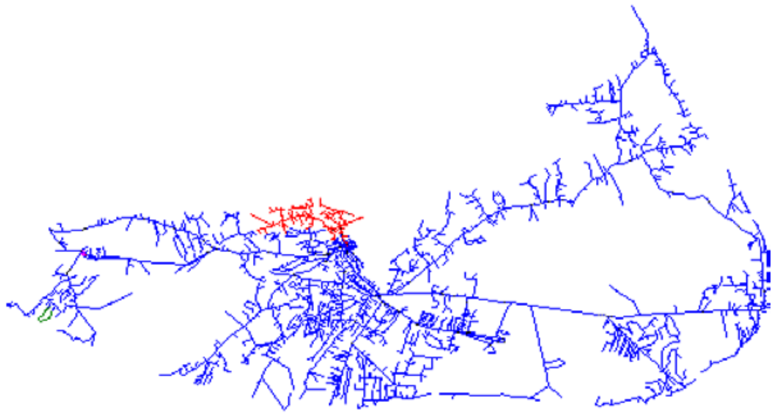


Figure 2.13. 101L3 Footprint (red) in OpenDSS Model

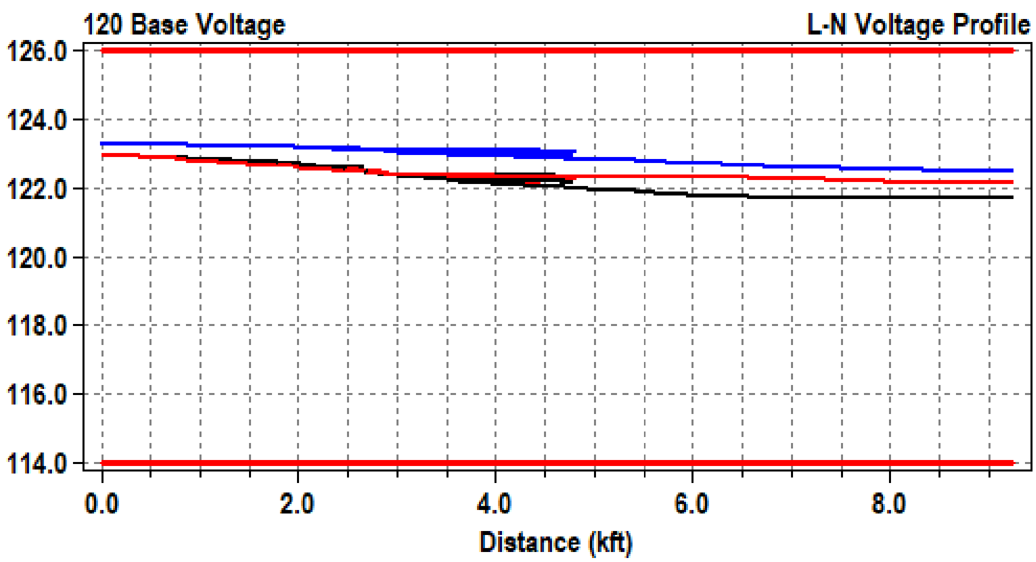


Figure 2.14. OpenDSS Voltage Profile of 101L3 at Peak Load

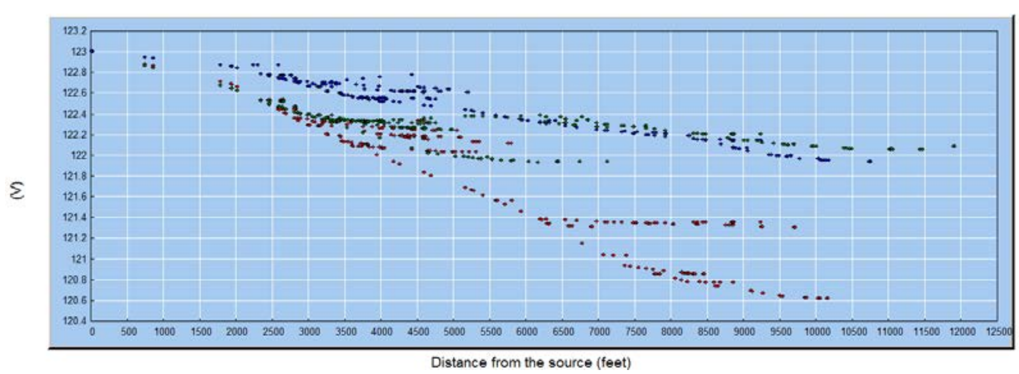


Figure 2.15. CYMDIST Voltage Profile of 101L3 at Peak Load, to 12 kft, 120.6-123.0 V

2.1.8 Feeder 101L4 Comparison

This feeder has capacitor banks on at Atlantic (1200 kVAR) but no line regulators. The furthest converted OpenDSS bus is 24570090-1.

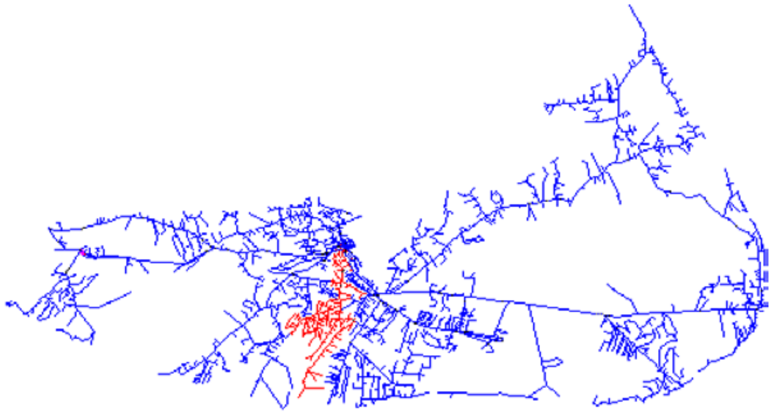


Figure 2.16. 101L4 Footprint (red) in OpenDSS Model

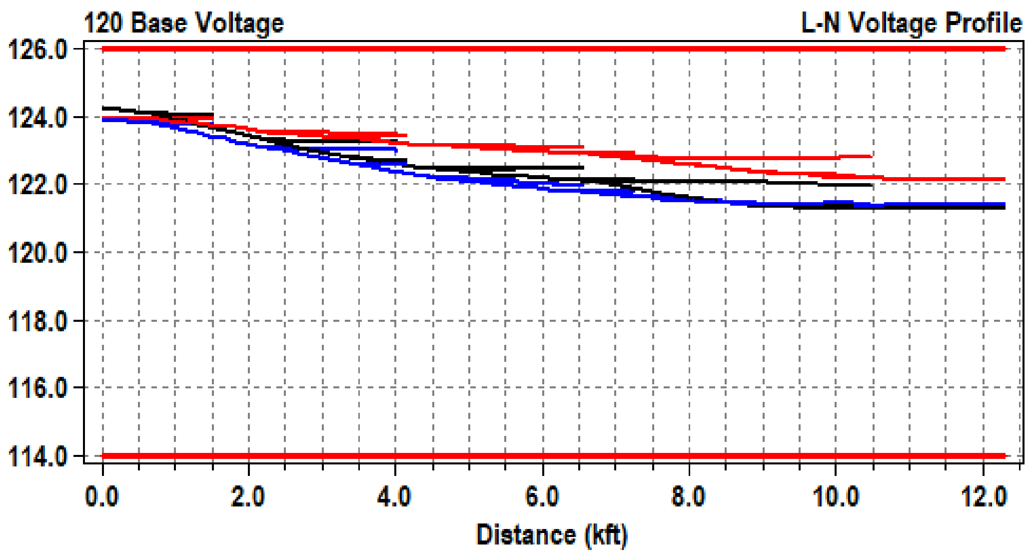


Figure 2.17. OpenDSS Voltage Profile of 101L4 at Peak Load

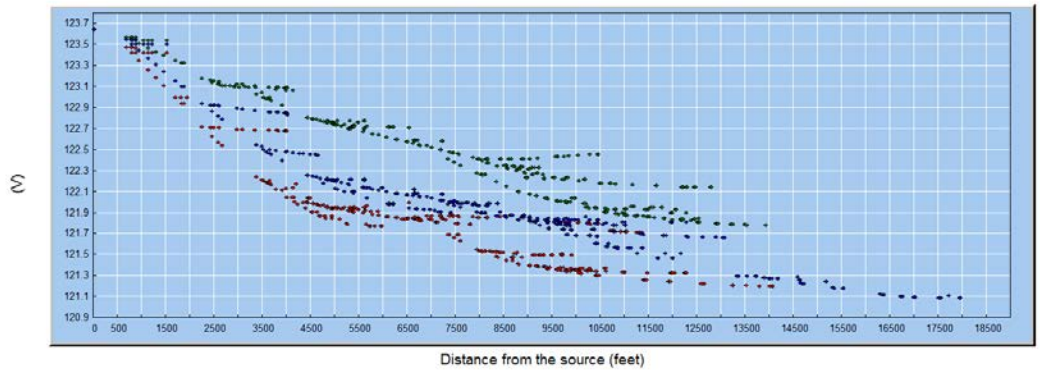


Figure 2.18. CYMDIST Voltage Profile of 101L4 at Peak Load, to 18 kft, 121.1-123.7 V

2.1.9 Feeder 101L5 Comparison

This feeder has capacitor banks on at Hummock Pond (900 kVAR) but no line regulators. The furthest converted OpenDSS buses are 24454358 and 55174950.

Figure 2.19. 101L5 Footprint (red) in OpenDSS Model

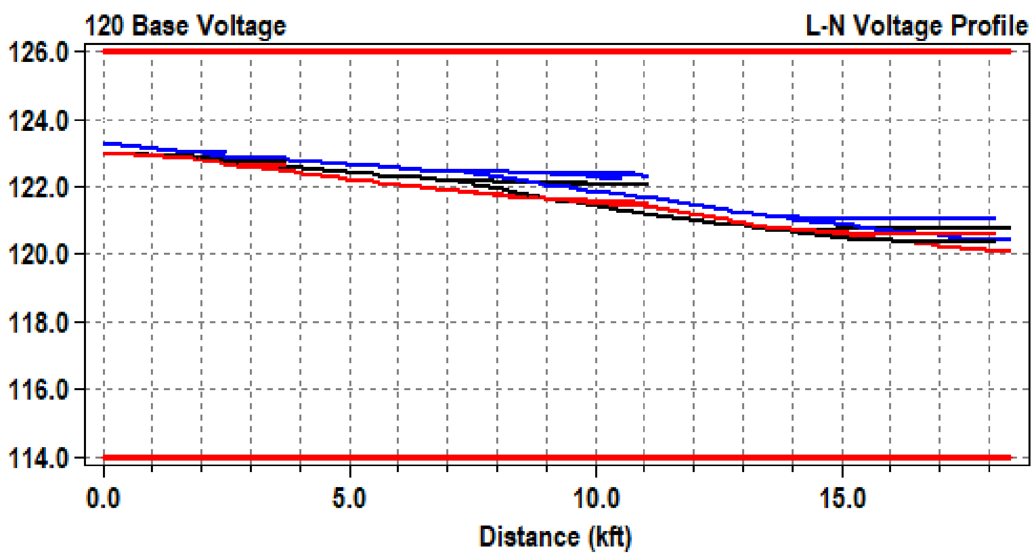


Figure 2.20. OpenDSS Voltage Profile of 101L5 at Peak Load

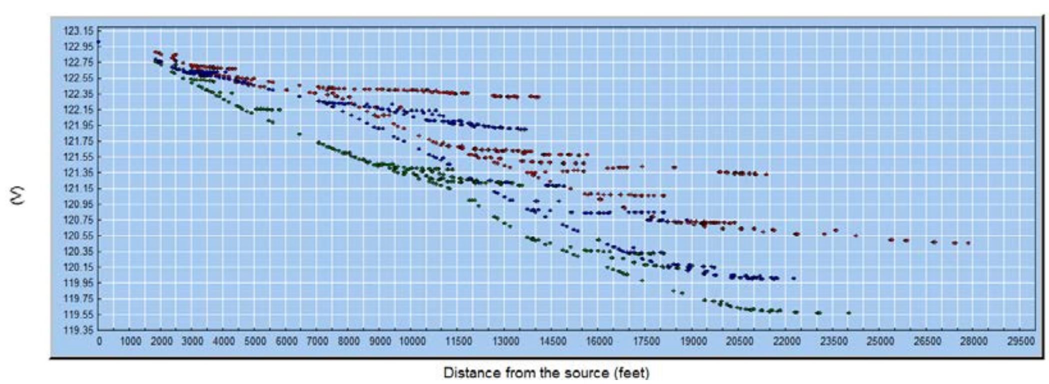


Figure 2.21. CYMDIST Voltage Profile of 101L5 at Peak Load, to 28 kft, 119.6-123.0 V

2.1.10 Feeder 101L6 Comparison

This feeder has capacitor banks on at N. Cambridge (600 kVAR) and Madaket (600 kVAR) but no line regulators. The furthest converted OpenDSS bus is 24636502-4.

Figure 2.22. 101L6 Footprint (red) in OpenDSS Model

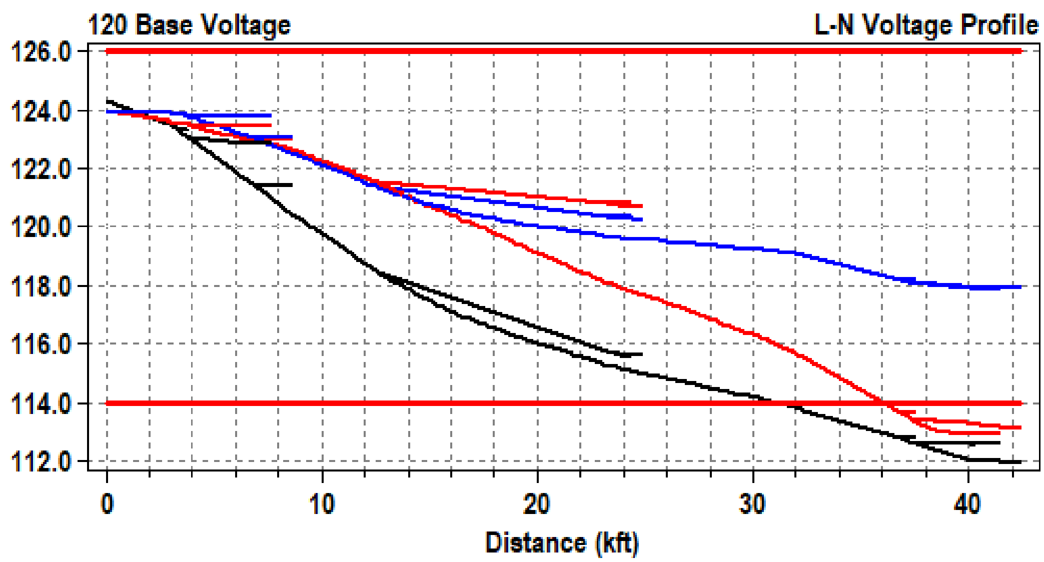


Figure 2.23. OpenDSS Voltage Profile of 101L6 at Peak Load

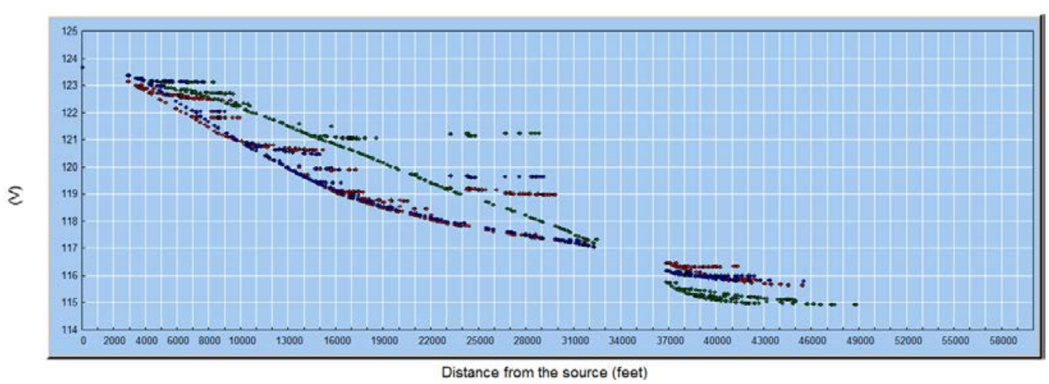


Figure 2.24. CYMDIST Voltage Profile of 101L6 at Peak Load, to 49 kft, 115.0-123.7 V

2.1.11 Feeder 101L7 Comparison

This feeder has capacitor banks on at Fairgrounds (1200 kVAR) and Old South (1200 kVAR) but no line regulators. The furthest converted OpenDSS buses are 24201178 and 121994291-6.

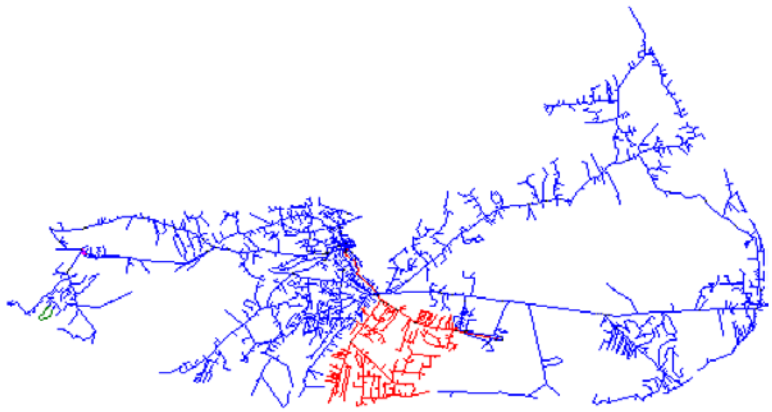


Figure 2.25. 101L7 Footprint (red) in OpenDSS Model

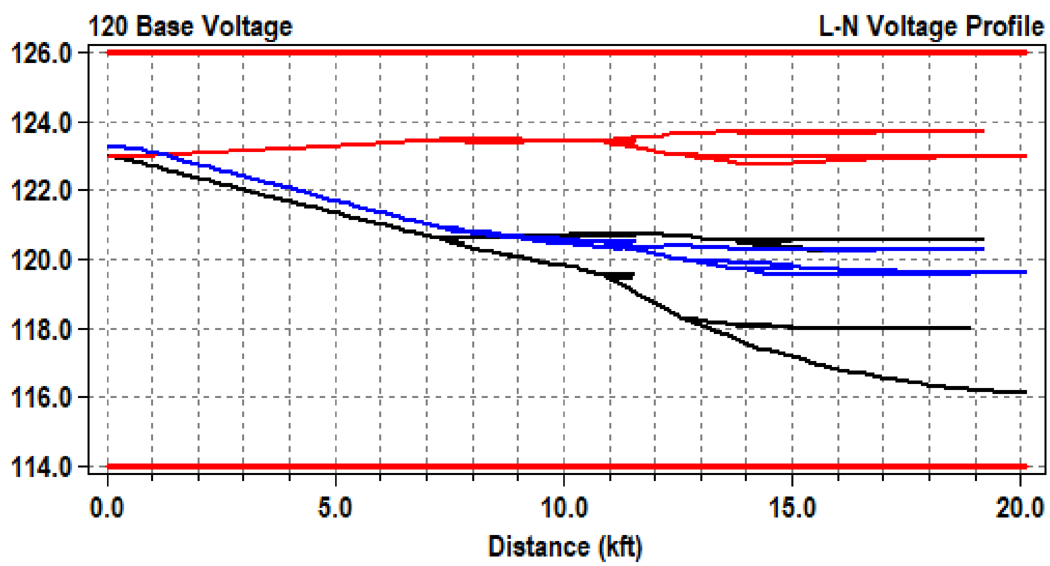


Figure 2.26. OpenDSS Voltage Profile of 101L7 at Peak Load

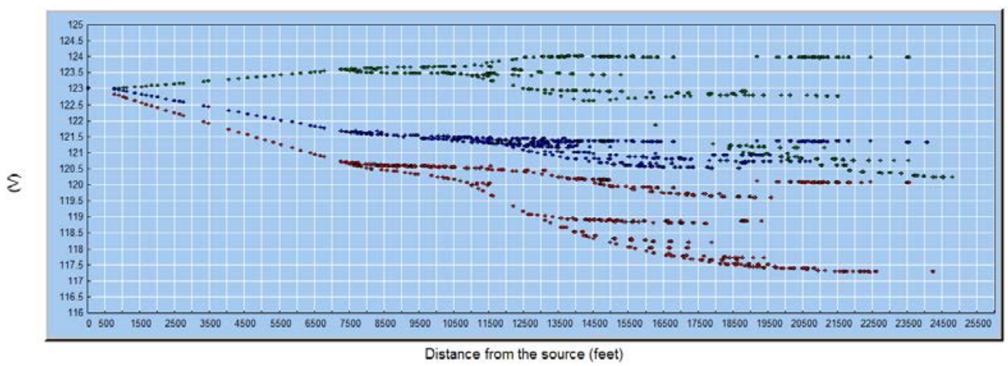


Figure 2.27. CYMDIST Voltage Profile of 101L7 at Peak Load, to 25 kft, 117.4-124.0 V

2.1.12 Feeder 101L8 (Future) Comparison

This feeder has capacitor banks on at Morey (600 kVAR) and Pleasant (1200 kVAR), plus one set of line regulators. The furthest converted OpenDSS buses are 34357663-1, 111173539 and 24453964-2.

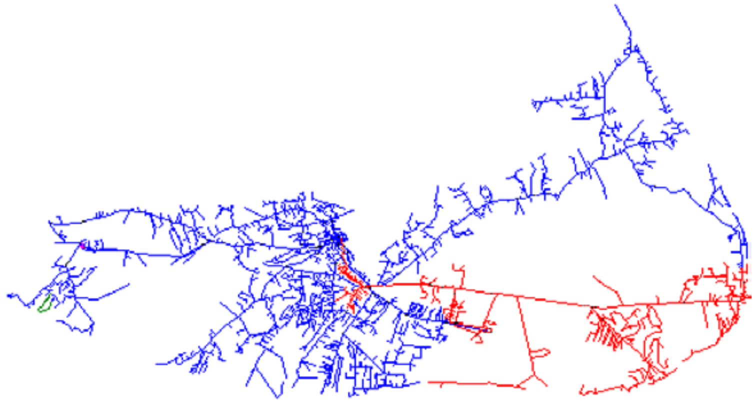


Figure 2.28. 101L8 Footprint (red) in OpenDSS Model

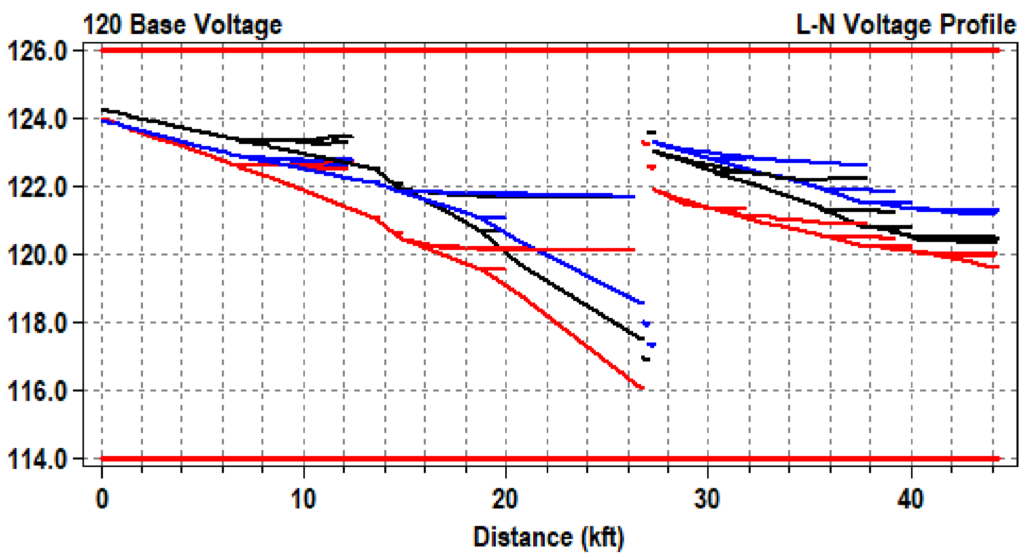


Figure 2.29. OpenDSS Voltage Profile of 101L8 at Peak Load

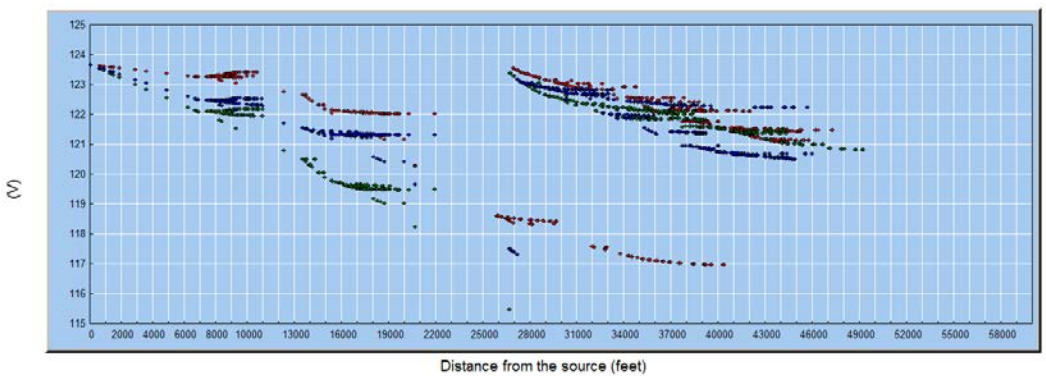


Figure 2.30. CYMDIST Voltage Profile of 101L8 at Peak Load, to 50 kft, 115.4-123.7 V

2.1.13 Customer-Owned PV Generation

After building the initial feeder model, 1,540 kW of customer-owned PV was added at 54 sites. Figure 2.31 shows the four largest installations, totaling 1,030 kW, relatively close to Candle Street. There is more PV generation in the connection queue.

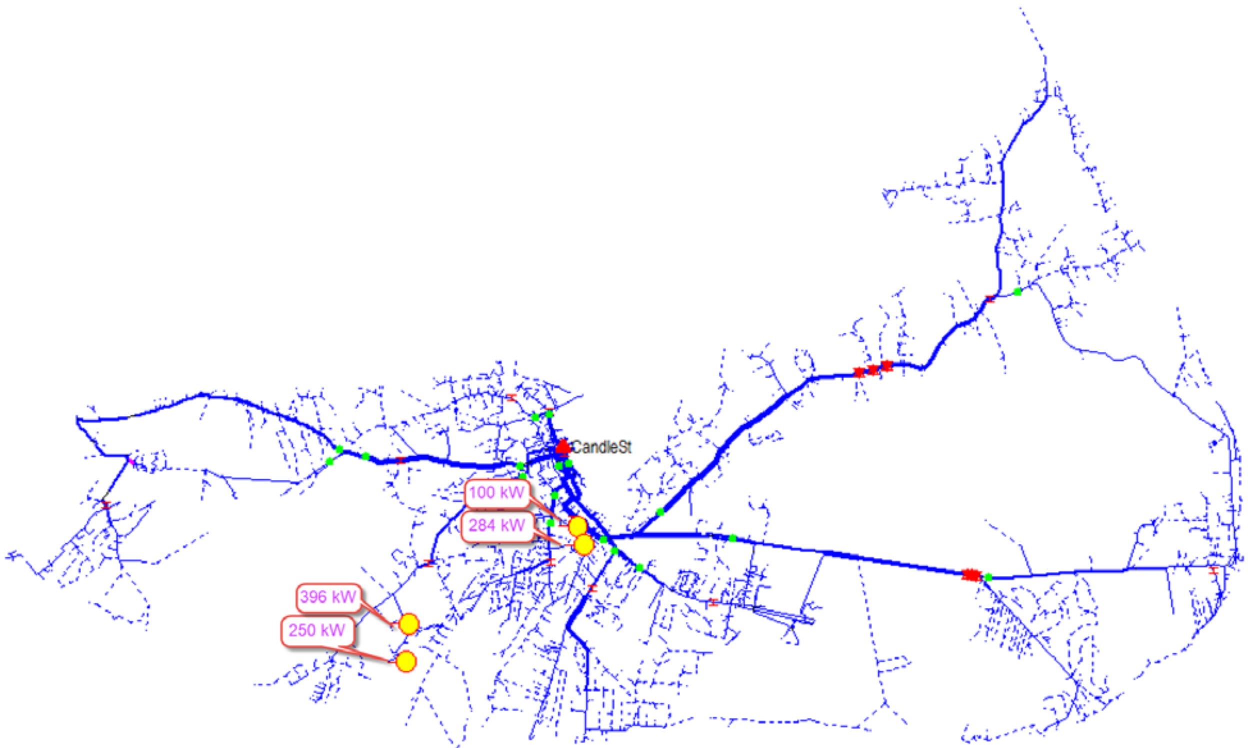


Figure 2.31. Distribution System with Four Largest PV Installations

2.2 Distribution System Analysis

The suggested operating practices and settings are based on the planned system with feeder 101L8 implemented. In this section, we describe the steady-state operation for the design combinations in Table 2.1. The impact on reliability metrics is described in section 3.4.2.

2.2.1 Recommended Upgrades for the Distribution System

Upon review of the system near Bunker Road, it became apparent that the BESS and CTG could not produce full output simultaneously without overloading the distribution system. The following upgrades are suggested to mitigate this and other limitations in the planned system.

1. There are two underground cable exits from Bunker Road, each rated at 420 Amps in the CYMDIST model. When both the BESS and CTG are at their maximum summer output, i.e., 6 and 13 MW respectively, a certain section in one of the cables exceeds that level (verified at maximum and minimum feeder load). If combined BESS/CTG output is de-rated by 2 MW, overloading vanishes. However, in order to have a full 19 MW export from Bunker Road, the conductors in the overloaded section (red section in Figure 2.32) are required to be upgraded. It is useful to note that with 19 MW export, the limiting section carries 463 amps. During winter time, additional output may be available from the CTG. To reflect that

situation, 21 MW export has been considered that increases the current flow to 513 amps. These results should be evaluated against the specific and seasonal cable ratings, which may not be included in the CYMDIST planning model.

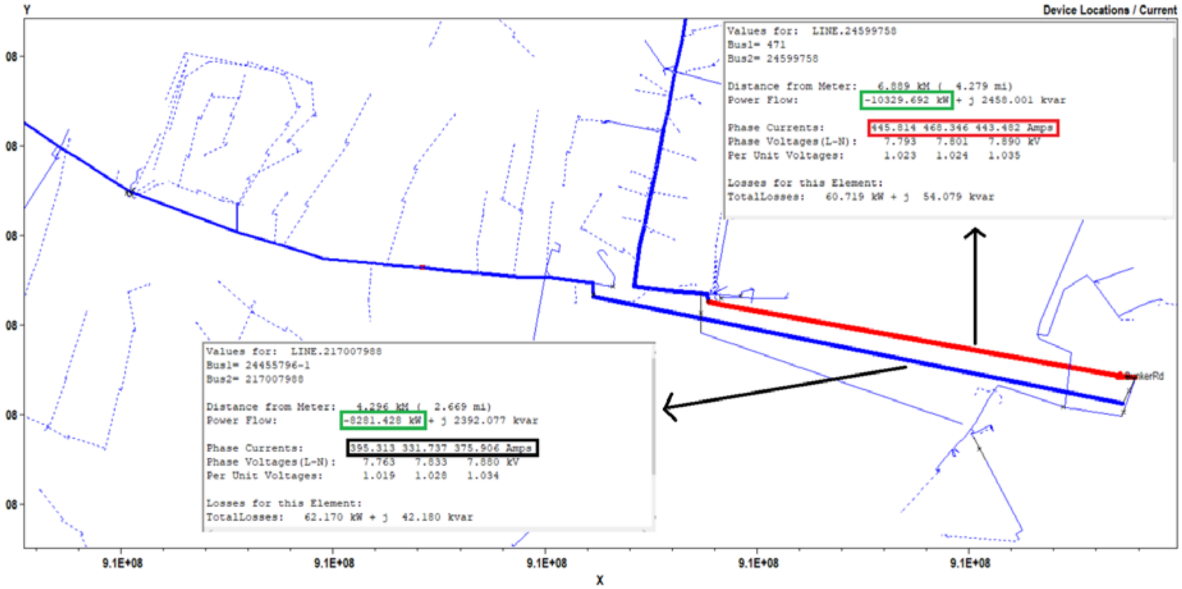


Figure 2.32. Overloaded Section in One of the Lines from Bunker Road at Full 19 MW Export

2. The hospital has a second feeder service from 101L5, which mitigates an outage on the main service from 101L4. In the 2019 feeder map, there are also two load breaks that connect 101L4 with 101L2. In case of an outage on 101L4 or outage of mainland cables, automatic switches in these locations can ensure timely supply to the hospital from the BESS/CTG. Hence, this upgrade seems to represent a potentially beneficial investment.

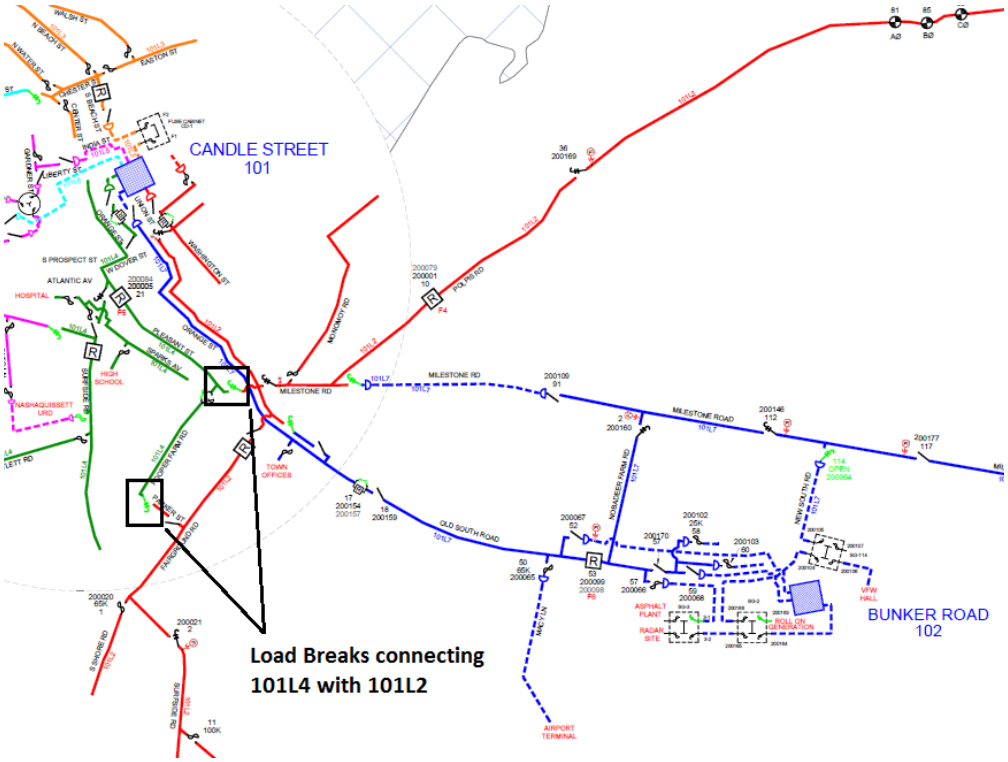


Figure 2.33. Load breaks on Pleasant Street and Hooper Farm Road connecting 101L4 with 101L2

3. In the existing feeder map, BESS/CTG can already supply the Town Offices. However, a recloser upstream of the Town Offices on 101L7 can make this supply more effective. Another possibility is to relocate the existing recloser 17/200154 to the other side of the Town Offices – i.e. on Orange Street.

