

Case Study: Implementing a Microgrid Protection and Control System for Avista's Shared Energy Economy Project

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Abstract—Microgrids provide assurance that electric power is available using reliable, resilient, and secure solutions for maintaining energy delivery with a high level of operating efficiency. This is achieved by integrating state-of-the-art protection, automation, and control schemes along with energy storage management and load-generation dispatch strategy.

This paper describes the authors' experiences in planning, designing, developing, testing, and validating a microgrid control system (MCS) implemented for Avista's Shared Energy Economy project. This project was implemented for a university campus consisting of two buildings supplied by one 13.2 kV utility feed. Each building contains a battery energy storage system (BESS), a photovoltaic (PV) rooftop installation, a building energy management system (BEMS) with optimization capability, as well as existing protection, control, and visualization systems.

The MCS serves as the protection, control, and monitoring layer for all assets within the extent of the microgrid, providing several different modes of successful microgrid operation: high-speed island detection and decoupling, grid-connected optimization mode, islanded mode operation, distributed energy resource (DER) and load management schemes, and automatic synchronization to the grid.

Details of system objective, design challenges, hardware selection, designed functionality, and communication and cybersecurity aspects are discussed, and results from controller hardware-in-the-loop (cHIL) testing are presented.

I. INTRODUCTION

The Washington State Department of Commerce's vision to promote clean energy via a grant to Avista Corporation is leading to innovative work on electric microgrid projects. Avista's pilot project of a microtransactive grid using a shared energy economy model focuses on demonstrating how distributed energy resources (DERs) can benefit consumers, prosumers, and the distribution system by orchestrating the operation of groups of assets based on system conditions and economic signals. The project and its studies will aim to develop use cases for efficient and reliable sharing of resources while maintaining grid resiliency.

A shared energy economy model can best be explained with an example from the transportation industry. To start a taxi company a decade ago, one would have needed a fleet of cars, a staff of drivers, and the resources required for a dispatch center. An individual or an entity owned the resources and required customers to pay for the services. Today, the industry is built on a shared economy model where anyone who owns a vehicle can share it to provide a service to a group connected

through the internet. Multiple individuals bound by a common set of taxi service rules now participate in a common market to share the cost and benefits. What would the shared economy model or the participation model mean for the energy industry?

Microgrids are small electrical grids capable of islanded operation separate from the main utility grid. These grids include high percentages of distributed power electronic energy sources including photovoltaic (PV) and battery energy storage system (BESS) sources. The fault ride-through capacities of these energy sources are smaller than those of conventional rotating energy sources. A microgrid control system (MCS), such as the one discussed in this paper, is used to address these inherent problems in a microgrid. The primary role of an MCS is to improve grid resiliency. Another objective of this project is to design an advanced, scalable, powerful, yet economical MCS solution that can be easily repeated by utilities as DERs become more prevalent. This MCS facilitates the sharing and optimization of DERs to improve building efficiency, renewable integration, grid coordination, and transactive energy use.

This paper details the system objectives, design challenges, hardware selection, designed functionality, communication and cybersecurity aspects, and results from controller hardware-in-the-loop (cHIL) testing. The design and optimization goals of the MCS are also discussed. In addition to improving grid resiliency, an MCS facilitates economic value exchange by sharing and optimizing the DERs and allowing transactive energy use while operating in parallel with the utility.

II. MICROGRID FUNCTIONALITY OVERVIEW

The Washington State University (WSU) Spokane campus was chosen for the pilot microgrid for several reasons, one of which was the switching abilities of the existing infrastructure.

Fig. 1 shows an overview map of the microgrid power system and the point of interconnection with the utility.

The point of common coupling (PCC) between the microgrid and utility includes an automatic transfer switch (ATS). The ATS includes a voltage-based automatic transfer scheme programmed in an intelligent electronic device (IED) to switch between the two available utility sources. The site includes campus building loads. The building energy management systems (BEMS) will be integrated into the MCS.

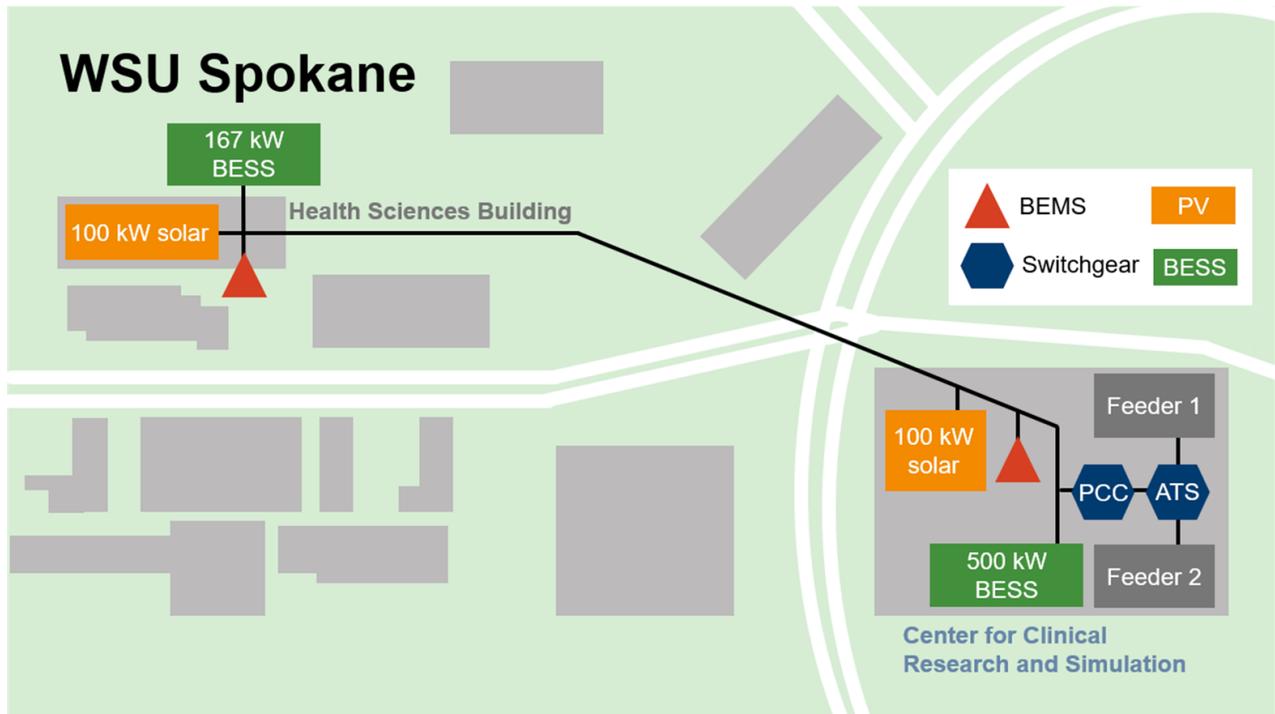


Fig. 1. Microgrid power system overview map

The site is strategically located so the project partners can collaborate on future research. The microgrid power system consists of two islands (north and south).

Each microgrid island will have one BESS, the south one (BESS 1) with an aggregate dc capacity of 756 kW/1,506.6 kWh, and the north one (BESS 2) with 168 kW/334.8 kWh. The BESS 1 inverter is rated at 500 kVA and the BESS 2 inverter is rated 250 kVA. There is also PV generation of 100 kW at each island. There are no rotational energy sources such as diesel generation connected to either island.

Fig. 2 shows the simplified one-line diagram of the proposed microgrid.

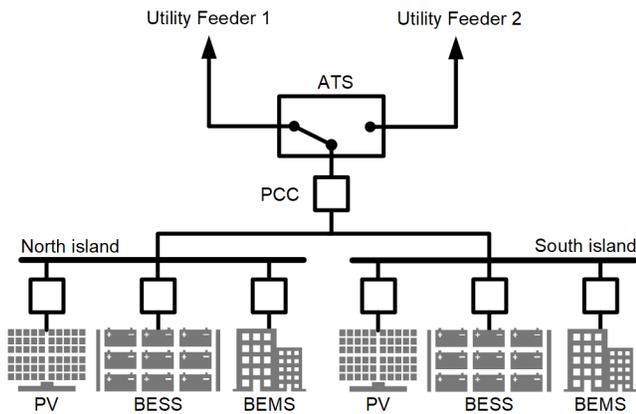


Fig. 2. Simplified one-line diagram of proposed microgrid

III. MCS

All hardware devices chosen for the MCS are protection-class substation-hardened equipment with extended temperature range, shock resistance, electromagnetic

immunity, and static discharge capabilities. Fig. 3 shows the MCS architecture using a layered and segmented representation. This architecture provides a logical representation of the MCS and is used to identify and define the security controls and patterns of the network design.

