

Lessons Learned From Hardware-in-the-Loop Testing of Microgrid Control Systems

E. Limpaecher, R. Salcedo, and E. Corbett
Massachusetts Institute of Technology Lincoln Laboratory

S. Manson, B. Nayak, and W. Allen
Schweitzer Engineering Laboratories, Inc.

Presented at the
Grid of the Future Symposium
Cleveland, Ohio
October 22–25, 2017



21, rue d'Artois, F-75008 PARIS
<http://www.cigre.org>

CIGRE US National Committee 2017 Grid of the Future Symposium

Lessons Learned From Hardware-in-the-Loop Testing of Microgrid Control Systems

E. Limpaecher*, **R. Salcedo***, **E. Corbett***, **S. Manson†**, **B. Nayak†**, and **W. Allen†**
*Massachusetts Institute of Technology Lincoln Laboratory
†Schweitzer Engineering Laboratories, Inc.
USA

SUMMARY

A key ingredient for the successful completion of any complex microgrid project is real-time controller hardware-in-the-loop (C-HIL) testing. C-HIL testing allows engineers to test the system and its controls before it is deployed in the field. C-HIL testing also allows for the simulation of test scenarios that are too risky or even impossible to test in the field. The results of C-HIL testing provide the necessary proof of concept and insight into any microgrid system limitations. This type of testing can also be used to create awareness among potential microgrid customers.

This paper describes the modeling benefits, challenges, and lessons learned associated with C-HIL testing. The microgrid system used in this study has a 3 MW battery, 5 MW photovoltaic (PV) array, 4 MW diesel generator set (genset), and 3.5 MW combined heat and power generation system (CHP).

KEYWORDS

Microgrid, C-HIL, system testing, switching transients, controller integration.

1 INTRODUCTION

Microgrids can increase energy resilience [1] and improve operating efficiency, but they are challenging to deploy. Because relatively few of these multimillion dollar systems are fielded, most engineers do not have experience assessing microgrid and distributed energy resource (DER) control technology. Some equipment vendors lack the prototyping capabilities to fully demonstrate their control solutions, leading to a higher perceived risk by project developers and financiers and concerns about “vaporware” by system integrators. The integration and testing method currently used by the industry—which typically requires all of the steel to be in the ground before control integration begins—pushes all project risk to the final field deployment stage rather than reducing risk through lower-cost laboratory integration and prototyping.

To help address these issues and accelerate microgrid adoption, the Department of Energy’s Office of Electricity Delivery and Energy Reliability sponsored the Massachusetts Institute of Technology Lincoln Laboratory (MIT-LL) to build a microgrid and DER control prototyping platform. MIT-LL is a U.S. Department of Defense federally funded research and development center, which provides neutral, third-party technical expertise to the federal government.

The source code and circuit designs for the resulting hardware-in-the-loop laboratory testbed and open platform (HILLTOP) have been made available as open-source on the electric power hardware-in-the-

papers@selinc.com

loop controls collaborative (EPHCC) repository [2], and the microgrid test feeder, code named “Banshee,” is now being used as a reference feeder by the industry, IEEE P2030.8, U.S. National Renewable Laboratories (NREL), and universities.

The HILLTOP platform was used to simulate the Banshee model during the Microgrid and DER Controller Symposium, held at the MIT campus in February 2017. Videos of these live demonstrations are available online at [3]. The symposium showcased how to use modern, real-time simulation technology to integrate, evaluate, and reduce the risk of distribution-level control deployments. Symposium attendees included utility engineers, project developers, systems integrators, engineering students, policymakers, and equipment vendors. The symposium was organized and hosted by the Massachusetts Clean Energy Center, National Grid, IEEE Power and Energy Society, Electric Power Research Institute, Greenovate Boston, Microgrid Knowledge, and MIT. MIT-LL used C-HIL, relaying, governor control, and inverter equipment from several manufacturers to build the prototyping platforms. Four manufacturers integrated their commercial microgrid controllers into the HILLTOP. NREL analyzed test results collected prior to the event.

