Robust Microgrid Control System for Seamless Transition Between Grid-Tied and Island Operating Modes

Scott Manson, Bharath Nayak, and Will Allen
Schweitzer Engineering Laboratories, Inc.

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***Abstract*—Critical facilities require electric power systems to stay fully energized during transitions between grid-connected and island modes. Providing this seamless transfer between island and grid modes is a complex challenge because of multiple dynamic interactions between distributed energy resources (DERs), electrical loads, and the bulk electric power system. Further complicating these transitions are the reduced kinetic energies and new dynamics associated with the black-box controls of power electronic DERs, such as photovoltaic (PV) and battery storage.**

The solutions to these challenges are fast, reliable, and adaptive protection and control systems commonly called microgrid control systems (MGCSs). This paper explains the design, testing, and results of an MGCS that uses subcycle (less than 16 ms) fast and deterministic control strategies to improve grid and island resiliency during the transitions from grid mode to island mode. The MGCS is known to prevent power outages (blackouts) during events such as islanding, synchronization, PV shading, islanded loss of generation, and variable loading under islanded conditions.

I. Introduction

This paper describes the microgrid controller functionality developed and tested to control a theoretical power system referred to as Banshee. The Banshee microgrid was created by the Massachusetts Institute of Technology Lincoln Laboratory (MIT LL) to assess distributed energy resources (DERs) and microgrid control system (MGCS) technology [1]. The U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability sponsored the MIT LL to build this model. The authors constructed both the controller and a model of the Banshee system with a hardware-in-the-loop (HIL) test bed. Both were demonstrated at the Microgrid & DER Controller Symposium held at MIT in Boston, Massachusetts in February, 2017 [2].

The authors created a real-time Electromagnetic Transients Program (EMTP) model for control hardware-in-the-loop (CHIL) testing. The CHIL model was created to test the MGCS. Once fully tested in the laboratory, the controller was sent to Boston for the symposium for test and evaluation by MIT LL.

The MGCS for this system includes configured protective relays at the point of common coupling (PCC) and custom software libraries running on an automation controller. Many real-life MGCS projects are accomplished entirely in the protective relays; the authors chose to use an automation controller for this project because of the programming flexibility and capability, human-machine interface (HMI), and protocol interfaces provided by the automation controller. Because of the complex topology of the microgrid, the number of DERs, and the intended testing regimen by MIT LL, an all-relay MGCS would have been very difficult to provide.

II. System Overview

The Banshee model is shown in Fig. 1. The microgrid is comprised of three areas, each of which are connected to the utility through separate PCC circuit breakers. Area 1 includes the 4 MVA diesel generator, Area 2 includes the 3 MVA battery energy storage system (BESS) and 5 MVA photovoltaic (PV) assets, and Area 3 includes the 3.5 MVA combined heat and power (CHP) generation system. Every load is assigned a priority: interruptible (I), priority (P), and critical (C).

There are several normally open (NO) tie breakers among the three areas that can be closed to form a larger microgrid and/or to transfer load from one area to another:

- One tie breaker (CB108) between Area 1 and Area 2 at 13.8 kV through a 3,000-foot cable run.
- One tie breaker (CB111) between Area 1 and Area 2 at 4.16 kV through a 2,000-foot cable run.
- One tie breaker (CB109) between Area 1 and Area 2 at 480 V through a 1,000-foot cable run.
- One tie breaker (CB113) between Area 1 and Area 3 at 480 V through a 2,000-foot cable run.
- Three tie breakers (CB213, CB216, and CB217) between Area 2 and Area 3 at 480 V through a 1,500-foot cable run.

The microgrid is normally operated in the topology state as shown in Fig. 1. However, the following scenarios are likely to occur in the microgrid:

- Areas 1, 2, and 3 are separated from each other.
- Areas 1 and 2 are connected through one or more tie breakers.
- Areas 1 and 3 are connected through a tie breaker.
- Areas 2 and 3 are connected through a tie breaker.
- Areas 1, 2, and 3 are connected through tie breakers.

Additionally, any breaker (i.e., PCC, topology, or load) may be opened or closed.