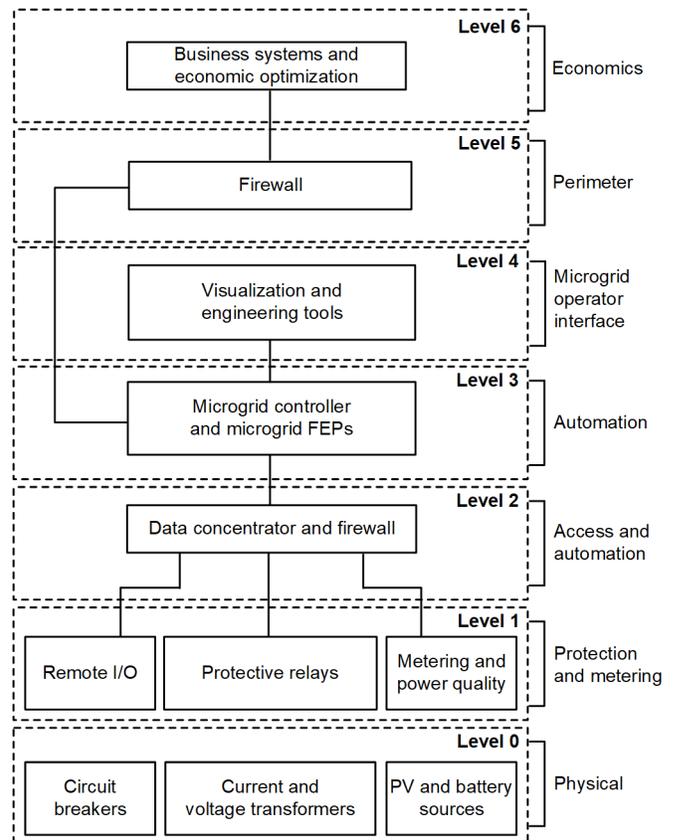


Fig. 3. Segmented MCS architecture

Level 0 comprises equipment within the microgrid power system. This equipment includes the circuit breakers, switchgears, instrument transformers, and energy sources. The devices at Level 0 integrate into the MCS via the devices in Level 1, which include protective relays, remote input/output (I/O) modules, and metering devices. The protective relays are required to protect the power system assets from damages during a power system fault. These protective devices are typically located at each PV site, BESS site, and the PCC between the utility and the microgrid. Apart from overcurrent protection, the protective relay at the PCC is also capable of localized controls, such as automatic transfer scheme or a synchronism-check element (25). Automatic synchronization schemes programmed in protective relays (A25A) adjust slip and voltage differences by having the MCS send raise or lower signals to a single DER. The meters at the electrical load center provide information about the electrical loads.

Level 2 of the MCS includes a data concentrator (DCON) that collects data from the protective devices, meters, and I/O modules and passes the information on to the devices in the upper levels. These data concentrators also serve as protocol translators and communicate securely with the devices at Level 2 using a standard set of protocols. This design allows the processing burden associated with the protocol translation to be limited to Level 2 devices. The stateful deny-by-default firewall (FW) at this level improves system awareness and provides the network segmentation explained later in this section.

Front-end processors (FEPs) provide great flexibility for microgrid scalability. They serve as the primary communications interfaces for all devices. The FEPs at Level 3 communicate with the data concentrators at Level 2 and collect information pertaining to the power system topology, load statuses, and DER statuses. The FEPs also communicate with external control systems, such as the distribution management system (DMS) and distributed energy resource management system (DERMS) at Level 6, to provide MCS visibility for operators. In certain cases, the FEPs also receive DER optimization control signals from the DERMS. It is important to maintain a single point of communications and a single control interface between the different control systems and the DERs in the field. The FEP in Level 3 serves as the data bus or the single point of communications integrating the different control systems. The MCS is always aware of the present state of the power system topology, fault conditions, and overall health of the DERs. Regardless of its mode of operation, the MCS continuously communicates the status of the power system and the DERs to the DERMS and the DMS. The DMS has the capability to shut down the MCS if required. Section IV of this paper explains the different modes of operation of the

MCS. The microgrid controller (MGC) at Level 3 is the brain of the MCS. It runs algorithms that make decisions and sends commands back to devices at Level 1.

Level 4 equipment includes a human-machine interface (HMI) that provides graphical system representations, access to real-time data, the ability to override points in a system, an interface with external management systems, and access to all supervisory monitoring and control functions. These visualization systems properly collect, manipulate, and present power system data as usable information. These systems enable operators, maintenance staff, and engineering staff to operate and manage the microgrid system and diagnose system events and minimize unnecessary maintenance. An electric power engineer can use these data for post-event analysis or fault diagnostics. Level 5 is the security perimeter that allows the MCS to communicate with other control systems, such as the DMS and the DERMS in Level 6. The MCS is designed such that any failure of equipment in Level 5 or Level 6 has no effect on the functionality of the microgrid.

A. MCS Network Architecture

Extreme care must be taken in designing a network for a critical infrastructure such as an MCS [1]. Designs involving a flat network reduce the number of switches and routers on the network, but they have drawbacks including poor security and lack of scalability. A segmented network approach was followed in designing the network for the MCS in this project. It is best to segment a network that follows the security principle that devices should communicate only with other devices that have a need to share data.

Network segmentation allows for fewer end points in a subnet, making it easier to set up end points for each type of multicast traffic. In addition, any broadcast traffic that is not filtered is much easier for devices to handle in a segmented network.

An intruder who gains access to a flat network can communicate with all devices on the network. On a segmented network, an intruder has access to only a portion of the network and must also gain access to individual subnets to cause significant damage.

Network management is simpler and more efficient when the network is segmented. Misconfigurations or device failures on a flat network are harder to detect, isolate, and fix. By segmenting the network into smaller, more manageable sections, the design implemented for the MCS can provide better security, resiliency, and control. A segmented network design also provides the distinct advantage of network scalability. Additional devices can be easily integrated into the network by extending the existing subnet with new device addresses or by adding a unique subnet for the new devices.