2 GENERIC POWER SYSTEM MODEL

The Banshee power system, shown in Figure 1, corresponds to a real-life, small industrial facility supplied via three utility radial feeders. The system resembles microgrids seen around the world and presents challenges found in a community microgrid, a small island, or industrial facilities, making it a solid benchmark for evaluating microgrid performance. The microgrid is composed of three adjacent feeders that may interconnect through normally open tie switches. The Banshee electrical demand ranges from 5 MW to 14 MW for minimum and peak load. System voltages include 13.8 kV at the distribution level and service voltages of 4.16 kV, 480 V, and 208 V. There are 18 aggregated loads categorized as critical, priority, and interruptible.

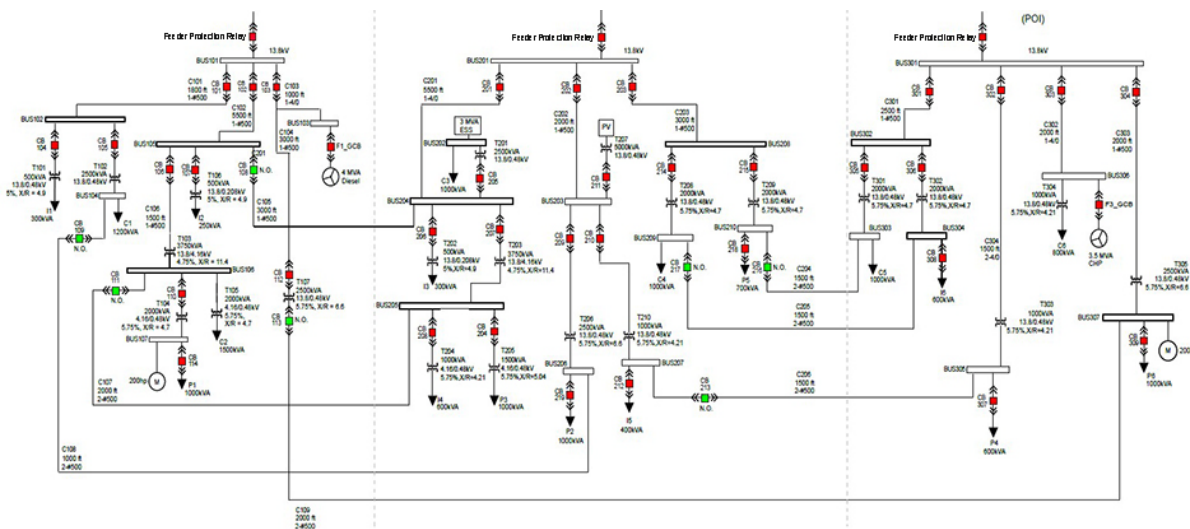


Figure 1 Banshee Power System

Loads follow electrical demand profiles extracted from the smart metering equipment installed at the existing site buildings. Critical loads, such as hospitals, denote high requirements for continuous electrical service and power quality. Priority loads are buildings that ideally have continuous electrical service, but during contingencies, these buildings may be disconnected. Interruptible loads are buildings that do not require electrical service during contingencies.

The Banshee power system contains a 4 MVA diesel generator and a 3.5 MVA combined heat and power system operating at a 13.8 kV nominal voltage. The generators are hardware interfaced with generation load-sharing controllers that operate and protect both units. The load-sharing controllers receive commands from the microgrid controllers without operator intervention.

The Banshee power system includes a PV array rated at 3 MW and a battery energy storage system (BESS) rated at 2.5 MW. Two power inverter module controllers capable of four-quadrant operations

and grid mode transition techniques operate these assets. The PV follows a user-defined irradiance profile. The microgrid controller dispatches the BESS unit to perform power factor correction and peak shaving and support power export requirements. The lack of generation and storage available in the Banshee system facilitates the evaluation of the microgrid controller’s ability to perform smart load shedding before and during islanded conditions.

System reconfiguration is available using 47 virtual circuit breakers commanded by the microgrid controller via hardware or virtual relays. Three hardware protective relays control and protect the three points of common coupling (PCC1, PCC2, and PCC3) with the utility grid. The virtual relays provide fault protection, automatic synchronism back to the grid, and telemetry. Additionally, these breakers can trip and close via Modbus[®] TCP for slow microgrid control schemes or quickly via IEC 61850 GOOSE for fast load shedding. Design and implementation details for the hardware interface circuitry of controllers and relays as well as the source code of simulated components are publicly available in the EPHCC repository [2].