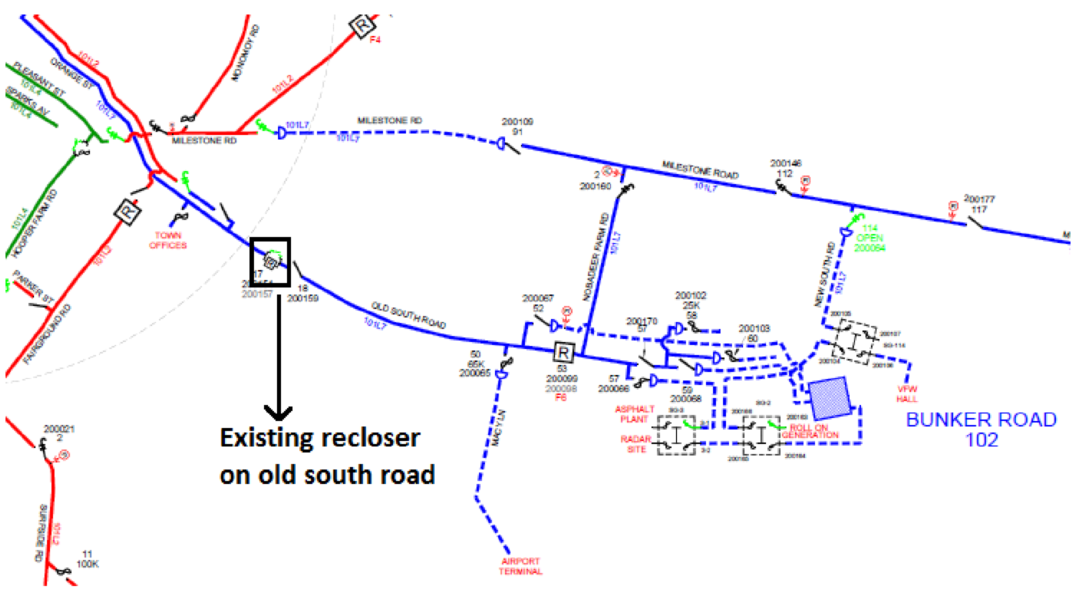


Figure 2.34. Existing Recloser on Old South Road (Feeder 101L7)

4. Since the BESS and CTG are located on 101L7, an automatic switch on Orange Street, which connects 101L7 and 101L2, can be a beneficial investment. This is especially true when an outage occurs on Orange Street and takes out 101L7 and 101L2.

All of these new or upgraded switches could have SCADA for operational dispatch, which would reduce the outage durations compared to manual switching.

2.2.2 P, Q dispatch tables for BESS

National Grid has elected to initially operate the BESS in a manual dispatch mode, with real power setpoints allowed from -6 MW (charging) to +6 MW (discharging), in steps of 2 MW only. This manual dispatch needs to work properly when the Bunker Road voltage is up to 1.03 pu, expected at light load or whenever the CTG regulates locally. The smart inverter functions will not be engaged initially but they could be at a later time. To determine the P, Q dispatch tables for the BESS, the following guidelines were followed:

1. The real power dispatch steps were restricted to P = -6, -4, -2, 0, 2, 4 and 6 MW as recommended by National Grid. Here, negative sign denotes real power consumed from the network.
2. The reactive power dispatch steps were chosen as Q = -3.6, -2.4, -1.2, 0, 1.2, 2.4 and 3.6 Mvar. Again, negative sign denotes reactive power absorbed from the network.
3. Real power set points for BESS and CTG were initially chosen as 6 and 13 MW, respectively.
4. The reactive power set point of BESS was varied over the full range i-e. [-3.6, 3.6] Mvar using increments of 1.2 Mvar and maximum voltage in the network was logged. For CTG, reactive power was allowed to swing in the range of [-7, 7] Mvar.
5. Step 4 was repeated for all real power set points of BESS and CTG. BESS Q set points that resulted in a maximum voltage of more than 1.05 pu were deemed non-permissible.

Figure 2.35 shows the maximum voltages recorded when the network was heavily or lightly loaded when both mainland cables were in service. As expected, when the BESS supplies more reactive power to the network, maximum voltage tends to increase. Similarly, maximum voltage also increases when total load on the network decreases. In Figure 2.35, heavy load refers to 50 MW which approximates the expected peak load of the Nantucket Island whereas light load is half of this peak i-e. 25 MW.

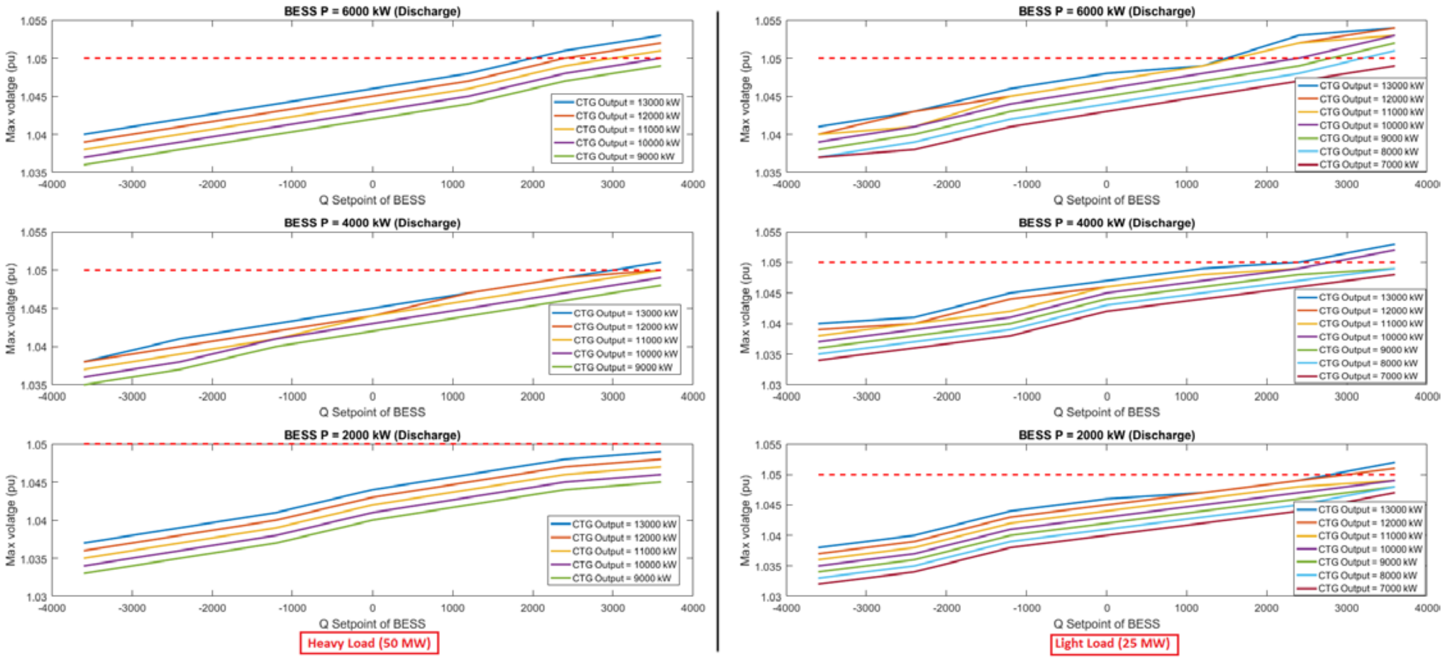


Figure 2.35. Maximum Feeder Voltage vs. BESS Q Set Point, Both Mainland Cables in Service

The P, Q dispatch tables were determined for three different scenarios using steps 1-5:

- When both mainland cables, i.e., 4605 and 4606 are in service and the Candle Street bus tie is open. See Table 2.3 and Table 2.4. These are Case1b and Case1c from Table 2.1.
- When only cable 4605 is in service and the bus tie is closed. See Table 2.5 and Table 2.6. These are Case4b and Case4c from Table 2.1.
- When only cable 4606 is in service and the bus tie is closed. See Table 2.7 and Table 2.8. These are Case5b and Case5c from Table 2.1.

Moreover, for each scenario, two tables were computed. One for combined operation of BESS and CTG and the other when CTG is not available.

Table 2.3. Permissible Q Set Points (kvar) for BESS in Increments of 1200 Kvar, Both Mainland Cables in Service, BESS/CTG Combined Operation, Case1c

Real Power Output of CTG (kW)	Heavy Load			Light Load		
	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW
13000	Q = [-3600, 1200]	Q = [-3600, 2400]	Q = [-3600, 3600]	Q = [-3600, 1200]	Q = [-3600, 1200]	Q = [-3600, 2400]
12000	Q = [-3600, 1200]	Q = [-3600, 2400]	Q = [-3600, 3600]	Q = [-3600, 1200]	Q = [-3600, 2400]	Q = [-3600, 2400]
11000	Q = [-3600, 2400]	Q = [-3600, 2400]	Q = [-3600, 3600]	Q = [-3600, 1200]	Q = [-3600, 2400]	Q = [-3600, 3600]
10000	Q = [-3600, 2400]	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 1200]	Q = [-3600, 2400]	Q = [-3600, 3600]
9000	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 2400]	Q = [-3600, 3600]	Q = [-3600, 3600]
8000	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 2400]	Q = [-3600, 3600]	Q = [-3600, 3600]
7000	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 3600]

Table 2.4. Permissible Q Set Points (kvar) for BESS, Both Mainland Cables in Service, Only BESS Operational, Case1b

Real Power Output of CTG (kW)	Heavy Load			Light Load		
	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW
0	Q = [-3600, 1200]	Q = [-3600, 2400]	Q = [-3600, 3600]	Q = [-3600, 2400]	Q = [-3600, 1200]	Q = [-3600, 2400]

Table 2.5. Permissible Q Set Points (kvar) for BESS in Increments of 1,200 Kvar, Only Cable 4605 in Service, BESS/CTG Combined Operation, Case 4c

Real Power Output of CTG (kW)	Heavy Load			Light Load		
	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW
13000	Q = [-3600, -1200]	Q = [-3600, 0]	Q = [-3600, 0]	Q = [-3600, -2400]	Q = [-3600, -2400]	Q = [-3600, -2400]
12000	Q = [-3600, -1200]	Q = [-3600, 1200]	Q = [-3600, 1200]	Q = [-3600, -2400]	Q = [-3600, -2400]	Q = [-3600, -1200]
11000	Q = [-3600, 0]	Q = [-3600, 1200]	Q = [-3600, 0]	Q = [-3600, -2400]	Q = -3600	Q = [-3600, -1200]
10000	Q = [-3600, 0]	Q = [-3600, 1200]	Q = [-3600, 1200]	Q = [-3600, -2400]	Q = [-3600, -1200]	Q = [-3600, -1200]
9000	Q = [-3600, 2400]	Q = [-3600, 0]	Q = [-3600, 3600]	Q = [-3600, -2400]	Q = [-3600, -1200]	Q = [-3600, 0]
8000	Q = [-3600, 1200]	Q = [-3600, -1200]	Q = [-3600, 3600]	Q = [-3600, -2400]	Q = [-3600, -1200]	Q = [-3600, 1200]
7000	Q = [-3600, 0]	Q = [-3600, -1200]	Q = [-3600, 0]	Q = [-3600, -1200]	Q = [-3600, 0]	Q = [-3600, 0]

Table 2.6. Permissible Q Set Points (kvar) for BESS in Increments of 1,200 Kvar, Only Cable 4605 in Service, Only BESS Operational, Case4b

Real Power Output of CTG (kW)	Heavy Load			Light Load		
	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW
0	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 1200]	Q = [-3600, 2400]	Q = [-3600, 2400]

Table 2.7. Permissible Q Set Points (kvar) for BESS in Increments of 1,200 Kvar, Only Cable 4606 in Service, BESS/CTG Combined Operation, Case5c

Real Power Output of CTG (kW)	Heavy Load			Light Load		
	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW
13000	Q = [-3600, -2400]	Q = [-3600, -1200]	Q = [-3600, 0]	Q = [-3600, 1200]	Q = [-3600, 1200]	Q = [-3600, 3600]
12000	Q = [-3600, -1200]	Q = [-3600, -2400]	Q = [-3600, 0]	Q = [-3600, 1200]	Q = [-3600, 1200]	Q = [-3600, 3600]
11000	Q = [-3600, -1200]	Q = [-3600, 0]	Q = [-3600, 0]	Q = [-3600, 1200]	Q = [-3600, 2400]	Q = [-3600, 3600]
10000	Q = [-3600, -2400]	Q = [-3600, 0]	Q = [-3600, 0]	Q = [-3600, 2400]	Q = [-3600, 3600]	Q = [-3600, 1200]
9000	Q = [-3600, 0]	Q = [-3600, -1200]	Q = [-3600, 0]	Q = [-3600, 1200]	Q = [-3600, 3600]	Q = [-3600, 2400]
8000	Q = [-3600, 0]	Q = [-3600, -1200]	Q = [-3600, 1200]	Q = [-3600, 1200]	Q = [-3600, 1200]	Q = [-3600, 2400]
7000	Q = [-3600, 0]	Q = [-3600, 0]	Q = [-3600, 2400]	Q = [-3600, 1200]	Q = [-3600, 2400]	Q = [-3600, 3600]

Table 2.8. Permissible Q Set Points (kvar) for BESS in Increments of 1,200 Kvar, Only cable 4606 in Service, Only BESS Operational, Case5b

Real Power Output of CTG (kW)	Heavy Load			Light Load		
	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW	BESS P = 6000 kW	BESS P = 4000 kW	BESS P = 2000 kW
0	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 3600]	Q = [-3600, 1200]	Q = [-3600, 3600]	Q = [-3600, 3600]

Interpreting the results:

- No over voltage was observed when BESS was in idle or charging state.
- These studies were performed using the switching configuration that ensures maximum export from Bunker Road while keeping line overloading at a minimum level.
- Bus-tie breaker at Candle Street was closed all the time as it is supposed to be when BESS/CTG are operational, in order to guarantee that backfeed cannot occur through either Candle St transformer at minimum load. Feeder switching of 101L2 and 101L7 may also guarantee that backfeed cannot occur, but this option was not simulated.

2.2.3 Fixed Power Factor Dispatch

National Grid has decided that the BESS real power output (P) can be dispatched from -6 MW (charging) to + 6MW (discharging), in steps of 2 MW. Table 2.3 through Table 2.8 summarize the results of a sensitivity analysis of the maximum feeder voltage to BESS reactive power, with the CTG regulating at 1.03 per-unit , as determined in the impact study submitted by National Grid to ISO New England (Ghavanati 2019a). From this perspective, the BESS reactive power could be set at 0 without creating over voltages. Figure 2.35 shows that the voltage can exceed 1.03 per-unit when the BESS injects real power in addition to the CTG. When the CTG supplies more real power, it also runs out of headroom for absorbing or injecting reactive power to regulate the voltage. In fact, if the BESS also injects reactive power, then the voltage can exceed 1.05 per-unit.

The impedance at the point of common coupling (PCC) depends on loading level. For short-circuit studies on distribution systems, the most rigorous approach includes the effect of load (Chen 1992). In a power flow solution, the load model includes a voltage dependence that is valid only near nominal voltage. In a short-circuit solution, the load is usually converted to constant impedance so it contributes to the Y_{bus} or Z_{bus} matrix, and it also affects the pre-fault voltages. It may be assumed that part of the load will drop out when its voltage becomes extremely low, but it takes time for those loads to trip off. OpenDSS can calculate the PCC impedance under either type of assumption. At full load:

- $Z_1 = 1.744 + j2.6797\ \Omega$ at 13.2 kV
- $Z_0 = 3.706 + j3.0256\ \Omega$ at 13.2 kV

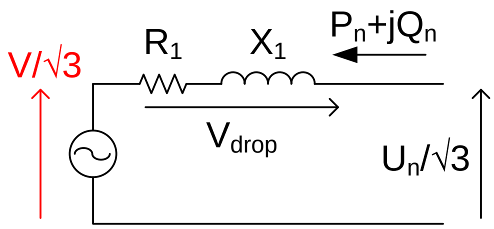
At no load:

- $Z_1 = 1.210 + j2.8339\ \Omega$ at 13.2 kV
- $Z_0 = 3.961 + j3.2135\ \Omega$ at 13.2 kV

Most short-circuit programs use the no-load assumption. As discussed later in section 2.3.3, the fault currents are nearly the same but the X/R ratios are significantly different. For the purpose of voltage regulation, the voltage remains near to nominal and the full-load PCC impedance is more appropriate to use.

When the BESS changes its power dispatch, a voltage step change occurs at the PCC, which may be approximated as $V_{drop} \approx I_R * R_1 + I_X * X_1$, where R_1 and X_1 are in ohms at the PCC, I_R is the real power component of current in amps, and I_x is the reactive power component of current in amps (Short 2014). In this case, $R_1=1.74$ and $X_1=2.68$. It's important to recognize that I_R and I_X may have the same or opposite signs, where positive signs mean the device absorbs real and/or reactive power. Injecting just 6 MW at 13.2 kV, the simplified formula estimates a voltage rise of 6%, which would lead to a step change in voltage of 6% if the BESS suddenly stopped injecting real power. If the BESS also injects 1.97 MVAR for a 0.95 lagging power factor (generator convention), the voltage rise increases to 9%. If instead the BESS absorbs 1.97 MVAR for a 0.95 leading power factor (generator convention), the voltage rise is only 3%. This approximation agrees well with time-series power flow simulation in OpenDSS (Cleary 2010) and with a more accurate formula (Ammar 2012).

Figure 2.36 shows the equivalent circuit and formulas for more accurately estimating voltage change, in percent, at the PCC due to sudden changes in the BESS injection, $P_n + jQ_n$. The units of R_1 and X_1 are Ohms, P_n is in three-phase MW, Q_n is in three-phase MVAr and U_n is in line-to-line kV, i.e., 13.2 kV in this case. In this model, the BESS injection helps establish voltage at the PCC, by its voltage drop through the grid impedance. When the BESS injection suddenly changes to zero, the PCC voltage will suddenly change to the equivalent source voltage behind grid impedance. Switched capacitor banks and tap changes may gradually correct the voltage change, but this will take several seconds.



$$V_{drop} = \frac{100}{U_n^2}\left(R_1 + jX_1\right)\left(P_n - jQ_n\right) \qquad [\%]$$

$$\Delta V = \sqrt{\left(100 - \mathrm{Re}V_{drop}\right)^2 + \left(\mathrm{Im}V_{drop}\right)^2} - 100 \qquad [\%]$$

Figure 2.36. Equivalent Circuit and Formulas for Voltage Step Change at the PCC

Figure 2.37 shows the step voltage change expected at Bunker Road with a step change of -6 MW in BESS output, i.e., from full discharge to idling. Figure 2.38 shows the voltage change for a +6 MW step in BESS output, i.e., from full charge to idling. Both grid impedance assumptions are included, and the PCC impedance with load is more severe for voltage regulation. At unity power factor, the voltage step changes for -6 MW and +6 MW are not the same, due to the sign of Q_n. Based on these results, the BESS could operate at a constant non-unity power factor in order to limit the voltage change to no more than 3%.

- When charging, the BESS power factor should be constant at about 0.93 lagging on the generator convention, i.e., supplying reactive power.
- When discharging, the BESS power factor should be constant at about 0.965 leading on the generator convention, i.e., absorbing reactive power.

Table 2.9 summarizes a table of manual dispatch points that meet the voltage step (Δv) limit of 3% over the range of expected PCC impedances. P and Q should always flow in opposite directions.

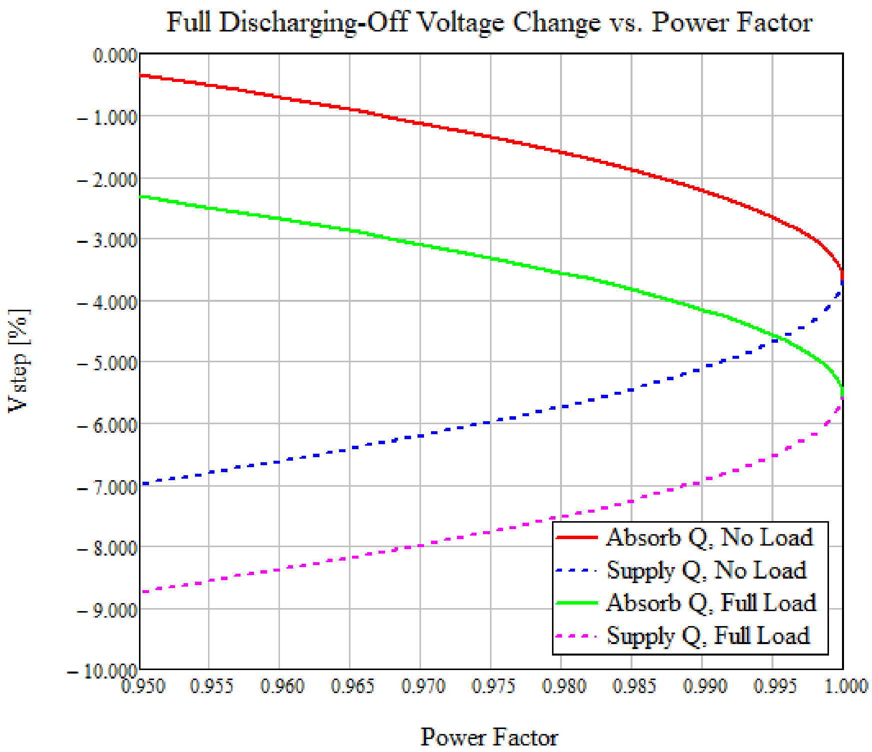


Figure 2.37. Maximum Voltage Change at the PCC From Full Discharge to Off

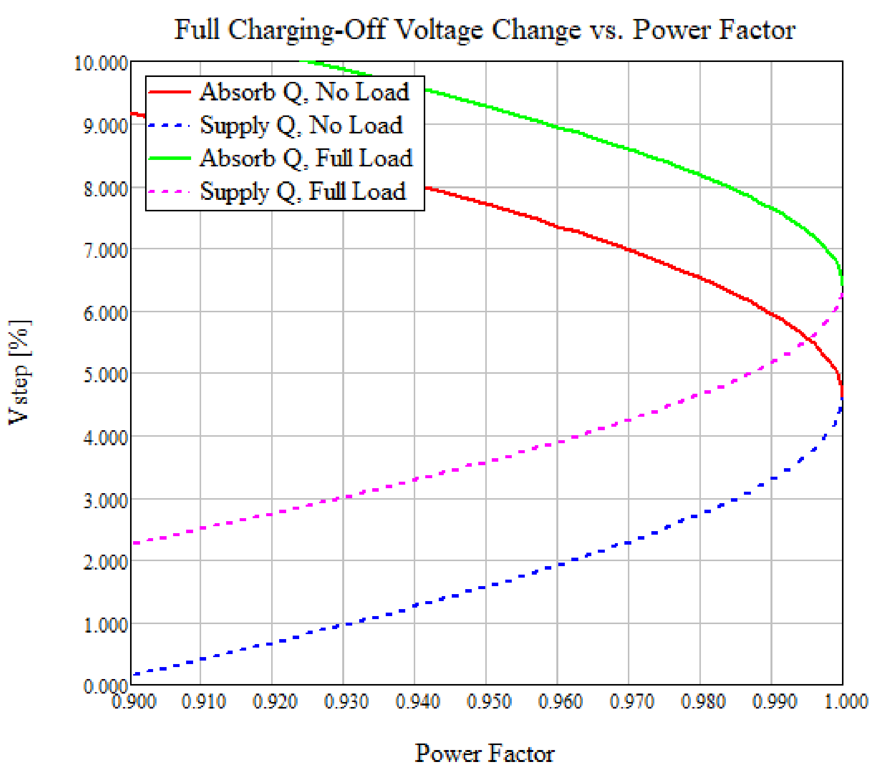


Figure 2.38. Maximum Voltage Change at the PCC from Full Charge to Off

Table 2.9. P and Q Manual Dispatch Levels

State	P [MW]	Q [MVAR]	pf	∆v Load [%]	∆v No-Load [%]
Discharge	6.0	-1.6	0.966	-2.936	-0.966
Discharge	4.0	-1.0	0.970	-2.202	-0.890
Discharge	2.0	-0.5	0.970	-1.167	-0.511
Idle	0.0	0.0	0.0	0.000	0.000
Charge	-2.0	0.8	0.928	0.845	0.160
Charge	-4.0	1.6	0.928	1.837	0.465
Charge	-6.0	2.4	0.928	2.970	0.912

At a later time, National Grid may wish to engage a smart inverter function on the BESS to help mitigate voltage steps. One such option is the volt-var function. Rather than using a fixed setpoint with a deadband, PNNL recommends use of the "autonomously adjusting reference voltage" described in the paragraph below Table 8 of IEEE Std 1547-2018 (IEEE 2018). The setpoint follows the measured grid voltage through a low-pass filter with time constant adjustable between 300s and 5000s. This feature can be used with no deadband, and it autonomously tracks variable grid voltage conditions, including the CTG on/off status. The lower time constant value of 300s is preferable (McDermott 2019).

Time series power simulations of the network with the BESS controlling reactive power using an IEEE 1547 suggested volt-var droop curve are presented in Section 4. Voltage profiles under various contingency situations and normal operation are shown to discuss how BESS reactive power could support network voltage.

2.2.4 Harmonic Analysis

OpenDSS has the ability to perform harmonic analysis, including frequency scans to identify series and parallel resonance, and harmonic voltage distortion estimates. Figure 2.39 shows a frequency scan from the candidate BESS location under two conditions. Without any feeder capacitor banks, the dominant parallel resonances occur at about the 4.7 and 11.5 harmonics. With all feeder capacitor banks on, more parallel resonances appear and the lowest one appears at about the 2.8 harmonic. These results would change with status of the 46-kV cables, local generation, and the damping from loads. With harmonic current injection data on the BESS inverters, the expected harmonic voltage distortion could be estimated under these various conditions. It is normal for a distribution system to exhibit parallel resonance near the 5th harmonic, similar to that in Figure 2.39, so these results are not particularly significant. The higher-order resonances are not severe enough to cause problems, as the BESS inverter complies with IEEE 1547 (IEEE 2018).

In addition to the base load flow model:

- *Fscan.ds* runs the frequency scan in OpenDSS
- *FreqScanI.dat* is a linear spectrum to sweep the injected current at the bus of interest; the resulting voltage magnitude is the driving point impedance, as plotted in Figure 2.39

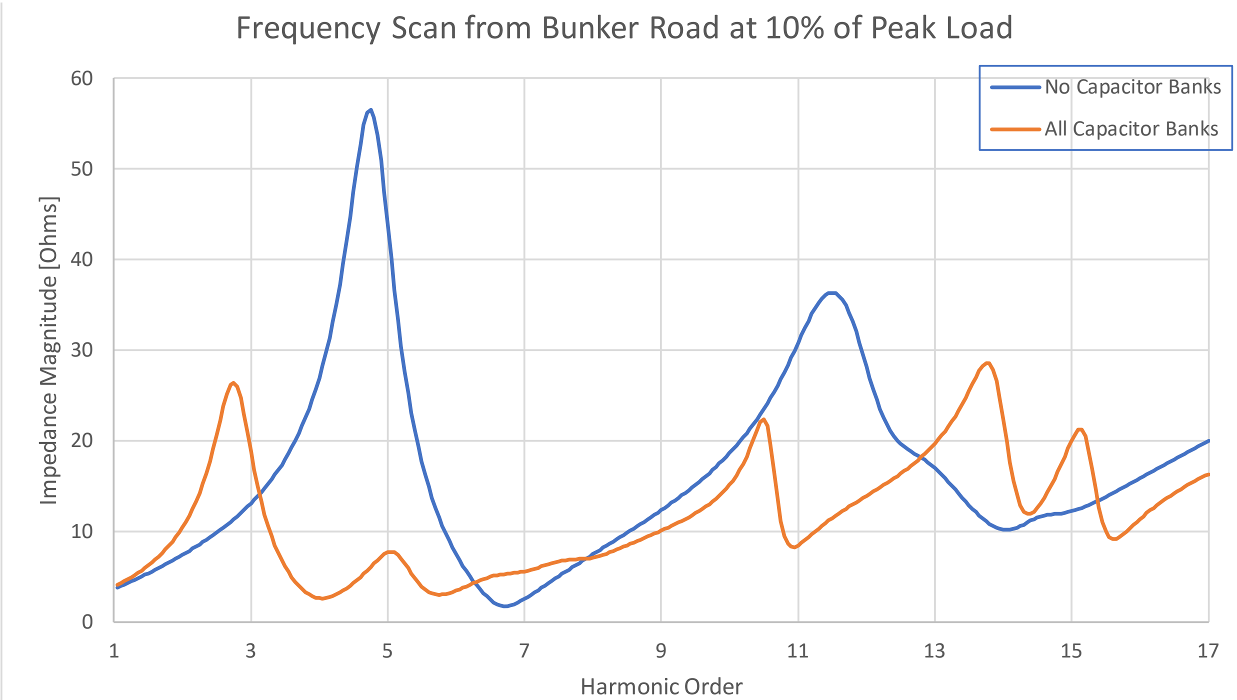


Figure 2.39. Frequency Scan from Bunker Road

2.3 Protection Settings

This sub-section describes a review of the model provided by Tesla for inverter behavior during faulted conditions, and suggested settings for the BESS. The CTG protection settings and feeder protection settings were not in PNNL's scope, but we did find that the CTG and BESS (with grounding transformer) contribute high single line-to-ground fault (SLGF) currents compared to the grid contribution. This means that National Grid or its consultant should complete a device coordination review of 101L7 and 101L8, either of which may serve Bunker Road.

2.3.1 Summary of Inverter Transient Model Evaluation

We tested and exercised the PSCAD transient model provided by Tesla (PNNL 2019). Based on that, we developed recommendations to be used for system protection studies. The main conclusions of this evaluation were:

1. National Grid should request Tesla to review and comment on these results, especially the pre-fault ripple shown in the PSCAD simulations.
2. The inverter trip, ride-through and reconnection behaviors are generally as expected, except for the scenario that a three-phase-to-ground fault is applied at transformer low-voltage side (inverter terminal). In this exceptional circumstance, the inverter trips during the discharging period while in other cases the inverter rides through.
3. For system protection studies in ASPEN or similar tools, the inverter should be modeled to mimic the following behaviors:
    a. Contribute 150% of rated current to faults on the faulted phases.

b. Maintain the current in phase with the voltage, as the terminal voltage angle changes during the fault.

c. Assume that the inverter will not trip except for close-in three-phase and line-to-line faults. At 58% retained voltage the inverter did not trip, but at 22% or less retained voltage, the inverter did trip. In those cases, the inverter trips in 11 cycles, but then reconnects immediately after the voltage returns.

2.3.2 DER Protection Requirements

For this size of inverter-coupled DER, National Grid's Electricity Supply Bulletin (ESB) 756 requires Category II capability from IEEE 1547-2018. The ESB requires primary protection (inverter internal relay functions) and secondary protection (utility-grade relay) for inverter-based DERs larger than 500kW as follows:

- Inverter relay functions: internal active anti-islanding, 27, 59, 81U/O
- Utility-grade relay functions: 27, 59, 81U/O, and either 51N or 51G (Figure 2 of ESB 756 Appendix C shows 51V, which may be considered a voltage-restrained variant of 51N).
- Because this project provides a ground source, no 3V0 scheme is required.

Electrically, there is no difference between customer-owned and utility-owned DER, so the ESB 756 requirements could apply to the Nantucket BESS.

As noted in section 2.2.3, the PCC impedance depends on loading assumptions. Table 2.10 summarizes the bounding results of loading assumptions on the calculated fault currents. Except for the Zig-Zag I_{SLGF}, these results are without the BESS or CTG. The current magnitudes don't vary significantly, but the current angles would, as evidenced by different X_1/R_1 ratios. Unless distance relays were used, these differences wouldn't matter for protection analysis.

Table 2.10. Short-Circuit Levels at the PCC

Parameter	No-Load	Full-Load
R_1 [Ω]	1.2100	1.7440
X_1 [Ω]	2.8339	2.6797
R_0 [Ω]	3.9612	3.7061
X_0 [Ω]	3.2139	3.0256
$I_{3\phi}$ [A]	2473	2384
I_{SLGF}[A]	2091	2070
Zig-Zag I_{SLGF} [A]	2608	2571
$MVA_{3\phi}$	56.5	54.5
X_1/R_1	2.34	1.54

There may be some remaining minor differences between Table 2.10 and the National Grid ASPEN model. These are most likely due to:

- The manually constructed sub-transmission model in Figure 2.2, which was done to represent contingencies and couplings between sources.

- Feeder switching to maximize BESS+CTG export from Bunker Road.

The BESS inverter contributes up to 150% of rated current to grid faults, where a PLL keeps the current in phase with voltage (PNNL 2019). At 13.2 kV and 7 MVA[1], this implies up to 459 Amps. However, the inverter only contributes positive and/or negative sequence current through the interconnection transformer, which has a delta winding on the low side. There is a zig-zag grounding transformer associated with the BESS, and according to one-line drawing H-113032-0, this provides a maximum 5.25 kA of ground fault current with near-zero grid impedance. As shown in Table 2.10, I_{SLGF} increases by approximately 500 A or 25% at this PCC, due to the BESS zig-zag grounding transformer. This increase is greater than National Grid would normally allow for customer-owned DER, so National Grid or its consultant should review the ground fault coordination on the whole 101L7 and 101L8 feeders.

The CTG is rated 15 MVA at 13.2 kV, with saturated X_d' = 0.175 and saturated X_d'' = 0.142. The Kato Engineering data sheet provides values for instantaneous symmetrical three-phase fault current of 4,613 Amps and SLGF current of 5,201 Amps. The 16-MVA CTG interconnection transformer has a delta winding on the CTG side, without any high-side neutral impedance according to H-113032-0. Thus, if the transformer impedance is 6.5%, the actual SLGF contribution would be around 4.2 kA from the CTG-plus-transformer, and the three-phase fault contribution would be around 3.2 kA. These fault current contributions are higher than the fault current contributions from the grid. Again, these increases ought to trigger a systematic review of device coordination on the 101L7 and 101L8 feeders. These feeder protection settings are outside PNNL's scope, so the foregoing observations are informative only.

2.3.3 BESS Protection Settings

This is a large (i.e., > 500 kW) type-tested inverter installation. Under ESB 756, there will be voltage and frequency trip functions built into the inverter as primary protection, with a utility-grade relay providing backup protection. The suggested settings for both, in Table 2.11, are taken from Table 7.6.11.1-1 of ESB 756, and consistent with Tables 6 and 7 of the BESS interconnection study (Ghavanati 2019b).

Table 2.11. BESS Voltage and Frequency Trip Settings

ANSI Function	1547-2018 Function	Level	Time	1547-2018 Defaults
27	UV1	88%	2.0 s	70% / 10.0 s
	UV2	50%	1.1 s	45% / 0.16 s
59	OV1	110%	2.0 s	Match
	OV2	120%	0.16 s	Match
81U	UF1	58.5 Hz	300 s	Match
	UF2	56.5 Hz	0.16 s	Match
81O	OF1	61.2 Hz	300 s	Match
	OF2	62.0 Hz	0.16 s	Match

[1] The current H-113032-0A drawing shows a transformer size of 7.5 MVA, along with 18 inverters at 432 kVA for a total inverter rating of 7.776 MVA, which is approximately equal to the transformer rating. Tesla verbally indicated that the BESS is limited to 7 MVA in control software.

Even if the inverter's default settings are for Category II, the function 27 settings will have to be changed.

The preliminary relay design brief for the BESS lists 67 and 67N functions to be provided in a SEL 351-6 relay. To coordinate with the BESS 10-second overload capability, 1.2 times the rated current of 328 Amps, the 67 function should be set to pick up slightly higher, such as 410 Amps on the primary. The 67N (or 51N) function should be set to pick up at no more than half of the zig-zag grounding transformer fault contribution, i.e., no more than 2.625 kA, with the level and time delay chosen to coordinate with other ground fault protection on the feeder.