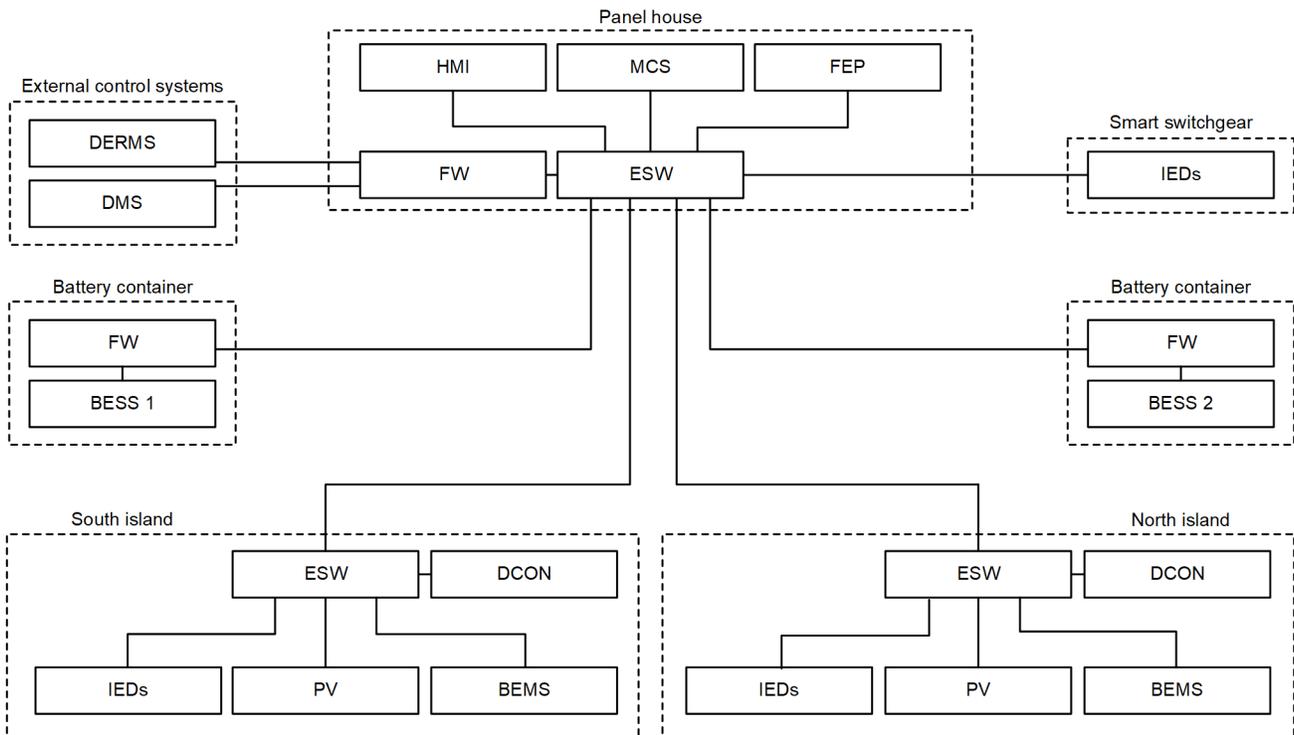


Fig. 4. Overall MCS network architecture

Fig. 4 shows the overall implemented architecture of the MCS and how typical DER assets and loads integrate with the central controllers. A typical PV, battery, and building site include Level 0, Level 1, and Level 2 devices. The FW device at Level 2 can be used to establish network segmentation between the different physical locations. The central control room (CCR) includes Level 3 and Level 4 devices. The FW at the CCR is the Level 5 FW that can be used to establish the MCS security perimeter. Relays in the smart switchgear and the external control system have dedicated fiber links to the microgrid CCR. The FWs at the ingress and egress points of each subnet allow rules to be established where multicast traffic within a subnet is contained within that portion of the network, reducing device load caused by multicast traffic. For example, rules can be generated on the segmented network to allow certain types of traffic to flow from the PV site to the CCR and not between the PV site and the battery site.

B. Data Flow Diagram

Data required for the operation of the MCS are collected from Level 1 equipment. The MCS also communicates certain important information with other control systems in Level 6. These data can be classified into high-speed data and low-speed data categories. Metering information, such as real power, load status, power factor, and voltage values required for calculating the actions, is not necessary at high speeds. Collecting all data at high speeds would require wide communication bandwidth, demanding additional communication infrastructure. In addition, the segregation of data into high speeds and low speeds has been proven to yield better performance on both large-scale and small-scale projects [2] [3] [4]. All digital and

analog data used by the MCS for calculations are based on speed and reliability. The MCS monitors the communications for failure at different levels of the network and selects the best data available. The final data used in the controller algorithms are chosen based on data quality. Data validation is accomplished by comparing the two sets of data and ensuring that neither is outside a given threshold from the other.

Data required for the operation of the MCS are collected from field devices using the Network Global Variable List (NGVL), IEC 61850 Generic Object-Oriented Substation Event (GOOSE), Distributed Network Protocol 3 (DNP3), and Modbus protocols. DNP3 and Modbus are traditional open-source protocols that operate on a client-server-based architecture, while GOOSE and NGVL operate as peer-to-peer protocols.

Fig. 5 shows the communications data flow diagram of the MCS. Communications between the DCON in the field and the centralized FEPs in the CCR will include both high-speed and low-speed data. The NGVL protocol is used as the primary protocol. The NGVL protocol allows data to be transmitted in a peer-to-peer format, using a configurable and flexible cyclic transmission interval between the DCONs and the FEPs. Message confirmations from remote devices using peer-to-peer protocols are required for the communications integrity. This can be achieved by establishing a data echo signal to ensure successful transmission. Network bandwidth allocations and timing of echo response signals should be taken into consideration while designing the data flow between devices using peer-to-peer protocols. Future provision for a second Open FMB protocol is also considered in the project design.

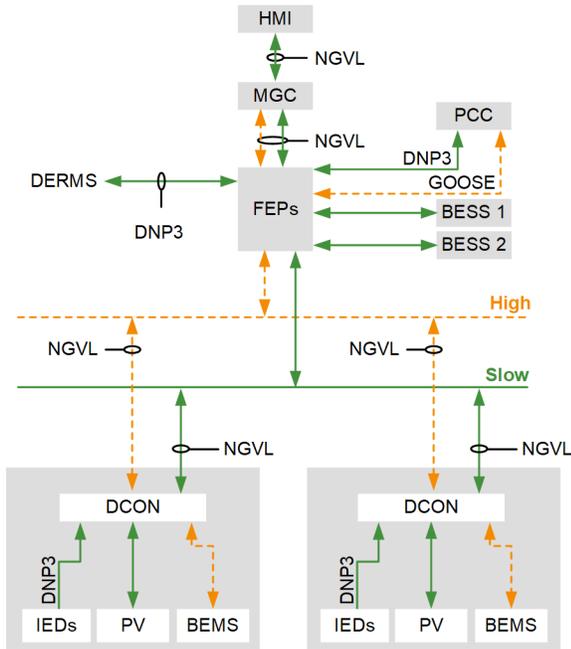


Fig. 5. Communications data flow diagram

C. HMI

The following sections show the HMIs developed for the project. This HMI (Fig. 6, Fig. 7, and Fig. 8) is also replicated at the DMS system for seamless integration with the current Avista DMS system for easy operation for the digital outputs (DO). Fig. 6 shows the overall HMI. The HMI includes a single-line diagram of the power system. This also allows the operators to view the status of each DER, including information such as state of charge (SOC), asset status (running, stopped, charging, or discharging), active power, reactive power, voltage, and frequency of the entire system in one glance. This also provides information to the operators regarding status of the MCS and current mode of operation. When the MCS is islanded, the total SOC and available operation time is also included as part of this screen.

1) Overall HMI

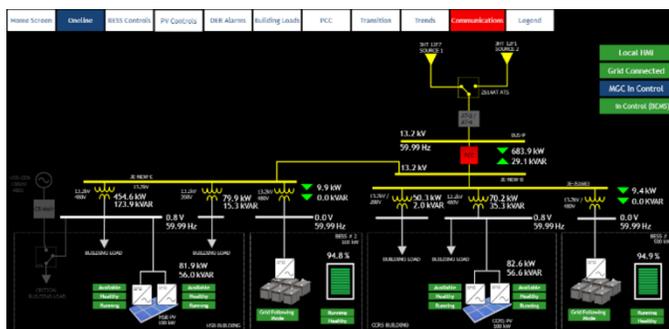


Fig. 6. Overall HMI

2) DER Status Screen

The DER status screen includes information such as auto or manual mode, along with the ability to manually control each of the DERs. This screen also features the ability to set the outage duration for the given utility so the MCS can manage the system loads by curtailing or restoring them to meet the

user-enterable set point. There is a unique screen for BESS and PV control.



Fig. 7. DER control

3) MCS Control

The MCS can operate in multiple scenarios, such as grid-connected or islanded. There are three transition periods during these stages, and they can be automatically or manually controlled using the MCS control screen. This screen also provides status while those transitions are in progress. The transition modes, such as automatic reconnect dead, automatic reconnect live, and black-start campus, can be set using this screen. Each of these transitions are explained in further detail in later sections.

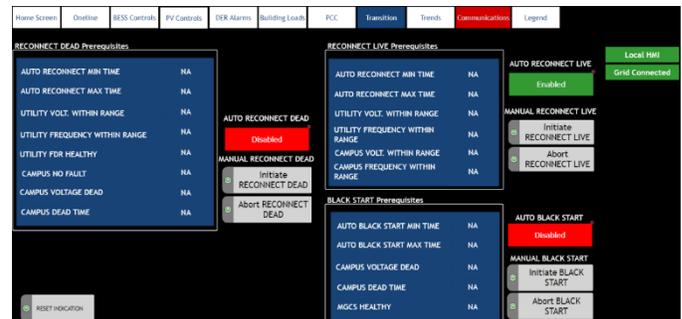


Fig. 8. MCS control

IV. MGC OPERATION

The microgrid power system is capable of operating in parallel with the utility in grid-connected mode and operating completely independently of the utility in islanded mode. The primary role of the MCS is to maintain power system stability whether operating in islanded mode or in grid-connected mode. It maintains the power system within the stability boundaries, or the boundary conditions set by the operator, by limiting the impact of user error or other third-party control decisions for optimization and protecting the DER assets.

The Avista WSU Spokane campus' MCS does not include seamless islanding due to project requirements and will either intentionally (during testing) or unintentionally (due to fault conditions) black out to initiate islanded mode. The MCS will manage the microgrid asset by allowing DERMS Spirae controls to manage loads, dispatch PV inverters, and dispatch BESS energy during grid-connected mode and assume full control during islanded mode the MCS will provide monitoring, visualization, and operator control during both grid-connected and islanded modes.

