Final Scientific / Technical Report

GE/Alstom Grid's Microgrid RD&D and Testing of PIDC and PWD Systems

Work Performed Under Agreement: DE-OE0000725

Version 1.0 – April 2021

GE Grid Solutions

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1. Preface

In 2015 General Electric (GE) purchased Alstom Grid, Inc., all of their assets, debts, product and projects. As such, this RD&D project, partially funded by DOE award DE-OE0000725, was acquired and incorporated into GE's portfolio of deliverables to the U.S. Department of Energy. Throughout this report any reference to Alstom, Alstom Grid, or Alstom Grid, Inc. are legacy and owned by GE. GE is the prime contractor on the remainder of the referenced project, however due to timing of the acquisition, dates of reporting and testing performed, and transfer of project information, some references to the legacy Alstom names remain in this project. All associations with Alstom should be referred hereto as GE.

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1.2 Acknowledgement

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1.3 Conventions

Table 1-1 lists terms and abbreviations used in this document.

Table 1-1 Terms and Abbreviations

Term/Abbreviation	Description
µPMUs	Micro phasor measurement units
AFB	Application Functional Block
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
BEMS	Building Energy Management System

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Term/Abbreviation	Description
BESS	Battery Energy Storage System
BTrDB	Berkeley Tree Database
CFE	Communication Front End
CHIL	Control hardware-In-the-Loop
CHP	Combined Heat Plan
CIEE	California Institute of Energy and Environment
DAP Server	Digital Automation Platform Server
DER	Distributed Energy Resource
DER-CAM	Distributed Energy Resources Customer Adoption Model
DMGCS	Distributed Microgrid Control System
DNP	Distributed Network Protocol
DOE	U.S. Department of Energy
DR	Demand Response
DTE	DTE Energy (formerly Detroit Edison)
DVR	Dynamic Voltage Restorer
EMS	Energy Management System
EPS	Electric Power System
EV	Electric Vehicle
FEP	Front End Processor
FOA	Funding Opportunity Announcement
GridNOC	Grid Network Operating Center
GridSTAR	Grid Smart Training and Application Resource
HMI	Human Machine Interface
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
MACS	Microgrid Automation Control System
MEMS	Microgrid Energy Management System
MiCOM	GE Trademark/Relay
MSCS	Microgrid Supervisory Control System
MVA	Mega Volt Amperes
NEMA	National Electrical Manufacturers Association
NETL	National Energy Technology Laboratory
NMPR	Navy Manufacturing and Propulsion Research
OE	Office of Electricity
PCC	Point of Common Coupling
PIDC	Philadelphia Industrial Development Corporation

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Term/Abbreviation	Description
PMUs	Phasor Measurement Units
PNNL	Pacific Northwest National Laboratory
POI	Point of Interconnection
PPM	Percent Per Million
PSRC	Power Systems Relaying Committee
PV	PhotoVoltaic
PWD	Philadelphia Water Department
RD&D	Research Design and Development
ROCOF	Rate of Change of Frequency
RTAC	Real Time Automated Controller (SEL automation platform/trademark)
SCADA	Supervisory Control and Data Acquisition
SDC	Substation Data Concentrator
SEL	Schweitzer Engineering Laboratories
SOC	State of Charge
TAG	Technical Advisory Group (for the DOE Office of Electricity)
TNY	The Navy Yard
TPO	DOE/NETL Technical Project Officer
TTL	Time To Live

2. Executive Summary

2.1 Background, Objectives and Vision

Alstom Grid Inc's (ALSTOM Grid) Research Design and Development (RD&D) project, "Microgrid RD&D and Testing for PIDC and PWD" was conducted in partnership with Philadelphia Industrial Development Corporation (PIDC) in its role as owner's representative and manager of a vibrant commercial and industrial community, involving critical loads in one of the nation's largest unregulated, non-military electric distribution systems. PIDC needed to develop solutions to address the planned considerable growth in Distributed Energy Resources (DER) Combined Heat Plan (CHP), Renewables, Distributed Generation (DG), Demand Response (DR) and Storage.

In supporting the corporate objective, PIDC needed a new class of control systems for achieving enhanced energy resilience of their critical infrastructure operation during adverse conditions together with carbon emission reduction and optimization of the overall system operation economics through system energy efficiency during normal and emergency operating conditions. Additionally, PIDC anticipated the need to support a new class of commercial agreements with tenants, such as those for Urban Outfitters, for guaranteed one hundred percent (100%) grid resilience and electric power supply in case of utility outage conditions.

2.1.1 Specific Objectives of the Project

Figure 2-1 shows the proposed objectives and planned methods of this RD&D project.

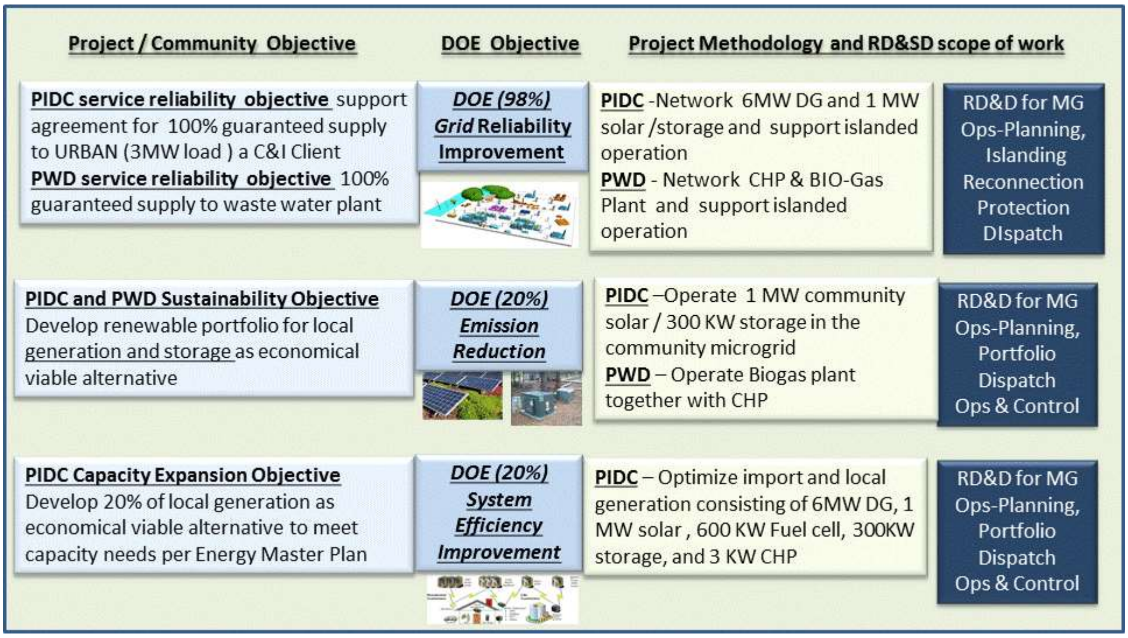

Figure 2-1 Project Objectives/Methods Employed for RD&D Scope of the Work

The project was designed to address the challenges for the commercial & industrial (C&I) communities. But more importantly, the project included development of scalable and replicable solutions intended to target a multitude of the nation's electric distribution communities. The project researched and developed a fully comprehensive prototype consisting of microgrid operation and control functions including islanding, synchronization and reconnection, protection, voltage, frequency, and power quality management, dispatch, and system resiliency. The project provided the foundation required to significantly enhance the overall national objectives set by the DOE for energy resilience, emission reduction and system energy efficiency improvement, including protection of critical infrastructure and public resources.

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2.2 Microgrid Controller Requirements and Project Result

The term "microgrid controller" as used in the DOE funding opportunity announcement (DE-FOA-0000997) refers to "…an advanced control system, potentially consisting of multiple components and subsystems, capable of sensing grid conditions, and monitoring and controlling the operation of a microgrid so as to maintain electricity delivery to critical loads during all microgrid operating modes (grid-connected, islanded, and transition between the two)."

A fundamental requirement is that the microgrid controller complies with the IEEE 1547™ [1] series of interconnection standards, including any revisions or applicable emerging standards that may become available during the course of the proposed effort. In addition, parallel to the project execution, the project team got engaged and contributed actively for developing IEEE standard resulting in publication of Microgrid Functional Specification, called IEEE 2030.7 [13] and Microgrid Test Specification, called IEEE 2030.8[14]. Additionally, the prototype controller shall be capable of dispatching microgrid assets, interfacing with external parties (e.g., aggregators, distribution utilities, market operators), and coordinating with grid protection schemes under all fault conditions (to ensure safeguarding of the system, equipment, and personnel).

Specifically, microgrid controllers developed under this FOA must (at a minimum) satisfy the following technical functional requirements for operating/managing a microgrid system.

2.2.1 Disconnection

While grid-connected, a microgrid must comply with the IEEE 1547™ Standards[8] at the point of common coupling (PCC).

2.2.1.1 FOA Requirements

Table 2-1 and Table 2-2 show the maximum islanding time criteria for different voltage and frequency ranges, respectively. In both tables, the maximum islanding time is interpreted as the maximum time between the start of the voltage or frequency range and microgrid islanding from the area EPS. Under this FOA, disconnection must be completed within the maximum islanding times specified in these tables.

Table 2-1 Microgrid Islanding Criteria Based on Voltage Ranges

Voltage (V) range in per unit (pu)	Maximum islanding time in seconds (s)
V < 0.5	0.16
0.5 ≤ V < 0.8	2.00
1.1 ≤ V < 1.2	1.00
V ≥ 1.2	0.16

Table 2-2 Microgrid Islanding Criteria Based On Frequency Ranges

Frequency (f) range in Hertz (Hz)	Maximum islanding time (s)
f > 60.5	0.16
f < {59.8-57.0} (adjustable set point)	Adjustable 0.16 to 300
f < 57.0	0.16

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2.2.1.2 Goal Achievement

The simulation shows the grid fault occurs at 4 seconds. The microgrid controller detects the fault and commands the PCC breaker to open at about 4.05 seconds. The time lag is attributed to communication latency and to ensure the fault is not due to measurement errors. Once the breaker gets an OPEN command, it takes about 5 more cycles for the breaker contacts to fully open. The breaker then eventually opens at about 4.15 seconds. Once the breaker opens completely, the microgrid controller transitions to islanded mode of operation by changing the battery's operation mode.

The simulation also shows the following transient measurement at time of islanding:

- Grid Power and Battery Power
- Grid and PCC Voltage and Frequency

2.2.2 Resynchronization and Reconnection

Before reconnecting the microgrid system to an area EPS, monitoring should first indicate the islanded microgrid is properly synchronized with the EPS. After an area EPS disturbance and subsequent microgrid islanding, reconnection shall not be initiated until the area EPS voltage is within Range B of the American National Standards Institute/National Electrical Manufacturers Association (ANSI/NEMA) Standard C84.1-2006, Table 1 [36], the phase angle difference is within the limits defined by IEEE 1547™[8], and the frequency range is between 59.3 Hz to 60.5 Hz[8].

2.2.2.1 FOA Requirement

The microgrid must ensure reconnection occurs when the frequency difference, voltage magnitude difference, and voltage phase angle difference between the area EPS and microgrid on either side of the microgrid switch are within the limits defined by IEEE 1547™ [8]. For a microgrid with a rating between 1.5 and 10 megavolt-amperes (MVA), Table 2-3 shows these reconnection requirements.

Table 2-3 Microgrid Reconnection Requirements

Microgrid rating (MVA)	Frequency difference (Δf, Hz)	Voltage difference (ΔV, %)	Phase angle difference (ΔΘ, °)
1.5-10	0.1	3	10

2.2.2.2 Goal Achievement

The simulation shows the system is in islanded condition up to 8 seconds. Then, the grid fault is cleared at about 8 seconds. The controller waits for about 1 second to ensure the grid parameters are within steady state and then initiates the resynchronization procedure. As a part of the resynchronization, the microgrid voltage (at the open PCC) is controlled to match the phase angle, frequency, and voltage of the grid. Eventually, when the voltages at the grid and microgrid side of the PCC are within a certain configurable tolerance, the PCC breaker closes. Thereby, resynchronizing the microgrid to the grid. The simulation shows that grid connection occurs at about 9.34 seconds.

The simulation also shows the following transient measurement at time of reconnection:

- Grid and PCC Voltage and Frequency

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2.2.3 Steady-State Frequency Range, Voltage Range, and Power Quality

2.2.3.1 FOA Requirement

An islanded microgrid in steady state operation must:

- Maintain the frequency in the range 59.3 Hz < f < 60.5 Hz — a range consistent with the frequency range for an area EPS and suitable for most loads — barring customer-specific requirements that may override this range.
- Maintain the voltage according to ANSI 84.1-2006 standards — specifically, the required voltage range for microgrid islanded steady-state operation is 0.95 pu<V< 1.05 pu at the PCC.
- Maintain the power quality at the PCC in compliance with customer-specific requirements.

2.2.3.2 Goal Achievement

The simulation showed that once the island stabilizes after the island formation, the CHP generator starts about 6 seconds. The initial inrush in power to the generator is the energization of the system. The power of the generator is ramped to about 20 kW, limited by the permissible ramp rate of the generator. Correspondingly, the battery power reduces by 20 kW to offset the power generation from the CHP generator.

The simulation also shows the following transient measurement from islanding to steady state:

- PCC Voltage and Frequency
- CHP and Battery Power Output

2.2.4 Protection

A microgrid must provide adequate protection in both grid-connected and islanded states. However, the challenges differ in these two states. The development of microgrid protection requirements is guided by the following three general principles, in order of priority:

1. Prevent injury to personnel and ensure public safety.
2. Prevent or minimize equipment damage.
3. Minimize loss of load within the constraints of 1 and 2.

The simulation is not applicable to protection function above.

2.2.5 Dispatch

This functionality was developed in close collaboration with IEEE 2030.7 and IEEE 2030.8 <JUN to ADD on IEEE 2030.7)

2.2.5.1 FOA Requirement

A microgrid controller is the unifying component that coordinates the operations of all resources and loads to ensure achievement of three fundamental microgrid objectives:

- Survivability
- Economic Operation
- Satisfactory Environmental Performance

2.2.5.2 Goal Accomplishment

Dispatch for microgrid survivability includes, but is not limited to:

- While grid-connected, ensuring sufficient resources (e.g., generation and/or energy storage) are operating and available to support the microgrid's seamless transition to island mode.
- While islanded, managing energy resources consistent with ensuring service to the microgrid critical loads for the duration of the islanded state.

Dispatch for economic operation may include, but is not limited to:

- Optimization of the microgrid's energy consumption and generation against electric and natural gas tariffs.
- Provision of services to the grid (area EPS), which got well defined and detailed as part of IEEE 2030.7[13], such as:
    - Energy,
    - Volt/VAR Support
    - Frequency Regulation
    - Spinning Reserve
    - Black Start Support
    - Demand Response

Dispatch for environmental performance includes reducing or limiting CO_2 emissions.

The microgrid controller must coordinate the operation of the microgrid resources consistent with the requirements of the foregoing dispatch objectives, including interaction with external entities when dispatched.

The resources and loads within an actual microgrid would likely be of different types, manufacture, and so on. As such, applications submitted in response to this FOA are expected to reflect this "real world" environment as much as possible. Therefore, while preparing their application, applicants should keep in mind that a desired outcome, under this FOA, is the development of interoperable approaches that enable simplified system integration.

The simulation is performed in terms of the following:

Load Management

The simulation shows the battery discharge power reduces by 30 kW to a very low value. The battery along with the solar power is then sufficient to meet the critical load. The load turns OFF at 8 seconds. The transient at about 9.2 seconds is due to the battery controller trying to regulate the PCC voltage to nominal after a certain time delay.

Solar-Storage Management

The simulation shows the optimizer has indicated that the battery should transition from charging to discharging mode to ensure it's ready to capture the solar available in the day ahead forecast. The dispatch from the optimizer and changes the reference to the battery controller.

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2.2.6 Enhanced Resilience

2.2.6.1 FOA Requirement

The microgrid controller must be capable of managing microgrid resources to meet the community-defined resilience objectives during disruptive events. The microgrid controller must also provide sufficient information to distribution system operators to enable the communication of accurate information on operating conditions of the microgrid to communities, especially those responsible for critical loads.

The simulation is not applicable to Enhanced Resilience above.

2.3 Project Community Partner – The Philadelphia Navy Yard

The Philadelphia Navy Yard has 125 years of heritage for being the country's premier military base and shipyard. In the year 2000, the 1,000-acre parcel was acquired by the Philadelphia Authority for Industrial Development (PAID), a public authority incorporated by the City of Philadelphia. PAID serves as a vehicle through which PIDC manages properties and industrial sites on behalf of the City including property acquisition, improvement, environmental remediation and/or sale. The Navy Yard (TNY) has historic waterfront campus with easy and fast access to airport, universities and regional highways.

One of the key planned contributions from the community partner TNY is includes the test bed for microgrid controller testing. Original plan was to leverage a pre-existing project /building called GRIDSTAR detailed later in the section. However, during course of execution of the project the plan was modified to use 7R building of Penn State university called GRIDTSAR2 as described in Chapter 5.

GRIDSTAR (Grid Smart Training and Application Resource) was net zero energy demonstration project spearheaded by GE and Penn State with support from the U.S. Department of Energy, Commonwealth of Pennsylvania and Philadelphia Industrial Development Corporation (PIDC), the GridSTAR Center was built to serve as a valuable hub for workforce training, building performance testing, energy management research and "smart" microgrid modernization deployments.

At the beginning of the DOE project, the TNY campus had over 120 companies and 10,000 employees with excess of 6.5 million sq. ft. occupied with the support of +$650 million of private investment. TNY established the ambition of aggressive real estate growth requiring a serious development of a campus microgrid to meet the electric supply and infrastructure needs. That led to the Five Point Action Plan as follows:

- "Smart Grid/Microgrid" Infrastructure
- The Business Model
- Building Owner Opportunities
- Testbed Outreach and Protocols
- Carbon Reduction and Sustainability

To a great extent, this GE/Alstom Grid project has helped PIDC in achieving the above goals.

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2.4 The Project Team

Figure 2-2 shows the organizational break down structure of the proposed team.

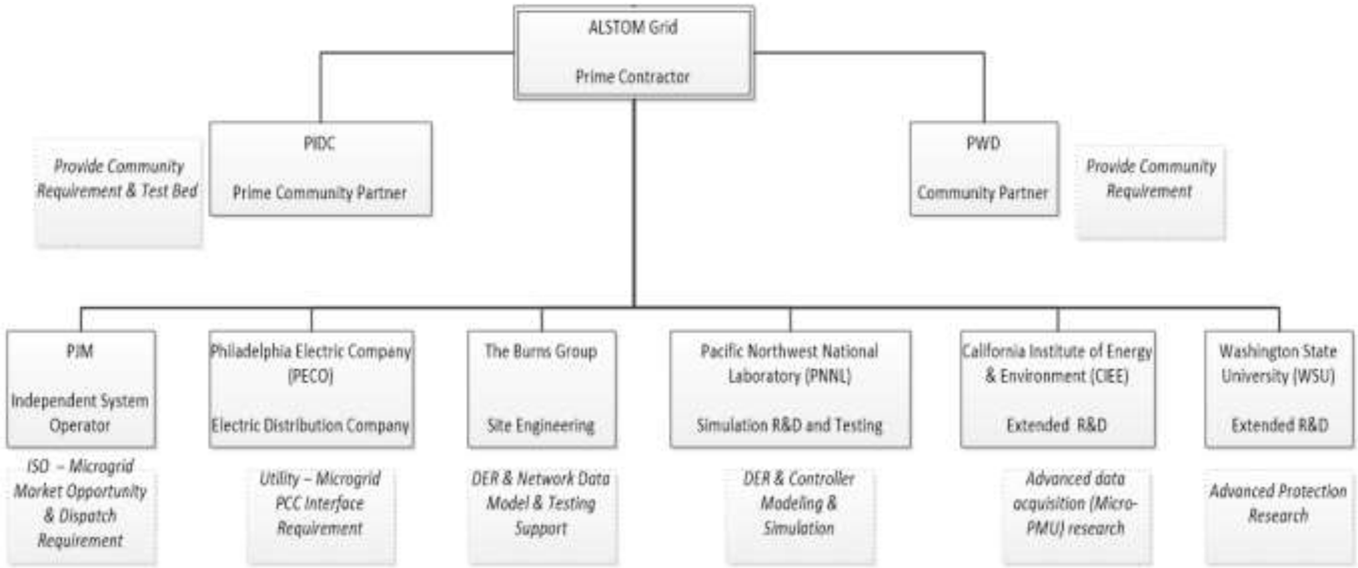

Figure 2-2 Organizational Breakdown Structure

The strong interactions that existed within the combined team of technical expertise, provided by GE Grid Solutions (Formerly ALSTOM Grid) and Burns Engineering Group, research being provided by PNNL, CIEE and Washington State University, and the commercial grid site of PIDC–where the business case was considered and demonstrated–provided data verification for significant enhancement to the viability of solutions developed.

Figure 2-2 also shows a summarized version of task assignment indicating roles and responsibilities in italics under the box of each of the team members. Section 2.5 shows the detailed task assignment of each team-member by work breakdown structure.

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2.5 Scope of Work from Statement of Project Objectives

The effort was organized into three phases of work:

- Planning and Requirement Research
- Research and Development of Prototype
- Simulation and Field Testing

2.5.1 Phase 1: Planning and Requirement Research

This phase consisted of:

- Performing a feasibility study and analysis of the selected microgrid site and to establish baselines for measurement and verification.
- Defining the microgrid operating scenarios and required distribution circuit switching design.
- Researching, analyzing, and establishing the requirements of microgrid system management functions and microgrid controller functions.

2.5.2 Phase 2: Research and Development of Prototype

This phase included:

- Developing a prototype microgrid system management module to support Dispatch Plan and Operation Plan (grid resilience) in a simulation environment.
- Developing a prototype microgrid controller management module to support microgrid islanding, synchronization and reconnection, protection, voltage, frequency, and power quality management.
- Preparing a test plan for simulation and field testing of the developed prototype.

2.5.3 Phase 3: Simulation and Field Testing

This phase involved:

- Performance of microgrid controller testing to validate functionalities.
- Conducting simulation and field testing.
- Analyzing test results and preparing required reports.

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3. Project Execution Summary & Compliance to SOPO

3.1 Project Milestone History

Table 3-1 shows the project milestone history.

Table 3-1 Project Execution Milestone

MS#	Milestone Title/Description	Planned Completion Date	Actual Completion Date
1	Award Definition	3/31/2015	3/31/2015
2	Updated PMP (within 30 days of Award)	12/3/2014	12/3/2014
3	Kick-off Meeting (within 30 days of updated PMP)	2/18/2015	2/18/2015
4	Updated preliminary test plan (due within 9 months of project award)	2/24/2016	3/4/2016
5	Final test plan (resubmitted to DOE within 30 days of receipt of DOE review comments)	1/31/2016	4/23/2016
6	A Summary Report describing the proposed microgrid (not less than 90 days prior to the planned start of testing activities)	3/1/2017	6/27/2018
7	Pre-test briefing – not less than 90 days prior to the planned start of testing	3/1/2017	6/27/2018
8	Start of Testing	6/1/2017	8/1/2018
9	End of Testing	8/31/2017	3/31/2021
10	Final project briefing – not less than 30 days prior to the end of the project	11/30/2017	4/28/2021
11	Final technical report (within 90 days after award ends)	12/31/2017	4/28/2021
12	Final Feasibility Study	12/31/2017	5/14/2021
13	Q1-2020 Due to further delays in testbed construction followed by Covid-19, it was agreed – (1) Testing will be limited to simulation only (2) MS #9, 10, 11 &12 completion to take place at earliest possible		3/31/2021

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3.1.1 Key Milestone/Delays Highlights

- Three "No Cost Extensions" were requested due to delays in contract finalization and other project operation/administrative activities resulting in 14 months of schedule impact. Consequently, the testing started on 8/1/2018 as opposed to the original milestone date of 6/1/2017.
- Additional no cost extensions were filed due to malfunctioning of testbed equipment and challenges in testbed construction resulting in overall 28 months of schedule impact.
- With the advent of COVID-19, during Q1-2020, the project team agreed and got approval from DOE to complete the project with "simulation test only". Accordingly, it was agreed to perform simulation only testing and complete the project with the following testing approach.

Table 3-2 Test Case and Test Approach Summary

Test Case Group	Test Methodology	Report Section
GridSTAR 2.0 Microgrid Control Simulation	Hardware in the Loop Simulation	Chapter 6
GridSTAR 2.0 Microgrid Optimization Simulation	Software Simulation	Chapter 7
Substation 93 and 602 Microgrid Test	Field Operation Test	Chapter 8

3.2 Key Project Accomplishments

FY 2014 – 2016

- **Unique Framework for Microgrid Design** - As described in Appendix A, the Navy Yard microgrid feasibility study work led to development of a unique framework for microgrid system planning and design.
- **Novel Methodology for Benefit to Cost Computation** – A novel methodology was developed for the computation of benefit to cost ratio for a given microgrid design operation especially when multiple stakeholders are engaged. See Appendix A for details.

FY 2015 – 2018

- **IEEE 2030.7 and IEEE 2030.8 Development and Approval** – The microgrid controller testing standard development was a collaborative effort by nearly 80 participants representing utilities, industry, and academia. The Alstom team contributed with active participation while working on DOE/OE's Microgrid Research Development and System Design project. On Thursday, June 14, 2018, the Standard for Testing of Microgrid Controllers (IEEE Std 2030.8) was approved as a new standard by the IEEE Standards Association (SA) Board preceded by IEEE 2030.7 standard approval and publication.
- **USA DOE – China NEA Collaboration for Climate change Working Group (CCWG)** – The microgrid Engineers and scientists from USA led by the US DOE Office of Electricity collaborated with the counterparts from China led by China National Energy Authority (NEA) for
    - Advancement of the state of art in Microgrid Technology
    - Benefit Evaluation of Microgrid design and operation

  Alstom project team made significant contributions to the CCWG workshops conducted over a 3 year period resulting into white paper publication.

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FY 2019 – 2021

Commercialization of the RD&D work – Alstom RD&D project led to commercialization of GE Microgrid Energy Management System Product and is now being deployed in multiple sites. Examples include but not limited to:

- DoD Site - Portsmouth Naval Shipyard
- University Site – Washington State University

3.3 SOPO Compliance to Project Tasks & Deliverables

Table 3-3 provides the full compliance to SOPO:

Table 3-3 Project SOPO Compliance

Phase 1	Task	SubTask	Description	Deliverables	Status	Status & Compliance
	Task 1.0		Project Management and Planning	Updated PMP	Complete	Submitted - 12/3/2014
		Subtask 1.1	Feasibility Study	Final Feasibility Study Report	Complete	Please see Appendix A
	Task 2.0		Environmental Questionare	Environmental Questionare	Complete	Submitted - 12/3/2014
Phase 1	Task 3.0		Microgrid System Planning and Design		Complete	Please see Chapter 4,5 and 6
		Subtask 3.1	Operating Scenarios		Complete	
		Subtask 3.2	Distribution Grid Configuration and Switching		Complete	
		Subtask 3.3	System and Utility Interface		Complete	
		Subtask 3.4	Controller Functionality		Complete	
	Task 4.0		Advanced Microgrid Controller Prototype R&D	Microgrid Summary Report	Complete	Please see Chapters 5,6,7 and 8
		Subtask 4.1	Development of Microgrid System Management and Simulator Prorotype		Complete	
Phase 2		Subtask 4.2	Implementation of the Microgrid Controller Configuration		Complete	
		Subtask 4.3	Integration of system management module with the controller		Complete	
	Task 5.0		Test Preparation	Preliminary Test Plan	Complete	Submitted - 4/23/2016
	Task 6.0		Test Execution	Final Test Report	Complete	This document
	Task 7.0		Analysis and Results Reporting		Complete	

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4. Project Technical Highlights

4.1 Project Technical Summary

Alstom Grid's preliminary test plan defined how the technical feasibility and economic performance of the controller functions (outlined in the DOE FOA [1] sections I.C.1 through I.C.6) would be validated through testing appropriate for the Navy Yard Microgrid System Design.

Figure 4-1 provides an overview of the TNY electrical distribution system [2]. The two major Navy Yard substations (shown in the figure as 93 and 664) are connected to two separate PECO substations. There is no interconnection between these two distribution stations at this stage. The microgrid substation system SS602 gets its supply from SS93 and the GridSTAR 2.0 microgrid system is supplied by SS664.

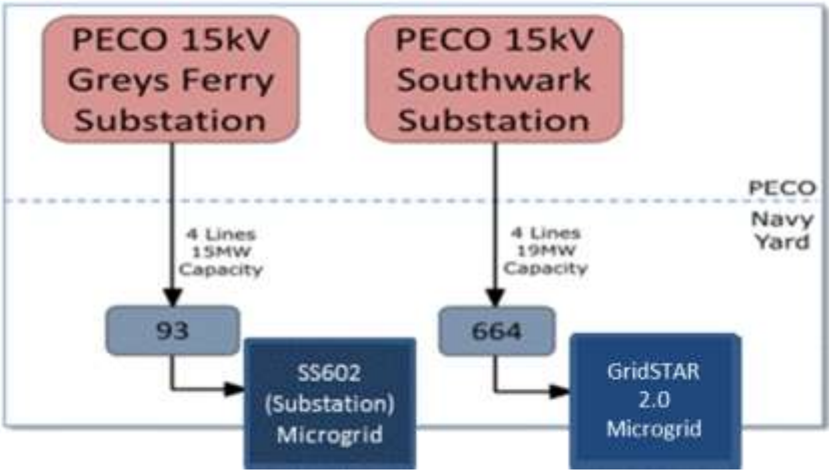

Figure 4-1 Overview of The Navy Yard Microgrid Electrical Distribution System

Table 4-1 presents details of the Navy Yard Microgrid assets and load.

Table 4-1 The Navy Yard Microgrid Assets and Electrical Load

Microgrid Assets & Loads	Microgrid System	Load kW		Distributed Energy Resources				
		Peak load	Minimum	Solar PV	Storage	NG Gen	CHP	Fuel Cell
Building 7R	GridSTAR 2.0	50	20	15	50kW/90kWh		65	
Building 661	GridSTAR 2.0	80	20					
Bldg 489 - 1	GridSTAR 2.0	74	30					
Bldg 489 - 2	GridSTAR 2.0	250	80					
Bldg 489 - 3	GridSTAR 2.0	100	60					
League Island Park	GridSTAR 2.0	4.5	0					
	Totals	**558.5**	**210**	**15**	**50**	**0**	**65**	**0**
		Average load	**Controllable load**					
Natural Gas Generators	SS602					6000		
Sustation Storage	SS602				2000			
Community Solar	SS602			750	250			
Aker Shipbuilding	SS602	3000	1000					
Naval research	SS602	6000						
TastyKake Bakeries	SS602	1300	400					
Rhodes Industries	SS602	800	200	2000	2000			
Central Fire Pump Station	SS602	100						
Urban Outfitters	SS602	1500	500				800	800
	Totals	**12700**	**2100**	**2750**	**4250**	**6000**	**800**	**800**

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Figure 4-2 below presents an overview of the Navy Yard Microgrid System design.

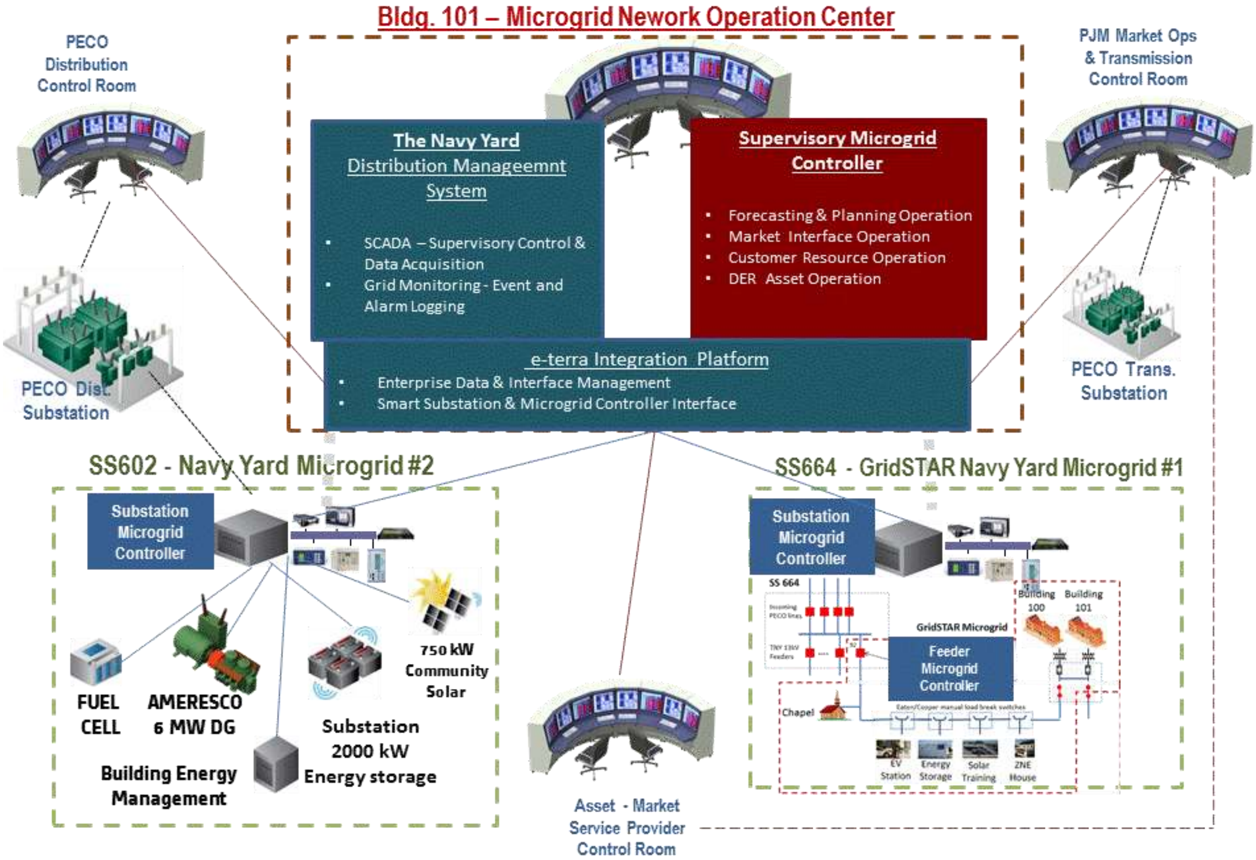

Figure 4-2 Overview of The Navy Yard Microgrid System Design

The essence of this project lies under the rubric of "microgrid automation". The brain for achieving automation is in the robust design, testing, and operation of a "Distributed Microgrid Control System (DMGCS)", which was a main objective of this project. The hierarchical control of the TNY microgrid was respected and followed strictly.

The following shows how to achieve this philosophy of distributed hierarchal control in the most efficient and effective manner:

- **First Level** – Supervisory Microgrid controller (Implemented using existing Alstom /GE **e-terra** *distribution* platform[9]) was configured for the entire TNY 13.2-kV power system. This will be an integral part of the GridNOC, which is located in Building 101.
- **Second Level - Substation Microgrid Controller** (Implemented using existing Alstom /GE **DAP***Server* platform[7]) was configured for the each of the SS664 and SS602 substations.
- **Third Level - Feeder Microgrid Controller** (Implemented using existing Alstom /GE **DAP***Server* platform) was configured for the Feeder 1305 making up the GridSTAR 2.0 microgrid system.
- **Fourth Level – Microgrid Device Controller** (Implemented using existing Alstom C264 *platform* wherever appropriate) was configured for the Point of Common Coupling (PCC) Control and other device controls as necessary.

Thus, ALSTOM/GE ***Distributed Microgrid Control System*** **(DMGCS)** supports a distributed hierarchal architecture. See Figure 4-3.

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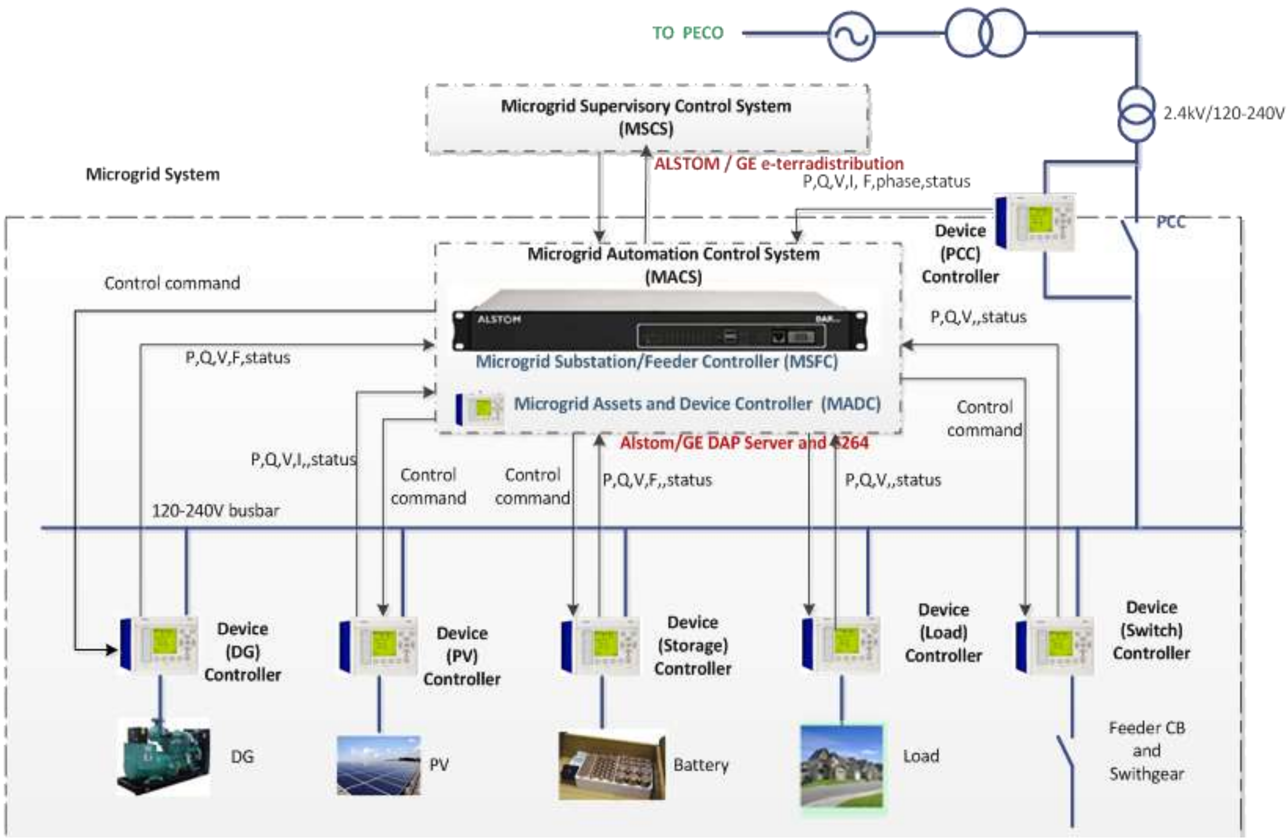

Figure 4-3 Alstom/GE Distributed Microgrid Control System (DMGCS) Architecture

DOE funding was used to develop the ALSTOM/GE ***Distributed Microgrid Control System*** **(DMGCS)** prototype through configuration and integration of the following existing ALSTOM /GE platforms:

- Alstom/GE **e-terra***distribution*[9] platform - Provides network modelling and power system analysis and simulation capabilities, such as power flows and resource dispatch applications as required meeting the needs for the Sections 2.2.5 and 2.2.6 of this report.
- Alstom/GE **DAP***Server*[7] / *Wide Area Control Unit* platform - Provides a rich set of monitoring, operation and control application function blocks (AFBs) for different applications, such as islanding, reconnection, voltage–frequency management, protection, dispatch, and enhanced resilience as specified in Sections 2.2.1 through 2.2.6 of this report.
- Alstom /GE **C264** Device Control platform - Provides front end device control for various scenarios wherever applicable, such as:
    a. PCC Controller
    b. Switch Controller
    c. DER (DG, PV, Storage, EV and Controllable Load) Controller

In summary, ALSTOM /GE ***Distributed Microgrid Control System*** **(DMGCS)** consists of two subsystems:

- Microgrid Supervisory Control System (MSCS), which includes:
    a. Alstom /GE **e-terra***distribution*
    b. PNNL GridLab-D[10]
- Microgrid Automation Control System (MACS), which consists of:
    a. Substation/Feeder Microgrid Controller (SFMC)
    b. Microgrid Device & Asset Controller (MDAC)

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4.2 GE Product Functions

Alstom/GE Microgrid Controller functions are classified into four categories:

- **Monitoring and Mode Management** - Manages the mode of operations, evaluates the microgrid conditions and performs status checks.
- **Control Functions -** Ensures reliable and efficient operation of the islanded microgrid autonomously and provide support functions to the supervisory controller for grid-connected mode.
- **Power Operation Mix Management Functions** - Perform or support power mix dispatch.
- **Protection and Resilience Functions**.

Table 4-2 and Table 4-3 describe the Alstom/GE MACS Application Functional Block (AFB) functions.

Table 4-2 Alstom/GE Microgrid Automation Control System (MACS) Top Level AFB Functions

Class	Top-Level Function	Description
Monitoring and Mode Management	F1. System Status	Establish connectivity state of the MG: interconnected or islanded.
	F2. System Monitoring	RT tracking of local load and DER.
Control Functions and Resiliency	F3. Operating Mode Transitions	Manages mode transition processes to ensure seamless transition to/from islanded mode.
	F4. Device Level Control	Provides coordinated control signals for local DER and switches in the MG.
	F5. Load Management	RT management, prioritization, and command of available MG controllable loads.
Power Mix Management	F6. Operation Strategy	Defines operating DER set points according to MG operating targets in the various operating modes.
Protection	F7. Protection	Adapts protection relay settings to the operating state of the MG.

Table 4-3 Addressing the DOE FOA Goals - C1 to C6 Top-Level Function Mapping

No.	Goals (functionalities) for TNY	Top-Level Functions Mapping per Goal
C1	Disconnection	F1, F2, F3, F4, F6, F7
C2	Resynchronization and Reconnection	F1, F2, F3, F4, F5, F6, F7
C3	Steady-State Frequency Range, Voltage Range, and Power Quality	F4, F5, F6
C4	Protection	F1, F2, F7
C5	Dispatch	F1, F2, F5, F6
C6	Enhanced Resilience	F1, F3, F5, F6, F7

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4.3 Test Approach for FOA Targets

Table 4-4 through Table 4-6 describe how the Alstom/GE team planned to test the FOA functionality C.1 through C.6 in the Navy Yard Microgrid Project.

Table 4-4 Test Scenario for FOA Functionality C1 thru C4

Case 1	Unplanned Islanding
Case 2	Grid Reconnection
Case 3	Island Mode- Voltage & Frequency Control
Case 4	Island Mode- Load Management
Case 5	Island Mode- Solar-Storage Management
Case 6	Island Mode- Controller Override Optimizer

Table 4-5 Test Scenario for FOA Functionality C3 thru C5

Case 1a	Grid Connected Economic Dispatch - SOC 100%
Case 1b	Grid Connected Economic Dispatch - Peak Load
Case 1c	Grid Connected Economic Dispatch - SOC 50%
Case 2	Grid Connected Mode - Peak Reduction Optimization
Case 3a	Island Mode - Planned Islanding Economic Dispatch
Case 3b	Island Mode - Peak Day planned Economic Dispatch
Case 4	Island Mode - Unplanned Islanding Economic Dispatch
Case 5a	Island Mode - Maximize Time to Live (TTL) Normal Day
Case 5b	Island Mode - Maximize Time to Live (TTL) Peak Day

Table 4-6 Basic Monitoring, Control, Situation Awareness Functions for C1 thru C3

Test 1.1	Measurement of Electrical Conditions on the Microgrid
Test 1.2	Load Measurements
Test 1.3	Microgrid Power Supply Measurement
Test 1.4	Control Output Delivery and Timing
Test 2.1	System Status
Test 2.2	System Monitoring

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5. Microgrid System Design and Test Plan

5.1 Overview

Purpose and background of Multiple Microgrid Systems for the Alstom Project

As described, Philadelphia Navy Yard consists of multiple microgrid systems of which two microgrid systems have been considered as part of the Alstom microgrid controller project with the following purposes:

- GridSTAR 2(Test System I) - Hardware in the loop simulation of C1, C2, and C3 Controller Functions as defined in the FOA.
- SS602 (Test System II) - Functional demonstration of the C5 controller function as well as all live demonstration of monitoring functions of the controller Feasibility and Simulation Study for Microgrid mode operation.

Study simulation scenario and the benefit to cost computation for microgrid controller is described in Appendix A in detail, which is based on the following cases of SS602 microgrid operation:

- **Case 1**: This configuration was designed to reduce the outage to minimum possible duration subject to economic constraint for a SS602 sub-microgrid within the Philly Navy Yard, resulting into 0.8 MW of Fuel Cell, 2.75 MW of PV, and 4.25 MW Storage as shown in Table 4-1 in this report. Also, this configuration also meets the carbon reduction goal of more than 20% as stipulated by the DOE FOA.
- **Case 2**: This case scenario is primarily driven by system efficiency gain objective through economic benefits realized by reducing peak charges. The scenario resulted in only 6 MW of IC Engine (Natural Gas Generation) at SS 602.
- **Case 3**: This scenario is combination of Case 1 and Case 2.

For this project, the Alstom team planned to develop and test two separate microgrids at the Navy Yard as follows:

- Microgrid Test System I - GridSTAR 2.0: Due to decommissioning of the GridSTAR Center, the GridSTAR 2.0 microgrid included demonstration of actual live operation of the distributed microgrid controller and associated facilities on the energized 13.2 kV circuit that normally supplies this portion of the Navy Yard.
- Microgrid Test System II - Substation 602 (SS602) microgrid: The SS602 test plan included software simulation by Alstom and Pacific Northwest National Laboratory (PNNL) and "hardware in the loop" testing for the DMGCS-MACS by Alstom and Washington State University (WSU). While live demonstration of the SS602 DMGCS-MACS on the actual circuit was planned, it was not included in the testing because some key DER assets did not become available in the project timeframe.

5.2 The Navy Yard - GridSTAR 2.0 Microgrid

The GridSTAR 2.0 microgrid, depicted in Figure 5-1, included a portion of the TNY 13.2 kV feeder F-1305 bounded by circuit breaker 05 at Substation 664 (the PCC for this microgrid) and a disconnecting switch that's just downstream of building 661. This switch was used to disconnect Building 489 loads that were not included in the GridSTAR 2.0 microgrid. The GridSTAR 2.0 microgrid included the critical loads and distributed energy resources that were connected to a portion of 13.2 kV feeder F-1305 normally supplied from Substation 664. This microgrid included generation sources, PV, CHP, energy storage, and controllable loads that enabled the proposed microgrid to operate in "islanded" mode (disconnected from the main power grid).

In addition to achieving new revenue streams from PJM market participation, the combined DMGCS-MACS developed by GE/Alstom also managed the operation of these DER assets in "grid-connected" mode.

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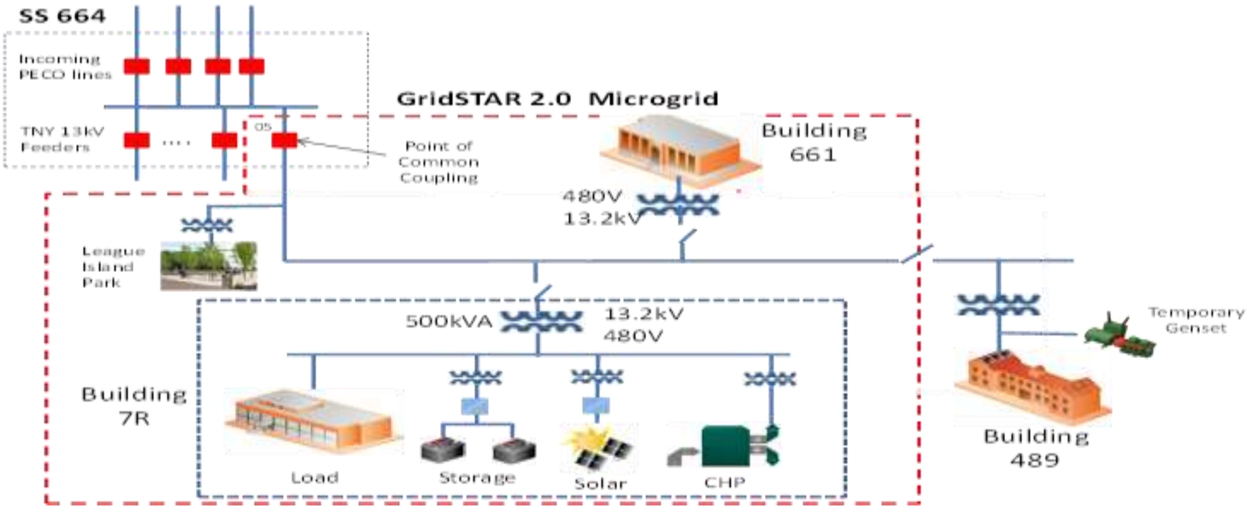

Figure 5-1 GridSTAR 2.0 Microgrid

The following table describes which microgrid system components are pre-existing before to the Alstom project and which ones are procured or configured/simulated or both as part of the project.