The suggested synch check (25 function) settings come from the last row of Table 7.6.11.1-2 in ESB 756. These are:

- Max Δf = 0.1 Hz
- Max ΔV = 3%
- Max $\Delta\phi$ = 10 degrees

In order to stay on line when both cables to the mainland are out of service, it is suggested that the BESS anti-islanding function be disabled[1]. If not, National Grid should consider increasing the default islanding trip time from 2 seconds to 5 seconds, as allowed in IEEE 1547-2018.

National Grid should also consider not activating the 51V function, even though this is required in ESB 756. The reason is that 51V may cause the BESS to trip under conditions when ride-through would be a better outcome. The inverter's built-in functions should protect the inverter itself when necessary. If activated in the utility-grade relay, 51V should not be set according to guidelines for rotating machines. For example:

- Current pickup at 1.25 times rating, or 410 Amps on the primary
- Voltage control (51V-C) setting at 75% of terminal voltage. It is suggested that voltage restraint not be used.
- Time delay should be at least 2 seconds to coordinate with UV1. National Grid should evaluate this suggestion against other feeder protective device tripping times, and the inverter capabilities, which include a breaker tripping time of 0.9 seconds and a 120% loading capability for 10 seconds.

2.4 Feeder Sensors

Table 2.12 enumerates five non-invasive sensors that were proposed for an earlier VVO/CVR pilot project on Nantucket Island. They are all intended to improve the estimates of downstream voltage profile.

[1] PNNL does not understand the need for a BESS shutdown when transitioning between on-grid and off-grid modes, and we don't see the mechanism for equipment damage occurring during this transition. Note that the voltage/frequency trip settings are still in place, but we recommend that the active islanding detection function, which is NOT the same as voltage or frequency tripping, be disabled.

Table 2.12. QinetiQ Clamp-On Power Sensors Proposed for Nantucket

Sensor	Location	Phasing	Pole
1	101L2: Polpis Rd.	3	56
2	101L6: N. Cambridge St.	3	1
3	101L7/L8: Milestone Rd.	3	121
4	101L2: Milestone Rd.	1	60 (tap)
5	101L7: Surfside Rd./ Fairgrounds Rd.	3	1

Voltage sensing in various feeders is an integral part of the CVR strategy proposed later in section 3.4.3 and volt-var control strategy described in Section 4.2.3. While implementing CVR and voltage support strategies, these leftover sensors can be re-used to avoid voltage violations, i.e., minimum voltage in the network falling below ANSI limit of 0.95 pu.

2.5 Transactive Energy System

The GridLAB-D model of Nantucket Island's distribution system can be run with PNNL's Transactive Energy Simulation Platform (Huang 2018), which supports the development and evaluation of software agents that could run on a smart meter or home energy management system. If the N-2 contingency lasts for more than several hours, a power-rationing scheme could prolong the service to critical loads. Such a power-rationing scheme would be invoked by a civil authority, not the utility alone. Three critical load areas totaling 20 MW have been identified, to be restored in a sequence of eight switching steps. The core load area was identified to have 272.5 kW existing generation, to which the BESS, CTG and 1540 kW of PV may be added. There may not be enough on-island generation to restore all of the critical load, especially if the CTG is unavailable. A more granular control and switching scheme could prolong service to selected loads, e.g., emergency services, hospital, and water pumping.

3.0 Economic Assessment

Nantucket Island is located off the coast of Massachusetts, as highlighted in blue in Figure 3.1. It has a fairly small resident population of approximately 11,000. During summer months, however, the population on the island can swell to over 50,000 (Town and County of Nantucket 2018). Currently, Nantucket's electricity is supplied by two submarine supply cables (as shown in Figure 3.2 by green and purple lines) with a combined capacity of 71 MW and two small on-island 3 MW CTGs. The small CTGs will be replaced by a single, larger CTG with a capacity that is temperature dependent and varies between 10 MW and 16 MW. National Grid is also adding a 6 MW / 48 MWh Tesla lithium-ion BESS. This brings the total energy supply capacity on the island to approximately 91 MW on the days when the grid faces peak energy demand.

Figure 3.1. Nantucket, MA

Figure 3.2. Two Supply Cables Connecting Massachusetts to Nantucket Island

These investments were taken after thoughtful consideration of all options, including the deployment of a third submarine transmission cable (National Grid 2016). In consultation with National Grid, PNNL defined a set of services to be evaluated from an economic perspective based on its experience in conducting similar assessments for various utilities across the U.S. As discussed later in this assessment, while the primary service provided by the BESS is responding to N-1 contingency events to defer investment in a third submarine transmission cable, there are additional local and market-based benefits that the BESS can also provide. This assessment evaluates each of the services outlined below:

1. Transmission deferral
2. Energy arbitrage
3. Capacity
4. Frequency regulation
5. Spinning reserve
6. Conservation voltage reduction/volt-VAR optimization
7. Outage mitigation.

The BESS and CTG systems will begin operation in 2019 and with augmentation and proper maintenance are expected to operate through 2039. The analytical base-year is 2019 and the analysis time horizon mirrors the economic lives of the BESS and CTG.

The Nantucket BESS is a Federal Energy Regulatory Commission (FERC) regulated asset and is in the rate base of a FERC regulated company, New England Power (NEP). NEP is a subsidiary of National Grid USA. NEP would need to petition FERC to allow a rate-based asset to participate in wholesale energy markets. If FERC approves market participation, National Grid will return all market revenues back to customers, hence no double recovery, and will have no monetary gain.

3.1 Tesla Battery Energy Storage System

The Nantucket BESS is a 6 MW/48 MWh lithium-ion Powerpack 2 system procured from Tesla, Inc. The total system will include the battery packs, a power conversion system (PCS), and a site-level controller. The BESS will be deployed at National Grid’s Bunker Road Substation located on Nantucket Island. The system as designed is expected to have an economic life of 20 years with preventative maintenance being conducted throughout to ensure its reliability. The system must be operated within the limits specified below in order to meet the warrantied performance specifications outlined in this section. Figure 3.3 below shows exterior and interior images of an example Powerpack 2 battery system (Tesla 2019).

Figure 3.3. Tesla Powerpack 2 Lithium-Ion Energy Storage System − Exterior and Interior

There is a guaranteed capacity level for the Tesla BESS that has been outlined as part of the battery agreement with National Grid. To ensure this value, National Grid will be required to adhere to the maximum annual throughput of energy when utilizing the battery for grid operation. For this system, this maximum annual throughput is 7,200 MWh/year. This is based on the number of annual discharge cycles that the battery system has been sized for (150 cycles/year) multiplied by the total kWh capacity of the system (48,000 kilowatt-hours [kWh]). Across the 20-year lifespan, this sums to 144,000 MWh in total throughput (Tesla 2017).

Operations and maintenance (O&M) requirements are spread across the 20-year life of the battery with repeated evaluations and replacements at annual, 5-year, and 10-year frequencies. Annual maintenance includes items such as communications checks, cleaning, and regular inspections. Every five years, however, the battery system will have its pumps replaced and in year 10, major replacement of inverter and powerpack components will be conducted to ensure a 20-year economic life (Tesla 2017).

Regarding the round-trip efficiency (RTE) of the system, consideration was made towards allowing variation due to external factors when modeling battery operation. RTE as used here is the ratio of the amount of energy that a storage system can deliver to the grid relative to the amount of energy taken from the grid and injected into the BESS. If a BESS has an RTE of 90%, it means that for every MWh of energy it pulls off the grid to charge the system, the BESS will only provide 900 kWh when discharging energy back onto the grid. The BESS RTE is used to factor energy losses into the simulation of economic performance.

Among other components, the RTE of a storage system changes based on the ambient temperature of its operating environment. For this analysis, a daily expected RTE for the BESS was calculated based on the average daily temperature in 2016 for Nantucket Island. The daily weather data for the calculation was retrieved from Weather Underground (2019) for the Brant Point Nantucket Weather Station located in Massachusetts. These data values were used in combination with weather-variant RTE values provided in the Nantucket EPC Agreement (Tesla 2017) by Tesla, shown below in Table 3.1.

Table 3.1. Round Trip Efficiency Variation of the Tesla Battery over Its Lifecycle

Parameter	Value for 4-Hour System or Longer at 500 kWp
Round-trip Efficiency (BOL) inclusive of thermal management loads	STC: 89.0% T_{AMBHOT}: 83.5% $T_{AMBCOLD}$: 85.5%
Indicative Minimum Round-trip Efficiency (CMA) over 10 years	STC: 85.0% T_{AMBHOT}: 78.5% $T_{AMBCOLD}$: 79.5%

In this table, BOL refers to Beginning of Life, and STC stands for Standard Test Conditions defined as a system at 77°F and 1 atmosphere (101.3 kPa) of pressure. The ambient temperature for cold weather performance is defined as the system soaked at -4°F, denoted by $T_{AMBCOLD}$, and the ambient temperature for hot weather performance is defined as the system soaked at 113°F, denoted by T_{AMBHOT} (Tesla 2017). Using these numbers, it was possible to interpolate the RTE for the temperature range between the temperatures specified. Given that the temperature on Nantucket Island historically stays between -4°F and 77°F, a linear equation was fitted to the RTEs provided for BOL and 10 years at these temperatures. These linear equations are listed in Table 3.2.

Table 3.2. Fitted Linear Equations to Predict RTE for Specified Temperature Range

Stage of Life	Fitted Linear Equation for Temperature Between -4°F and 77°F
BOL	RTE = 0.0004 * (Temp) + 0.8567
10 Years	RTE = 0.0007 * (Temp) + 0.7977

Using the 2016 average daily weather data for Nantucket as illustrative data for an average year, the daily RTE at BOL and 10 years of life was calculated. This resulted in average yearly RTE of 87.77% at BOL and 83.44% over 10 years of life. The average RTE of 83.44% was used for all operations. We assume that both the charging and discharging efficiencies are 91.34%.

3.2 Bunker Road Combustion Turbine Generator

National Grid has will soon be deploying a Power Generation Titan™ 130S Gas Turbine-Driven Generator Set designed by Solar Turbines, incorporated at the Bunker Road Substation. The unit comes with a Turbotronic 5 Control System (Solar Turbine 2015). This unit will be replacing two 3 MW generators, which will be disconnected once the larger turbine is operational.

The capacity of the CTG in MW of electrical energy is depicted in Figure 3.4. As shown, the CTG's capacity is temperature dependent. At 0.8 Power Factor, output can vary roughly between 10.6 MW and 16.7 MW as the temperature rises from negative 20°C to positive 50°C (Kato Engineering 2017). This relationship is defined quantitatively by Equation 1. To obtain the capacity curve of the generator throughout the year, the hourly temperature data for the year 2016 is used to generate the temperature-dependent CTG rating. For Nantucket, the capacity range goes from 13.28 MW to 16.67 MW, with a year-round average of 14.88 MW.

$$\text{kW Output} = -0.2362(\text{Temperature in F}^{o})^{2} - 20.027 * (\text{Temperature in F}^{o}) + 16{,}637 \quad (1)$$

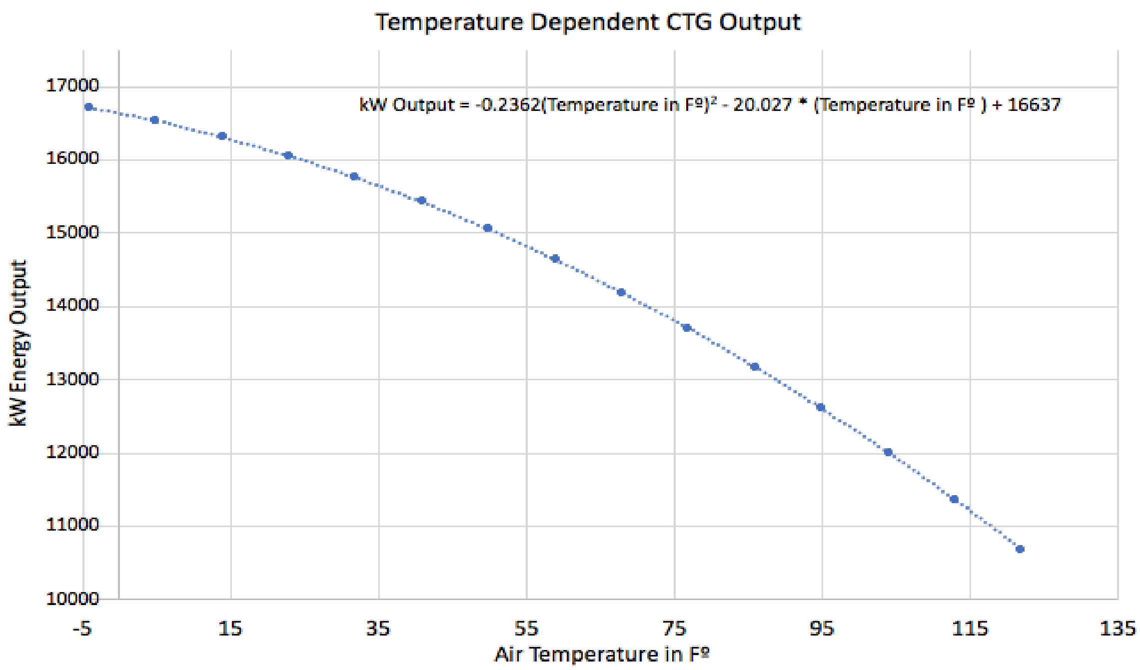


Figure 3.4. Variation in kW Electrical Energy Output with Temperature Change (in Fahrenheit)

3.3 System Costs

The local system benefits outlined in the next section result from the operation of both the CTG and the Tesla BESS. The full cost of the CTG is estimated at $35.6 million. The cost of the Tesla BESS, including all PCS, balance of plant, interconnection, and construction/ commissioning costs totals $33.0 million. The full costs of the CTG and BESS at the Bunker Road substation on Nantucket Island are estimated at $68.6 million.

The costs outlined above, however, do not include all those that are ultimately passed on to customers. Additional costs associated with tax, return on investment, depreciation, administrative/general expenses, and operations and maintenance costs were included in a rate impacts workbook prepared by National Grid. The full system costs over the life of the systems were estimated at $163.8 million, but these costs are spread over 20 years. Annualized costs were discounted at the 6.85% weighted cost of capital for National Grid to develop a lump sum present value cost of $93.3 million to National Grid customers.

3.4 Benefits of Local Operations

There are several services that generate benefits locally, including transmission deferral, volt-VAR/CVR, and outage mitigation. In all cases, these services are assigned value based on costs avoided to National Grid and its customers. The remainder of this section describes these services. Note that the costs and economic assessment of local operations includes impacts of both the BESS and CTG because both are essential to driving the primary service – transmission deferral. The CTG only obtains benefits associated with local operations while the benefits associated with bidding the BESS into the ISO-NE market are defined in Section 3.5.

3.4.1 Transmission Deferral

In the event that one of the supply cables fails (i.e., an N-1 contingency is triggered), the island would face an energy shortage and outage threats during a small number of days during peak summer months. One way to augment the current energy supply would be to install a third submarine transmission cable; however, the cost of doing so could be between $105-$205 million (National Grid 2016). The enhanced energy supply is only required during a time when one of the supply cables becomes non-functioning, and only during the peak demand period in the summer.

This presents a scenario where enhanced local generation and battery storage alleviates the need for a third transmission cable and provides transmission upgrade deferral benefits. Transmission upgrade deferral refers to delaying the cost of upgrading the transmission system by installing a battery storage unit, which would provide energy-limited reliability services to the grid. Delaying expenditures results in present value (PV) cost savings. Thus, we seek to answer three questions through the load analysis:

1. What is the shape of the load profile for Nantucket Island?
2. How many years of deferral could we attribute to CTG plus energy storage? What is the value of this service?
3. When can the BESS be safely engaged in market operations, or stated differently, when must it be set aside only for local reliability operations?

3.4.1.1 Load Profile

Figure 3.5 shows the hourly energy demand on Nantucket Island in 2016. Historic load data demonstrates that load peaks each year in the July/August period. In Figure 3.5 the horizontal lines show the various capacities of the island grid under competing scenarios. The orange line mirrors the capacity when Cable 4606, which is the cable with the higher capacity, is off-line, leaving only Cable 4605 with the contingency power rating of 38 MW. The grey and yellow lines represent the capacity with Cable 4605 and new CTG, and Cable 4605, new CTG, and BESS, respectively. To obtain the capacity curve of the generator throughout the year, the hourly temperature data for the year 2016 is used to generate the temperature-dependent CTG rating. The CTG rating for the peak load hour of the year 2016, which comes out to be 13.8 MW, is used for comparison across various years.

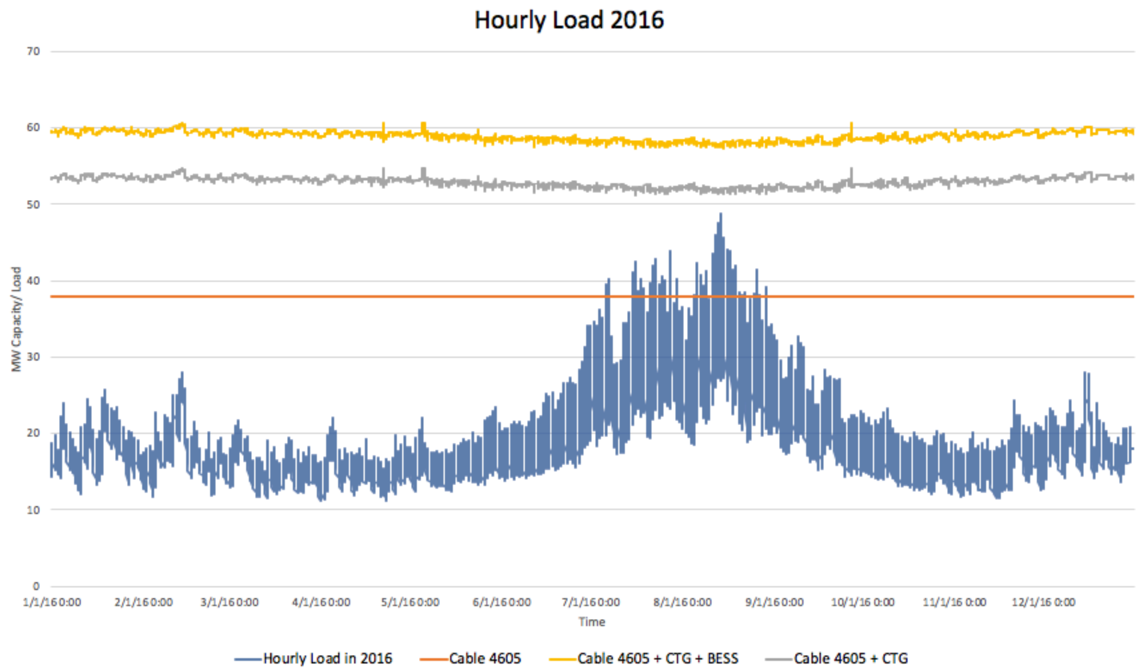


Figure 3.5. Hourly Maximum Peak Load 2016

Using the hourly load data from 2016 and load growth forecasts provided by National Grid, the hourly load profile for the year 2019 can be obtained. This is presented in Figure 3.6. While 265 hours in 2016 were exceeding the cable 4605's contingency capacity of 38 MW in 2016, this number rises to 425 in 2019. However, it still does not exceed the combined capacity of Cable 4605 and the new CTG, represented by the grey line.

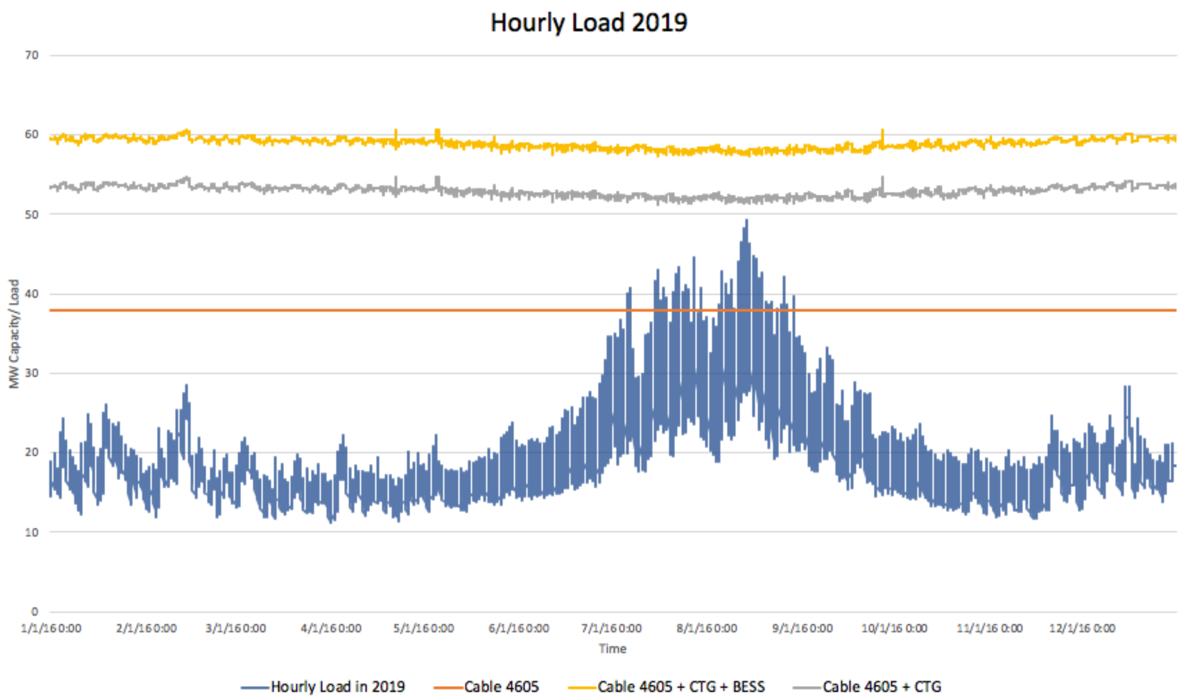


Figure 3.6. Projected Hourly Maximum Peak Load 2019 Using Expected Load Growth Rate

When the extreme N-1 load contingency numbers for load provided by National Grid are used instead for the year 2019, while maintaining the load shape from the year 2016, load exceeds the N-1 contingency with CTG capacity four hours in 2019 (Figure 3.7). These four hours take place in mid-August.

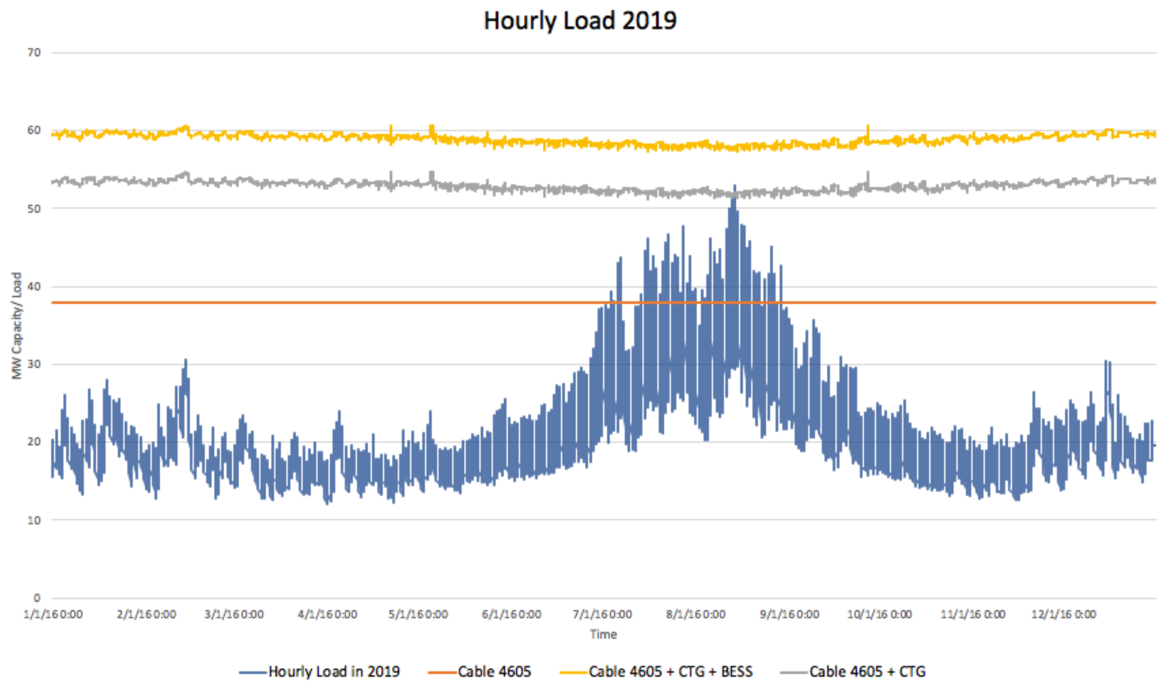


Figure 3.7. Projected Hourly Maximum Peak Load 2019 Using Expected Peak Load

In addition to typical annual load growth, there have been some proposed developments that would potentially alter loads on Nantucket Island. Along with that, new distributed energy generation resources could alter the projected growth rates of energy supply needed on the island. These have been accounted for in the final projected peak loads by the National Grid.

Figure 3.8 presents the 95th percentile extreme peak load identified by National Grid for the years 2006-2018 and projected future maximum load values through 2033, indicated by the blue dots. In Figure 3.8, the dashed lines indicate the capacity with the battery (6 MW), the new CTG (13.8 MW), and the cable (38 MW). The solid lines indicate capacity with an old CTG (6MW) and cable 4605 (38 MW), without the battery. Using the given growth rates, the projections of future peak demand indicate that it is necessary to augment the current energy supply because the peak demand in 2012 is expected to have surpassed the capacity of cable 4605 and the old generator on the island. The augmented capacity on the island in the future, during an N-1 contingency, consists of the cable 4605, new CTG, and BESS. This capacity is expected to be exceeded in 2025.

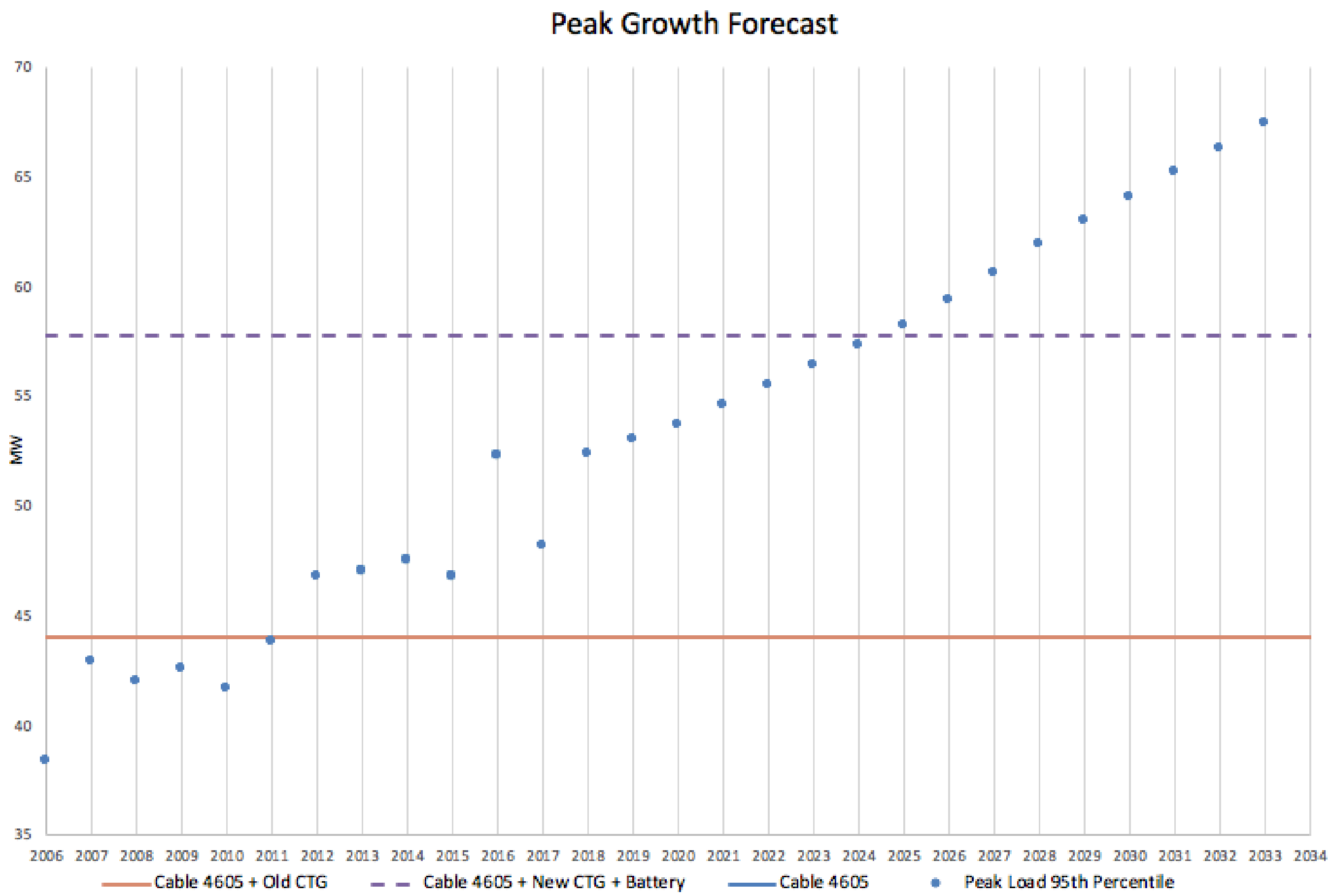


Figure 3.8. Historical and Project Extreme Load Peaks

In the event that transmission cable 4606 fails during the peak load season, the island faces a threat of power outage and would not be able to support even current energy demand without the new CTG and BESS. Adding these assets to the grid ensures that the need for a third supply cable to the island can be pushed back by roughly 13 years. While some of these years have already passed, National Grid has proven willing to accept a small degree of risk associated with N-1 contingency events in the past and could do so in the future. Thus, we count all 13 deferral years. In calculating deferral benefits, we inflated the mid-point of the third cable cost ($155 million) from 2016 to 2019 dollars using the consumer price index, resulting in a current cost of $165 million. Using National Grid's suggested capital cost inflation rate of 2% and the weighted average cost of capital (WACC) of 6.85% as the discount rate, PNNL estimates the reductions in PV costs at $109.5 million. Note that we assume the third cable will have the same treatment as the BESS and CTG; however, National Grid may choose another method to calculate revenue requirements later when purchasing and deploying the third cable.

3.4.1.2 When to Designate the Battery for Local Reliability Services

The focus of this analysis is the uppermost range of energy demand that threatens the reliability of energy supply to Nantucket Island. It is instructive to look at how the past energy demand has changed over the years. To this end, Figure 3.9 provides a basic idea about how the energy demand changes over the course of a year from 2013-2016. The darker sections indicate a higher demand in MW and these sections are stacked over each other by year for a comparative idea about how the period of higher energy demand varies from year to year. It is clear from the graph that the peak energy demand appears to be starting in late June and ending in late August.

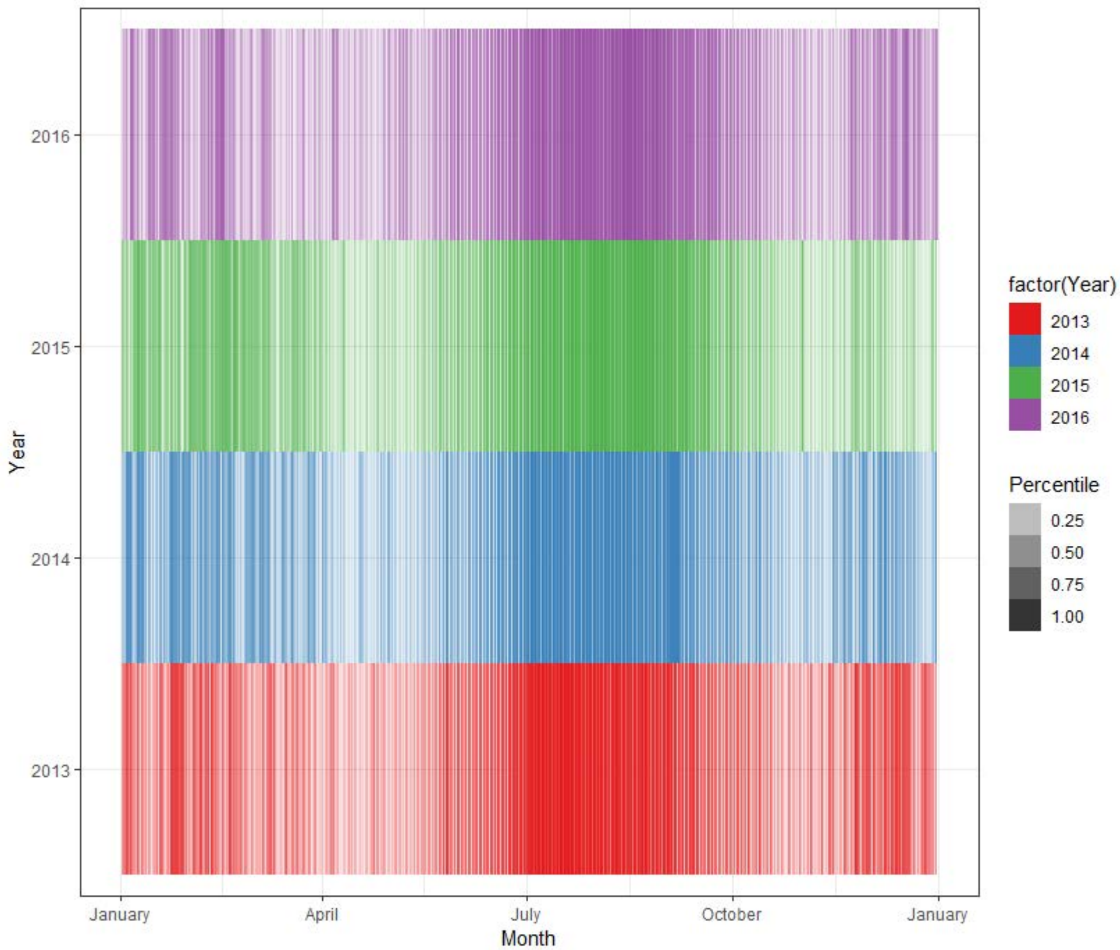


Figure 3.9. Peak Load Density per Year by Percentiles

For a better understanding of the peak demand, we identify when the top 10%, 5%, and 1% energy demand hours of the year occur. This is shown in Figure 3.10–Figure 3.12 with the upper and lower bounds for these periods. The 90th percentile approximately covers 34% to 58% of the current capacity (without battery), through all the years, which is a wide range. Specifically, for 2016, it increases from 42% to 58%. The top 5% isn't a narrow range either, running from 41% to 58%. With the 99th percentile, it is a comparatively narrower range with all the periods having energy demand higher than 41 MW and running from 50% to 58% of available capacity in the year 2016.

In 10 years, this range would be expected to shift forward. For example, in 2028, considering the current capacity of the energy supply on the island, the 95th percentile would range between 52% to 71% of the total capacity without battery. It will be between 96% to 130% for the capacity available when the older cable is unable to supply energy. Similarly, the 99th percentile in 2028 goes from 62% to 71% of the current total available capacity to 112% to 130% in case of the N-1 contingency.