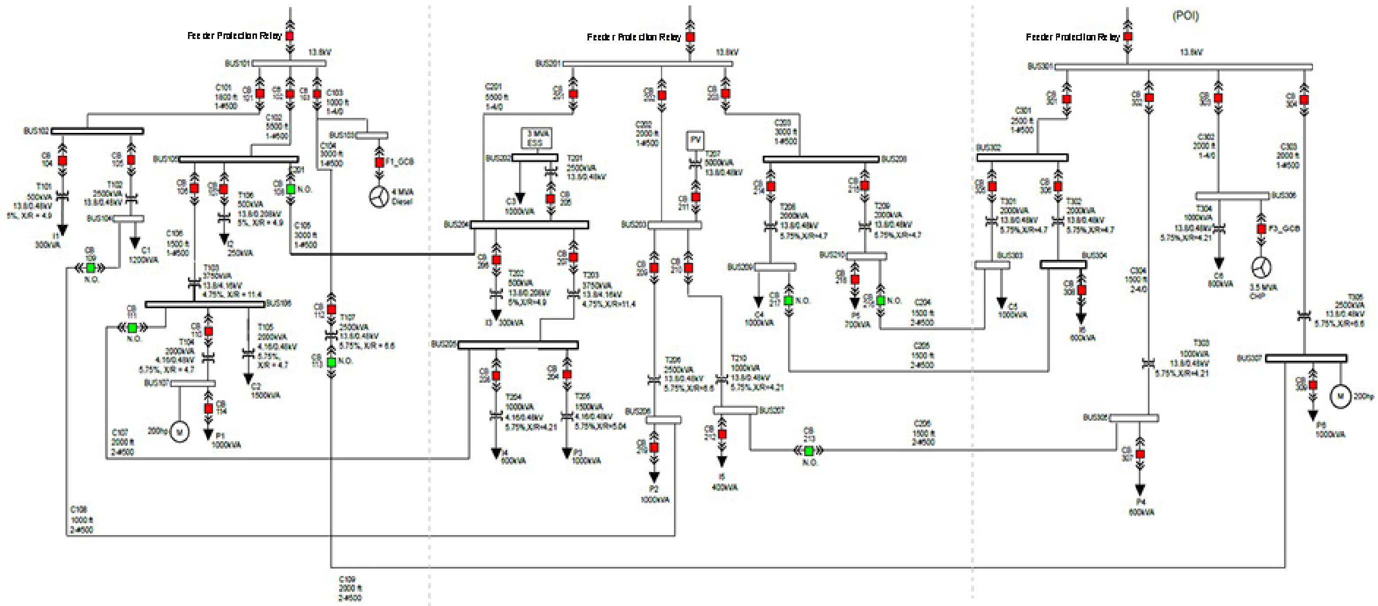


Fig. 1. One-line diagram of the Banshee microgrid

III. Technical Objectives

The technical objectives of the centralized MGCS designed for this project are as follows:

1. Operate all islands without power outages (seamless operation) during transitions between island and grid modes.
2. Interface with diesel and natural gas (NG) CHP generation control systems.
3. Interface with PV and BESS converters.
4. Interface with PCC breaker relays.
5. Interface with load bank breaker relays.
6. Assess the diesel generator, CHP, PV, and BESS control capability.
7. Implement an automatic generation control (AGC) parallel load-sharing system [3] to:
   a) Control all generation assets to share active load while maintaining favorable individual machine margins.
   b) Control generation assets to regulate frequency when disconnected from the utility grid.
8. Implement a voltage control system (VCS) parallel VAR-sharing system [3] to:
   a) Control all generation assets to share reactive load while maintaining favorable individual machine margins.
   b) Control all generation assets to regulate voltage when disconnected from the utility grid.
9. Employ the island control system (ICS) to detect and track island conditions and to inform the AGC and VCS of grid topology changes [3].
10. Simultaneously control multiple DERs (PV, BESS, diesel generator, and NG CHP generation control system).
11. Provide resilience (prevent blackouts) during scenarios such as an open PCC breaker, rapid load changes, loss of generation, or a motor start [4].
12. Dispatch active and reactive power at the PCC.
13. Implement simultaneous advanced automatic synchronization to all three areas of the grid [5].
14. Program automatic black-start and load restoration functions.
15. Provide an operator interface via the HMI and provide post-event analysis.

IV. Data Flow Diagram

The microgrid controller (MGC) consists of a centralized automation controller that executes functions such as AGC, VCS, ICS, contingency load-shedding processor (CLSP), and advanced automatic synchronization. The HMI is configured to provide all necessary operator interface functions. Fig. 2 illustrates the physical architecture connecting the MGC with the microgrid equipment.

V. MGC Control Philosophy

The control philosophy of the MGC is mainly composed of the utility-connected mode of operation (grid mode of operation) and the utility-disconnected mode of operation (island mode of operation). The idea is to control various DERs with appropriate modes to ensure reliable and sustained microgrids. The control strategy is tabulated in Table I.