3 C-HIL PLATFORM

A simplified diagram depicting the C-HIL architecture is shown in Figure 2. The system is comprised of four main components:

- Microgrid controller (MGC) and communications interfaces.
- Device controllers, relays, and high-speed digital interface.
- Custom electronics interfaces for device controllers and relays.
- C-HIL real-time simulation platform.

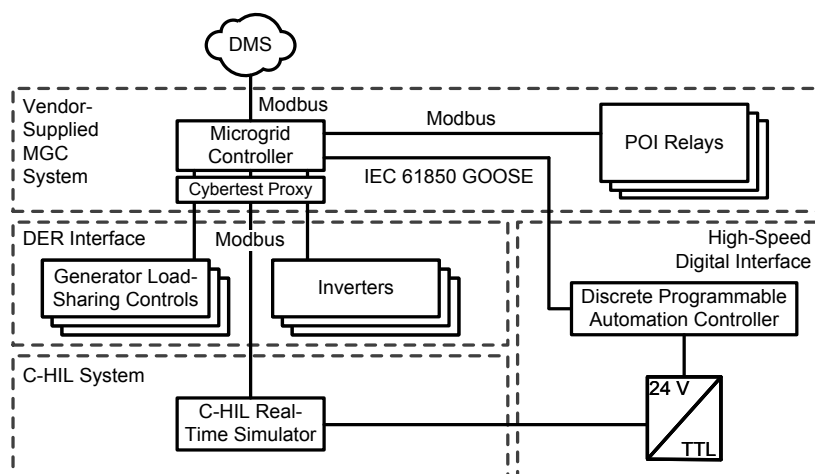


Figure 2 C-HIL Architecture

The microgrid controller communicates with all hardware and software devices primarily through a Modbus TCP interface. A cybertest command and control proxy computer is used to assess communications resistance to man-in-the-middle cyberattacks. An optional IEC 61850 GOOSE high-speed message interface is available to directly control simulated circuit breakers through a discrete programmable automation controller for fast load-shedding capability.

Two genset load-sharing controllers are used for control, one for the simulated 4 MW diesel genset and another for the 3.5 MW simulated natural-gas-fueled engine used in the simulated CHP plant. The load-sharing controllers are custom-configured to match the engine type (diesel or natural gas) and are operated in linear frequency and voltage droop. The load-sharing controllers are interfaced to the C-HIL platform analog outputs using transconductance amplifiers as CTs and voltage amplifiers as PTs. The C-HIL analog and digital inputs are driven directly by load-sharing controller outputs.

Two power inverter controllers are also used, one for controlling a simulated 5 MW PV inverter and another for controlling a 3 MW simulated battery storage system inverter. Three hardware protective relays are implemented as feeder protection relays with protection elements for overcurrent,

undervoltage, underfrequency, and rate-of-change of frequency. A discrete programmable automation controller is used to sample the status of 32 of the 45 simulated circuit breakers and report status to the microgrid controller over the IEC 61850 communications link.

4 C-HIL MODEL VALIDATION

The Banshee power system model was built in three different C-HIL platforms. Modeling engineers validated the Banshee power system models against data collected from several similar in-service grids. Validated models confirm that the simulated response to a disturbance or event reasonably matches the measured response to a similar disturbance.

To validate these models, specific tests were performed to confirm that their behaviors were normal for such systems. These tests included, but were not limited to, PV irradiance profiles, PV performance during fault conditions, PV dynamic response to MGC commands, distributed generation load rejection and load acceptance tests, distributed generation fault condition tests, grid compliance tests, load flow tests, and voltage and frequency response validation. Figure 3 shows an example of the genset load rejection tests performed on the two diesel engines.