Sections	The Navy Yard - GridSTAR 2.0 Microgrid	Pre-existing Assets	DOE Project Configuration
5.2.1	GridSTAR 2.0 Loads	x	
5.2.2	GridSTAR 2.0 Distributed Energy Resources	x	
5.2.3	Energy Storage	x	
5.2.4	Generating Capabilities	x	
5.2.5	Controllable Loads	x	
5.2.6	Monitoring (Measuring Devices) and Control Facilities	x	
	Digital relays (Protection devices)	x	
	Advanced Metering Infrastructure	x	
	Substation Data Concentrator (SDC):		
	Microgrid Controller		x
	Energy Storage Controller:		x
	Building Energy Management System	x	

5.2.1 GridSTAR 2.0 Loads

Critical loads in the GridSTAR 2.0 microgrid included TNY Building 7R, which also housed the distributed energy resources (DERs) that would supply power to the GridSTAR 2.0 microgrid when operating in “islanded” mode. Other loads served by the GridSTAR 2.0 microgrid included Building 661 and a small load at League Island Park.

5.2.2 GridSTAR 2.0 Distributed Energy Resources

The GridSTAR 2.0 microgrid includes numerous existing DERs for use in grid-connected and islanded mode. It will also achieve maximum possible revenue streams from PJM market participation while in grid-connected mode.

The GridSTAR 2.0 DERs include solar PV units, combined heating and power (CHP), energy storage, and controllable loads (demand response facilities). The Solar PV and Energy Storage are inverter-based units that can sustain operation of the microgrid in islanded mode without the benefit and physical inertia of rotating generating sources. The CHP unit may also play a role in sustaining the operation of the GridSTAR 2.0 microgrid when operating in islanded mode.

The following sections describe the DERs available on the GridSTAR 2.0 microgrid.

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The following table describes which microgrid system components are pre-existing before to the Alstom project and which ones are procured and/or configured/simulated as part of the project.

Sections	The Navy Yard - Substation 602 Microgrid	Pre-existing Assets	DOE Project Simulation
5.3.1	Critical Loads on the SS 602 Microgrid	x	
	Aker shipbuilding facility	x	
	Urban Outfitters (UO)	x	
	Navy Manufacturing and Propulsion Research (NMPR) facilities	x	
	TNY Central Fire Pump Station	x	
	TastyKake Baking Company	x	
	Rhoads Industries	x	
5.3.2	SS602 Distributed Energy Resources		x
5.3.3	Energy Storage (Future)		x
5.3.4	Generating Capabilities		x
	Natural Gas Fired Combustion turbines		x
	Bloom Energy Fuel Cell	x	
	Solar PV Generating Resources (Future):	x	
	Backup Generator at Urban Outfitters	x	
5.3.5	Controllable Loads	x	
5.3.6	Summary of Loads and DERs on the SS602 Microgrid	x	
5.3.7	Monitoring and Control Facilities	x	
	Digital relays (Protection devices)	x	
	Advanced Metering Infrastructure	x	
	Substation Data Concentrator (SDC)	x	
	Microgrid Controller		x
	Energy Storage Controller		x
	Generation Controller	x	

5.2.3 Energy Storage

The GridSTAR 2.0 microgrid includes a 50 kWh lead acid battery and a 40 kWh Li-Ion battery. These batteries feed a single Inverter rated for 50kw. In other words, the total energy storage rating is 50kW for 90kWh. The energy storage facility includes batteries, smart inverter, and a battery energy management system. This energy storage facility will be the primary source of power when the GridSTAR 2.0 microgrid is operating in "islanded" mode (along with solar PV generating units that are described in the next section of this test plan).

PIDC and its partners may elect to deploy a larger energy storage facility that is able to sustain critical loads while in islanded mode. However, during this project, the schedule for implementing a larger unit was uncertain. Therefore, the test plan was based on using the existing energy storage unit.

5.2.4 Generating Capabilities

The GridSTAR 2.0 microgrid includes solar photovoltaic (PV) generating facilities that are mounted on the Building 7R roof. Maximum output from these generating units is 15 kW.

It should be emphasized that the GridSTAR 2.0 microgrid at present contains renewable resources. But, it is a challenge to protect it in the islanded mode since protective schemes do not exist today. Significant research activities for this are taking place around the world, including at the IEEE PES Power Systems Relaying Committee (PSRC).

5.2.5 Controllable Loads

Another existing DER within the GridSTAR 2.0 is controllable loads (a.k.a., demand response) that will enable the microgrid controller to balance the connected load with the available power supply to achieve more effective control of voltage and frequency when the GridSTAR 2.0 microgrid is operating in islanded mode. When energy supply resources (i.e., storage and generation) on the islanded microgrid are limited, some of the controllable loads can be shed to balance load and power supply (generation and storage).

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Because of smart inverter schemes included in these resources, it is also possible to dispatch the controllable load facilities to shed load automatically during power shortages when the microgrid is operating in grid-connected mode.

During "islanded mode" testing of the GridSTAR 2.0 microgrid, it will be necessary to disconnect the load at the three buildings that comprise Building 489. Since the electrical load for Building 489 exceeds the ratings of the DERs in Building 7R, these buildings would then be powered through the existing backup generator.

If it is necessary to balance load and generation on the microgrid, the GridSTAR 2.0 load can be reduced manually by operating circuit breakers in the power distribution panels in Buildings 7R and 661. However, this method is relatively slow due to manual intervention and cannot be used when rapid (immediate) load curtailment is needed.

5.2.6 Monitoring (Measuring Devices) and Control Facilities

The GridSTAR 2.0 microgrid (Test System I) includes numerous devices for real time monitoring and control. These enable (real-time) detection of electrical conditions requiring alteration of the dispatch of available DERs and high-speed transition to islanded mode when abnormal electrical conditions that warrant transition to islanded operations occur, per IEEE 1547a[8]. Much of the monitoring and control facilities either exist (e.g., asset controllers for energy storage at Building 7R) or will be added in the near future as part of the ongoing grid modernization efforts at the Navy Yard Substation 602 (Test System II)

The following is a summary of the monitoring and control facilities that will be included in the GridSTAR 2.0 microgrid. Figure 5-2 also shows these monitoring and control facilities.

- Advanced Metering Infrastructure: Advanced metering infrastructure (AMI) supplied by Landis and Gyr (L+G) was installed at the major sites (SS664, Building 7R, Building 661, Building 489, and League Island Park) prior to this project. This system will supply average load information for each site every five minutes to the microgrid controller to support demand-supply balance calculations that will be performed by the DMGCS-MACS in grid-connected mode and islanded mode.
- Microgrid Controller: The DMGCS-MACS (the "brains" of the planned GridSTAR 2.0 microgrid) interfaces directly with the SDC and the individual asset controllers. For the GridSTAR 2.0 microgrid, the DMGCS-MACS will be installed at SS664. While in "grid-connected" mode, this DMGCS-MACS will continuously monitor the electrical conditions at SS664 to detect conditions (such as a main bus fault at SS664) requiring disconnection from the main power grid. While in "islanded" mode, if voltage and frequency degradation is detected, the DMGCS-MACS will monitor the electrical conditions internal to the microgrid and initiate corrective actions (e.g., load shedding).
- Energy Storage Controller: The existing energy storage controllers, "AllCell" for the Li-Ion battery and "Enersys" for the lead acid battery, will be used to manage the operation of the GridSTAR 2.0 energy storage unit in grid-connected and islanded mode. The energy storage controller will accept set points downloaded from the Alstom DMGCS-MACS and execute the requested actions using its "native" control capabilities. See Table 2-1.
- Building Energy Management System: The GridSTAR 2.0 microgrid control system will use the existing building energy management solution, which enables automatic or remote control of building lighting and HVAC systems. To achieve balance between supply and demand on the islanded microgrid, the microgrid controller will use this system as needed to shed non-critical load.

L+G AMI communication has been deployed to enable high-speed, standards-based (IEC 61850) communication between the three main sites associated with the GridSTAR 2.0 microgrid (SS664, Building 7R, and Building 661). These facilities use wireless point-to-point line-of-site communications between the microgrid locations or fiber optic cables that also provide a high level of system security.

5.2.7 Simulation Testing Cases of Microgrid Controller for GridSTAR 2.0 Microgrid

Table 5-1 Test Case Reference

Test Section	Test Case Description	Test Objective	FOA Objective
6.1	**Microgrid Control Mode**	T2.1.1	C1, C2, C3 & C4
6.2	Case 1: Unplanned Islanding	T2.1.2	
6.3	Case 2: Grid Reconnection	T3.3.2,T3.3.3	
6.4	Case 3: Island Mode- Voltage & Frequency Control	T5.1.1,T5.2.1	
6.5	Case 4: Island Mode- Load Management	T5.3.1,T5.3.4	
6.6	Case 5: Island Mode- Solar-Storage Management	T5.3.2,T5.3.3	
6.7	Case 6: Island Mode- Controoler Override Optimizer	T4.1.2,T4.2.2	
7.1	**Optimzation Mode**		C5 & C6
7.2	Case 1a: Grid Connected Economic Dispatch - SOC 100%	T4.1.3,T4.2.3	
7.3	Case 1b: Grid Connected Economic Dispatch - Peak Load	T4.1.3,T4.2.3	
7.4	Case 1c: Grid Connected Economic Dispatch - SOC 50%	T4.1.3,T4.2.3	
7.5	Case 2: Grid Connected Mode - Peak Reduction Optimization	T4.1.2,T4.2.2	
7.6	Case 3a: Island Mode - Planned Islanding Economic Dispatch	T4.1.3,T4.2.3	
7.7	Case 3b: Island Mode - Peak Day planned Economic Dispatch	T4.1.3,T4.2.3	
7.8	Case 4: Island Mode - Unplanned Islanding Economic Dispatch	T4.1.3,T4.2.3	
7.9	Case 5a: Island Mode - Maximize Time to Live (TTL) Normal Day	T4.1.2,T4.2.2	
7.1	Case 5b: Island Mode - Maximize Time to Live (TTL) Peak Day	T4.1.2,T4.2.2	

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5.3 The Navy Yard - Substation 602 (SS602) Microgrid

The SS602 microgrid, depicted in Figure 5-2, includes a portion of load that is served by TNY substation 602. The PCC on the supply side of the SS602 microgrid consists of the four circuit breakers at SS602 on the tie lines from main substation 93. It is necessary to trip all four tie line circuit breakers to disconnect the SS602 microgrid from the main grid. This is different from many microgrid PCCs that exist today, which include a single switch at the PCC. Coordinating the operation of these four circuit breakers is one of the research objectives for this microgrid. The research result for a multiple-CB PCC will have significant industry value, because the Alstom team believes this is a common configuration for many candidate microgrids.

The SS602 microgrid includes numerous 13.2kV feeders supplied by the SS602 main bus via feeder circuit breakers. The feeders included in the microgrid serve critical industrial and commercial loads, such as Aker Shipbuilding, a Naval Research facility, TastyKake Bakeries, Rhodes Industries, Urban Outfitters, and the Central Fire pumping station. Non-critical loads will be disconnected from the SS602 microgrid using the feeder circuit breakers that serve these non-critical loads.

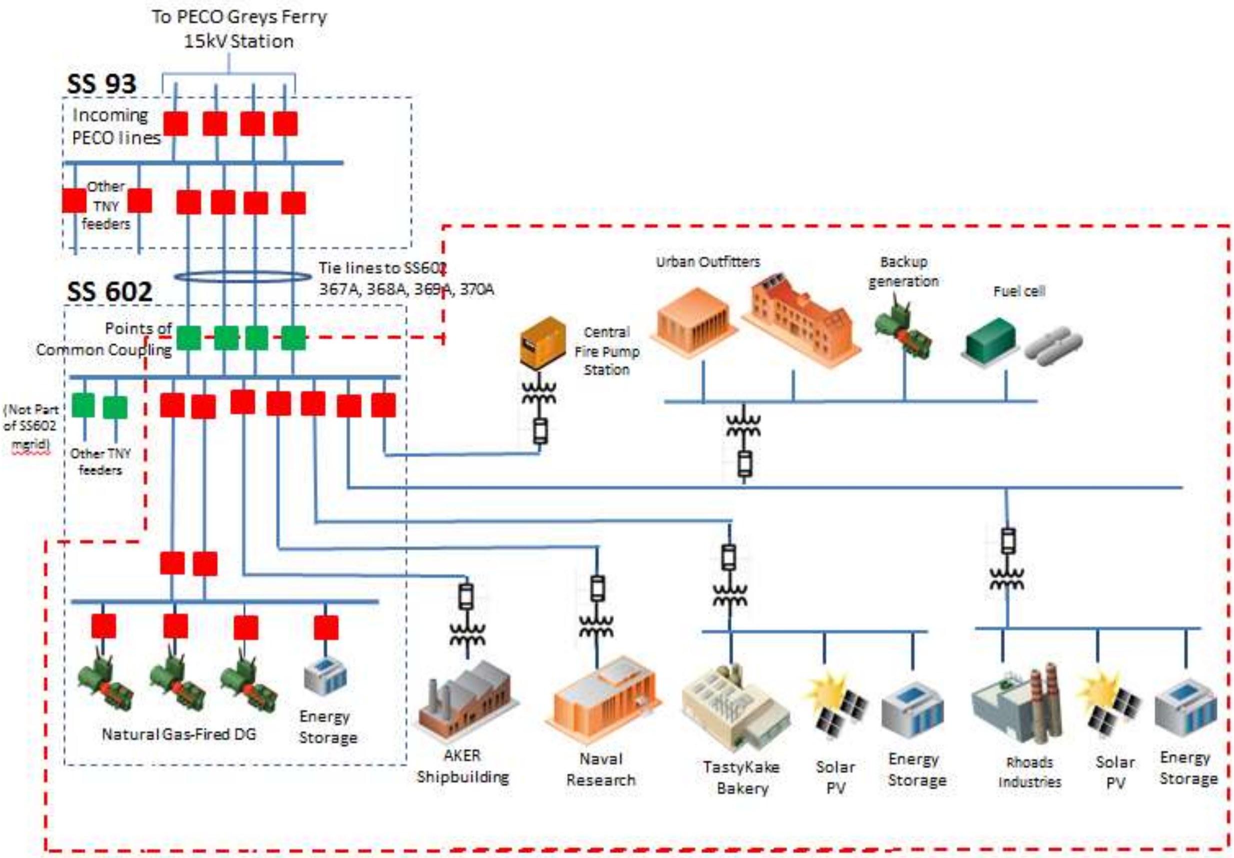

Figure 5-2 SS 602 Microgrid

5.3.1 Critical Loads on the SS 602 Microgrid

The SS602 microgrid will serve the following critical loads:

- **Aker shipbuilding facility:** The load at the Aker shipbuilding facilities is best characterized as heavy industrial processes involving complex construction with a high degree of automation. Loss of power to these facilities would cause an immediate interruption of operations. Average load in year 2012 was approximately 3 MW with a peak load of approximately 5 MW.
- **Urban Outfitters (UO)**: The SS602 microgrid will include several of the nine buildings that comprise the Urban Outfitters campus that houses global headquarters for five subsidiaries, along with critical design facilities, a data center, and central heating/cooling plant for the UO campus that serves approximately 2,000 employees. Average load in year 2012 was approximately 1.5 MW with a peak load of approximately 2.3 MW.
- **Navy Manufacturing and Propulsion Research (NMPR) facilities:** This is a "mission critical" facility that involves engineering and manufacturing work performed by approximately 2,500 employees. Loss of research results at some of the facilities could pose a threat to national security. The average load during 2012 was approximately 6 MW with a peak load of approximately 8.0 MW.
- **TNY Central Fire Pump Station:** The central fire pump station provides 100 psi water to the fire protection system serving multiple mission critical Navy facilities. It is considered a critical safety system for these facilities, because a power outage at this location would cause a loss of fire protection services for the nearby industrial customers. Average load in year 2012 was approximately 50 kW with a peak load of approximately 300 kW.
- **TastyKake Baking Company:** This is a large manufacturing and baking facility that also includes a shipping complex. Average load in year 2012 was approximately 1.3 MW with a peak load of approximately 2.4 MW.
- **Rhoads Industries:** Rhoads Industries includes over 200,000 square foot of fabrication facilities located adjacent to deep water with wharf access. Rhoads fabricates process equipment, vessels, duct/stacks/breechings, and large modular components. It is also involved with Department of Defense commercial ship, military fabrications, and assembly work. Rhoads is also working within the Naval Surface Warfare Center Land-Based Test Facility, providing fabrications including custom foundations for supporting marine gas turbines. Average load in year 2012 was approximately 750 kW with a peak load of approximately 1.0 MW.

The SS602 microgrid will enable TNY to supply power to the critical loads listed above during an extend loss of supply from the local distribution utility.

Table 5-2 contains a breakdown of the load on each of these facilities based on recent meter readings from the AMI facilities that have recently been installed at these facilities.

Table 5-2 Summary Loads on SS602 Microgrid

Microgrid Assets & Load	Microgrid System	Load (kW)	
		Avg Demand	Controllable Load
Aker Shipbuilding	SS 602	3000	1000
Naval Research	SS 602	6000	
TastyKake Bakeries	SS 602	1300	400
Rhodes Industries	SS 602	800	200
Central Fire Pump Station	SS 602	100	
Urban Outfitters	SS602	1500	500
TOTAL		12700	2100

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5.3.2 SS602 Distributed Energy Resources

The SS602 microgrid includes numerous existing DERs that will be used in grid-connected and islanded modes to increase reliability and efficiency, reduce emissions, maximize the resiliency of the SS602 microgrid, achieving maximum possible revenue streams from PJM market participation while in grid-connected mode.

The SS602 DERs include generation sources and energy storage. Currently, there are no automated load curtailment facilities at the customer sites that are included in the SS602 microgrid. If load reduction is needed for balancing electrical supply and demand within the microgrid, this will be accomplished by tripping feeder circuit breakers at SS602. This will interrupt all loads connected to that feeder.

A variety of power supply resource technologies are available on the SS602 microgrid, providing an excellent testbed for evaluating the effectiveness of common types of generating resources that are available in the industry. The technologies include rotating generation resources (natural gas fired combustion turbines) and inverter-based units (solar PV units and fuel cells). This combination of generation resources, together with available energy storage facilities, will sustain operation of the microgrid in islanded mode for at least one hour.

The following sections describe DERs currently available on the SS602 microgrid.

5.3.3 Energy Storage (Future)

The following energy storage facilities are planned on the SS602 microgrid include:

- An energy storage facility that is connected to the SS602 main bus. This energy storage unit will be rated 2.0 MW (2.0 MWh) and (when operating in grid-connected mode) will be used to participate in the PJM Frequency Regulation market. The energy storage facility will include batteries, smart inverter, and a battery energy management facility.
- An energy storage facility at Rhoads Industries that is rated 2.0 MW (1.6 MWh). This unit will be used to participate in the PJM Frequency Regulation market. The energy storage facility will include batteries, smart inverter, and a battery energy management facility.
- The Community Solar project (by the side of TastyKake Bakery) includes a 250 kW (250 kWh) battery that assists in managing the microgrid voltage and frequency when operating in islanded mode. Like the other energy storage facilities on this microgrid, this storage will also participate in Frequency Regulation market when the microgrid is operating in grid-connected mode.

5.3.4 Generating Capabilities

The SS602 microgrid will include several generating facilities that can be used to supply power to critical loads when operating in islanded mode. One of the generating resources (a set of three natural-gas fired combustion turbines) will also be used to assist in the frequency regulation market when the microgrid is operating in grid-connected mode.

The following is a list of the generating resources that are or are expected to be available in the SS602 microgrid:

- **Natural Gas Fired Combustion turbines**: Three, natural gas fired combustion turbines, each rated 2 MW (for a total of 6 MW), are now connected to the main bus at SS602. To limit the amount of greenhouse gas emissions from these units, the maximum hours of operation of these units will be approximately 1,100 hours per year. As a result, these generating units may not be running at the time when a transition to islanded mode is needed. Startup time for these units to go from 0 MW output to full capacity (6 MW output) is approximately ten minutes. If the combustion turbines are not running when a transition to islanded mode is needed, the microgrid controller may temporarily shed limited critical load on the SS602 microgrid until the combustion turbines are running at full capacity.
- **Bloom Energy Fuel Cell:** A Bloom Energy fuel cell rated at 800 kW (owned by Urban Outfitters) is installed on one of the feeders that is connected to SS602. This is an available source of power (as needed) for the SS602 microgrid.

- **Solar PV Generating Resources (Future):** A total of 4.5 MW of solar PV generating capability will be connected to the SS602 microgrid. Approximately 2.0 MW of capacity is planned that will be installed at SS602. A 2 MW solar PV facility is also panned by Rhoads Industries. Also, approximately 500 kW of solar PV capability is available at the TastyKake Bakery location. All of these generating units will play a role in powering the SS602 microgrid, and may help meet the growing energy requirements at these facilities.
- **Backup Generator at Urban Outfitters:** Urban Outfitters Building 543 includes a 500 kW generating unit that is started automatically when a local power outage is detected. This generator has been designed to power all of the loads in the building except for heating ventilating and air conditioning (HVAC). Besides serving these internal building needs, the generator is a resource that can supply power to the SS602 microgrid when needed. Therefore, it is included as an available source that can be dispatched by the SS602 DMGCS-MACS.

5.3.5 Controllable Loads

An automatic load shedding facility is currently available at Urban Outfitters Building 543, which will be included in the SS602 microgrid. Load shedding is automatically triggered to reduce approximately 750 kW of demand when a local power outage occurs. This automatic load shedding facility can be dispatched by the SS602 microgrid controller in its algorithms for balancing demand and supply.

If additional load shedding is needed to balance supply and demand on the SS602 microgrid when the microgrid is operating in islanded mode, this will be accomplished by opening feeder circuit breakers at SS602. This will shed the entire load on a given feeder. In the future, it is expected that several of the key customers served by this microgrid will deploy Building Energy Management Systems (BEMS) that will enable the SS602 microgrid controller to shed additional non-critical load. Therefore, potentially avoiding the need to shed an entire feeder to achieve supply and demand balance. However, for purposes of this microgrid test plan, it was assumed that such facilities are unavailable.

5.3.6 Summary of Loads and DERs on the SS602 Microgrid

Table 5-3 contains a summary of the SS602 loads and available DERs on the SS602 microgrid. This table shows the available DERs (including storage, generation, and controllable loads) exceed average demand, making the SS602 microgrid a viable candidate for islanded operation under average (off peak) conditions. Note additional load control is possible by opening circuit breakers at SS602. This capability may be used during a transition to islanded mode when the 6 MW natural gas fired units are off line.

Table 5-3 Summary of SS602 Microgrid Loads and DERs

Microgrid Assets & Load	Microgrid System	Load (kW)		Distributed Energy Resources (kW)			
		Avg Demand	Controllable Load	Solar PV	Storage	NG Generator	Fuel Cell
Natural Gas Generator	SS 602					6000	
Substation Storage	SS 602				2000		
Community Solar	SS 602			750	250		
Aker Shipbuilding	SS 602	3000	1000				
Naval Research	SS 602	6000					
TastyKake Bakeries	SS 602	1300	400				
Rhodes Industries	SS 602	800	200	2000	2000		
Central Fire Pump Station	SS 602	100					
Urban Outfitters	SS602	1500	500			800	800
TOTAL		12700	2100	2750	4250	6800	800

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5.3.7 Monitoring and Control Facilities

The SS602 microgrid includes numerous facilities for real time monitoring and control that will enable high speed (real-time) detection of electrical conditions requiring alteration of the dispatch of available DERs and high speed transition to islanded mode when abnormal electrical conditions that warrant transition to islanded operations occur. Most of the monitoring and control facilities were added in the first quarter of 2016 as part of the ongoing grid modernization efforts at the Navy Yard. Monitoring and control equipment including the distributed microgrid controller itself was added as part of this DOE microgrid project. The mix of already installed and autonomous load and generation together with systems controlled by the Alstom distributed microgrid requires a high level of coordination that will be demonstrated for this project.

The following is a summary of the monitoring and control facilities included in the SS602 microgrid.

- **Digital relays (Protection devices)**: Digital relays supplied by Alstom (MiCOM DG14 relays) and Schweitzer (SEL 351A relays) already existed or were installed by the first quarter of 2016 in substations SS602 and SS93, which is the normal power source to the SS602 microgrid. These digital relays provide rapid detection of fault conditions and initiate tripping of the appropriate circuit breakers to isolate the faulted power system component in the grid-connected mode. Existing protective relays at SS93 provide directional overcurrent protection on the incoming lines from the local utility (PECO Energy) and instantaneous and time-delayed overcurrent protection of the 13.2kV lines that supply the TNY customers. In the future, substation bus differential protection will be added at SS93 using IEC 61850 communications between the existing relays. This will enable instantaneous detection of main bus faults at SS93, which is a key triggering event for microgrid islanding.

  In addition to providing the required protection functions for the proposed SS602 microgrid, the digital relays supply valuable information (e.g., line loading, voltage, frequency) to the microgrid controller as needed to support both islanded and grid-connected application functions.

- **Advanced Metering Infrastructure**: Advanced metering infrastructure (AMI) supplied by Landis and Gyr (L+G) was installed at all of the loads that are served by the SS602 microgrid. This system supplies loading information for each site every five minutes to the distributed microgrid controller to support demand-supply balance calculations that are performed by the controller in grid-connected mode and islanded mode.

- **Substation Data Concentrator (SDC):** Alstom "**DAP** Server" data concentrators were installed at Substation 93 and SS602 as part of TNY's ongoing grid modernization effort during the first quarter of 2016. These substation data concentrators (SDC) serve as the main interface that enable information to flow rapidly between the microgrid controller, digital relays, and other intelligent devices at Substation 602. The SDC also provides an interface to the TNY GridNOC , which performs the "enterprise" level functionality for the microgrid control scheme.

- **Microgrid Controller:** The microgrid controller (the "brains" of the SS602 microgrid) interfaces directly with the SDC and the individual asset controllers. While in "grid-connected" mode, this controller continuously monitors the electrical parameters at SS602 to detect conditions (such as the loss of more than two of the four tie lines to SS602 from SS93). While in "islanded" mode, if voltage and frequency degradation is detected, the controller will monitor the electrical conditions internal to the microgrid and initiate corrective actions (e.g., load shedding. A prototype of this controller was developed and tested as part of this project.

- **Energy Storage Controller:** The energy storage units for the SS602 microgrid (a 2-MW energy storage system including a new BEMS) are still in the planning stage. Because this project is still in the planning stage (awaiting project approval and funding authorization), the specific asset controllers were not determined. These asset controllers will be able to support the requirements in grid-connected mode and islanded mode. The energy storage asset controllers will accept set points downloaded from the Alstom microgrid controller and execute the requested actions using its "native" control capabilities.

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- **<u>Generation Controller:</u>** The Navy Yard has installed natural gas fired generating units rated a total of 6-MW (three 2-MW units). These generating units are equipped with continuous monitoring and remote control capabilities to enable these units to be monitored and controlled by the DMGCS-MACS. These asset controllers will support operation in grid-connected mode and islanded mode. Islanding functionality will be developed in the future.

5.3.8 Live System Testing for SS602 Microgrid

Table 5-4 Test Case Summary of SS602 Microgrid

Test Section	Test Case Description	Test Objective	FOA Objective
8	SS93-602 Microgrid Test Plan and Execution Result		C1, C2 & C3
8.1	Coorelation of Test Plan with Functional Requirement		
8.2	**Test Set 1 - Basic Monitoring and Control Fuction**		
8.2.1	Test Set 1.1 Measument of Electric Condition of Micgrid	T1.1	
8.2.2	Test Set 1.2 Load Measurement	T1.2	
8.2.3	Test Set 1.3 Power Supply Measurement	T1.3	
8.2.4	Test Set 1.4 Control OutPut Delivery and Time	T1.4	
8.3	**Test Set 2 - Situation Awareness, Alarms, HMI**		
8.3.1	Test Set 2.1 System Level Status	T2.1.1	
8.3.2	Test Set 2.2 Load Reporting	T2.2.1	
8.3.3	Test Set 2.3 Power Supply Reporting	T2.2.2,T2.2.3	
8.3.4	Test Set 2.4 PCC Monitoring	T2.2.4	
8.4	**Test Set 3 - Control Function**		
8.4.1	Test Set 3.1 Asset Control	T3	
8.4.2	Test Set 3.1.1 Load Control	T3.2.1,T3.2.2,T5.3.1,T5.3.4	
8.4.3	Test Set 3.1.2 Generation Control	T3.2.3,T3.2.3,T5.3.2,T5.3.3	

6. GridSTAR 2.0 Microgrid Control Simulation – Objectives C1, C2, & C3

6.1 Microgrid Control Model Overview

The GridSTAR 2.0 microgrid was simulated in the MATLAB®/Simulink Environment using built-in models of simPowerSystem and other models specifically developed for the testing purposes. The model includes the following two parts:

- Microgrid Controller Model.
- GridSTAR 2.0 Microgrid System Model.

Figure 6-1 shows the GridSTAR 2.0 microgrid circuit.

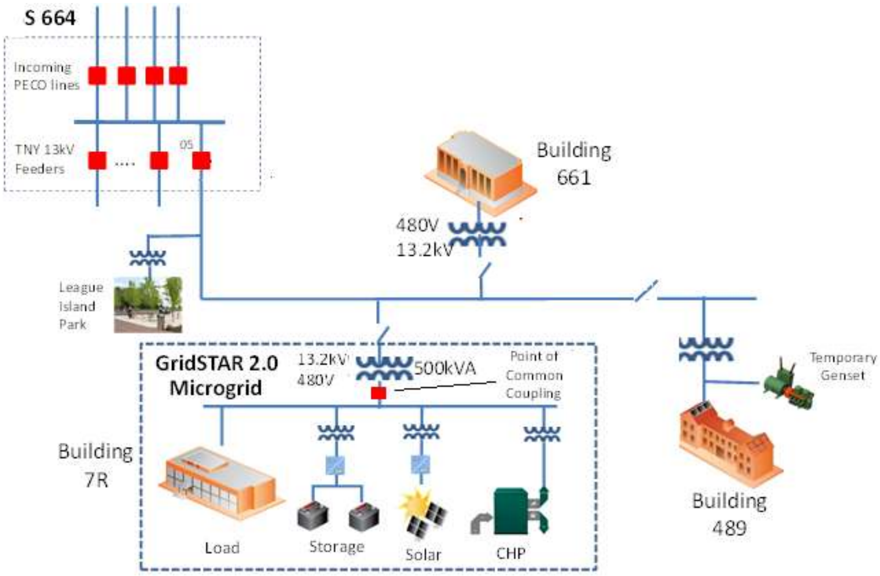

Figure 6-1 - GridSTAR 2.0 Microgrid Circuit

Figure 6-2 shows a model of the microgrid control system with its major components labeled. The microgrid controller model can be replaced with the actual controller to demonstrate the functionality of the hardware.

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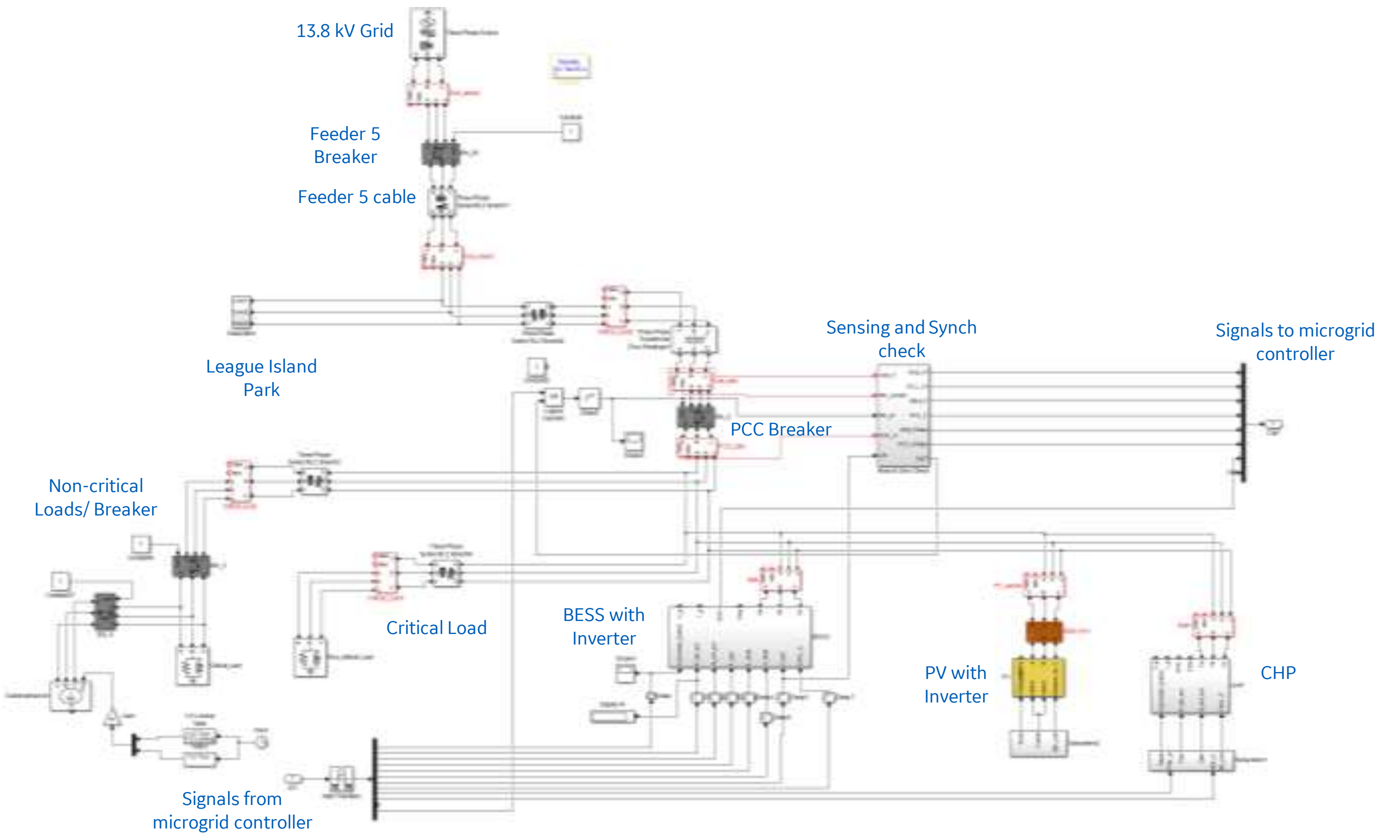

Figure 6-2 - Microgrid Control System

The major components of the model are:

- **Grid Model:** The grid model used in this simulation represents the bulk power grid that supplies power to 13.8kV feeder 1305. The bulk grid is modeled as a constant voltage source behind an impedance. The short circuit (SC) level at this point is assumed to be approximately 50 MVA.
- **Cables**: The cables are modeled as a combination of Resistance-Inductance (RL) elements to simulate the drop in the network.
- **Transformer:** The transformer at Building 7R is represented by built-in blocks in MATLAB®/Simulink that simulate voltage stepdown from 13.2 kV voltage to 480 V.
- **Circuit Breakers:** Circuit Breakers are controllable elements from the simPowersys library of MATLAB®. The circuit breaker contacts open at zero current crossing. Its operation can be delayed simulating the mechanical operating mechanism.
- **PCC Breaker:** The PCC breaker is an instance of the circuit breaker element mentioned above and is connected between the Building 7R transformer and the Building 7R 480V bus where the microgrid DERs are connected. This breaker is used for disconnecting the Building 7R microgrid from Building 7R transformer, which is energized from 13.2kV feeder 1305. The breaker is introduced to ensure that the 500 kVA transformer does not get energized (backfed) from the limited sources available in building 7R. The PCC breaker has voltage transformers (VTs) on the line side of the switch and on the load side of the switch that are used for synchronization checking purposes when reconnecting the Building 7R microgrid to feeder 1305.
- **BESS with Inverter:** The BESS model with the inverter includes a built-in model for the two energy storage batteries at Building 7R that are rated for 90 kWh and 50 kWh respectively. The BESS also includes a custom-built inverter model, rated for 50 kVA. The inverter controls are modeled based on typically available control structures and has grid connected and island modes of operation.

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- **PV with Inverter:** The PV inverter model comprises of the PV panel model and the inverter model. The inverter model is in grid connected mode and has relevant voltage based protections.
- **CHP Model:** The CHP model is a simplified representation of the CHP generator. The focus is on the electrical system, comprising of an inverter, controlled in a grid connected model of operation. The output power from the CHP generator is ramp-rate limited to account for the mechanical system limitations of the CHP generator.
- **Loads:** The loads are modeled as impedances and have both a real and a reactive power component. The loads are segregated into critical and non-critical loads, with controllable breakers on the non-critical loads. These loads can be turned off if the generation capacity and battery discharge capability in the islanded microgrid is lower than the total load at Building 7R. The loads can also be turned off if the cost of meeting these loads exceeds the cost of disconnecting these loads.

6.2 Case 1 – Simulation of Mode Transition with Unplanned Islanding

6.2.1 Objective

Operating mode transitions with unplanned islanding

6.2.2 Description

In this scenario, a fault is simulated on the 13.2 kV feeder (feeder number 05). The resulting voltage dip at the PCC, triggers the microgrid controller to transition to an islanded mode of operation. The microgrid controller, on detection of the low voltage, after a certain time delay triggers the PCC breaker to open, creating the island. The controller, based on the breaker status, enables the necessary assets to transition to an island forming mode and continue operation.

6.2.3 Test Result

The following figures show the waveforms for the grid power, battery power, and grid voltage.

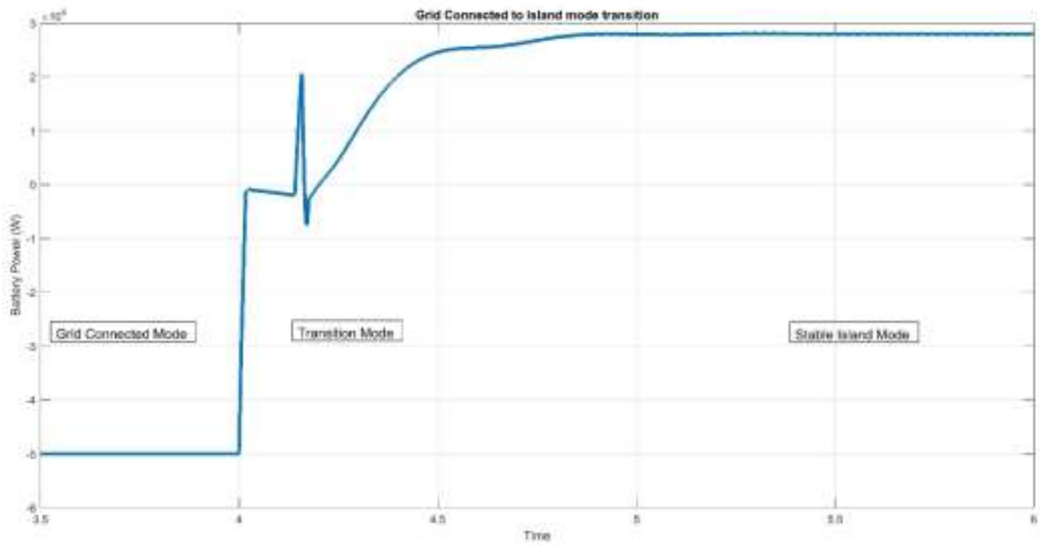

Figure 6-3 – Power Output Results from the Grid

6.2.3.1 Battery Power

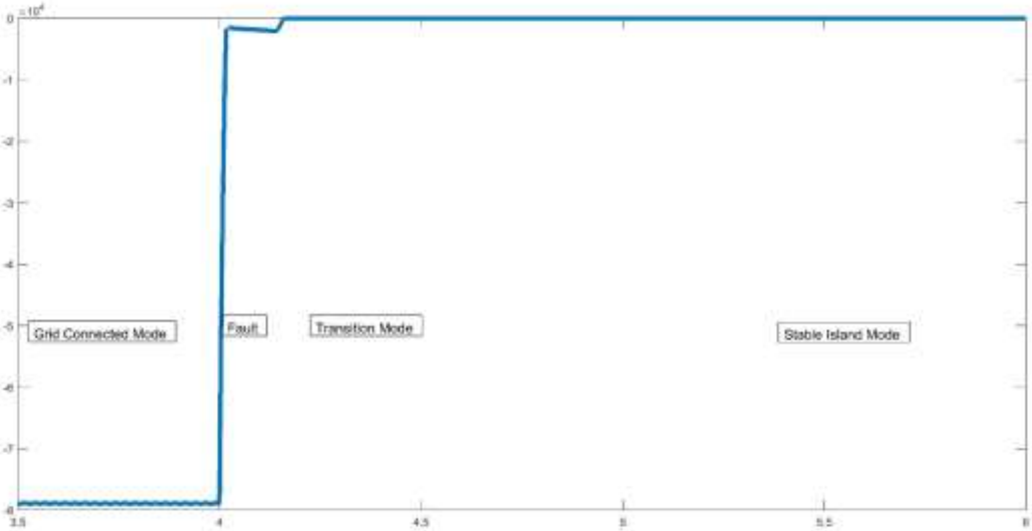

Figure 6-4 – Battery Power Results from the Grid

6.2.3.2 Grid Power

As shown in Figure 6-4 before the fault, Building 7R was drawing about 80 kW, including the load and the battery charging component. At 4 seconds, a fault on the 13.2 kV feeder results in the grid voltage at the PCC collapsing and the grid power reducing to almost zero. Post the transition to island mode, the grid power drops to zero, due to the PCC breaker opening.

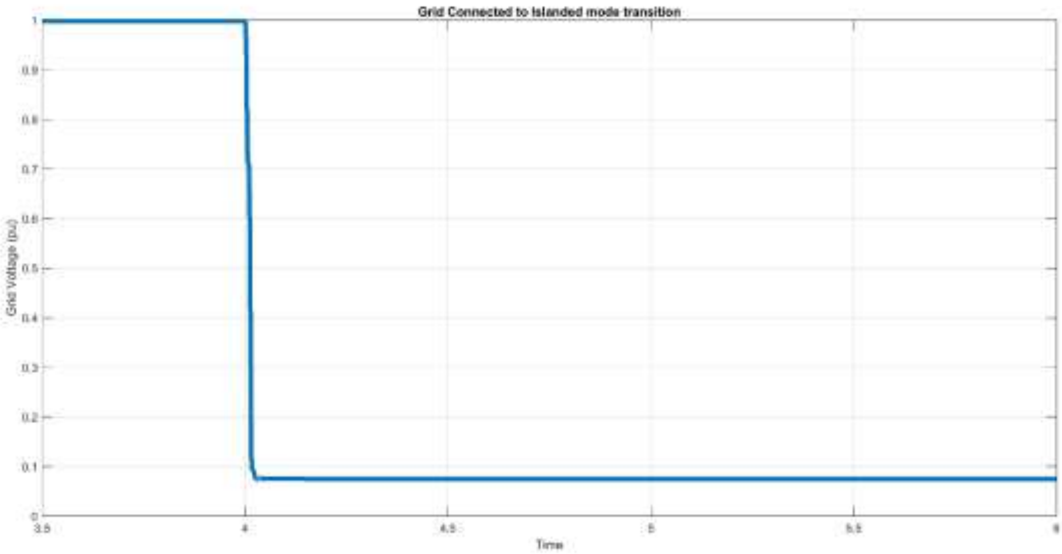

Figure 6-5 – Grid Power Results from the Grid

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6.2.3.3 Grid Voltage

As shown in Figure 6-5, the grid voltage dips to about 0.1 pu and stays low to indicate a persistent fault.

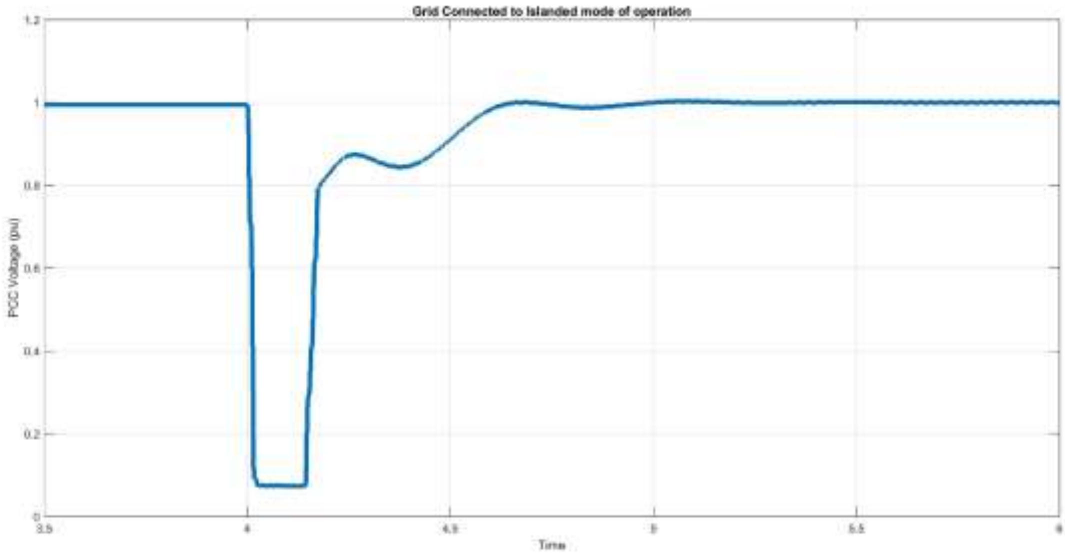

Figure 6-6 – Grid Power Results from the Grid

6.2.3.4 PCC Voltage

As shown in Figure 6-6, the voltage at PCC dips to a low value during fault. After a programmable time delay, the PCC voltage recovers, by tripping the PCC breaker and the microgrid assets controlling the grid voltage and frequency.

6.2.3.5 PCC Frequency

Figure 6-7 shows the breaker operating command and currents.

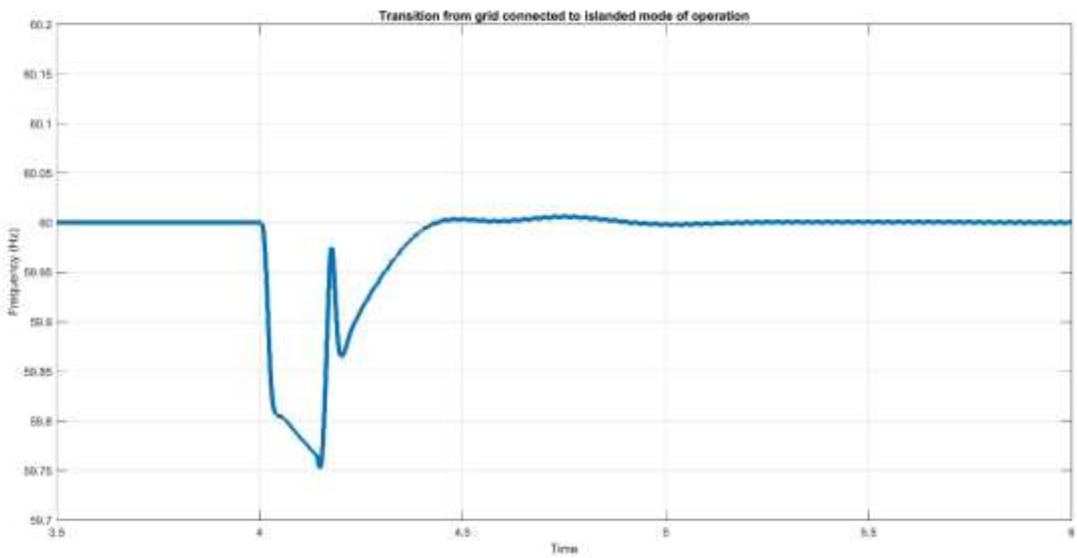

Figure 6-7 – Breaker Operating Command and Current Waveform Results from the Grid

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6.2.3.6 PCC Frequency

Figure 6-8 shows the breaker operating command and currents.