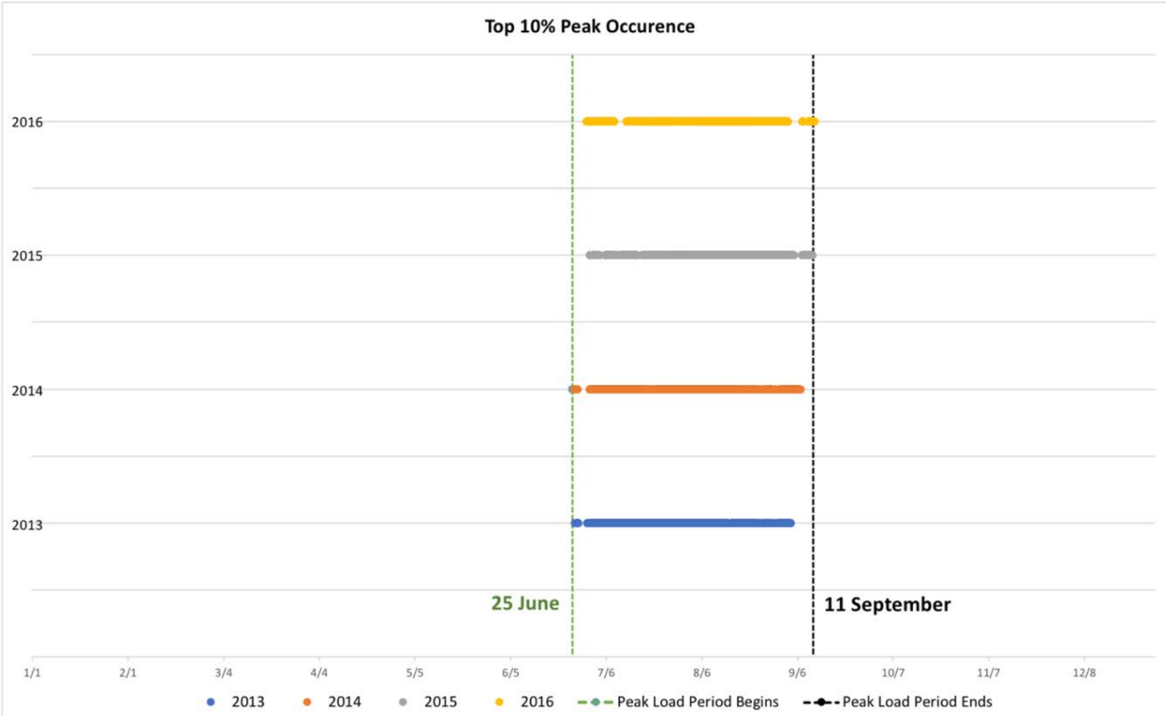


Figure 3.10. Time of 90th Percentile Peak Demand Occurrence in Each Year

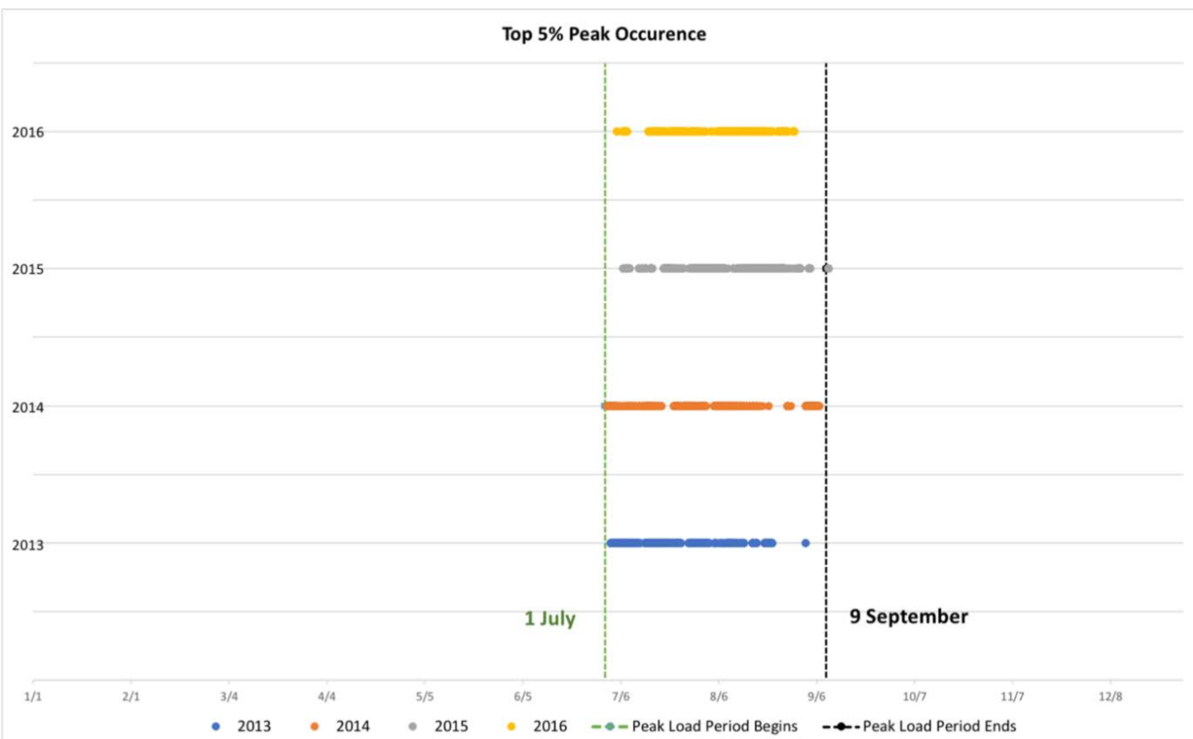


Figure 3.11. Time of 95th Percentile Peak Demand Occurrence in Each Year

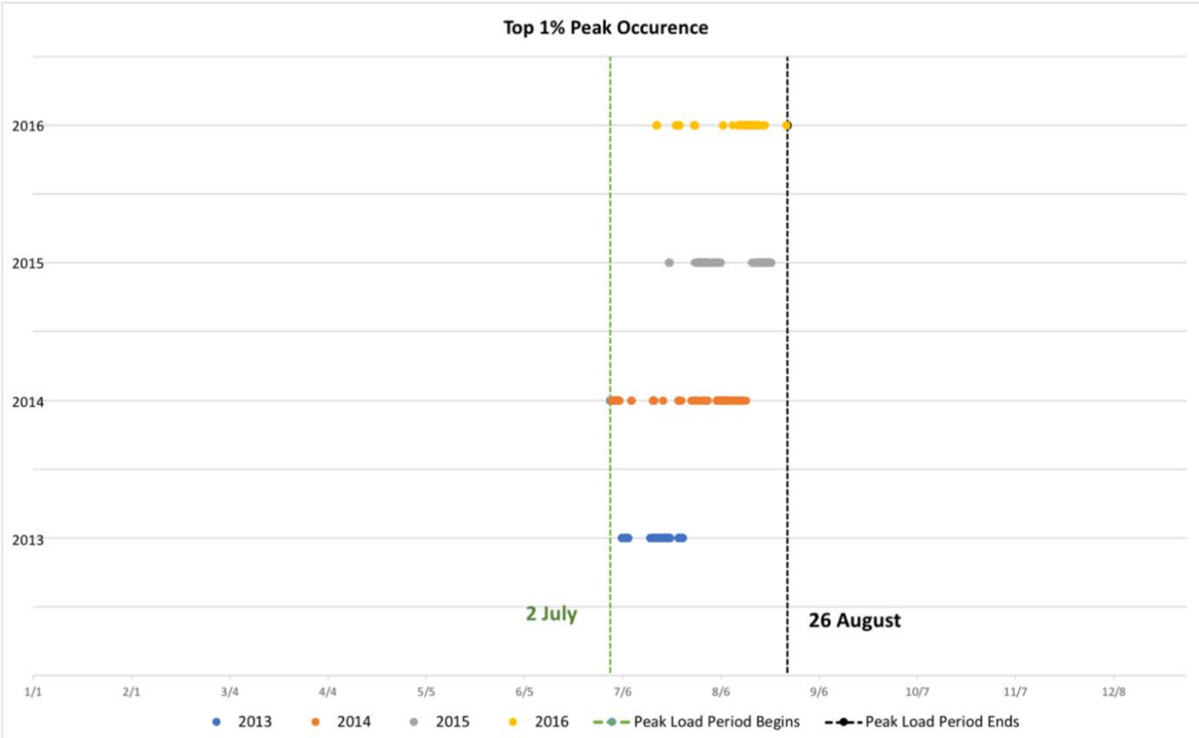


Figure 3.12. Time of 99th Percentile Peak Demand Occurrence in Each Year

One significant highlight is that the 90th, 95th and 99th percentile, despite being a wide range, all appear to fall in the same time period for all the years. Additionally, this range becomes narrower and more precise as we restrict our focus to the 99th percentile, which seems to be the most relevant group to study for reliability purpose. Another important takeaway from this analysis is that this range seems to be shifting forward as we move from 2013 to 2016. This is evident in Figure 3.10 where the standard deviation appears to be lower and the cluster of data points moves forward in time through 2013-2016. From these empirical observations, there would appear to be days between July 1st & August 31st where reserving some portion of battery storage would be prudent for whole island contingency based reliability. In a limited number of hours during many of these summer days, the BESS would also be available for market participation. For additional security and a buffer around the top 1% of all load hours, the time span could be expanded to June 15th – September 15th.

Note that based on current ISO-NE market rules for continuous storage facilities (CSF), any designation designed to reserve the battery for reliability purposes can be presented on an hourly basis. By bidding higher prices that include the opportunity costs of forgoing a response in an N-1 contingency scenario, the BESS can remain available during peak load hours for local reliability purposes with the proper control system, as outlined in Section 4.0.

To address how the bands identified in Figure 3.10–Figure 3.12 align with expectations, we extended the load forecast through 2033 while maintaining the load shape found in 2016. Hourly load values within each year were then compared to the N-1 contingency capacity on Nantucket Island to determine the hours expected to exceed the N-1 contingency. The number of hours exceeding the N-1 capacity, and the percentage of annual hours that those hours represent, are presented in Table 3.3. The number of hours exceeding the N-1 contingency over the 15-year time horizon is forecast to expand from 4, or less than 0.0% of all hours, in 2019 to 290, or 3.3%

of all hours, by 2033. The number of each hour exceeding the N-1 contingency is presented in Appendix A. For modeling purposes, PNNL used the hours identified for 2029 in the one-year simulation of energy storage operations. The year 2029 was chosen because it represents the mid-point of the analysis time horizon and we assume that the BESS will be called on to shave peak loads over its entire economic life. The formulation is designed to ensure that the BESS could meet any N-1 contingency. During N-1 contingency hours, we increase the SOC of the BESS to 100% and maintain it there until the end of the N-1 contingency window.

Table 3.3. Number and Percentage of Hours Exceeding N-1 Contingency by Year

Year	Num. Hours	Percentage of Hours Annually
2019	4	0.0%
2020	6	0.1%
2021	9	0.1%
2022	19	0.2%
2023	26	0.3%
2024	32	0.4%
2025	48	0.5%
2026	66	0.8%
2027	90	1.0%
2028	116	1.3%
2029	145	1.7%
2030	176	2.0%
2031	219	2.5%
2032	251	2.9%
2033	290	3.3%

3.4.2 Outage Mitigation

In the event of an outage, the BESS would have the capacity to effectively operate in an islanded mode on Nantucket Island, subject to distribution system constraints. This service would result in benefits accruing to National Grid customers located in the area of the outage and are monetized in terms of the value of loss of load.

To estimate the benefits that can be derived from outage mitigation, historic outage events were examined for Nantucket Island. The number of outages for each year examined are presented in Table 3.4. There were 704 outages over 11 years, averaging 64 annually. All outages with secondary/service, transformer, and fused branch in the description were eliminated because the BESS could not address them. Over the 11-year history, 43 outages were identified with a description tag of either “company”, “main line”, or “T&D line”. These outages were examined further.

Table 3.4. Number of Annual Outages on Nantucket Island

Year	Outages	Customer Minutes Interrupted (Thousands)
2007	90	292
2008	84	608
2009	61	298
2010	87	323
2011	64	336
2012	54	347
2013	59	578
2014	62	409
2015	84	14,800
2016	72	429
2017	77	1,100
Total	704	19,520
Annual Average	64	1,775

The remaining outages were reviewed against a feeder map provided by National Grid in order to identify which could have been shortened by the BESS plus CTG with feeder switching. Of the 43 outages, 13 were on a radial section on the far western side of the island, 6 represented a local outage on a radial section or single customer outages, 11 outages were less than 60 minutes (and we assume the switching take one hour), and two had insufficient information to determine for certain that the BESS could assist. After removing these additional outages, 11 outages over the 11-year time horizon that could have been partially mitigated by islanding customers using the BESS and CTG were left.

To compute reductions in customer minutes of outage, the battery power capacity of 6 MW, the CTG capacity of 13 MW, and the total load at the time of the outage were determined. Since a switching reconfiguration time of 60 minutes is assumed, the best possible outcome is to reduce the outage duration to 60 minutes under a scenario when no additional investments are undertaken. This assumption also means that under the base case analysis, no outage under 60 minutes can be addressed. For the remaining customers whose load exceeds the capacity of the BESS plus CTG, outage minutes would remain unchanged. Candle Street load data were acquired to estimate the total load at the time of the outage. The number of customers affected by each outage are identified in the outage data. We assume the SOC of the BESS to be 50%, or the SOC floor set for the BESS, when the outage strikes.

One outage where the BESS and CTG could have been used to reduce lost load to customers is presented in Figure 3.13. In this case, Nantucket Island was disconnected from the mainland, resulting in the complete blackout of the Island. Examining the network map, the area that can be supplied by the BESS and CTG is identified and shown in Figure 3.13. Here the BESS supplies a fraction of feeders 101L2 and 101L7, which are in fact the feeders with the most customers. In this case, the percentage reduction in the CMI due to the BESS and CTG would be 37% under the base case analysis.

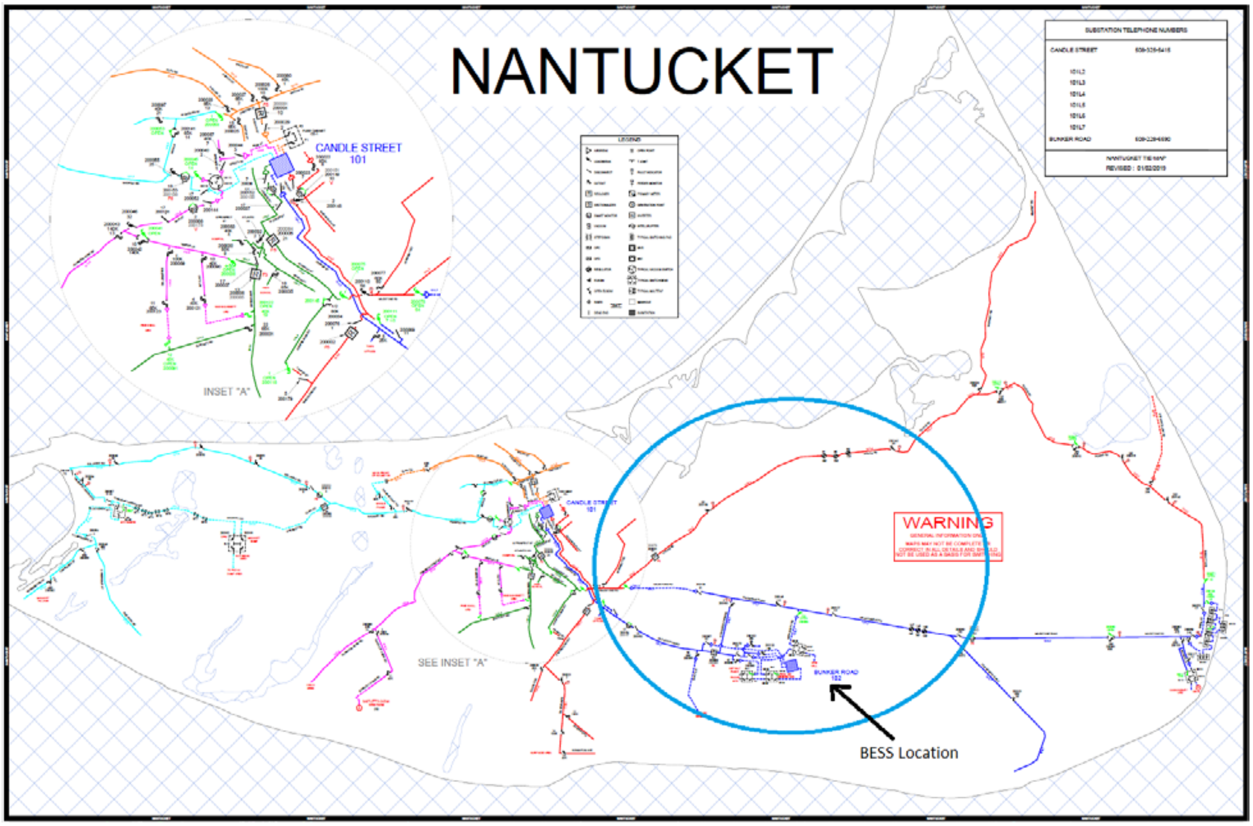


Figure 3.13. Area that Can Be Supplied by BESS and CTG Is Highlighted along with Location of the BESS and CTG

For the modeling simulation, we randomly selected an outage that strikes on January 27th at 7am. The BESS was modeled to inject power into the grid at 6MW continuously until completely depleted. A supplemental analysis was performed where a 2nd outage occurred on August 31st for 36 minutes.

Outages were also modeled under scenarios where additional distribution-level investments enable 5- and 1-minute response times. These lower response times could be enabled through automation at the following loadbreaks: 200064, 200071, 200111, 200075, 200118, 200038, and 200078. All loadbreaks recommended to be automated are located between Candle Street and Bunker Road except one, which is located between feeders 101L2 and 101L7 on the eastern side of the island. When the response time is reduced to 5 minutes, the outages the BESS/CTG combination can mitigate is expanded to include six additional outages. Lowering the response time to 1 minute adds one more outage, bringing the total number of outages with the potential for mitigation over 11 years to 18.

It is important to note that the distribution system is not currently capable of accepting a full injection of power from the CTG and BESS simultaneously; however, it could with selected reconductoring projects being carried out. Thus, additional scenarios are explored where the CTG and BESS are used in combination to eliminate outages and the full capacity of the assets are enabled.

Using the customer breakdown provided to PNNL on Nantucket Island, the residential customers constitute 89% of the total number of customers on the Island. Small commercial and industrial customers (C&I), which have an energy demand of less than 50,000 kWh are, on an average, 10.9% of the same. The remaining 0.1% are the medium and large C&I customers, which have annual load that exceeds 50,000 kWh. Using cost functions prepared by PNNL based on outage cost data presented in Sullivan et al. (2015), the cost of a one-hour outage could be estimated at $5.16 for a residential customer, $716.16 for a small C&I customer, and $18,537.25 for a medium/large C&I customer. These values were inflated to 2018 dollars using the Consumer Price Index Inflation Calculator (BLS 2019). This customer breakdown is applied across all feeders.

We study two broad scenarios, with and without reconductoring, which are further broken down to study benefit variation owing to the aforementioned different response times (1 hour, 5 minutes, and 1 minute). To achieve the quicker response times, feeder automation would be required as described previously. For each scenario, we evaluate all applicable outages under the with- and without-BESS/CTG condition. The cost difference in terms of the value of loss of load (VoLL) to Nantucket Island customers is estimated. The results from this analysis are provided in Table 3.5.

Table 3.5. Annual Outage Cost Savings on Nantucket Island

Response Time	Without Reconductoring	With Reconductoring
1 Hour	$783,124	$876,157
5 Minutes	$909,293	$1,011,754
1 Minute	$920,382	$1,023,523

3.4.3 Conservation Voltage Reduction/Volt-VAR Optimization

CVR is an approach to intentionally reduce system voltage in such a manner that customers' voltage stays within allowable bounds but at the same time reduces the power and energy consumption due to the existence of voltage dependent loads. Many utilities have exercised this approach to achieve economic benefits of reduced power demand and energy consumption. Typically, CVR is implemented as a large area wide project consisting of multiple feeders. A BESS connected to a substation or at another location within the area of a CVR project may be directed by a distribution automation system or a VVO controller for sinking VAR. This will reduce voltage in the feeders in varying degree depending on the location of the BESS, available VAR capability of the BESS inverter, and VAR to voltage sensitivity at the locations of interest within the feeders. CVR could be classified as a specific VVO application for reducing voltage. Another application of VVO is to support voltage by supplying VAR. One of the most well-known benefits of improving voltage is reduced line loss in the network which could be monetized as a benefit of VVO.

In this work, CVR is implemented by consuming VAR using the BESS inverter at the maximum possible amount without violating the ANSI voltage limit (95% of rated voltage, or 0.95 per unit) within the island network. For VVO, or more specifically voltage support, a Volt-VAR droop curve defined in IEEE 1547 standard is used. Voltage at terminals of BESS is sensed and reactive power is supplied or consumed according to the droop curve shown in Figure 3.14. The set points, slope and dead band are defined as suggested by IEEE standard 1547. In Figure 3.14, positive VAR indicate supply of reactive power to the grid. When implemented, absorption of reactive power is called upon if the voltage begins to exceed a pre-determined upper level (as defined by the droop curve). Conversely, if lower than nominal voltages are sensed, reactive power would be delivered to the grid to help boost the voltage back to nominal levels. Analysis of market operation benefit suggests that the BESS will mainly be deployed for regulation services in a normal operation day. Therefore, a significant portion of the inverter capacity will be available for reactive power related operation. Therefore, a Volt-VAR droop curve with higher slope setting than the curve presented in Figure 3.14 could be used, if needed.

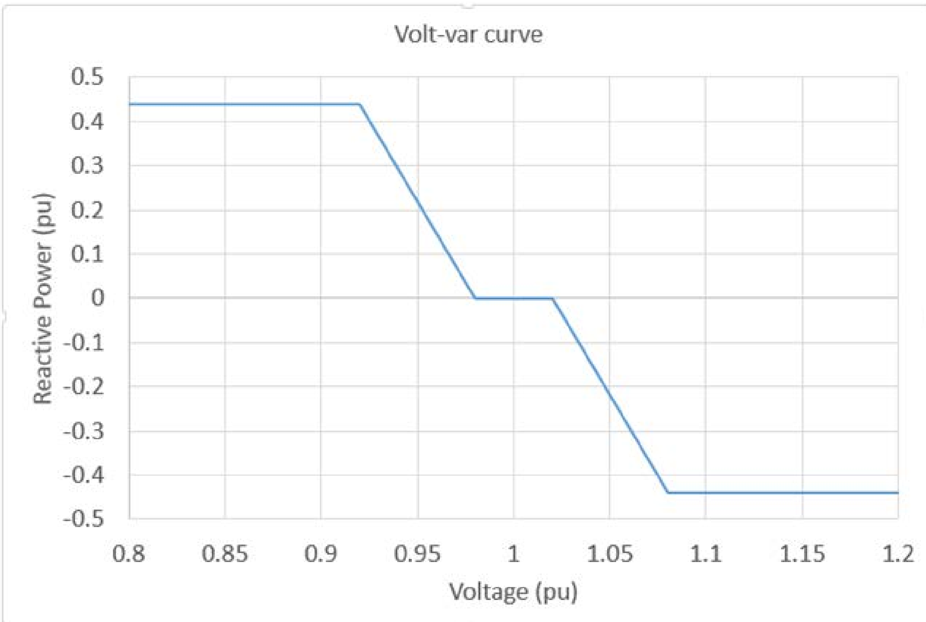


Figure 3.14. IEEE 1547 Volt-VAR droop curve

In the absence of a distribution network model, the general expression used to determine the reduction in active power is shown in equation (2) where, P_{red} is the reduction in active power demand, CVR_{fP} is the CVR factor (percent reduction in active power demand per 1% reduction in voltage) for active power, ΔV is the reduction in voltage resulting from CVR, P is the amount of active power flow in the feeder, n is the total number of feeders in the CVR engagement area, and k is a given time instant (e.g., at a given hour) when the benefit is being assessed.

$$P_{red}(k) = \sum_{i=1}^{n} CVR_{fP} \times \Delta |V(k)|_i \times P_i(k) \tag{2}$$

Hourly reduction in active power demand can be translated into reduction in energy consumption over a given period (e.g., a year) and energy price (e.g., locational marginal price (LMP) at relevant node) can be used to monetize CVR benefit. Since the Nantucket Island distribution network model was developed as a part of this project, CVR benefit is estimated by determining reduction in energy consumption by running time series power flow analysis of the network model over a year with the BESS set up to consume reactive power using the approach described above. Voltage dependency of the island loads was not available from prior studies. Therefore, typical voltage dependency parameters corresponding to distribution network loads (expressed by portion of constant current and constant impedance load) are used.

To estimate benefit from the proposed CVR/VVO scheme, a year-long time series simulation is performed at hourly time interval using 2017 load data. It is to be noted that CVR/VVO benefit in this report refers to the benefit obtained from BESS actions only. A system-wide VVO project with additional voltage control equipment could produce additional benefit, which is not considered in this report. When CVR is implemented, minimum voltage in the network is of concern as it should not fall below the ANSI standard. Annual voltage profile data obtained from time series power flow analysis of the network (without BESS and CTG) is analyzed to determine any limitation in CVR application round the year. Hourly voltage profile data in Figure 3.15 shows that during the months of July and August, minimum voltage in the network falls below 0.95 per unit. Although locations of minimum voltage are not in the vicinity of the BESS (in fact they are far away on the other side of island), CVR operation is suspended for these two months to avoid any undesired impact.

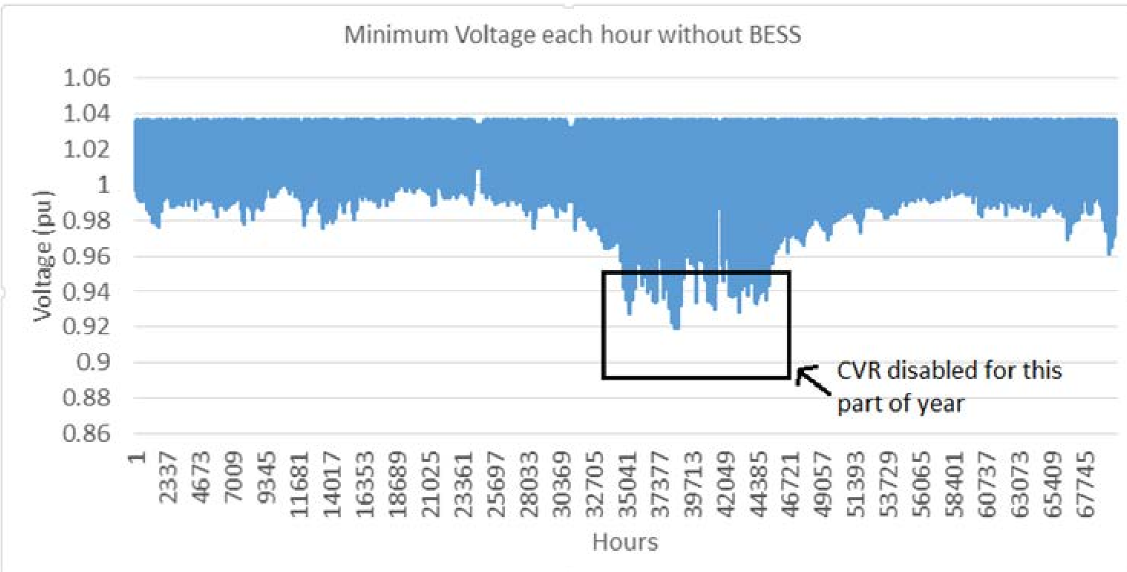


Figure 3.15. Minimum Voltage on Network Violating ANSI Standard for Some Part of the Year

Two scenarios of CVR/VVO combination are explored in a 24-hour period by dividing the day into peak and off-peak hours, as illustrated in Figure 3.16. In Scenario 1, CVR is deployed during peak demand hours (i.e.,18-22), and VVO is deployed for remaining (off-peak) hours. In Scenario 2, the opposite operation is performed, i.e., VVO is deployed during peak demand hours and CVR for the remaining hours.

All simulations are performed using the distribution system analysis tool OpenDSS. The BESS real power dispatch profile obtained from economic co-optimization is used to determine available VAR capacity. Voltage dependency of loads is modeled using 30% constant impedance load, 30% constant current load, and 40% constant power load. Monetization of energy savings is performed using ISO-NE 2017 real time LMP data pertaining to the corresponding node. Combined CVR and VVO benefits under Scenarios 1 and 2 are listed in Table 3.6. Since the benefit is higher in Scenario 2, it is used for further economic analysis.

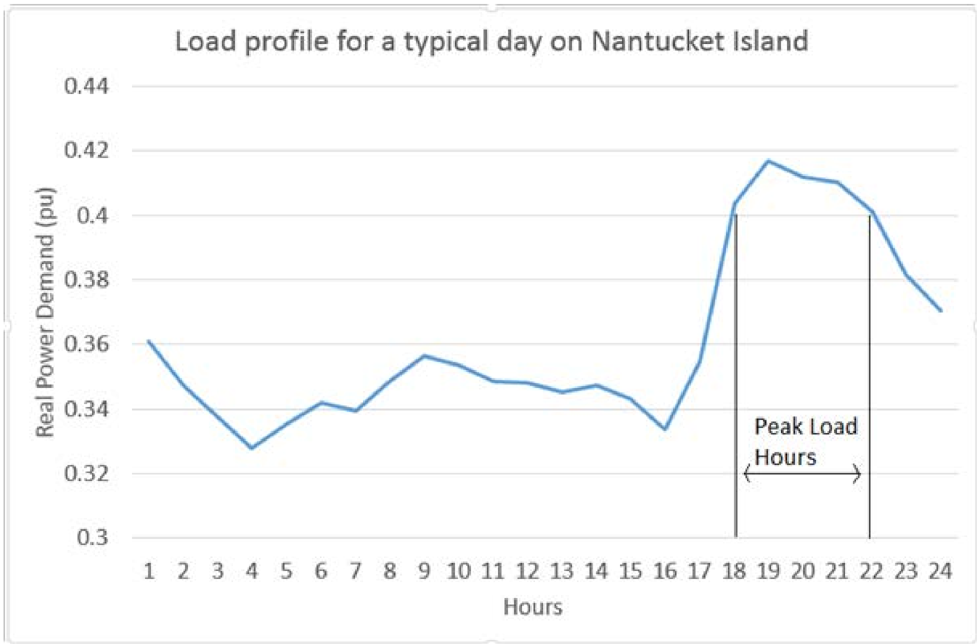


Figure 3.16. Typical Daily Load Profile on Nantucket Island

Table 3.6. Annual CVR/VVO Benefit on Nantucket Island

Scenario-1	Scenario-2
$2,705	$5,372

3.5 Market Operations

ISO-NE has revised its rules governing storage participation to allow for greater participation from energy storage systems. As shown in the flow chart below, energy storage, such as the Nantucket Island BESS, with its rated power capacity of in excess of 5 MW, can register as three forms of an asset: modeled dispatchable generator asset, a dispatchable asset-related demand (DARD) asset, and an alternative technology regulation resource (ATRR). Registering as each of these assets enables continuous storage facility (CSF) participation in the energy, reserves, regulation, and capacity markets. The flowchart in Figure 3.17 demonstrates how to determine what type of program each asset is qualified in which to participate. These rules took effect April 1, 2019 (Peet et al. 2019).

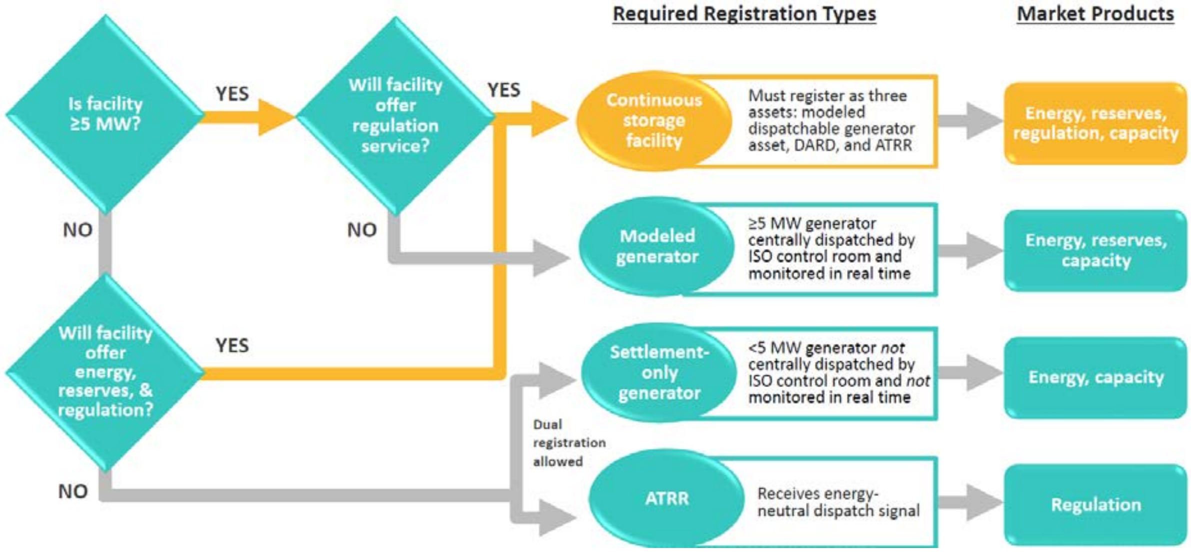


Figure 3.17. Mapping Registration Types to Market Products that Could Be Offered in the ISO-NE Market

To qualify as a CSF, the BESS must meet the following requirements: (1) must be registered as an ATRR that represents the same equipment filed as both a Generator Asset and DARD; (2) must be capable of transitioning between its maximum output and maximum consumption in 10 minutes or less; (3) is precluded from utilizing storage capability that is shared with another Generator Asset, DARD, or ATRR; (4) must follow specific bidding procedures tied to its minimum economic limit, down time, startup time, and minimum downtime; and (5) must be self-scheduled in the day-ahead and real-time energy markets and operate in an on-line state, unless the facility is declared unavailable by the market participant. CSFs cannot participate as a demand response asset and must be directly metered with no load behind the same meter (Peet et al. 2019).

To ensure that the BESS has sufficient reserves to respond to reserve, capacity, and outage events, for modeling purposes we have assigned a 50% SOC floor when the BESS is engaged in market operations. A well-designed control system could enable the BESS SOC to drop below 50% during market operations. Thus, this assumption is conservative. Note also that we assume that the BESS would not be available for market operations of any kind until 2020 due to the time required to register the asset. Further, we assume the BESS could not participate in the forward capacity market until 2024 for reasons specified in the next section.

3.5.1 Forward Capacity Market

The forward capacity market is designed to ensure that ISO-NE has sufficient resources to meet future peak demand for electricity. The asset, which in this case is the BESS, would be bid in for a year-long capacity commitment, spanning from June to May of the following year. The obligation requires daily bidding into the day-ahead energy market to ensure availability during a shortage event.

The capacity payment is equal to the capacity service obligation (CSO) multiplied by the net regional clearing prices. To obtain the capacity value, the BESS must be bid into the ISO-NE energy market on the day of the shortage event. It is the responsibility of the bidder to ensure that the bid enables them to meet any CSO. To mirror the calls on CSOs, PNNL has relied on historic OP4 events called in the ISO-NE market. To be conservative, we have assumed that each event and audit taking place in 2016, a year with an above-average number of events and audits, would occur in the 1-year simulation period.

Forward capacity auction (FCA) regional clearing prices are presented in Table 3.7. Note that the FCA is carried out annually covering future time periods, and thus the clearing prices currently extend through the 2022-2023 time period. From 2023 through 2031, annualized net regional clearing prices presented in Table 3.7 are based on an average of multiple price forecasts obtained by National Grid. These forecasts were extended through 2039 using the average annual growth rate (3.5%) forecast from 2023 through 2031. National Grid will also miss the 2023-2024 FCA because it did not file during the April 12-24 show of interest time window in 2019. Therefore, we assume the first year of FCM benefits accrue in 2024.

Table 3.7. ISO-NE Net Regional Clearing Prices ($/kW-month)

	Net Regional Clearing Price	
Time Period	Actual	Forecast
2019-2020	7.03	
2020-2021	5.30	
2021-2022	4.63	
2022-2023	3.80	
2023		5.81
2024		6.40
2025		7.02
2026		7.56
2027		7.41
2028		7.65
2029		7.88
2030		7.41
2031		7.65
2032		7.91
2033		8.19
2034		8.48
2035		8.77
2036		9.08
2037		9.40
2038		9.73
2039		10.07

The Tesla Nantucket Island BESS could obtain a CSO of up to 6 MW. To obtain the full CSO, the BESS must be online and capable of providing 6MW continuously for the duration of a scarcity event. The SOC of the BESS can be managed in anticipation of scarcity events. If it fails to meet its CSO, the BESS operator would be penalized at the rates outlined in Table 3.8. Monthly base payments would be calculated using Equation 3. A performance payment or penalty would be calculated using Equation 4.