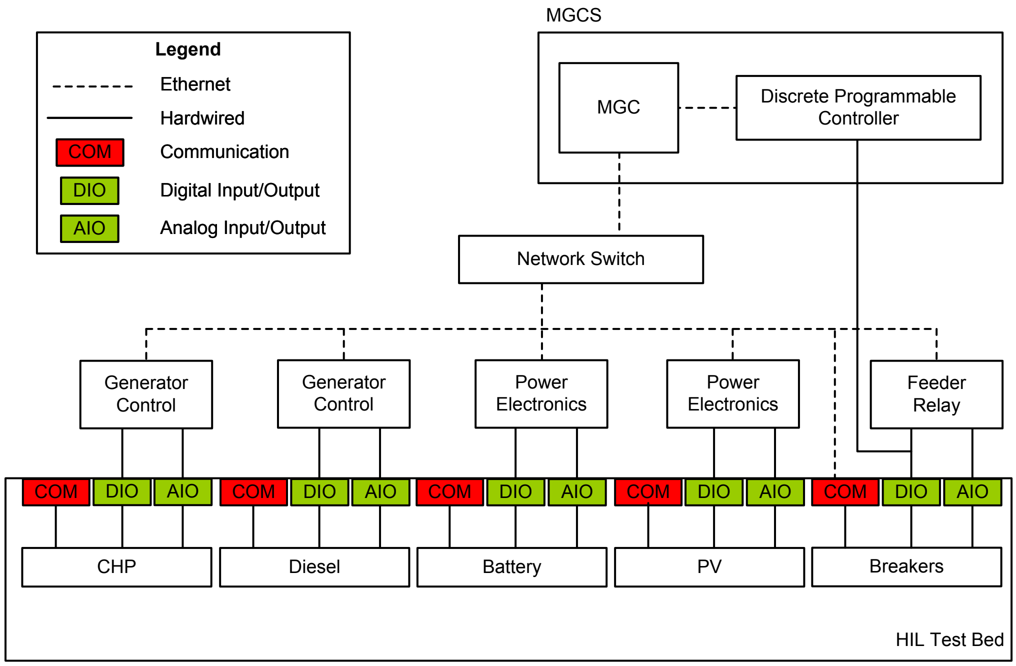


Fig. 2. Physical data flow diagram

TABLE I
MGCS CONTROL STRATEGY MATRIX

Strategy	Grid Mode	Island Mode
PCC power flow	MGC[1]	NA[2]
PCC power factor	MGC[1]	NA[2]
Microgrid frequency	Utility[3]	MGC[1]
Microgrid voltage	Utility[3]	MGC[1]
Diesel generator	Droop[4]	Droop[4]
NG generator	Droop[4]	Droop[4]
BESS asset	P/Q[5]	P/Q[5]
PV asset	P/Q[5]	P/Q[5]

Note 1: Microgrid controller is responsible.

Note 2: Not applicable.

Note 3: Utility is responsible.

Note 4: Active frequency droop and voltage droop.

Note 5: Constant real and reactive power control to set point.

A. Utility-Connected Mode of Operation

When utility-connected, the MGC controls the total power flow across the PCC breakers to achieve the target set point. The total power flow is the sum of power measurement across each PCC breaker.

The MGC controls the combined power factor (PF) at the PCC breakers to achieve a target set point. The MGC calculates a reactive power set point based on a user-defined power factor set point and the user-defined power set point. The MGC defines a dead-band control boundary in the PQ plane to avoid excessive control adjustments due to hunting and inherent instability of the power factor controls during low-power conditions. Fig. 3 illustrates the power factor control strategy used by the MGC. Values shown on the P and Q axes have units of megawatt (MW) and megavolt-ampere reactive (MVAR), respectively. Positive values indicate flow into the microgrid. The dark area represents the region where active power factor control occurs. The light area represents the region where active power factor control is suspended.

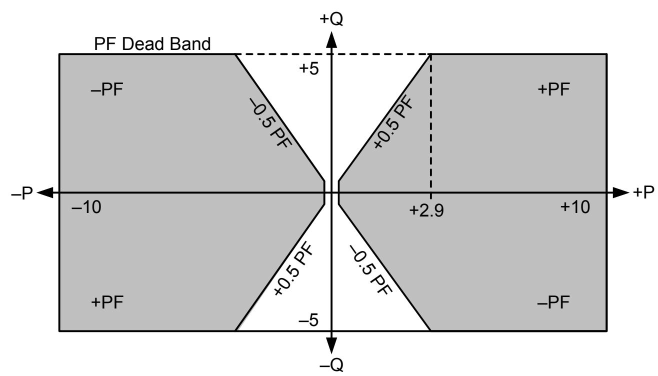


Fig. 3. Power factor control strategy

Voltage and frequency are assumed to be the responsibility of the utility when grid-connected. The MGC commands the DERs to the modes indicated in Table I.

The diesel and NG generators are controlled to share load and maintain operating margins to enhance disturbance rejection. The real power set point for the PV asset is set to maximize the PV power output. The real power set point for the BESS asset is normally maintained at zero. The MGC responds quickly by increasing or decreasing power output to compensate for frequency deviations (e.g., if the microgrid is islanded).

The reactive power set points for the two generators, as well as the PV and BESS assets, are dispatched to share (i.e., equal percentage sharing based on asset capability limits). Simultaneously, the DERs dispatch reactive power to maintain the power factor control at the PCC. While the PCC is open, these same assets are equally dispatched to an MVAR output while maintaining system bus voltages.

B. Island Mode of Operation

The capacity of the microgrid is the summation of the online diesel generator, CHP generation system, PV, and BESS capacities. The available capacity is the present power plus the incremental reserve margin (IRM) of the generation assets. Load is shed based on the user-settable priorities to balance load and available capacity in the resulting microgrid(s).

The diesel and NG generators are controlled to share load and maintain operating margins to enhance disturbance rejection. The MGC dispatches the real power set point for the PV asset to maximize the PV power output.

The MGC dispatches the real power set point for the BESS asset to maintain the power output at zero. The MGC responds quickly by increasing or decreasing the power output to compensate for frequency deviations. Frequency deviations may be caused by sudden shading of the PV array, large motor starting, or topology changes.

The MGC biases the operation of the diesel and NG generators to maintain islanded system frequency at the set point and drive the BESS power output to zero (if possible).

The MGC dispatches reactive power set points for the two generators, as well as the PV and BESS assets, to share (i.e., equal percentage sharing) the reactive power load required to maintain system voltage at the set point.

If load with priority P is shed to survive a disturbance, then the MGC restarts these P loads (one at a time at 10-second intervals) after the disturbance is cleared. Loads are only restarted if the IRM of the associated island can support it. Loads are restored based on user priority.