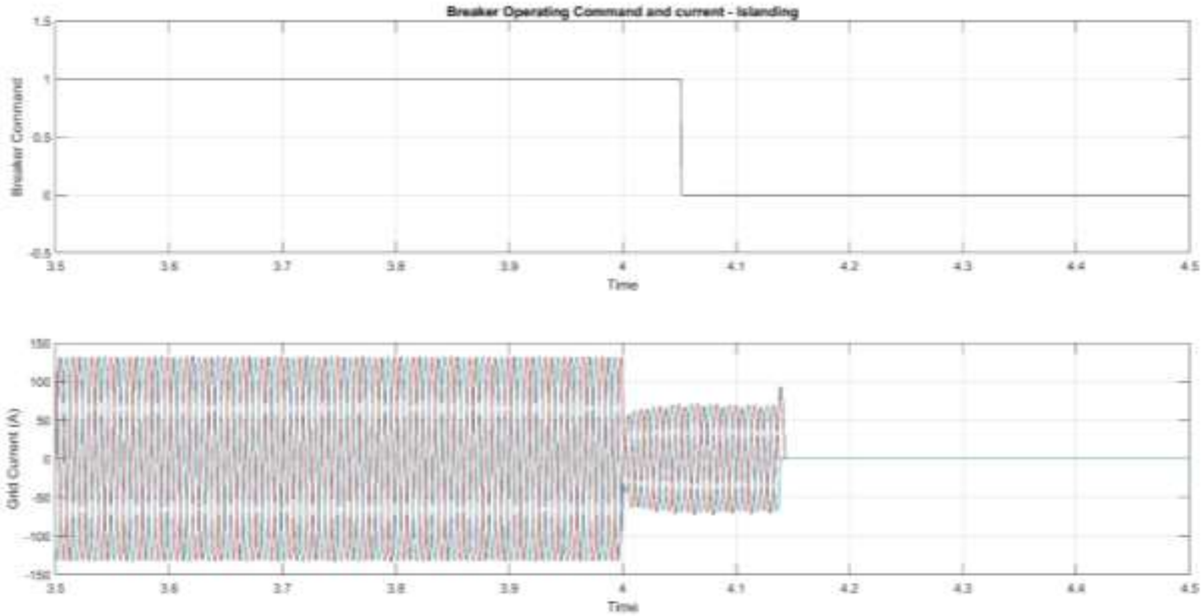

Figure 6-8 – Breaker Operating Command and Current Results from the Grid

This figure shows the grid fault occurs at 4 seconds. The microgrid controller detects the fault and commands the PCC breaker to open at about 4.05 seconds. The time lag is attributed to communication latency and to ensure that the fault is not due to measurement errors. Once the breaker gets an OPEN command, it takes about 5 more cycles for the breaker contacts to fully open and, as shown by Figure 6-8, the breaker eventually opens at about 4.15 seconds. Once the breaker opens completely, the microgrid controller transitions to islanded mode of operation by changing the battery's operation mode.

6.3 Case 2 – Grid Reconnection

6.3.1 Objective

Test of grid resynchronization.

6.3.2 Description

When grid power is restored (with the PCC breaker open), the grid resynchronization process initiates. The microgrid controller monitors the grid voltage and waits for the voltage to be within the normal range for a pre-defined time period. Once normal grid voltage has been restored, the microgrid controller starts the resynchronization process, controlling the voltage (on the microgrid side of the PCC) until it is within a specified synchronizing range. This will ensure the PCC breaker (with a resynchronizing relay.) only closes when the grid and microgrid voltage are matched in magnitude, frequency, and phase angle.

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6.3.3 Test Result

As shown in Figure 6-9, system is in islanded condition up to 8 seconds, and the grid fault is cleared at about 8 seconds. The controller waits for about 1 second to ensure that the grid parameters are within steady state and then initiates the resynchronization procedure. As a part of the resynchronization, the microgrid voltage (at the open PCC) is controlled to match the phase angle, frequency and voltage of the grid. Eventually, when the voltages at the grid and microgrid side of the PCC are within a certain configurable tolerance, the PCC breaker closes, thereby resynchronizing the microgrid to the grid. In Case 2 – Grid Reconnection, this occurs at about 9.34 seconds, when the "red" microgrid voltage, merges with the "blue" grid voltage.

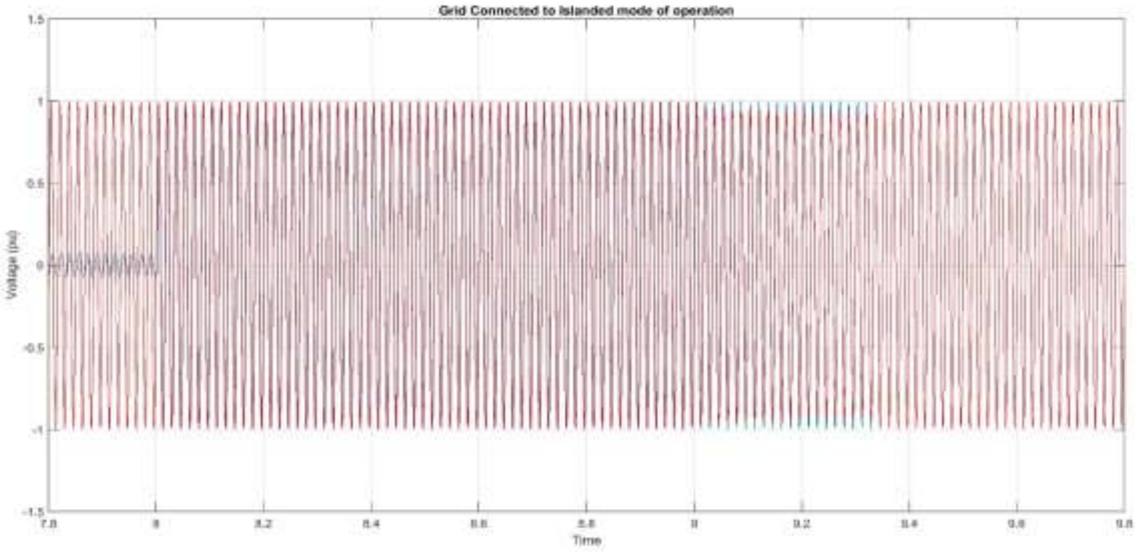
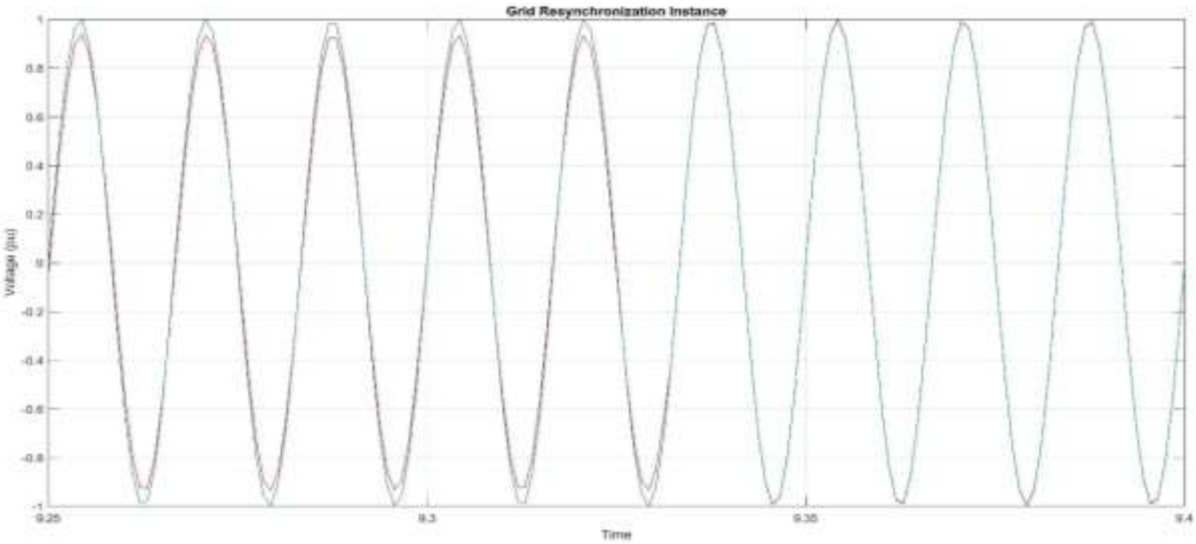


Figure 6-9 – Grid and PCC Voltage Synchronization

Figure 6-10 Synchronization Instant



For the simulation, Table 6-1 shows the tolerances considered for synchronization.

Table 6-1 Tolerances for Synchronization

Δ Voltage	Δ Frequency	Δ Phase
0.07 pu	0.1 Hz	0.1 deg

As shown in Figure 6-11, the grid power is almost zero (apart from the small power drawn by the PCC transformer) and drops to import of about 60 kW after synchronization.

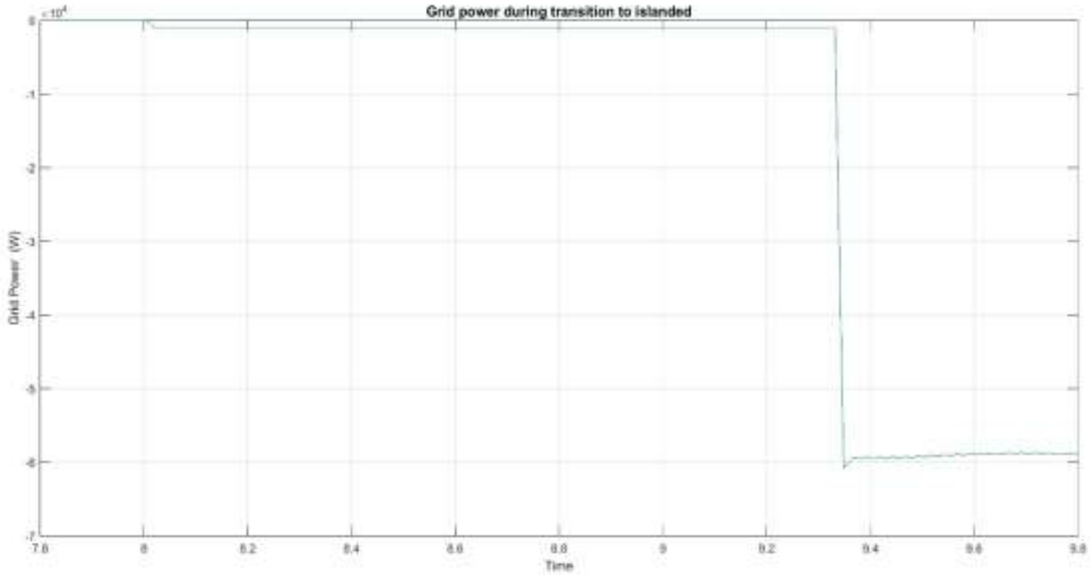


Figure 6-11 Grid Power During Transition to Islanded Mode

As shown in Figure 6-12, the battery is in discharge mode when the microgrid is disconnected from the grid. When the microgrid starts preparing for resynchronization, the battery power reduces. When the grid synchronization completes, the battery goes to discharging mode with about 30 kW.

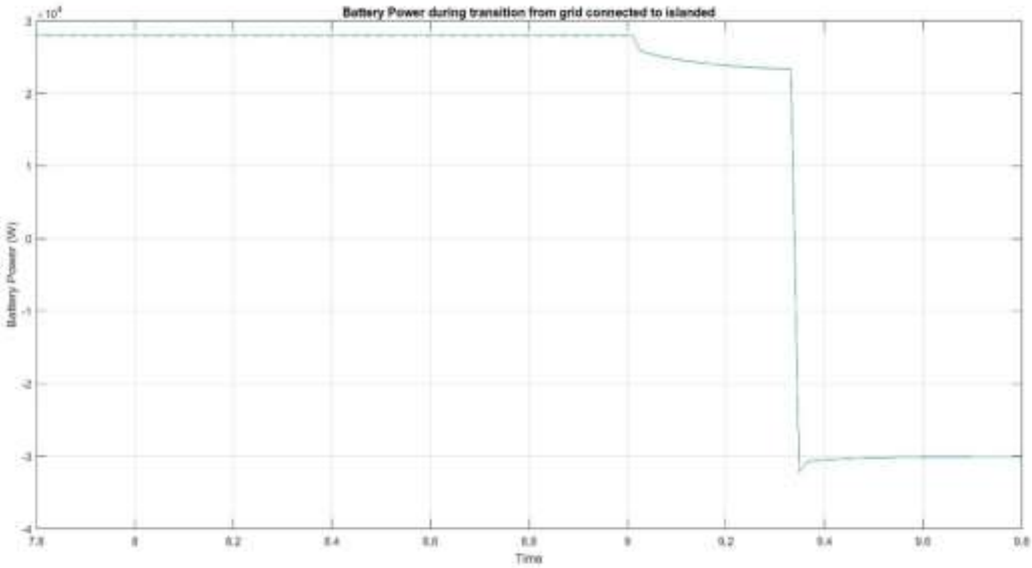


Figure 6-12 Battery Power During Transition to Islanded Mode

6.4 Case 3 – Island Mode – Voltage & Frequency Management

6.4.1 Objective

Test of CHP generator in islanded mode.

6.4.2 Description

As shown in the Dispatch Optimization, the generator may not be ON, when the system is operating in grid connected mode of operation. However, once the system is in islanded mode, the CHP generator would supply the load and charge the battery, if required. The microgrid controller in islanded mode, runs the dispatch optimizer to determine the schedule for the generator. The dispatch command based on the optimizer is then communicated to the CHP generator to turn it ON in the grid connected mode and ramp up its output power. The battery continues to be in the grid forming mode and decides its mode of operation based on the power supplied by the generator, solar, and the loading on the system.

6.4.3 Test Result

Figure 6-13 shows the electrical output power of the CHP generator.

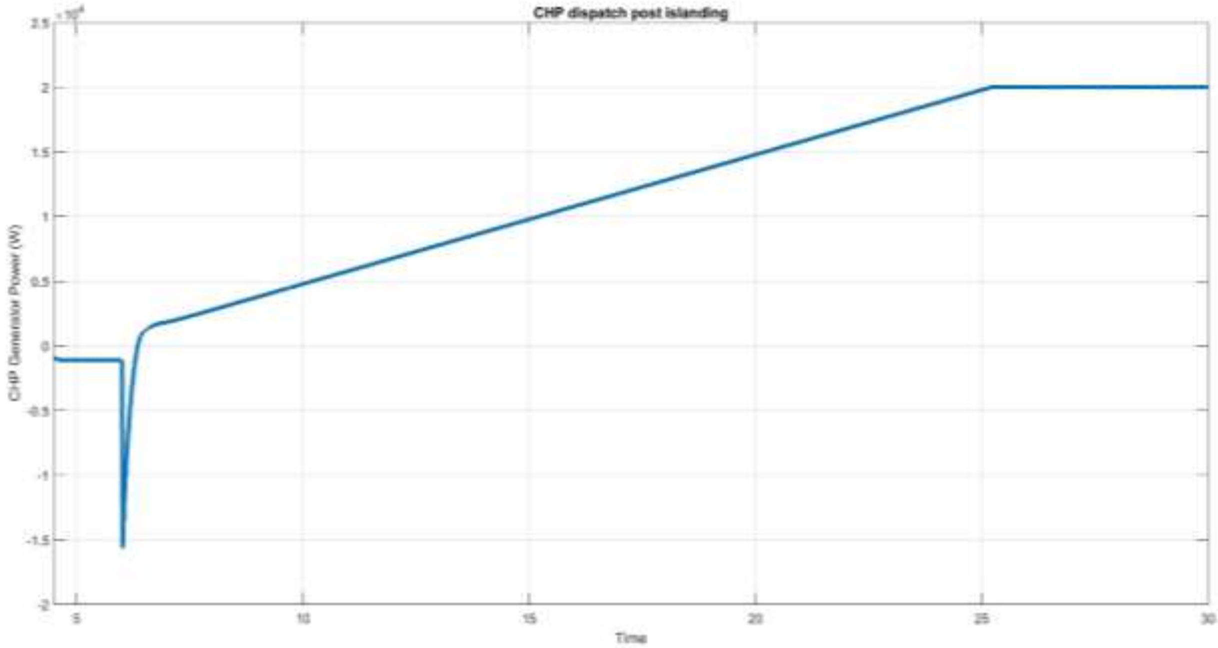


Figure 6-13 Electrical Power Output from CHP Generator

Once the island stabilizes after the island formation, the CHP generator is started at about 6 seconds. The initial inrush in power to the generator is the energization of the system. The power of the generator is ramped to about 20 kW, limited by the permissible ramp rate of the generator. Correspondingly, the battery power reduces by 20 kW to offset the power generation from the CHP generator.

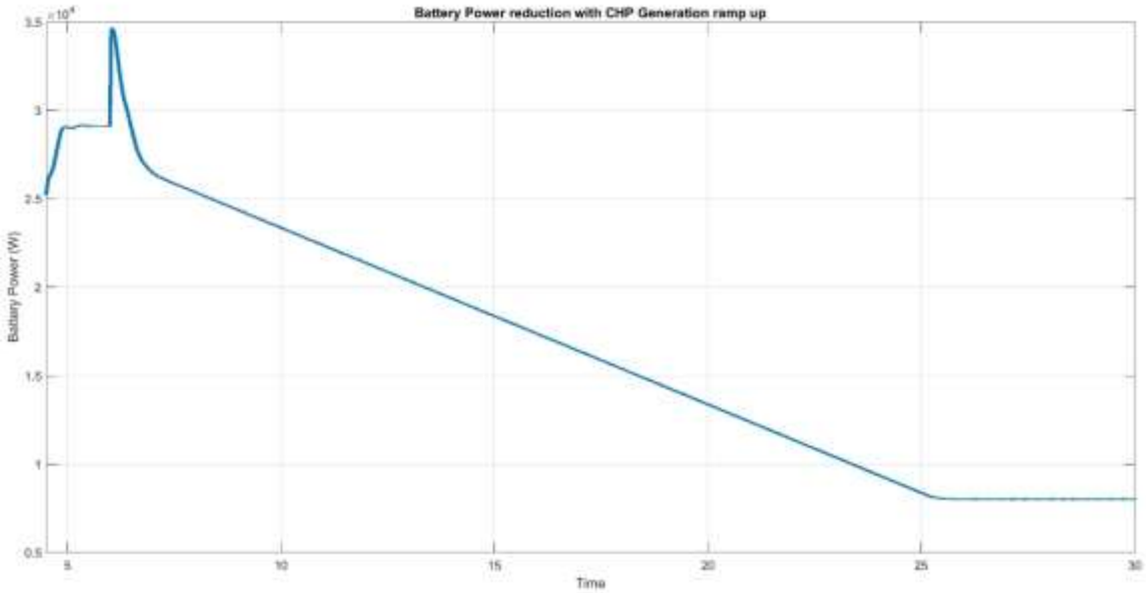


Figure 6-14 Reduced Battery Power Output from CHP Generator During Ramp-Up

As shown in Figure 6-14, the battery output stabilizes to about 28 kW in island mode, to meet the load along with the solar. At 6 seconds, when the CHP generator starts, the output power from battery increases and then slowly ramps down as the generator picks up part of the load.

The voltage fluctuations at the PCC correspond to the dynamics of the system with low inertia. See Figure 6-15.

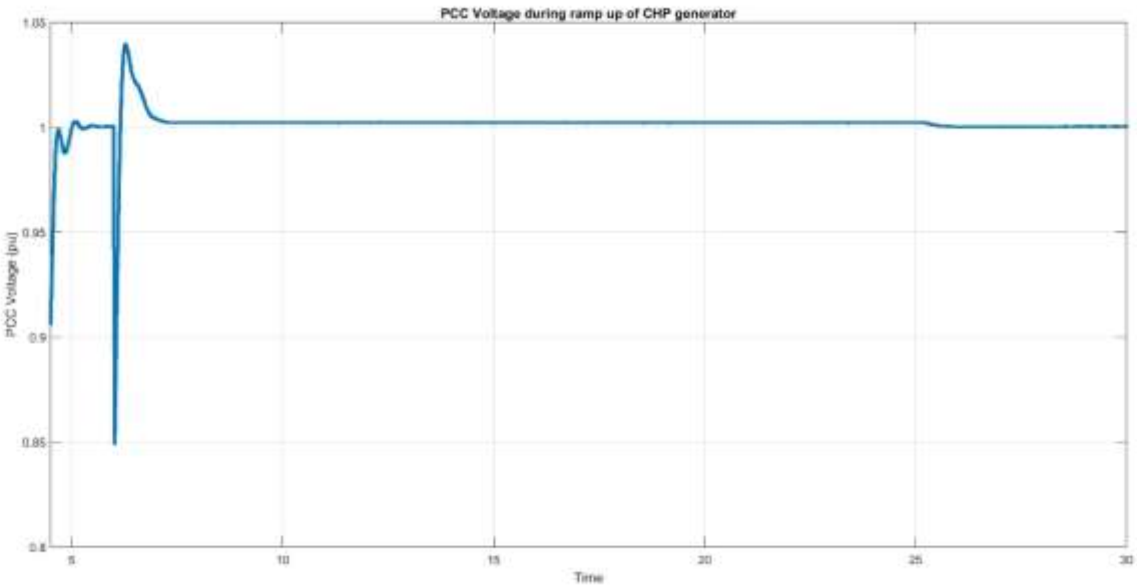


Figure 6-15 PCC Voltage from CHP Generator During Ramp-Up

As shown in Figure 6-15, the voltage may instantaneously dip to about 0.85 pu due to the inrush of the CHP starting. Then, it stabilizes to rated value as the CHP generator takes over its share of power. The starting power of the CHP plant needs to be investigated during the design stage of the microgrid.

6.5 Case 4 – Island Mode – Load Management

6.5.1 Objective

Test of load control in islanded mode.

6.5.2 Description

Consider a scenario where the system is in islanded mode and the CHP generator is unavailable, the battery is discharged, and solar power is insufficient to supply the load. For this case, the microgrid controller would make a decision to shed the non-critical load to ensure that critical load can be supplied for a longer period of time.

6.5.3 Test Result

The waveforms below indicate the response of the system under this scenario, of about 30 kW load shed. See Figure 6-16.

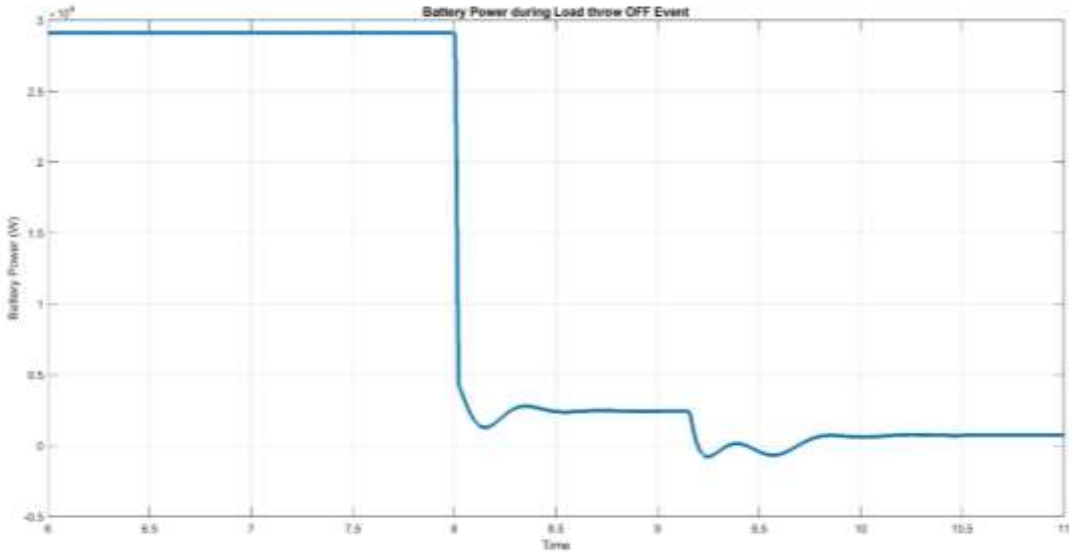


Figure 6-16 Battery Power During Load Shed

As shown, the battery discharge power reduces by 30 kW to a very low value. The battery along with the solar power is then sufficient to meet the critical load. The load turns OFF at 8 seconds. The transient at about 9.2 seconds is due to the battery controller trying to regulate the PCC voltage to nominal after a certain time delay. Figure 6-17 shows the voltage response.

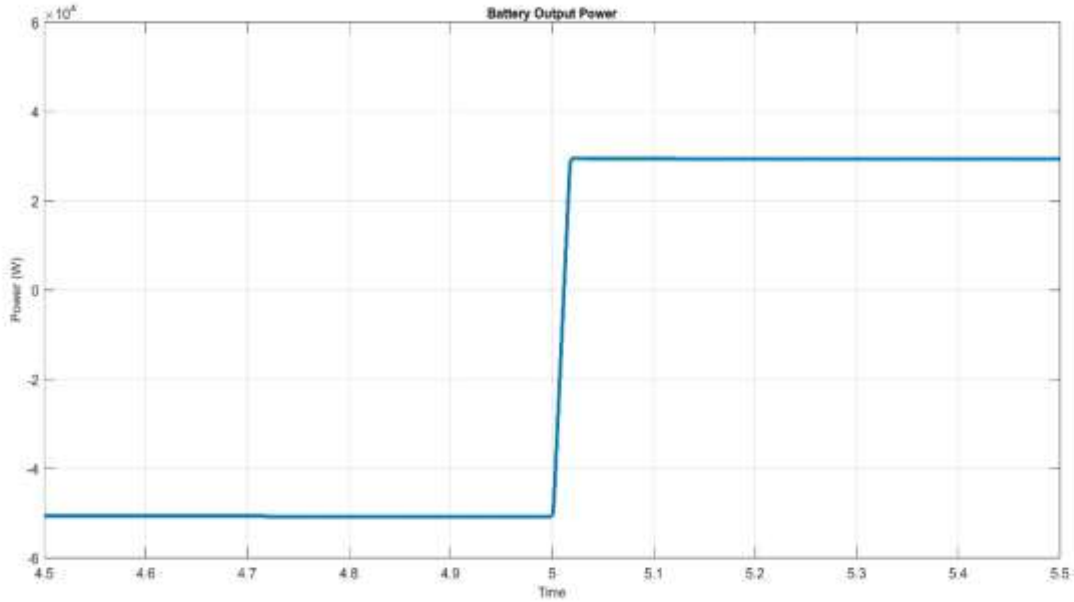


Figure 6-17 PCC Voltage During Load Shed in Islanded Mode

6.6 Case 5 – Island Mode – Solar-Storage Management

6.6.1 Objective

Microgrid controllers respond to the dispatch optimizer instruction.

6.6.2 Description

In this scenario, the optimizer has indicated that the battery should transition from charging to discharging mode to ensure it's ready to capture the solar available in the day ahead forecast. The Microgrid Energy Management System (MEMS)[13][14]controller accepts the dispatch from the optimizer and changes the reference to the battery controller. Figure 6-18 and Figure 6-19 show the corresponding waveforms for the grid power, voltage and battery power. In this case, it's assumed that the solar power is zero and the CHP is turned OFF.

6.6.3 Input

- Solar power is zero.
- CHP is off.

6.6.4 Test Result

As shown in Figure 6-17, the battery reference power changed from about 50 kW charging to 30 kW discharging at 5 seconds. Then, the battery started discharging to respond to the command. Figure 6-18 shows the corresponding change in grid power.

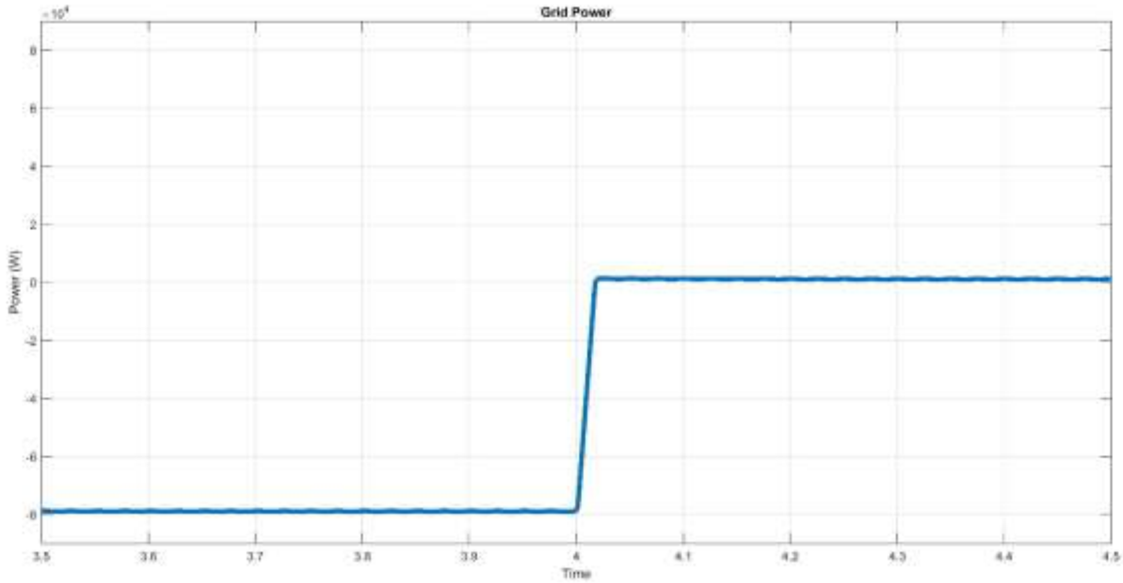


Figure 6-18 Grid Power Output Changes

Corresponding to the change in the battery power, the grid power import is reduced from about 90 kW to 10 kW, to account for the delta change in battery power of 80 kW (-50 kW to + 30 kW).

The reduction in the grid import results in the voltage going up at the PCC. See Figure 6-19.

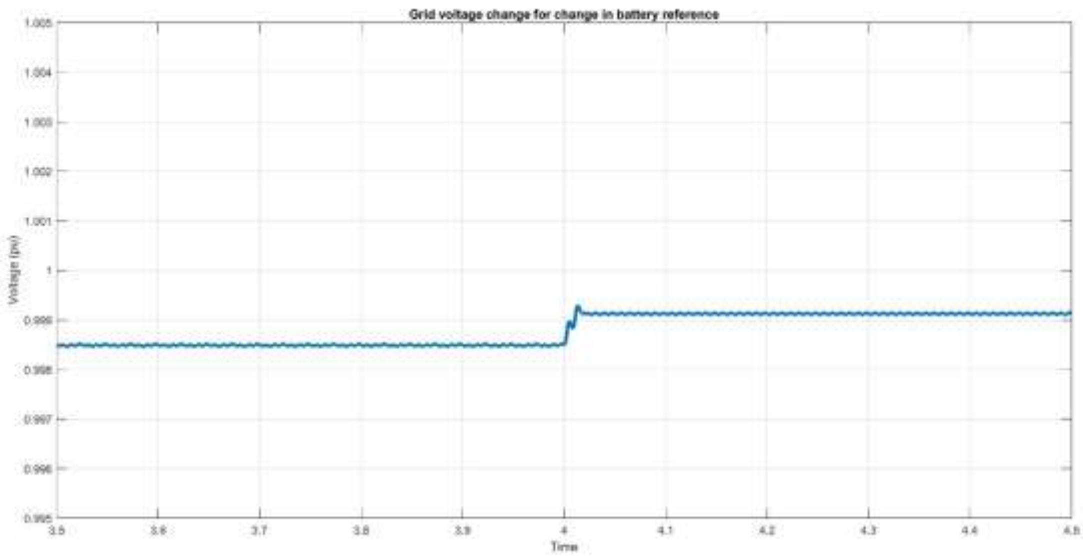


Figure 6-19 Battery Power Output Changes

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6.7 Case 6 – Island Mode – Controller Overrides Optimizer

6.7.1 Objective

Microgrid controllers override the dispatch optimizer instruction.

6.7.2 Description

This scenario involves the MEMS controller overriding the Dispatch optimizer during the condition of ensuring no grid export power. Consider this scenario where the Building 7R needs to always be in an import mode. The errors in forecast may result in the grid import falling below a certain limit. In this case, the MEMS controller monitors the grid power and calculates the new dispatch to ensure the grid import does not fall further. This would typically depend on the current system condition and may require intervention such as solar curtailment, which is demonstrated in the next simulation.

6.7.3 Test Result

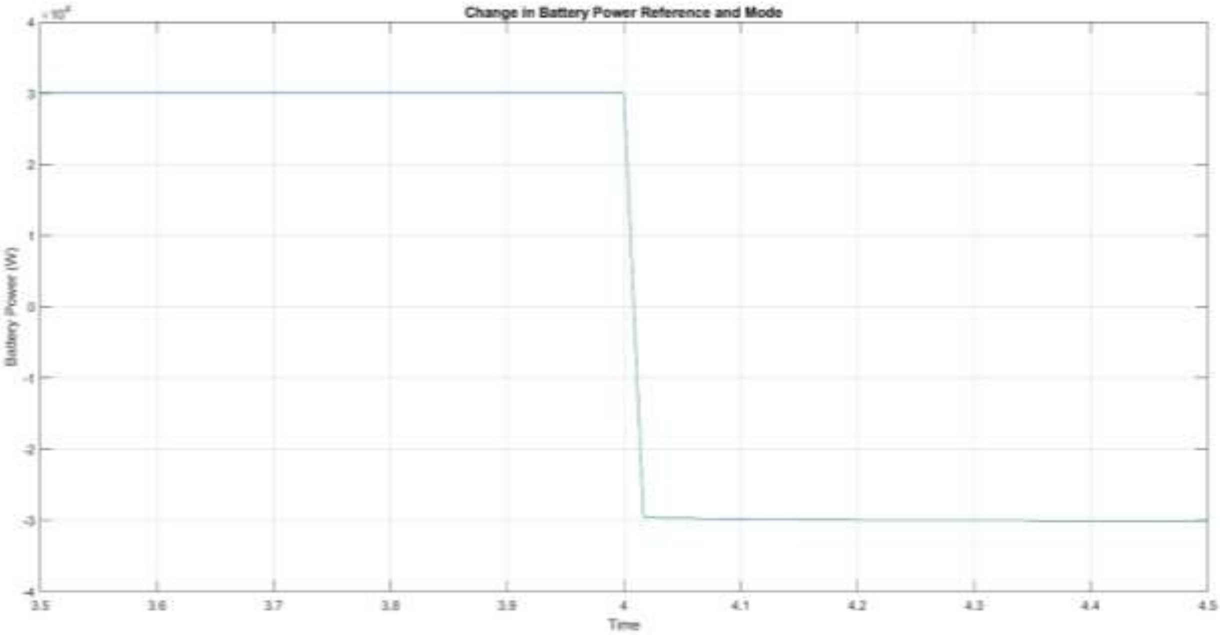

Figure 6-20 Battery Power Output Changes

6.7.3.1 Battery Power

As shown in Figure 6-20, the battery discharges at 30 kW, and the power reference changes to 30 kW Charge, after reaching the SOC limit. Correspondingly, the grid import went up by 60 kW, and the PCC voltage dipped from about 1 pu to 0.996 pu due the increased import. See Figure 6-21.

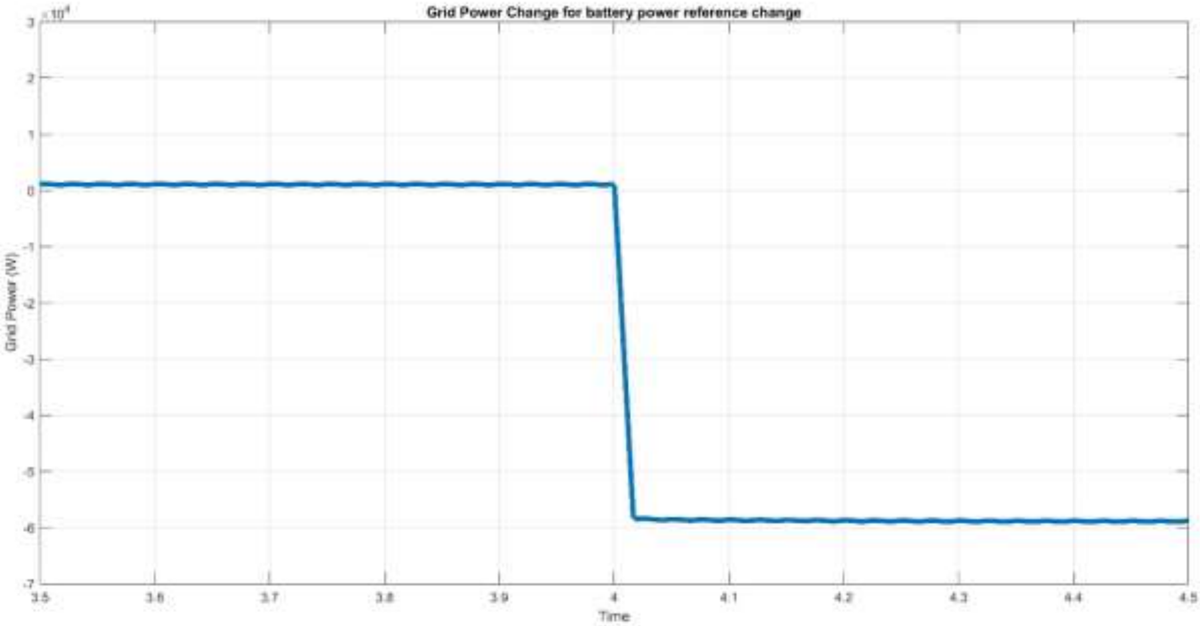

Figure 6-21 Grid Power Output Changes

7. GridSTAR 2.0 Microgrid Optimization Simulation – Objective C5

7.1 Optimization Model

7.1.1 Overview

The microgrid controller demand/supply balancing strategy has a three-level hierarchical design. The control strategy is governed by IEEE 2030.7[13] and test case is following the IEEE 2030.8[14] . These hierarchical layers are classified as follows:

1. **Dispatch Optimization**: The demand/ supply balancing is carried out by the Dispatch Optimizer using the load forecast, solar forecast, and the asset availability. This can either be a day ahead or hour ahead forecast. The optimizer's objective function can be economic dispatch, grid peak response reduction, and other objective functions.
2. **MEMS Controller Dispatch**: The MEMS controller is responsible for managing the demand/supply balance that may occur due to errors in the load/solar forecast. This typically would operate in the minutes/seconds time frame. If asset limits are violated, the MEMS controller dispatch level can override the dispatch from the Dispatch Optimization (level 1). For example, if the battery discharges more than a certain limit, the MEMS controller may turn on the CHP to charge the battery and supply the load. In this case, the dispatch would be non-optimal but would prevent any system limits from being violated. The MEMS is also responsible for selecting the mode of operation of the different assets (e.g., change battery mode from charging to discharging) and is defined based on the requirements from the system.
3. **Local Controls:** These are the individual asset level controls that take care of supply/ demand unbalance in the millisecond/second range, especially in islanded mode of operation. These include sudden load turn ON/OFF events.

7.1.2 Model Description

Table 7-1 lists the dispatch optimization as a supervisory function that carries out the dispatch of the microgrid under various conditions and can have multiple objective functions. The remaining subsections explain output of the dispatch optimization for supply/demand balancing.

Table 7-1. Test Cases for the Dispatch Optimizer

Case	Name	Description
1(a)	Grid connected economic dispatch. Battery SOC = 100%	Grid Connected cost-based day ahead optimal dispatch with initial battery SOC at 100%.
1(b)	Grid connected economic dispatch - Peak Loading day	Grid Connected cost-based day ahead optimal dispatch, with initial battery SOC at 100%, on a day with higher loads.
1(c)	Grid connected economic dispatch = Battery SOC = 50%	Grid Connected cost-based day ahead optimal dispatch with initial battery SOC at 50%.
2	Grid connected peak reduction	Reduction of grid import during peak hours.
3(a)	Islanded economic dispatch – Planned	Economic dispatch for day ahead with known grid outage scenario.
3(b)	Islanded Economic Dispatch–Planned at peak loading day	Economic dispatch for day ahead with known grid outage scenario for peak loading day.

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Case	Name	Description
4	Islanded Economic Dispatch–Unplanned	Economic dispatch for day ahead after islanding condition occurs.
5(a)	Islanded TTL without CHP	Maximum time to last in islanded mode without running conventional CHP generator.
5(b)	Islanded TTL without CHP – Peak loading day	Maximum time to last in islanded mode without running conventional CHP generator.

7.1.3 System Configuration

The system considered for optimization is Building 7R comprising the assets shown in Table 7-2.

Table 7-2 Building 7R Assets

Microgrid Assets & Loads	Microgrid System	Load kW		Distributed Energy Resources				
		Peak load	Minimum	Solar PV	Storage	NG Gen	CHP	Fuel Cell
Building 7R	GridSTAR 2.0	50	20	15	50kW/90kWh		65	

For the optimization consideration, the load is further classified into the following three groups:

- Critical load – About 40% of the total load
- Non-critical Load 1 – 30% of the total load
- Non-critical load 2 – Balance 30% of the total load

Typical load profile of Building 7R is over several days. See Figure 7-1.

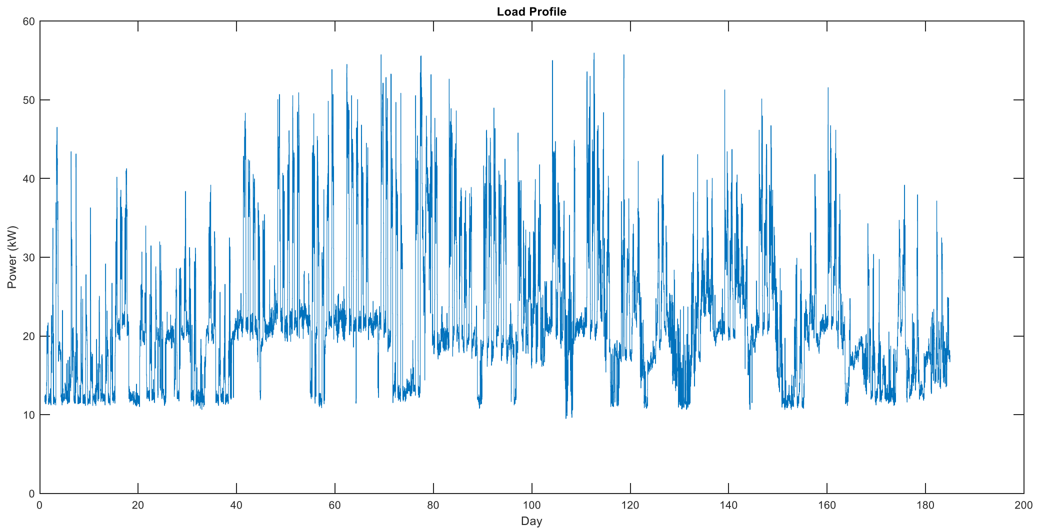

Figure 7-1. Daily variation in load profile for Building 7R

For the analysis presented in this section, load profiles from two different days were chosen: (i) first is a *nominal day* where the power demand is on the lower end (peak load < 22 kW), and (ii) second is a *peak loading day* where the peak load is about 2.5 times that of the nominal day in case (i). Figure 7-2 shows the two load profiles.

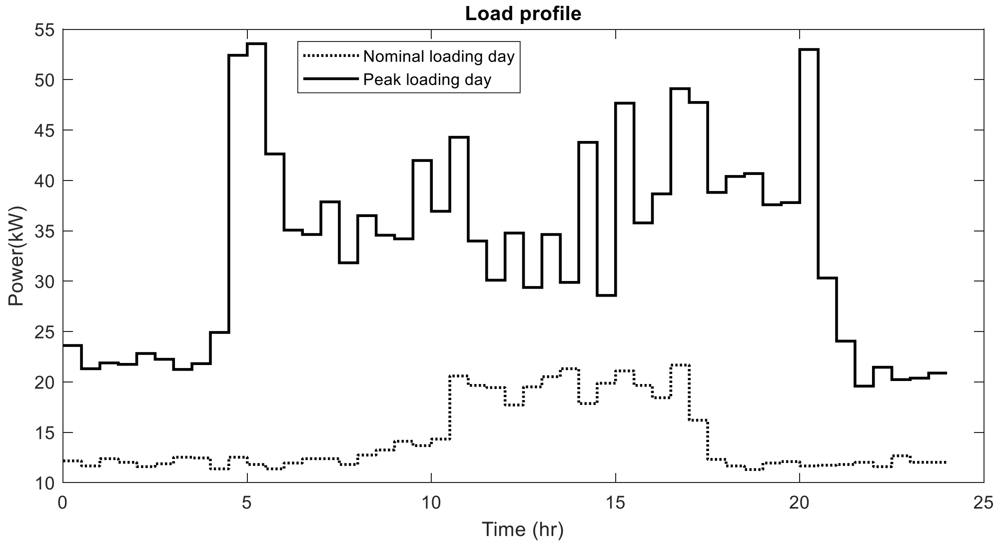

Figure 7-2. Nominal and peak loading day profiles

To optimally schedule the power resources, the dispatch optimizer also needs to know the variation in grid price and the solar forecast. Figure 7-3 shows the grid price as a function of hour, and the day-ahead solar forecast, as assumed for the optimization.

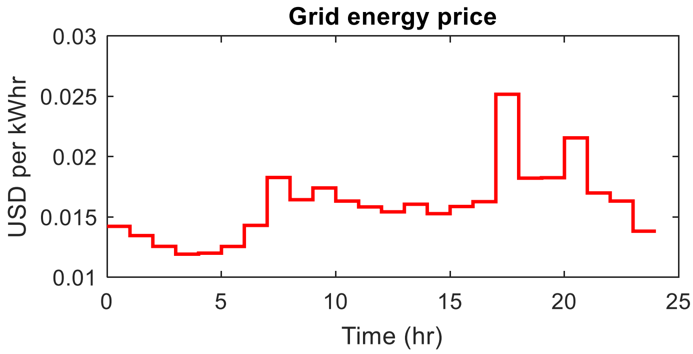

Figure 7-3. Hourly variation in grid import price

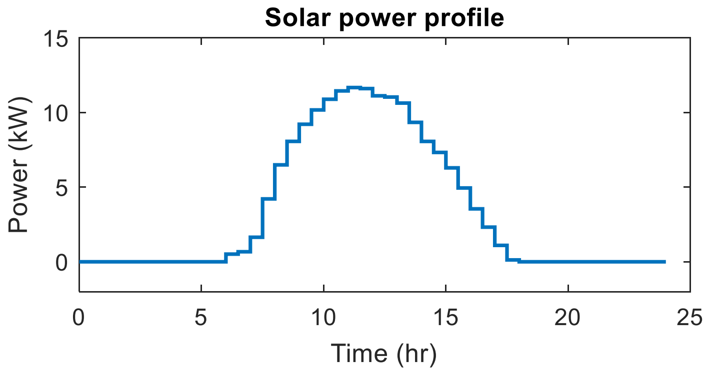

Figure 7-4. Hourly variation in solar profile

For the given configuration, the optimizer also accepts operational parameters and costs from energy storage (e.g., initial state of charge, maximum rate of discharge) and CHP (ramp rate, minimum uptime and downtime). With these inputs and operational constraints, the dispatch optimizer prepares a day-ahead schedule for the dispatch of energy resources available in the microgrid.

Generally, the dispatch optimizer plans the resource schedule to minimize overall operating cost while meeting the load demand. However, it is also capable of handling more critical scenarios, such as islanding or planning for load shedding when the available power is not enough to meet the load demand. In the following sections, the test cases listed in Table 7-1 were used to demonstrate several important features and capabilities of the dispatch optimizer.

7.2 Case 1a – Grid Connected Economic Dispatch-SOC 100%

7.2.1 Objective

Grid connected economic dispatch for nominal load profile, with initial battery SOC at 100%

7.2.2 Description

Figure 7-2 shows the considered load profile as the one for nominal loading day. This is a typical load profile obtained for Building 7R. The peak load appears to be in the morning from about 10 am to 4 pm.

7.2.3 Input

- Initial Battery SOC at 100%.
- Typical Load Profile obtained for Building 7R Profile.
- Grid Price (see Appendix B).
- CHP Initial Conditions.

7.2.4 Expected Result

- Grid price is low and CHP is expected to be off.
- It is expected that the battery discharges during the day to reach a minimum SOC of 20% by night.

7.2.5 Test Result

Based on the inputs provided, the following figures show the dispatch optimizer prepares a day ahead dispatch schedule.

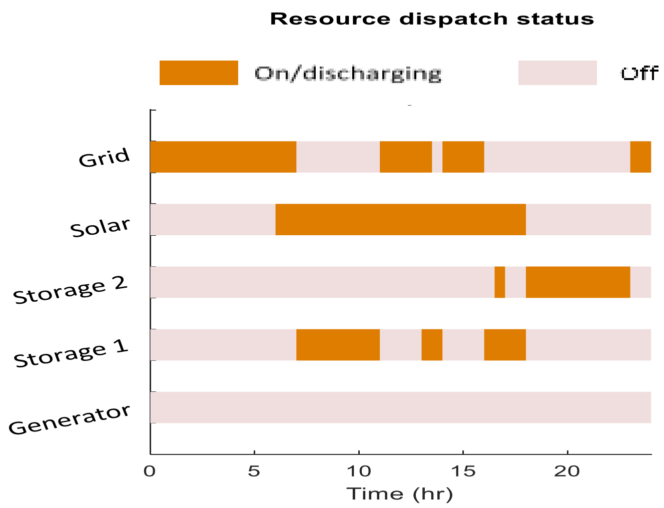

Figure 7-5. Asset dispatch status for Table 7-1-Case 1(a)

Figure 7-5 shows the asset dispatch schedule and the cumulative power (normalized to maximum load for the given day) drawn from various assets, as planned by the dispatch optimizer. In Figure 7-6, the different colors indicate the energy contribution from individual power resources, at different times of the day.