Base Payment =	(Forward capacity clearing price x CSO x No. of months)	(3)
Performance Payment =	(Actual capacity provided during event – ((Load + reserve requirement)/CSO) * Total CSO) * Performance price)]	(4)

The simulation prioritizes participation in the capacity market and demonstrates that the BESS could meet its CSO. Thus, we assume it meets its obligation and no performance payments or penalties are received.

Table 3.8. ISO-NE Pay for Performance Prices

Year	Price
June 1, 2018 – May 31, 2021	$2,000/MWh
June 1, 2021 – May 31, 2024	$3,500/MWh
June 1, 2024 – May 31, 2025	$5,455/MWh

3.5.2 Arbitrage

Arbitrage is the practice of taking advantage of differences between two market prices. In the context of energy markets, a BESS can be used to charge during low-price periods (i.e., buying electricity) in order to discharge the stored energy during periods of high prices (i.e., selling during high-priced periods). The economic reward is the price differential between buying and selling electrical energy, minus the cost of RTE losses during the full charging/discharging cycle and losses during rest. The Tesla BESS could provide up to 48 MWh of energy, though not more than 6 MWh of energy in any given hour. Under the new CSF participation model, the BESS would be eligible to set price as supply and demand, assigned the nodal LMP for its supply and demand.

The BESS could participate in both the day-ahead energy market (DAM) and/or real-time market (RTM). We obtained hourly DAM and RTM data for the Candle Street node (ID:16255) in the ISO New England service territory. Data were collected for years 2016 to 2018. DAM clearing prices are based on the supply offers by the energy providers and the demand bids by the load serving entities. RTM clearing prices are based on dynamic market conditions throughout the day and are, therefore, more volatile. Table 3.9 presents descriptive statistics for the DAM and RTM data for the Candle Street node. RTM data fluctuates between -$156 and $2,513 per MWh over the three years, while the DAM data varies only from $0-$387. The standard deviation for the RTM is higher in all three years as well.

Table 3.9. Summary Statistics for Day-Ahead and Real-Time LMP Comparison

	Day Ahead LMP ($/MWh)			Real Time LMP ($/MWh)		
	2016	2017	2018	2016	2017	2018
Min	0	1.02	1.77	-156	-126	-135
Max	242	236	387	1459	696	2513
Median	25.6	28	34.8	23.9	26.2	31.8
Mean	30	33.4	46.2	29.1	34.1	43.8
Standard Deviation	16.5	21.9	35.3	34.6	31.4	49.2

Figure 3.18 presents hourly LMP data for both the RTM and DAM for the month of December 2018. It can be seen that the RTM price data are much more volatile. While this presents opportunities for arbitrage revenue using the BESS, predicting those swings is challenging and fraught with risk. The price range during the month is tighter in the DAM, which is denoted by the blue color, when compared to the RTM data shown in orange.

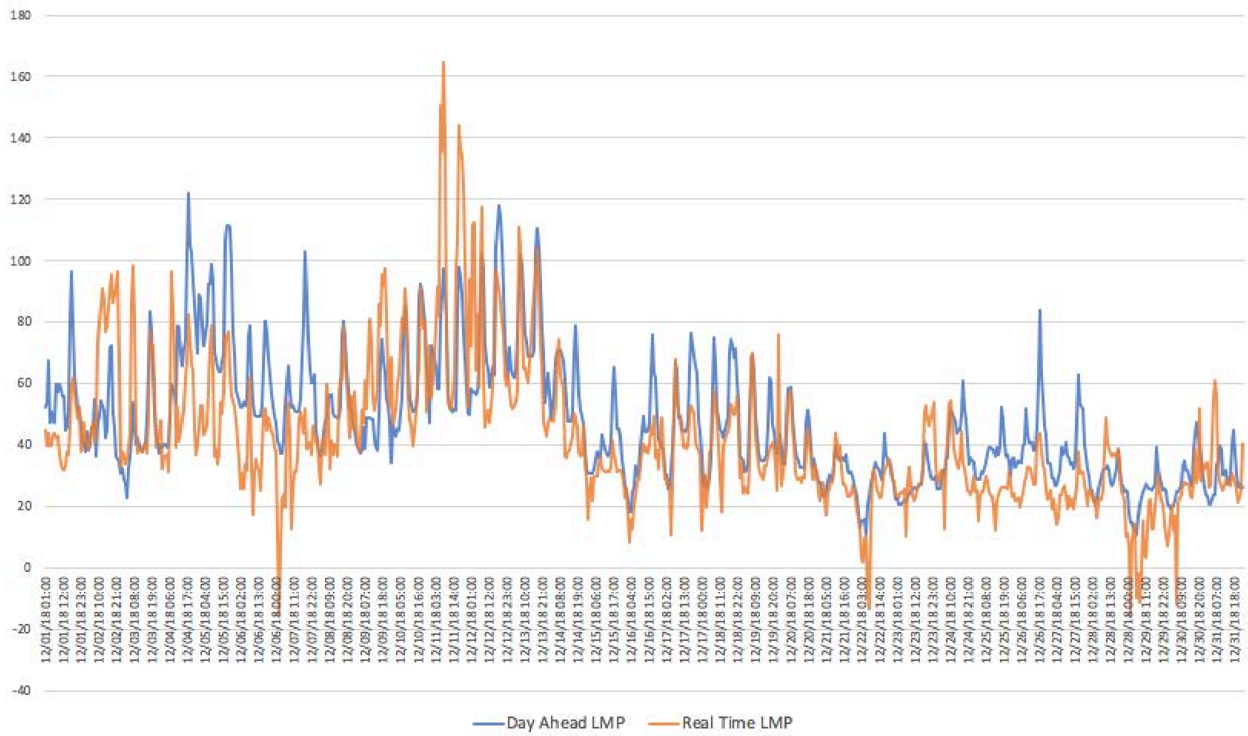


Figure 3.18. Day Ahead and Real Time LMP by Hour in December 2018

3.5.2.1 Accounting for Prediction Error

Most economic assessments of energy storage rely on an assumption of perfect foresight while declaring that such an assessment, which uses historical price data, represents an upper bound on the value that could be obtained from storage. In this section, we describe an approach for accounting for prediction error.

Ideally, in order to optimize benefits from the Tesla BESS being deployed on Nantucket Island, an operator would minimize prediction error in future energy market clearing prices. This would help identify opportunities and prepare the battery optimally for participation in the DAM as well as the RTM. However, since perfect foresight is unrealistic, we have evaluated avenues for developing energy market clearing price predictions. The objective of our analysis is to identify and compare the different methodologies for predicting the RTM and DAM LMPs, without the assumption of perfect foresight, in order to evaluate the sensitivity of the benefits associated with the prediction error from these methods. There are, thus, two parts to this analysis:

1. Forecasting the RTM LMP. In this situation, we only know the day-ahead LMP or DALMP and real-time LMP or real time LMP (RTLMP) for any previous period of time.
2. Forecasting the DAM LMP. For this, we assume we have knowledge of all the past day ahead LMPs (DALMPs) from Jan 1, 2015 onwards.

3.5.2.2 Model Background

For the RTM, we first explored four simple approaches for estimating RTM LMP. We assume that it would be the same as the DAM LMP for that hour, previous day's RTM LMP, last week's RTM LMP, and last year's RTM LMP for the same day. The best performing metric in terms of the least root mean square error (RMSE) was DAM LMP, as shown in Figure 3.19. The DALMP in the energy market, as explained in the previous sections, can give a sense of the expected RTLMP. This is because the DAM is a financial market clearing bids that reflect expectations for the next day's market operations.

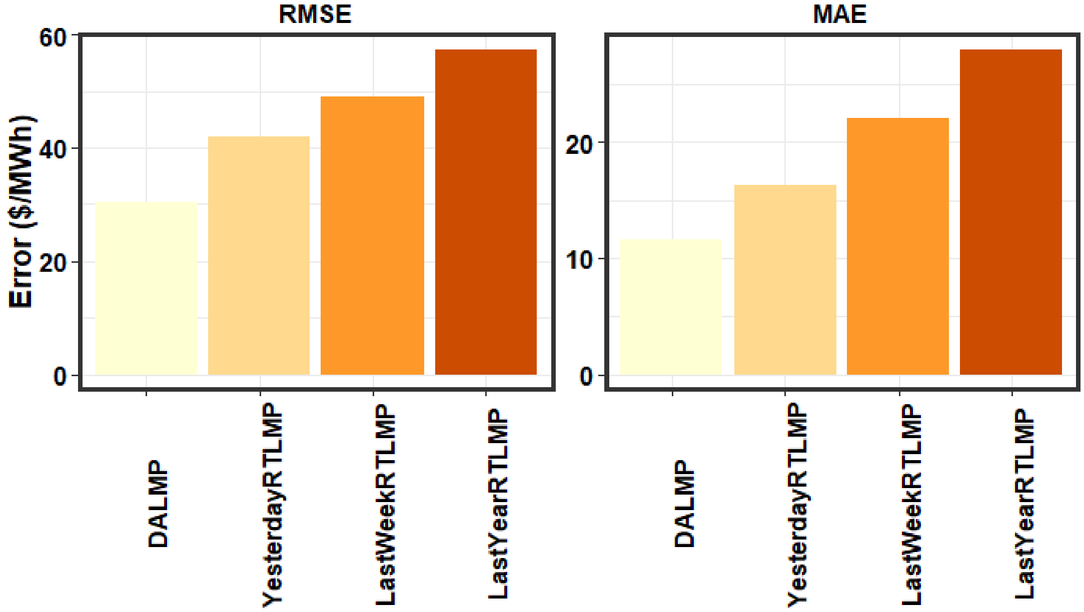


Figure 3.19. Root Mean Square Error Comparison for the Naïve Predictors of RTLMP

For the DAM, the three elementary approaches we employed were to assume that a price in any given hour would be the same as the DALMP for the same hour last day, DALMP for the same hour of the same day last week, or DALMP of the same hour of the same date last year. Here, the last day DALMP for that hour was able to have the least RMSE, as shown in Figure 3.20. Any econometric model that we look at for predictions would only be useful if it performs better than our naïve approaches.

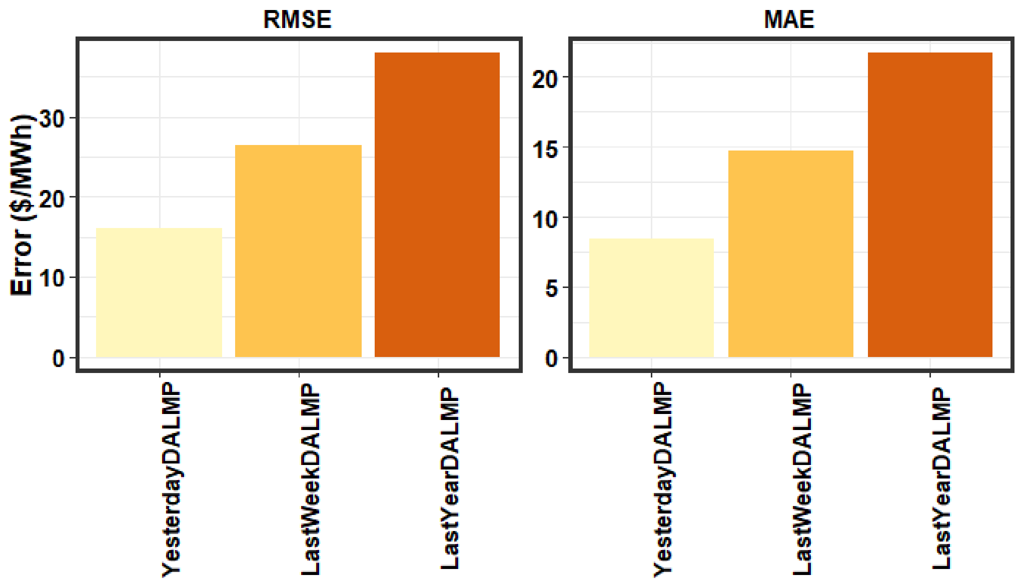


Figure 3.20. Root Mean Square Error Comparison for the Naïve Predictors of DALMP

We then explored several more complex predictive models. Models explored for this assessment included:

1. ARMA Model: ARMA stands for Autoregressive Moving Average. This is a general form time series model that assumes that the time series outcomes are explicitly correlated over time, i.e. LMP in this time period is dependent on LMPs in previous time periods. In addition, the average of the LMP in the current period is treated as a weighted sum of past noise.
2. ARIMA Model: ARIMA is the same as ARMA but with the feature to model an “integrated” time series. An integrated series is not a stationary series, i.e., there is a drift in the average of the predicted variable, which is LMP in this case.
3. ARIMAX Model: The aforementioned methods do not allow usage of an external regressor. Thus, to avoid chances of underfitting, we used the ARIMAX model, which is ARIMA with external regressors.
4. Random Forest Model (RFM): the random forest technique is an ensemble method in which a random subset of predictors and a random subset of data are used to grow decision trees. This sub-setting makes the algorithm good at finding interactions while also avoiding overfit.
5. Gradient Boosting Machine (GBM): A decision tree is iteratively improved using the gradient method to fit first one model, then its residuals, and so on.
6. XGBoost (eXtreme Gradient Boosting): A more specific implementation of above, where a more sophisticated regularization metric is introduced to punish model complexity (and reduce overfit).

After testing each model, the two approaches that were used to generate final predictions for DAM LMP and RTM LMP are ARIMA and GBM. GBM when fed with ARIMA and DALMP was able to perform the best and had the lowest RMSE for the RTM. For the DAM, it was the GBM fed with DAM LMP for the same hour last day, ARIMA predicted DAM LMP, ARIMA predicted RTM LMP, and temperature, which form the major components of the model. These results are discussed in detail later in this report. The theoretical approaches of ARIMA and GBM are discussed below.

3.5.2.3 ARIMA

As discussed, ARIMA(p,d,q) models are a general form of time series model capable of modeling autoregressive and integrated time series data, which is also expected to have a moving average over time. The key assumption underlying the model is still that all unobserved shocks, after we have accounted for the nature of time series, are Gaussian white noise. The three components of the model have their individual representation and can be modelled together in an ARIMA process. These are:

1. AR(p) model, that is, an AR model of degree p, involves p lags of the dependent variable, and is written as:

$$y_t = \beta_1 y_{t-1} + \beta_2 y_{t-2} + \cdots + \beta_{p-1} y_{t-p+1} + \beta_p y_{t-p} + u_t = u_t + \sum_{j=1}^{p} \beta_j y_{t-j} \quad (5)$$

   where β_t stands for the estimated parameter for the dependent variable lagged *t* times, and u_t is the error in predicting the dependent variable at time *t*.

2. MA(q) model, that is, an MA model of degree q, involves q lags of the current white noise as well as noise in the prior periods, and is written as:

$$y_t = \varphi_1 u_{t-1} + \varphi_2 u_{t-2} + \cdots + \varphi_{q-1} u_{t-q+1} + \varphi_q u_{t-q} + u_t = u_t + \sum_{j=1}^{q} \varphi_j u_{t-j} \quad (6)$$

   where φ_j stands for the estimated parameter for the error lagged *j* times, and u_t is the error in predicting the dependent variable at time *t*.

3. ARIMA(p,d,q) models consist of an "integrated" term, which is an average trend over time. The 'd' is the number of times data has to be differenced to make it stationary. If the model is integrated of order 1, the ARIMA model equation becomes:

$$\Delta y_t = \Delta u_t + \sum_{j=1}^{p} \beta_j \Delta y_{t-j} + \sum_{j=1}^{q} \varphi_j \Delta u_{t-j} \quad (7)$$

   where Δy_t is the first order difference for the predicted variable at time *t*.

We used the function "auto.arima" in R to optimize the ARIMA model. This function tries to find the best fit without over parametrizing. This gave us an optimal ARIMA model with p=5, d=1, and q=1, which was later incorporated into the GBM, for both the real time and day ahead energy market.

3.5.2.4 GBM

The Gradient Boosting Machine method, or GBM, is a machine learning method where a weak model is iteratively upgraded into a strong one by minimizing the loss function, in this case simply the mean square error. The model builds a tree, and then looks at the residuals. The residuals are used to build another tree in order to minimize the loss function, which is added. This is done iteratively, with the number of iterations being a tuning parameter, which we set to 50. The stochastic implementation we used avoids overfit by taking a different random subset of the data to build the tree during each iteration.

3.5.2.5 Validation

To validate the models, predictions were made one day ahead while training on all previous data. The RMSE reported are for out of sample predictions and thus are a fair evaluation of model performance. Out of sample predictions involved division of the data into training set and validation set. The parameters evaluated from the training set were used to predict the validation set and verify if the model was doing well in this “out-of-sample” forecasting. To make the model more robust, time slicing was performed to incorporate each previously predicted data point from the validation set into the training set, iteratively. No future observation is used to form the training set, which results in reliable time series cross-validation results.

Note that for random forest, one week was predicted at a time instead of one day, due to computational time limits. This model was ruled out, without any further improvements in granularity, because there was decreasing improvement in prediction power with decreasing predicted time span. At one-week iterative prediction, it was still reporting a significantly higher RMSE than DAM LMP to be able to improve considerably with a shorter time span prediction.

3.5.2.6 Predictors

The GBM, XGBoost, and RandomForest algorithms are all good at avoiding overfit, and hence many predictors could be tested as inputs. The most obvious predictors used were the DALMP (for predicting RTLMP) and decomposing the date time into the hour of the day, the day of the week, the day of the year. Whether a day was a weekend or a holiday was also considered. Furthermore, we also used predictions of RTLMP and DALMP from ARIMA, ARIMAMAX, and SARIMAX as inputs. Finally, some other predictors from outside the original dataset were implemented. Weather data for temperature and wind were scraped from WeatherUnderground, giving the hourly weather (Weather Underground 2019). The temperature was scaled to mean 0 and standard deviation 1, then squared and cubed to be used as predictors. Due to Nantucket’s large reliance on the tourist industry, air traffic data was also scraped and used as a predictor in order to gauge periods of high tourist activity. Ultimately however, only DALMP, ARIMA, and temperature were deemed useful for the final model, and hence, retained.

3.5.2.7 Results and Conclusions

RTM LMP Forecast

All the methods discussed previously were evaluated across 2017 and 2018, through out of sample prediction, after being allowed to learn from 2015 and 2016. Results are presented in Figure 3.21. The GBM method outperformed the others with an RMSE of $30.3/MWh, and barely beat the DAM LMP prediction of RTLMP, with an RMS of $30.5/MWh.

As highlighted in Figure 3.22 and Figure 3.23, the GBM daily out of sample prediction seems to be doing better than the DAM LMP prediction, overall. However, the times when it doesn’t do well are the times when the RTM LMP suddenly spikes, increasing by more than 14-20 times the previous value. Such spikes, which are not Gaussian white noise, are uncharacteristic of a traditional time series data and that explains why the model doesn’t do well in these short bursts of times. Because these changes have a significantly larger magnitude, they increase the RMSE dramatically, even though GBM performs better than the DAM LMP for the most part.

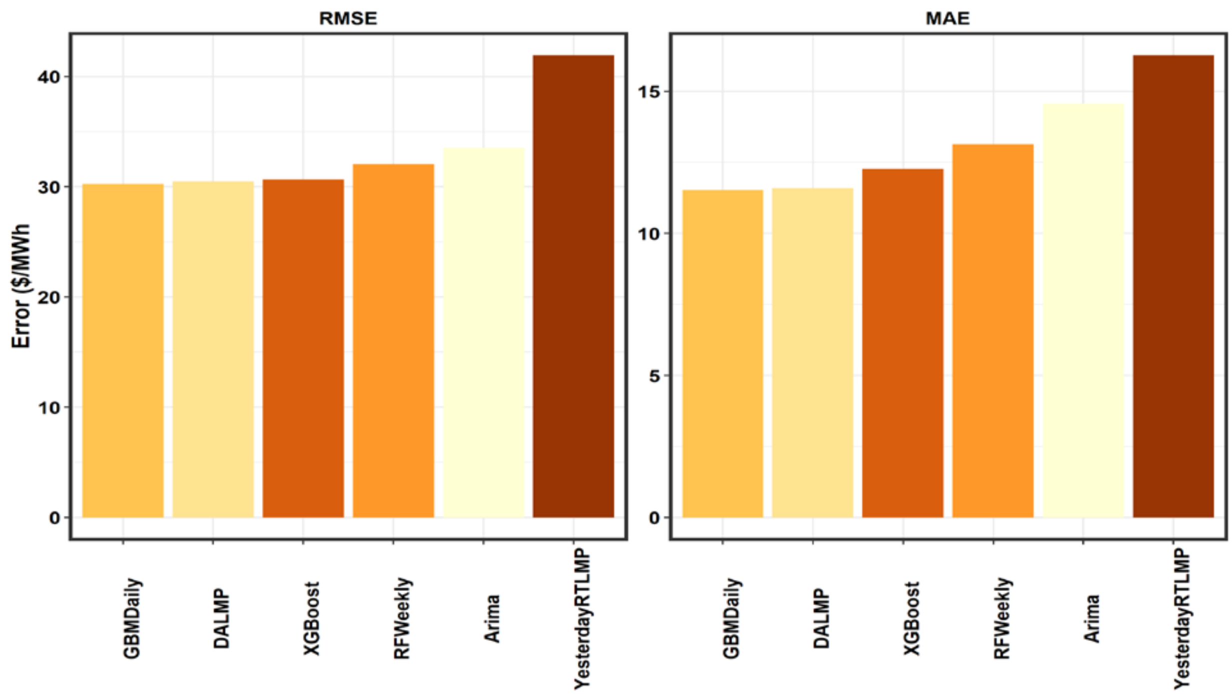


Figure 3.21. Error Comparison of RTLMP Prediction for Various Algorithms

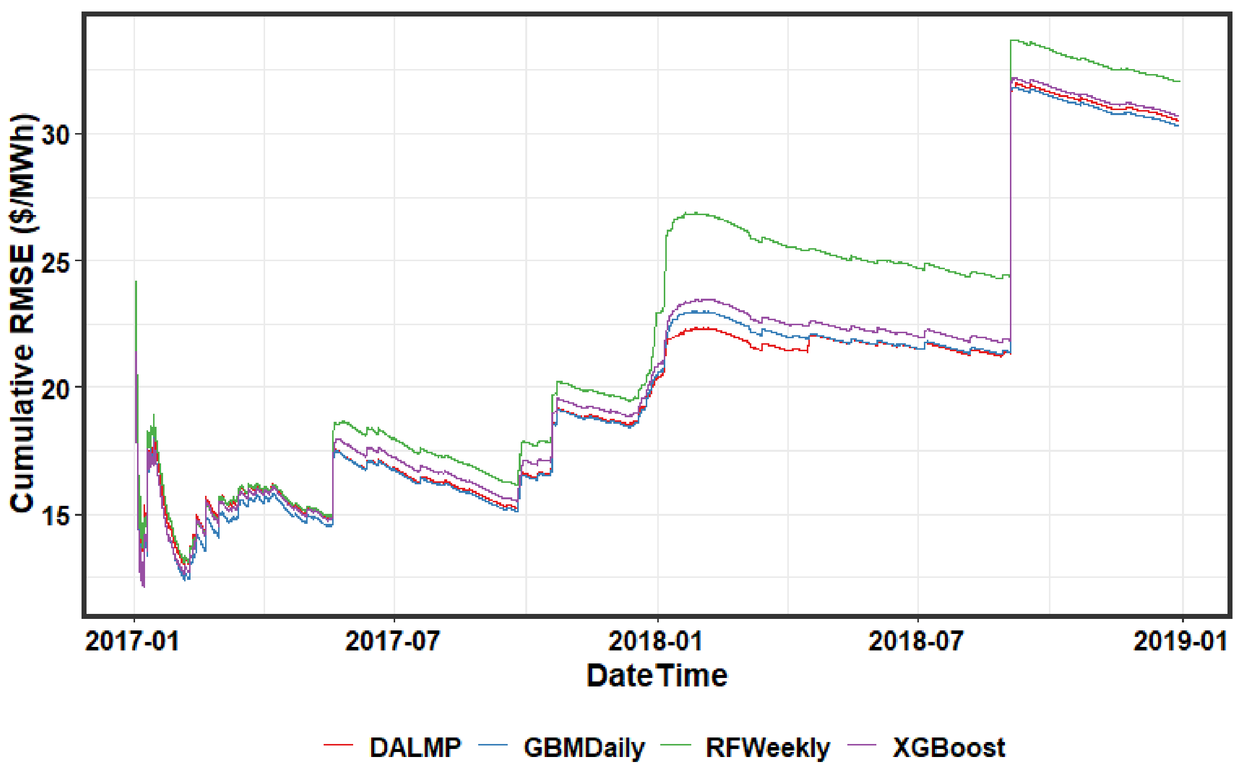


Figure 3.22. Cumulative RMSE vs Time for Various Methods

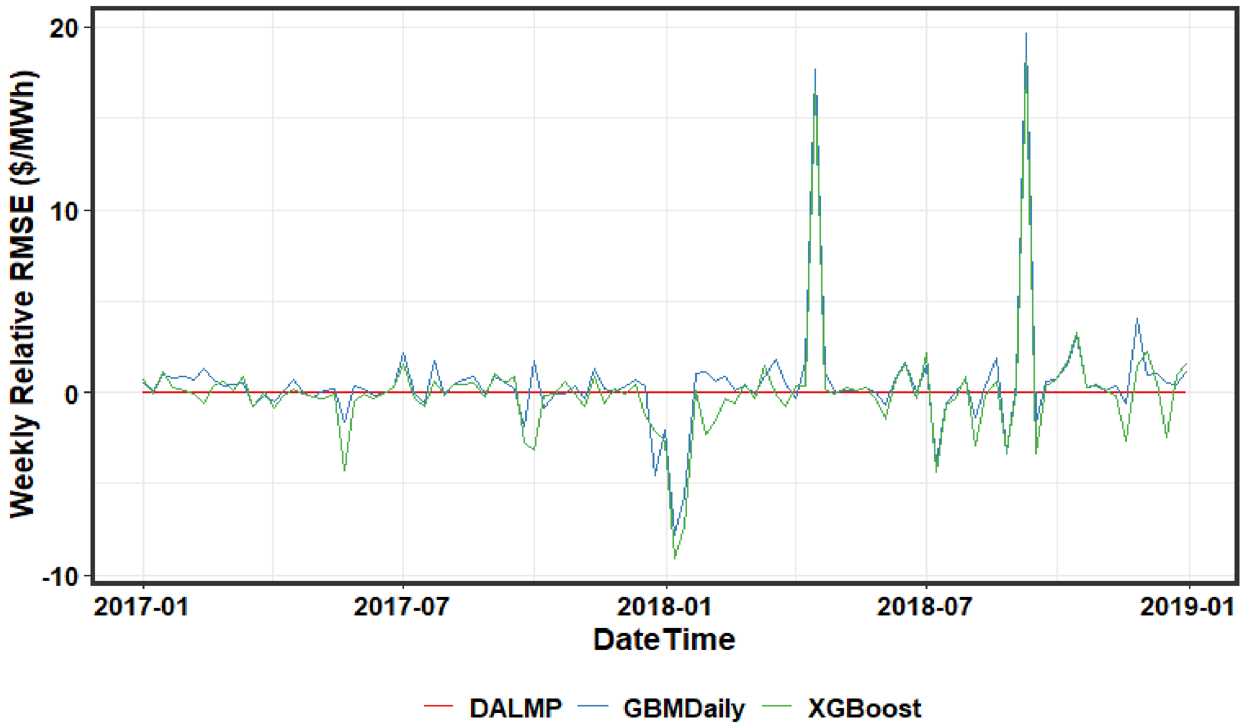


Figure 3.23. Weekly RMSE of Various Methods Subtracted from the DAM LMP Weekly RMSE

When fed with all the predictors discussed in Section 3.3, for predicting the RTLMP, GBM mostly utilized DALMP and ARIMA with almost no support from other expected predicting variables. This result is likely since the effect of temperature, weekdays, holidays, seasons etc. is expected to be incorporated in the DALMP and the predictors do not add any new information to the model. Since ARIMA is able to account for the time series variation not accounted for by the DALMP, it is incorporated in the GBM model, to some extent. The individual contribution of the predicting variables is highlighted in Figure 3.24.

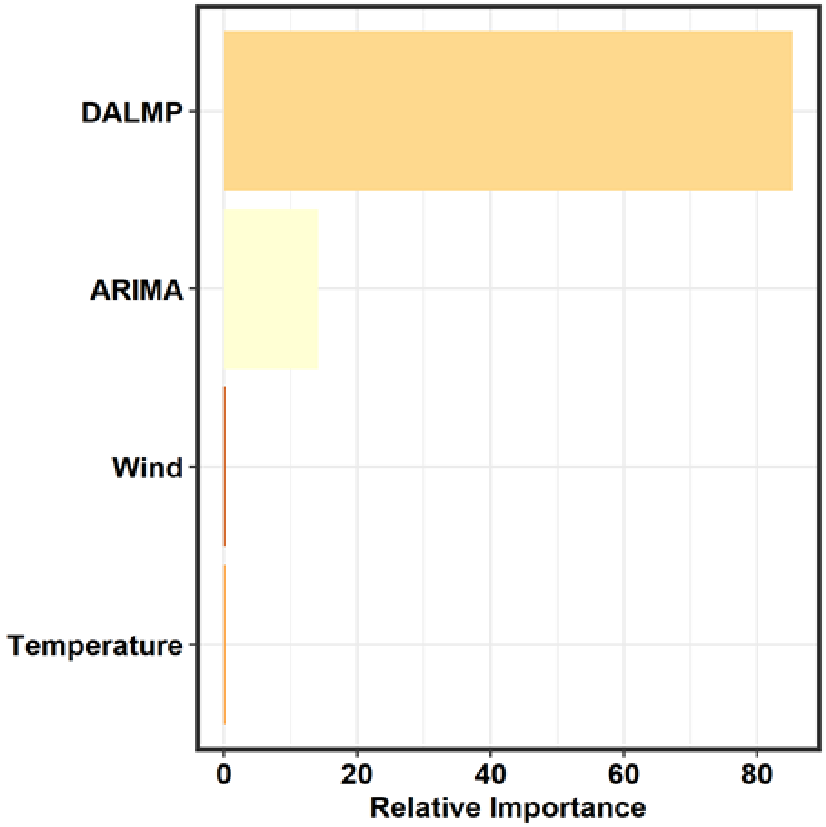


Figure 3.24. Relative Importance of Predictors in the GBM Predicting RTLMP

DAM LMP Forecast

For the DAM LMP predictions, we repeated the process of modelling using various time series and predictive models, and again, GBM was able to perform better than any other model, as highlighted in Figure 3.25. There was an improvement in RMSE, when compared to yesterday's DAM LMP as well, owing to the fact that there is much less unexplained variation in DAM LMP and thus, it can be modeled better.

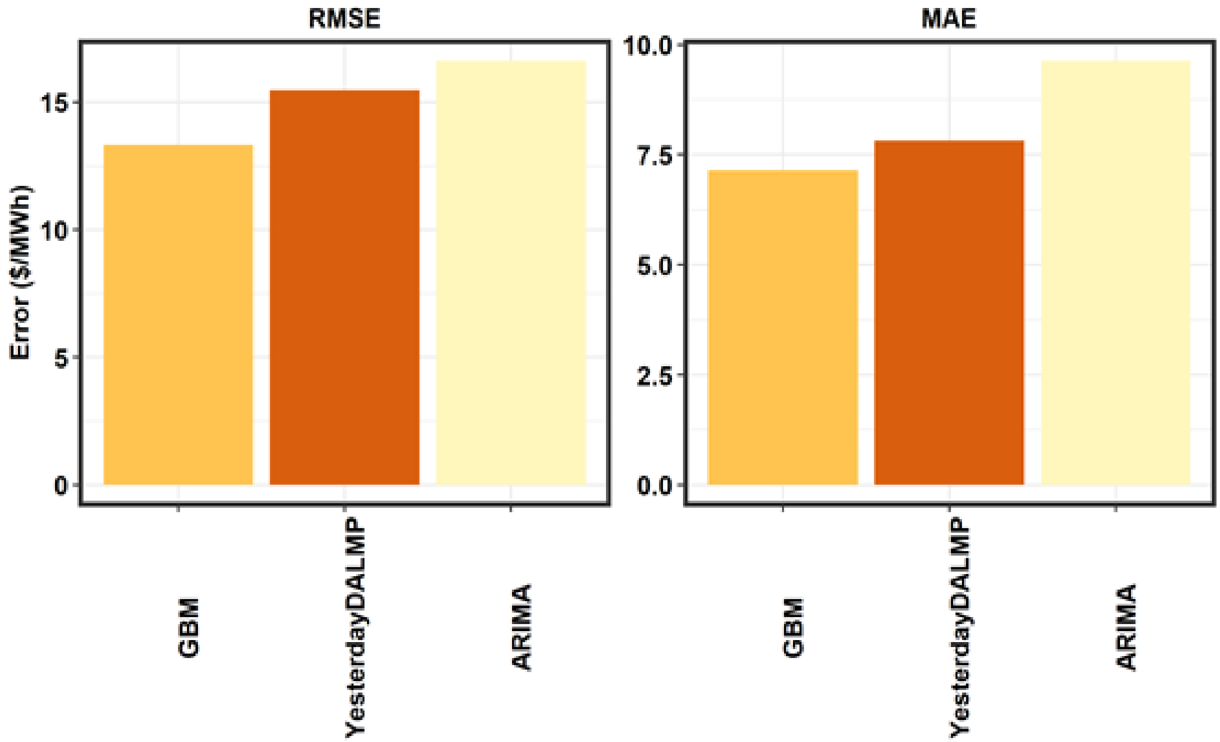


Figure 3.25. Error Comparison of DALMP Prediction for Various Algorithms

Figure 3.26 and Figure 3.27 show that the GBM is able to perform consistently better in its out of sample predictions and in the absence of sudden spikes, maintains its edge over other predictive methods in both the day ahead and week ahead predictions.