A. Grid-Connected Mode

During grid-connected operation the MCS passes on commands from the DERMS server based on DER optimization and economic operation decisions. The FEPs communicate the present state of the power system topology and overall health of the DERs to the DERMS. When DERMS is not available, the MCS continuously monitors and tracks the status of PV generation and present loading and load-status information. The MCS will then charge the batteries to their grid-connected maximum and await either islanded mode operation or return of DERMS. Because the MCS continuously monitors the topology of the power system, dispatch control signals are dynamically recalculated under all system bus configurations.

B. Islanded Mode

The MCS communicates with the smart switchgear to collect breaker status indications and voltage and current measurements to detect the loss of a utility tie. Although possible, seamless islanding of a microgrid was not applied for this use case. Automatic decoupling schemes using frequency, rate-of-change of frequency, and directional power elements were investigated and can be enabled in future stages of this project. These types of decoupling schemes are required to prevent damage to the microgrid components during a disturbance on the main utility grid.

After a microgrid island is formed, the MCS modifies the mode and dispatch of islanded generation and loads to keep the microgrid stable. The system keeps the frequency and voltage within allowable parameters for any number of islands. Load-shedding management is performed to disconnect loads in the microgrid after the formation of an island. This is to avoid cold load pickup that may trip the BESS asset. This also includes incremental load additions after the black-start process is completed. The MCS places BESS with greater SOC in terms of kWh in grid-forming mode and provides the voltage and frequency set-point reference for an island such that the PV sources can start providing power to the islanded microgrid. Once all available assets are energized, the MCS energizes all critical loads incrementally, and following critical load restoration, the MCS dispatches any excess energy in the islanded system to the noncritical loads based on the results of the SOC calculation. If there is additional energy available, the second grid-following BESS can be charged prior to PV curtailment.

C. Frequency Control

When the microgrid is islanded from the utility the MCS will select one DER for isochronous operation. The selected DER will regulate its power output to maintain a provided frequency set point on the island. An isochronous priority is assigned to each BESS based on available SOC in kWh.

Table 1
DER Mode Selection for Frequency and Active Power Control

DER	Grid-Connected	Islanded
BESS 1 and BESS 2	Grid-following Constant power (P) and (Q)	Grid-forming Grid-following*
PV 1 and PV 2	Constant power (P) and (Q)	Constant power Volt-VAR mode

*Only one grid-forming allowed in any given island

D. Voltage Control

When the microgrid is connected to the utility, the MCS does not control the voltage of the power system. In this case, all DERs at the campus will produce or consume reactive power based on a dispatch signal received from DERMS, or by an autonomous operating mode, such as volt/VAR, also known as voltage droop. The DERs will be either in a voltage droop mode or a constant power mode of operation when the microgrid is connected to the utility.

When the campus is islanded from the utility, the MCS will attempt to regulate voltage at the main bus at the PCC by adjusting the reactive power output of all participating DERs.

The MCS will command participating DERs to the following modes based on grid-connected or islanded operation.

E. BESS Strategy

During grid-connected operation, the BESS for the Avista microgrid will be primarily used for experimentation to achieve the use case evaluation outcomes that Avista has agreed upon with the Washington State Department of Commerce. Examples include optimizing PV utilization, distribution power quality and efficiency, and demonstrating participation in wide-area grid services.

While the campus is islanded, the BESS will provide backup power to a subset of loads on the WSU campus for as long as possible given the amount of load requested, battery SOC, and PV generation available. The BESS is controlled by its dedicated controller, which accepts set points from MCS.

The BESS control strategy is summarized in Fig. 9. Depending on the state of energy, the BESS will have three distinct areas of operation, which will in turn reflect the availability of BESS to charge or discharge energy. Each area is bounded by user-settable limits. The user-defined HMI-settable limits are defined as follows:

1. Full charge limit
2. Grid-limit
3. Islanded discharge limit

BESS can be controlled in Areas 1 and 2 during grid-connected mode and Areas 1, 2, and 3 during islanded mode. The reserve capability limit is provided for any emergency use and auxiliary loads for the BESS. The BESS will not be permitted to operate in Area 4.

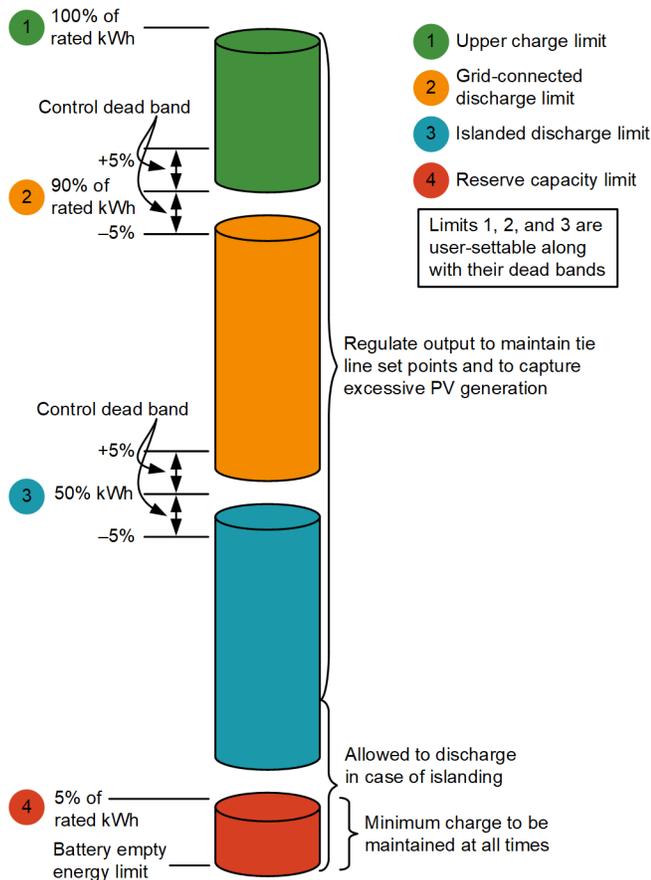


Fig. 9. Areas of operation

F. PV Strategy

There are a total of two installations of PV systems at Avista's MCS. Each PV system has two inverters with a dedicated controller accepting the power set points from the MCS. The main intent of PV dispatch is to displace the electricity consumption from the utility to evaluate smart inverter operation for the use case experiments.

The inverters have three main control modes, and they were investigated during testing:

- Constant Power mode, which generates fixed real and reactive power
- Volt-VAR mode, which regulates the grid voltage by supplying reactive power
- Frequency-Watt mode, which limits real power in case of high frequency

All PV output will be directed to serve the load or charge the BESS in the Avista MCS electrical network. The inverters will generate maximum electrical power based on irradiance and temperature. During grid-connected mode MCS will pass the controls from DERMS as long as it is within the use settable limits. PV output can be curtailed if no further loads are available to restore or BESS is fully charged and cannot absorb excess PV generation.

V. MCS TRANSITIONS

Unplanned islanding can happen due to a sudden loss of utility voltage, fault at the utility substation, or the opening of circuit breakers or switches in the utility system upstream from the microgrid.

These scenarios will likely result in a blackout. When the PCC is open, the MCS will issue a command to disconnect all DERs from the dead electrical system and set all set points to prepare for a manual or automatic black-start operation.

Once the system is blacked out, one or more of the following methods may be initiated.

A. Reconnect Dead

Reconnect dead is the process of connecting the microgrid to the utility after a blackout. This is the fastest way to restore power and operation after an event. This requires that the utility is available and healthy, and the campus has been dead for predefined time window.

The MCS will respond to a request to reconnect the dead campus to the utility by executing the following actions:

1. Confirm that the utility voltage and frequency are within healthy limits for the predefined time limit.
2. Confirm that the campus voltage is below the dead threshold for the predefined time limit.
3. Confirm via the breaker protective relay for dead bus and live utility scenario.
4. Close the campus PCC breaker to energize the campus.
5. Restore all system loads.

B. Reconnect Live

Reconnect live is the process of connecting the microgrid to the utility after a blackout, and power to the microgrid is restored. This is a seamless process that requires the utility to be available and healthy. The campus also needs to be available and healthy for predefined time window.