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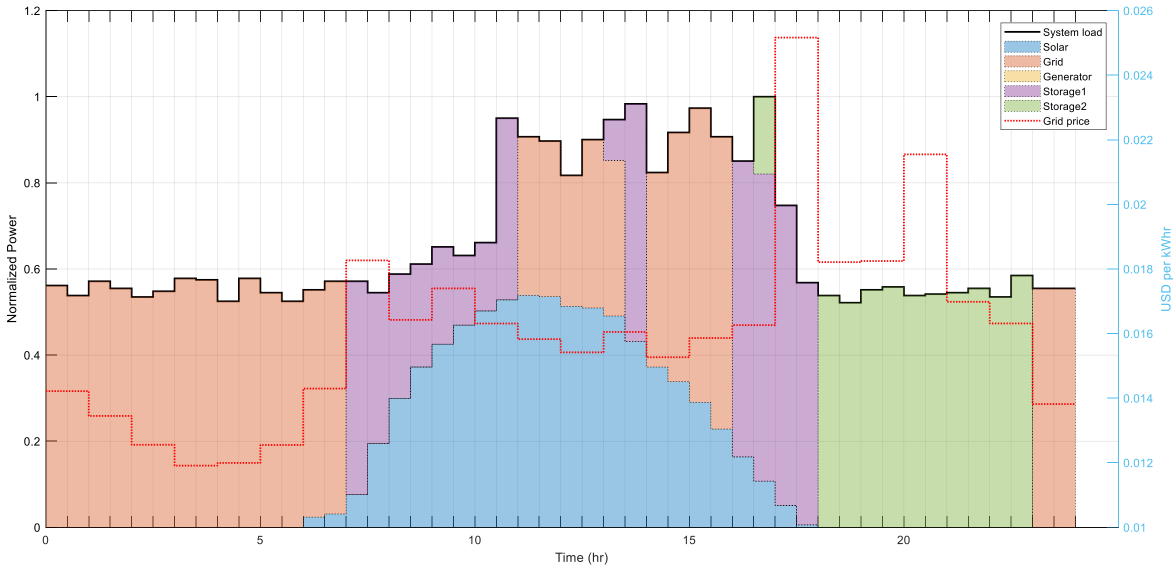

Figure 7-6. Asset dispatch schedule for Table 7-1-Case 1(a)

As shown in the dispatch schedule, the CHP generator is not required to be turned ON at the current grid prices and the price of the natural gas assumed for the dispatch. During the time from about 7 am to 11 am, the battery and solar combination is used to supply the load. This minimizes the amount of power drawn from the grid when grid prices are higher and is constrained by the availability of energy storage during that time period. Energy storage also comes into the play during the evening hours, where the grid prices are higher than the morning or night. Figure 7-7 shows the battery SOC as a function of time.

It is expected that the battery discharges during the day to reach a minimum SOC of 20% by night. The battery gets charged during the night at the lower grid prices to reach 100% SOC by morning, and the dispatch cycle can continue.

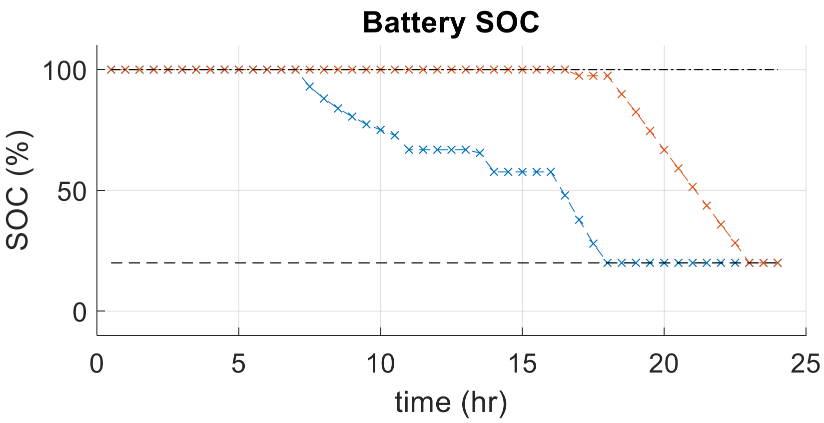

Figure 7-7. Battery SOC for Table 7-1-Case 1(a)

Table 7-3. Asset dispatch cost for Table 7-1-Case 1(a)

	Generator O&M	Battery	Renewable	Emissions	Energy Import
Cost (USD)	0	5	0	0	3.92

7.3 Case 1b – Grid Connected Economic Dispatch-Peak Loading Day

7.3.1 Objective

Grid connected economic dispatch for peak loading day with initial battery SOC at 100%

7.3.2 Description

The previous case considered grid connected economic dispatch for nominal load profile. We now consider the load profile from one of the peak loading days, where the peak loads are much larger than the loads on a nominal day. Figure 7-2 shows the considered peak loading day profile.

7.3.3 Input

- Initial Battery SOC at 100%.
- Typical Peak Load Profile obtained for Building 7R Profile shown in Figure 7-2.
- Grid Price (see Appendix B).
- CHP Initial Conditions.

7.3.4 Expected Result

- Grid price is low and CHP is expected to be off.
- Due to the peak load, the grid import is expected to increase.
- It is expected that the battery discharges during the day to reach a minimum SOC of 20% by night.

7.3.5 Test Result

Based on the inputs provided, the following figures show the dispatch optimizer prepares a day ahead dispatch schedule.

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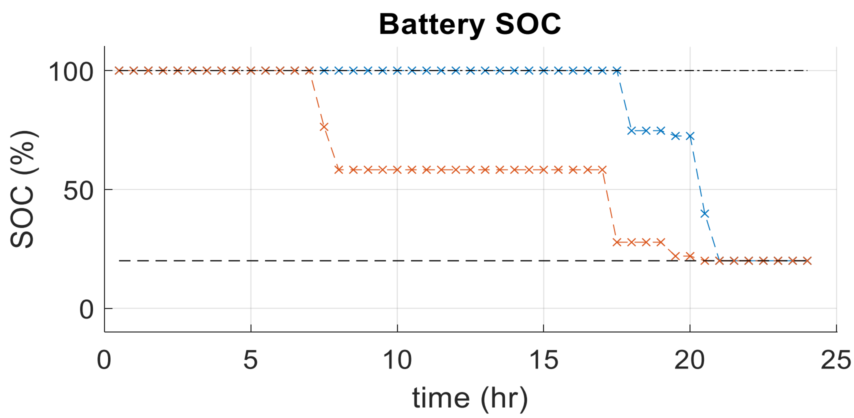

Figure 7-8. (a) Battery SOC for Table 7-1-Case 1(b)

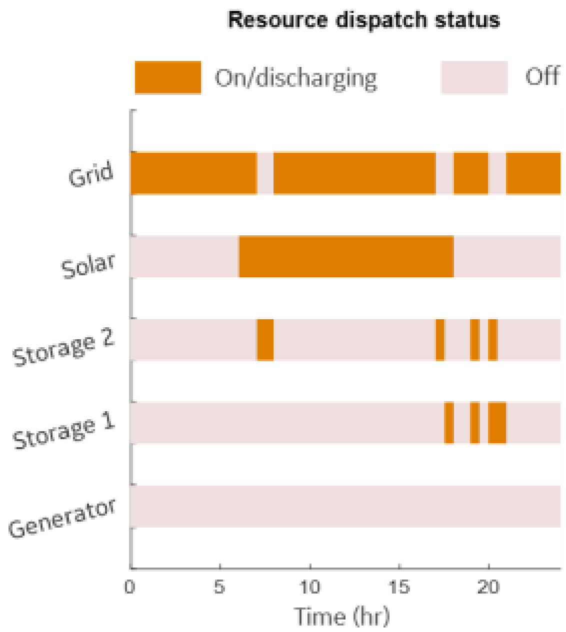

Figure 7-9. (b) Asset dispatch status for Table 7-1-Case 1(b)

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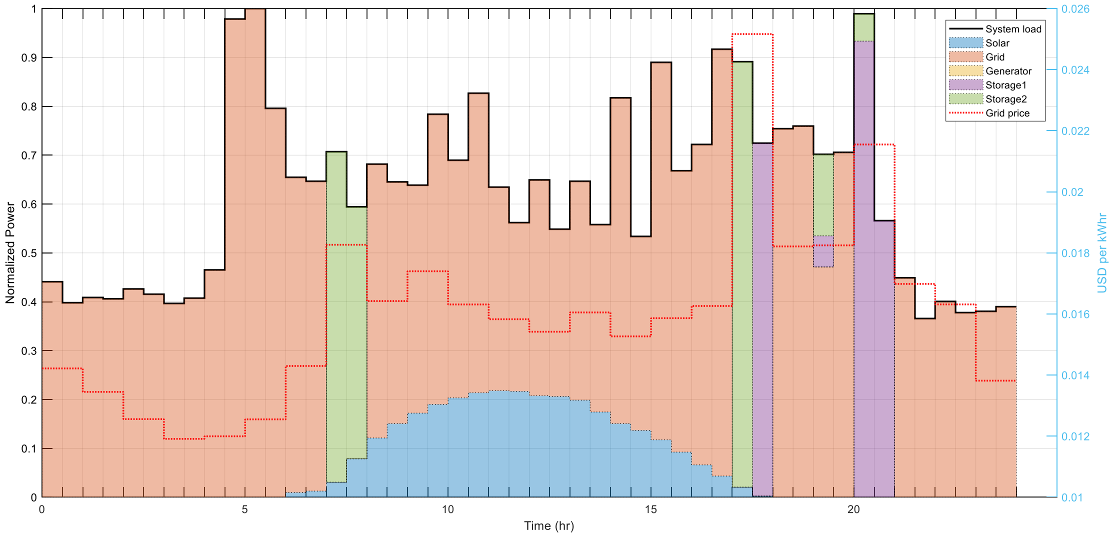

Figure 7-10. Asset dispatch schedule for Table 7 1-Case 1(b)

Note that similar to Table 7-1-Case 1(a), the dispatch optimizer uses a combination of grid, energy storage units, and solar energy to meet the load demand, and recommends not to turn ON the CHP to minimize the cost of meeting the load. However, as compared to Table 7-1-Case 1 (a), the load demand has increased considerably. See Figure 7-2. Therefore, the dispatch optimizer increases the grid utilization to meet the increased demand. See Figure 7-11 and Figure 7-12.

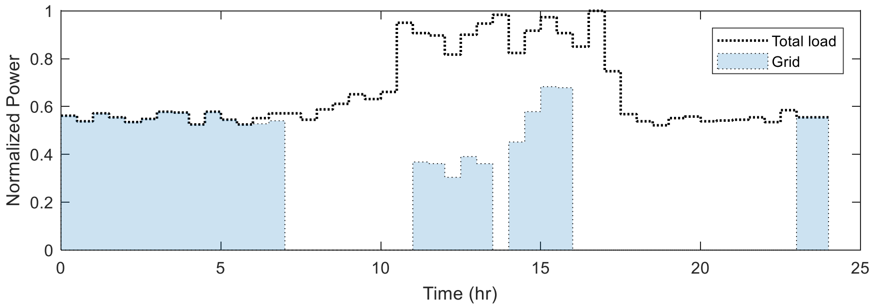

Figure 7-11 Grid utilization for nominal loading day, Table 7-1-Case 1(a)

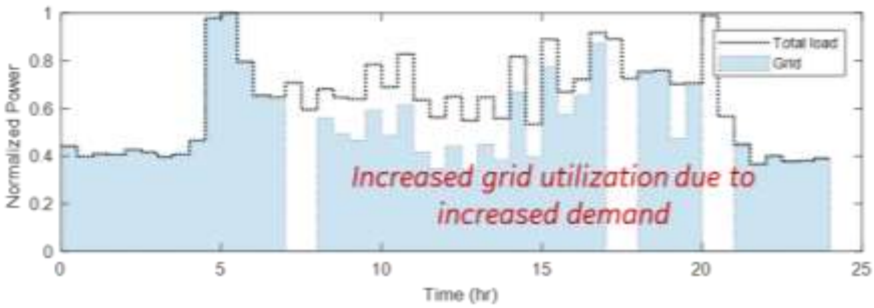

Figure 7-12 Grid utilization for peak loading day, Table 7-1-Case 1(b)

Table 7-4. Asset dispatch cost for Table 7 1-Case 1(b)

	Generator O&M	Battery	Renewable	Emissions	Energy Import
Cost (USD)	0	5	0	0	18.27

7.4 Case 1c – Grid Connected Mode - Economic Dispatch-SOC 50%

7.4.1 Objective

Grid connected economic dispatch for nominal load profile with initial battery SOC at 50%

7.4.2 Description

In two previous cases, we notice that often, a dispatch schedule which leads to minimal cost of serving the load, requires the battery to discharge during the day and reach a lower SOC by night. Therefore, it is but obvious to consider an economic dispatch test case where the battery is only partially charged at the beginning of the day.

7.4.3 Input

- Initial Battery SOC at 50%.
- Typical load profile obtained for Building 7R Profile shown in Figure 7-2.
- Grid Price (see Appendix B).
- CHP initial conditions.

7.4.4 Expected Result

- Grid price is low and CHP is expected to be off.
- It is expected that the battery discharges during the early morning to charge and discharge during the peak hours and reach a minimum SOC of 20% by night.

7.4.5 Test Result

Based on the inputs provided, the following figures show the dispatch optimizer prepares a day ahead dispatch schedule. In contrast to Table 7-1-Case 1(a)-(b), where the energy storage units were at an initial SOC of 100%, let us now consider a scenario where the two energy storage units are at 50% SOC at the beginning of the day. Figure 7-2 shows the load profile considered is from a nominal loading day. For this case, the asset dispatch schedule generated by the dispatch optimizer. See Figure 7-13 and Figure 7-14.

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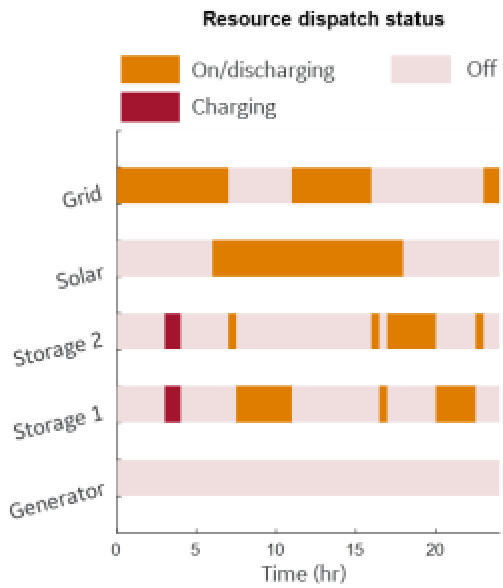

Figure 7-13. Asset dispatch status for Table 7-1-Case 1(c)

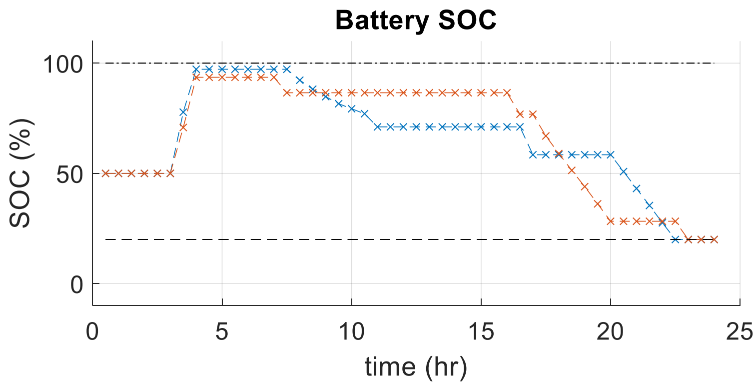

Figure 7-14 Battery SOC for Table 7-1-Case 1(c)

From these figures, it's clear that to minimize the cost of meeting the load demand, the optimizer first suggests charging the battery from the grid early in the morning when grid prices are lower. The stored energy is then used to meet the demand later in the day when grid prices are relatively higher.

Table 7-5. Asset dispatch cost for Table 7-1-Case 1(c)

	Generator O&M	Battery	Renewable	Emissions	Energy Import
Cost (USD)	0	7.8	0	0	6.09

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7.5 Case 2 – Grid Connected Mode - Peak Reduction Optimization

7.5.1 Objective

Grid connected economic dispatch with the cap on the maximum import.

7.5.2 Description

This set-up considers a day-ahead economic dispatch of the CHP, two energy storage units, grid power and solar power, with a reduction of available grid import during peak hours. Figure 7-2 shows the nominal load profile considered. For the given load profile, the load demand peaks during 12pm to 4:30pm with a maximum of ~21kW; available grid power import during this time is limited to 5kW. The dispatch optimizer accepts this as an added constraint in the grid operation and generates the dispatch schedule. See Figure 7-15 and Figure 7-16.

7.5.3 Input

- Initial Battery SOC at 100%.
- Typical Day Load Profile obtained for Building 7R Profile shown in Figure 7-2.
- Grid Price (see Appendix B).
- Grid power import during this time is limited to 5kW.
- CHP Initial Conditions.

7.5.4 Expected Result

- Grid price is low and CHP is expected to be off.
- Due to the cap on the maximum import during the peak load, CHPS are expected to be brought online.
- It is expected that the battery discharges during the day to reach a minimum SOC of 20% by night.

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7.5.5 Test Result

Based on the inputs provided, the following figures show the dispatch optimizer prepares a day ahead dispatch schedule.

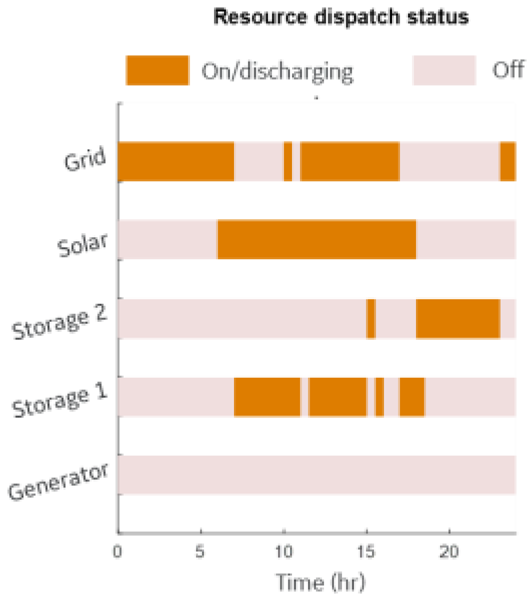

Figure 7-15. Asset dispatch status for Table 7-1-Case 2

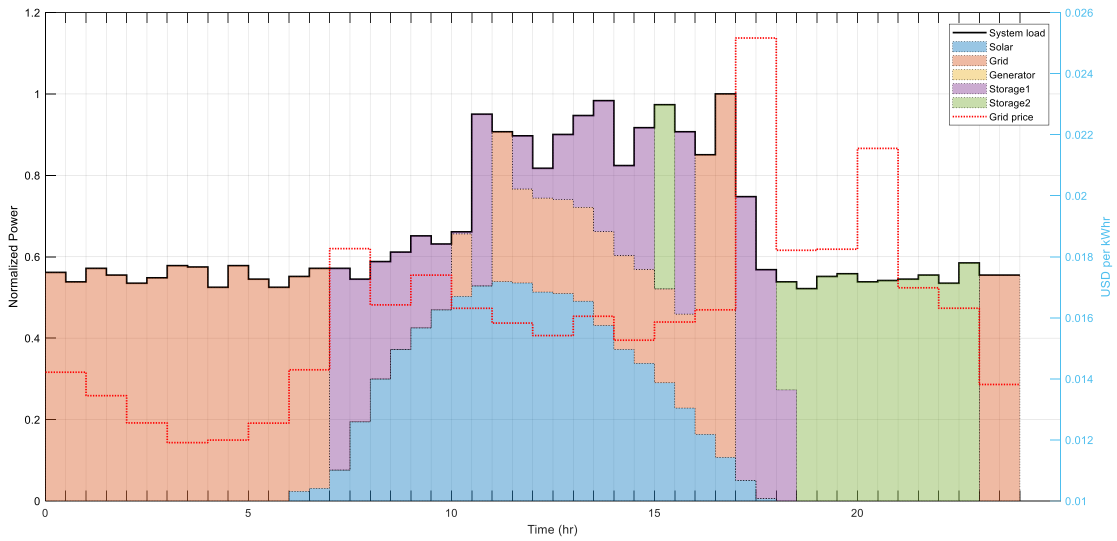

Figure 7-16. Asset dispatch schedule for Table 7-1-Case 2

Figure 7-17 shows, compared to the grid connected economic dispatch case described in Table 7-1-Case 1(a), the dispatch schedule for grid import power is limited to 5kW during the peak reduction hours 12pm – 4:30pm. Also, the power from energy storage is used to compensate for the reduced grid import.

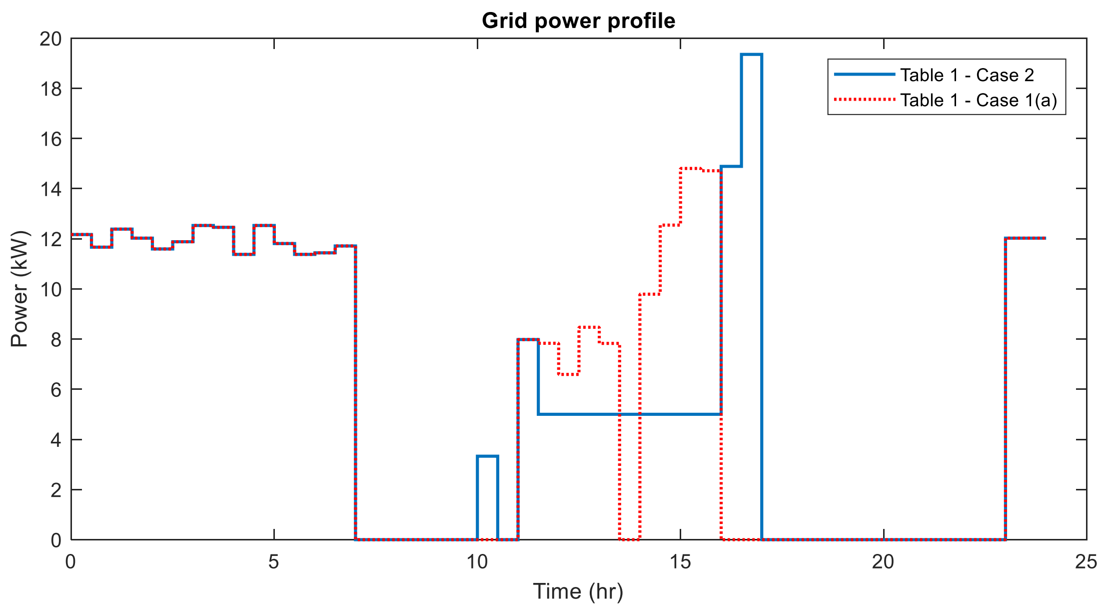

Figure 7-17. Comparison between grid import profiles for Table 7-1-Case 1(a) and Table 7 1-Case 2

Table 7-6. Asset dispatch cost for Table 7-1-Case 2

	Generator O&M	Battery	Renewable	Emissions	Energy Import
Cost (USD)	0	5	0	0	3.94

7.6 Case 3a – Island Mode – Planned Islanding Economic Dispatch

7.6.1 Objective

Planned islanding between 12pm to 4:30pm for nominal load day, with initial battery SOC at 100%

7.6.2 Description

In this case, the nominal load profile shown in Figure 7-2 is used. The peak load occurs between 10:30am – 5:30pm. An islanding event is planned between 12pm and 4:30pm. As this is 'planned' islanding, the dispatch optimizer generates a day-ahead dispatch schedule while accounting for the grid unavailability between 12pm-4:30pm. Figure 7-19 shows the generated dispatch schedule, along with the battery SOC profile.

7.6.3 Input

- Initial Battery SOC at 100%.
- Typical Load Profile obtained for Building 7R Profile shown in Figure 7-2.
- Grid Price (see Appendix B).
- CHP Initial Conditions.
- Islanding event is planned between 12pm and 4:30pm.

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7.6.4 Expected Result

- Because islanding occurs during non-peak hours, the BESS has enough capacity to meet the load, and the CHP is expected to stay off line.
- BESS discharges the most during the islanding hour and reaches a minimum SOC of 20% by night.

7.6.5 Test Result

The following shows the results from the islanding test.

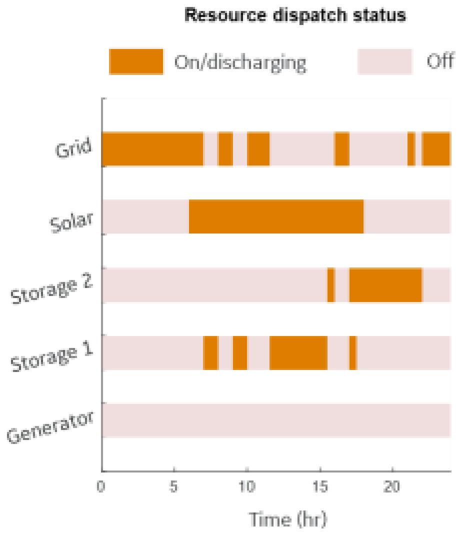

Figure 7-18. Asset dispatch status for Table 7-1-Case 3

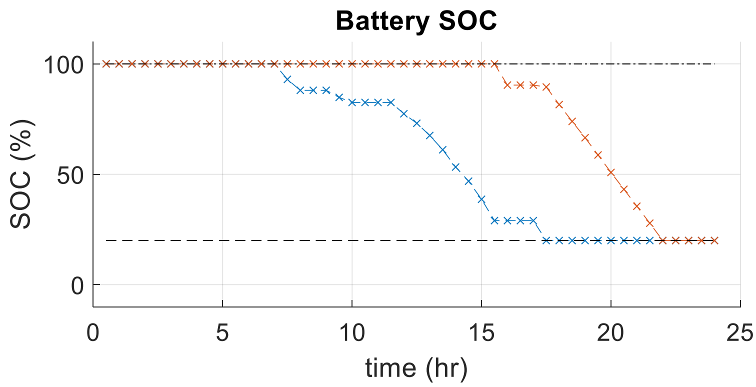

Figure 7-19. (a) Asset dispatch status for Table 7-1-Case 3(a);
(b) Battery SOC for Table 7-1-Case 3(a)

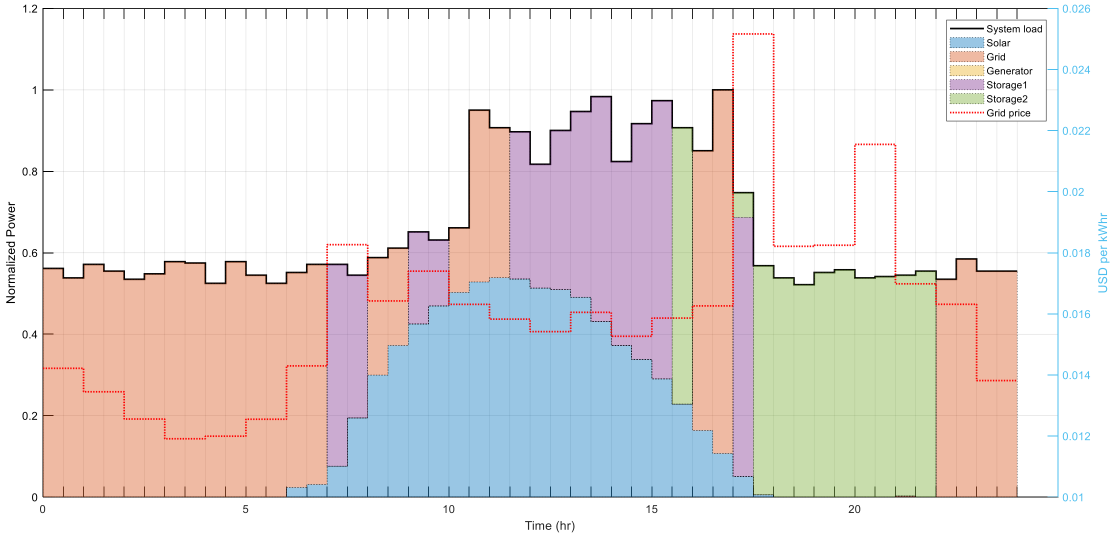

Figure 7-20. Asset dispatch schedule for Table 7-1-Case 3(a)

As the load demand is relatively low for this load profile, a combination of power from grid, solar, and energy storage can optimally meet the demand. The reduction in availability of grid power during islanding is compensated by the increased usage of energy storage units as compared to Table 7-1-Case 1(a). See Figure 7-21.

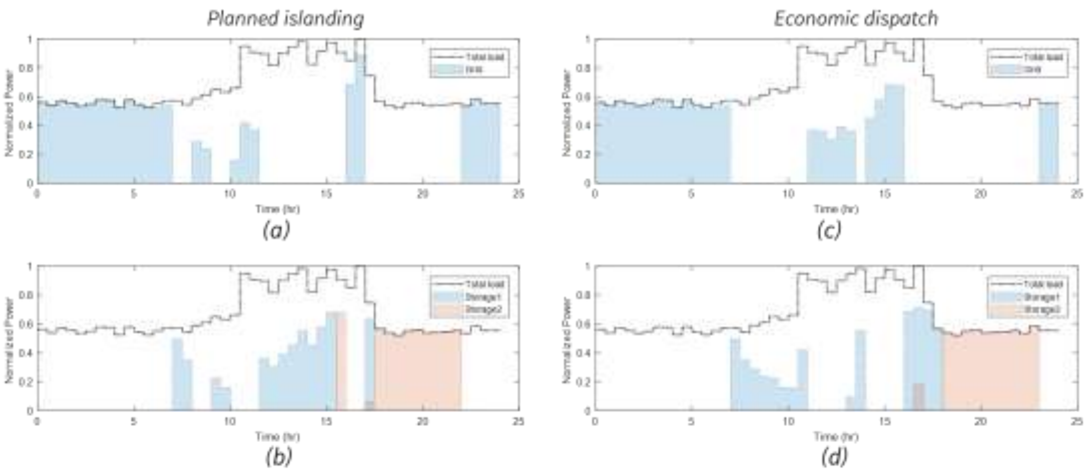

Figure 7-21. (a)Grid import profile and (b) energy storage dispatch schedule for Table 7-1-Case 3(a); (c) Grid import profile and (d) energy storage dispatch schedule for Table 7-1-Case 1(a)

Table 7-7. Asset dispatch cost for Table 7-1-Case 3(a)

	Generator O&M	Battery	Renewable	Emissions	Energy Import
Cost (USD)	0	5	0	0	3.97

7.7 Case 3b – Island Mode – Peak Day Planned Economic Dispatch

7.7.1 Objective

Planned islanding for peak loading day between 3pm to 8:30pm, with initial battery SOC at 100%.

7.7.2 Description

In contrast to the last scenario, this case considers a load profile from one of the peak loading days with an islanding planned from 3pm to 8:30pm.

When there was no islanding and the dispatch optimizer was planning for a grid connected day-ahead economic dispatch (Table 7-1-Case 1(b)), utilizing solar energy, battery, and grid power can meet load demand. However, due to islanding from the grid during peak loading hours of 3pm-8:30pm for the given day, load demand could no longer be met by just using solar and battery. Therefore, the dispatch optimizer plans for a CHP dispatch from 4:30pm-7:30 pm, as shown in the dispatch schedule below. Note that the CHP is not turned ON during any other time of the day because using CHP is more expensive than solar power, energy storage, and power import from the grid.

7.7.3 Input

- Initial Battery SOC at 100%.
- Typical Load Profile obtained for Building 7R Profile shown in Figure 7-2.
- Grid Price (see Appendix B).
- CHP Initial Conditions.
- Islanding event is planned from 3pm to 8:30pm.

7.7.4 Expected Result

- Because islanding occurs during peak hours and the BESS does not have enough capacity to meet the load demand, CHP is expected to go online when generated solar is not enough.
- BESS discharges the most during the islanding hour and reaches a minimum SOC of 20% by night.

7.7.5 Test Result

When there was no islanding and the dispatch optimizer was planning for a grid connected day-ahead economic dispatch (Table 7-1-Case 1(b)), utilizing solar energy, battery, and grid power can meet load demand. However, due to islanding from the grid during peak loading hours of 3pm-8:30pm for the given day, load demand could no longer be met by just using solar and battery. Therefore, the dispatch optimizer plans for a CHP dispatch from 4:30pm-7:30 pm. See Figure 7-22. Note that CHP is not turned ON during any other time of the day because using CHP is more expensive than solar power, energy storage, and power import from the grid.

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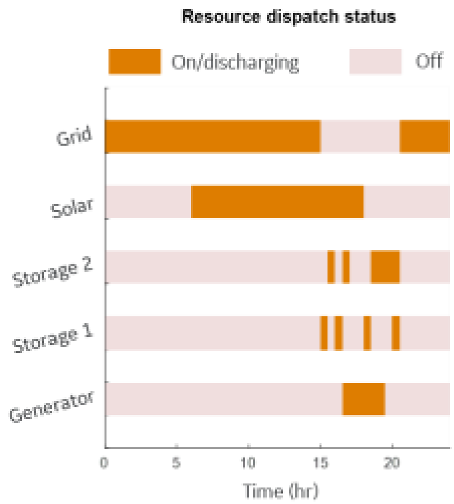

Figure 7-22. Asset dispatch status for Table 7 1-Case 3(b)

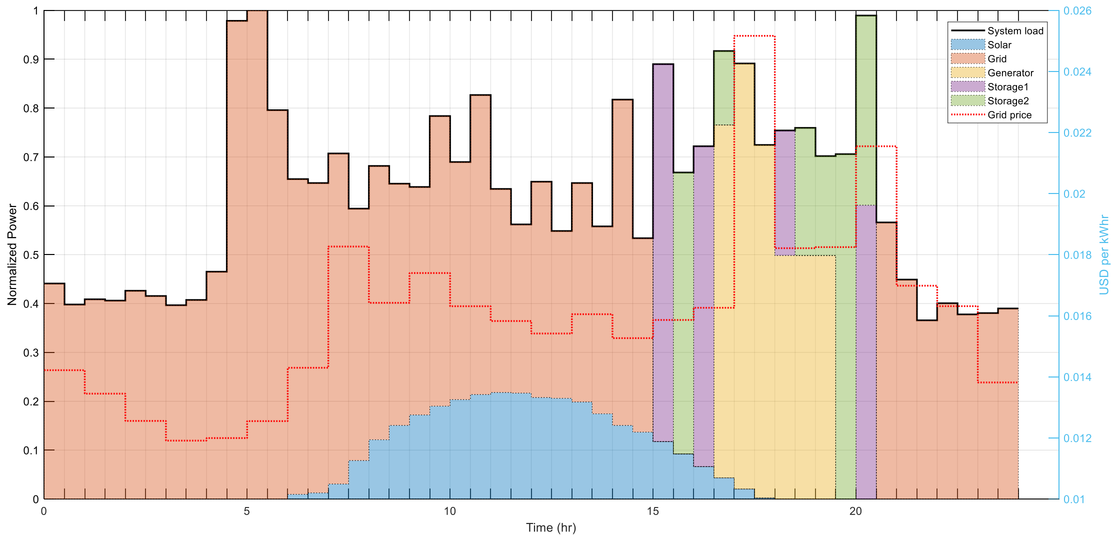

Figure 7-23. Asset dispatch schedule for Table 7 1-Case 3(b)

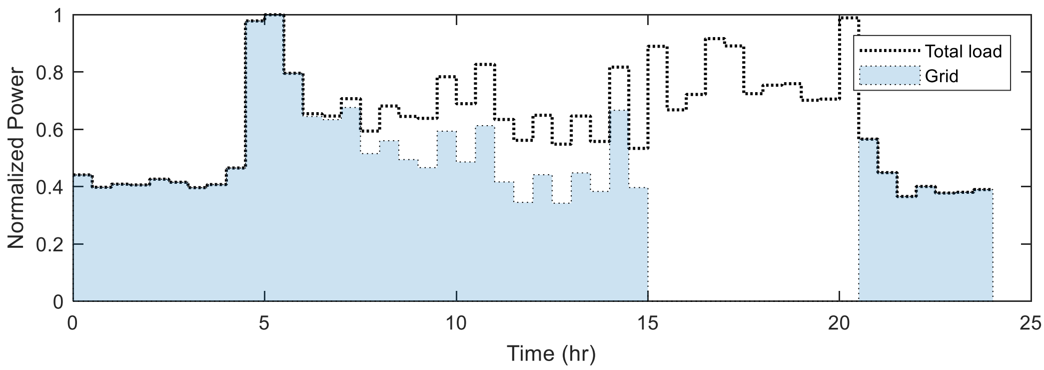

Figure 7-24. Grid import profile for Table 7 1-Case 3(b)

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Table 7-8. Asset dispatch cost for Table 7 1-Case 3(b)

	Generator O&M	Battery	Renewable	Emissions	Energy Import
Cost (USD)	0	5	0	0	14.98

7.8 Case 4 – Island Mode – Unplanned Islanding Economic Dispatch

7.8.1 Objective

Unplanned islanding

7.8.2 Description

In the last section, we discussed when an islanding event is planned and the dispatch optimizer is aware of it in advance. This case (listed in Table 7-1-Case 4), presents a different scenario where an unplanned islanding disconnects the microgrid from the main grid. As the dispatch optimizer is unaware of the unplanned islanding event when generating the day-ahead dispatch schedule, the microgrid may no longer be able to meet the load demand after islanding has occurred, let alone be optimal. Therefore, a re-planning is required after the islanding occurs whereby the dispatch optimizer generates a new dispatch schedule for the next 24 hours.

7.8.3 Input

- Battery SOC at 66.84% and 100% when islanding occurs..
- Load and solar data when islanding occurs.

This scenario considers the nominal load profile shown in Figure 7-2. Since the dispatch optimizer is initially unaware of the future unplanned islanding, it generates a grid connected economic dispatch schedule presented in Table 7-1-Case 1(a). This case also considers that an unplanned islanding occurs between 12pm-4:30pm. After the unplanned islanding occurs, the dispatch optimizer re-plans the dispatch schedule for the next 24hrs starting at 12pm.

Figure 7-25 and Figure 7-26 show the load profile and solar power profile for next 24hours.

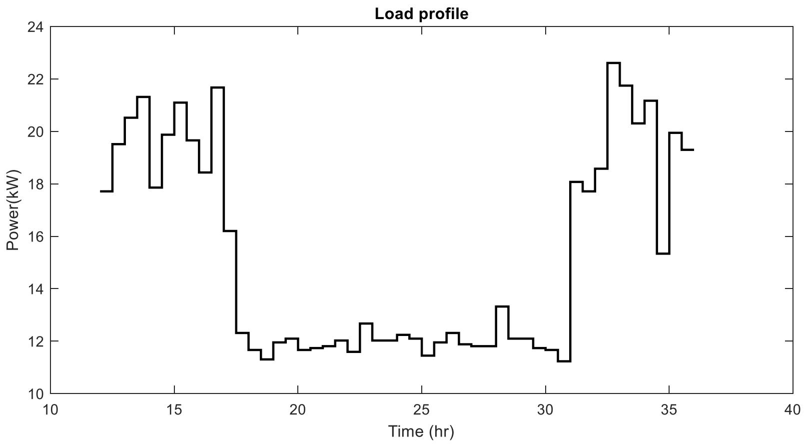

Figure 7-25. Day-ahead load profile used for rescheduling in Table 7 1-Case 4

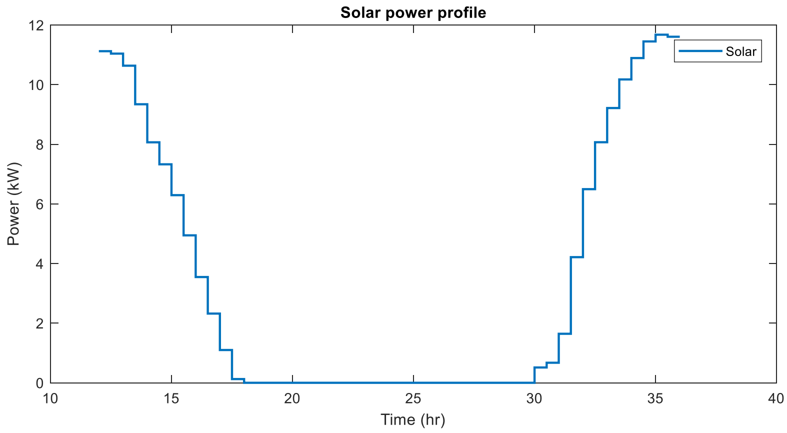

Figure 7-26. Day-ahead solar profile used for rescheduling in Table 7 1-Case 4

7.8.4 Expected Result

- Because islanding occurs during peak hours and the BESS does not have enough capacity to meet the load, the CHP is expected to go online when generated solar is not enough.
- BESS discharges the most during the islanding hour and reaches a minimum SOC of 20% by night.

7.8.5 Test Result

The following figures shows the newly generated dispatch schedule.

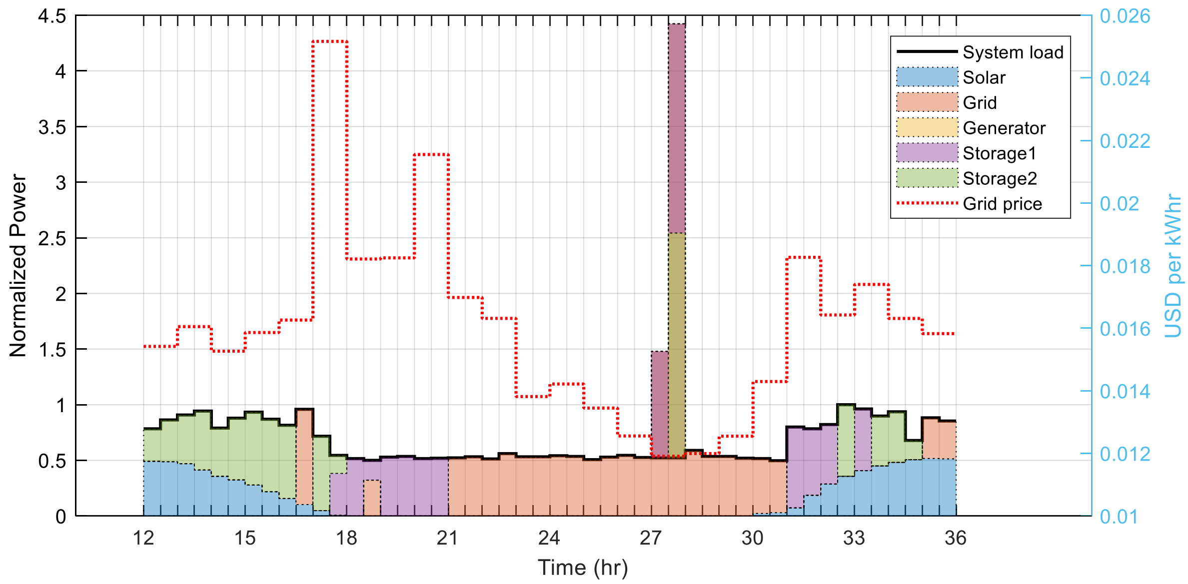

Figure 7-27. Asset dispatch schedule for Table 7 1-Case 4

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The dispatch optimizer uses the energy storage to compensate for the lost grid power during islanding (12pm-4:30pm) and charges the storage units later when the grid prices are low (between 3am-4am). This is clear from the battery power profiles shown below.

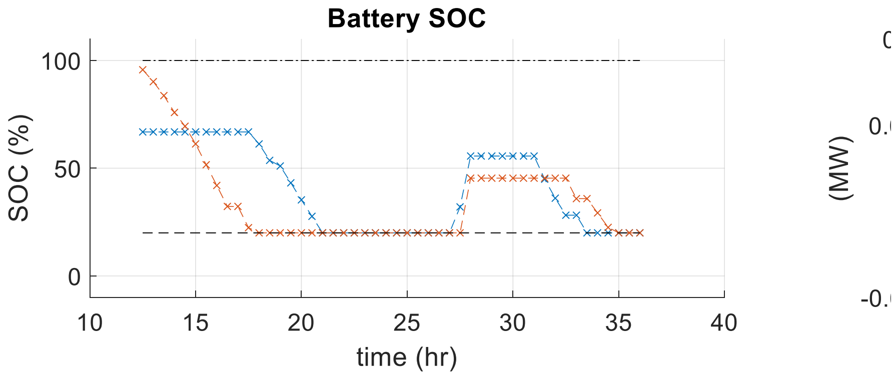

Figure 7-28. Battery SOC for Table 7 1-Case 4

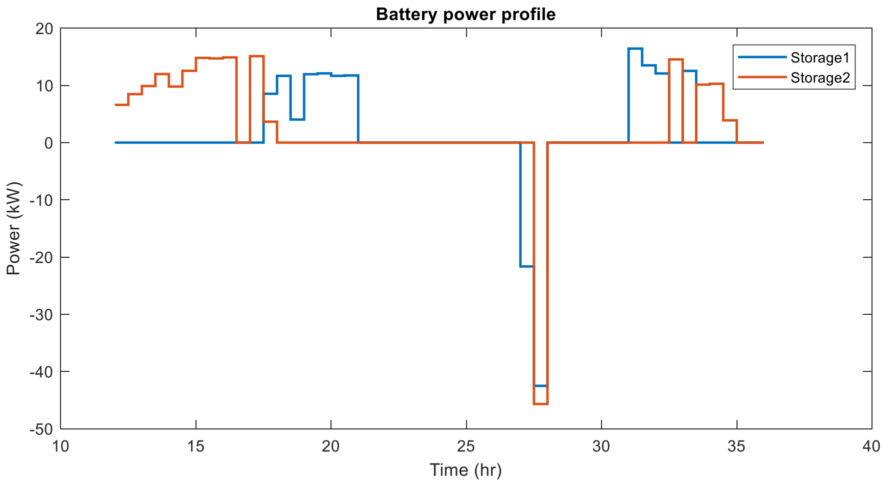

Figure 7-29. Battery energy dispatch for Table 7-1-Case 4

Table 7-9. Asset dispatch cost for Table 7-1-Case 4

	Generator O&M	Battery	Renewable	Emissions	Energy Import
Cost (USD)	0	8	0	0	5.3

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7.9 Case 5a – Island Mode – Maximize Time to Live (TTL) normal day

7.9.1 Objective

Islanded TTL without CHP for nominal load day with initial battery SOC at 100%.

7.9.2 Description

The "islanded TTL without CHP" case considers a scenario where the microgrid is islanded from the main grid for the entire day and the CHP is also not available. Two different load profiles are described in Section 7.1.3 and Figure 7-2. The first case with nominal load profiles is listed in Table 7-1-Case 5(a). The islanded TTL without CHP at peak loading day is listed in Table 7-1-Case 5(b). In addition, the load from Building 7R is split into a critical load, and two non-critical loads of equal priority as described in Section 7.1.3.

7.9.3 Input

- Initial Battery SOC at 100%.
- Nominal Load Profile obtained for Building 7R Profile shown in Figure 7-2.
- Grid Price (see Appendix B).

7.9.4 Expected Result

The BESS will charge at the hours solar production exceeds load and discharge when the solar production cannot meet the load demand.

7.9.5 Test Result

The dispatch optimizer takes the load profile, solar power profile, parameters and operational constraints of energy storage as input and generates the following day-ahead dispatch schedule for the assets.

Figure 7-30. Asset dispatch status for Table 7 1-Case 5(a)

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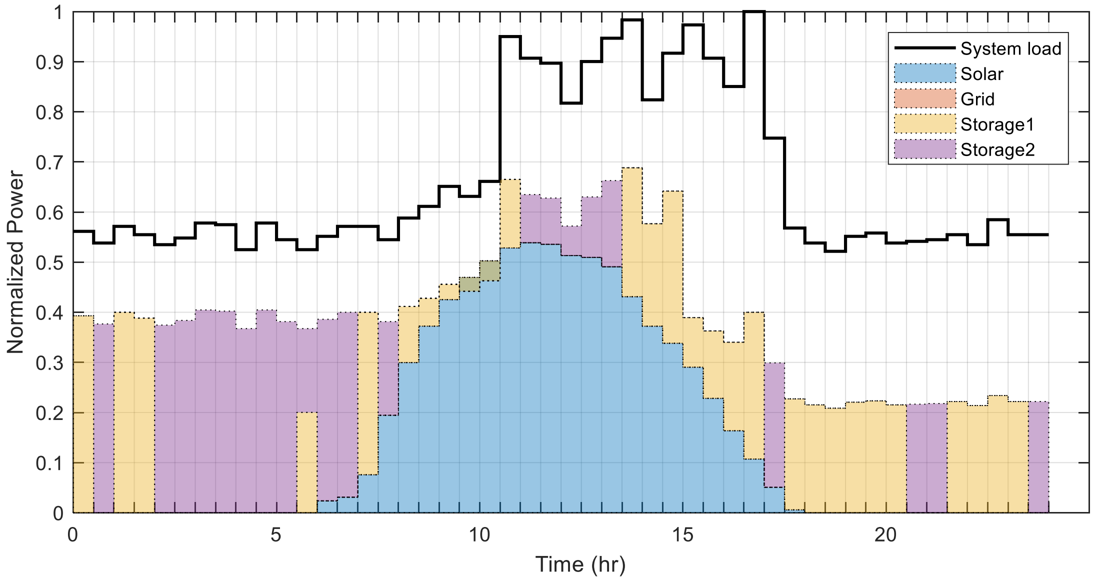

Figure 7-31. Asset dispatch schedule for Table 7 1-Case 5(a)

While islanded and with CHP unavailable, the microgrid cannot draw any power from the main grid or the CHP. Although the battery is fully charged at the beginning of the day, the total power available from the two storage units and solar is insufficient to meet the total load demand of the microgrid. Figure 7-32 shows the dispatch optimizer shedding part of the load.