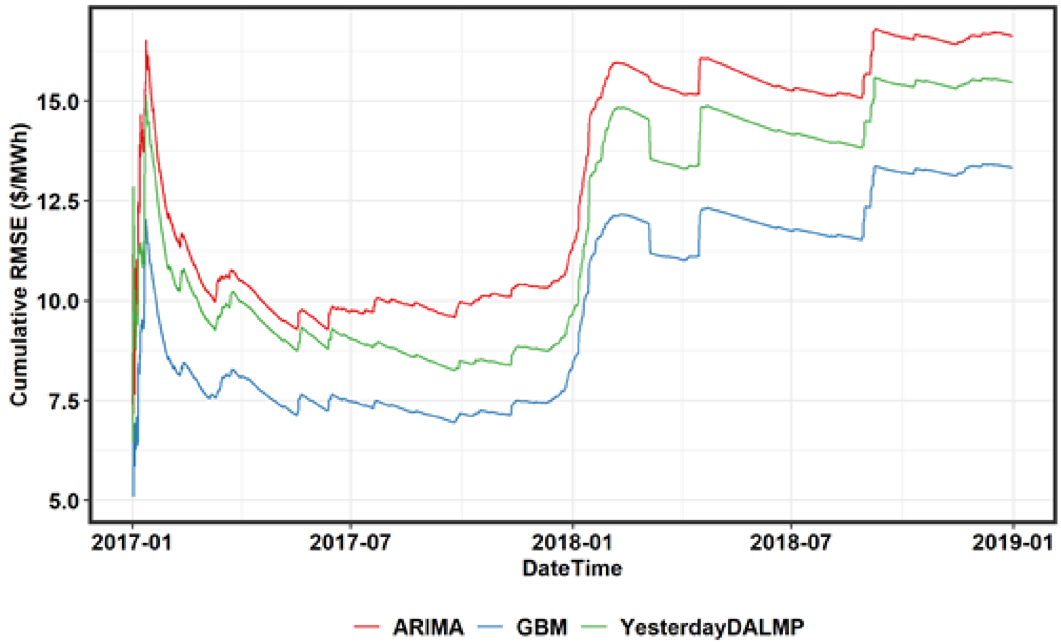


Figure 3.26. Cumulative RMSE vs Time for Various Methods

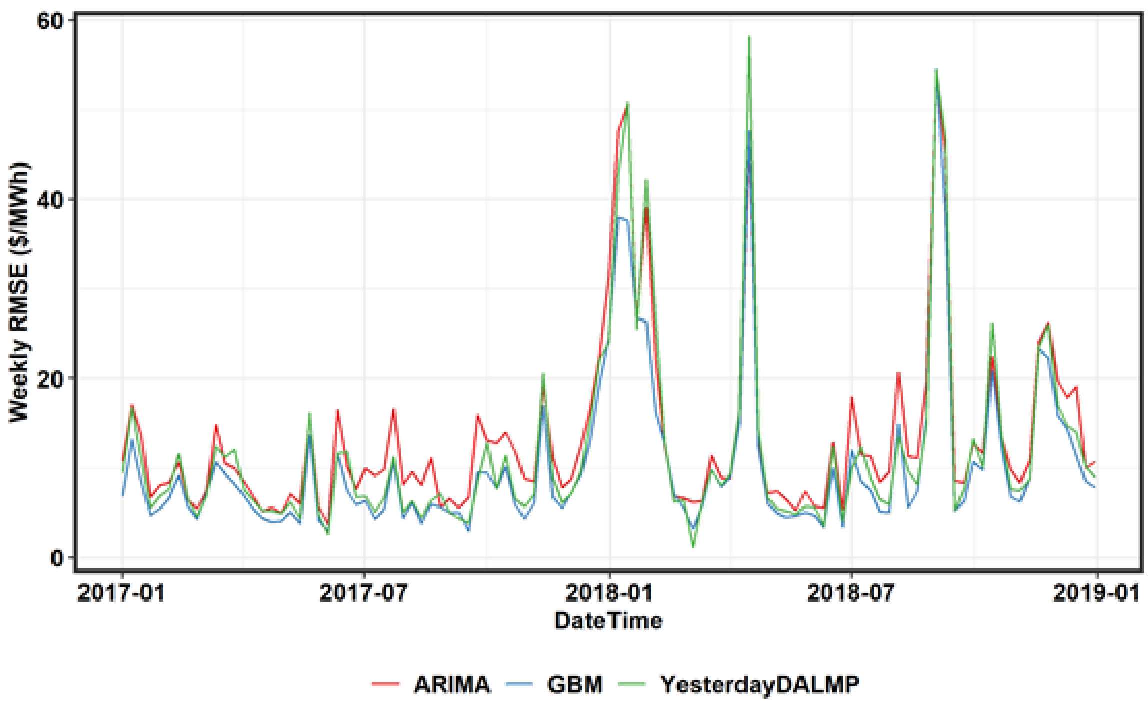


Figure 3.27. Weekly RMSE of Various Methods

When the GBM for DAM LMP predictions was fed with all the predictors discussed previously, GBM again mostly utilized yesterday's DALMP and ARIMA. This time, it also took support from predicted DAM LMP using ARIMA, predicted RTM LMP using ARIMA, as well as the temperature data. The reason for this is that since we do not have any baseline predictions for the DAM LMP, most of the variation due to temperature, hour of the day, and other predictors is not incorporated into the model yet. Since ARIMA is able to account for the time series variation not accounted for by yesterday's DALMP, it is incorporated in the GBM model. The individual contribution of the predicting variables is highlighted in Figure 3.28.

These predictions were, in turn, fed into our economic model. We bid into the ISO-NE market based on these predictions under several scenarios but revenue is tied to actual market clearing prices.

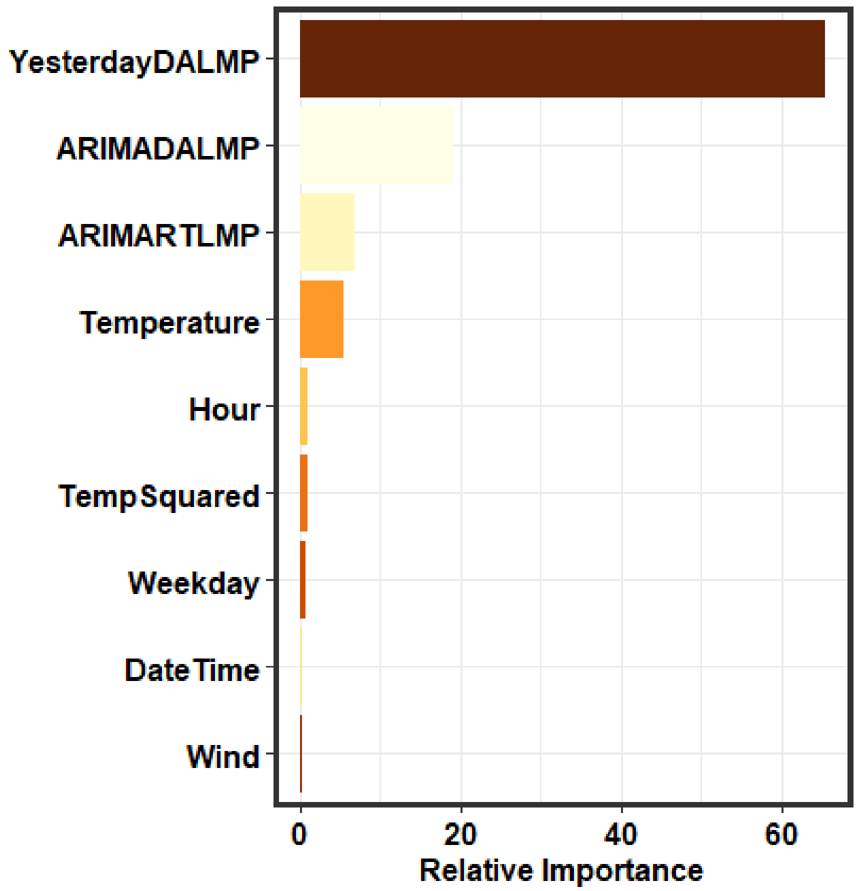


Figure 3.28. Relative Importance of Predictors in the GBM Predicting DALMP

3.5.3 Regulation

The electric power system must maintain a near real-time balance between generation and load. Balancing generation and load instantaneously and continuously is difficult because loads and generators are constantly fluctuating. Minute-to-minute load variability results from the random turning on and off of millions of individual loads. The services needed to meet such a balancing requirement are referred to as "ancillary services," which are necessary to generate, control, and transmit electricity in support of the basic services of generating capacity, energy supply, and power delivery.

Regulation service is required to continuously balance generation and load under normal conditions. Regulation is the use of online generation, storage, or load that is equipped with automatic generation control (AGC) and that can change output quickly to track the moment-to-moment fluctuations in customer loads and to correct for the unintended fluctuations in generation. Regulation helps to maintain system frequency, manage differences between actual and scheduled power flows between control areas, and match generation to load within the control area. Regulation service has been identified as one of the best “values” from energy storage for increasing grid stability because of the high cost of regulation services.

FERC Order 784 requires transmission providers to consider both speed and accuracy in the determination of regulation and frequency response requirements, and FERC Order 755 ensures that providers of frequency regulation are paid just and reasonable rates based on system performance. In providing frequency regulation, organizations are required to include both a capacity payment that considers the marginal unit’s opportunity cost and a pay for performance component based on the mileage or the sum of the up and down signal followed by the provider. ISO-NE market participants are compensated for the regulation capacity and regulation service or mileage provided by the BESS. The service payment is equal to the product of the mileage, regulation service clearing price, and performance score.

Because the research team does not possess detailed performance data for the Tesla BESS, we undertook a literature review to establish a reasonable performance score for a modern lithium-ion BESS. In agreement with the foundational basis of FERC Order 784, the literature does indicate that batteries perform better than traditional generators in providing frequency regulation. For example, Chakraborty et al. (2018) tracked the performance score for a BESS powered by wind energy and found that when the BESS was committed to providing AGC 100% of the time during the 29-day test period, its performance score was 93.2%. This was higher than resources powered by fossil fuels.

Several research studies have used PJM metrics and calculation methods to calculate performance scores for BESSs. From their own RegD AGC signals for resources that responded rapidly, like batteries, they reported an average performance efficiency between 94% and 95% (Benner 2015). This observation is supported by Benn (2014), which refers to the Midcontinent Independent System Operator (MISO) tracking energy storage’s response to the AGC signal with 4-second variations (Benn 2014). Benn (2014) reported that when the ramp rate is high enough, the hourly performance test results for flywheels and BESSs were close to perfect (99.9% performance efficiency) for the year 2015. These results were obtained in ideal conditions and not in field operation. Nguyen (2017) used 2014 results for MISO but adjusted for constraints, yielding performance scores closer to 95%.

Watson et al (2018) further tested a sodium-nickel chloride battery for performance scores and found the PJM performance scores to be above 90% while also providing other services. However, since this type of battery’s charge rate is limited, accuracy is affected at a higher SOC. Xu et al. (2018) simulated an energy neutral AGC signal to test the optimal control policy and optimal bidding policy for a BESS participating in a performance-based regulation market. The simulated battery efficiency was set to be between 100% or 92% for their policy testing, with those values not being an outcome of their tests but rather inputs based on previous test results. Similarly, Avendano-Mora et al. (2015) used 95% based on previous test results.

Based on our review of the literature, we have used 95% as the expected performance score for the Tesla lithium-ion battery. Findings of the relevant literature are summarized in Table 3.10.

Table 3.10. Performance Score as Reported in Literature

Study Year, Authors	Study Type	Trial Period	Performance Efficiency Average	Maximum	Minimum
2014, Benn	Ideal Testing Conditions with No Constraints	Year- 2015	99.9%	-	-
2015, Avendano-Mora et al	Energy Storage Performance Review	-	95%	-	-
2015, Benner	Actual AGC Tracking	Year- 2013	94% - 95%	97.7%	-
2018, Chakraborty et al.	Actual AGC Tracking	29 Days	-	93.2%	33.9%
2017, Nguyen et al.	MISO (2014) Results Adjusted for Constraints	Year- 2015	95%	-	-
2018, Watson et al.	Actual AGC Tracking	July-November 2015	91.47%	94.9%	84.3%
2018, Xu et al.	Simulation AGC Tracking	100 Simulated Regulation Signals	-	100%	92%

As a CSF, the Nantucket BESS can simultaneously provide energy, regulation, and reserve services. If, for example, a 10 MW BESS identifies an economic maximum limit for the energy market of 6 MW in its bid to ISO-NE, it could have a regulating range of 8 MW (+4 MW to -4 MW) (ISO-NE 2018). This case is illustrated in Figure 3.29. In this case, the BESS would be compensated for providing 10 MW of energy and 4 MW of regulation capacity. ISO-NE allows for CSFs to follow an energy neutral dispatch signal; ISO-NE establishes multiple signals that if aggregated equal the region's AGC signal. ISO-NE rules indicated that the AGC signal can include a small bias towards charging to account for efficiency losses. For example, the operation outlined in Figure 3.29 could be altered to have a regulation high limit of 3.2 MW and a regulation low limit of 4.0 MW, thus establishing a bias towards charging to account for efficiency loss. In our formulation, we follow the energy neutral signal without bias.

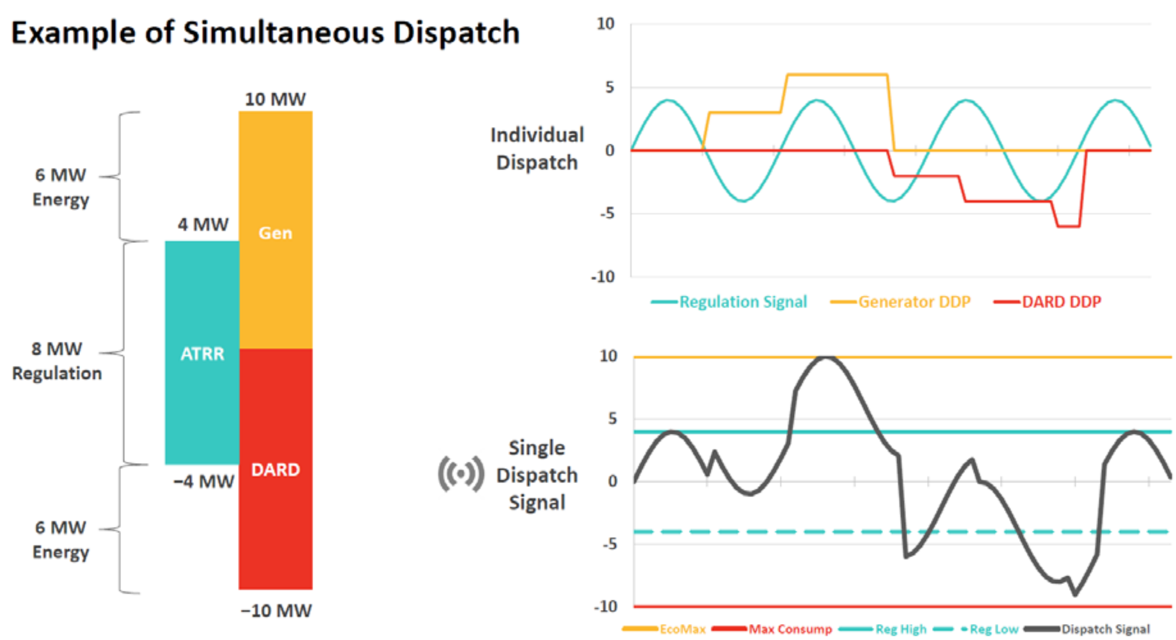


Figure 3.29. Simultaneous Dispatch of a CSF in the ISO-NE Market

For this study, regulation prices were obtained from the ISO-NE market database for the time period 2016-2018. Regulation prices represent systemwide regulation pool prices. The amount of regulation services in each hour is limited by both the power and energy capacities of the Tesla BESS. Such constraints have been modeled in the optimal scheduling process. When regulation services are being called, the BESS needs to charge/discharge in order to follow an AGC signal. Charging and discharging operations affect the BESS SOC.

Two datasets pertaining to the regulation market were retrieved from the ISO-NE website:

- Energy Neutral AGC Dispatch data: This dataset contains simulations of four-second AGC setpoints. The AGC setpoint data is based on some representative conditions such as system conditions, resource characteristics, and AGC dispatch methodologies, which are essential to normal AGC dispatch.
- Hourly Regulation Clearing Prices (RCP): This dataset contains final hourly regulation clearing prices from 30th Nov. 2010 up to 6th Feb. 2019. However, the regulation clearing price starting from March 31, 2015 is decomposed into the regulation service clearing price (RSCP) and regulation capacity clearing price (RCCP). RCSP is the price of the highest regulation service offer provided amongst the resources in the specific interval and RCCP is the price that warrants recovery of the energy opportunity costs, regulation capacity costs, and resource-specific incremental cost savings. All these figures are in $/MW units.

The final decomposed hourly regulation clearing prices are further broken down into five minute intervals starting November 30, 2017. To compile the data and keep it consistent, the average of the five-minute intervals was obtained to maintain a database of hourly RCPs.

The hourly RCP has been increasing both in terms of magnitude and standard deviation from 2010 to 2019. Table 3.11 summarizes the RSCP and RCP in the dataset. Note that while the maximum bids are capped for the RSCP and RCCP at $10/MWh and $100/MWh, respectively, prices have climbed as high as $2,331.55 per MWh due to the opportunity cost component of the market clearing price. These high prices reflect price spikes in the RTM that drive up the value of the next best alternative use of the market asset.

Table 3.11. Summary Statistics of the Regulation Clearing Price Data

Year	RSCP ($/MWh)	RCCP ($/MWh
Min	0	0
Median	0.15	17.64
Max	10	2,331.55
Mean	.34	27.86

3.5.4 Spinning Reserves

Spin reserve is provided by power sources already online and synchronized to the grid that can increase output immediately in response to a major generator or transmission outage, and can reach full output within 10 minutes. For generators, the spinning reserve is the extra generating capacity that is available by increasing the power output of generators that are already connected to the power system. Unlike regulation service that is exercised from hour to hour, spinning reserve is not called upon unless the contingency occurs. As the frequency of contingency events is very low, for the purposes of this analysis, it is assumed that the Nantucket BESS will not be called on while providing spin reserve services.

CSFs can provide 10-minute spinning reserves in the real-time reserve market. As a generator asset reserves counted from current MW to economic maximum parameter. The economic maximum is constantly recalculated and a participant must bid an economic minimum of 0 MW. For a DARD asset, the reserve is counted from current MW to minimum consumption based on the absolute value of the telemetered output. CSFs are required to always be operational and online unless declared unavailable (ISO NE 2019). Thus, they are always available to provide spinning reserves and can do while also providing regulation service.

Hourly real-time hourly reserve data for the 2016-2018 Massachusetts rest of system reserve area were obtained and used to establish reserve prices used in this assessment.

3.6 Valuation Modeling Approach

PNNL modified its battery storage evaluation tool (BSET) to run a one-year simulation, evaluating the benefits of BESS operation when offering local- and market-based services. Note that we assumed that the CTG would not be bid into the ISO-NE market due to noise and emission concerns. The services explored in this chapter were defined by PNNL in partnership with National Grid. For each service, revenue or avoided costs were defined on at least an hourly basis using the methods outlined in this chapter, and those values were matched with corresponding capacity and energy requirements. BSET was then used to co-optimize the benefits among these services, subject to the technical constraints of the BESS, over a one-year simulation period. In this control strategy, at each hour, a look-ahead optimization was first formulated and then solved to determine the battery base operating point. The minute-by-minute simulation was then performed to simulate the actual battery operation. Model output includes the value assigned to each service and the number of hours each year the BESS would be optimally engaged in the provision of each service. The remainder of this section details the formulation used to model the BESS in BSET.

3.6.1 Objective and Constraints

This section briefly describes BESS operational constraints and grid service requirements, as well as the revenue calculation, which are used to formulate the BESS optimal dispatch problem. A detailed notation is provided in Appendix B.

3.6.2 BESS Operation Model

In this work, constant charging and discharging efficiencies are used to capture the losses from the battery and energy conversion system. To capture temporal interdependency of BESS operation, the dynamics of BESS energy state is modeled in (8).

$$\mathrm{Energy}_{h+1} = \mathrm{Energy}_h - \frac{\mathrm{Power}_h^+}{\eta^+} + \eta^- \mathrm{Power}_h^-, \quad \forall h \tag{8}$$

where Power_h^+ and Power_h^- are introduced to capture different losses in discharging and charging operation. In this work, the lower bound of energy state is set to be 50% of energy capacity in order to ensure that the BESS is available for capacity, reserve, and outage events, as expressed in (9).

$$0.5 \cdot \mathrm{Energy}^{\max} \leq \mathrm{Energy}_h \leq \mathrm{Energy}^{\max}, \quad \forall h \tag{9}$$

The BESS power can be expressed as

$$\text{Power}_h^{\text{out}} = \text{Power}_h^{+} - \text{Power}_h^{-}, \quad \forall h \tag{10}$$

A BESS cannot be charged and discharged simultaneously. To restrict Power_h^{+} and Power_h^{-} from nonzero simultaneously, a binary variable b_h is introduced and used to limit the discharging and charging power, as shown in (11) and (12).

$$0 \le \text{Power}_h^{+} \le b_h \, \text{Power}^{\text{max}}, \quad \forall h \tag{11}$$

$$0 \le \text{Power}_h^{-} \le (1 - b_h) \, \text{Power}^{\text{max}}, \quad \forall h \tag{12}$$

where in this BESS system we set $\text{Power}^{\text{max}} = 6$ MW.

3.6.3 Grid Service Requirement

This section describes grid service requirements by service.

3.6.3.1 Transmission Deferral and Outage Mitigation

For transmission deferral, the required discharging power level can be estimated based on the capacity of transmission lines and load projection to meet the N-1 criteria. The hourly required discharging power is used to set the lower bound of BESS power, as expressed in (13).

$$\text{Power}_k^{\text{req}} \le \text{Power}_k^{\text{out}}, \quad \forall k \in K \tag{13}$$

This constraint can also be used to capture the requirement on the BESS for outage mitigation.

3.6.3.2 Regulation and Spin Reserve

The regulation capacity provided by a BESS is limited by both its power capacity and scheduled base operating point, as expressed in (14) and (15).

$$0 \le \text{Reg}_h^{\text{up}} \le \text{Power}^{\text{max}} - \text{Power}_h^{\text{out}}, \quad \forall h \tag{14}$$

$$0 \le \text{Reg}_h^{\text{dn}} \le \text{Power}^{\text{max}} + \text{Power}_h^{\text{out}}, \quad \forall h \tag{15}$$

We assume that regulation up and down are equal to each other, though this is not a requirement of ISO-NE. This also helps to lower the requirement of energy reserved for regulation service using an energy neutral AGC signal provided by ISO-NE.

$$\text{Reg}_h^{\text{up}} = \text{Reg}_h^{\text{dn}}, \quad \forall h \tag{16}$$

The spinning reserve and regulation up services compete with each other for limited capability of increasing power output, as captured in (17)

$$0 \le \text{Spin}_h \le \text{Power}^{\text{max}} - \left|\text{Power}_h^{\text{out}}\right| - \text{Reg}_h^{\text{up}}, \quad \forall h \tag{17}$$

In addition to the power requirement, there is also energy associated with regulation and spin reserve. Constraint (18) and (19) are used to ensure BESS energy state is between 0 and energy capacity when the energy associated with regulation and spin reserve is added.

$$\text{Energy}_h + \eta^- \cdot \varepsilon_h \cdot \text{Reg}_h^{\text{dn}} \leq \text{Energy}^{\text{max}}, \quad \forall h \tag{18}$$

$$0 \leq \text{Energy}_h - \frac{\varepsilon_h \cdot \text{Reg}_h^{\text{up}} + \text{Spin}_h}{\eta^+}, \quad \forall h \tag{19}$$

3.7 The Optimal Power Dispatch Problem

The total revenue of the BESS is given by

$$\text{Revenue} = \text{Rev}_{energy} + \text{Rev}_{reg\_cap} + \text{Rev}_{spin} \tag{20}$$

which respectively are

1. revenue from the energy settlement: $\text{Rev}_{energy} = \sum_h \lambda_h \text{Power}_h^{\text{out}}$
2. revenue from the regulation capacity payment: $\text{Rev}_{reg\_cap} = \pi \cdot \left(\sum_h \beta_h \text{Reg}_h^{\text{up}}\right)$
3. revenue from the spinning reserve: $\text{Rev}_{spin} = \sum_h \mu_h \text{Spin}_h$

The revenue from the regulation service payment was obtained by a posteriori calculation.

$$\text{Rev}_{reg\_serv} = \pi \cdot \left(\sum_h \gamma_h \text{Reg}_h^{\text{serv}}\right)$$

Therefore, the final optimal power dispatch problem can be formulated as

Maximize Revenue subject to (8) – (19) (21)

3.8 Results

This economic analysis is designed to enhance the value that the Nantucket Island BESS and CTG can provide to National Grid and the customers it serves. In doing so, the analysis could also be useful to other utilities facing similar investment decisions and those attempting to extract maximum value from existing energy storage assets. The case for the Nantucket Island BESS was made by National Grid based on the opportunity to defer an investment in a third transmission cable connecting the island to mainland Massachusetts. Additional value streams have not been fully considered by National Grid to date.

3.8.1 Evaluation of BESS and CTG Benefits and Revenue Requirements

In this section, benefits associated with BESS and CTG operations are specified, beginning with a local operations only scenario and then running through several cases involving market participation. We also report the number of hours the BESS would be optimally engaged in the provision of each service under the base case, and test the sensitivity of results with respect to changing various assumptions. Note that while benefits of local operations result from CTG operations, the CTG is not bid into the ISO-NE market in this analysis.

The first step in estimating the return on investment (ROI) for the BESS plus CTG was to explore a local operations only scenario, where services are limited to transmission deferral, outage mitigation, and Volt-VAR/CVR. This scenario assumes no market penetration and therefore, the operational requirements of the BESS are greatly simplified; the annual output of energy from the BESS under this scenario is limited.

Results of this case are presented in Table 3.12 and Figure 3.30. Over the 20-year economic life of the BESS, we estimate that the benefits of local operations would total roughly $122 million. Of those benefits, the vast majority (89.8%) result from deferring the investment in the third transmission cable for 13 years. Deferral reduces the PV costs of that cable by $109.5 million, which is more than the revenue requirements for the BESS plus CTG ($93.3 million). Outage mitigation adds an additional $12.3 million, or 10.1% of local operations benefits, over the 20-year economic life of the systems. CVR/Volt-VAR benefits were estimated to be negligible at just over $5,000 annually. Local operations alone yield a 1.30 ROI ratio. Thus, for every dollar invested in the BESS and CTG, National Grid could expect $1.30 in return.

Table 3.12. Benefits vs. Revenue Requirements – Local Operations

Service	Present Value Benefits over 20-Year Economic Life of BESS/CTG	Share of Total Benefits
Transmission Deferral	$109,490,163	89.8%
Outage Mitigation	$12,330,455	10.1%
CVR	$80,043	0.1%
Total	$121,883,411	

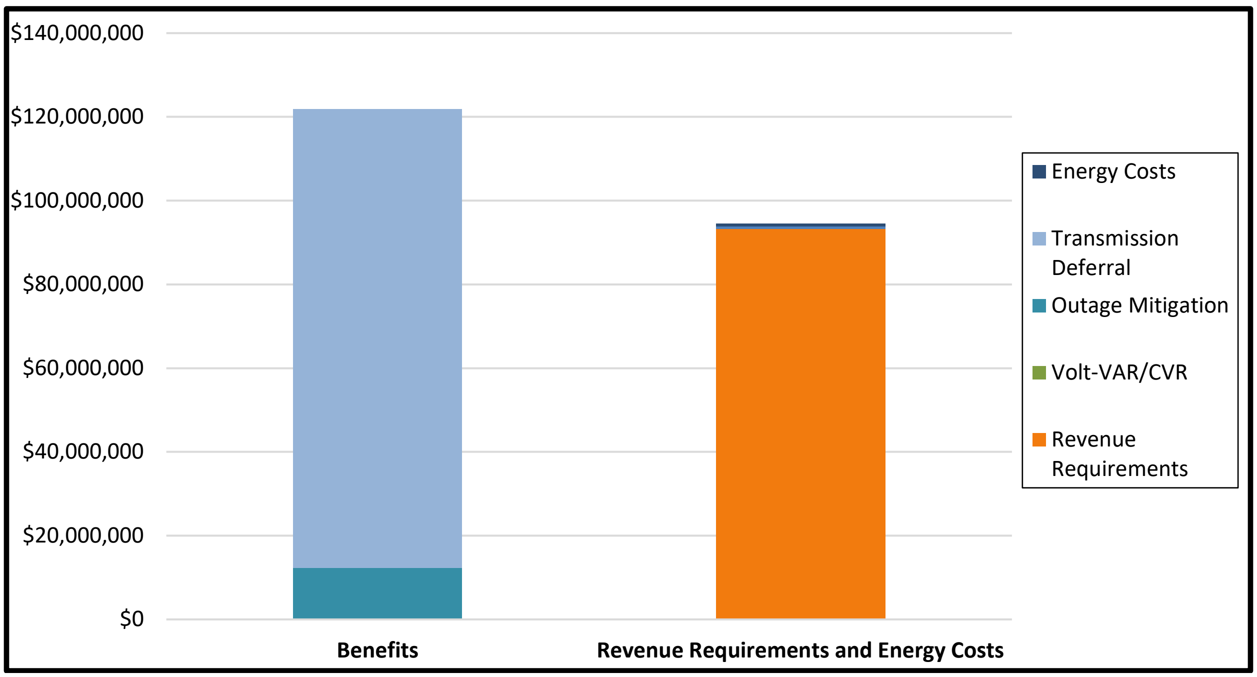


Figure 3.30. Benefits of Local Operations vs. Revenue Requirements

Expanding beyond local operations, we evaluated first the benefits of obtaining arbitrage benefits by bidding into the ISO-NE DAM and RTM. As discussed in Section 3.5.2, daily operation is based on forecast prices while revenue results from market clearing prices. Thus, this evaluation does not assume perfect foresight but rather reflects the impacts of prediction error. Arbitrage revenue was estimated for 2016-2018 in the DAM and RTM. Results by year for each prediction method are presented in Table 3.13. Annual arbitrage benefits varied from $87,452 annually to $154,096. Results varied significantly by year and prediction method. Revenues were higher in the RTM relative to the DAM, even when accounting for forecast error. While the GBM method yielded the most precise estimates statistically, use of the DAM LMP as a predictor of RTM LMPs resulted in the highest revenue because that method was more likely to identify unusually high prices in the next day's RTM.

Table 3.13. Arbitrage Revenue by Year by Prediction Method

Market/Prediction Method	2016	2017	2018	Average
GBM Prediction of DALMP	110,058	95,585	133,560	113,068
Yesterday DALMP as Predictor of DALMP	101,746	87,453	123,486	104,228
GBM Prediction of RTM	137,519	124,620	85,866	116,002
DALMP Prediction of RTM	154,096	131,988	107,506	131,197

This analysis was then extended to account for arbitrage plus regulation revenue. Results of this evaluation are presented in Table 3.14. Arbitrage revenue was negligible in this scenario because regulation offered more value for each increment of energy provided by the BESS, and when the 7,200 MWh annual limit established in the Tesla BESS warranty was imposed as a constraint in the model, relatively lower value arbitrage operations were eliminated. Because the arbitrage revenue is eliminated, the prediction method only influences charging costs. Thus, the results for the various prediction methods converge and revenue is higher when bidding in the DAM due to the lower energy costs. Note results would be higher if the BESS could be bid into the ISO-NE market without consideration of maximum annual discharge requirements. A case was run with the BESS bidding into ISO-NE markets without limit and the results indicated that the BESS would obtain an additional $12,930 and $38,790 when bidding into the DAM and RTM, respectively. Nearly all of those funds would be tied to arbitrage operation.

Table 3.14. Arbitrage plus Regulation Revenue by Year by Prediction Method

Market/Prediction Method	2016	2017	2018	Average
GBM Prediction of DALMP	1,275,790	1,358,226	1,295,250	1,309,755
Yesterday DALMP as Predictor of DALMP	1,275,790	1,358,226	1,295,245	1,309,754
GBM Prediction of RTM	1,275,648	1,355,728	1,294,895	1,308,757
DALMP Prediction of RTM	1,275,648	1,355,686	1,294,895	1,308,743

The results for the co-optimized base case scenario, which includes all local and market operations, are presented in Table 3.15 and Figure 3.31. The base case scenario employs the following assumptions:

1. Average revenue for market operations over the three year 2016-2018 timeframe are used as the revenue for the base year (2019). Base year values are grown at 2.64% over the economic life of the units.
2. Results are based on the average of the four prediction methods.
3. Outages are modeled based on randomly selected historical outage dates/times, and the BESS responds with no foresight.
4. The BESS maintains a 50% SOC floor during market operations to ensure it is available to respond to reserve calls, capacity events, and outages.
5. The BESS is charged to full capacity and is maintained at that level during N-1 contingency operations. These hours are defined in Appendix A.

6. After all other service-based commitments have been met, the remaining capacity of the Nantucket Island BESS can be used to provide Volt-VAR and CVR support as needed.
7. An annual output limit of 7,200 was modeled as a constraint.
8. The CTG does not participate in market operations.
9. We assume that the BESS begins participation in the ISO-NE energy and ancillary service markets in 2020; the first year of forward capacity market operation is in 2024.

In totality, we view these as fairly conservative assumptions meaning that the estimates presented in this report would appear to be achievable at a high level of confidence.

Total 20-year lifecycle benefits of BESS plus CTG operations are estimated at $145.9 million, yielding a 1.55 ROI ratio when compared to $93.9 million in revenue requirements and energy costs. The majority (75.0%) of the benefits are tied to deferring investment in the third transmission cable. An additional $18.8 million (12.9%) result from regulation services. Outage mitigation yields $12.3 million (8.4%) in benefits. Forward capacity market operations generate $4.1 million (2.8%) in total revenue. Spinning reserves are estimated to generate $1.2 million, or 0.8% of total benefits. Volt-VAR/CVR operations yield negligible benefits.

Table 3.15. Benefits vs. Revenue Requirements – All Operations under Base Case

Element	Benefits	Revenue Requirements and Energy Costs
Capacity	$4,060,124	
Regulation	$18,757,805	
Spin Reserves	$1,195,419	
Volt-VAR/CVR	$80,043	
Outage Mitigation	$12,313,206	
Transmission Deferral	$109,490,163	
Energy Costs		$657,898
Revenue Requirements		$93,264,355
Totals	$145,896,759	$93,922,253

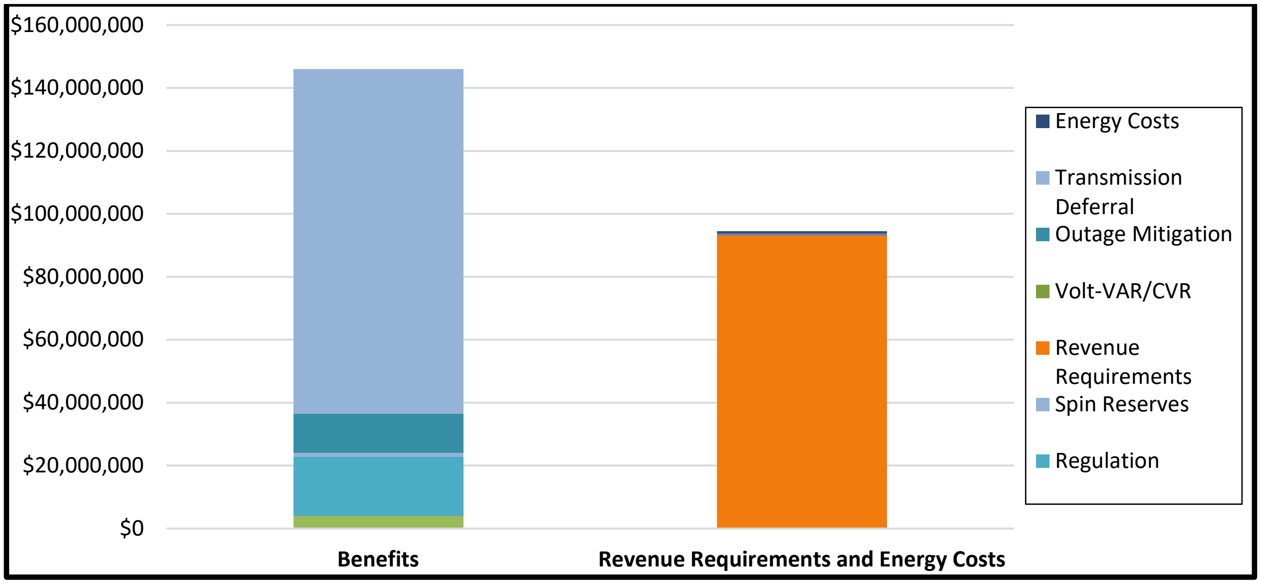


Figure 3.31. Benefits of Local and Market Operations (Base Case) vs. Revenue Requirements

Table 3.16 presents the annual application hours for the BESS when operated optimally under the base case. Regulation service dominates the application hours, with the BESS engaged in the provision of this service 7,900 hours each year. The number of hours presented in Table 3.16 exceed the number of hours in a year (8,760) because some services can be provided simultaneously. Outage mitigation and transmission deferral provided tremendous value despite the fact that those services are concentrated in a very small number of hours each year – 5 and 145, respectively.

Though six value streams are available, the Nantucket Island BESS when operated in an optimal manner would remain idle a small number of hours each year. The BESS would be idle when energy prices and RTE losses result in operating costs that would exceed the value of services provided.