1. The MCS will respond to a request to reconnect the dead by executing the following actions:
2. Confirm that the utility campus to the utility voltage and frequency are within healthy limits for the predefined time limit.
3. Confirm that the campus voltage and frequency is within in healthy limits for the predefined time limit
4. Confirm via the breaker protective relay for live bus and live utility scenario..
5. Close the campus PCC using slip compensated algorithm to close when system parameters, such as voltage, frequency, slip, voltage difference and angle difference, are all within range.
6. Restore any system loads if curtailed during islanded mode are automatically restored following the PCC breaker close with mode transitions for the DERs assets.

C. Black-Start Campus

Black starting the campus differs from the Reconnect Dead Campus procedure because this sequence will start the campus under its own power using available DERs. This method will allow the campus to be restored and operate during a utility outage. If both the black-start campus and reconnect dead are set in automatic mode, the reconnect-dead sequence will start if the utility voltage is healthy and black-start campus will start if the utility is not available.

The MCS will respond to a request to black start the dead campus by executing the following actions:

1. Confirm that the campus voltage is below the campus dead threshold for a predefined time.
2. Trip all DERs, and noncritical loads from the campus island.
3. Enable BESS with highest SOC in grid-forming mode and establish system voltage and frequency.
4. Bring all DER assets online gradually.

Fig. 10 shows the MGC operational flow chart.

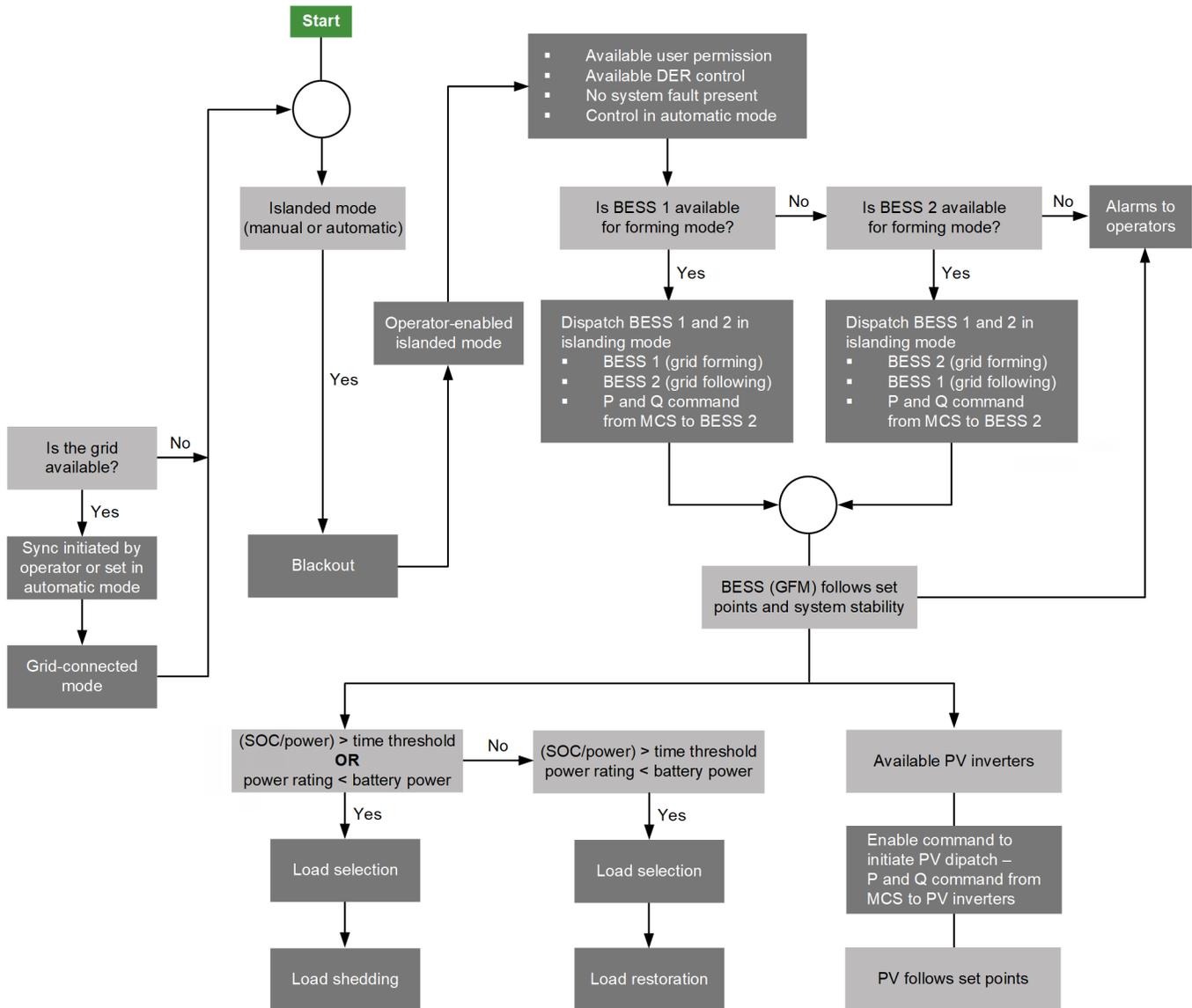


Fig. 10. Simplified MCS SOE flow chart

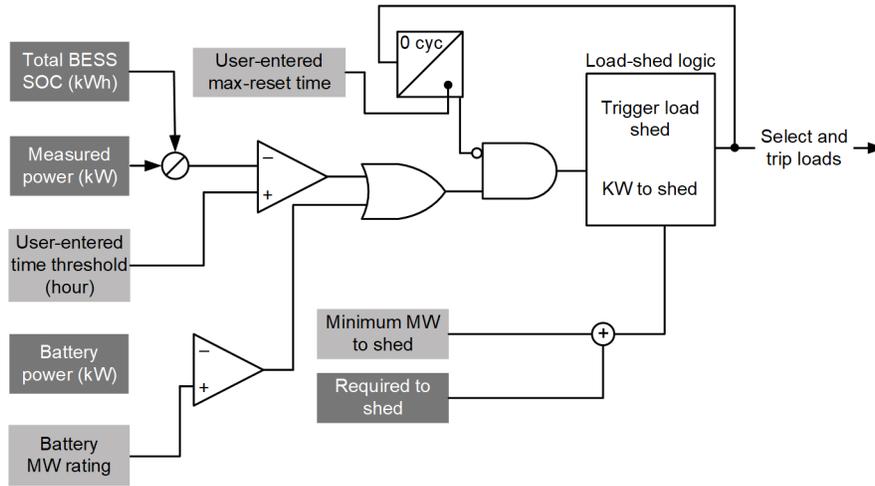


Fig. 11. Load management algorithm

VI. AUTOMATIC LOAD MANAGEMENT

The MCS performs automatic load management to equalize the load with generation for grid stability. For this project, access to individual load breakers was not available so a load management algorithm was utilized to manage system loads. Fig. 11 shows the load management algorithm where additional loads are shed if available SOC limits the operation of the MCS outside of user-defined outage time, whereas if calculated outage time is smaller than available SOC, loads are restored. The load restoration or curtailment is based on user-defined priorities that can be set from the HMI, as seen in Fig. 12.

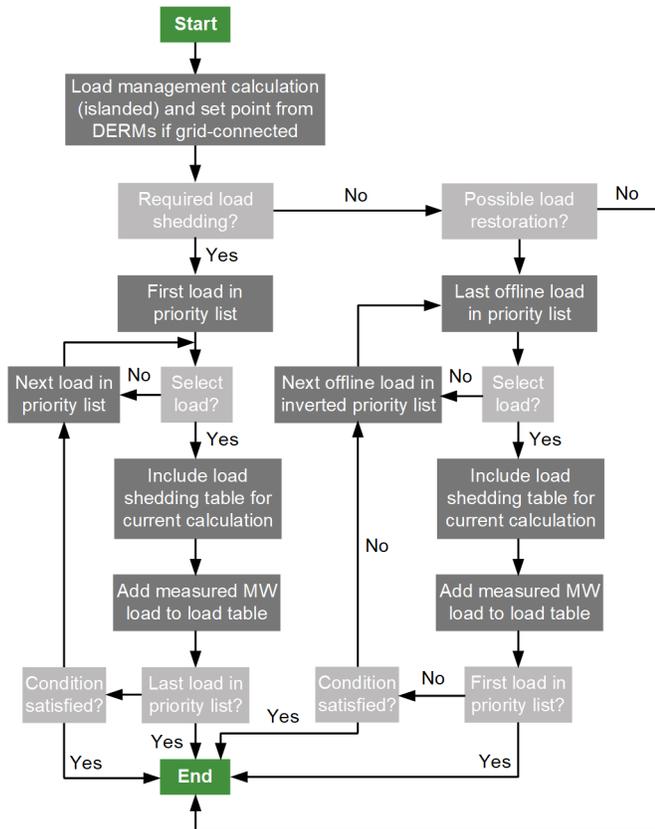


Fig. 12. Load selection logic

VII. MG PROTECTION

Avista’s microgrid protection is designed to protect the campus during grid-connected mode and islanded mode. The breaker protective relay installed at the PCC will be the primary protective device along with fuses and DER assets. The system has built-in protection from any abnormal operation. Fig. 13 shows the protection scheme and elements implemented for Avista’s MCS. The Yg/Yg transformer is used for interconnecting the DERs since this connection supports better ground faults and detection, and also prevents overvoltage induced by LG faults [5].