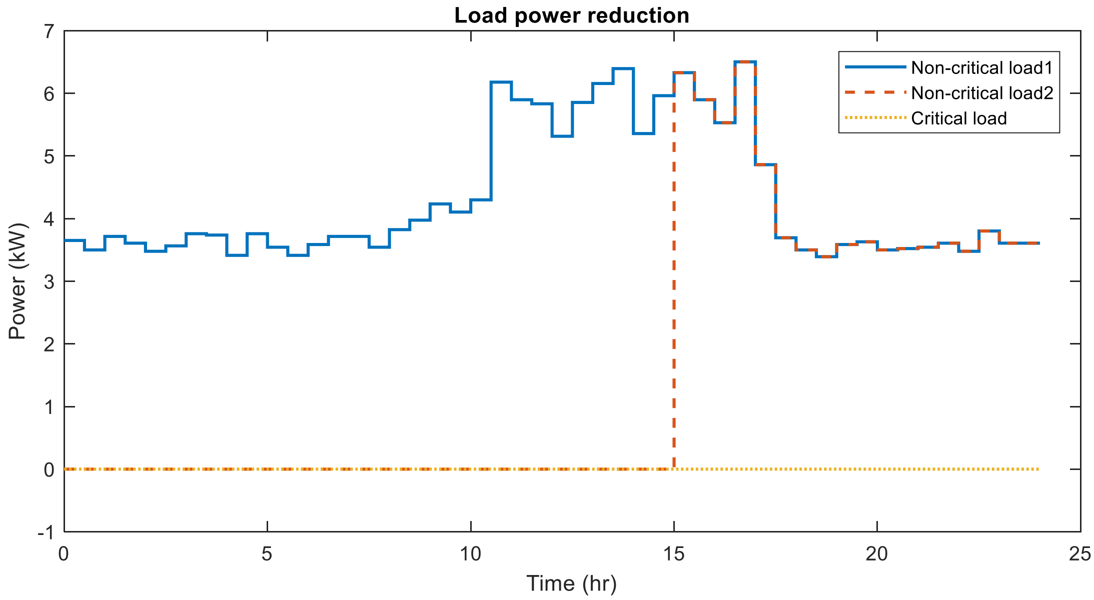

Figure 7-32. Load Power Reduction Schedule Planned by the Dispatch Optimizer for Table 7 1-Case 5(a)

As 40% of the load from Building 7R is modeled as a critical load, and the remaining 60% as two non-critical loads of equal power requirement, the dispatch optimizer evaluates the generation-demand balance and finds that the critical load can be met for the entire duration. However, the dispatch optimizer, giving priority to critical load, sheds one of the non-critical loads for the entire day. It then sheds the other non-critical load starting at 3 pm. The maximum TTL in this case is 24 hours (i.e., critical load can be met for the entire duration of the scheduled dispatch).

Table 7-10. Asset dispatch cost for Table 7 1-Case 5(a)

	Generator O&M	Battery	Renewable	Emissions	Energy Import
Cost (USD)	0	5	0	0	0

7.10 Case 5b – Island Mode – Maximize Time to Live (TTL) Peak Day

7.10.1 Objective

Islanded TTL without CHP for peak loading day with initial battery SOC at 100%

7.10.2 Description

In contrast to nominal load profile, the load demands on peak loading day are much higher with peak load reaching almost 2.5 times that of nominal day peak load. Therefore, when the microgrid is islanded and CHP is unavailable, the available power from energy storage and solar is not enough to meet the critical load for the entire day. The dispatch optimizer evaluates this mismatch between load and generation and returns a maximum TTL of 10 hours. Here, the two non-critical loads are always shed and critical load cannot be met after 10 am.

7.10.3 Input

- Initial Battery SOC at 100%.
- Peak Loading Profile obtained for Building 7R Profile shown in Figure 7-2.
- Grid Price (see Appendix B).

7.10.4 Expected Result

- Dispatch sheds non-critical load.
- BESS will charge at the hours solar production exceeds load and discharge when the solar production cannot meet the load.

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7.10.5 Test Result

The following shows the dispatch schedule for maximum TTL of 10 hours and the load reduction profiles.

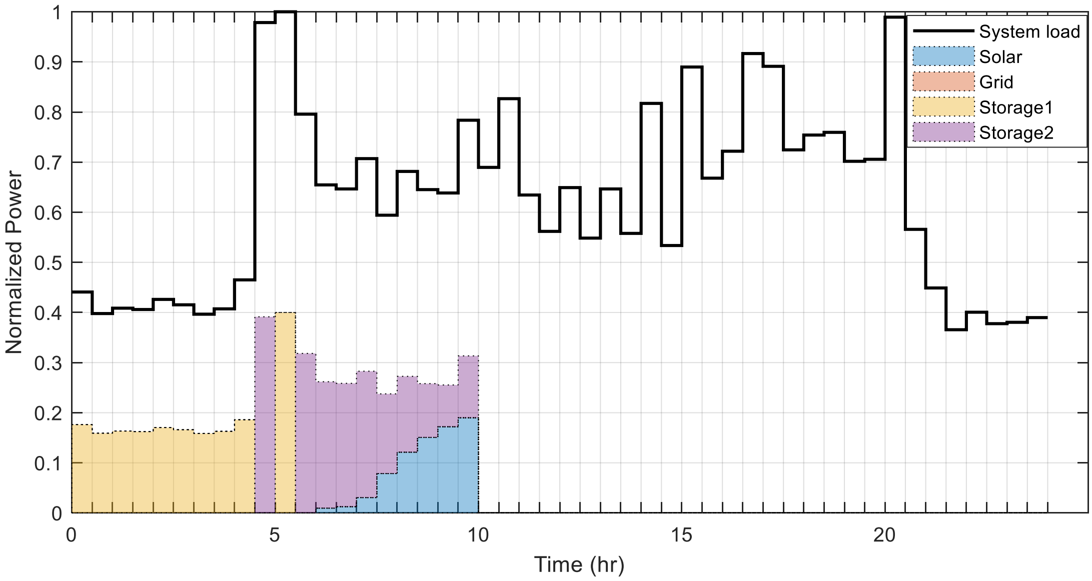

Figure 7-33. Load power reduction schedule planned by the dispatch optimizer for Table 7 1-Case 5(b)

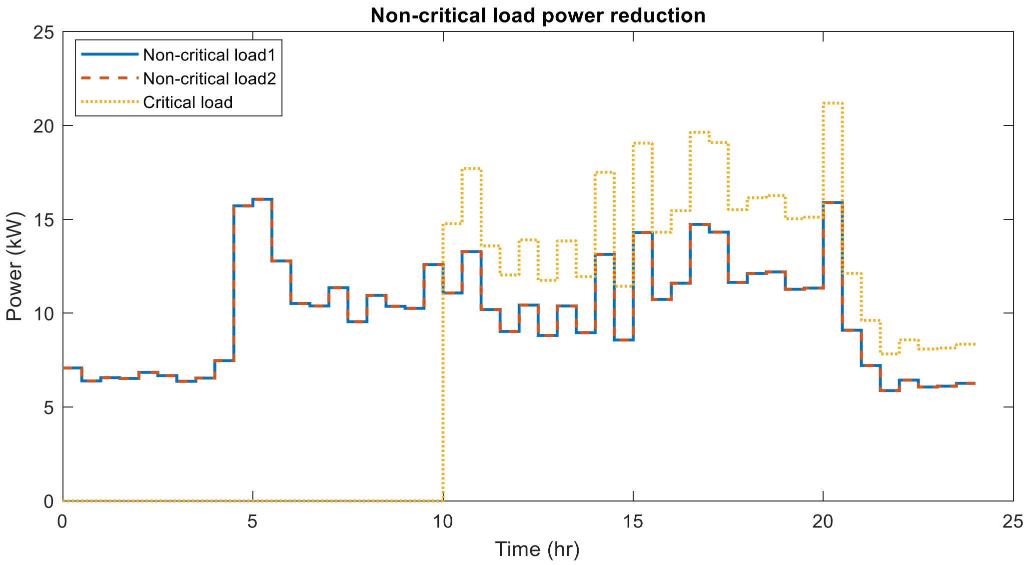

Figure 7-34. Asset dispatch schedule for Table 7 1-Case 5(b)

Table 7-11. Asset dispatch cost for Table 7 1-Case 5(b)

	Generator O&M	Battery	Renewable	Emissions	Energy Import
Cost (USD)	0	4.2	0	0	0

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8. SS93-602 Microgrid Test Plan & Execution Results

Based on distributed hierarchal control architecture stated in the project goal, this section will test the first two of the Microgrid Controller's following three levels:

- **First Level – Supervisory Microgrid controller** (Implemented using existing GE **e-terra** *distribution* platform, including Front End Processor(FEP) and Supervisory Control and Data Acquisition(SCADA)) has been configured for the entire TNY 13.2-kV power system. This has been an integral part of the GridNOC which is located in Building 101.
    - FEP: FEP is located in Control Center and communicate with Substation RTU/Gateway via specific protocols.
    - SCADA: SCADA is located in Control Center and used by Dispatcher to operate grid.
- **Second Level - Substation Microgrid Controller** (Implemented using existing GE **DAP***Server* platform) has been configured for the each of the SS664 substations.
    - DAPServer: DAPServer is located in Substation and communicate with IED ad forward data to FEP.
- **Third Level – Microgrid Device Controller** (Implemented using existing GE C264 *platform* wherever appropriate) has been configured for the Point of Common Coupling (PCC) Control and other device controls as necessary.

8.1 Correlation of test plans with functional requirements

Table 8-1 Test Sets and Function Requirements

Test Set	Test Function Description	Test Sub-Function Description	Key FOA Requirement
TEST SET 1 Basic Monitoring and Control Functionality	Test 1.1: Measurements of Electrical Conditions on the Microgrid		C.1
	Test 1.2: Load Measurements		C.3
	Test 1.3: Microgrid Power Supply Measurement		C.3
	Test 1.4: Control Output Delivery and Timing		C.1
TEST SET 2 Situational Awareness, Alarms, HMI	Test 2.2: System Monitoring	Test 2.2.1: Feeder Monitoring Test 2.2.2: Load Reporting Test 2.2.3: Generator Reporting Test 2.2.4: PCC Monitoring	C.3 C.3 C.1 C.1
TEST SET 3 Control Functions	Test 3.1 Device Level Control	Test 3.1.1: Load Control Test 3.1.2 Generation Control	C.3 C.3

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8.2 Test Set 1 – Basic Monitoring and Control Functionality

The purpose of Test set 1 is to verify that the Level 2-substation microgrid controller satisfies the basic requirements for the controller's data acquisition and control facilities. This includes testing that the controller acquires data accurately, and on a timely basis, from all data sources. This test set also verifies that the microgrid controller can send control commands to each of the microgrid assets and confirm that the control commands are received by the assets and switches within the specified timeframe.

8.2.1 Test Set 1.1 – Measurement of Electrical Conditions

8.2.1.1 Test Objective

The objective of this test is to verify that Level 2 - substation microgrid controller (Implemented using the GE **DAP***Server* platform) can continuously monitor and detect changes in microgrid electrical conditions. The ability to acquire information from all data sources that supply data on the electrical conditions (e.g., voltage, frequency, current flow, circuit breaker, and intelligent switch status).

8.2.1.2 Test 1.1.1 (7R Feeder Monitoring) Setup

This table shows the Substation and Feeder Devices that were monitored.

Table 8-2 Substation and Feeder Device For 7R Feeder Monitoring Setup

Device	IP Address	Protocol	GPS Clock
Substation 664	192.64.1.4	IEC 61850	IEEE 1558
Feeder 1305	192.64.1.20	IEC 61850	IEEE 1558

8.2.1.3 Test Procedure

To perform Communication Verification:

1. On FEP server, start the DAP Studio Application, using **project 640 Substation** and connect to **DAPServer**.
2. Select Client Application.
3. Verify **Feeder 1305 Relay** is configured on **DAP**. See below.

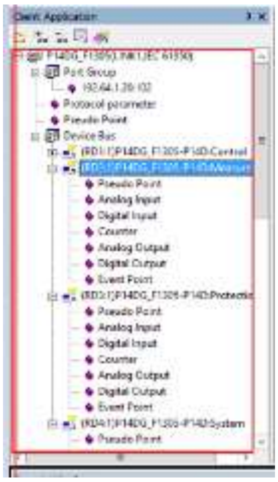

Figure 8-1. Feeder 1305 Relay set to DAP

4. Verify Feeder 1305 device protocol detail by clicking **Protocol parameter**. See below.

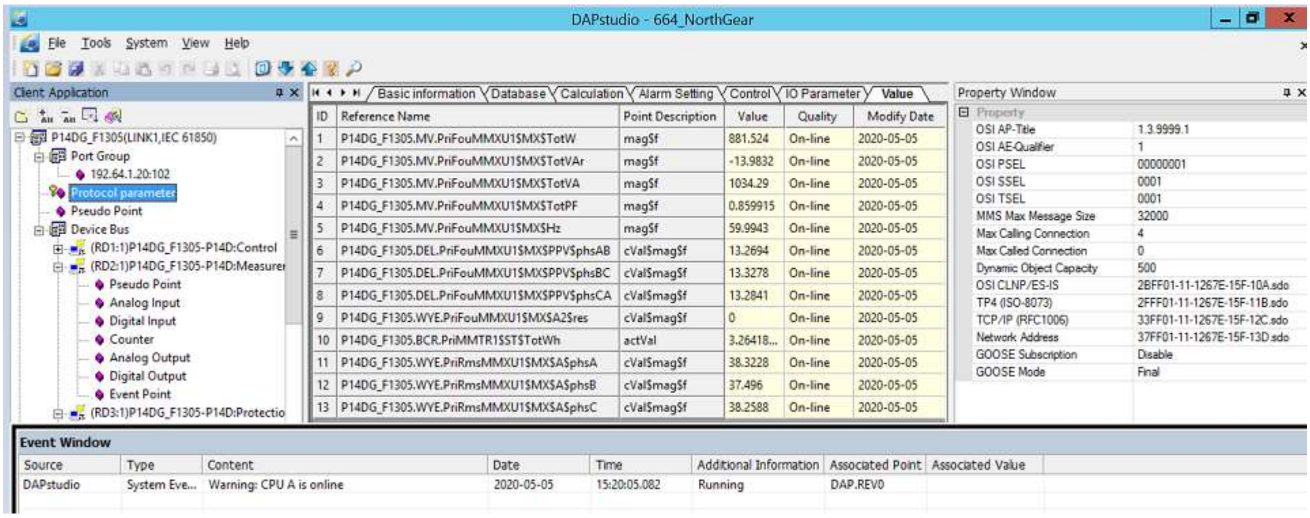

Figure 8-2. Feeder 1305 Protocol Details

5. Verify DAP is communicating with Feeder relay by checking communication icon blink status. See below.

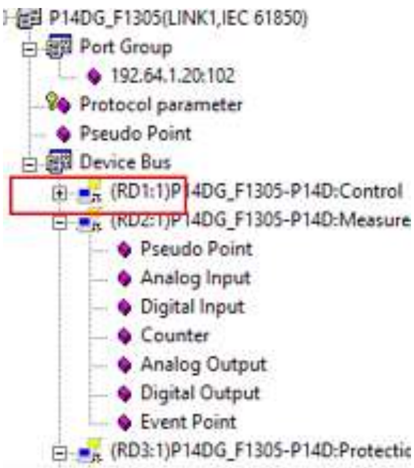

Figure 8-3. Verifying Feeder 1305 Relay and DAP Connection

To perform Digital Input Verification:

1. Click **Feeder F1305**.
2. Select **Digital Input** and select the **Value** tab.
3. Verify the status point values are correct, the data is updated with "on-line" quality bit set, and the **Modify Date/Modify Time** is current. See Figure 8-4.

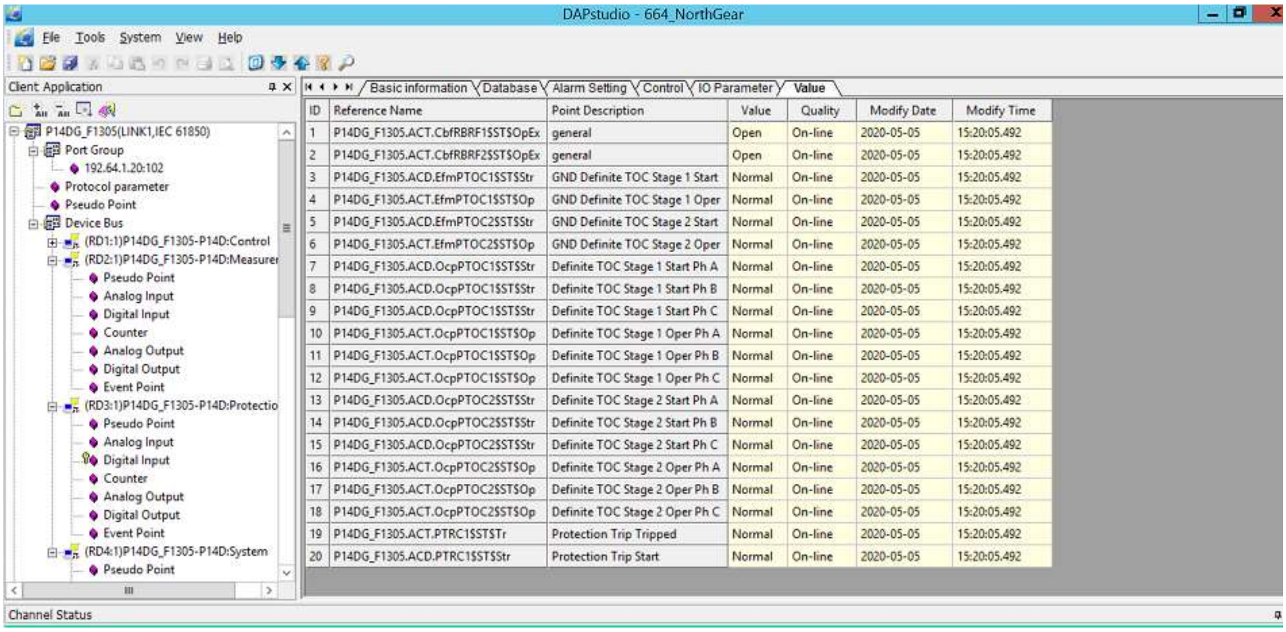

Figure 8-4. Feeder 1305 Digital Input Values

To perform Analog Input Verification:

1. Click **Feeder F1305**.
2. Select **Analog Input** and select the **Value** tab.
3. Verify the analog point values are correct, the data is updated with "on-line" quality bit set, and the **Modify Date/Modify Time** is current. See below.

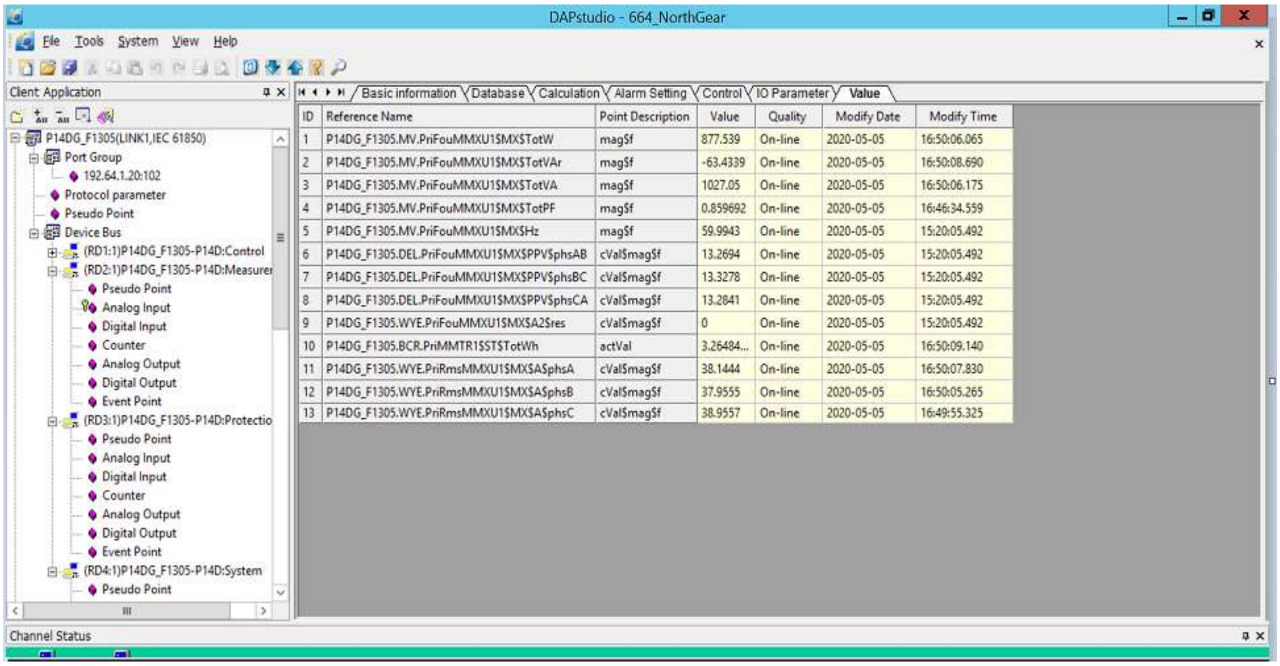

Figure 8-5 Feeder 1305 Analog Input Values

8.2.2 Test Set 1.2 – Load Measurements

8.2.2.1 Test Objective:

The objective of this test is to verify that the Level 2 substation microgrid controller (implemented using GE's **DAP** *Server* platform) can continuously monitor and detect changes in load values for each load that is connected to the microgrid. The test loads are 2 large furnaces that are connected to Feeder 1362 and F1364. These heating loads can be used to participate in load shed operations in the event of microgrid islanding at Substation level.

8.2.2.2 Test 1.2.1 (Critical Load Measument) Setup

This table shows the Substation and Feeder Devices that will be monitored.

Table 8-3 Substation Feeder Device Names Critical Load Measurement Setup

Device	IP Address	Protocol	GPS Clock
Substation 602	192.2.1.4	DNP 3.0	IEEE 1558
Feeder 1362 (Critical Load)	192.2.1.33	DNP 3.0	IEEE 1558

8.2.2.3 Test Procedure

To perform Communication Verification:

1. On FEP server, start the DAP Studio Application, using **project 602 Substation** and connect to **DAPServer**.
2. Select Client Application.
3. Verify the **Feeder 1362** is configured on DAP. See below.

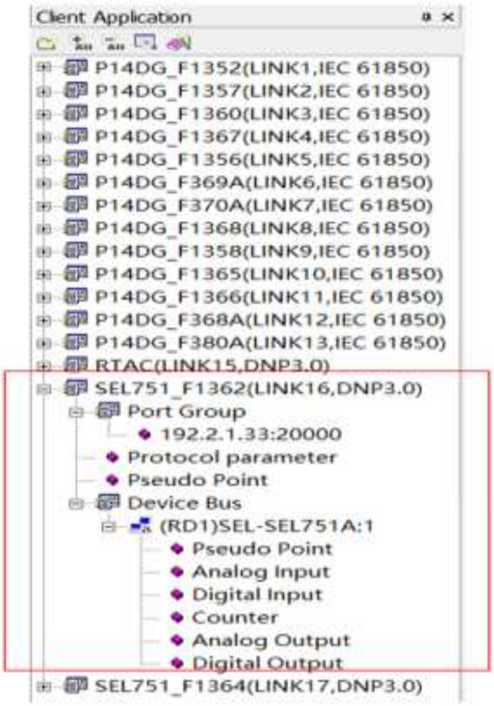

Figure 8-6. Verifying Feeder 1362 Relay is set to DAP

4. Verify the DNP source address by clicking Protocol Parameter. See below.

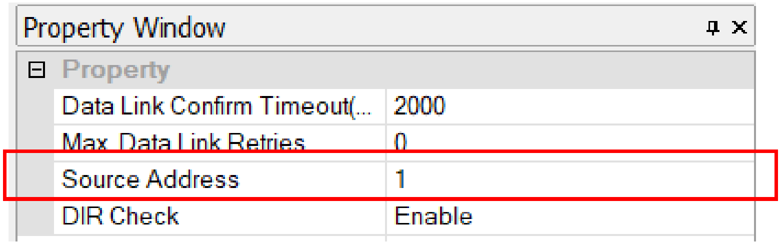

Figure 8-7. Feeder 1362 Source Address

5. Verify the DNP device address by clicking **Device Bus**. See below.

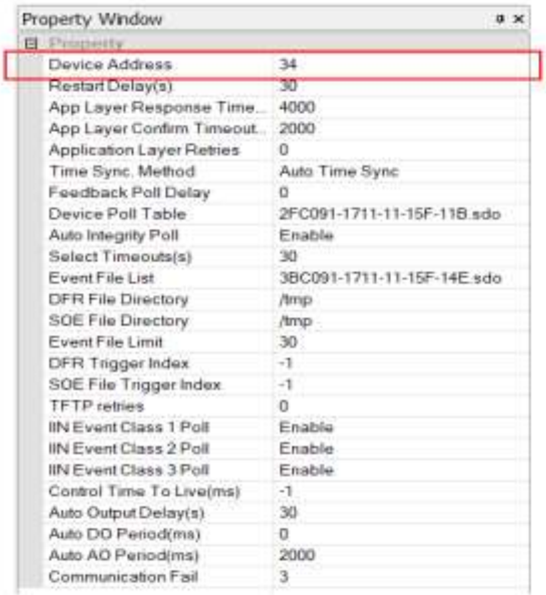

Figure 8-8. Feeder 1362 Device Address

6. Verify that DAP is communicating with Feeder relay by checking communication icon blink status:

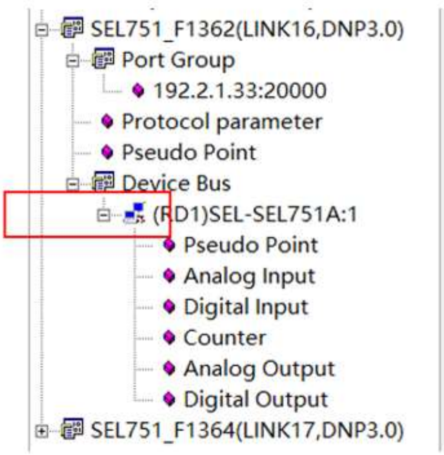

Figure 8-9. Verifying Feeder 1362 Communication to DAP

To perform Digital Input Verification:

1. Click **Feeder F1362**.
2. Select **Digital Input** and select the **Value** tab.
3. Verify the status point values are correct, the data is updated with "on-line" quality bit set, and the **Modify Date/Modify Time** is current. See below.

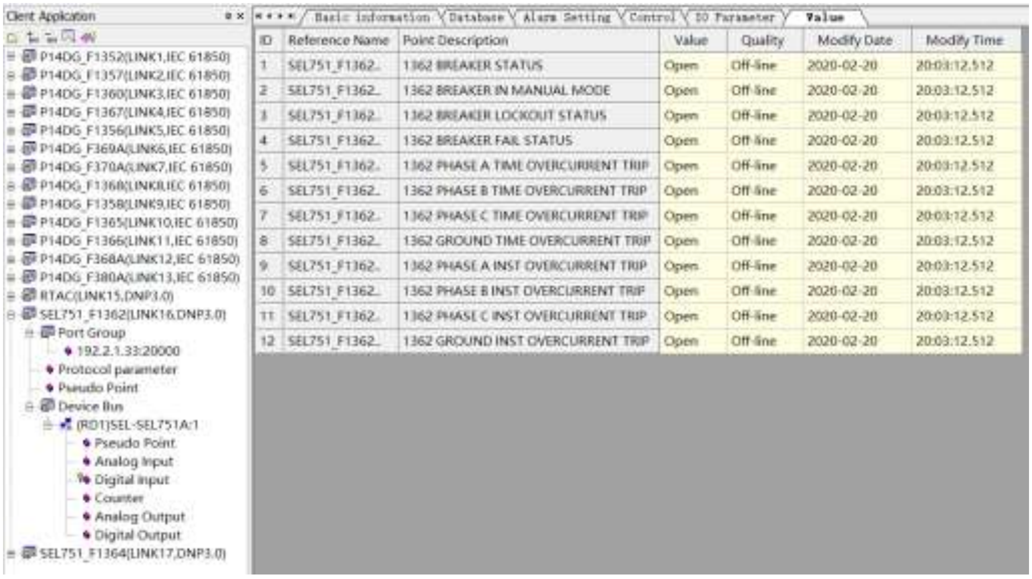

Figure 8-10. Feeder 1362 Digital Values

4. Compare each digital point with SEL 751A reading. See Table 8-4.

Table 8-4 Feeder 1362 Digital Input Names with Substation Readings

Feeder 1362 Digital Input Name	SEL 751A Reading	DAP Reading
1362 BREAKER STATUS	CLOSE	CLOSE
1362 BREAKER IN MANUAL MODE	AUTO	AUTO
1362 BREAKER LOCKOUT STATUS	NORMAL	NORMAL
1362 BREAKER FAIL STATUS	OPEN	OPEN

To perform Analog Input Verification:

1. Click **Feeder F1362**.
2. Select **Analog Input** and select the **Value** tab.
3. Verify the analog point values are correct, the data is updated with "on-line" quality bit set, and the **Modify Date/Modify Time** is current. See Figure 8-11.

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Figure 8-11. Feeder 1362 Analog Values

4. Compare each analog point with SEL 751A reading. See Table 8-5.

Table 8-5 Feeder 1362 Analog Input with Substation Readings

Feeder 1362 Analog Input Name	SEL 751A Reading	DAP Reading
1362 IA PHASE A MAG	14.4	14.5
1362 IB PHASE B MAG	14.5	14.7
1362 IC PHASE C MAG	15.6	15.6
1362 IN NEUTRAL MAG	0.7	0.7
1362 VAB	13.4	13.4
1362 VBC	13.5	13.4
1362 VCA	13.6	13.5
1362 POWER FACTOR	1	1
1362 FREQUENCY	59.9	59.9
1362 MW3 REAL POWER THREE PHASES	289.1	288.4
1362 MVAR3 REACTIVE POWER THREE PHASES	151.5	151.6
1362 MWH3L REAL ENERGY IN	370213	370064
1362 MVH3L REACTIVE ENERGY IN	12301	12052

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8.2.2.4 Test 1.2.1 (Non-Critical Load Measument) Setup

This table shows the Substation and Feeder Devices that will be monitored.

Table 8-6 Substation and Feeder Names for Non-Critical Load Measurement Setup

Device	IP Address	Protocol	GPS Clock
Substation 602	192.2.1.4	DNP 3.0	IEEE 1558
Feeder 1364 (Non-Critical Load)	192.2.1.34	DNP 3.0	IEEE 1558

8.2.2.5 Test Procedure

To perform Communication Verification:

1. On FEP server, start the DAP Studio Application, using **project 602 Substation** and connect to **DAP Server**.
2. Select Client Application.
3. Verify Feeder 1364 is configured on DAP. See below.

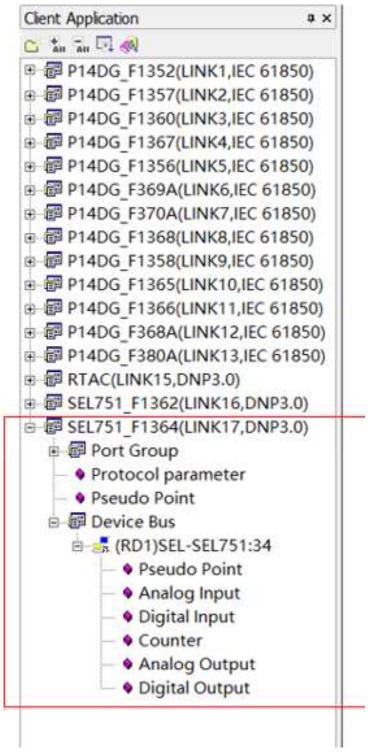

Figure 8-12. Verifying Feeder 1364 Relay is set to DAP

4. Verify DNP source address by clicking **Protocol Parameter**. See below.

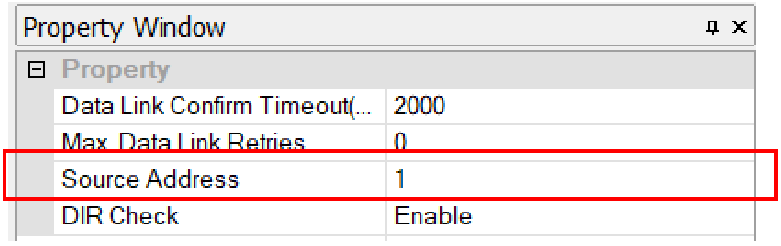

Figure 8-13. Feeder 1364 Source Address

5. Verify DNP device address by clicking **Device Bus**. See below.

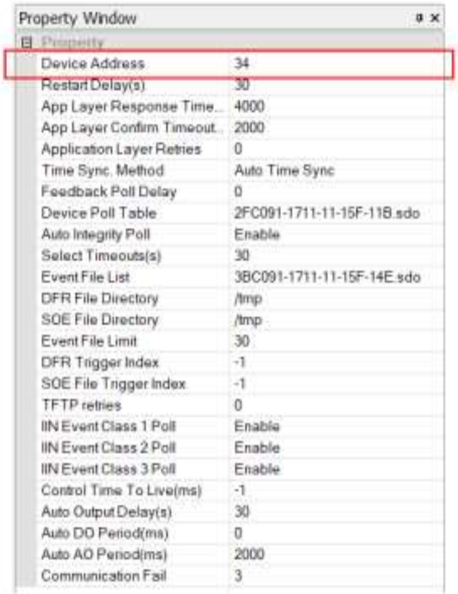

Figure 8-14. Feeder 1364 Device Address

6. DAP is communicating with Feeder relay by checking communication icon blink status. See below.

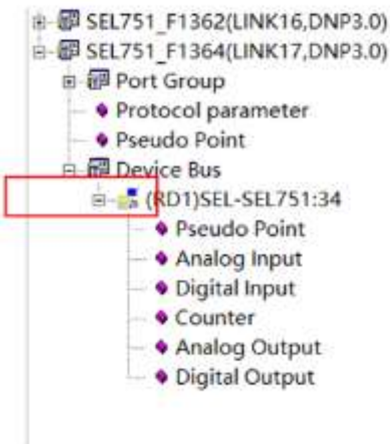

Figure 8-15. Verifying Feeder 1364 Communication to DAP

To perform Digital Input Verification:

1. Click **Feeder F1364**.
2. Select Digital Input and select Value Tab.
3. Verify the status point values are correct, the data is updated with "on-line" quality bit set, and the **Modify Date/Modify Time** is current. See below.

Figure 8-16. Feeder 1364 Digital Values

4. Compare each digital point with SEL 751A reading. See Table 8-7.

Table 8-7 Feeder 1364 Digital Input Names with Substation Readings

Feeder 1364 Digital Input Name	SEL 751A Reading	DAP Reading
1364 BREAKER STATUS	CLOSE	CLOSE
1364 BREAKER IN MANUAL MODE	AUTO	AUTO
1364 BREAKER LOCKOUT STATUS	NORMAL	NORMAL
1364 BREAKER FAIL STATUS	OPEN	OPEN

To perform Analog Input Verification:

1. Click **Feeder F1364**.
2. Select **Analog Input** and select the **Value** tab.
3. Verify the status point values are values are correct, the data is updated with "on-line" quality bit set, and the **Modify Date/Modify Time** is current. See Figure 8-17.

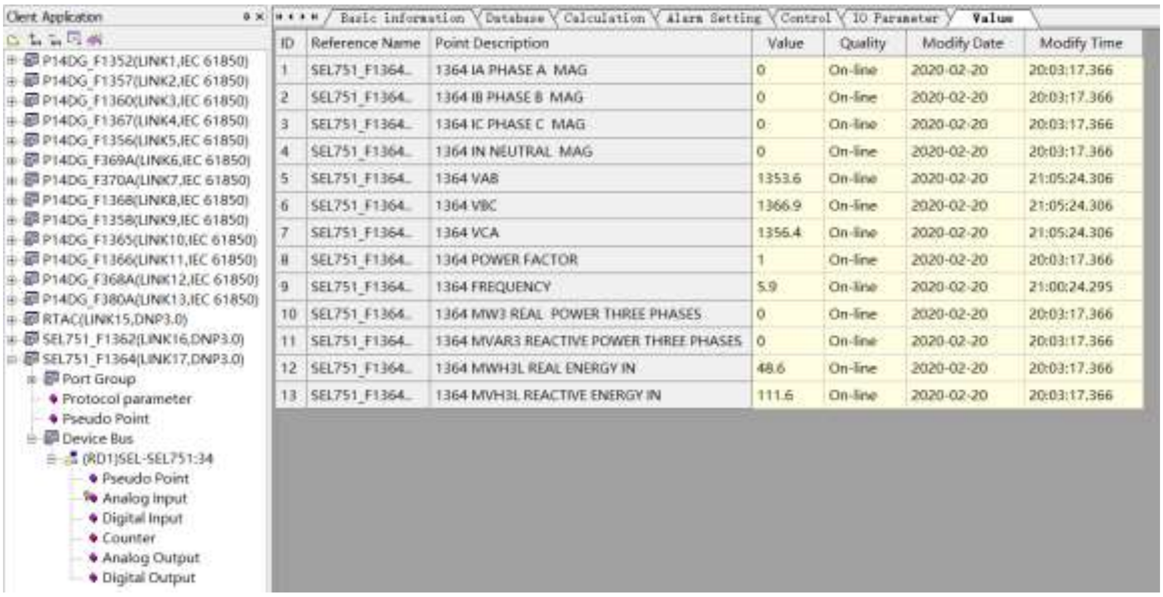

Figure 8-17. Feeder 1364 Analog Values

4. Compare each analog point with SEL 751A reading. See Table 8-8.

Table 8-8 Feeder 1364 Analog Input Names with Substation Readings

Feeder 1364 Analog Input Name	SEL 751A Reading	DAP Reading
1364 IA PHASE A MAG	0	0
1364 IB PHASE B MAG	0	0
1364 IC PHASE C MAG	0	0
1364 IN NEUTRAL MAG	0	0
1364 VAB	1352.4	1352.6
1364 VBC	1353.5	1353.9
1364 VCA	1353.6	1353.6
1364 POWER FACTOR	1	1
1364 FREQUENCY	6	5.9
1364 MW3 REAL POWER THREE PHASES	0	0
1364 MVAR3 REACTIVE POWER THREE PHASES	0	0
1364 MWH3L REAL ENERGY IN	48.6	48.6
1364 MVH3L REACTIVE ENERGY IN	111.6	111.6

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8.2.3 Test Set 1.3 – Power Supply Measurements

8.2.3.1 Test Objective:

The objective of this test is to verify that the Level 2-substation microgrid controller (implemented using GE's **DAP***Server* platform) can continuously monitor the output of all supply sources within the microgrid (e.g., CHP, Energy storage facility, solar PV units). These generation sources can be used to service critical load in the event of an islanding operation at the Substation level.

8.2.3.2 Test 1.3.1 (Power Generation Monitoring) Setup

This table shows the Substation and Feeder Devices that will be monitored.

Table 8-9 Substation Feeder Device Names Power Generation Monitoring Setup

Device	Communication	Protocol	GPS Clock
Substation 602	RS 232 Comm	DNP 3.0	IEEE 1558
Power Plant (G1-G4)	RS 232 Comm	DNP 3.0	IEEE 1558

8.2.3.3 Test Procedure

To perform Communication Verification:

1. On FEP server, start the DAP Studio Application, using project 602 Substation and connect to DAP Server.
2. Select Client Application.
3. Verify the RTAC is configured on DAP. See below.

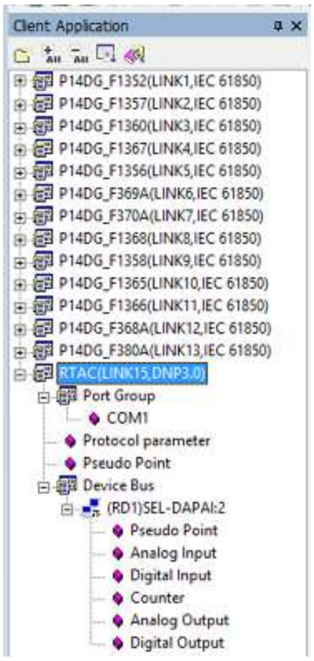

Figure 8-18. Verifying RTAC is set to DAP

4. Verify DNP source address by clicking **Protocol Parameter**. See below.

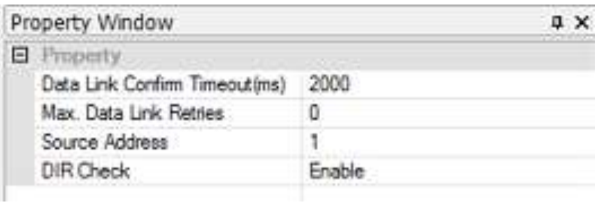

Figure 8-19. RTAC Source Address

5. Verify DNP device address by clicking **Device Bus**.

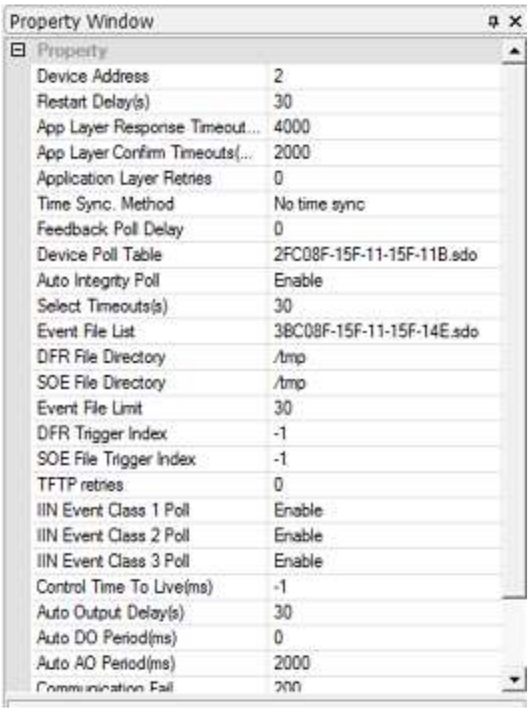

Figure 8-20. RTAC Device Address

6. Verify DAP is communicating with Feeder relay by checking communication icon blink status. See below.

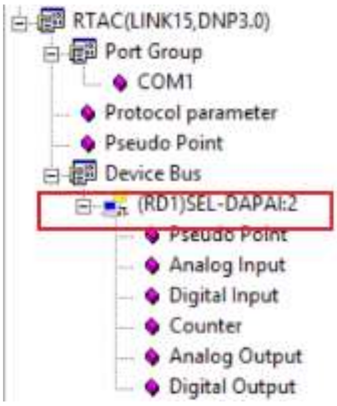

Figure 8-21. Verifying Feeder 1364 Communication to DAP

To perform Digital Input Verification:

1. Click **RTAC**.
2. Select **Digital Input** and select the **Value** tab. See below.
3. Verify the status point values are values are correct, the data is updated with "on-line" quality bit set, and the **Modify Date/Modify Time** is current. See below.

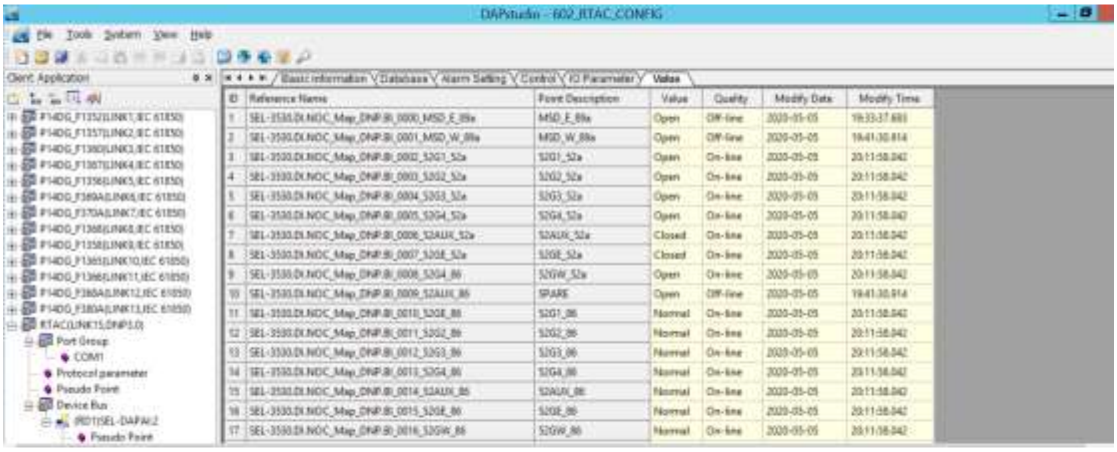

Figure 8-22. RTAC Digital Values

4. Compare each digital point with RTAC reading. See Table 8-10.

Table 8-10 Generator Digital Input Names with Substation Readings

Generator Digital Input Name	RTAC Reading	DAP Reading
GENERATOR 1 Status (52G1_52a)	OPEN	OPEN
GENERATOR 2 Status (52G2_52a)	OPEN	OPEN
GENERATOR 3 Status (52G3_52a)	OPEN	OPEN
GENERATOR 4 Status (52G4_52a)	OPEN	OPEN

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To perform Analog Input Verification:

1. Click **RTAC**.
2. Select **Analog Input** and select the **Value** tab.
3. Verify the status point values are values are correct, the data is updated with "on-line" quality bit set, and the **Modify Date/Modify Time** is current. See below.

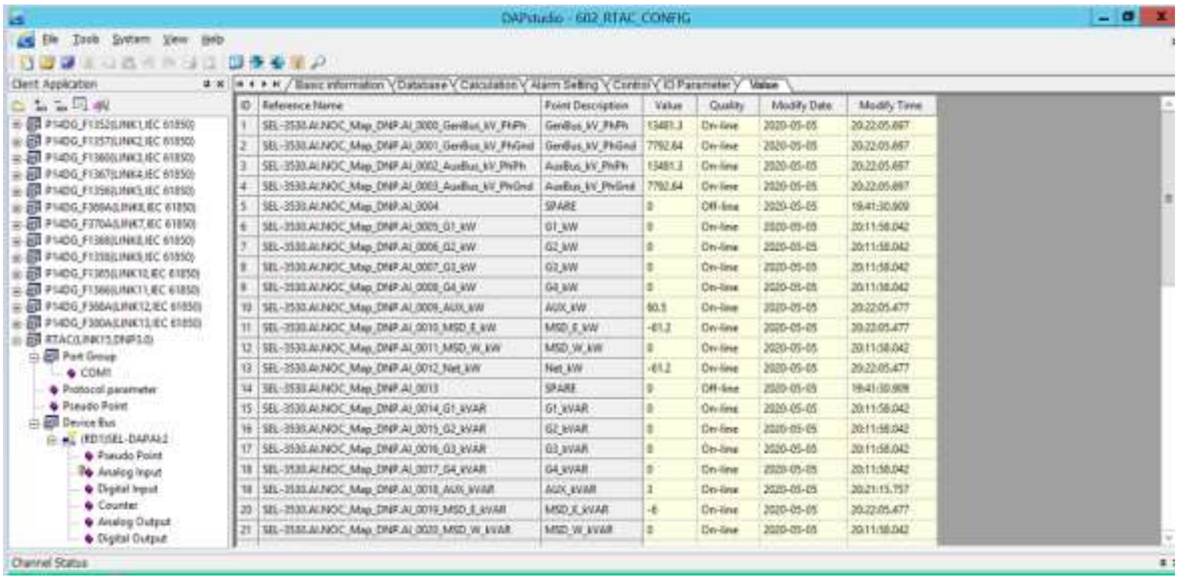

Figure 8-23. RTAC Analog Values

4. Compare key analog point with RTAC reading. See Table 8-11.

Table 8-11 Generator Analog Input Names with Substation Readings

GENERATOR Analog Input Name	RTAC Reading	DAP Reading
GENERATOR 1 KW (G1_kW)	0.97	0.97
GENERATOR 2 KW (G2_kW)	0.96	0.96
GENERATOR 3 KW (G3_kW)	0.97	0.97
GENERATOR 4 KW (G4_kW)	0.25	0.25

8.2.4 Test Set 1.4 – Control Output Delivery and Timing

8.2.4.1 Test Objective:

The objective of this test is to verify that Level 2 - substation microgrid controller (implemented using the GE **DAP***Server* platform) can reliably and effectively deliver control commands to controllable microgrid assets (generation units, microgrid switchgear, and other controllable devices) within the strict time constraints required for effective microgrid operation at Substation level.

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8.2.4.2 Test 1.4.1 (Load Control) Setup

This table shows the load feeder that will be controlled.