Table 3.16. Annual Application Hours of the Energy Storage System under the Base Case

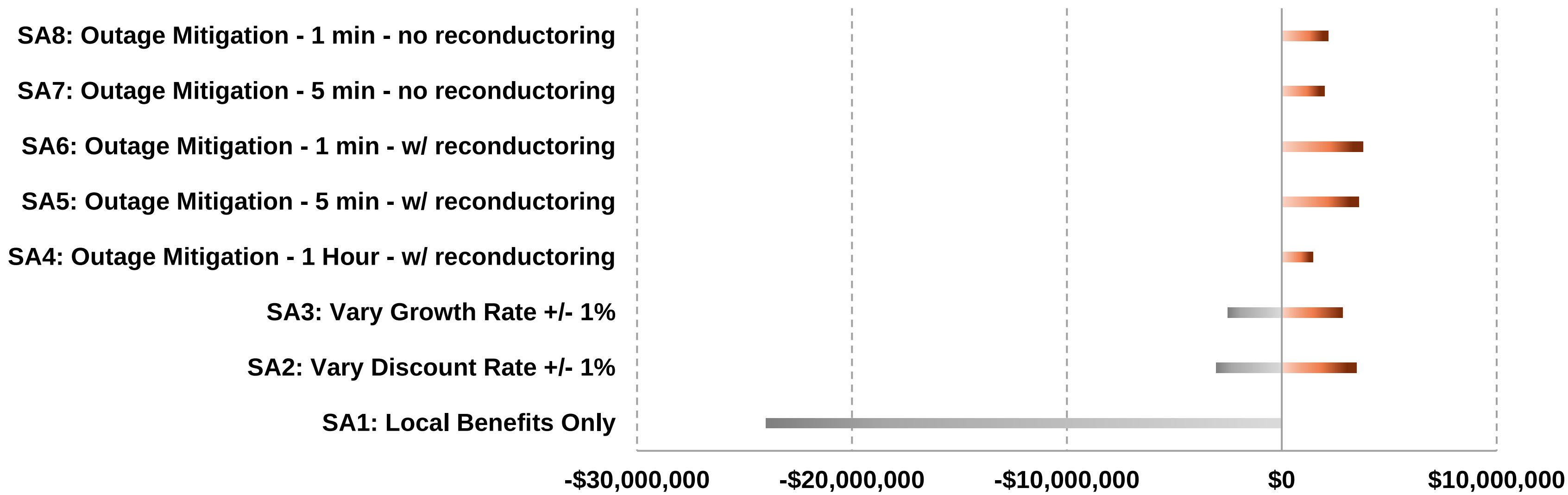
Element	Annual Number of Hours
Capacity	3
Regulation	7,900
Spin Reserves	388
Volt-VAR/CVR	1,825
Outage Mitigation	5
Transmission Deferral	145

To explore the sensitivity of the results to varying a number of key assumptions, the research team conducted a series of sensitivity analyses. The various scenarios are outlined below and their impacts were measured in comparison to the base case. Sensitivity analysis was performed by making the following adjustments to the assumptions:

- SA 1 – Analysis includes only local benefits
- SA 2 – Vary discount rate by +/- 1%

- SA 3 – Vary price growth rate by +/- 1%
- SA 4 – Outage mitigation is aided through reconductoring
- SA 5 – Outage mitigation is aided through reconductoring and feeder automation with a 5-minute response time
- SA 6 – Outage mitigation is aided through reconductoring and feeder automation with a 1-minute response time
- SA 7 – Outage mitigation is aided through feeder automation with a 5-minute response time, no reconductoring
- SA 8 – Outage mitigation is aided through feeder automation with a 1-minute response time, no reconductoring.

The results of each sensitivity analysis are presented in Figure 3.32. Note that the table with results appears below the figure. The scenario that would eliminate market operations has a significant impact on results, reducing benefits by $24.0 million. The impacts of all other sensitivity analyses are negligible, indicating that results are not highly dependent on the assumptions evaluated here.



	SA1: Local Benefits Only	SA2: Vary Discount Rate +/- 1%	SA3: Vary Growth Rate +/- 1%	SA4: Outage Mitigation - 1 Hour - w/ reconductoring	SA5: Outage Mitigation - 5 min - w/ reconductoring	SA6: Outage Mitigation - 1 min - w/ reconductoring	SA7: Outage Mitigation - 5 min - no reconductoring	SA8: Outage Mitigation - 1 min - no reconductoring
Low-End	$(24,013,348)	$(3,063,391)	$(2,506,423)					
High-End		$3,486,622	$2,835,348	$1,462,781	$3,594,791	$3,779,846	$1,983,777	$2,158,132

Figure 3.32. Sensitivity Analysis Results

4.0 Control Strategies

This section of the report presents general considerations for developing control strategies for the Nantucket Island 6 MW/48 MWh BESS, presents an illustrative control/coordination strategy, and elaborates on a few specific scenarios using simulation studies. Indicative results/findings are presented drawing connection to further studies in order to obtain more detailed and specific information for control system implementation.

The purpose of the Nantucket Island BESS control strategies is to utilize the power and energy capacity of the BESS in a coordinated fashion to improve the island's power supply reliability and potentially participate in the ISO-NE market. While the focus is the control of the BESS, it is not an isolated device. Rather, it is part of a complex system. As shown in Figure 4.1, how the BESS will be dispatched will depend on a diverse set of inputs and constraints associated with the BESS itself (Section 3.1, technical and contractual aspects, including annual throughput limits), the CTG (Section 3.2), island loads and network constraints (Section 2), and bulk power system aspects, including submarine transmission cables (Section 2).

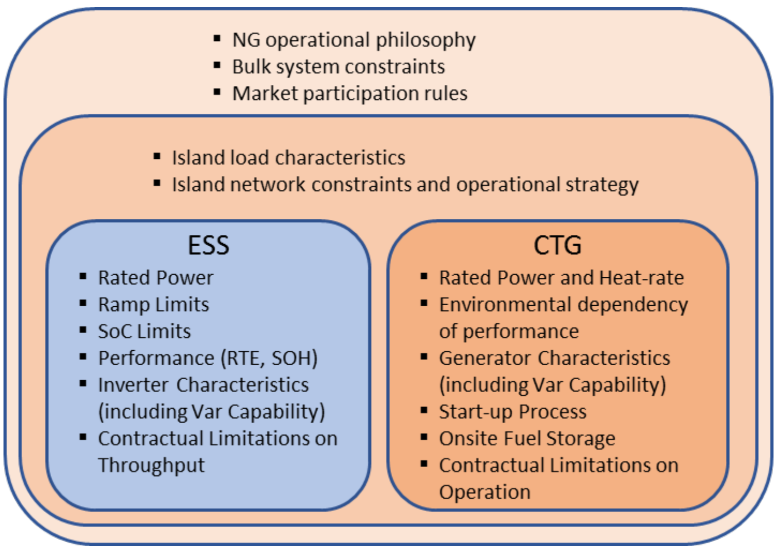


Figure 4.1. Dependency of BESS Control Scheme on Other Systems/Components

While Nantucket Island is primarily supplied by power imported from the mainland through two submarine transmission cables with a combined capacity of 71 MW, outage of one or both cables, defined respectively as "N-1" and "N-2" contingency, will lead to dependency on island-based local generation for supplying peak loads. A load analysis performed for Nantucket Island by PNNL suggests that an outage of the larger capacity transmission cable (4606) during summer months (June-September) of 2019 may need the CTG and BESS to supply maximum peak demand for a couple of hours under an N-1 contingency scenario. When there is no transmission cable contingency, the BESS could be used for market participation and distribution system reliability and performance improvement (e.g., local outage mitigation, voltage management). The control strategy should be designed to ensure the best utilization of the BESS asset in normal and contingency situations.

4.1 Control and Coordination Scheme

During early stage operation in 2019, National Grid will implement a manual peak shaving strategy to discharge the BESS for supporting peak load. Charging of the BESS for peak shaving purposes could be performed using grid supply, depending on prevailing system conditions and the CTG air permit, which allows CTG operation only during contingencies or monthly tests. While a rule-based control strategy will be considered at an intermediate stage of the project, the long-term goal is to design and incorporate an optimal control approach based on optimization of the island network and market operations. The initial operation with a rule-based approach will generate useful experience, data, and lessons for developing optimal control strategies.

Basic functional aspects of an illustrative rule-based strategy are described briefly below.

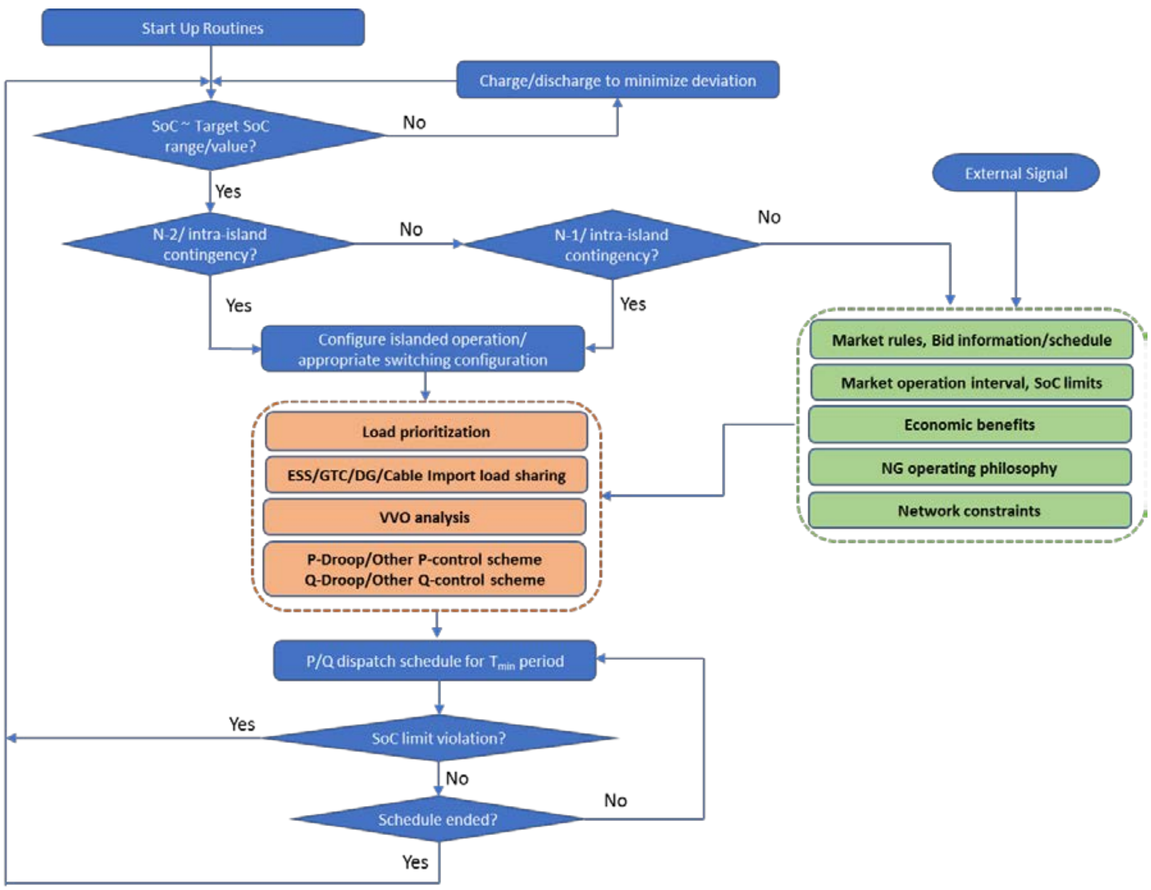


Figure 4.2. Preliminary Control/Coordination Framework

As the control system commences operation and completes any initial start-up routine it needs to perform, it checks to ensure the SoC is within a user-defined range or target. If not, it then commands the BESS to charge/discharge as needed to minimize SoC deviation. Analysis of various services and their impacts on battery SoC can provide useful information to determine an optimal target SoC level. In this version of the work, a target SoC of 50% is used based on co-optimization of various services under consideration. Once operational data starts to become available, advanced data analysis could be performed to obtain a realistic estimate. Charge/discharge can typically be performed at rated power, while deviation from rated power can also be allowed to respond to various system conditions, provided the safety/reliability aspects are not compromised.

Once the SoC is within the desired range, at any given time, the BESS control strategy needs to respond to one of three distinctive situations as described below.

4.2 N-2 Contingency

This low probability, high impact event arises when both transmission cables are disconnected from the mainland. Therefore, only local generation resources are available to supply island load demand. Since the island will be electrically isolated from the mainland, one of the local sources need to form a local microgrid. Currently, National Grid is considering the CTG as the grid-forming source, i.e., the “swing” or “reference” generator. During the initial testing/commissioning period, the substation emergency generator will be used to black start the BESS, which will then provide startup energy for the CTG. Once started, the BESS will be synchronized with the CTG and will share load as commanded by the BESS control system. While “control system” in the version of the report refers to a BESS control system, a higher level site control system could also be used, as discussed in Section 4.5. Once the testing/commissioning period is over, National Grid is planning to use a 1.25MVA, 1,000kW emergency generator for the startup process. The technical capability of the BESS to act as a grid-forming source will be revisited by National Grid at a later phase in this project.

According to the CTG manual, “isochronous kW share control” and “droop speed/load control” modes are available for islanded operation. Isochronous mode will maintain the frequency at a constant setting. For the CTG deployed by National Grid, this is a default mode of operation in an islanded situation. Droop mode of operation changes output according to frequency. Detailed study will be needed to coordinate the CTG and BESS operation if both use droop control in islanded operation. Islanded operation of the CTG-BESS combined asset could also be useful to supply part of the island network when it is isolated from the main transmission supply due to scheduled/forced outage within the island’s distribution system.

Real (P) and reactive (Q) power decision support for the BESS could be made through analytical exercises for determining the critical loads that must be supplied during N-2 contingency, how the supply burden will be shared among local resources, how the reactive power capacity will be utilized for supporting island voltage during contingency, etc. These analytical components are shown in the control/coordination flowchart in Figure 4.2 and briefly described below. Time series power flow analysis was conducted on a few situations in the respective subsections below to analyze the impact of BESS P-Q control on the island network. More comprehensive scenario analysis will need to be performed prior to implementation of rule-based strategies.

4.2.1 Load Prioritization

An approach needs to be defined to prioritize the loads that must be served when electricity supply capacity available at the island is limited. National Grid can deploy various criteria, including degree of importance of the load, operational experience, and financial impact to develop a prioritization scheme. The scheme should be dynamic in nature for responding to various system conditions on the island.

For the current version of the work, a strategy is formulated using load tier criteria defined by National Grid. Tier 1 includes load such as the airport, downtown core area, Brant Point Coast

Guard, and sewer pump station. These loads reside in Feeders 101L7 and 101L3. Tier 2 loads include the local high school and elementary school, hospital, fire station and water utility. These loads are located on Feeder 101L7 and 101L4. Tier 3 loads include senior housing, a wastewater treatment plant and Fairgrounds town offices mostly in area of feeder 101L2.

4.2.2 Load Sharing

Since the CTG will be used as a swing generator during N-2 contingency operations and essentially responsible for voltage control, its real power output may need to be reduced below the rated value to meet the requirement to provide reactive power for maintaining desired voltage at CTG terminals. Power capacity limits of the CTG and BESS are discussed in Section 2.2.1. With such limitation on real power output from the CTG and in the absence of any other local generation capacity, the BESS will most likely need to supply real power at its full capacity. However, depending on load and supply situation in the long term, a load sharing strategy may need to be defined to split the load serving duty among the CTG, BESS, and other resources (e.g., 1.25 MVA emergency diesel generator). Operating limits, performance information (e.g., heat rate for CTG, RTE for BESS), and relevant O&M cost information of these resources can be used to share the loads in an economic manner. With the availability of adequate information on CTG and BESS operational costs, a more sophisticated approach (e.g., incremental or marginal cost curve) could be defined for load sharing.

An illustration of a marginal cost curve approach is provided below. CTG hourly fuel input data as a function of output is used to construct a generator cost curve with a diesel LHV value of 0.139MMBTU/gallon and a price of $3.17/gallon. The marginal cost curve is obtained by taking the first derivative of the cost curve. The BESS cost curve is obtained using the amount of energy depleted (hence, cost) from the BESS at various discharge rates (MW) over a given interval (e.g., an hour). Additional cost components (e.g., degradation) could be incorporated with further refinement of the approach, provided necessary data is available. Cost of the energy stored in the BESS at a given instant of time could be determined from electricity tariff or LMP, as applicable, and amount of energy stored. In this version of the work, both Nantucket retail tariff for 2019 (0.06$/kWh) and real time LMP of 2017-2018 are explored. Approximately 90% of the time, LMP was found to be less than the retail tariff.

Aggregate supply curve is constructed by sorting the pairs of power quantity and marginal cost for individual supply curves of the CTG and BESS in ascending order of marginal cost. Individual and aggregate marginal cost curves are shown in Figure 4.3(a) and (b), respectively, for the assumed diesel price and unit electricity price.

An example of using the aggregate supply curve is shown in Figure 4.3(b) where a total power supply burden of 9.3 MW is split between the BESS (6 MW) and CTG (3.3 MW). The BESS is fully loaded first because of lower marginal cost. Given the current limited generation capacity on Nantucket Island, this strategy would be more applicable for N-1 contingency; N-2 contingency will need the maximum capacity from both resources, subject to thermal limit or other constraints associated with substation/network equipment. If the BESS charging cost is increased due to an increase in electricity price, the BESS and CTG loading order may be reversed or mixed. An example is showed in Figure 4.3(c) where the BESS marginal cost is increased by doubling the electricity price (0.12$/kWh instead of 0.06$/kWh). As a result, the 9.3 MW load sharing between the CTG and BESS is changed, as shown in Figure 4.3(d).

While marginal cost or similar type of approach provide an economic way of sharing the load supply burden, there are additional constraints that may impact such economic operation. For instance, if the CTG is limited to a certain minimum output level due to emission constraints (currently, National Grid reported a 65% minimum output limit) and has a higher priority than the economic output, then a load sharing approach satisfying the emission constraint will be followed, instead of the marginal cost approach. Similarly, network overload or thermal limits need to be adhered to while making dispatch decisions for the BESS and CTG. An island-wide optimal power flow could provide useful information in this regard. The CTG 65% minimum loading criterion may be advantageous in some cases where the BESS needs to be changed and import from the mainland is limited due to contingency or any other constraint.

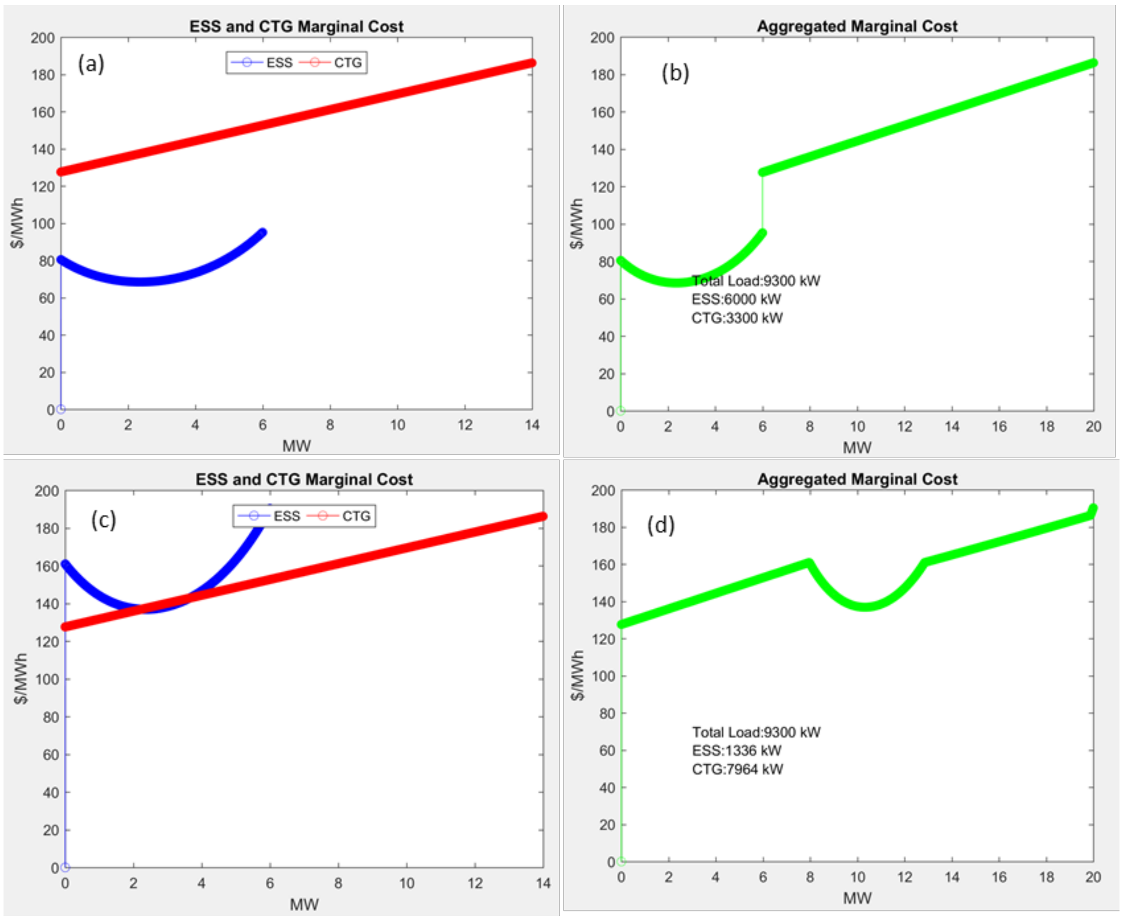


Figure 4.3. Marginal Cost Curves of CTG and BESS

4.2.3 Volt-VAR Optimization

With the CTG setting the system frequency and primarily responsible for maintaining voltage, the BESS reactive power capacity can be used to support voltage as needed. BESS Q-dispatch needs to be such that it does not create any adverse impact on voltage control by the CTG. A constant Q-control could be used or a droop curve with less sensitive setting. It also should not increase the tapping operation of transformers and voltage regulators. Detailed simulation needs to be carried out to ensure the settings are acceptable. For the current version of the work, a generic volt-var droop curve suggested in IEEE 1547 standard (IEEE 2018) is used to provide reactive power support from the BESS during normal operation and contingencies. The curve is shown in Figure 3.14 and can be made more aggressive depending on the requirements. Analysis of voltage profile measurements from the island network, while this generic droop curve is deployed, could be performed to tune the curve for more effective voltage support performance. Before implementing a volt-var droop curve, the fixed power factor approach presented in Section 2.2.4, can be used. Illustrative settings are presented in in Table 2.9.

Once in place, the BESS Q-control approach should be able to integrate with any existing or future VVO scheme. One option to incorporate the BESS with the VVO scheme is to model the BESS inverter as a time varying reactive power device. The VVO controller will assess the BESS inverter reactive power capability in a dynamic fashion (e.g., change in available reactive power capability caused by the need to dispatch real power) and request reactive power dispatch based on the its central VVO algorithm.

4.2.4 N-2 Contingency Simulations

To understand system behavior under N-2 contingencies, a 24-hour time-series power flow simulation was performed. Contingency is simulated by taking both mainland cables out of service during off-peak (hours 4-9) and peak hours (16-21) to assess impacts in two extreme scenarios. The load profile in Figure 4.4 used for time series analysis corresponds to a day with peak load from the year 2017. A transition period of one hour is assumed that accounts for BESS/CTG startup, synchronizing and switching reconfiguration. After that, BESS and CTG operate at their maximum output, i.e., 6 and 13 MW, respectively. Since the total load exceeds combined maximum output of BESS and CTG, hence certain feeders are shut down for load shedding according to the list in Table 4.1. This ensures that critical loads (as previously characterized) are supplied for the longest time period.

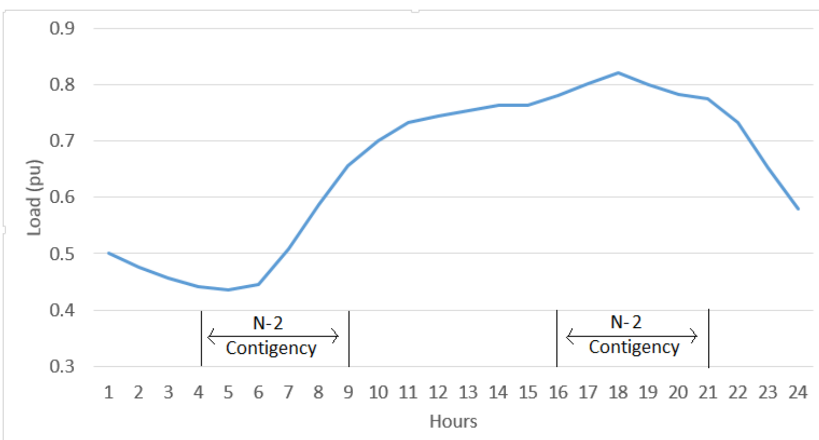


Figure 4.4. Load Profile for Contingency Simulation

Table 4.1. Feeder Shut Down Priority

Hour	Feeders Shut Down
5, 17	101L6
6, 18	101L6
7, 19	101L6, 101L5
8, 20	101L6, 101L5, 101L7 (downstream of Polpis Road pole10)
9, 21	101L6, 101L5, 101L7 (downstream of Polpis Road pole10)

Figure 4.5 shows the minimum and maximum voltages in the network for 24 hours. It is observed that during an N-2 contingency, minimum voltage falls below 0.95 per unit (ANSI standard). Maximum voltage remains well below ANSI limit (1.05 per unit). The location of minimum voltage remains the same and is shown in Figure 4.6. It is important to note that at this time there is no regulator or capacitor bank upstream of this location on feeder 101L7 that can be used to enhance this voltage. Figure 4.6 shows the location of maximum voltage during N-2 contingencies.

Figure 4.7 shows how load (real power) is shared between mainland cables, BESS and CTG over 24 hours. During N-2 contingencies, the BESS and CTG operate at their maximum power outputs. However, BESS/CTG output need to be controlled to adhere to any applicable loading constraints of network elements during implementation of the control system and shall be a control system design factor during a future implementation. Note that some load is not served during N-2 since non-critical feeders are shut down using the load prioritization criteria defined in Table 4.1.

State of charge profile for the BESS is shown in Figure 4.8. Since the BESS is discharged at a constant rated power of 6 MW during N-2 contingency, its SOC decreases at a constant rate. Approximately 60% decrease in SoC is observed to serve the critical loads. The BESS is recharged between two contingencies to ensure it has enough stored energy for the peak-hour N-2 contingency simulation, as shown in Figure 4.8 – it does not reflect an actual recharge requirement.

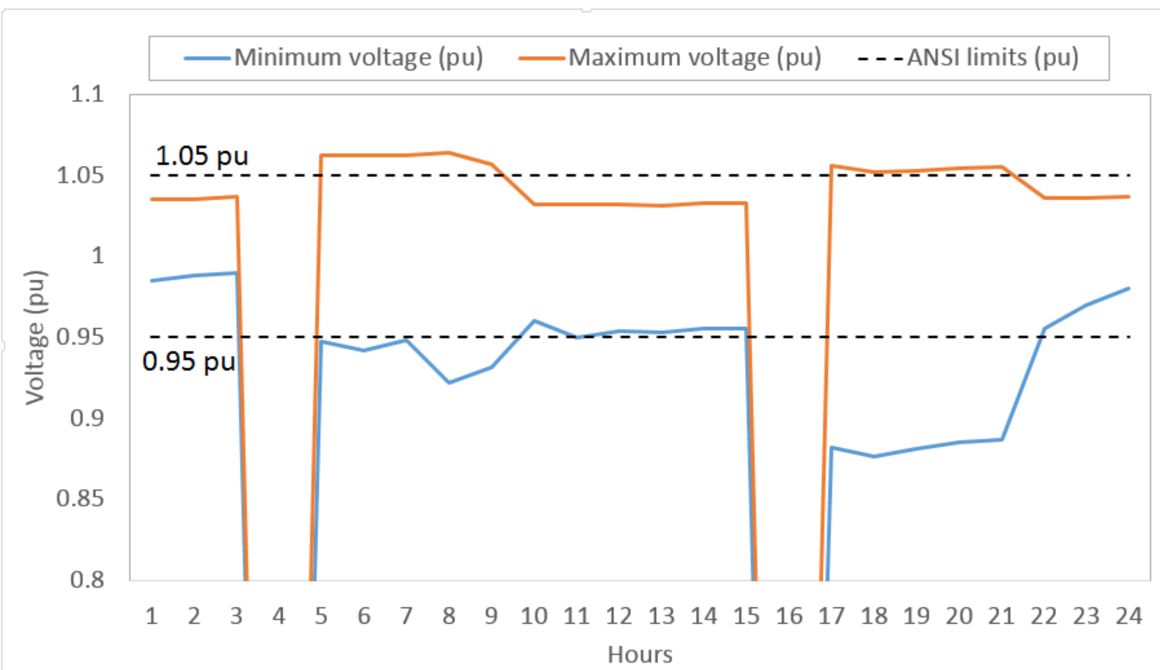


Figure 4.5. Minimum and Maximum Voltage Profile during N-2 Contingency

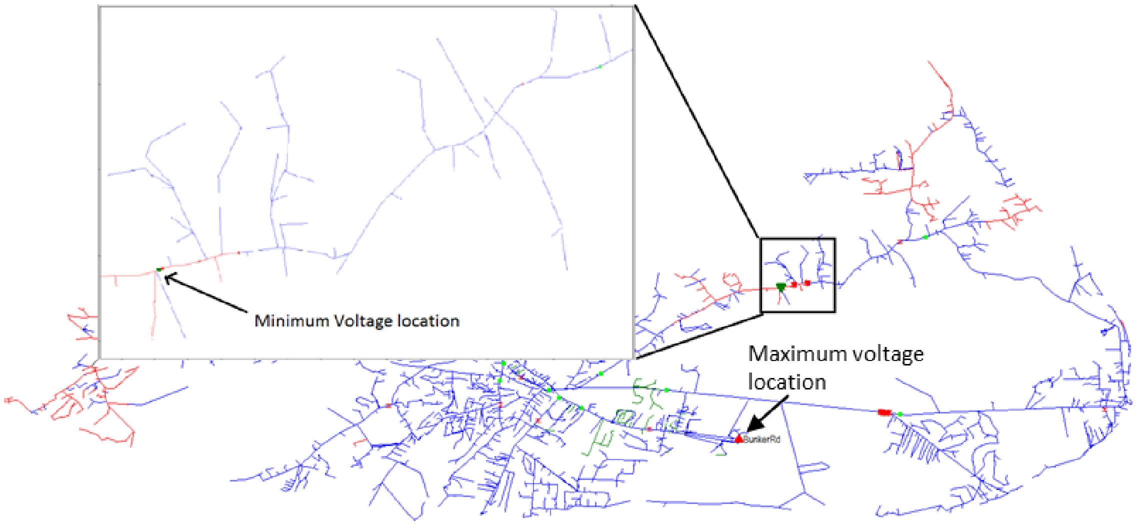


Figure 4.6. Minimum and Maximum Voltage Location

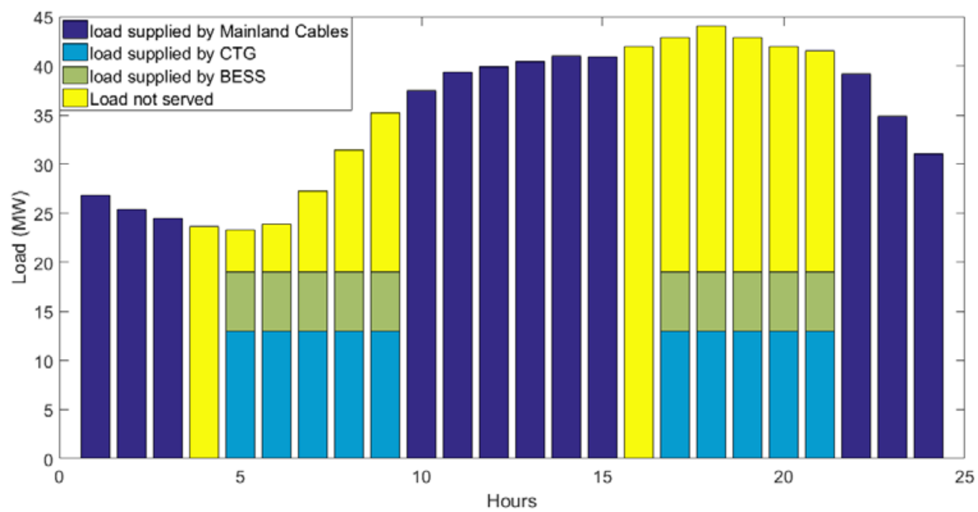


Figure 4.7. Load Sharing among BESS, CTG, and Mainland Cables during N-2 Contingency

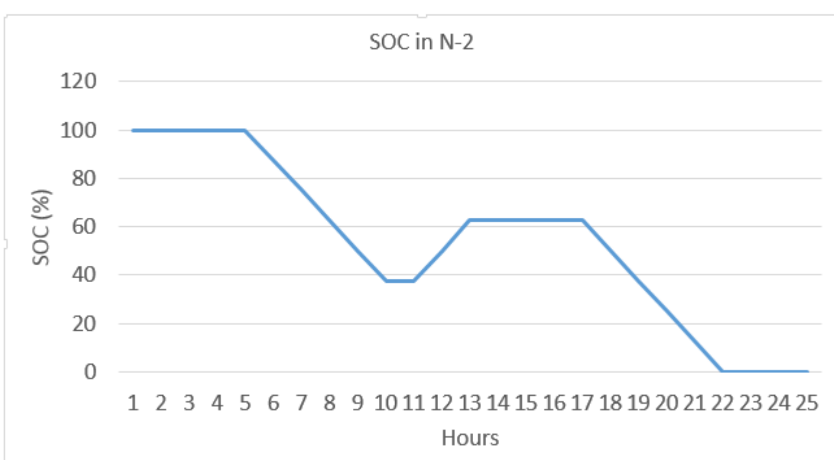


Figure 4.8. BESS SoC Profile Resulting from Power Discharged during N-2 Contingency

Based on discussions with National Grid, a voltage setpoint of 1.03 per unit is used for the CTG. Simulation results show that when contingency is applied during a peak-load hour, the CTG may reach the reactive power limit and hence will not be able to maintain target voltage. Optimal power flow analysis of the island network in various contingency situations would be useful to identify more effective setpoints.

4.3 N-1 Contingency

This situation could arise from a scheduled outage or failure of one of the transmission cables. From now to several years ahead, a major portion of the load demand during this contingency will be served by power imported from the mainland. Local generation resources (CTG, BESS, emergency diesel generator) will be deployed if the total load demand is greater than the in-service cable's power transfer capacity. It also needs to be ensured that the combined local generation does not violate the total thermal limit of the feeders at the Bunker Road Substation. Currently, the combined rated output of the CTG and BESS causes a thermal overload in the network, as indicated in Section 2.2.1. However, this risk will be alleviated once installation of feeder 101L8 is complete.

In principle, BESS real and reactive power decision support during this contingency could be made using similar analytical components discussed in Section 4.2.1-4.2.3, with a major exception that the system is now interconnected with the mainland bulk transmission system, which will change the voltage regulation scenario. Load prioritization and load sharing analysis will be performed as needed depending on the peak load to be served and local resources need to be engaged. While in extreme load situations during an N-1 contingency, both the CTG and BESS will be needed to serve peak load for a few hours, the full BESS capacity may not be needed for serving island load in most of the occasions before 2025.

Detailed economic analysis can be performed to determine if there are technical advantage or economic values in reducing cable loading and utilizing local generation instead. Strategic use of the combined CTG and BESS capacity helps significantly in deferring investment in a third transmission cable, generating a significant benefit to National Grid customers. BESS reactive power capacity can be used to support island voltage and its Q-dispatch setting could be determined using voltage profile analysis of the island network. During an initial phase of operation, a simple IEEE 1547 standard based droop curve could be used with its impact verified via power flow simulation, and monitoring/analyzing operational data, as suggested in Section 4.2.3.