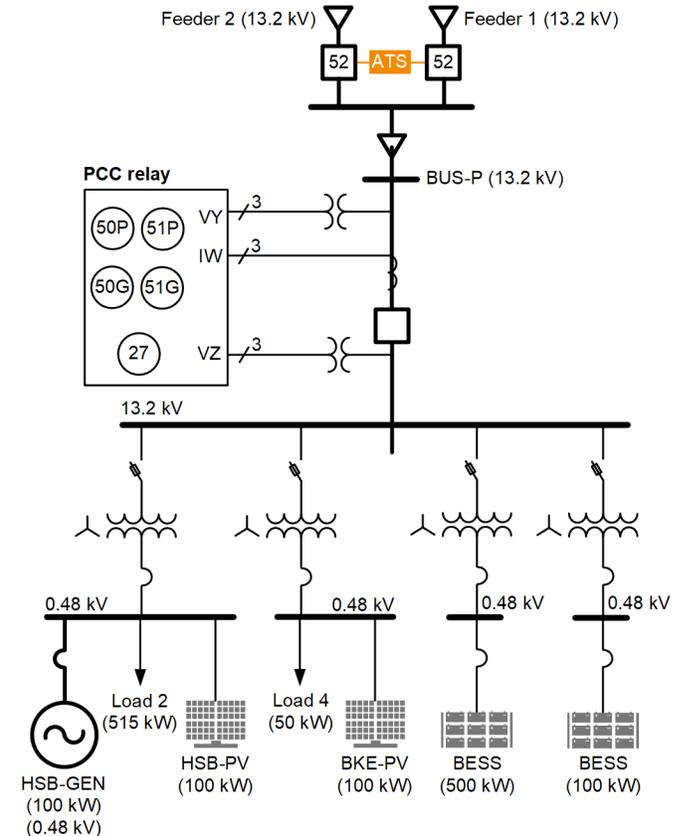


Fig. 13. Protection scheme and elements

A. Grid-Connected

During grid-connected mode, both internal and external faults can occur. The internal faults, which can occur in the microgrid network during grid-connected mode, will have sufficient fault contribution from the utility. The overcurrent elements enabled on the breaker protective relay at the PCC will detect those faults and protect the microgrid network components (transformers, cables) by tripping the PCC breaker. Phase time-overcurrent (51G1), phase instantaneous (50P1), residual-ground time-overcurrent (51S2), and residual-ground instantaneous (50G1) were enabled in coordination with transformer's high side fuses for phase and ground fault protection.

It was confirmed that DERs will stop their contributions independently for the prolonged internal faults on the microgrid 13.2/0.48 kV network and provide a faulted status to the MCS.

For external faults on the utility side distribution network, the PCC relay cannot detect low fault current contributed from online DERs, hence, the relay is insufficient for making tripping decisions. This can be investigated in the future for this project.

For close in external faults, it was confirmed that all the DERs will stop their contributions and alarm the operators based on the fault detection and will not restart until they receive the START command from the MCS.

B. Islanded

When the MCS is islanded, overcurrent elements enabled on the breaker protective relay will be unable to protect the islanded grid. The fuse in the high side of transformers will not operate for the fault on 13.2 kV buses because of insufficient contribution from the DERs. It was confirmed DERs will stop their contributions independently for the faults on the microgrid's 13.2 kV or 480 V networks.

The undervoltage (27) element supervised was utilized with the PCC breaker status as backup protection of the microgrid for faults in the MCS network. The delay on the 27 elements will incorporate the response time of the DERs after the instant of islanding and the time required by the DERs to clear the fault on the 480 V side. If the undervoltage condition rides through the delay on the 27 element, the breaker protective will give the command to isolate all the DERs feeding the faults via MCS.

VIII. HARDWARE-IN-THE-LOOP (HIL) TESTING

The main objective of real-time HIL testing of this concept microgrid is to analyze the combined performance of the MGCs and other control systems, such as DERMS or BEMS. A real-time simulator allows for dynamic modeling of the microgrid

and the utility power system interconnection with a simulated small-time step to test all closed-loop controls. The power system model built-in the real-time simulator will represent the Level 0 equipment in the microgrid. The real-time simulator I/O module allows the dynamic model to interface with relays, meters, and other equipment in Level 1 and higher levels.

Significant time and effort are devoted to configuring and testing the power converter models and communications interface between different components of the MCS.

A. Model Development

The model developed for real-time digital simulator testing will represent the complete system based on the simplified one-line drawing approved by Avista. The data required for modeling different power system components (generators, transformers, distribution lines and cables, and loads) shall be provided by Avista. Appropriate assumptions were made based on its previous modeling experience at places where there are insufficient data.

B. PV Validation

The objective of this section is to show the model development and validation for the two developed real-time digital simulator 100 kW PV systems.

Fig. 14 shows the schematic of a two-level voltage source converter (VSC) grid-connected PV system. The main building blocks of the PV system are an array of panels, a VSC, and interface reactors. The PV array is comprised of a parallel and series connection of strings of modules. The PV array is connected in parallel to the dc-link capacitor (CAP dc) and the dc-side terminals of the VSC.

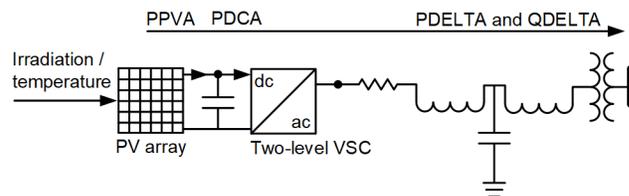


Fig. 14. Typical circuit of a PV system

The PV inverter is modeled as a VSC using an average converter model with low loss. Typically, the topology of actual control systems is not made available by the manufacturer. For this reason, a traditional direct-quadrature (DQ) current mode VSC controller strategy was adopted [5]. The interface reactors connect the ac-side terminals of the VSC to the corresponding phases of the PCC.

The PV module is a function of three inputs: irradiance watts per square meter (W/m^2), temperature ($^{\circ}C$), and module dc voltage. To analyze the effect of external factors on the PV

power, a PV module needs to be simulated to represent semiconductor material characteristics. Then, a set of curves must be developed by varying the irradiance input to analyze the power versus voltage curve and current versus voltage curve (Fig. 15).

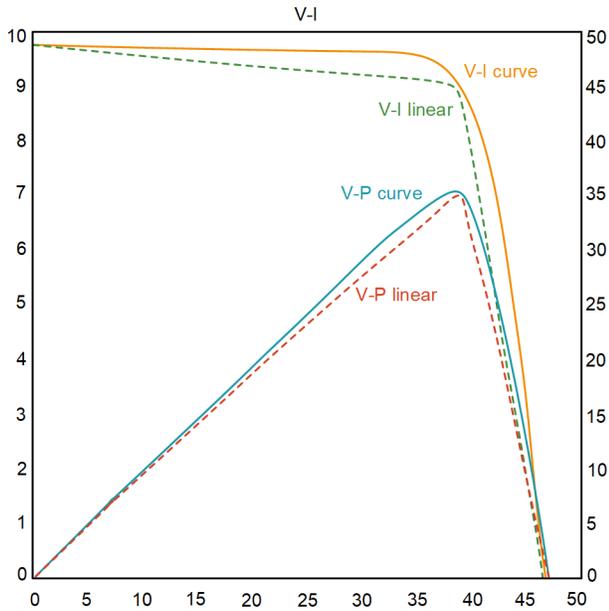


Fig. 15. PV curves

C. BESS Validation

The objective of this section is to show the model development and validation for the developed real-time digital simulator BESS systems. To validate the BESS control and response. The control strategy is based on voltage control of a VSC, which is applicable to grid-connected and islanded modes of operation. The control strategy regulates voltage and frequency when the BESS is not connected to the grid and follows the active and reactive power command when connected to the grid.