Table 8-12 Substation Feeder Device Names For Load Control Setup

Device	IP Address	Protocol	GPS Clock
Substation 602	192.2.1.4	DNP 3.0	IEEE 1558
Feeder 1362 (Critical Load)	192.2.1.33	DNP 3.0	IEEE 1558
Feeder 1364 (Uncritical Load)	192.2.1.34	DNP 3.0	IEEE 1558

8.2.4.3 Test Procedure

To perform Non-Critical Load Control Verification:

1. Click **Feeder F1364**.
2. Right-click **Digital Output** and select **Remote Control.** See below.

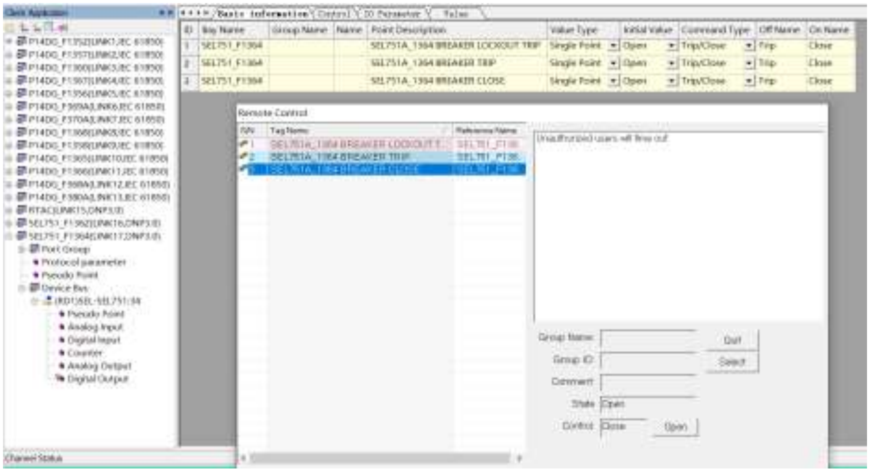

Figure 8-24. Feeder F1364 Remote Control Selected

3. Select **CLOSE** command.
4. Verify SEL 751A receives and executed the command. See Table 8-13.

Table 8-13 Feeder 1364 Results using CLOSE Command

Feeder 1364 Digital Input Name	SEL 751A Received	SEL 751A Executed
SEL751A_1364 BREAKER CLOSE	Success	Success

5. Select **TRIP** command.
6. Verify SEL 751A receives and executed the command. See Table 8-14.

Table 8-14 Feeder 1364 Results Using TRIP Command

Feeder 1364 Digital Input Name	SEL 751A Received	SEL 751A Executed
SEL751A_1364 BREAKER LOCKOUT TRIP	Success	Success
SEL751A_1364 BREAKER TRIP	Success	Success

To perform Critical Load Control Verification:

1. Click **Feeder F1362**.

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2. Right-click **Digital Output** and select **Remote Control**. See below.

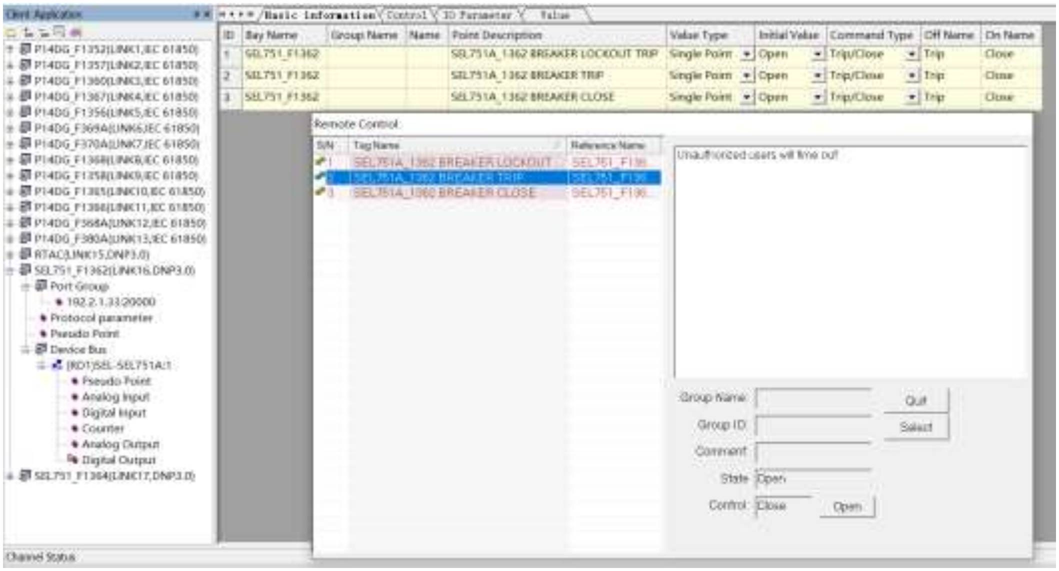

Figure 8-25. Feeder F1362 Remote Control Selected

3. Select **CLOSE** command.
4. Verify SEL 751A receives and executed the command. See Table 8-15.

Table 8-15 Feeder 1362 Results Using CLOSE Command

Feeder 1362 Digital Input Name	SEL 751A Received	SEL 751A Executed
SEL751A_1362 BREAKER CLOSE	Success	Success

5. Select **TRIP** command.
6. Verify SEL 751A receives and executed the command. See Table 8-16.

Table 8-16 Feeder 1362 Results Using TRIP Command

Feeder 1362 Digital Input Name	SEL 751A Received	SEL 751A Executed
SEL751A_1362 BREAKER LOCKOUT TRIP	Success	Success
SEL751A_1362 BREAKER TRIP	Success	Success

8.2.4.4 Test 1.4.2 (Generation Control) Setup

This table shows the generation that will be controlled.

Table 8-17 Substation and Feeder Devices for Generation Control Setup

Device	IP Address	Protocol	GPS Clock
Substation 602	192.2.1.4	DNP 3.0	IEEE 1558
RTAC (Setpoint)	RS232 COMM Port 1	DNP 3.0	IEEE 1558

8.2.4.5 Test Procedure

To perform Generation Setpoint Verification:

1. Click Generation Device RTAC .
2. Right-click **Analog Output** and select **Remote Control**. See below.

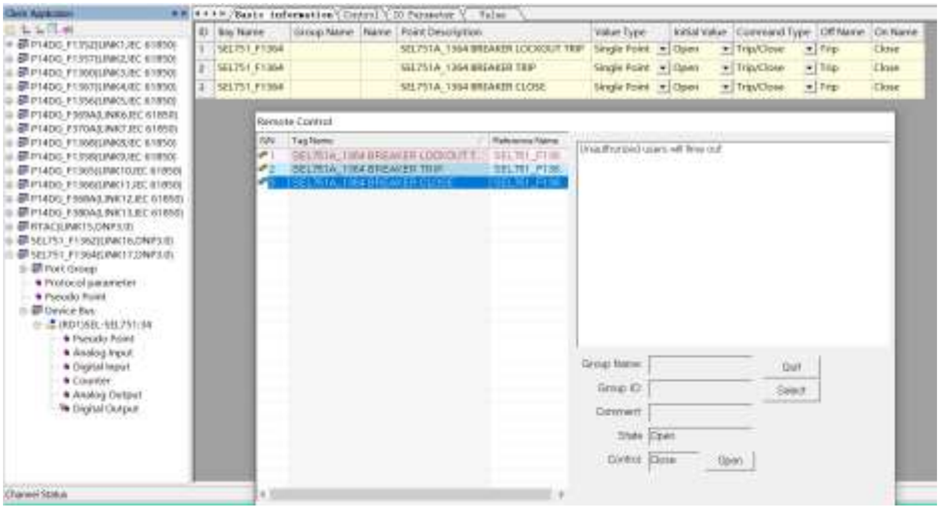

Figure 8-26. RTAC Remote Control Selected

3. Select **SETPOINT** command.
4. Verify RTAC receives and executed the command. See Table 8-18.

Table 8-18 Feeder 1362 Results Using SETPOINT Command

Feeder 1362 Digital Input Name	SEL 751A Received	SEL 751A Executed
GENERATION SETPOINT	1000 Received Successfully	1000 Sent Successfully

8.3 Test Set 2 – Situational Awareness, Alarms, HMI

The purpose of Test set 1 is to verify that the Level 1–Supervisory microgrid controller (implemented using GE's **e-terra**distribution platform) satisfies the basic requirements for the controller's data acquisition and control facilities. This includes testing that the controller acquires data accurately, and on a timely basis, from all data sources. Those will provide NOC operator with Situational awareness, alarm and HMI. This test set also verifies that the microgrid controller can send control commands to each of the microgrid assets from the NOC and confirm that the control commands are received by the assets and switches within the expected timeframe.

8.3.1 Test Set 2.1 – System Level Status

8.3.1.1 Test Objective:

The objective of this test is to verify that Level 2-substation microgrid controller (implemented using the GE **DAP***Server* platform) can continuously monitor and detect changes in microgrid electrical conditions. The ability to acquire information from all data sources that supply data on the electrical conditions (e.g., voltage, frequency, current flow, circuit breaker and intelligent switch status).

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8.3.1.2 Test 2.1.1 (Measurement Monitoring) Setup

This table shows the substation and feeder devices that will be monitored.

Table 8-19 Substation and Feeder Names for Measurement Monitoring Setup

Device	IP Address	Protocol	GPS Clock
NOC EMS	192.108.1.1	DNP	IEEE 1558
Substation 664	192.64.1.4	IEC 61850	IEEE 1558
Feeder 1305	192.64.1.20	IEC 61850	IEEE 1558

8.3.1.3 Test Procedure

To perform Substation 664 to NOC communication Verification:

1. On FEP server, start the e-terra FEP application.
2. Select Communication – CFE COMState Display.
3. Verify the DAP to Substation 664 DAP is communicating. See below.

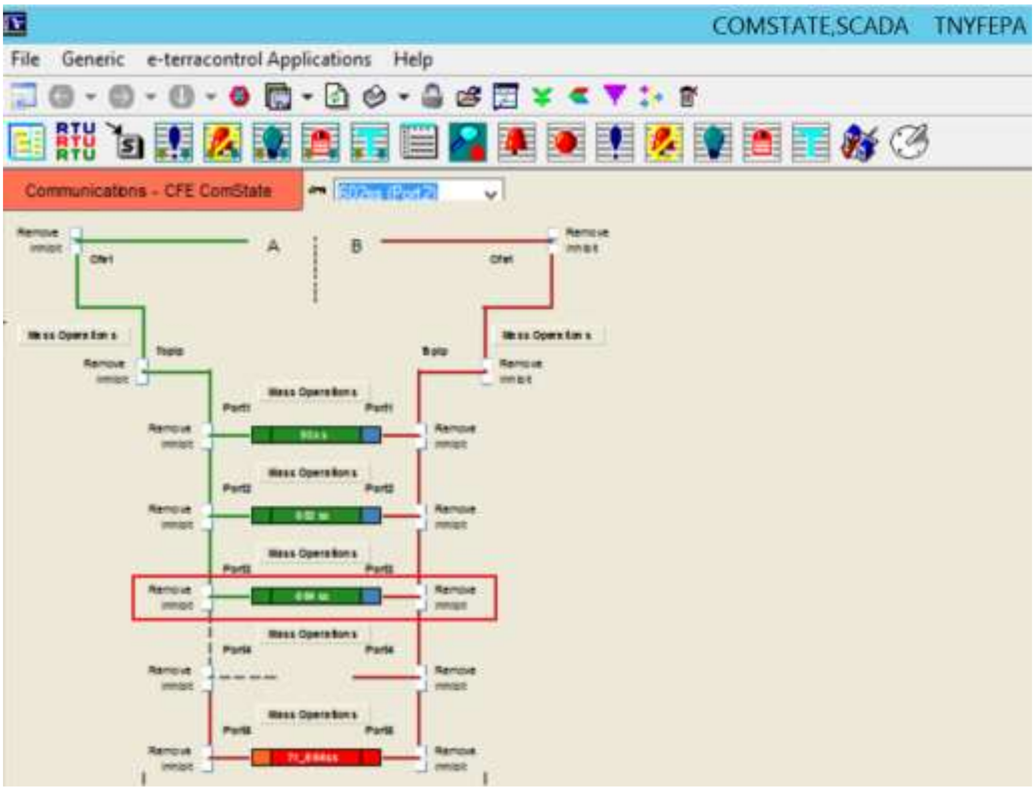

Figure 8-27. DAP and Substation 664 DAP Communicating

To perform Digital Input Verification:

1. Use the same Measurements Display.
2. Scroll through the measurement till **F1305**.
3. Check the value and data quality. See Figure 8-28.

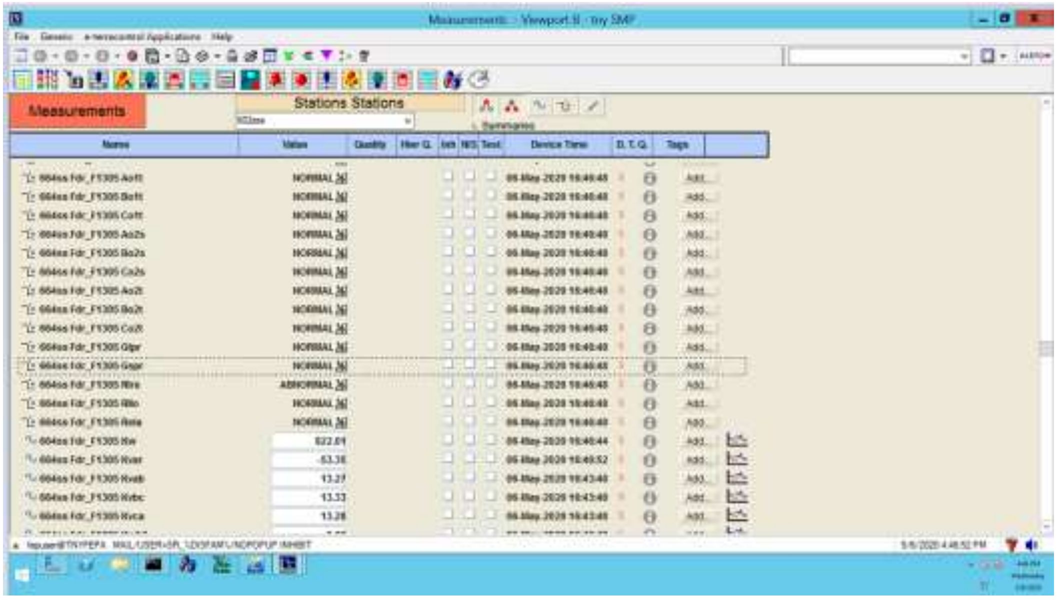

Figure 8-28. F1305 Measurements

4. Verify the status point values are correct, the data is updated with quality bit not in **Abnormal State**, and **Device Time** is current.

5. Compare key status point with DAP reading. See Table 8-20.

Table 8-20 Feeder 1305 Digital Input Results with Substation Readings

Feeder 1305 Digital Input Name	DAP Reading	FEP Reading
1305 BREAKER STATUS	CLOSE	CLOSE

To perform Analog Input Verification:

1. On e-terra FEP application, select the **Measurements Display**.
2. Enter Filter **664SS** for Substation 664.
3. Scroll the measurement till **F1305**.

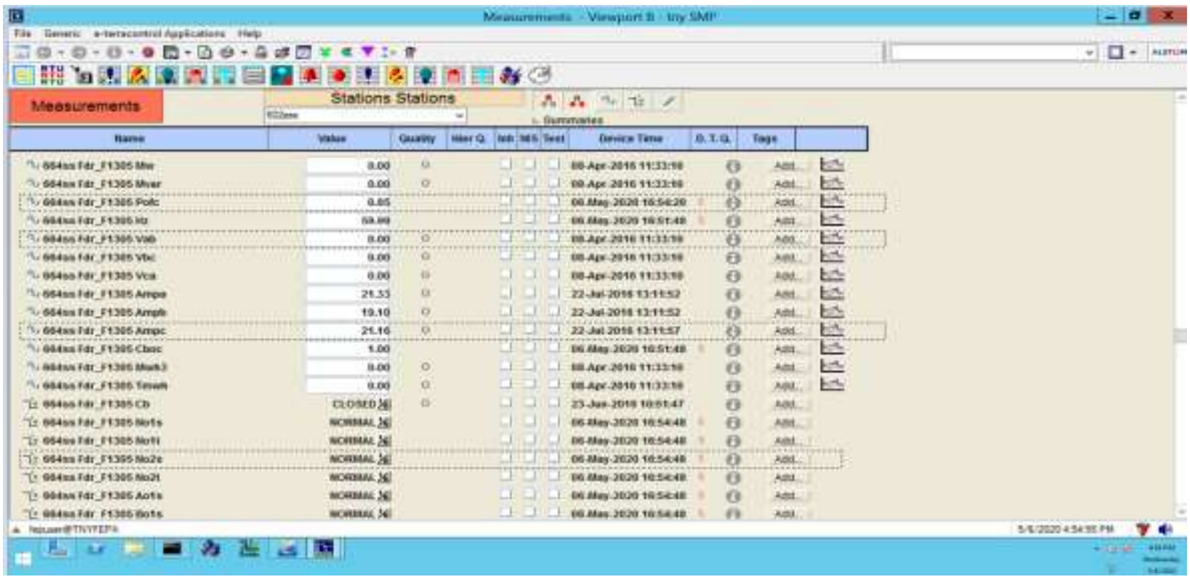

Figure 8-29. F1305 Measurements using 664SS

4. Verify the status point values are correct, the data is updated with quality bit not in **Abnormal State**, and Device Time is current.

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5. Compare key analog point with DAP reading. See Table 8-21.

Table 8-21 Feeder 1305 Analog Input Results with Substation Readings

Feeder 1305 Analog Input Name	DAP Reading	FEP Reading
1305 IA PHASE A MAG	21.19	21.33
1305 IB PHASE B MAG	19.10	19.10
1305 IC PHASE C MAG	21.16	21.16
CB STATUS	CLOSE	CLOSE
1305 VAB	13.26	13.26
1305 VBC	13.32	13.32
1305 VCA	13.28	13.28
1305 POWER FACTOR	0.85	0.85
1305 FREQUENCY	59.99 HZ	59.99 HZ
1305 MW3 REAL POWER THREE PHASES	0	0
1305 MVAR3 REACTIVE POWER THREE PHASES	0	0
1305 MWH3L REAL ENERGY IN	0	0
1305 MVH3L REACTIVE ENERGY IN	0	0

8.3.1.4 Test 2.1.2 (HMI Verification) Setup

This table shows the substation and feeder HMI will be verified.

Table 8-22 Substation Feeder Device HMI Verification Setup

Device	IP Address	Protocol	GPS Clock
NOC EMS	192.108.1.1	DNP	IEEE 1558
Substation 664	192.2.1.	IEC 61850	IEEE 1558
Feeder 1305	192.2.1.	IEC 61850	IEEE 1558

8.3.1.5 Test Procedure

To perform Substation 664 Verification:

1. On EMS server, start the e-terra HMI application.
2. Select the 664 Substation One line Diagram. See Figure 8-30.

3. Verify all Key measurement is shown on Substation One line Diagram.

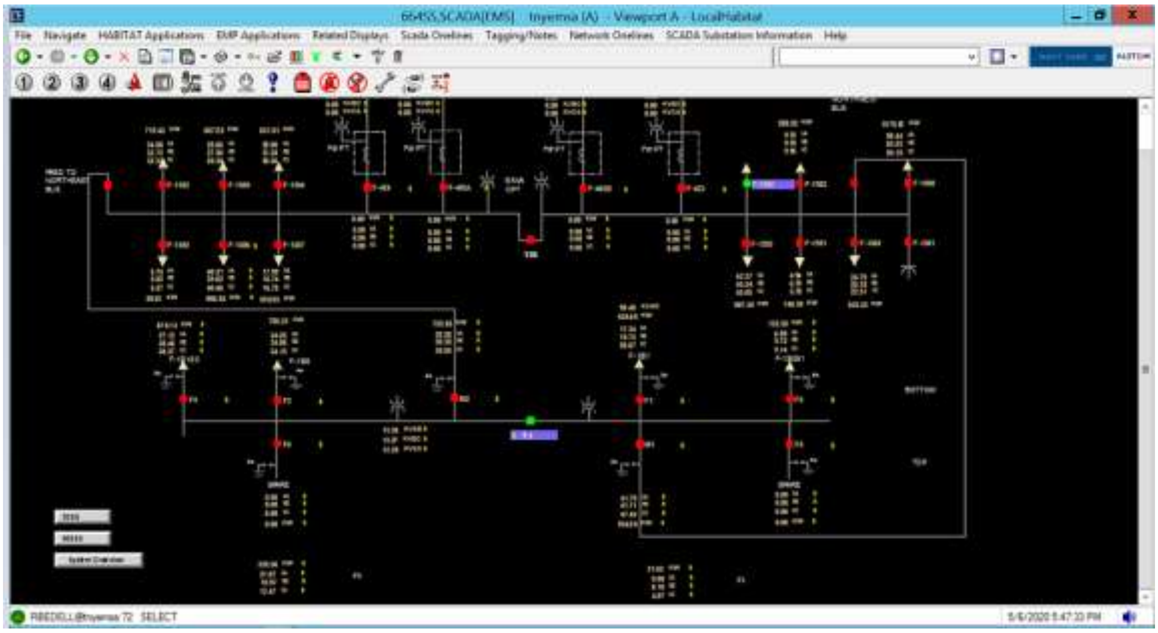

Figure 8-30. 664 Substation One line Diagram

To perform Feeder F1305 Verification:

4. On EMS server, start the e-terra HMI application.
5. Select the 664 Substation One line Diagram.
6. Select F1305 Feeder.
7. Verify all Feeder measurement and status are correct. See below.

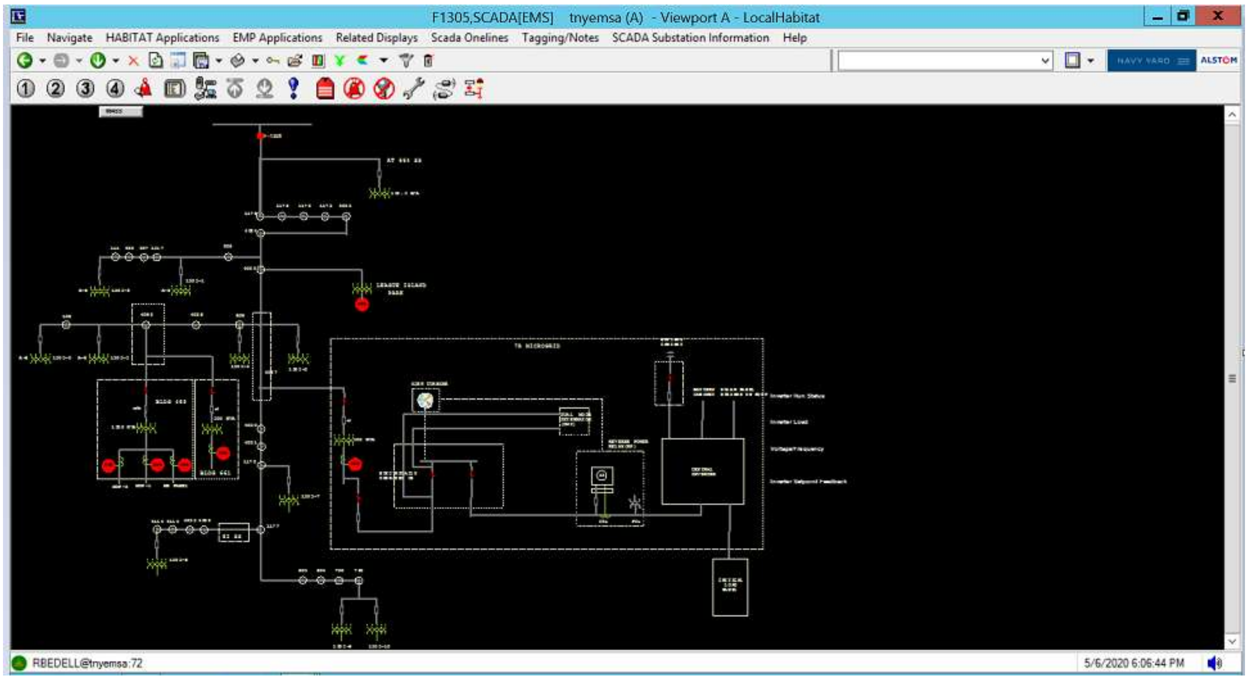

Figure 8-31. Feeder 1305 Diagram

8. Verify that all Key measurement show on the Substation One line Diagram. See Table 8-23.

Table 8-23 Key Measurements for Feeder 1305

Feeder 1305 Key Input Name	FEP Reading	HMI Shown
1305 IA PHASE A MAG	21.19	21.33
1305 IB PHASE B MAG	19.10	19.10
1305 IC PHASE C MAG	21.16	21.16
1305 CB STATUS	CLOSE	CLOSE

8.3.1.6 Test 2.1.3 (Alarm Verification) Setup

This table shows the substation and feeder alarms that will be verified.

Table 8-24 Substations and Feeders for Alarm Verification Setup

Device	IP Address	Protocol	GPS Clock
NOC EMS	192.108.1.1	DNP	IEEE 1558
Substation 664	192.64.1.4	IEC 61850	IEEE 1558
Feeder 1305	192.64.1.20	IEC 61850	IEEE 1558

8.3.1.7 Test Procedure

1. On EMS server, start the e-terra HMI application.
2. Select the **Alarm** Icon to see system alarm. See below.

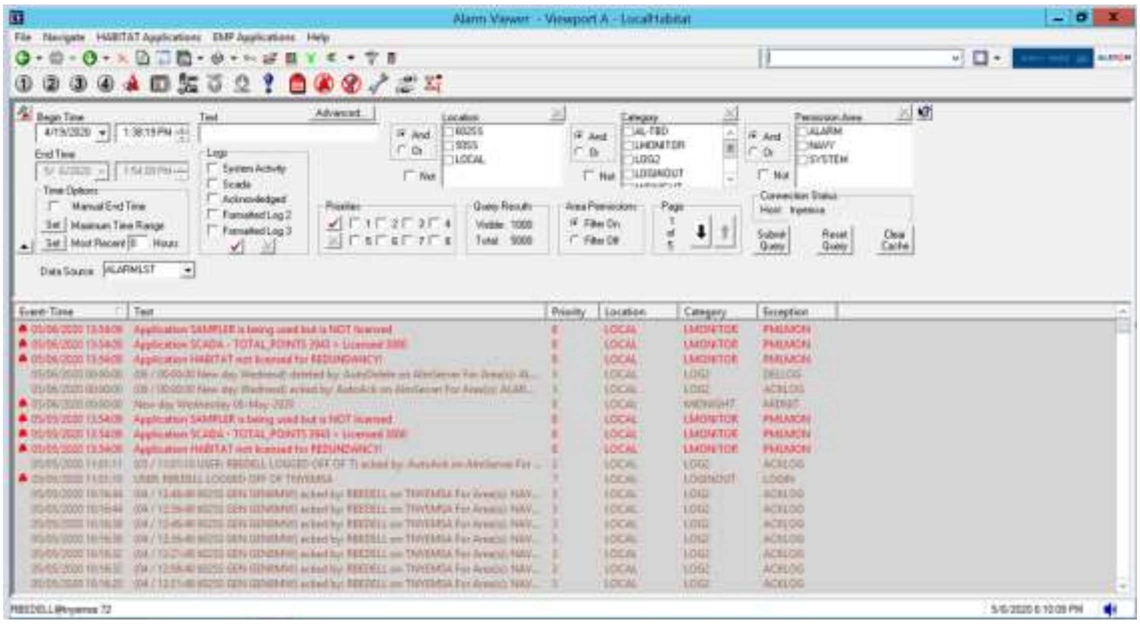

Figure 8-32. List of Alarms for F1305 after Selecting the Alarm icon

8.3.2 Test Set 2.2 – Load Reporting

8.3.2.1 Test Objective

The objective of this test is to verify that Level 1–Supervisory microgrid controller (implemented using the GE **e-terra** distribution platform) can continuously monitor and detect changes in load values for each load that is connected to the microgrid. The test loads are 2 large furnaces that are connected to Feeder 1362 and F1364. These loads can be used to participate in load shed operations in the event of microgrid islanding at Substation level.

8.3.2.2 Test 2.2.1 (Load Measurement) Setup

This table shows the substation and load measurements that will be verified.

Table 8-25 Substation and Feeder for Load Measurement Setup

Device	IP Address	Protocol	GPS Clock
Substation 602	192.2.1.4	DNP 3.0	IEEE 1558
Feeder 1362 (Critical Load)	192.2.1.33	DNP 3.0	IEEE 1558
Feeder 1364 (Non-Critical Load)	192.2.1.34	DNP 3.0	IEEE 1558

8.3.2.3 Test Procedure

To perform Substation 602 to NOC communication Verification:

1. On FEP server, start the e-terra FEP application.
2. Select the Communication – CFE COMstate Display.
3. Verify the DAP to Substation 602 DAP is communicating. See below.

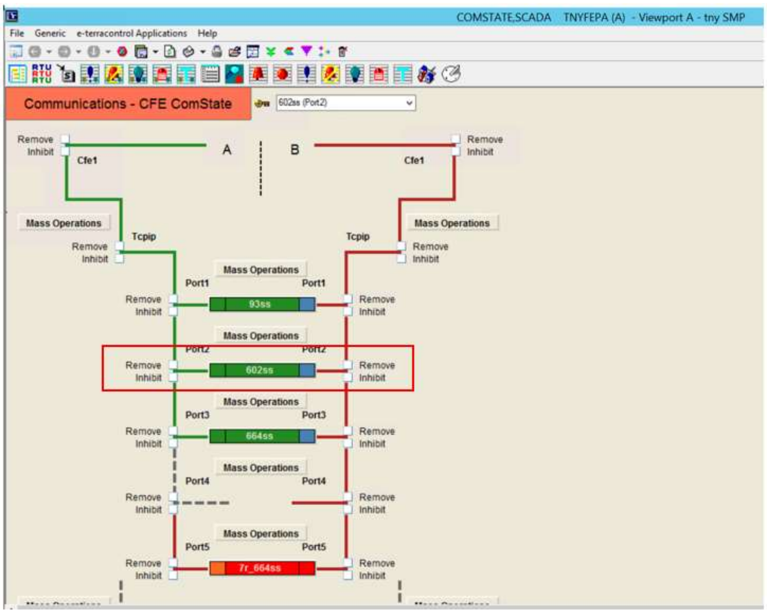

Figure 8-33. DAP and Substation 602 DAP Communicating

To perform Analog Input Verification:

4. On e-terra FEP application, select the **Measurements Display**.
5. Enter Filter **602SS** for Substation 602.

6. Scroll the measurement till **F1362**.

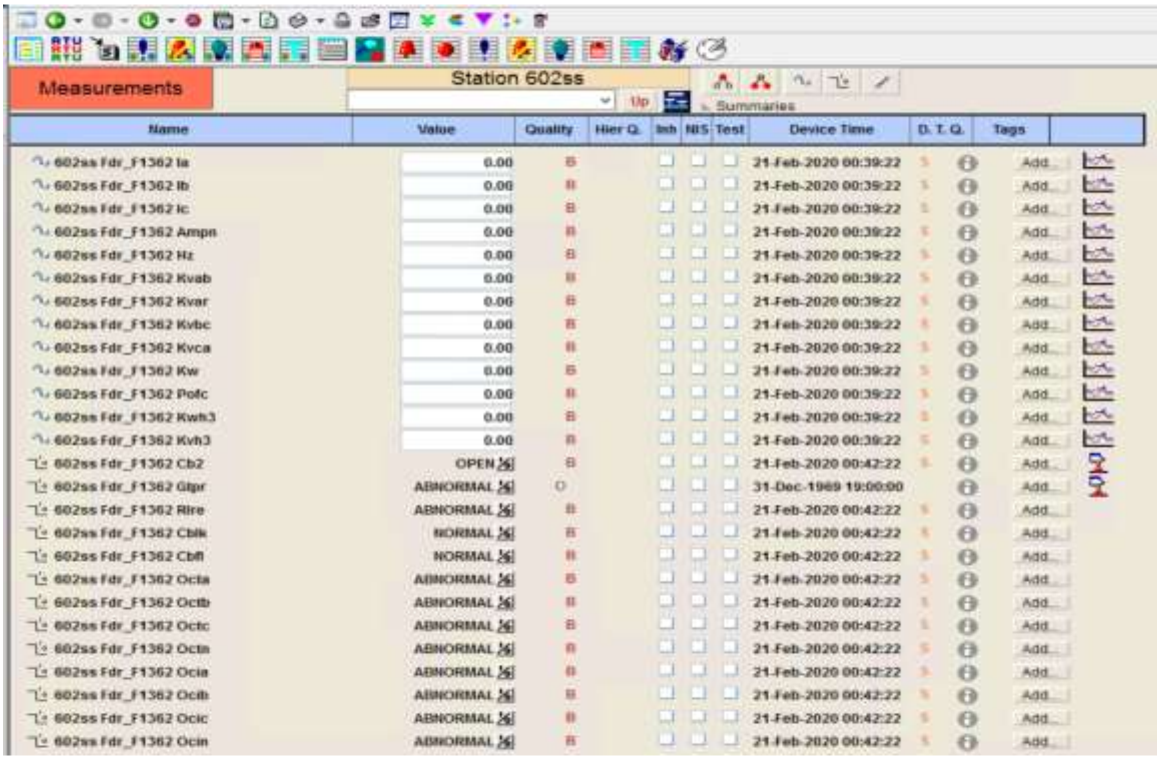

Figure 8-34. F1362 Measurements

7. Check the value and data quality. See Table 8-26.

Table 8-26 Feeder 1362 Analog Input Results with Substation Readings

Feeder 1362 Analog Input Name	DAP Reading	FEP Reading
1362 IA PHASE A MAG	0.0	0.0
1362 IB PHASE B MAG	0.0	0.0

8. Scroll through the measurement to **F1364**. See Figure 8-35.

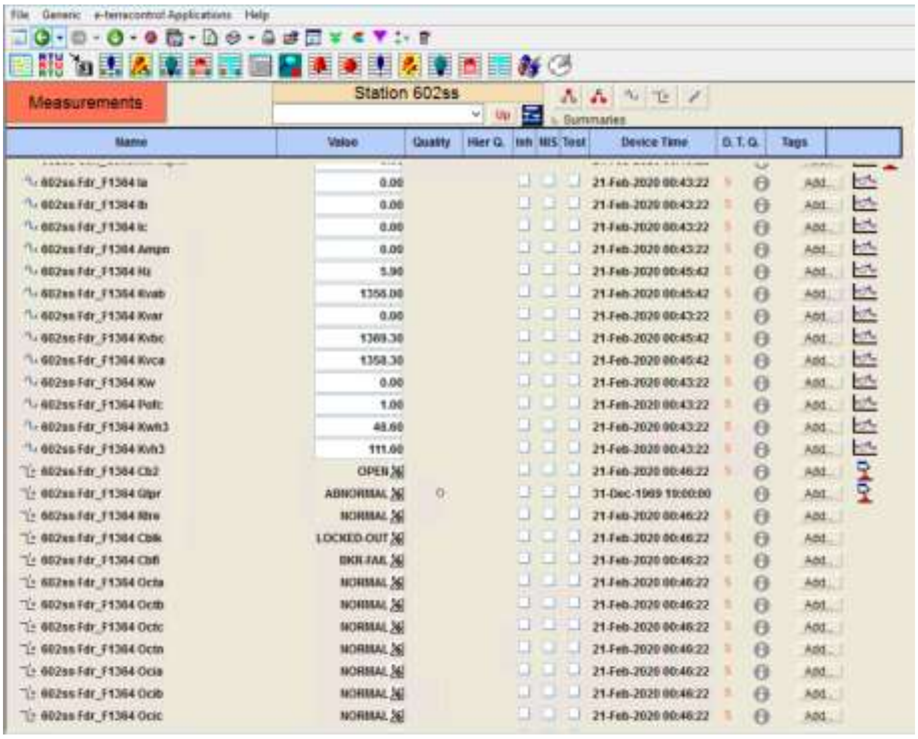

Figure 8-35. F1364 Measurements

9. Check the value and data quality. See Table 8-27.

Table 8-27 Feeder 1364 Analog Input Names with Substation Reading Comparison

Feeder 1364 Analog Input Name	DAP Reading	FEP Reading
1364 IA PHASE A MAG	0	0
1364 IB PHASE B MAG	0	0
1364 IC PHASE C MAG	0	0
1364 IN NEUTRAL MAG	0	0
1364 VAB	1356.00	1356.00
1364 VBC	1369.30	1369.30
1364 VCA	1358.30	1358.30
1364 POWER FACTOR	1.00	1.00
1364 FREQUENCY	5.9 HZ	5.9 HZ
1364 MW3 REAL POWER THREE PHASES	0	0
1364 MVAR3 REACTIVE POWER THREE PHASES	0	0
1364 MWH3L REAL ENERGY IN	48.60	48.60
1364 MVH3L REACTIVE ENERGY IN	111.60	111.60

8.3.2.4 Test 2.2.2 (Load Measurement HMI) Setup

Table 8-28 shows the substation and load measurement HMI that will be verified.

Table 8-28 Substation and Feeder Device Name for Load Measurement HMI Setup

Device	IP Address	Protocol	GPS Clock
Substation 602	192.64.1.4	DNP 3.0	IEEE 1558
Feeder 1362 (Critical Load)	192.64.1.33	DNP 3.0	IEEE 1558
Feeder 1364 (Uncritical Load)	192.64.1.34	DNP 3.0	IEEE 1558

8.3.2.5 Test Procedure

To perform Substation 602 Verification:

1. On EMS server, start the e-terra HMI application.
2. Select the 602 Substation One line Diagram.

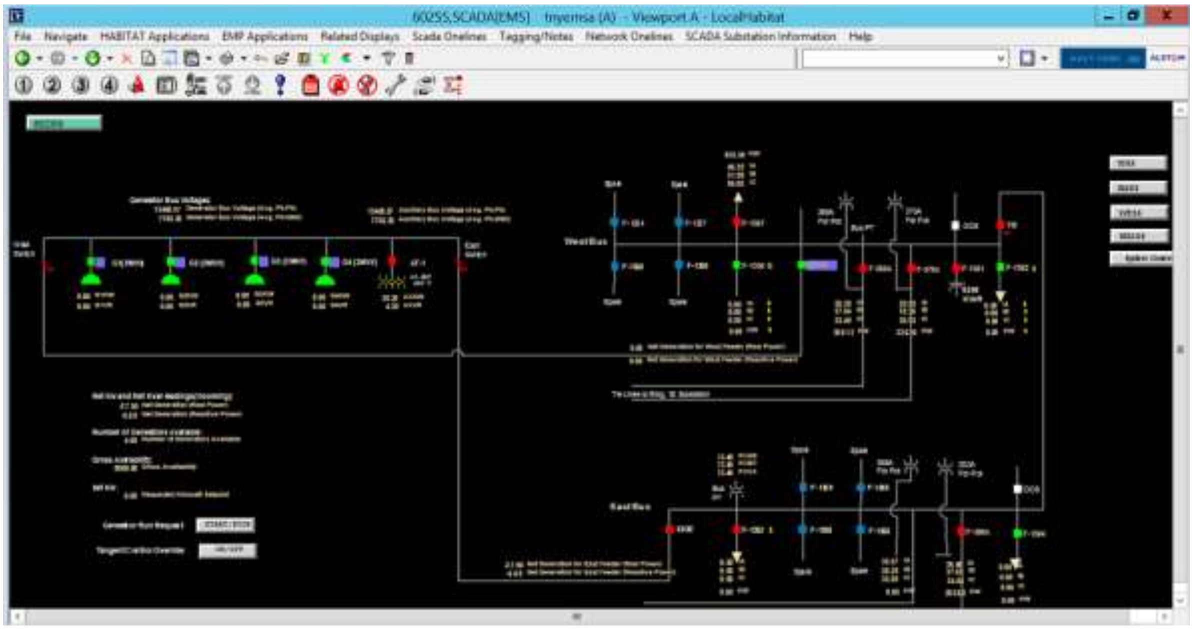

Figure 8-36. 602 Substation One line Diagram

3. Verify all Feeder measurement and status are correct.

To perform Feeder F1362 & F1364 Verification:

1. On EMS server, start the e-terra HMI application.
2. Select the 602 Substation One line Diagram.
3. Select F1362 and F1364 Feeder.

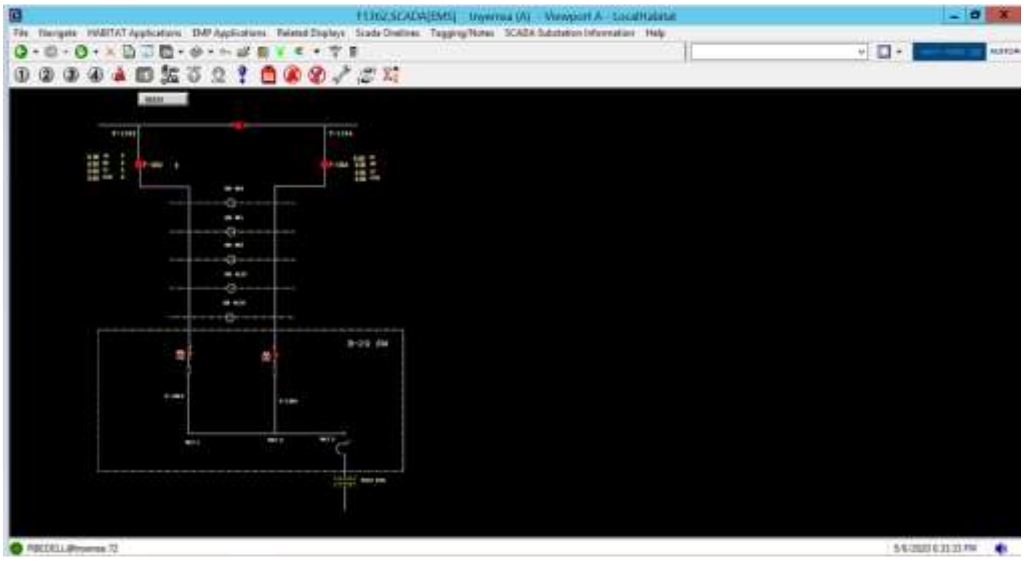

Figure 8-37. F1362 and F1364 Diagram

4. Verify F1362 and F1364 Feeder measurement and status are correct.

8.3.2.6 Test 2.2.3 (Load Alarm) Setup

This table shows the substation and feeder alarms that will be verified.

Table 8-29 Substation and Feeder for Load Alarm Setup

Device	IP Address	Protocol	GPS Clock
Substation 644	192.64.1.4	DNP 3.0	IEEE 1558
Feeder 1362 (Critical Load)	192.64.1.33	DNP 3.0	IEEE 1558
Feeder 1364 (Uncritical Load)	192.64.1.34	DNP 3.0	IEEE 1558

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8.3.2.7 Test Procedure

1. On EMS server, start the e-terra HMI application.
2. Select the Alarm Icon to see system alarm. See below.

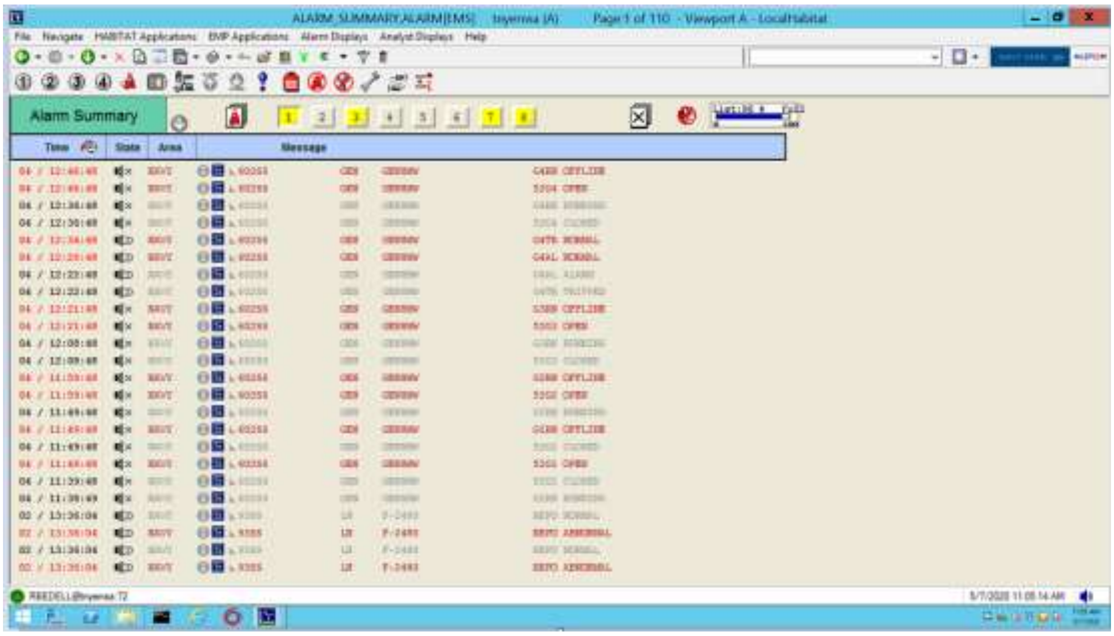

Figure 8-38. List of Alarms for F1362 and F1364 after Selecting the Alarm icon

8.3.3 Test Set 2.3 – Power Supply Reporting

The objective of this test is to verify that Level 1-supervisory microgrid controller (implemented using GE's **e-terra** distribution platform)) can continuously monitor the output of all supply sources within the microgrid (e.g., CHP, Energy storage facility, solar PV units). These generation assets can be used to service critical load in the event of a microgrid island at system level.

8.3.3.1 Test 2.3.1 (Power Supply Measurement) Setup

This table shows the power plant and generator measurement that will be verified.

Table 8-30 Power Plant Device Names for Power Supply Measurement Setup

Device	IP Address	Protocol	GPS Clock
Substation 602	192.2.1.4	DNP 3.0	IEEE 1558
RTAC (Power Supply)	RS232 COMM Port 1	DNP 3.0	IEEE 1558

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8.3.3.2 Test Procedure

To perform Substation 602 to NOC Communication Verification:

1. On FEP server, start the e-terra FEP application.
2. Select the Communication – CFE COMState Display.
3. Verify the DAP to Substation 602 DAP is communicating.

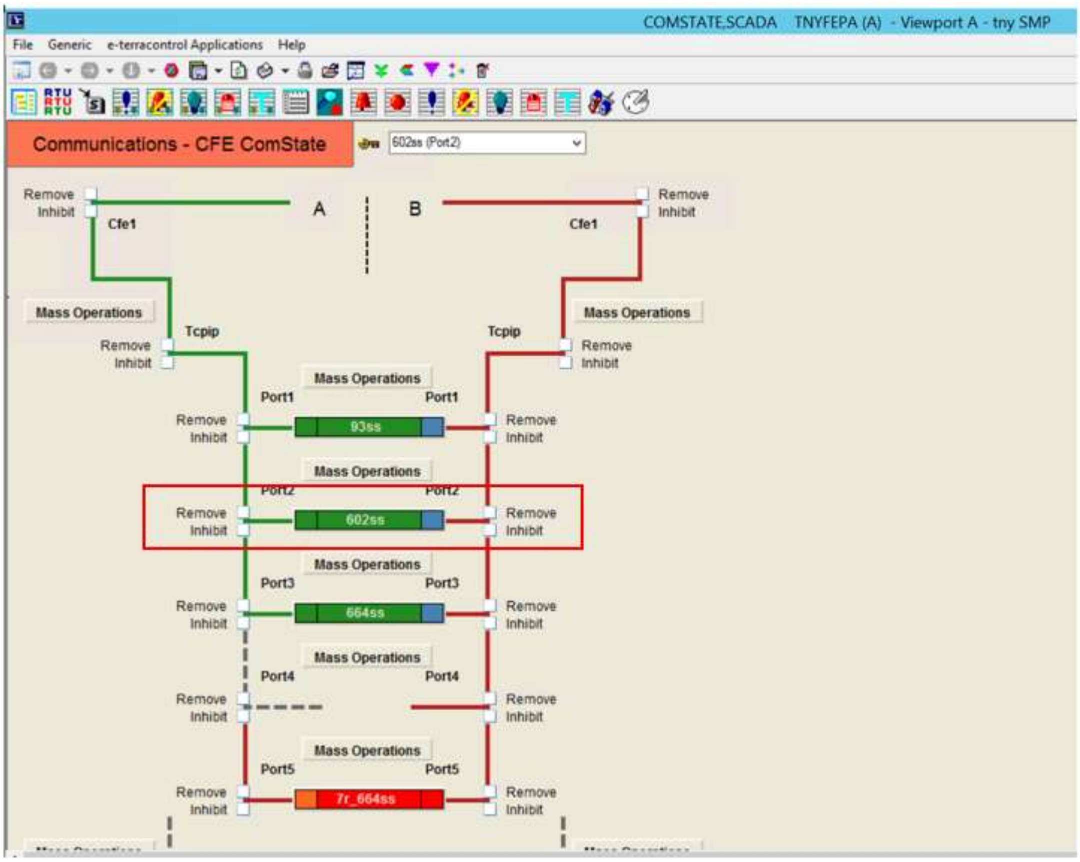

Figure 8-39. DAP and Substation 602 DAP Communicating for NOC

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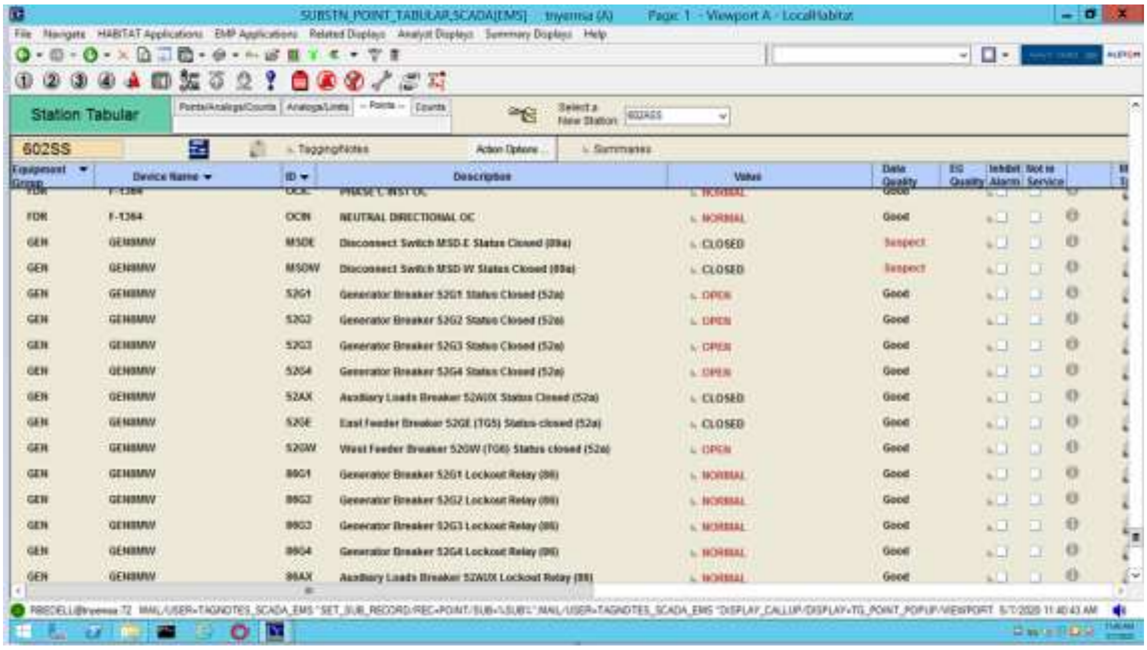
To perform Digital Input Verification:

1. Using the same **Measurements Display**.
2. Scroll through the measurement till **G1, G2, G3, G4**.
3. Check the value and data quality. See below.