4.3.1 N-1 Contingency Simulations

Same as N-2 contingency analysis, a 24-hour time series analysis was performed where N-1 contingencies are triggered during off peak hours 4-9 and peak hours 16-21 to analyze extreme scenarios. The N-1 contingency is introduced by taking out mainland cable 4606. During the first hour of each contingency, only cable 4605 supplies the load since BESS and CTG are in the startup phase.

The N-1 contingency during off-peak hours does not require the intervention of the BESS and CTG since total island load remains well below transmission capacity (35 MW) of the available cable. Hence, the full load is served despite the existence of an N-1 contingency during hours 4-9. Load sharing among CTG, BESS, and mainland import are shown in Figure 4.9. The situation however changes when N-1 contingency occurs in peak hours (16-21). For hour 16, when the BESS and CTG are at a startup stage and total load is more than the capacity of the available cable, some load is lost as shown in Figure 4.9. For remaining hours of a contingency event, the BESS and CTG share load that is greater than the capacity of the available mainland cable and no load is lost. The load split between BESS and CTG is computed using the lower marginal cost approach as illustrated before in Figure 4.3. The Decision Support Control System would need to have this capability for proper decision making.

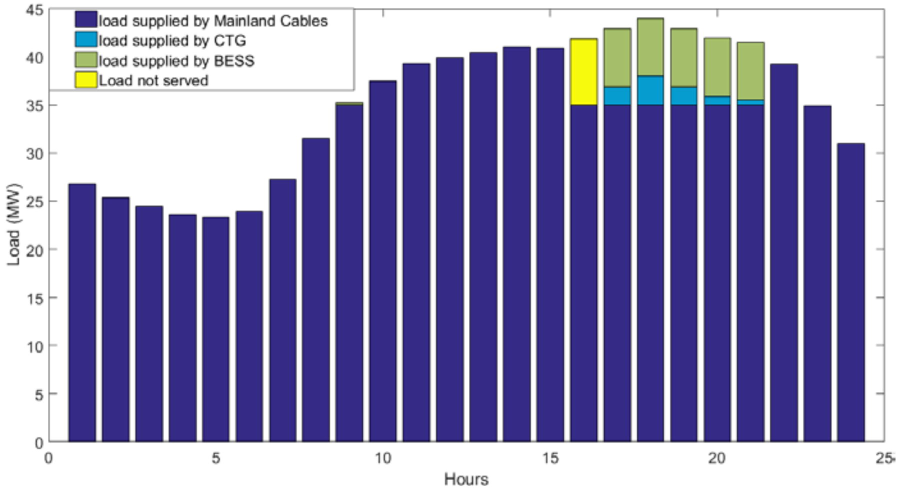


Figure 4.9. Load Sharing among BESS, CTG, and Mainland Cables during N-1 Contingency

The minimum and maximum voltage in the network for all 24 hours is shown in Figure 4.10. It shows that when an N-1 contingency occurs, minimum voltage falls below ANSI standard (0.95 per unit) for both peak and off-peak hours. Reduction in voltage is attributed to an increase of equivalent resistance between the mainland and the Candle Street Substation as one of the cables are switched out. Maximum voltage remains well below the ANSI limit (1.05 per unit) for all the hours. The location of minimum voltage remains the same as found during N-2 contingencies.

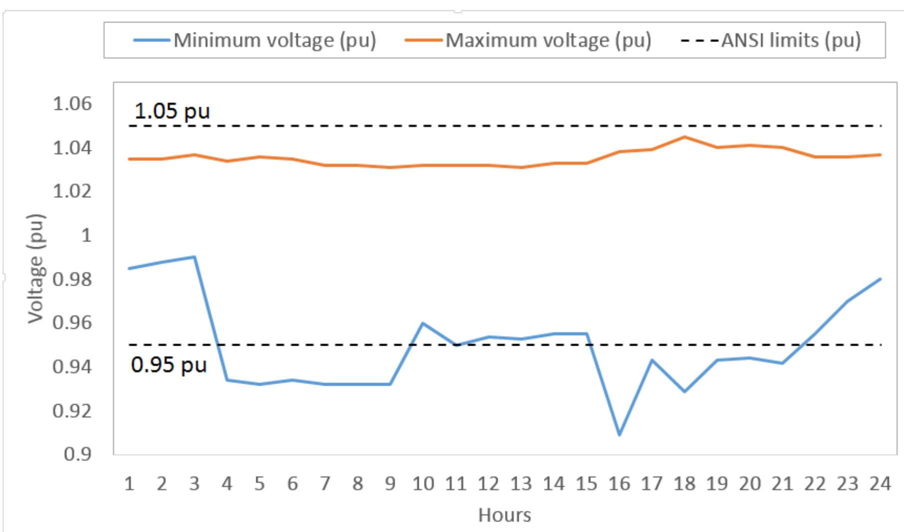


Figure 4.10. Minimum and Maximum Voltage Profile during N-1 Contingency

The SOC profile for the BESS is shown in Figure 4.11. The SOC reduction is very minimal during an off-peak N-1 contingency event, which corresponds to the island load sharing diagram in Figure 4.9. During the peak hour N-1 contingency, the BESS is discharged at rated power and an approximately 60% drop in SOC is observed.

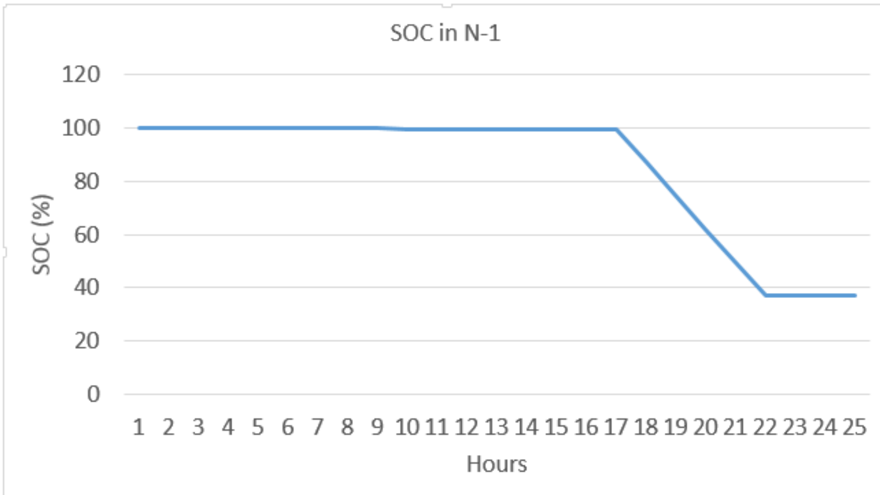


Figure 4.11. SoC Profile during N-1 Contingency

Another simulation is performed adhering to the minimum 9 MW output limit of CTG due to an emissions constraint, and the resulting load sharing is shown in Figure 4.12. As expected, the BESS is only discharged when the local supply requirement exceeds 9 MW. In this case it was only for an hour. Therefore, the SOC reduction is much less (about 2%) as shown in Figure 4.13.

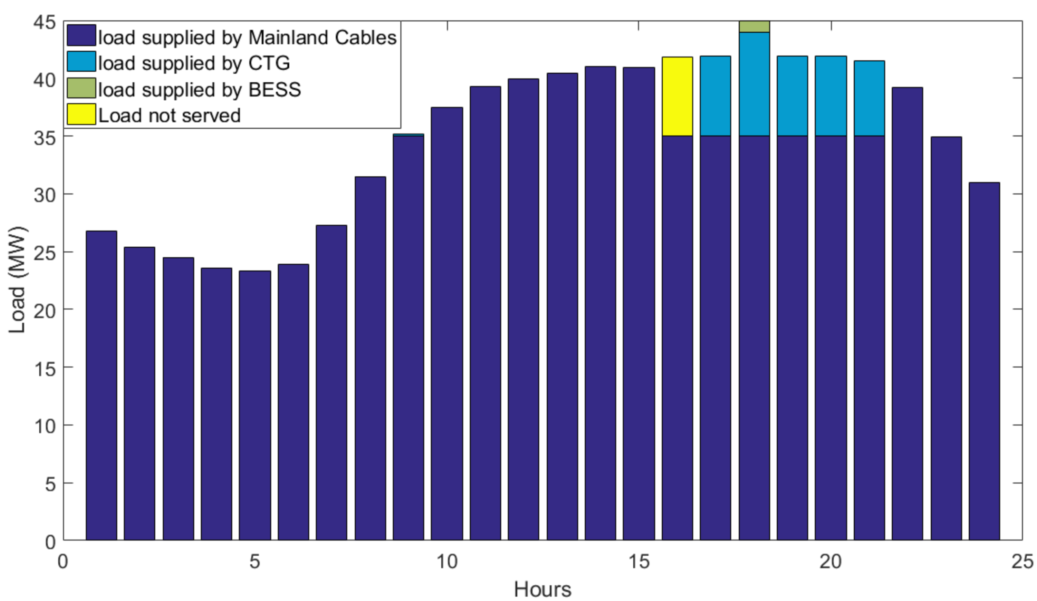


Figure 4.12. Load Sharing among BESS, CTG and Mainland Cables during N-1 Contingency with CTG 65% Minimum Loading Limit

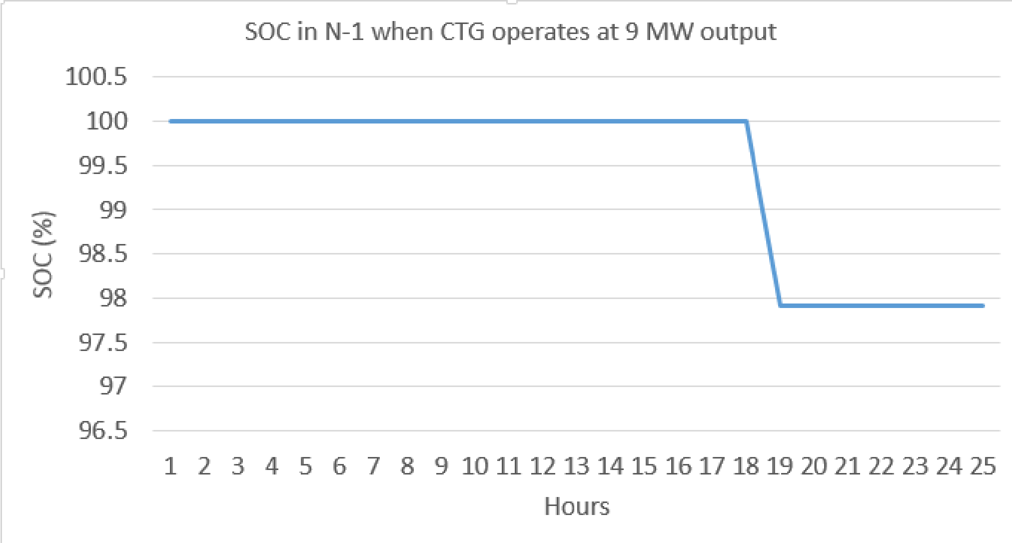


Figure 4.13. SOC Profile During N-1 contingency with CTG 65% Minimum Loading Limit

4.4 Normal Operation

During normal day-to-day operation, the island load will be served by power imported from the mainland. Under this scenario, its stored energy can be used for ISO-NE market participation through reductions of on-island loads. Economic evaluation of various market opportunities has resulted in a preliminary priority ranking of potential market participation services in the following order: (a) regulation, (b) forward capacity, (c) real-time reserve, and (d) energy.

While actively participating in the market, BESS real power will be controlled according to the dispatch order issued by ISO-NE, adhering to the BESS technology constraints (e.g., limits associated with SOC, ramp rate). During market participation, available var capacity of the inverter can be used for voltage support application, if necessary, if it does not create adverse interaction with other voltage regulating resources. It could also be used for CVR if financially attractive and technically prudent. While in normal operation, there could be various changes in network configuration to accommodate scheduled maintenance (e.g., annual scheduled maintenance of a network segment or equipment) or any special testing requirement. The BESS control system should be able to support the island network during those situations. Power flow analysis of network configuration(s) with expected changes can be used to determine how the BESS could support during those cases.

Study of market rules suggest that the BESS can participate in market operation on a continuous basis, though it can also be practically excluded from market operation during N-1 contingency periods or during island outages. Statistical analysis of peak load data suggests that it would be prudent to reserve the BESS capacity during certain hours between mid-June to mid-September for reliability purposes. An indirect approach to prevent the BESS being called for market services would be to bid at a very high price during that period. An alternative approach could be to bid the BESS into the market with a pre-allocated amount of energy. The allocation would be such that with the rest of the stored energy, the BESS can sustain the rated 6 MW discharge for a user-defined interval, during which the utility can complete maintenance work or can make alternate arrangements for supplying the critical consumers. For the present version of analysis, it is being assumed that a day-ahead assessment will be performed using load forecast, CTG status (e.g., fuel storage, maintenance), and other relevant considerations, whether the BESS will be needed during N-1 contingency. If yes, then the entire energy stored in the BESS will be reserved for reliability support. If no, SOC will be maintained at 50% and BESS will participate market operation as directed by ISO-NE. Further analysis may be conducted to identify which option would be more feasible.

4.4.1 Normal Operation Simulations

Hours 1-3, 10-15 and 22-24 in Figure 4.5 and Figure 4.10 simulate normal operation when both mainland cables are available to supply the island. Since the BESS is not bidding in the market in those simulation cases, its SOC remains constant during these periods. Economic analysis presented in Section 3.5 suggests that the most attractive service for market participation is regulation, which would be performed using an energy neutral signal. Therefore, a large deviation in SoC for normal day-to-day operation is not anticipated. Minimum and maximum voltages in the network remains within ANSI limits. For verification purpose, minimum and maximum voltage profiles in the island over 2017 are presented in Figure 4.14.

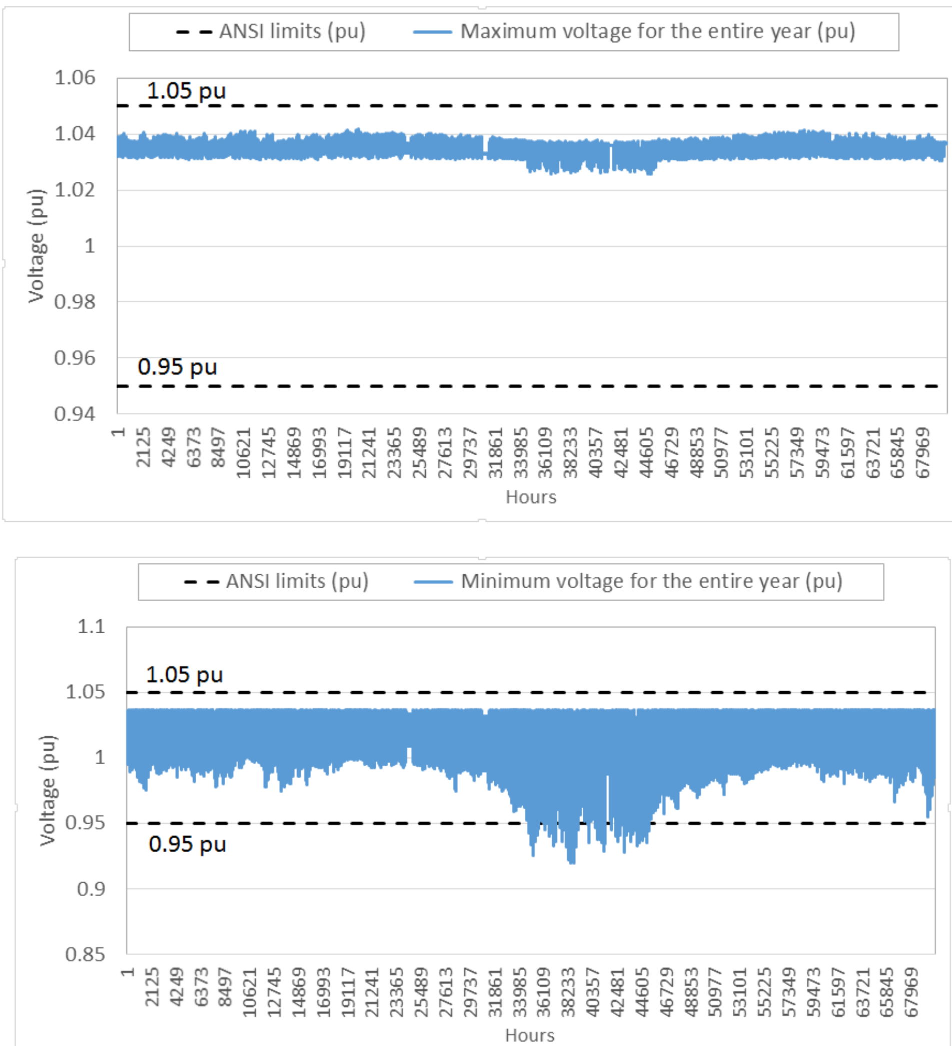


Figure 4.14. Minimum and Maximum Voltage Profile during Normal Operation

The ESS control system will send P and Q dispatch settings for the BESS, determined using the approaches discussed in Section 4.2.1-4.2.3, to the next lower level control layer and monitors its impact on SoC. If the SoC is beyond an allowable range, it breaks the operation to start over from the beginning of the control system loop (Figure 4.2) where charge/discharge is performed to minimize SOC deviation from a target/setpoint. If the SOC is within allowable range, then the operation continues using the P and Q setpoint schedule (a time series of BESS power to serve a specific purpose in a given condition – to be developed while rule-based or optimal control strategies are implemented). Once a given schedule ends, the control system resumes from the starting point.

4.5 Considerations for Control System Implementation

Hardware/software selection for implementing the control and coordination scheme presented in this report should be able to process information from multiple systems (e.g., BESS, CTG, substation, network) for making appropriate operation/control decisions. Parallel processing capability would be desirable for fast decision making. Interrupt requests will be beneficial to monitor/analyze quantities/events/status that will need the control system to switch among multiple control functions. For instance, while performing a market-based P-dispatch schedule for a given period, the island system could face a contingency. In that situation, the control system will need to interrupt the ongoing market operation and commence operation under a contingency support scheme. Standard industrial control system hardware and software are well capable of implementing such features. However, proper integration and customization of commercially available hardware and software systems will need to be performed to achieve the desired control capabilities.

Instead of a BESS-only control system, National Grid desires to explore the possibility of developing a site level controller at the Bunker Road Substation that will control multiple assets (e.g., CTG, BESS, emergency generator) in the substation, individually or in combination, as needed. Various network and non-network information will be processed for making control decisions. The National Grid team produced a conceptual diagram of the system, as shown in Figure 4.15. The key modules proposed are briefly mentioned below.

- Volt/VAR management module determines appropriate VAR setpoints for coordination of various VAR control assets on the island for VVO/CVR or relevant objectives.
- Scheduler/Optimizer module determines the schedule for co-operation of the BESS and CTG based on specific requirements of a simulation or an application case.
- Dispatch and AGC module manages start-up and operation of CTG including load/frequency control.
- BESS supervisory module manages BESS operation, in coordination with CTG.
- Ancillary service module commands BESS and CTG control modules to respond to market signals or deliver market services.

The modules and functionalities discussed above aligns with the control flow chart of Figure 4.2 at a high level with the exception that the control flow chart is developed focusing on the BESS. With further analysis, the BESS-centric control strategies can be expanded for coordinated operation of the BESS, CTG, emergency diesel generator, and other assets using a site level controller. Commercially available modules capable of performing the required functions could be integrated as a platform, and customized to build a more holistic control system. However, significant customization would be necessary to incorporate various features discussed above, and comprehensive studies will be needed to support that customization process.

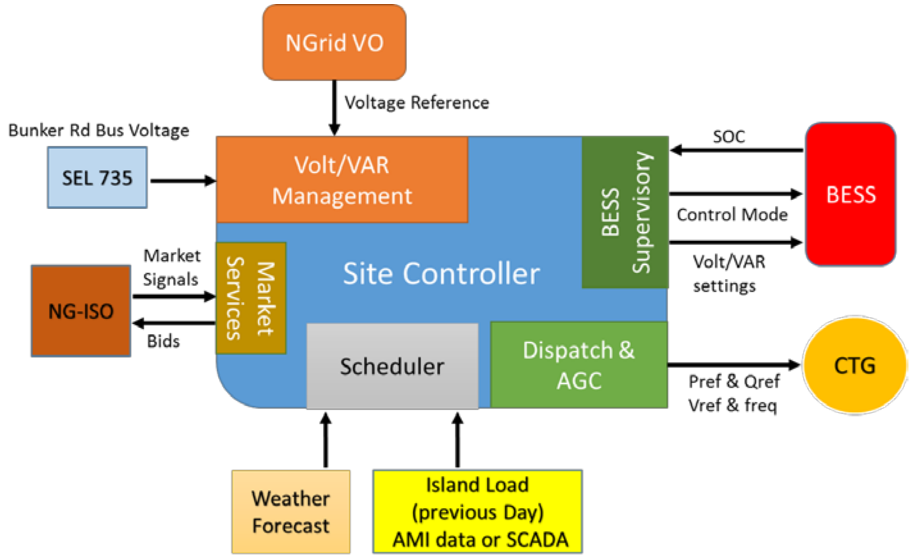


Figure 4.15. An Illustration of Desired Site Controller Modules (Developed by National Grid Team)

4.6 Further Studies

PNNL and National Grid identified some study elements that would be beneficial for better understanding of the island system operation requirements, and hence will help developing overall site control system specifications. These studies are listed in Table 4.2 below identifying relevant scope.

Table 4.2. List of Further Studies

Study Elements	Scope
Historical and simulated voltage profile analysis at strategic locations within the network.	VVO, Network optimization
Technoeconomic comparison between local generation and import from mainland	CTG/BESS control, Network optimization
SOC setpoints, SOC utilization range, and impact on throughput limits, under various applications during normal operation and contingency	Optimal control of BESS
Auto synchronization at Candle Street after islanding from mainland	System restoration/Reliability
Assessment of advanced control, protection, and communication features for optimizing the usage of CTG/BESS asset portfolio	System operation, restoration/ reliability
Optimal power flow of the island network with transmission cables	Optimal control of integrated island system
CTG and BESS droop control modes	CTG and BESS coordination, Site level controller

5.0 Conclusions

This assessment examined the technical and financial feasibility of a 6 MW / 48 MWh BESS and 13 MW CTG deployed at the Bunker Road Substation on Nantucket Island by monetizing the value derived from numerous local and market services that could be realized for National Grid and the customers it serves. We also evaluated the grid conditions necessary to fully realize the benefits of these assets and developed control strategies for realizing these benefits in real time.

The results provide crucial insights into the practical application of the Nantucket Island BESS and CTG. The following lessons were drawn from this analysis:

1. We defined seven services of value to National Grid and its customers from operating the Nantucket Island BESS and CTG: transmission deferral, CVR/VVO, outage mitigation, capacity, energy arbitrage, frequency regulation, and spinning reserve.

2. Total 20-year lifecycle benefits of BESS plus CTG operations are estimated at $145.9 million, yielding a 1.55 ROI ratio when compared to $93.9 million in revenue requirements and energy costs.

3. The majority (75.0%) of the benefits are tied to deferring investment in a third transmission cable serving the island. An additional $18.8 million (12.9%) result from regulation services. Outage mitigation yields $12.3 million (8.4%) in benefits. FCM operations generate $4.1 million (2.8%) in total revenue. Spinning reserves are estimated to generate $1.2 million, or 0.8% of total benefits. Volt-VAR/CVR operations by the BESS yield approximately $80,000 (0.1%) in total benefits.

4. Even when limited to non-market operations, the value of the Nantucket Island BESS and CTG ($122 million) exceeds the $93.3 million in revenue requirements for the systems, yielding an ROI of 1.30. Nearly 90% of the local benefits result from deferring the investment in the third transmission cable for 13 years. Deferral reduces the PV costs of that cable by $109.5 million. Based on a Nantucket Island load analysis conducted by PNNL, we estimate that the BESS will be required to cover four hours of an N-1 contingency event in 2019 and that the number of hours when National Grid will be operating in the N-1 contingency window on Nantucket Island will expand to 290 hours, or 3.3% of all hours, by 2033.

5. PNNL used BSET to simulate operation of the BESS while engaged in local and market operations for a one-year period. Based on the BSET operation algorithm, regulation service would dominate the application hours, with the BESS engaged in that service 7,900 hours each year. The BESS would provide VVO/CVR service 1,825 hours per year, spin reserves 388 hours per year, and would be available to provide capacity and outage mitigation as called upon. The annual hours of service noted above exceeds the number of hours in a year (8,760) because some services can be provided simultaneously. Outage mitigation and transmission deferral provides tremendous value despite the fact that those services are concentrated in a very small number of hours each year – 5 and 145, respectively. For modeling purposes, the simulation maintained a 50% SOC throughout the year to ensure the BESS would be available to provide outage mitigation and capacity services; the BESS SOC was raised to 100% during N-1 contingency events.

6. Upon review of the distribution system near the Bunker Road Substation, it became apparent that the BESS and CTG could not safely provide full power simultaneously. The following upgrades are suggested to mitigate limitations in the distribution system:

    a. There are two underground cable exits from Bunker Road, each rated 420 Amps. When both the BESS and CTG are at their maximum output, i.e., 6 and 13 MW respectively, a certain section in one of the cables gets overloaded (verified at maximum and minimum feeder load). If combined BESS/CTG output is de-rated by 2 MW, overloading vanishes. However, in order to have a full 19 MW export from Bunker Road, the conductors in an overloaded section identified in Section 2.2.1 of this report are required to be upgraded. It is useful to note that with 19 MW export, the limiting section carries 463 amps. During winter time, additional output may be available from the CTG. To reflect that situation, 21 MW export has been considered that increases the current flow to 513 amps.

    b. In the 2019 feeder map, there are two load breaks that connect 101L4 with 101L2. In case of an outage on 101L4 or outage of mainland cables, automatic switches in these locations can ensure timely supply to the area hospital from the BESS/CTG. Hence, this upgrade seems to represent a potentially beneficial investment.

    c. Load breaks on Pleasant Street and Hooper Farm Road connecting 101L4 with 101L2 are required.

    d. In the existing feeder map, BESS/CTG can already supply town offices. However, a recloser upstream of the town offices on 101L7 can make this supply more effective. Another possibility is to relocate the existing recloser 17/200154 to the other side of town offices, i.e., on Orange Street.

    e. Since the BESS and CTG are located on 101L7, an automatic switch on Orange Street, which connects 101L7 and 101L2, can be a beneficial investment. This is especially true when an outage takes place on Orange Street and takes out 101L7 and 101L2. All of these new or upgraded switches could have SCADA for operational dispatch, which would reduce the outage durations compared to manual switching.

7. Outages were modeled under scenarios where the additional distribution-level investments outlined above enable full output of the BESS/CTG and 5- and 1-minute response times. When the systems are able to operate at full power and respond more rapidly, the VoLL to customers on Nantucket Island is reduced by as much as $240,000 annually. Thus, these investments would appear to be cost-effective.

This report concludes by presenting an illustrative rule-based control/coordination strategy, while elaborating on a few specific scenarios using simulation studies tied to N-2, N-1, and normal operating scenarios. The illustrative scenarios do not cover the entire spectrum of events that might occur during actual operation. However, it would provide guidance on the aspects one should consider before implementing a rules-based strategy.

We have identified several areas for potential future study, including the design and incorporation of a more optimal control approach based on optimization of the island network and simulation and quantification of the benefits of a firm/non-firm transactive energy system under islanded conditions.

6.0 References

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Appendix A – Projected Hours Exceeding N-1 Contingency (2019-2038)

Table A.1. Hour of the Year Exceeding Cable 4605 and CTG Capacity

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
5416	5416	5416	5416	5416	5416	5416	5416	5416	5416	5416	5416	5416	5416	5416
5417	5417	5417	5417	5417	5417	5417	5417	5417	5417	5417	5417	5417	5417	5417
5441	5441	5441	5441	5441	5441	5441	5441	5441	5441	5441	5441	5441	5441	5441
5442	5442	5442	5442	5442	5442	5442	5442	5442	5442	5442	5442	5442	5442	5442
	5418	5418	5418	5418	5418	5418	5418	5418	5418	5418	5418	5418	5418	5418
	5440	5440	5440	5440	5440	5440	5440	5440	5440	5440	5440	5440	5440	5440
		5414	5414	5414	5414	5414	5414	5414	5414	5414	5414	5414	5414	5414
		5415	5415	5415	5415	5415	5415	5415	5415	5415	5415	5415	5415	5415
		5443	5443	5443	5443	5443	5443	5443	5443	5443	5443	5443	5443	5443
			5393	5393	5393	5393	5393	5393	5393	5393	5393	5393	5393	5393
			5394	5394	5394	5394	5394	5394	5394	5394	5394	5394	5394	5394
			5412	5412	5412	5412	5412	5412	5412	5412	5412	5412	5412	5412
			5413	5413	5413	5413	5413	5413	5413	5413	5413	5413	5413	5413
			5436	5436	5436	5436	5436	5436	5436	5436	5436	5436	5436	5436
			5438	5438	5438	5438	5438	5438	5438	5438	5438	5438	5438	5438
			5439	5439	5439	5439	5439	5439	5439	5439	5439	5439	5439	5439
			5444	5444	5444	5444	5444	5444	5444	5444	5444	5444	5444	5444
			5465	5465	5465	5465	5465	5465	5465	5465	5465	5465	5465	5465
			5466	5466	5466	5466	5466	5466	5466	5466	5466	5466	5466	5466
				5395	5395	5395	5395	5395	5395	5395	5395	5395	5395	5395
				5410	5410	5410	5410	5410	5410	5410	5410	5410	5410	5410
				5411	5411	5411	5411	5411	5411	5411	5411	5411	5411	5411
				5419	5419	5419	5419	5419	5419	5419	5419	5419	5419	5419
				5435	5435	5435	5435	5435	5435	5435	5435	5435	5435	5435
				5437	5437	5437	5437	5437	5437	5437	5437	5437	5437	5437
				5464	5464	5464	5464	5464	5464	5464	5464	5464	5464	5464
					5396	5396	5396	5396	5396	5396	5396	5396	5396	5396
					5420	5420	5420	5420	5420	5420	5420	5420	5420	5420
					5434	5434	5434	5434	5434	5434	5434	5434	5434	5434
					5445	5445	5445	5445	5445	5445	5445	5445	5445	5445
					5489	5489	5489	5489	5489	5489	5489	5489	5489	5489
					5512	5512	5512	5512	5512	5512	5512	5512	5512	5512
						5032	5032	5032	5032	5032	5032	5032	5032	5032
						5033	5033	5033	5033	5033	5033	5033	5033	5033
						5034	5034	5034	5034	5034	5034	5034	5034	5034
						5369	5369	5369	5369	5369	5369	5369	5369	5369
						5370	5370	5370	5370	5370	5370	5370	5370	5370
						5388	5388	5388	5388	5388	5388	5388	5388	5388

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
						5389	5389	5389	5389	5389	5389	5389	5389	5389
						5390	5390	5390	5390	5390	5390	5390	5390	5390
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						5392	5392	5392	5392	5392	5392	5392	5392	5392
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						5467	5467	5467	5467	5467	5467	5467	5467	5467
						5490	5490	5490	5490	5490	5490	5490	5490	5490
						5513	5513	5513	5513	5513	5513	5513	5513	5513
						5514	5514	5514	5514	5514	5514	5514	5514	5514
							4745	4745	4745	4745	4745	4745	4745	4745
							4914	4914	4914	4914	4914	4914	4914	4914
							5371	5371	5371	5371	5371	5371	5371	5371
							5372	5372	5372	5372	5372	5372	5372	5372
							5387	5387	5387	5387	5387	5387	5387	5387
							5397	5397	5397	5397	5397	5397	5397	5397
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							5458	5458	5458	5458	5458	5458	5458	5458
							5460	5460	5460	5460	5460	5460	5460	5460
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							5488	5488	5488	5488	5488	5488	5488	5488
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							5510	5510	5510	5510	5510	5510	5510	5510
							5511	5511	5511	5511	5511	5511	5511	5511
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								5373	5373	5373	5373	5373	5373	5373
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								5507	5507	5507	5507	5507	5507	5507
								5509	5509	5509	5509	5509	5509	5509
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								5562	5562	5562	5562	5562	5562	5562
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									4911	4911	4911	4911	4911	4911
									5028	5028	5028	5028	5028	5028
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									5273	5273	5273	5273	5273	5273
									5322	5322	5322	5322	5322	5322
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									5398	5398	5398	5398	5398	5398
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									5537	5537	5537	5537	5537	5537
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										4980	4980	4980	4980	4980
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										5082	5082	5082	5082	5082
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										5272	5272	5272	5272	5272
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										5433	5433	5433	5433	5433
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										5727	5727	5727	5727	5727
										5728	5728	5728	5728	5728
										5732	5732	5732	5732	5732
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											4528	4528	4528	4528
											4529	4529	4529	4529
											4530	4530	4530	4530
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											4739	4739	4739	4739
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											4955	4955	4955	4955
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											5374	5374	5374	5374

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
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											5517	5517	5517	5517
											5536	5536	5536	5536
											5540	5540	5540	5540
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												4748	4748	4748
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												4790	4790	4790
												4791	4791	4791
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												4917	4917	4917
												4936	4936	4936
												4938	4938	4938
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												4963	4963	4963
												4964	4964	4964
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												5247	5247	5247
												5297	5297	5297
												5298	5298	5298
												5319	5319	5319
												5320	5320	5320
												5323	5323	5323
												5362	5362	5362
												5386	5386	5386
												5423	5423	5423

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												5555	5555	5555
												5556	5556	5556
												5557	5557	5557
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													4719	4719
													4723	4723
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													4770	4770
													4771	4771
													4787	4787
													4788	4788
													4789	4789
													4795	4795
													4864	4864
													4867	4867
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													4906	4906
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													5245	5245
													5246	5246
													5276	5276
													5277	5277
													5456	5456
													5470	5470
													5494	5494
													5535	5535
													5541	5541
													5585	5585
													5633	5633
													5634	5634
													5753	5753
													5800	5800
													5802	5802
														4504
														4507

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
														4526
														4718
														4738
														4765
														4768
														4796
														4816
														4883
														4935
														4939
														5084
														5226
														5243
														5244
														5270
														5271
														5296
														5317
														5318
														5324
														5408
														5447
														5481
														5533
														5534
														5565
														5584
														5586
														5609
														5610
														5632
														5682
														5705
														5706
														5752
														5754
														5799

Appendix B – Optimal Dispatch Formulation Notation

Decision Variables	Description	Unit
Power_h^{+}	Discharged power into the grid in hour h	MW
Power_h^{-}	Charged power from the grid in hour h	MW
b_h	Binary variable: charging/discharging in hour h	N/A
$\text{Power}_h^{\text{out}}$	Power output of the BESS in hour h	MW
Energy_h	Energy state of the BESS in hour h	MWh
Reg_h^{up}	Regulation-up capacity in hour h	MW
Reg_h^{dn}	Regulation-down capacity in hour h	MW
$\text{Reg}_h^{\text{serv}}$	Regulation service energy in hour h	MWh
Spin_h	Spinning reserve in hour h	MW

Parameters	Description	Unit
η^{+}	Discharging efficiency	N/A
η^{-}	Charging efficiency	N/A
$\text{Power}^{\text{max}}$	Maximum power capacity of the battery	MW
$\text{Energy}^{\text{max}}$	Maximum energy capacity of the battery	MWh
$\text{Power}_k^{\text{req}}$	Output power requirement in hour k	MW
ε_h	Reserved regulation energy ratio in hour h	MWh/MW
λ_h	Predicted energy price of hour h	$/MWh
π	Regulation performance score	N/A
β_h	Regulation capacity price of hour h	$/MW
γ_h	Regulation service price of hour h	$/MWh
μ_h	Spinning reserve price of hour h	$/MW

PNNL-28941

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