A BESS load acceptance test was performed with field equipment. The BESS system is disconnected from the utility grid and placed in islanded mode of operation. A load of 0.5 MW is added, and the frequency settles around 60 Hz (Fig. 16). The frequency waveform of the simulated model (Fig. 17) is compared with the waveform obtained from the field to validate the system performance.

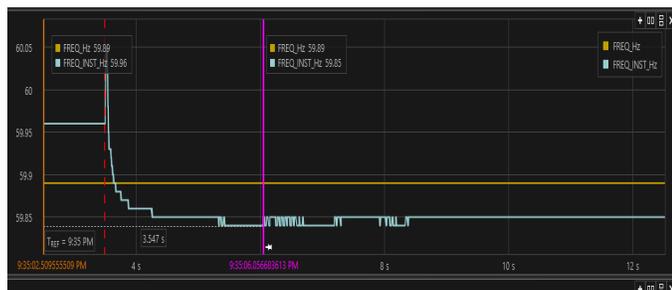


Fig. 16. Field result

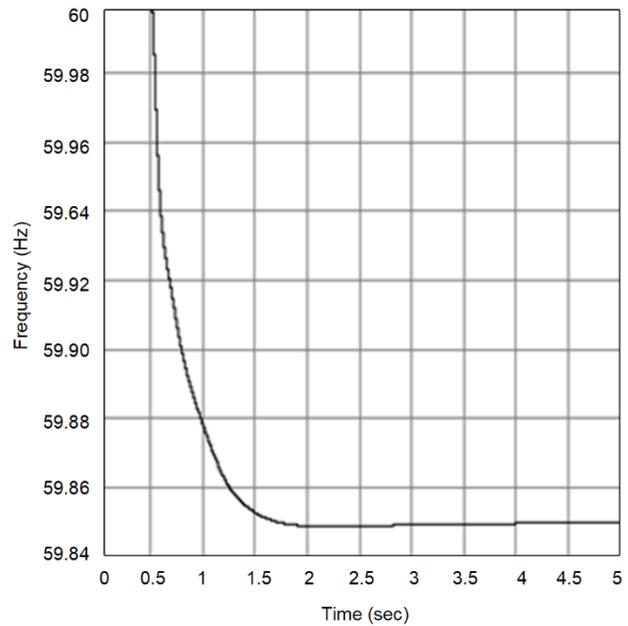


Fig. 17. Simulated result

IX. DYNAMIC TESTING AND ANALYSIS

Prior to installation of the MCS at the facility, complete factory acceptance testing (FAT) was performed in a laboratory using a real-time digital simulator model created as described above to validate the functionality of the MCS. The real-time model also permitted the MCS to be tested as a live simulation in the user-observed FAT. This was accomplished by connecting the MCS to the simulation hardware as shown in Fig. 18.

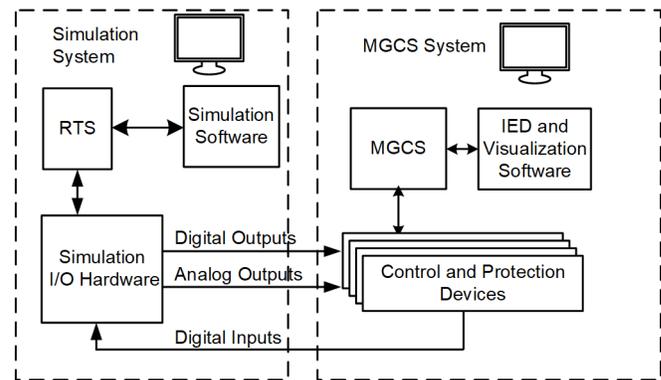


Fig. 18. System simulation setup

Several studies were done using the model, providing insight into system operation, vulnerabilities, and the system’s response for contingency events. Studies were also completed to determine optimal set points for the MCS. This section provides details for witnessing microgrid states and transitions handled by the MCS as described in Section V.

A. Case 1—Reconnect Dead

The objective of this testing was to demonstrate the operation of the MCS when the operator initiates a reconnect-dead command from the MCS HMI. For this test, initially, the PCC breaker is opened, and the campus blacks out. The MCS responds to the request to reconnect the dead campus to the utility by executing the functions as mentioned in Section V. Fig. 19 shows the system response after the sequence is initiated. The MCS closes the PCC breaker, and the campus is energized by the utility. The MCS starts the BESS in the South and North islands in grid-following mode with charging set points of 130 kW and 0 kW, respectively. Then the PVs are started in PQ mode and are dispatched to produce maximum power of 100 kW each. In grid-connected mode, the DERs are dispatched to maintain a fixed power factor across the PCC. Initially, the campus is dead, and after it is reconnected, the frequency is recovered to nominal. The voltage also recovers quickly to a steady state nominal value.

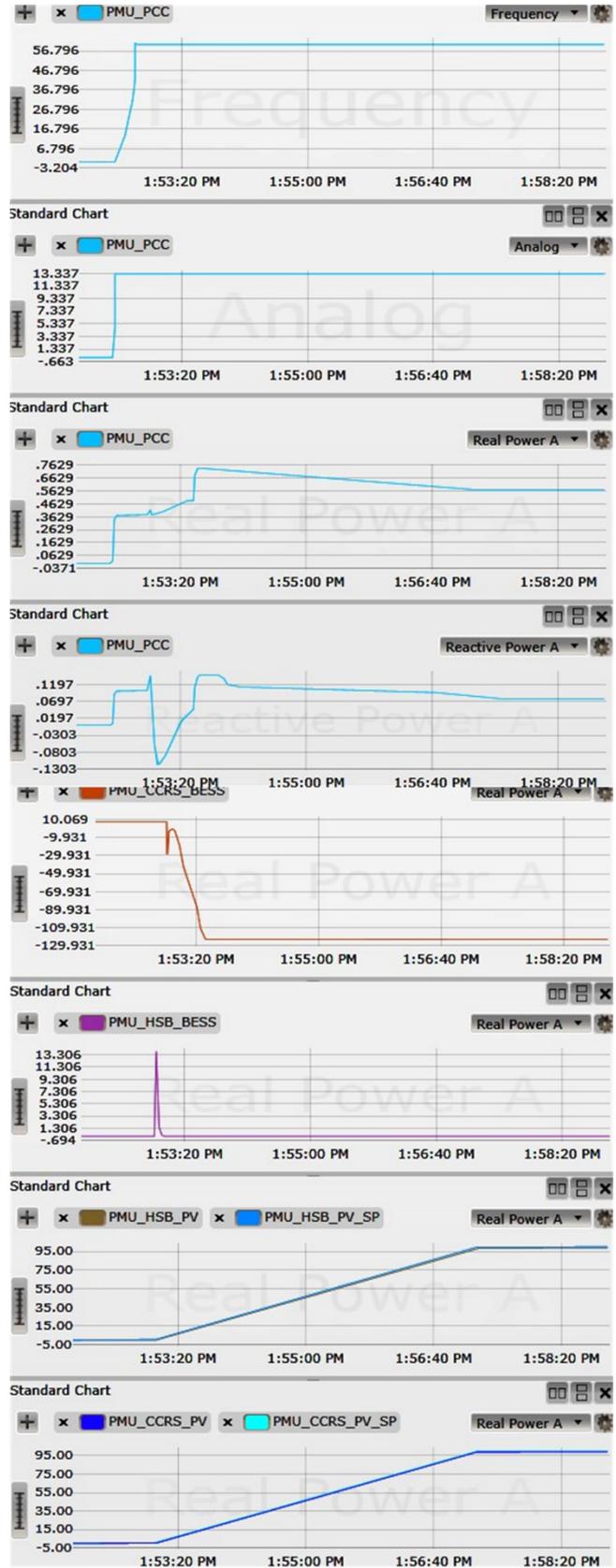


Fig. 19. Case 1—DER active and reactive power

B. Case 2—Black-Start Campus

The objective of this test was to demonstrate the operation of the MCS when the operator initiates a black-start command from the MCS HMI. For this test initially the PCC breaker is opened and the campus blacks out. The MCS responds to the request to black start the dead campus by executing the functions as mentioned in Section V. Fig. 20 shows the system response after the sequence is initiated. The MCS starts the BESS 1 in grid-forming mode and the BESS 2 is started in PQ mode after a time delay with a set point of 57 kW. The PV is started in PQ mode and dispatched to produce maximum power. The load management system adds building loads based on the BESS SOC and outage time as entered by the operator.