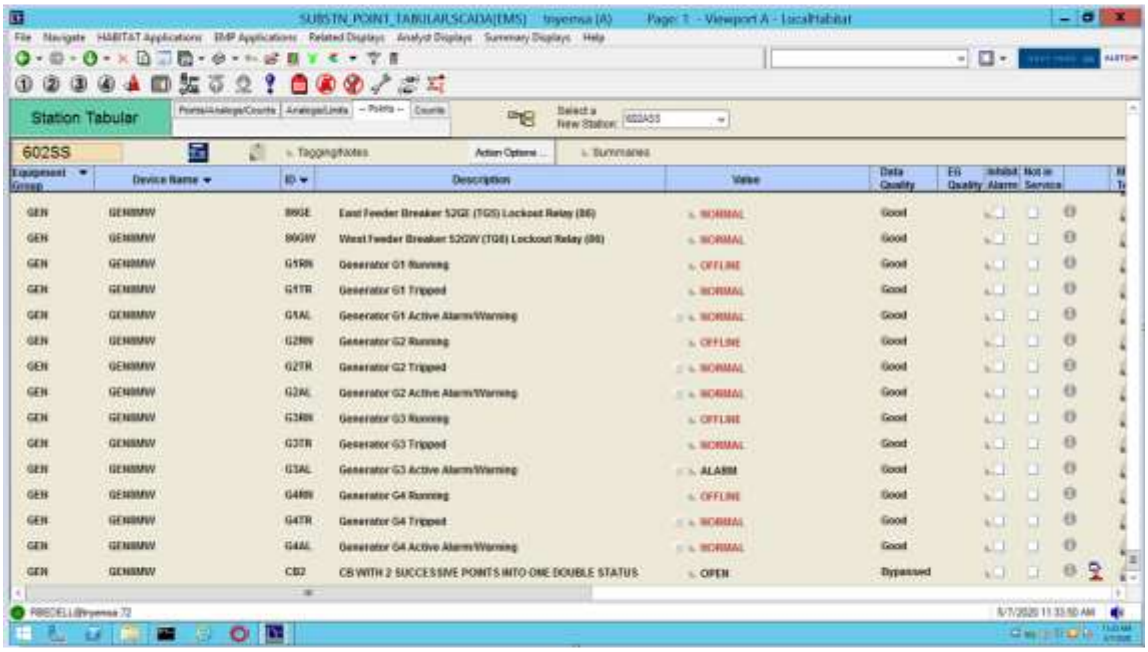


Figure 8-40. G1, G2, G3, G4 Measurements

4. Compare the Key Generation status with Substation readings. See Table 8-31.

Table 8-31 Key Generation Points with Substation Reading Comparison

Generator Digital Input Name	SCADA Reading	DAP Reading
GENERATOR 1 CB Closed Status (52)	OPEN	OPEN
GENERATOR 1 CB Closed Status (52)	OPEN	OPEN
GENERATOR 1 CB Closed Status (52)	OPEN	OPEN
GENERATOR 1 CB Closed Status (52)	OPEN	OPEN

To perform Analog Input Verification:

1. On e-terra FEP application, select the **Measurements Display**.
2. Enter Filter **602SS** for Substation 602,
3. Scroll through the measurement till **G1, G2, G3, G4**. See below.

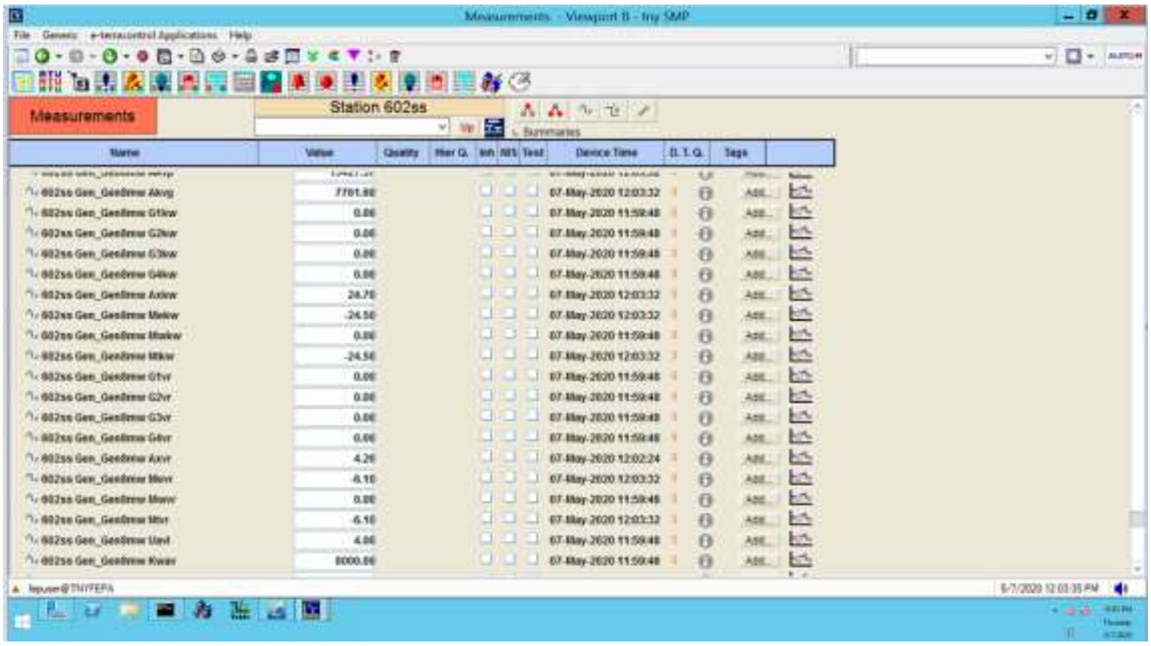


Figure 8-41. F1364 Measurements for 602SS

4. Compare key analog point with Substation reading. See Table 8-32.

Table 8-32 Key Analog Points with Substation Reading Comparison

Generator Input Name	SCADA Reading	DAP Reading
GENERATOR 1 KW (G1kw)	0.00	0.00
GENERATOR 2 KW (G2kw)	0.00	0.00
GENERATOR 3 KW (G3kw)	0.00	0.00
GENERATOR 4 KW (G4kw)	0.00	0.00

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8.3.3.3 Test 2.3.2 (Power Supply HMI) Setup

This table shows the power plant and generator measurement that will be verified.

Table 8-33 Substation Device Names for Power Supply HMI Setup

Device	IP Address	Protocol	GPS Clock
Substation 602	192.2.1.4	DNP 3.0	IEEE 1558
RTAC (Power Supply)	RS232 COMM Port 1	DNP 3.0	IEEE 1558

8.3.3.4 Test Procedure

To perform Substation 602 Verification:

1. On EMS server, start the e-terra HMI application.
2. Select the 602 Substation One line Diagram. See below.

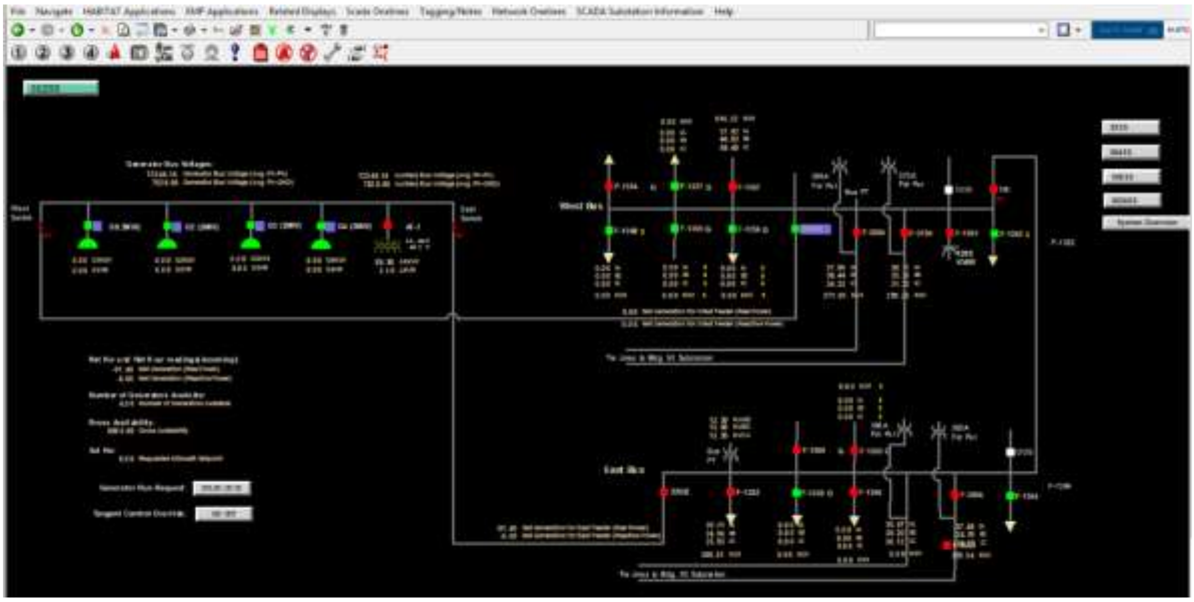

Figure 8-42. 602 Substation One line Diagram

3. Verify all generation measurement and status are shown correctly on one line diagram

8.3.3.5 Test 2.3.3 (Power Supply Alarm) Setup

This table shows the power plant and generator alarm that will be verified.

Table 8-34 Substation Device Names for Power Supply Alarm Setup

Device	IP Address	Protocol	GPS Clock
Substation 602	192.2.1.4	DNP 3.0	IEEE 1558
RTAC (Power Supply)	RS232 COMM Port 1	DNP 3.0	IEEE 1558

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8.3.3.6 Test Procedure

1. On EMS server, start the e-terra HMI application.
2. Select the Alarm Icon to see system alarm

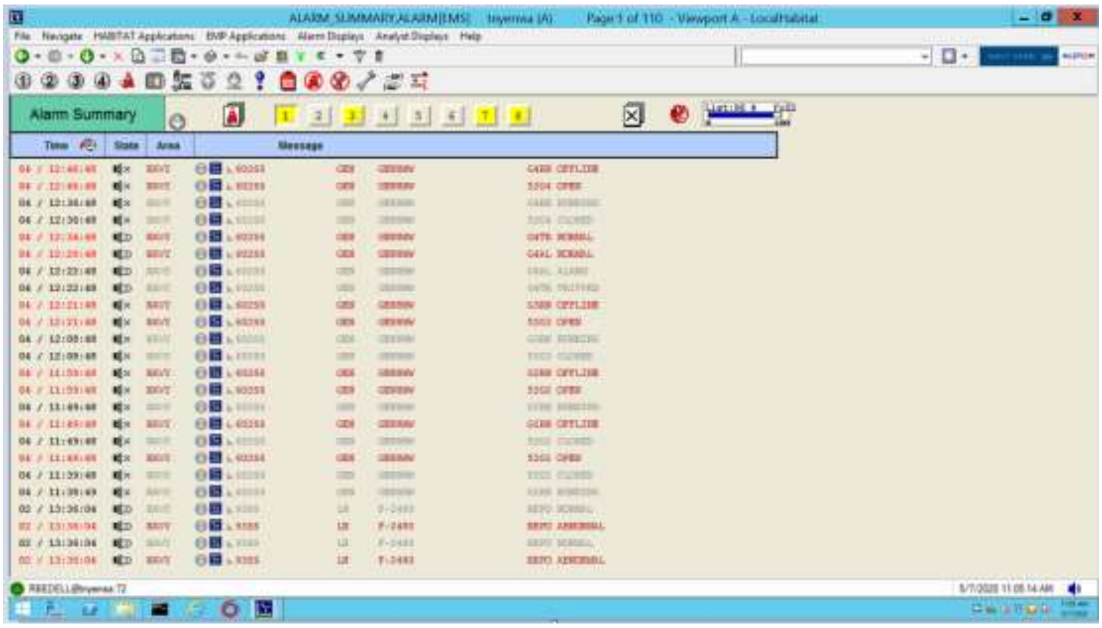

Figure 8-43. List of Alarms for Substation 602 after Selecting the Alarm icon

8.3.4 Test Set 2.4 – PCC Monitoring

8.3.4.1 Test Objective:

The objective of this test is to verify that Level 1-substation microgrid controller (implemented using GE's **e-terra** distribution platform) can continuously monitor and detect changes at the PCC.

8.3.4.2 Test 2.4.1 (PCC Measurement) Setup

This table shows substation and PCC measurement that will be verified.

Table 8-35 Substation Device Names for PCC Measurement Setup

Device	IP Address	Protocol	GPS Clock
Substation 93	192.93.1.4	DNP 3.0	IEEE 1558
F2468	192.93.1.27	DNP 3.0	IEEE 1558
F2469	192.93.1.24	DNP 3.0	IEEE 1558
F2470	192.93.1.25	DNP 3.0	IEEE 1558
F2480	192.93.1.26	DNP 3.0	IEEE 1558

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8.3.4.3 Test Procedure

To perform Substation 93 to NOC communication Verification:

1. On FEP server, start the e-terra FEP application.
2. Select the Communication – CFE COMState Display.
3. Verify the DAP to Substation 93 DAP is communicating.

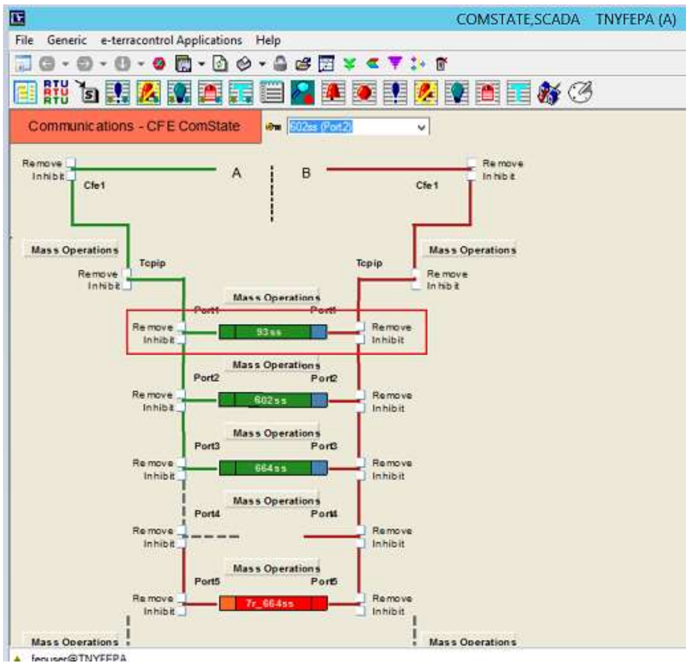

Figure 8-44. DAP and Substation 93 DAP Communicating

To perform Digital Input Verification:

1. Use the same Measurements Display.
2. Scroll to find the measurement to all 4 feeders.
3. Check the value and data quality. See below.

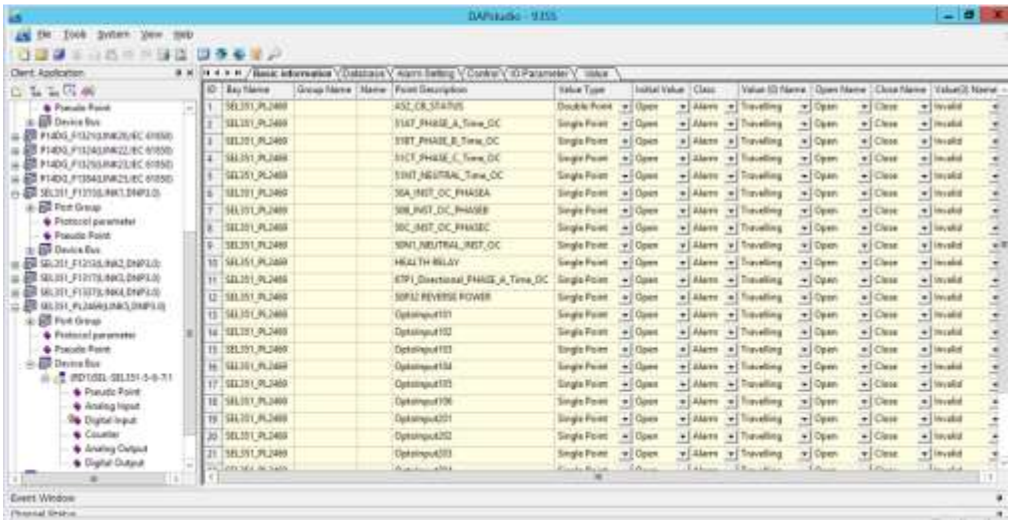

Figure 8-45. DAP and Substation 93 DAP Communicating

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4. Compare Key measurement data with substation data. See Table 8-37.

Table 8-36 PCC Digital Input Names

PCC Digital Input Name	SCADA Reading	DAP Reading
F2467 CB Status	CLOSE	CLOSE
F2468 CB Status	CLOSE	CLOSE
F2469 CB Status	CLOSE	CLOSE
F2480 CB Status	CLOSE	CLOSE

To perform Analog Input Verification:

1. On e-terra FEP application, select the Measurements Display,
2. Enter Filter **93SS** for Substation 93.
3. Scroll through the measurements till **F2468, F2469, F2470, F2480**.

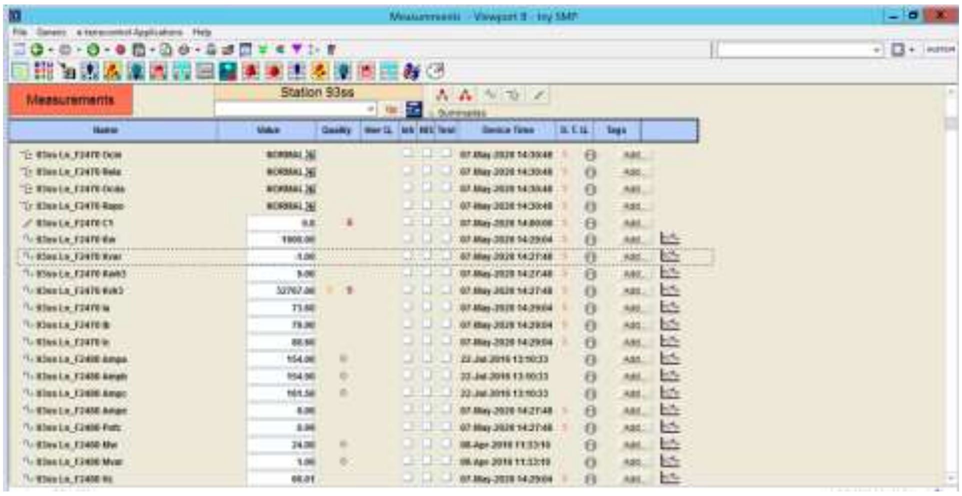

Figure 8-46. F2468, F2469, F2470, F2480 Measurements

4. Compare Key measurement data with substation data. See Table 8-37.

Table 8-37 Substation Device Names for PCC Alarm Setup

PCC Analog Input Name	SCADA Reading	DAP Reading
F2467 VAB	13.4	13.4
F2467 VBC	13.4	13.4
F2467 VCA	13.4	13.4
F2467 IA	62.3	62.3
F2467 IB	69.0	69.0
F2467 IC	66.7	66.7
F2467 MW	1500	1500
F2468 VAB	13.4	13.4

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PCC Analog Input Name	SCADA Reading	DAP Reading
F2468 VBC	13.4	13.4
F2468 VCA	13.4	13.4
F2468 IA	63.8	63.8
F2468 IB	70.6	70.6
F2468 IC	69.3	69.3
F2468 MW	1500	1500
F2469 VAB	13.4	13.4
F2469 VBC	13.4	13.4
F2469 VCA	13.4	13.4
F2469 IA	62.5	62.5
F2469 IB	69.5	69.5
F2469 IC	67.5	67.5
F2469 MW	1500	1500
F2480 VAB		13.4
F2480 VBC		13.4
F2480 VCA		13.4
F2480 IA		61.4
F2480 IB		67.1
F2480 IC		65.0
F2480 MW		1400
F2480 CB Status		CLOSE

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8.3.4.4 Test 2.4.2 (PCC HMI) Setup

This table shows substation and PCC HMI that will be verified.

Table 8-38 Substation Device Names for PCC HMI Setup

Device	IP Address	Protocol	GPS Clock
Substation 93	192.93.1.4	DNP 3.0	IEEE 1558
F2468	192.93.1.27	DNP 3.0	IEEE 1558
F2469	192.93.1.24	DNP 3.0	IEEE 1558
F2470	192.93.1.25	DNP 3.0	IEEE 1558
F2480	192.93.1.26	DNP 3.0	IEEE 1558

8.3.4.5 Test 2.4.2 (PCC HMI) Setup

To perform Substation 93 Verification:

1. On EMS server, start the e-terra HMI application.
2. Select the 93 Substation One line Diagram.
3. Verify all PCC measurement and status are shown correctly on one line diagram. See below.

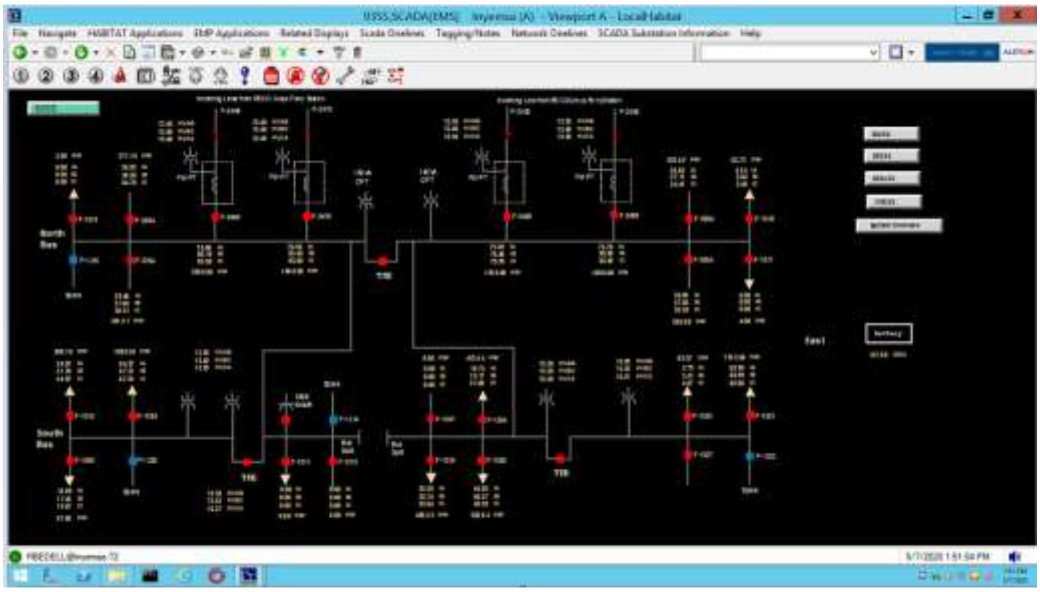

Figure 8-47. 93 Substation One line Diagram

8.3.4.6 Test 2.4.3 (PCC Alarm) Setup

This table shows the substation and PCC Alarm that will be verified.

Table 8-39 Substation Device Names for PCC Alarm Setup

Device	IP Address	Protocol	GPS Clock
Substation 93	192.93.1.4	DNP 3.0	IEEE 1558
F2468	192.93.1.27	DNP 3.0	IEEE 1558
F2469	192.93.1.24	DNP 3.0	IEEE 1558
F2470	192.93.1.25	DNP 3.0	IEEE 1558
F2480	192.93.1.26	DNP 3.0	IEEE 1558

8.3.4.7 Test Procedure

1. On EMS server, start the e-terra HMI application.
2. Select the Alarm Icon to see system alarm. See below.

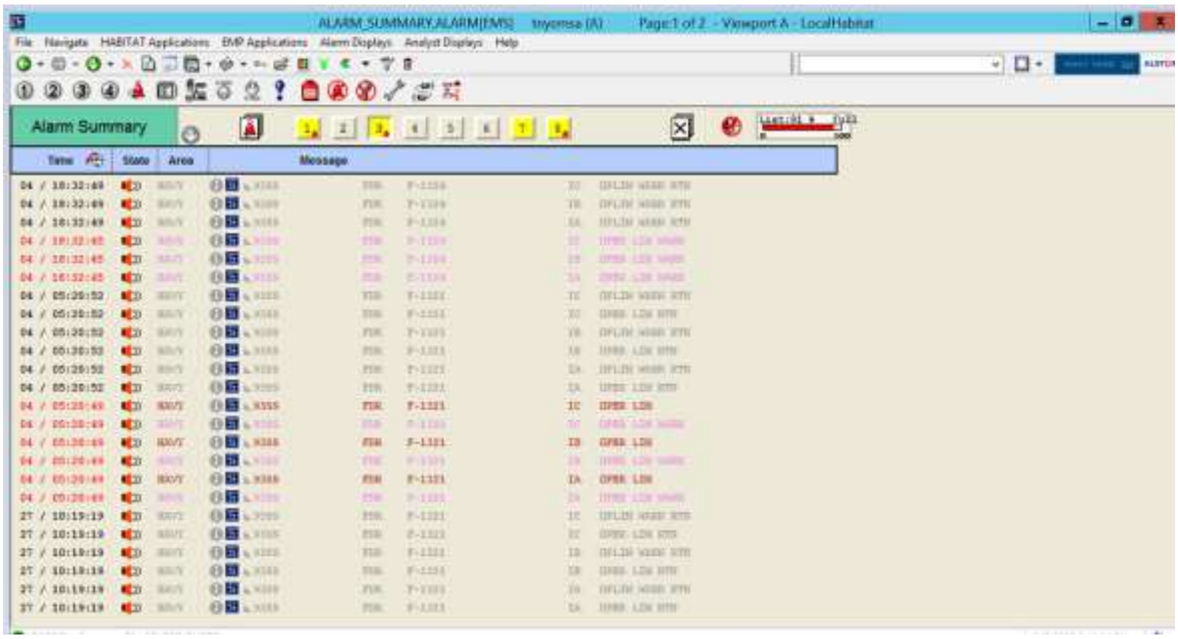

Figure 8-48. List of Alarms for 93 Substation after Selecting the Alarm icon

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8.4 Test Set 3 – Control Functions

8.4.1 Test Set 3.1 – Asset Control

8.4.1.1 Test Objective

The objective of this test is to verify that Level 1 -supervisory microgrid controller (implemented using the GE **e-terra** distribution platform) can reliably and effectively deliver control commands to controllable microgrid assets (generation unit, microgrid switchgear, and other controllable devices) within the strict time constraints required for effective microgrid operation at system level.

8.4.1.2 Test 3.1.1 (Load Control) Setup

This table shows the feeder load control that will be verified.

Table 8-40 Feeder Load Control Device Names

Device	IP Address	Protocol	GPS Clock
Substation 602	192.2.1.4	DNP 3.0	IEEE 1558
Feeder 1362 (Critical Load)	192.2.1.33	DNP 3.0	IEEE 1558
Feeder 1364 (Non Critical Load)	192.2.1.34	DNP 3.0	IEEE 1558

8.4.1.3 Test Procedure

1. On EMS server, start the e-terra HMI application.
2. On the same 602 Substation One-line Diagram, click Feeder 1362 Circuit Breaker Icon and popup Device panel. See below.

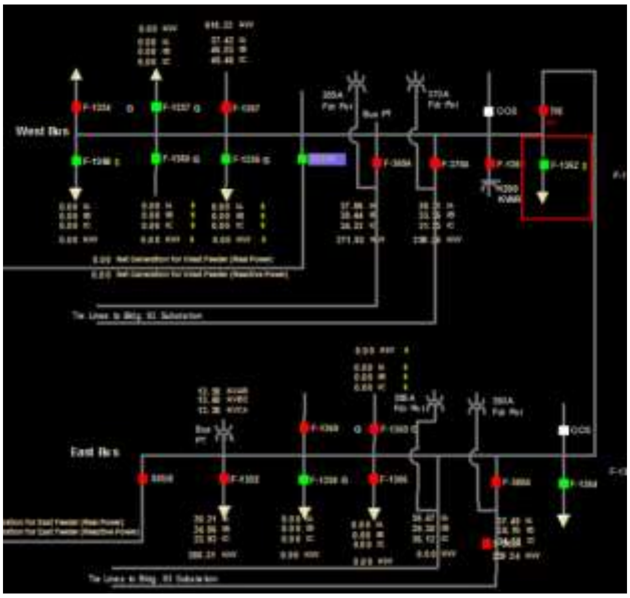

Figure 8-49. Feeder 1364 Circuit Breaker

3. Click Control Icon to popup Control panel.
4. Click **Control**.

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5. Select **Open/Close** command. See below.

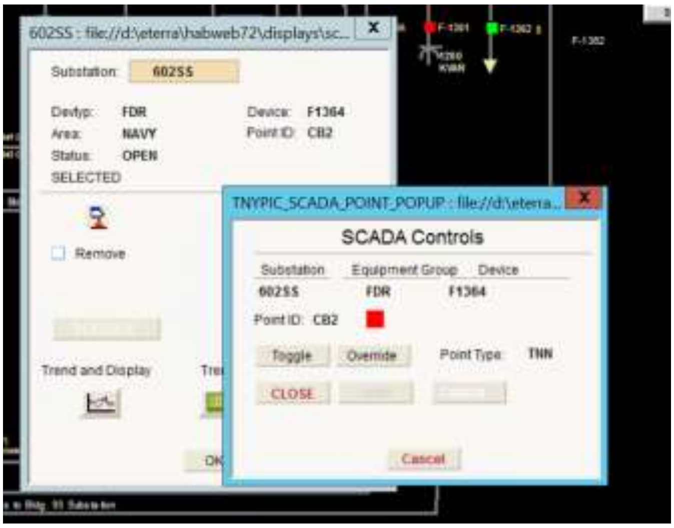

Figure 8-50. Feeder 1364 Circuit Breaker SCADA Controls

6. Click Execution.
7. Select **OK** to send command.

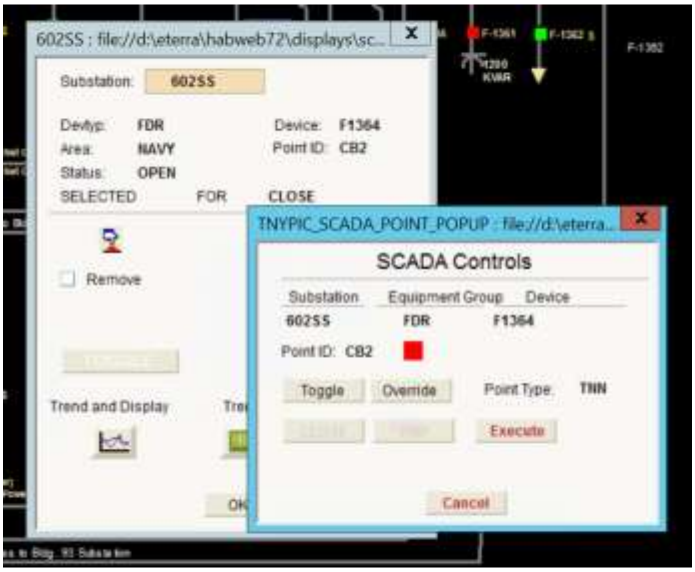

Figure 8-51. Feeder 1364 Circuit Breaker SCADA Controls after Sending Ok.

8. Verify the command is received by Feeder 1362 and executed.
9. Click Feeder 1364 Circuit Breaker Icon and popup Device panel. See Figure 8-53.

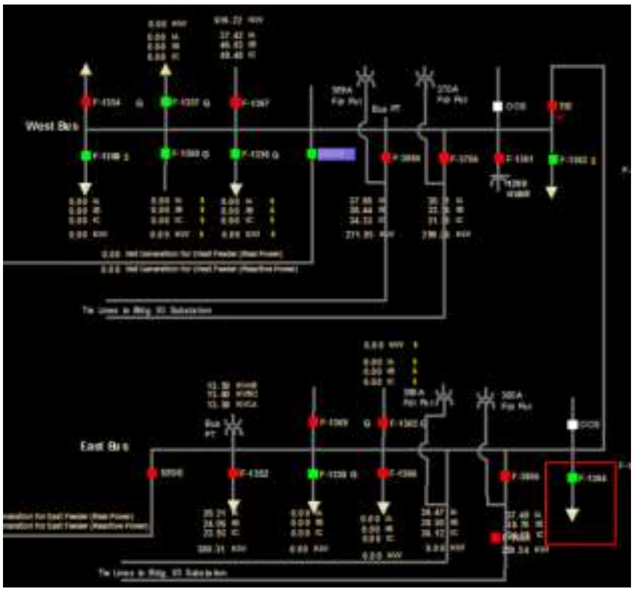

Figure 8-52. Feeder 1364 Circuit Breaker After Executing Command

10. Click Control Icon to popup Control panel.
11. Click **Control**.
12. Select **Open/Close** command.

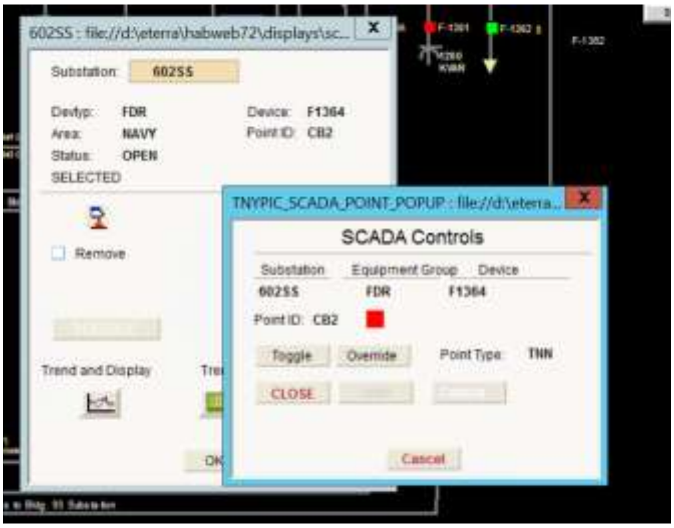

Figure 8-53. Feeder 1364 Circuit Breaker with SCADA Control After Executing Command

13. Click Execution.
14. Select **OK** to send command.

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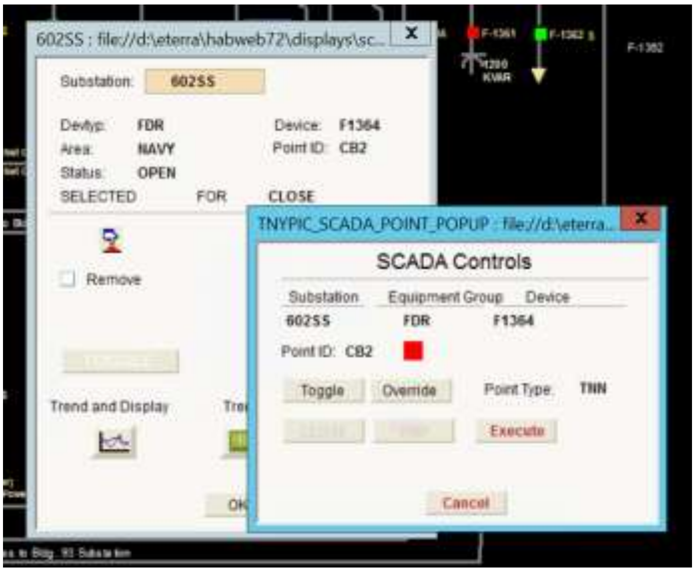

Figure 8-54. Feeder 1364 Circuit Breaker with SCADA Control After Executing Command Twice

15. Verify the command is received by Feeder 1364 and executed.

8.4.1.4 Test 3.1.2 (Generation Control) Setup

This table shows generation control that will be verified.

Table 8-41 Substation for Generation Control Setup

Device	IP Address	Protocol	GPS Clock
Substation 602	192.2.1.4	DNP 3.0	IEEE 1558
RTAC (Power Supply)	RS232 COMM Port 1	DNP 3.0	IEEE 1558

8.4.1.5 Test Procedure

1. On EMS server, start the e-terra HMI application.
2. On the same 602 Substation One-line Diagram, click **Generation Run Request** and **Setpoint Device panel**. See below.

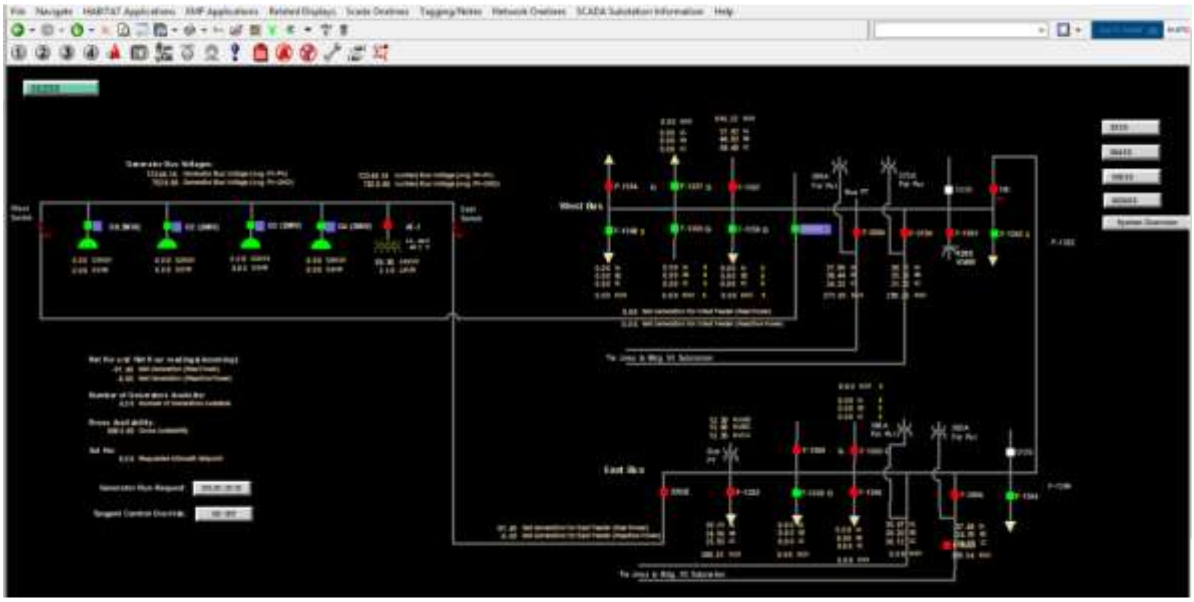

Figure 8-55. 602 Substation One-Line Diagram for Setpoint Device

3. Click Control Icon to popup Control panel.
4. Click **Control**.
5. Select **Open/Close** command.
6. Click Execution.
7. Select **OK** to send command.

   (Added Setpoint Screen Shot)
8. Verify the command is received by RTAC and executed.

9. PNNL Simulation Study and Testing

9.1 Research Objective

Microgrids are a technology that can help to mitigate the outages in service inherent in the operation of an electric power system. Whether the outage is due to a local event or an extreme regional weather event, microgrids have proven effective at maintaining continuity to critical end use loads. The majority of microgrids are customer owned systems that reside within a university campus, military base, or industrial facilities. But in some regions, utility owned microgrids are deployed.

To improve the economics of microgrids when grid connected, it is typical to use a communications system to optimize operations. The challenge with resiliency-based microgrids is that they are expected to operate under conditions where it is unreasonable to assume the communications network will always be available. For this reason, these microgrids need to be able to have their assets operate independently when in islanded operation, using primary controls if the communications infrastructure is unavailable.

One of the most common methods of islanded operation without communications is a variation of the traditional linear droop curves where adaptive or non-linear curves are used. While the mathematical basis for these works is sound, the majority of microgrids currently being deployed for resiliency applications are AC. Fortunately, there has also been a significant amount of work on implementing droop controls for AC microgrids, with the more recent work examining inverter-based systems.

This research will present a method of using adaptive nonlinear droop control for resiliency-based microgrids. The method will use a simple "slider" based control that will allow the operator to slightly bias operations between "more resilient" and "more efficient". This system is intended to be added to an existing microgrid control and will not be deployed as a stand-alone system.

9.2 Research Methodology

Because the slider-based control is a trade-off between resiliency and efficiency, the research implemented the 4-step process for determining the optimized droop settings based on operator input preferences.

9.2.1 A. Step 1: Resiliency Representation

For a given commitment of generation assets in an islanded microgrid, the dynamic stability and efficiency of the island will be a function of the dispatch. As the load is transferred between generators, the dynamic stability, and efficiency of a dynamic power system will change.

9.2.2 B. Step 2: Efficiency Representation

Efficiency in an islanded microgrid is a function of the individual generator efficiencies and system losses. For small to moderate size microgrids, losses associated with generators are typically significantly higher than system losses.

9.2.3 C. Step 3: Development of the operational input data set

Once there are representations for resiliency and efficiency, it is necessary to determine the resiliency and efficiency metrics for varying events, such as a step increase in load, over varying values of droop, R, for each generator and inverter.

9.2.4 D. Step 4: Optimization Based on Slider Setting

Because of the potential size and complexity of the operational data set it is not always possible to determine the desired droop values based on observations.

The detailed step procedure can be found in paper.[4]

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9.3 Use Case Analysis

A modified version of the IEEE 123 Node Test System is used. The IEEE 123 Node Test System is used as a microgrid because the PES Test Feeder Working Group has not yet completed a microgrid test case.

Three cases will be examined to highlight the utility of the presented method.

In each of the three cases, the 4-step process will be executed to update the droop values to reflect current preferences between resiliency and efficiency.

Case 1 will examine a system with only diesel generation.

Case 2 will examine a combination of diesel generators and inverter connected generation.

Case 3 will examine a system with only inverter connected generation.

Due to the desire to integrate high penetrations of renewable resources there is an increasing number of purely inverter-based microgrids. One such system is the GridSTAR microgrid at the Philadelphia Navy Yard. GRIDSTAR was net zero energy demonstration project spearheaded by GE and Penn State with support from the U.S. Department of Energy, Commonwealth of Pennsylvania and Philadelphia Industrial Development Corporation (PIDC), the GridSTAR Center was built to serve as a valuable hub for workforce training, building performance testing, energy management research and "smart" microgrid modernization deployments.

The GridSTAR microgrid includes a portion of a TNY 13.2-kV feeder and utilized only inverter-based assets. These assets include an Electric Vehicle Charging Station, energy storage system, and solar photovoltaic system.

The detailed simulation result was documented in paper [4], which also references similar work described in publications and research papers [37]-[84].

9.4 Conclusion and Recommendations

This research presents an intuitive method for microgrid operators to balance between two operational goals: resiliency and efficiency. The method is based on the use of adaptive non-linear droop curves that will balance operational objectives based on operator input.

The droop control is adaptive based on the operator's desire to balance between resiliency and efficiency. It is also similar to transactive controls where end-users can select between "more efficient" and "more comfort". If the communications infrastructure is lost, the microgrid will continue to operate using the primary frequency controls with the last set of updated droop values. This scheme ensures the operator is able to adapt to changing system conditions when a communications network is available and to maintain stable operations, if it is lost.

The dual objectives of resiliency and efficiency reflect the need for islanded microgrid operations to address:

- Scenarios where there may be follow-up events that will impact the microgrid(s).
- Scenarios where the outage could last for a prolonged period of time with only the on-site fuel resources available.

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10. WSU Simulation Study and Testing

10.1 Research Objective

In the past few decades, the penetration of distributed energy sources (DER) in the utility grid has increased to meet the high electricity demand. This in turn has increased the normal current level and has resulted in a corresponding increase in the short-circuit current level of the grid. High fault currents can cause mechanical forces and thermal stress that result in damage to the equipment, circuit breakers, transformers, and transmission lines. This increased current level requires two modifications:

- Retrofitting the already installed devices and circuit breakers with higher rated equipment.
- Installation of protective devices to handle the high level fault currents.

Replacement and upgrading of equipment and circuit breakers are a possible but expensive solution to deal with the high fault current levels.

There are different approaches to tackle increased fault currents in the distribution system:

- One approach is to include bus splitting in power grid, upgrading the switchgear, and using higher voltage connections. However, these techniques cause problems such as loss of power system safety, increased cost, and high power losses.
- An alternate approach is to use high impedance transformers, but their constant impedance causes high losses, low voltage regulation, and inefficiency. Iron-core inductors can mitigate fault currents, but they are bulky and cause high voltage drop and losses in the grid.
- A third option is fault-limiting fuses, but they need to be replaced after every fault occurrence and are suitable for voltages below 35 kV.

Fault current limiters (FCL) were developed to overcome the problems mentioned above. They avoid the need to upgrade circuit breakers and replace the power equipment. FCLs prevent transformer damage, alleviate the voltage dips, and help in supplying uninterruptible power to the end consumers.

The objective of this research is to develop a fault limiting strategy based on a saturable reactor and compare the proposed approach with a DVR (dynamic voltage restorer). The performance of these two methods was evaluated through simulation studies performed in PSCAD/EMTDC environment for both temporary and permanent short-circuit faults for balanced and unbalanced conditions [5].

10.2 Research Methodology

The following shows the analysis for two fault current limiting strategies in the project.

10.2.1 Saturable Reactor

A saturable reactor is based on the magnetic amplifier concept first developed during World War II. The reactor consists of two windings:

- A control winding.
- An AC winding.

These windings are connected so that the flux produced by one winding opposes the flux produced by the other. The AC winding carries the line current, while the control winding, connected to an external DC source, carries a DC current.

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The basic principle of operation of a saturable reactor as an FCL is based on the magnetic saturation of the core that acts as a variable reactance. The inductance offered by the saturable reactor depends on the saturation condition of the core; a low steady-state value in the saturated state and a higher value in the unsaturated state. During normal condition, a high DC current is injected into the control winding of the reactor that keeps the operating point in the saturated state, which in turn causes the injection of a very small reactance into the system.

The detailed implementation of this strategy is descripted in paper[5].

10.2.2 Dynamic Voltage Restorer

The DVR is a custom power device used for compensating voltage sags. It can operate in two different modes:

- Voltage-compensating mode in balanced and unbalanced conditions.
- Fault current limiting mode during short circuit faults.

The DVR is connected to the main grid through a series transformer and a harmonic filter. The DVR operates as a compensating solid-state device that injects a controlled three-phase AC voltage in series with the supply voltage. The injected voltage is equal to the voltage sag and regulates the voltage magnitude, angle, and waveform. By compensating voltage sags, the DVR protects sensitive loads and equipment.

The conventional DVR is expanded to function as a fault current interrupter. A control strategy is proposed in by employing additional bidirectional thyristors within the conventional DVR system. The DVR operates in fault limiting mode with 100% voltage injection capability. The fault is detected and the voltage introduced by the DVR is changed within one cycle. The injected voltage is out of phase with the supply voltage, which cancels the effect of supply voltage and decreases the magnitude of the fault current to keep it within the nominal rating of circuit equipment/devices.

The detailed implementation of this strategy is descripted in paper [5].

10.3 Use Case Analysis

The performance of the mentioned topologies was evaluated by performing different fault scenarios in the PSCAD/EMTDC environment on a radial system and the CIGRE-IEEE model for the North American low-voltage industrial system.

The following shows the analysis of the use case.

10.3.1 Fault Current Limitation During a Three-Phase Fault

The test system is subjected to a three-phase short circuit fault. This case study evaluates the performance of the saturable reactor and the DVR as FCL devices.

10.3.2 Fault Current Limitation During a Phase-to-Phase Fault

The test system is subjected to a line-to-line fault (i.e. Phase B to Phase C).