If the reserve margin is not sufficient to accommodate all the P loads that were shed, then the MGC sends a start command to an available generation asset in the associated island.

Fig. 4 illustrates the strategy employed by the MGC related to real power and frequency control. Fig. 5 illustrates the strategy employed by the MGC related to reactive power and voltage control.

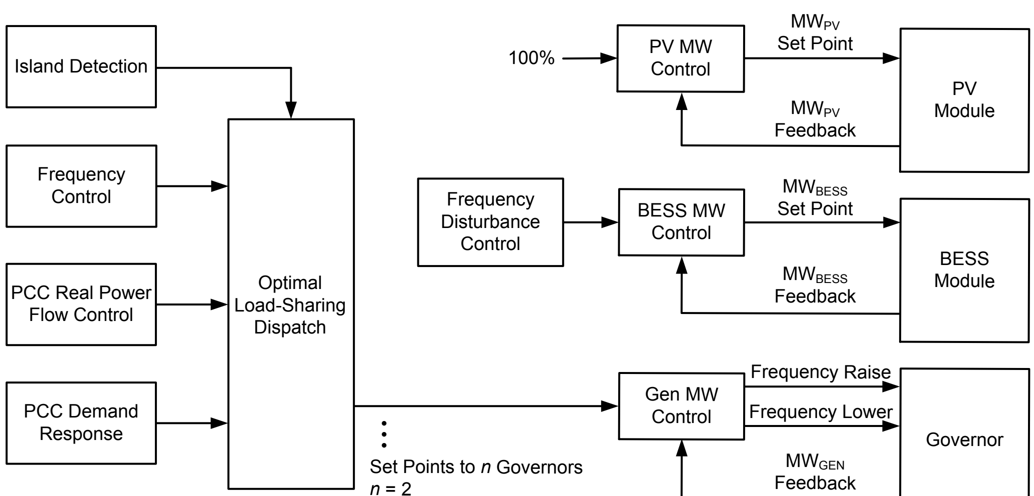


Fig. 4. Real power and frequency control strategy

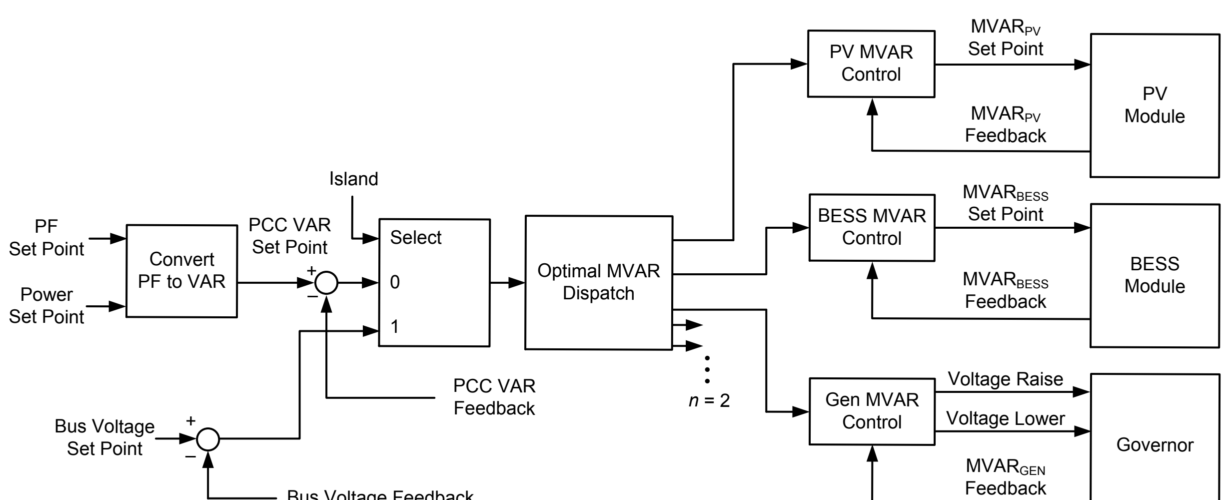


Fig. 5. Reactive power and voltage control strategy

C. *BESS Charging Strategy*

The MGC charges the BESS based on a two-strategy approach. Strategy 1 is independent of the PV output power. It is designed to ensure that the BESS charge is maintained even if the PV asset is offline or producing at a low level. Strategy 2 is designed to favor charging the BESS during times of high PV power output.

In Strategy 1, as shown in Fig. 6, the MGC starts to charge the BESS if it has less than A% charge and there is excess power available from any source. The charging power C is configurable; however, it is limited by the available capacity of the connected island. The MGC stops charging the BESS once it exceeds B% charge. This ensures that the battery has sufficient charge available when it is called on to reject disturbances such as sudden shading of the PV array, load changes, and topology changes. Parameters A, B, and C are configurable. Default values are set to A = 50%, B = 75%, and C = 10%.