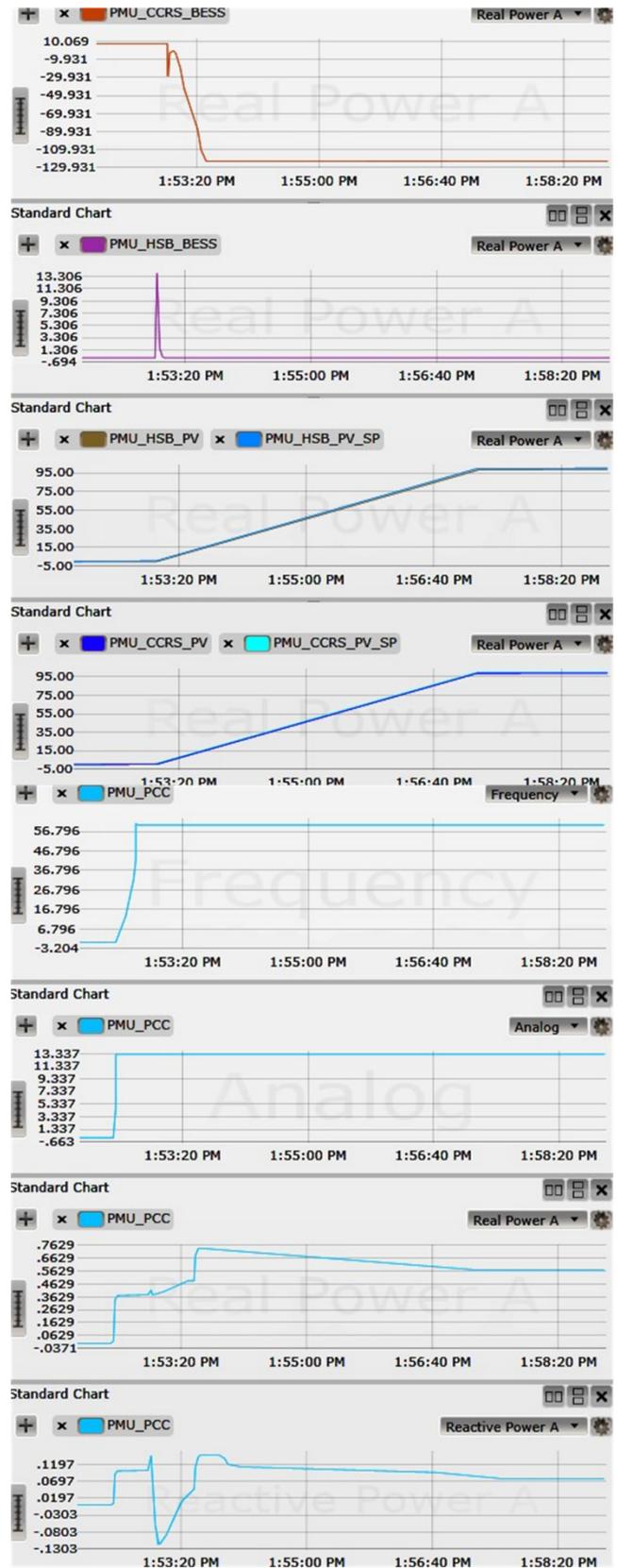


Fig. 20 Case 2—system frequency and voltage

C. Case 3—Reconnect Live

The objective of this test was to demonstrate the operation of the MCS when the operator initiates a reconnect live from the MGCS HMI after the black-start sequence is completed. For this test, the system is in an islanded state and has completed a black-start sequence. The MCS responds to the request by executing the functions as mentioned in Section V. The MCS sends a frequency bias to the BESS 1 to synchronize the PCC breaker. There is a slight frequency overshoot of 60.087 Hz after the breaker closes as shown in Fig. 21. The MCS dispatches the BESS 1 and BESS 2 with charging set points of 140 and 40 kW, respectively. The PVs continue to produce maximum power of 100 kW each. The utility import starts to increase as the MCS is charging the battery.

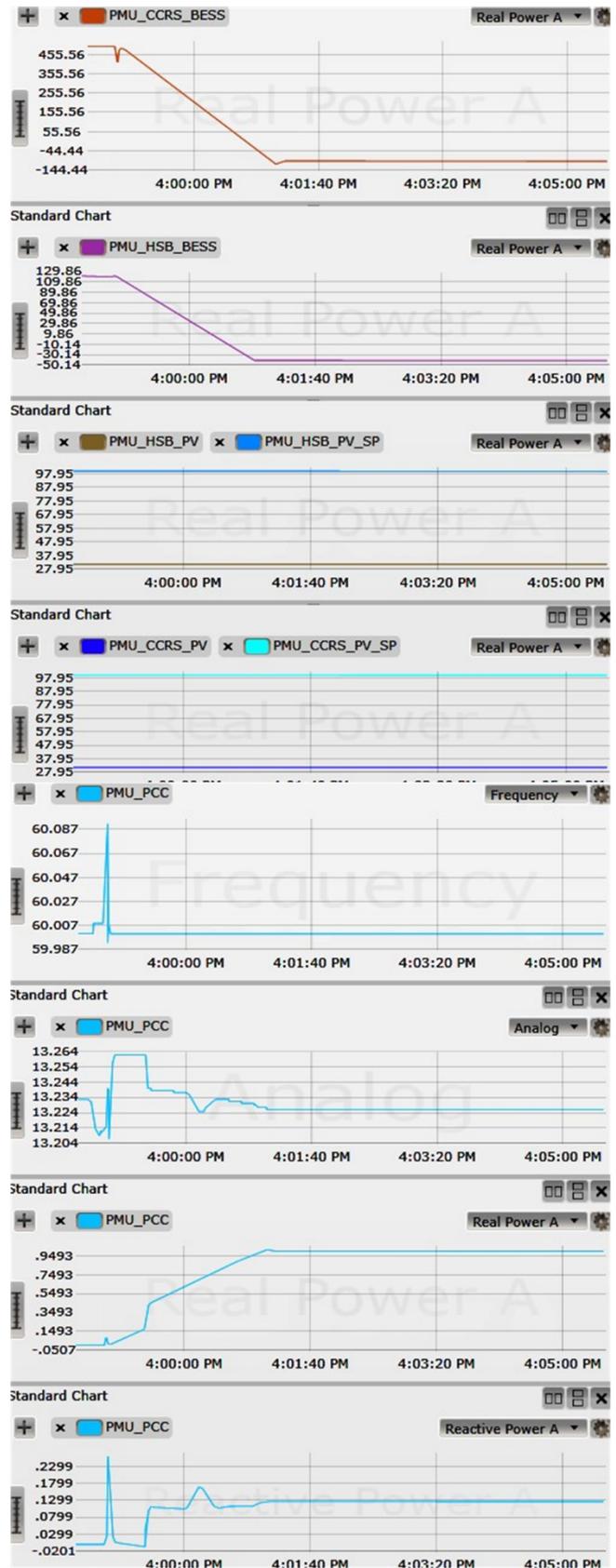


Fig. 21. Case 3—system voltage and frequency

X. CONCLUSION

This paper demonstrates the design, development, and validation testing and commissioning of the MCS implemented for the Avista Clean Energy Fund (CEF) 2 project in Spokane, Washington. Each function of the MCS was tested prior to running system-wide tests to validate integrated operation. Since then, the system at the Avista MCS has been commissioned for MCS functionality and in service.

Avista's CEF project demonstrated the benefits of a shared energy economy model for the control and optimization of DERs. The goal is to increase the use of the electric distribution system and DERs, benefiting consumers and the utility system. The MCS design for this pilot project was focused on addressing and investigating the following:

- Experimenting with various modes of microgrid operation and determining their values in a real-world scenario
- Verifying protection coordination in transitioning from grid-connected mode to islanded mode and vice versa
- Investigating advantages, challenges, and use cases of a microtransactive grid

The system presented in this paper describes the MCS functionality needed to achieve the project goals while providing safe and reliable energy service to customers within the microgrid, whether it is islanded or grid connected. This microgrid will serve as a platform for future research and experimentation related to distributed energy.

XI. ACKNOWLEDGMENTS

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XIII. BIOGRAPHIES

John Gibson, PE, received his BS in electrical and civil engineering from Gonzaga University and his master's degree in engineering management from Washington State University. He is a registered PE in the state of Washington and has worked in the electric utility industry for over 25 years. His experience in the industry consists of electric distribution planning, distribution system

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