10.3.3 Fault Current Limitation During a Single-Phase-to-Ground Fault

Phase B of the test system is subjected to a permanent fault.

The detailed implementation of this strategy is shown in paper [5], which also references similar work discussed in publications and research papers [85]-[100].

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10.4 Conclusion and Recommendations

This project implements two fault current limiting techniques based on a saturable reactor and the DVR. The case studies are implemented on:

- A radial system.
- The CIGREE-IEEE low-voltage system.

Magnetic saturation of the core is controlled by DC bias, which changes the reactance inserted in the line of the system based on the fault condition. The fault limiting strategy, implemented for both balanced and unbalanced fault scenarios, is presented based on time-domain simulation studies in the PSCAD/EMTDC simulation environment.

The results show that as an FCL, the saturable reactor limits the flow of fault current in less than one cycle, while the DVR requires an unknown number of cycles.

In comparison to the DVR, a saturable reactor limits the fault current to a lesser value. Therefore, it does not require replacement of existing (low power rating) switches (and other equipment). In short, the saturable reactor is faster and cheaper than the DVR.

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11. CIEE Study Analysis

11.1 Research Objective

The Alstom/GE microgrid controller that was deployed/tested at the Philadelphia Navy Yard could in theory be supported in a variety of its anticipated functions by distribution synchrophasor data (µPMU). An earlier report [6]by CIEE discussed various strategies by which the 20 functionalities of the microgrid controller (enumerated in Alstom/GE's Test Plan) might be enhanced by such measurements. State estimation, or more simply the estimation of real-time voltages, loads and power flows in various parts of the network based on limited available measurements, is a fundamental enabling component of several of these 20 functions. Synchrophasor data have the potential to assist in state estimation, contributing extremely high-fidelity measurements that can inform any power flow calculations or control algorithms.

The purpose of this report is to investigate the limitations of these methodologies that should be expected, in practice, due to errors introduced by instrument transformers. The micro-phasor measurement units (µPMUs) which are slated for deployment at TNY microgrid, can provide voltage and current phasor measurements with accuracies to within 3.6 degree-seconds (0.001 degrees) of angle and 2 PPM in magnitude. However, the precision of a µPMU's end-product data will be limited in its practical application by the need to connect that µPMU through instrument transformers when dealing with TNY's 13.2 kV distribution lines. Instrument transformers, including both potential transformers (PTs) and current transformers (CTs), significantly degrade the accuracy of µPMU measurements. This effect has come into play in other CIEE synchrophasor projects and remains an important source of limitation for some µPMU applications, but not others.

Understanding the nature of transducer errors and their propagation through power flow calculations is an important initial step in determining the role of µPMUs in operations or analysis in any given deployment. CIEE's work on TNY project is directed toward building that understanding.

The following sections of this report describe our preliminary attempt to quantify the effects of instrument transformer-induced measurement error on various applications and use cases for a limited subset of the distribution network at TNY – namely, the GridSTAR circuit – using best guesses and typical values where no detailed component models were available.

11.2 Research Methodology

To quantify the error in power calculations introduced by instrument transformers, our group ran a large number of simulated power flow calculations with voltage values perturbed by stochastic transformer error.

The first step of the analysis, which is the establishment of "true" voltage phasor values for a given set of loads, was carried out in GridLAB-D using a model of the GridSTAR microgrid and consisting of a single-phase, seven-bus approximation of the network that is meant to reproduce the connection diagrams from the TNY test plan. As such, all nodes in the network lie along a single branch of the distribution feeder that begins at Substation 664 and ends at a normally open switch on the far side of Building 101. Substation 664, the Chapel of Four Chaplains, the EV charging station, the energy storage facility, the Zero Net Energy (ZNE) House, Building 100, and Building 101 are considered to be connected in that order.

The detailed GridSTAR model is shown in paper[6].

The second step is to run error modeling analysis by perturbing the voltage phasor values with simulated transformer error. For this analysis, reasonable error values were based on instrument transformer manufacturer specifications. Instrument transformer accuracy is an established concern. So, these specifications are given in terms of well-defined requirements. There are several classes of instrument transformer accuracy defined by IEEE standard C57.13, each of which has a burden-dependent threshold for allowable error. In the portion of the IEEE standard covering potential transformers, an error is assumed to take the form of a phasor multiplier. For example, an error term that affects a voltage phasor by directly multiplying its magnitude and by adding to its angular value.

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The detailed transformer error modeling procedure is shown in paper[6].

11.3 Use Case Analysis

11.3.1 Case 2: Voltage and Current Measurements Available

As mentioned in the objective, the bulk of the analysis described in this research is aimed at understanding transformer-induced error in power flow when calculated from voltage phasor measurements alone. This is discussed in detail in the next subsection. In the alternative case, where current measurements are available as well, it's possible to calculate a worst-case bound on the error in estimated power at any node.

The detailed use case analysis is shown in paper[6].

11.3.2 Case 2: Voltage Measurements Only

Where current measurements are not available, instrument transformers can have significant impact on µPMU inputs to power calculations.

The detailed use case analysis is shown in paper [6].

11.4 Conclusion and Recommendations

Table 11-1 summarizes the expected impacts of transducer errors and their propagation through power flow calculations and thus state estimation, relative to the specific 20 functionalities of interest in the Test Plan.

Table 11-1 Impacts from Transducer Errors

No.	Function	Potential Contribution from µPMUs	Description
1	Operating Mode Management	High-resolution µPMU measurements on the microgrid can be included among other input data in the decision algorithm to inform which operating mode is appropriate at a given time. The high-resolution measurement of grid frequency and ROCOF can provide an early indication of oscillations prior to conventional threshold triggers.	Depending on frequency measurement, this application is unlikely to be affected by transformer error.
2	Detection Of Unintentional Islanding	By direct comparison of the voltage phasor on either side of the PCC, µPMU measurements can assist in identifying an islanded condition.	Transformer error will decrease the precision of phasor angle comparison to the level of the transformer's accuracy. But, µPMU data could still be used in detection methods based on frequency or parameter changes in time.
3	Load Reporting	µPMU measurements streaming at up to two samples per cycle (120 samples per second) will provide extremely high-resolution reports of load at suitable level of spatial aggregation to inform resource control and forecasts.	Visualization of transients or other timeseries behavior are unlikely to be affected by transformer error. Estimations of absolute power demand could be significantly affected in the case where current measurements are not available.

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No.	Function	Potential Contribution from µPMUs	Description
4	Storage Unit Status Reporting	µPMU measurements streaming at up to two samples per cycle will provide extremely high-resolution reports of storage unit status.	Time-series measurements related to charging or discharging are unlikely to be affected by transformer error. Absolute voltage measurements meant to be used in determining state of charge will have precision reduced to the level of the transformer's accuracy.
5	PV and Generator Performance Reporting	µPMU measurements of magnitude and phase angle, streaming at up to two samples per cycle, will provide extremely high-resolution reports of PV, inverter and generator performance.	Frequency-based fault detection, operating status detection/confirmation, and other similar analytics are unlikely to be affected by transformer error. Estimations of absolute power generation will be significantly affected in the case where current measurements are not available.
6	PCC Monitoring	µPMU measurements at the PCC will provide high-resolution (120 samples per second) time series recording of voltage, frequency, real and reactive power.	Frequency monitoring is unlikely to be affected by transformer error. The precision of voltage measurements will be decreased to the accuracy of the transformer. Estimations of power demand will be significantly affected where current measurements are not available.
7	Planned Disconnection	µPMU measurements will monitor load/generation matching on the microgrid at high time resolution to support stability and forecasting.	Frequency measurements and the detection of potentially relevant transients are unlikely to be affected by transformer error. Absolute measurements of voltage or phase angle differences will be affected to the level of the transformer's accuracy, though sustained observation could mitigate the effects by establishing expected error adjusted voltage and phase angle differences at connection points.
8	Unplanned Disconnection	µPMU measurements can support load shedding during unplanned disconnection in the following ways: • Inform load-shedding decisions. • Validate load shedding. • Monitor response of loads to transients to avoid unintentional tripping of critical loads.	Unlikely to be affected by transformer error. µPMUs should be very effective in reporting load volatility, which could be used as an input to load-shedding decisions. They will also be an effective means of confirming load disconnection based on frequency measurements.

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No.	Function	Potential Contribution from µPMUs	Description
9	Load Control	µPMU measurements will dramatically increase the time resolution of load monitoring and validate the response to on/off signals.	As in the load reporting task, visualization of transients or other time-series behavior are unlikely to be affected by transformer error. Estimations of power demand could be significantly affected where current measurements are not available.
10	Feeder Control	High-resolution µPMU measurements could provide verification of feeder control operations and observation of transient response to connect/disconnect operations at the feeder level.	Any time-series measurements are unlikely to be affected by transformer error. Power estimations could be significantly affected where current measurements are unavailable.
11	DER control	High-resolution µPMU measurements could provide the following support for DER control: • Verifying DER control operations. • Comparing current source vs. voltage source inverter modes. • Observing transient response to DER control operations at the generator bus.	As in the generator reporting task, frequency-based fault detection, operating status detection/confirmation, and other analytics are unlikely to be affected by transformer error. Estimations of power generation could be significantly affected where current measurements are not available.
12	PCC Disconnection	µPMU measurements would support the development of a phasor-based control (PBC) strategy for refined synchronization that uses DER to drive the voltage phasor difference across the PCC to zero before opening the switch.	Any PBC techniques would need to be robust to the levels of phasor error discussed in the report.
13	PCC Reconnection	Analogous to the above, a phasor based control (PBC) strategy would use DER to drive the voltage phasor difference across the PCC to zero before closing the switch.	Any PBC techniques would need to be robust to the levels of phasor error discussed in the report.

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No.	Function	Potential Contribution from µPMUs	Description
14	Computation of References for Local Controllers	µPMU measurements could inform the computational algorithm through archival data at high time resolution to account for short-term volatility.	Power-related reference calculations would be significantly affected by transformer error in the case where current measurements are not available. However, µPMU archival data could still provide utility an understanding of the expected volatilities of energy resources. Measurements of volatility would be unaffected by transformer error.
15	Load Priorities Management Lookup Table	µPMU measurements would increase the time resolution for load and power flow tracking, to allow for the observation of dynamic behavior.	Estimations of absolute power demand could be significantly affected where current measurements are not available. However, µPMU data would still be able to contribute to an understanding of the dynamic behavior of system loads.
16	Load Shedding/Pickup Algorithm	µPMU measurements would support evaluation of the microgrid load pickup capability by including dynamic behavior and short-term volatility, down to the sub-second level.	As above, estimations of absolute power demand could be significantly affected where current measurements are unavailable. However, µPMU data would still be able to contribute to an understanding of the dynamic behavior of system loads.
17	Resynchronization Check	µPMU measurements would monitor the voltage phasor difference across the breaker. µPMU data would also provide frequency and ROCOF.	Frequency measurements and the detection of potentially relevant transients are unlikely to be affected by transformer error. Absolute measurements of voltage or phase angle differences would have precision reduced to the level of the transformer accuracy discussed in this report.
18	Power Dispatch	µPMU data could inform the dispatch algorithm to support efficient, economical and stable operation via the following: • Real and reactive power measurements. • Increased time resolution. • Data mining supported by extremely fast searches of archival load and generation data at full resolution in BTrDB.	Calculations of real or reactive power would be significantly affected by transformer error in the case where current measurements are not available. However, µPMU archival data could still provide the utility an understanding of the expected volatilities of energy resources. Measurements of dynamics would be unaffected by transformer error.

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No.	Function	Potential Contribution from µPMUs	Description
19	Stability Control	Voltage measurements will validate bus voltage stiffness. Correlation of precisely time stamped voltage and current measurements in the BTrDB would support analytics to determine source impedance and disaggregate causes of voltage variations.	Voltage measurement precision would be reduced to the level of transformer accuracy. The ability of µPMU data to support dynamics-based analytics would be unaffected.
20	Adaptive Protection Settings	High-resolution µPMU measurements would allow for a refined classification of operating modes to include a gradation of stress levels, in both islanded and grid-connected modes, based on frequency stability, voltage stability, and phase imbalance.	µPMU ability to measure frequency stability will be unaffected by transformer error. Voltage and phase measurement precision will be reduced to the level of the transformer's accuracy.

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12. Technology Transfer

12.1 Publications

R. Khan and A. Mehrizi-Sani, "Comparison of fault current limitation with saturable reactor and dynamic voltage restorer," accepted for the 2017 IEEE PES General Meeting, Chicago, IL, July 16-20, 2017.

12.2 Conference Presentations

"New York Power Summit" organized by EUCI at Millennium Broadway Hotel, New York April 20-21, 2015.

- Will Agate, Sr VP, TNY presented the PIDC Microgrid System and Plans.
- Dr. Jayant Kumar, Alstom Grid conducted Microgrid Workshops and presented the "Alstom DOE Project".

"IEEE PES General Meeting" organized by IEEE PES at Denver, July 26 to 30, 2015 - Dr. Jayant Kumar, Alstom Grid presented as a panel speaker on "Energy System Integration."

"World Protection, Automation and Control Conference" at Raleigh, NC, September 1 to 3, 2015 - S. S. Venkata and Jinfeng Ren, Alstom Grid presented a paper on "Emerging Distribution Grid and Microgrid: Advanced Architecture, Adaptive Protection, Control and Automation."

"US DOE–CHINA Climate coordination Working Group (CCWG) Meeting" organized by USTDA at Beijing, China, October 26 to 29, 2015–Dr. Jayant Kumar, Alstom Grid presented as a panel speaker on "The Navy Yard Microgrid Cost-Benefit Model and Analysis Methodology."

Jayant Kumar and Mani Venkata presented three panel sessions on the TNY microgrid controller project:

- Microgrid resilience in the 2016 IEEE PES General Meeting in Boston, MA during July 18-21, 2016.
- Mani Venkata made presentation on "GE/Alstom Microgrid Controller RD&D and Testing Project" in the Microgrid and DERs in the Evolving Distribution System Panel on July 19, 2016
- Mani Venkata and Jayant Kumar made presentation on "Enabling and Enhancing Resilience."

"The Navy Yard Case" in Measuring and Enabling Resiliency using Microgrid Panel on July 20, 2016.

Jayant Kumar and Mani Venkata participated in the DOE Microgrid Conference during August 16 and 17, 2016 at Chicago.

Mani Venkata made a WebEx based TechTalk presentation on "The Reality of Microgrids and Their Benefits to Society" to all GE Global personnel on August 18, 2016.

Mani Venkata organized a panel on Microgrid Controller at the IEEE-ISGT Conference at Minneapolis during September 6-9, 2016.

Mani Venkata participated in the P2030.7 draft review WebEx meeting on September 23, 2016.

Mani Venkata participated in the P2030.8 WG meeting at Schweitzer Labs., in Pullman, WA during September 27-28, 2016.

"Mani Venkata made two presentations on "The Reality of Microgrids and Their Benefits to Society" as an IEEE-DLP speaker on November 30 and December 07, 2016.

Mani Venkata participated in the P2030.7 and P2030.8 WG draft review WebEx meetings on October 14 and 28, 2016.

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Dr. Jayant Kumar presented the "Navy Yard Microgrid Project Modeling and Simulation Framework" at "UI-ASSIST" convention before the IEEE meeting, August 3, 2018, organized by WSU at Portland, OR.

Will Agate and Dr. Jayant Kumar presented "Optimizing Available Generation & Demand with Advanced Microgrids" at CIGRE Conference, August 27, 2018, organized by GE at Paris, France.

Dr. Jayant Kumar presented the "Navy Yard Microgrid Project-System Integration Design" at Microgrid Development in Pennsylvania – Case studies on Systems Integration and Controls, November 8, 2018, organized at Penn State University, Philadelphia, PA.

Dr. Jayant Kumar presented the panel titled "Philadelphia Navy Yard Microgrid – What Comes Next, an Exciting Story in the Making" at "Pennsylvania Energy & Innovation Workshop," November 8, 2018, organized by AMERESCO at Philadelphia Navy Yard.

Mr. Scott Hoyte, Managing Director, Microgrids, GE, as the keynote speaker, presented the "Future of Power" as "Pennsylvania Energy & Innovation Workshop," November 8, 2018, organized by AMERESCO at Philadelphia Navy Yard.

Dr. Jayant Kumar and Matt Nicholls presented the "Navy Yard Microgrid Control System Integrating On-Site Distributed Energy Resources" at On-Site Resilience Power conference, June 27, 2019, organized at Brooklyn NY by NYSERDA (New York State Energy Research Development Agency).

Dr. Jayant Kumar presented the "Philadelphia Navy Yard Microgrid Project" at "DOE UI Assist Annual Workshop," June 13, 2019, organized by Washington State University at Spokane, WA.

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A. Feasibility Study

A.1 Feasibility Study Approach

The Alstom project team applied an integrated approach for performing a feasibility study where the framework was developed to analyze and compute benefits of the advanced microgrid controller system to meet the targets driven by the DOE FOA objectives together with incremental objectives set forth by the Philadelphia Navy Yard.

A.2 DOE FOA Objectives and TNY Objectives

A.2.1 DOE FOA Objectives

Overarching DOE FOA objectives focus on the following three specific performance targets with the advanced microgrid controller:

- Reducing outage time of critical loads by >98% at a cost comparable to non-integrated baseline solutions (such as an uninterruptable power supply [UPS] with backup generator).
- Reducing emissions by >20%.
- Improving system energy efficiencies by >20%.

Critical loads as defined by the customer and electrical service to those loads must meet the stated DOE performance target of reducing outage time by >98%.

The term "emissions" refers to annual marginal emissions of carbon dioxide (CO_2), which are associated with the combustion of fossil fuels. The emissions baseline is the total annual marginal emissions of CO_2 associated with serving both the electrical and thermal loads within the area to be supplied.

A.2.2 TNY Goals and Objectives

The business problem that needs to be addressed by the Navy Yard Electric Utility (NYEU) is to determine the most cost-effective means for adding significant electric capacity—both in terms of the quantity of electricity required and in terms of installing new distribution infrastructure where it does not presently exist—and to keep customer electric costs as low as possible, but at least competitive with what each customer would pay if they were direct customers of the local regulated utility.

In understanding the business problem in overview, it is also important to understand that the NYEU must constantly develop goals and implementation that support the overall economic development agenda at The Navy Yard, which requires keeping existing business happy, attracting businesses to The Navy Yard, and in providing a place that attracts companies from outside of the greater Philadelphia region.

To address this business problem, the NYEU energy team developed a set of five goals to be achieved with various objectives and target benefits associated with each goal as shown in Table A-1.

Table A-1 The Philadelphia Navy Yard (TNY) Goals & Objectives

Goal	Goal Description	Objective / Target Benefits
Goal 1	Provide competitively priced energy supply to all Navy Yard customers	Reduction in total cost of ownership
		Reduction in electric bills
		Optimization of new asset operation
		Improvement in schemes for avoided Capital Costs
		Increase in new revenue stream due to markets and other mechanism
		Optimization of risk mitigation costs
		Improvement in Efficient use of real-estate
Goal 2	Continue to develop, brand and market the Smart Energy programs under development in order to attract more attention by energy-centric businesses, R&D entities and organizations	Reduction in system carbon footprint
		Improvement is sustainability and tenant attraction
		Increased potential public-private partnership
		Increased potential of grant research opportunity
Goal 3	Broadly attract businesses to The Navy Yard, in part drawn by progressively developing various alternative energy and energy efficiency offerings	Innovation in business models and customer collaboration models
		Improvement in sustainability and tenant attraction
Goal 4	Attract innovative companies interested in demonstrating and deploying energy-related technologies, business propositions, and practices particularly focused on distributive generation, storage and distribution and achieving energy efficiencies in buildings and over the electric grid	Innovative in business models and customer collaboration models
		Improvement in sustainability and tenant attraction
		Increased potential of public-private partnership
		Increased potential of grant research opportunity
Goal 5	Develop, demonstrate, and maintain sustainable self-funding business models around energy and energy efficiency projects	Innovation in business models and customer collaboration models
		Increased potential of public-private partnership

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A.3 Basis of Study Framework with map to DOE FOA and/or TNY Objectives

The framework for performing a feasibility study for The Philadelphia Navy Yard (TNY) is based on computing a set of project benefit to cost (B/C) ratios for a given set of microgrid operation scenarios compared to baseline operation scenarios defined as follows:

- Baseline operation scenario - In this scenario, there does not exist any microgrid controller or onsite generation.
- Microgrid operation scenarios – For the feasibility study purpose, three microgrid operating scenarios were defined as follows:
    - **Case 1**: This configuration was designed to reduce the outage to minimum possible duration subject to economic constraint for a SS602 sub-microgrid within the Philly Navy Yard, resulting into 0.8 MW of Fuel Cell, 2.75 MW of PV, and 4.25 MW Storage as shown in Table 4-1 in this report. Also, this configuration also meets the carbon reduction goal of more than 20% as stipulated by the DOE FOA.
    - **Case 2**: This case scenario is primarily driven by system efficiency gain objective through economic benefits realized by reducing peak charges. The scenario resulted in only 6 MW of IC Engine (Natural Gas Generation) at SS 602.
    - **Case 3**: This scenario is combination of Case 1 and Case 2.

Key focus on this feasibility study is to compute B/C ratios for each of the cases for microgrid operation scenarios with respect to baseline operation scenarios where benefits and cost assessment variables are categorized. See Figure A-1.

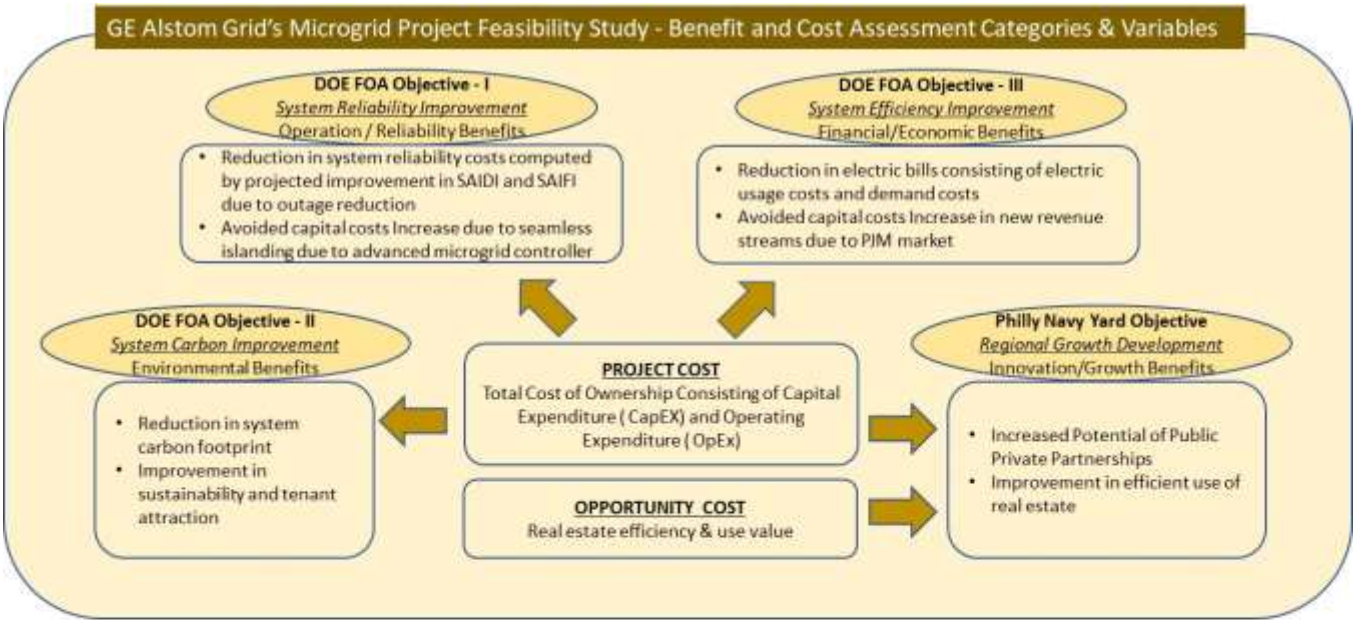

Figure A-1 Feasibility Study – Benefit and Cost Assessment Categories and Variables

A.4 TNY Benefit Stakeholders

An important component of the overall Navy Yard benefit Analysis is identifying the primary stakeholders in TNY microgrid project. Furthermore, each stakeholder is assigned a percent weight, called Stakeholder Percentage Weight (SPW) representing how much their preference will be given weight in decision making processes. TNY stakeholders and their corresponding SPW's are defined as shown in Table A-2.

Table A-2 The Philadelphia Navy Yard (TNY) Stakeholders their % Weightage

No	Stakeholder Long Name	Stakeholder short name	% Weightage in Decision Making
1	Philadelphia Industrial Development Corp	PIDC	40%
2	Tenant A (Tenant - Category A)	TNA	15%
3	Tenant B (Tenant – Category B)	TNB	10%
4	Detroit Edison Energy	DTE	5%
5	Philadelphia Electric Company	PECO	10%
6	The "Pennsylvania-Jersey-Maryland" Market	PJM	10%
7	Public-Private Partnership	PPP	10%

A.4.1 Stakeholder Descriptions

Philadelphia Industrial Development Corp (PIDC) – The Project Community Partner

PIDC is Philadelphia's public-private economic development corporation. PIDC took over the management of the Philadelphia Navy Yard (TNY) in early 2000. It has developed in to one of the region's strongest and fastest growing mixed-use commercial and industrial business campuses. As an important component of developing the overall TNY community, PIDC established a separate operation known as the NYEU, which owns and operates the unregulated electric distribution grid and provides services to TNY's 70 electric customers.

Tenant A (TNA)

Generally speaking, the electricity customers of TNY electricity utility are referred to as its tenants, of which there are currently approximately 70. It is important to realize that there are effectively two classifications of tenants, or customer, as determined by their size and level of sophistication when making their individual energy consumption decisions.

The stakeholder referred to as Tenant A represents the 9 largest electric customers at TNY that collectively consume approximately 90 % of all electricity. As high energy users, this stakeholder group as a whole has a significant impact on key parameters such as peak demand of the overall Navy Yard. Tenant A will likely be TNY's most invested stakeholder, shaping its energy use, and concerned whether alternative energy is available at TNY.

Tenant B (TNB)

The second classification of TNY electricity customers, Tenant B, represents smaller users. While B Tenants collectively use only about I0% of the total electricity consumption, they are roughly 60 of the 70 total customers. They also are very concerned with cost per kWh.

While significant differences exist between the profiles of Tenant A and Tenant B, each wants to demonstrate strong sustainability practices to its customers and is interested and engaged in achieving energy efficiency improvements within its overall business practices.

Detroit Edison Energy (DTE)

DTE is the third party firm that is contracted by PIDC to maintain and operate NYEU. Given DTE's overall responsibility for operating the utility as efficiently and effectively as possible, this stakeholder will share many of the same concerns that PIDC has for effective operations but is less invested in the financial performance of the alternatives being considered.

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Philadelphia Electric Company (PECO)

As the regulated public utility that delivers any of the off-site electricity to TNY, PECO is particularly interested in interconnection and the reliability of on-site DER alternatives. PECO has been an outstanding partner in supporting TNY electric utility initiatives. It is also very interested in grant and research opportunities of partnering between PECO and TNY.

The "Pennsylvania-Jersey-Maryland" (PJM) Interconnection

Considered one of the most forward thinking and progressive regional transmission operators (RTOs) in Northern America, PJM is also interested in the operational, security, optimization, and resiliency characteristic of alternative energy infrastructure. Additionally, PJM has established itself as a highly sophisticated innovative market designer. It will also continue to be particularly interested in demand response, smart buildings, vehicle and building to grid, dynamic markets, and grid interaction potential of each alternative being considered.

Public-Private Partnership (PPP)

One of the business models used to develop and implement energy generation and infrastructure projects at TNY is referred to as a public-private partnership (PPP). PPPs are often used by government entities to shift the economic and operational risk of certain projects and infrastructure investments to private sector entities eager to deploy capital and leverage expertise. Currently, several PPP entities are developing projects at TNY. Going forward, it is anticipated that more PPPs will be used to fully implement TNY's master plan. For these reasons, many of the same factors that are important to PIDC will also be important to PPPs.

A.5 Assessment Standard Variables & Weight Matrix for Benefit and Cost Calculations

Sixteen Assessment Standard Variables (ASVs) for the purpose of benefit and cost computations were defined. Given the differing perspectives of each of the above defined stakeholders, it was not only important to define the weight values for each of the 16 ASVs but also different weight dimensions were defined. All of the definitions used are as follows:

- ASC: Assessment Standard Category
- ASV: Assessment Standard Variable
- AWV: Assessment Weight Value (with respect to each variable)
- SPW: Stakeholder - %Weight (with respect to each stakeholder)
- SWV: Stakeholder Weight Value (with respect to each variable)
- SCW: Stakeholder Composite Weight (Calculated with respect to Stakeholders)
- ACW: Assessment Composite Weight (Calculated with respect to each of the variable)

Table A-3 shows the resulting Weight Matrix.

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Table A-3 Stakeholder Weight Matrix

	ASC	ASV	AWV	Stakeholder - %Weight (SPW) & Weight Value (SWV)							SCW	ACW
No	Assessment Standards Category	Assessment Standards Variable	Assessment Weight Value	PIDC 40%	Tenant A 15.00%	Tenant B 10.00%	DTE 5.00%	PECO 10.00%	PJM 10.00%	PPP 10.00%	Stakeholder Comp.Weight	Assessment Comp.Weight
1	Financial /Economic	Annual CapX Cost ($)	3	5	4		3		4	4	3.55	10.65
2		Annual OpEx Cost ($)	2	5						4	2.40	4.80
3		Annual Electricity Usage Cost ($)	2	5	5	5	3			4	3.80	7.60
4		Annual Electricity DemandCost ($)	3	5	5		3		5	4	3.80	11.40
5		Annual OpEx - Onsite DER ($)	3	5	4		3		4	4	3.55	10.65
6		Annual OpEx - Fuel Costs ($)	3	4	3		3		3	5	3.00	9.00
7		Annual Avoided CapEx Cost (-$)	3	5	4			5		5	3.60	10.80
8		Annual Revenue From DER (-$)	2	5	4	3	3	5	4	5	4.45	8.90
9		Financial Risk ($)	2	5	3		3	2	2	4	3.40	6.80
10	Iperational Reliability & Efficiency	System Reliability Cost Impact ($)	2	5	5	4	5	5			3.90	7.80
11		System Reliability Cost Gain($)	2	5				2	4	4	3.20	6.40
12	Environmental	System Carbon footprint ($)	2	4	4	4	4				2.60	5.20
13		Tenant impact & sustainability	3	5	5	4					3.15	9.45
14	Innovation & Economic Growth	Public-Private Partnership Value ($)	2	4	4					5	2.70	5.40
15		Grant/Research Opportunity Value ($)	2	3				4	4	3	2.30	4.60
16		Real Estate Efficient Use Value ($)	1	5				4	4	4	3.10	3.10

A.6 Feasibility Simulation Study Input Data

A.6.1 Input Set 1: Load Profiles

Figure A-2 shows the electrical Hourly Load Profiles for weekday.

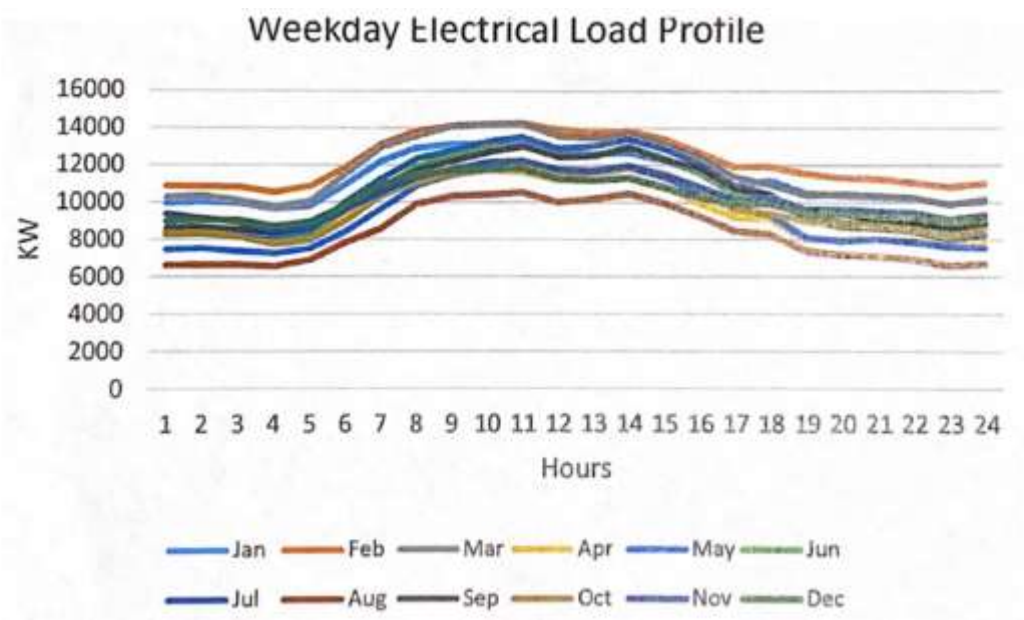

Figure A-2 Feasibility Study – Benefit and Cost Assessment Categories and Variables

A.6.2 Input Set 2: Utility Tariff and Fuel Price

- Electricity:
  - Average Usage Rates: $0.13 per kWh
  - Monthly Demand Charge for June, July, Aug, Sep: $30 per kWh
  - Monthly Demand Charge (exclude June, July, Aug, Sep): $10 per kWh
- Natural Gas: $0.78 per CCF ($0.026 per kWh)

A.6.3 Input Set 3 and 4: DERs Data

Available Distributed Energy Resources (use models provided by DER-CAM)

- DERs Options:
  - FC-med-30, (800 kW Fuel Cell)
  - Investment capital cost $2889/kW
  - Maximum output 800kW
  - 10 years lifetime, operation, and maintenance cost 0.33/kW
  - Efficiency 0.46 natural gas fuel
- Renewable Source and Storage Options:
  - 100,000 sqft possible space available for PV installation:
    - Investment fixed cost $3851
    - Investment variable cost $3237/kW
    - 30 year lifetime
    - Fixed operation maintenance cost $0.25/kW per month
  - Electric Storage:
    - Investment fixed cost $295,
    - Investment variable cost $300/kW
    - 5 year lifetime
    - No fixed operation and maintenance cost

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A.7 Feasibility Simulation Output Results

Feasibility Simulation study was structured in 2 parts as follows:

A.7.1 Part I – Development of Baseline for FOA Objective I Feasibility - System Reliability

Key Input/Consideration for this part of the feasibility study is summarized as follows:

- Outages in the Philadelphia Navy Yard may be attributed to two sources:
    - Outages/Fault due to Feeder on PECO side
    - Outages/Fault due to Feeder within The Philadelphia Navy Yard
- Reliability Performance Metrics for the PECO utility as published by Pennsylvania Public Utility Commission in Aug 2014 was as follows:
    - PECO_CAIDI 112 minutes
    - PECO_SAIDI138 minutes
    - PECO_SAIFI 1.23
- CAIDI for TNY Utility is averaged to be 90 minutes (TNY_CAIDI = 150 minutes)
- Total Outage duration during a 5-year period (2010 to 2014) prior to the beginning of the DOE project in TNY due to PECO is calculated as
    - TOD_DueToPECO = PECO_CAIDI * No of incidences in 5 years in Navy Yard due to PECO
- Total Outage duration during a 5-year period (2010 to 2014) prior to the beginning of the DOE project in TNY due to faults/outages internal to is calculated as
    - TOD_DueToTNY = TNY_CAIDI * No of incidences in 5 years in Navy Yard due to PECO
- The methodology used to calculate for projected Total Outage Duration Index (TODI) per year for The Philly Navy Yard Community (TNY) is as follows:
    - TNY_TODI = [TOD_DueToPECO + TOD_DueToTNY] / 5
- Table A-4 was created to capture all the outage incidents occurred in Philadelphia Navy Yard during the 5 year period prior to project start (from 2010 to 2014).

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Table A-4 Philly Navy Yard Outage History

Year /Date of Incidence	Line Impacted	Outage Source	# of Inc. Due to PECO	# of Inc. Due to TNY
12/16/2014	2468	PECO	5	0
12/16/2014	2470	PECO		
12/14/2014	2468	PECO		
12/14/2014	2469	PECO		
3/10/2014	2468	PECO		
7/31/2013	2470	Customer	3	2
7/28/2013	2468	PECO		
7/12/2013	2469	Customer		
4/12/2013	2469	PECO		
3/25/2013	2480	PECO		
11/30/2012	2480	Customer	7	3
11/18/2012	2480	Customer		
8/7/2012	2468	PECO		
8/6/2012	2480	PECO		
8/3/2012	2468	PECO		
7/28/2012	2469	PECO		
6/27/2012	2480	PECO		
6/13/2012	2480	Customer		
5/15/2012	2468	PECO		
4/25/2012	2480	PECO		
5/9/2011	2468	PECO	2	0
4/13/2011	2470	PECO		
11/29/2010	2468	PECO	3	2
10/1/2010	2468	Customer		
7/20/2010	2468	PECO		
7/14/2010	2469	PECO		
7/6/2010	2468	Customer		
		TOTAL	**20**	**7**

- Using the methodology described above, the following computations are performed:
  - TOD_DueToPECO = 20 * 112 = 2240 mins
  - TOD_DueToTNY = 7*150 = 1050 mins
- Baseline TNY Outage Duration Index = (2240+1050)/5 = 658 mins per year

A.7.2 Part 2 – Development of Baseline for FOA Objective II and III – Carbon and System Efficiency

Table A-5 shows the computed base case data.

Table A-5 Base Case Data

Item Description	Unit	Qty
Total Annual Energy Cost	$	25,159,148
Total Annual CO2 Emission	kg	87,093,843
Total Annual Electricity Purchased from Utility	$	22,028,503
Total Annual Electricity kWh Usage cost	$	16,629,777
Total Annual Electricity Demand cost	$	5,394,915
Total Annual Electricity Purchased from Utility	kWh	127,921,362
Total Fuel Cost	$	3,130,646

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A.7.3 Part 3 – Microgrid Operation Scenario Results

Microgrid operation cases-The microgrid controller optimization engine in conjunction with TNY tools was used for computation of each of the three cases (Case 1, 2, and 3) of microgrid operation.

Case 1

Table A-6 Case 1 Microgrid Operation Data

Item Description	Unit	Qty	Difference Compared to Base
Total Annual Cost (including investment annualization capital cost and energy cost)	$	24,702,418	-1.82%
Total Annual CO2 Emission	kg	84,233,080	-3.28%
From Utility-Total Annual Electricity Purchase	$	19,846,946	-9.90%
From Utility-Total Annual Electricity kWh Usage cost	$	15,021,087	-9.67%
From Utility-Total Annual Electricity Demand cost	$	4,822,049	-10.62%
From Utility-Total Annual Electricity	kWh	115,546,820	-9.67%
From on-site DGs-Total Annual Electricity	kWh	12,393,914	
From on-site DGs-Total Annual O&M cost	$	295,280	

Case 2

Table A-7 Case 2 Microgrid Operation Data

Item Description	Unit	Qty	Difference Compared to Base
Total Annual Cost (including investment annualization capital cost and energy cost)	$	23,566,047	-6.33%
Total Annual CO2 Emission	kg	86,664,385	-0.49%
From Utility-Total Annual Electricity Purchase	$	15,830,546	-28.14%
From Utility-Total Annual Electricity kWh Usage cost	$	11,604,687	-30.22%
From Utility-Total Annual Electricity Demand cost	$	4,222,049	-21.74%
From Utility-Total Annual Electricity	kWh	89,266,820	-30.22%
From on-site DGs-Total Annual Electricity	kWh	38,673,914	
From on-site DGs-Total Annual O&M cost	$	689,480	

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Case 3

Table A-8 Case 2 Microgrid Operation Data

Item Description	Unit	Qty	Difference Compared to Base
Total Annual Cost (including investment annualization capital cost and energy cost)	$	22,614,681	-10.11%
Total Annual CO2 Emission	kg	89,081,416	2.28%
From Utility-Total Annual Electricity Purchase	$	12,008,558	-45.49%
From Utility-Total Annual Electricity kWh Usage cost	$	8,198,558	-50.70%
From Utility-Total Annual Electricity Demand cost	$	3,806,190	-29.45%
From Utility-Total Annual Electricity	kWh	63,065,830	-50.70%
From on-site DGs-Total Annual Electricity	kWh	64,861,376	
From on-site DGs-Total Annual O&M cost	$	1,082,292	

A.8 Summary

Table A-9 shows the study results for benefit to cost ratio for the advanced microgrid controller integrated microgrid operation for each scenario.

Table A-9 Summary of Benefit to Cost Ratio

		MGC with 0.8 MW Fuel Cell (FC) 2.75 MW PV 4.25 MW Storage	MGC With 6 MW Natural Gas (NG) Generator	MGC With 0.8MW FC 2.75 MW PV 4.25 MW Storage 6 MW NG
	Scenarios -------->	**Case 1**	**Case 2**	**Case 3**
	Weighted Benefit to Cost (B/C) Ratio	2.92	4.24	6.12
	Total System Cost	$ 2,025,801	$ 2,408,338	$ 3,184,005
	Fianncial /Economic Benefit	$ 2,207,801	$ 7,678,780	$ 12,264,213
	Operation/Reliability Benefit	$ 334,256	$ 355,030	$ 466,857
	Environemntal Benefit	$ 958,202	$ 143,146	$ (666,067)
	Innovation & Growth Benefit	$ 125,000	$ 75,000	$ 150,000
DOE Target	**DOE FOA Objective**			
98%	DOE FOA Objective I - Outage Reduction	53%	48%	76%
20%	DOE FOA Objective II - Carbon Reduction	3.28%	0.49%	-2.28%
20%	DOE FOA Objective III - System Efficiency	1.82%	6.33%	10.11%

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Key observation and conclusions are as follows:

- DOE FOA objectives and partially met with respect to these targets:
    - Advanced Microgrid Controller improves the reliability performance at the maximum value of 76% when all the DER assets are deployed to serve critical loads in the event of outages.
    - Advanced Microgrid Controller marginally improves the carbon reduction at the maximum value of 3.28% in case of Case 1, which is quite obvious. Feasibility of more PV deployment is limited to Philadelphia Navy Yard's real estate restrictions.
    - Highest gain is achieved for system efficiency by advanced microgrid controller at the value of 10.11% in case of Case 3 as the controller exploits the benefits of PJM markets together with overall peak charge reduction.
- Overall benefit to cost ratio reflects the Navy Yard stakeholders and cost of benefit realization in an integrated manner as follows:
    - Case 1, which happens to be green only objective, has the least score of B/C. As mentioned, this scenario is driven by economics and real estate limitation in the Navy Yard.
    - Even though Case 1 has the least score of B/C, overall Case 3 (which does include Case 1 integrated with Case 2) happens to be the best B/C score, indicating the impact of combinatorial optimization performed by microgrid controller.

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B. Grid Price

This is the grid energy price used for various optimization simulation test case in Chapter 7.

Table B-1 Grid Energy Prices

Datetime beginning_utc	Datetime beginning_ept	pnode_id	pnode_name	type	system_energy_price_rt	total_lmp_rt
7/5/2014 4:00	7/5/2014 0:00	51288	WESTERN HUB	HUB	22.7425	22.573975
7/5/2014 5:00	7/5/2014 1:00	51288	WESTERN HUB	HUB	23.109167	22.986319
7/5/2014 6:00	7/5/2014 2:00	51288	WESTERN HUB	HUB	21.498333	21.378411
7/5/2014 7:00	7/5/2014 3:00	51288	WESTERN HUB	HUB	20.188333	20.071119
7/5/2014 8:00	7/5/2014 4:00	51288	WESTERN HUB	HUB	19.935833	19.850694
7/5/2014 9:00	7/5/2014 5:00	51288	WESTERN HUB	HUB	19.513333	19.426571
7/5/2014 10:00	7/5/2014 6:00	51288	WESTERN HUB	HUB	19.7725	19.689835
7/5/2014 11:00	7/5/2014 7:00	51288	WESTERN HUB	HUB	18.530833	18.480459
7/5/2014 12:00	7/5/2014 8:00	51288	WESTERN HUB	HUB	19.905833	19.80052
7/5/2014 13:00	7/5/2014 9:00	51288	WESTERN HUB	HUB	23.8025	23.916352
7/5/2014 14:00	7/5/2014 10:00	51288	WESTERN HUB	HUB	29.271667	29.260415
7/5/2014 15:00	7/5/2014 11:00	51288	WESTERN HUB	HUB	52.2875	54.270592
7/5/2014 16:00	7/5/2014 12:00	51288	WESTERN HUB	HUB	43.065	43.930135
7/5/2014 17:00	7/5/2014 13:00	51288	WESTERN HUB	HUB	38.430833	39.111534
7/5/2014 18:00	7/5/2014 14:00	51288	WESTERN HUB	HUB	48.170833	48.45083
7/5/2014 19:00	7/5/2014 15:00	51288	WESTERN HUB	HUB	60.688333	60.343366
7/5/2014 20:00	7/5/2014 16:00	51288	WESTERN HUB	HUB	108.291667	110.797535
7/5/2014 21:00	7/5/2014 17:00	51288	WESTERN HUB	HUB	57.620833	60.373457
7/5/2014 22:00	7/5/2014 18:00	51288	WESTERN HUB	HUB	178.261667	189.34185
7/5/2014 23:00	7/5/2014 19:00	51288	WESTERN HUB	HUB	51.381667	55.466406
7/6/2014 0:00	7/5/2014 20:00	51288	WESTERN HUB	HUB	40.278333	41.473138
7/6/2014 1:00	7/5/2014 21:00	51288	WESTERN HUB	HUB	38.706667	38.54663
7/6/2014 2:00	7/5/2014 22:00	51288	WESTERN HUB	HUB	33.549167	33.782184
7/6/2014 3:00	7/5/2014 23:00	51288	WESTERN HUB	HUB	34.236667	33.976483
7/6/2014 4:00	7/6/2014 0:00	51288	WESTERN HUB	HUB	31.141667	30.959582
7/6/2014 5:00	7/6/2014 1:00	51288	WESTERN HUB	HUB	23.8125	23.70717
7/6/2014 6:00	7/6/2014 2:00	51288	WESTERN HUB	HUB	22.920833	22.830633
7/6/2014 7:00	7/6/2014 3:00	51288	WESTERN HUB	HUB	21.91	21.787725
7/6/2014 8:00	7/6/2014 4:00	51288	WESTERN HUB	HUB	22.693333	22.330772
7/6/2014 9:00	7/6/2014 5:00	51288	WESTERN HUB	HUB	24.739167	24.233732
7/6/2014 10:00	7/6/2014 6:00	51288	WESTERN HUB	HUB	24.6625	24.233602
7/6/2014 11:00	7/6/2014 7:00	51288	WESTERN HUB	HUB	26.144167	25.532126
7/6/2014 12:00	7/6/2014 8:00	51288	WESTERN HUB	HUB	31.751667	31.17894
7/6/2014 13:00	7/6/2014 9:00	51288	WESTERN HUB	HUB	33.445	33.087577
7/6/2014 14:00	7/6/2014 10:00	51288	WESTERN HUB	HUB	33.6125	33.097777
7/6/2014 15:00	7/6/2014 11:00	51288	WESTERN HUB	HUB	39.5	39.231448
7/6/2014 16:00	7/6/2014 12:00	51288	WESTERN HUB	HUB	39.895833	40.563321
7/6/2014 17:00	7/6/2014 13:00	51288	WESTERN HUB	HUB	57.375833	56.126585
7/6/2014 18:00	7/6/2014 14:00	51288	WESTERN HUB	HUB	51.941667	52.308945
7/6/2014 19:00	7/6/2014 15:00	51288	WESTERN HUB	HUB	53.229167	51.759154
7/6/2014 20:00	7/6/2014 16:00	51288	WESTERN HUB	HUB	44.983333	44.220986
7/6/2014 21:00	7/6/2014 17:00	51288	WESTERN HUB	HUB	43.905833	42.842549
7/6/2014 22:00	7/6/2014 18:00	51288	WESTERN HUB	HUB	41.7575	43.645706
7/6/2014 23:00	7/6/2014 19:00	51288	WESTERN HUB	HUB	44.556667	45.681764
7/7/2014 0:00	7/6/2014 20:00	51288	WESTERN HUB	HUB	46.821667	47.407815
7/7/2014 1:00	7/6/2014 21:00	51288	WESTERN HUB	HUB	48.365	50.012542
7/7/2014 2:00	7/6/2014 22:00	51288	WESTERN HUB	HUB	36.791667	37.007027
7/7/2014 3:00	7/6/2014 23:00	51288	WESTERN HUB	HUB	35.35	35.591896

- **Datetime beginning_utc**: Beginning Hour of Energy Price Data (In Universal Time Stamp).
- **Datetime beginning_ept**: Beginning Hour of Energy Price Data (In Eastern Time Stamp).
- **pnode_id**: Grid Point of Common Coupling ID.

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- **pnode_name**: Grid Point of the Common Coupling Name.
- **type**: Grid Point of the Common Coupling Type.
- **system_energy_price_rt**: System energy price for that hour.
- **total_Imp_rt**: Total Import for that hour.