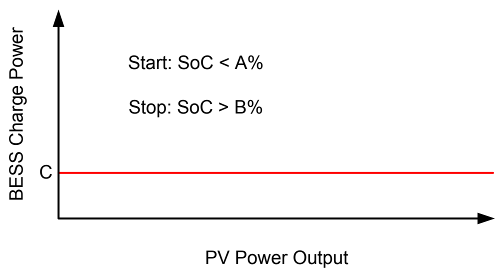


Fig. 6. BESS state-of-charge Strategy 1

In Strategy 2, as shown in Fig. 7, the MGC controls the BESS to charge in times when the PV output is high (i.e., above a configurable threshold F). In this case, the MGC starts to charge the BESS if it has less than D% charge. The charging power is proportional to the PV output that is above the threshold F. The MGC stops charging the BESS once it exceeds E% charge. Parameters D, E, and F are configurable and can be tuned during the factory acceptance test. Default values are set to D = 80%, E = 90%, and F = 80%.

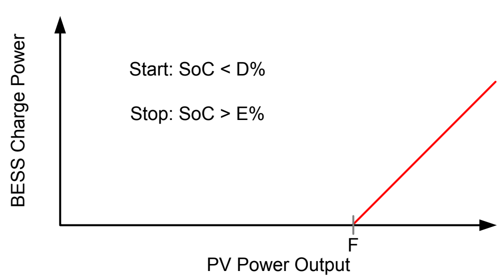


Fig. 7. BESS state-of-charge Strategy 2

D. *Black-Start Functions*

The MGC provides effective blackout prevention in most scenarios. However, in some cases a blackout is unavoidable.

The Banshee model power system includes three areas. Areas 1 and 3 incorporate conventional generation assets. If these assets are running, the MGC provides seamless transition from grid-connected to islanded operation for most decoupling events. If these assets are not running, then the MGC black starts the area according to the flow chart in Fig. 8.

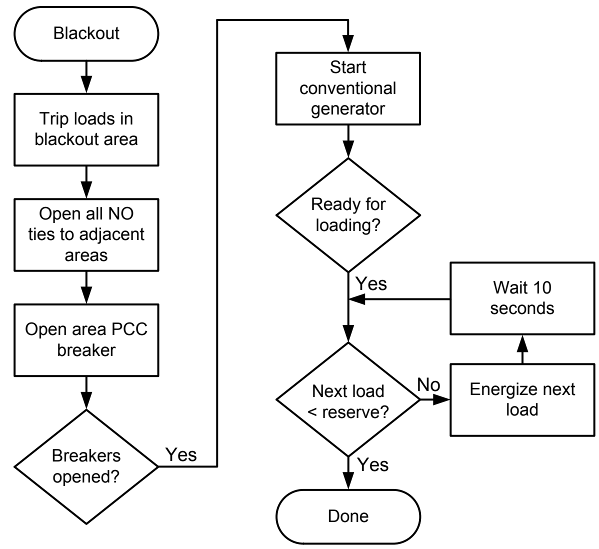


Fig. 8. MGC black-start sequence for Areas 1 and 3

Area 2 of the Banshee model includes two inverter-based sources. If only the PV asset is connected, then decoupling from the utility results in tripping the PV, leaving Area 2 de-energized. The battery storage asset may also not be able to survive if islanded on its own. The black-box controllers that are commonly used with inverter-based sources often trip the inverter at the first sign of trouble. This results in no other option except to de-energize Area 2 and connect it to Area 1 or Area 3, followed by full Area 2 energization. Fig. 9 shows the black-start sequences employed by the MGC to re-energize Area 2 and restart the inverter-based sources.

VI. Closed-Loop Testing and Results

The objective of the closed-loop test setup is to create a test interface that simulates power system dynamics of DER sources, local controller functions, electrical network with transformer and cable impedances, and communications protocols between local controllers and the MGC. Fig. 10 shows the closed-loop test interface used to validate the functionality of the MGC.

An interface data concentrator was programmed to serve as a bridge between the power system model and the MGCS hardware. To simulate communication between the data concentrator and the field IEDs, the DER's primary local controller, and the MGC, two steps were required. First, an extensive input/output (I/O) list was developed to analyze the data types (such as active power, reactive power, bus frequency, bus voltage, breaker status, trip commands, and analog control set points). Second, the interface data concentrator was programmed to represent parallel communications channels simulating communications delays and protocols, such as IEC 61850, DNP 3.0, and Modbus®. The following subsections contain results from the tests performed with HIL testing for this project.

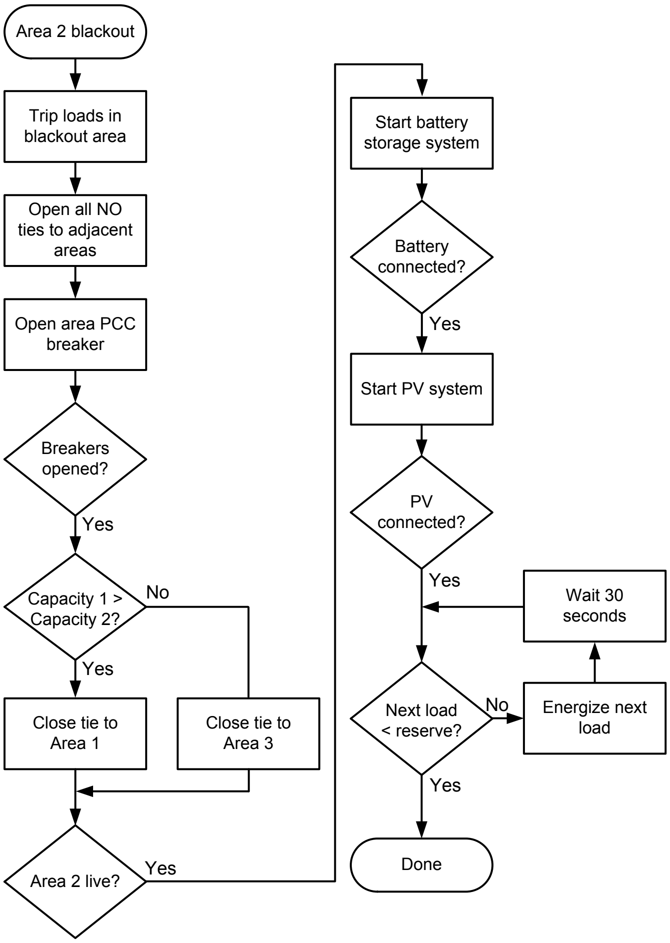


Fig. 9. MGC black-start sequence for Area 2

A. Test A: Utility-Connected Tie Flow Control

This scenario simulates a condition in which the system is connected to the grid in tie line control mode and power factor control mode.

The tie line power flow initially decreased because of the sudden loss of load. The MGCS controlled the diesel and CHP generation systems governors to restore the tie line set point to 1 MW import. Equal percentage load sharing between the two generators was accomplished.

The MGCS controlled the exciters of the diesel and CHP generation systems, as well as the reactive power set points of the BESS and the PV array, to share the reactive power requirement to restore the tie line power factor to 0.95. Fig. 11 shows the precondition set points programmed in the HMI.

To achieve the target set point of 1 MW and 0.95 PF (0.31 MVAR), the MGCS dispatched DERs in each area to regulate power flow across each PCC breaker. Therefore, the aggregate of all PCCs resulted in approximately 0.94 MW and 0.96 PF. Fig. 12 shows the variations in tie flow control and Fig. 13 shows the redispatch of the DERs to achieve the results shown in Fig. 12. Fig. 14 shows the dispatch values of each DER after the event.

It is noteworthy that there is no overshoot, ringing, or unstable behavior in the PCC or DER active or reactive power because the PCC and DER controls do not use proportional integral derivative (PID) control methods; instead, they use advanced adaptive control methods, which creates a more reliable strategy than using PID.

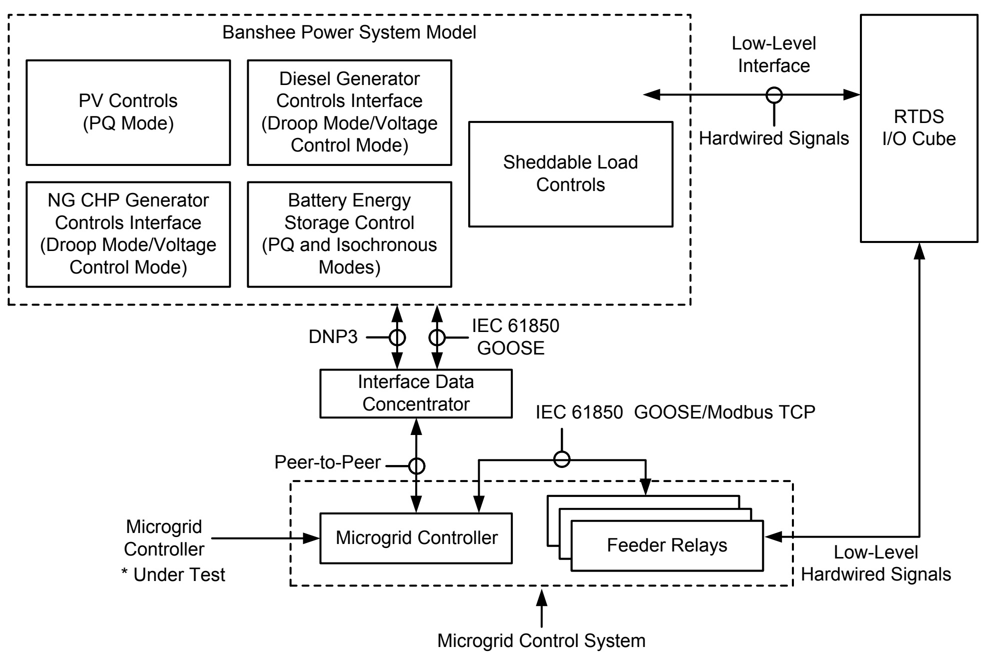
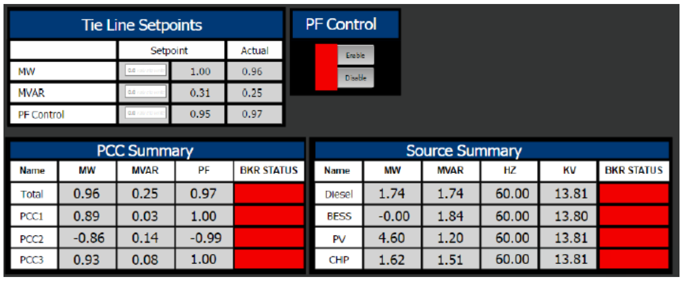


Fig. 10. HIL test setup


Tie Line Setpoints

	Setpoint	Actual
MW	1.00	0.96
MVAR	0.31	0.25
PF Control	0.95	0.97

PF Control

PCC Summary

Name	MW	MVAR	PF	BKR STATUS
Total	0.96	0.25	0.97	
PCC1	0.89	0.03	1.00	
PCC2	-0.86	0.14	-0.99	
PCC3	0.93	0.08	1.00	

Source Summary

Name	MW	MVAR	HZ	KV	BKR STATUS
Diesel	1.74	1.74	60.00	13.81	
BESS	-0.00	1.84	60.00	13.80	
PV	4.60	1.20	60.00	13.81	
CHP	1.62	1.51	60.00	13.81	

Fig. 11. HMI summary before the event

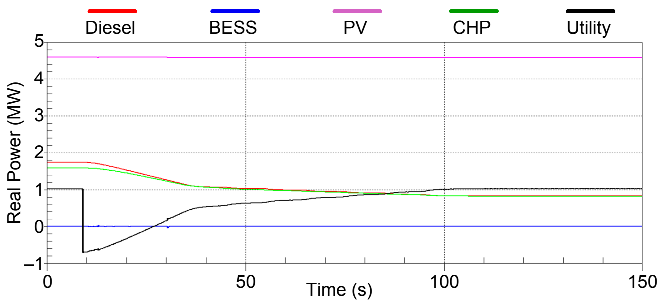


Fig. 12. MGCS real power tie flow control action to the event

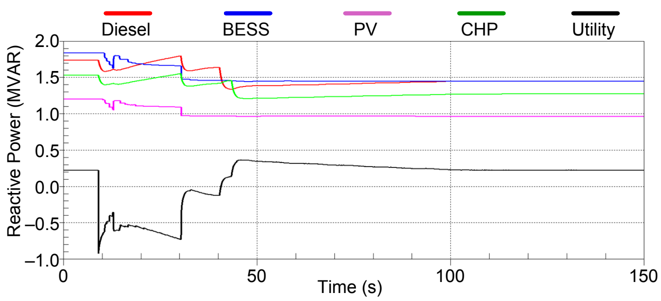
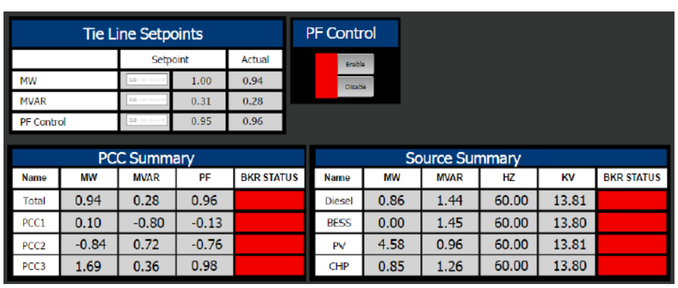


Fig. 13. MGCS reactive power tie flow control action to the event


Tie Line Setpoints

	Setpoint	Actual
MW	1.00	0.94
MVAR	0.31	0.28
PF Control	0.95	0.96

PF Control

PCC Summary

Name	MW	MVAR	PF	BKR STATUS
Total	0.94	0.28	0.96	
PCC1	0.10	-0.80	-0.13	
PCC2	-0.84	0.72	-0.76	
PCC3	1.69	0.36	0.98	

Source Summary

Name	MW	MVAR	HZ	KV	BKR STATUS
Diesel	0.86	1.44	60.00	13.81	
BESS	0.00	1.45	60.00	13.80	
PV	4.58	0.96	60.00	13.81	
CHP	0.85	1.26	60.00	13.80	

Fig. 14. HMI summary after the event

B. *Test B: Decoupling Event – Simultaneous Formation of Multiple Islands*

This scenario simulates a condition in which PCC1, PCC2, and PCC3 all trip simultaneously because of a decoupling event (81RF element feeder relays) to form three simultaneous islands. Fig. 15 and Fig. 16 show the frequency response of the DERs to the formation of three islands. During the transition from grid-connected mode to island mode, it is shown that the MGCS load-shedding systems prevent the frequency and voltage from collapsing. These transients are typical for seamless islanding controls when accompanied by a fast, contingency-based load-shedding method.

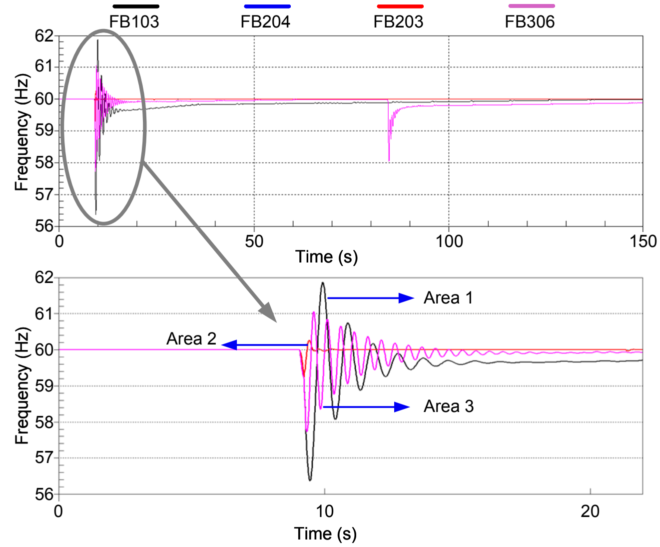


Fig. 15. Frequency response of all PCCs (top) and zoom in of the dynamic frequency response to the event (bottom)

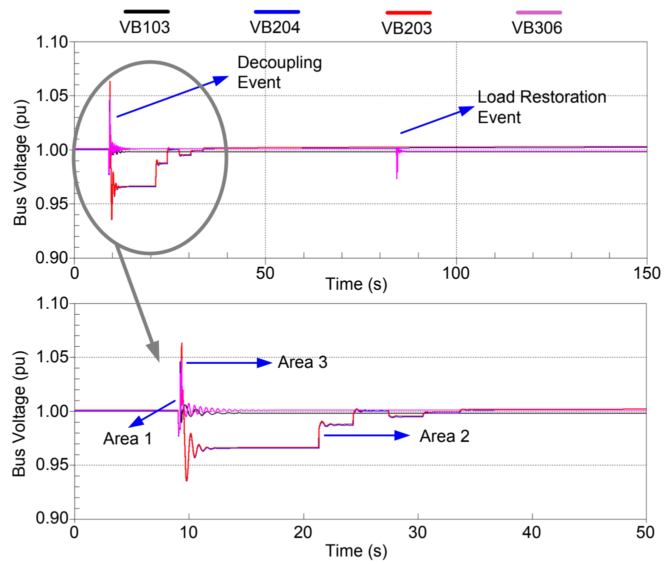


Fig. 16. Voltage response of all PCCs (top) and zoom in of the dynamic voltage response to the event (bottom)

In Area 1, the MGC shed Loads I1, I2, and P1 to ensure that the diesel generator would survive the opening of PCC1. Following the load shedding, the MGCS controlled the diesel generator governor and exciter set points to bring the islanded grid frequency and voltage to nominal.

In Area 2, when the PCC2 breaker opened, the MGC put the PV and BESS in nonregulated mode. The MGC set the PV Q_setpoint to zero. The BESS was put in voltage/frequency (V/F) mode to regulate voltage and frequency at its terminals in Area 2. The MGC incremented the PV Q_setpoint to restore system voltage to nominal in Area 2. The MGC chose not to shed loads in Area 2 because the BESS had sufficient IRM to support the event.

In Area 3, the MGC shed Loads I6 and P4 to ensure that the CHP generation system would survive the opening of PCC3. Following the load shedding, the MGCS controlled the CHP generation system to adjust the frequency and voltage to nominal. After a certain time, Loads I6 and P4 were automatically restored.

VII. Conclusion

The main objective of this project was to develop and test a centralized MGCS that would improve stability, survivability, and resilience in the Banshee system. During the phases of the project, the authors observed several key points that are critical to both the design of the model and testing of the MGCS. These key points are as follows:

1. The MGCS requires fast, subcycle communication and logical interactions between the MGC and the PCC relays.
2. Because of fast, contingency-based load shedding, seamless islanding is possible for microgrids with mixed DER types with high renewables penetration.
3. The mature MGC libraries used by the authors successfully controlled the Banshee power system.
4. The results of HIL testing of the Banshee power system and the MGCS are similar to those of many other in-service MGCSs.
5. To confirm a successful transition from grid-connected mode to island mode, protection coordination of various DERs and MGC actions were analyzed to verify that no protection thresholds were violated. This also ensured the successful transition from grid-connected mode to island mode.
6. HIL testing is necessary on projects of this complexity to ensure the MGCS strategy supplied functions as designed.

VIII. References

[1] Electric Power HIL Controls Consortium Repository, “Electric Power Hardware-in-the-Loop Controls Collaborative,” 2017. Available: github.com/PowerSystemsHIL/EPHCC.

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IX. Biographies

Scott Manson received his M.S. in electrical engineering from the University of Wisconsin–Madison and his B.S. in electrical engineering from Washington State University. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2002, Scott was a control systems engineer responsible for designing, installing, and commissioning automated control systems for manufacturing and research processes with The 3M Company. Scott is presently a principal engineer and director of technology at SEL Engineering Services, Inc. In this role, he provides consulting services on control and protection systems worldwide. He has significant experience in power system protection, real-time modeling, power management and microgrid control systems, remedial action schemes, turbine control, multi-axis motion control, web line control, robotic assembly, and precision machine tools. Scott is a registered professional engineer in Alaska, Idaho, Louisiana, North Dakota, and Washington.

Bharath Nayak received his M.Sc. in electrical engineering from the University of Wyoming and his B.Sc. in electrical engineering from the P.E.S. Institute of Technology, India. Bharath joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2012 as an associate automation engineer. In his present role, he serves as a power system modeling engineer with SEL Engineering Services, Inc. His focus includes tuning and commissioning of generator control systems, validation and modeling of large-scale industrial plants, countrywide remedial action schemes, power management systems, distributed energy resource modeling, microgrid modeling, and hardware-in-the-loop testing.

Will Allen received his B.Sc. in electrical engineering from the University of Alberta. He has broad experience in the fields of industrial control systems and power system automation. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2000 and is currently a senior engineer with SEL Engineering Services, Inc. His current focus is on applying protection and control strategies to improve the operation of microgrids that include diverse resources. He is a registered professional engineer in Washington and in the provinces of Alberta, Ontario, and Saskatchewan.