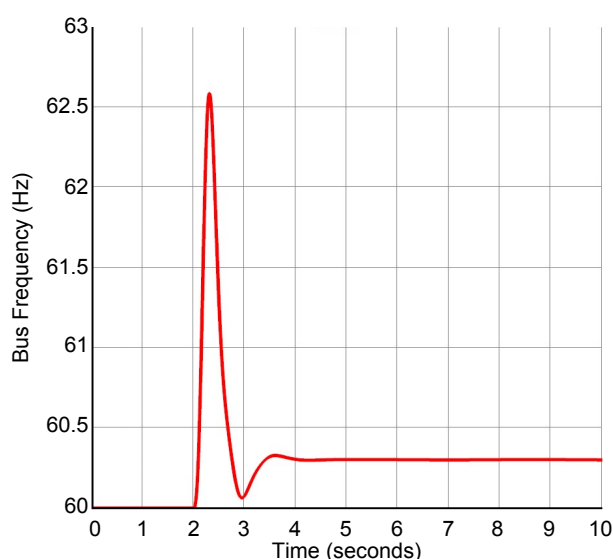


Figure 3 Genset Load Rejection Test

Once the entire C-HIL model was validated against known behaviors of similar power systems, the team continued to validate the microgrid controller and relaying operations using a live simulation of the C-HIL environment.

5 MICROGRID CONTROLLER

MGC systems include a vendor-supplied microgrid controller and three protective relays, one at each PCC. Relays and controllers work together symbiotically in the MGC system. The MGC system's primary function is to allow a small grid section to operate independently by preventing, detecting, and mitigating system blackouts. Automated control systems simultaneously control the DER for optimal economic dispatch and environmentally sound operation.

MGC systems contain power factor control, distributed generation sharing and optimization, load shedding, load management, bidirectional power flow management, peak shaving, grid decoupling, grid autosynchronization, monitoring, and alarming. The MGC system dispatches the DER power output to maintain power interchange at the PCC within predetermined limits simultaneously to share load between parallel-connected DERs.

Figure 4 shows protective relay recordings at PCC1 during an upstream utility power system fault. As part of the test sequence and before triggering the fault, the diesel genset was set to carry portions of the feeder load. Approximately 200 ms after the fault, the relay sends a trip command to the PCC1 breaker. The breaker contacts opened about 100 ms after receiving the trip signal due to inherited mechanical delays. At this point, all of the feeder load is transferred to the diesel genset, momentarily

exceeding its capacity. To maintain microgrid island stability, the MGC executes its fast load-shedding mechanism and disconnects sufficient load to support frequency recovery. This is a normal sequence of events for seamless islanding of a microgrid after a system fault.

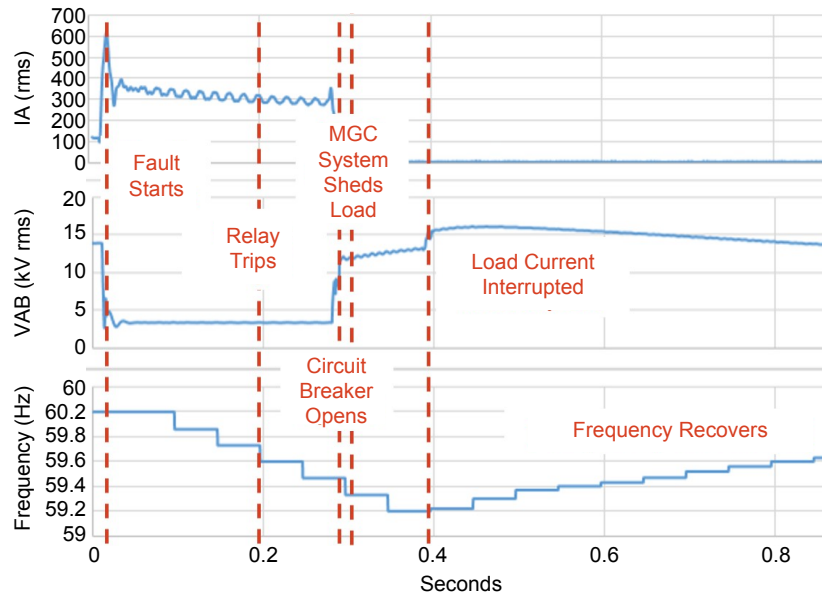


Figure 4 Simulated Islanding Event

6 STANDARDIZED TEST SEQUENCE

The main goal of the symposium test was to illustrate some of the major benefits of utilizing a microgrid controller to manage the generation, distribution, and protection resources of a smart power distribution system. The three plots in Figure 5 show the standard test sequence used at the symposium to evaluate the four different microgrid vendor solutions.

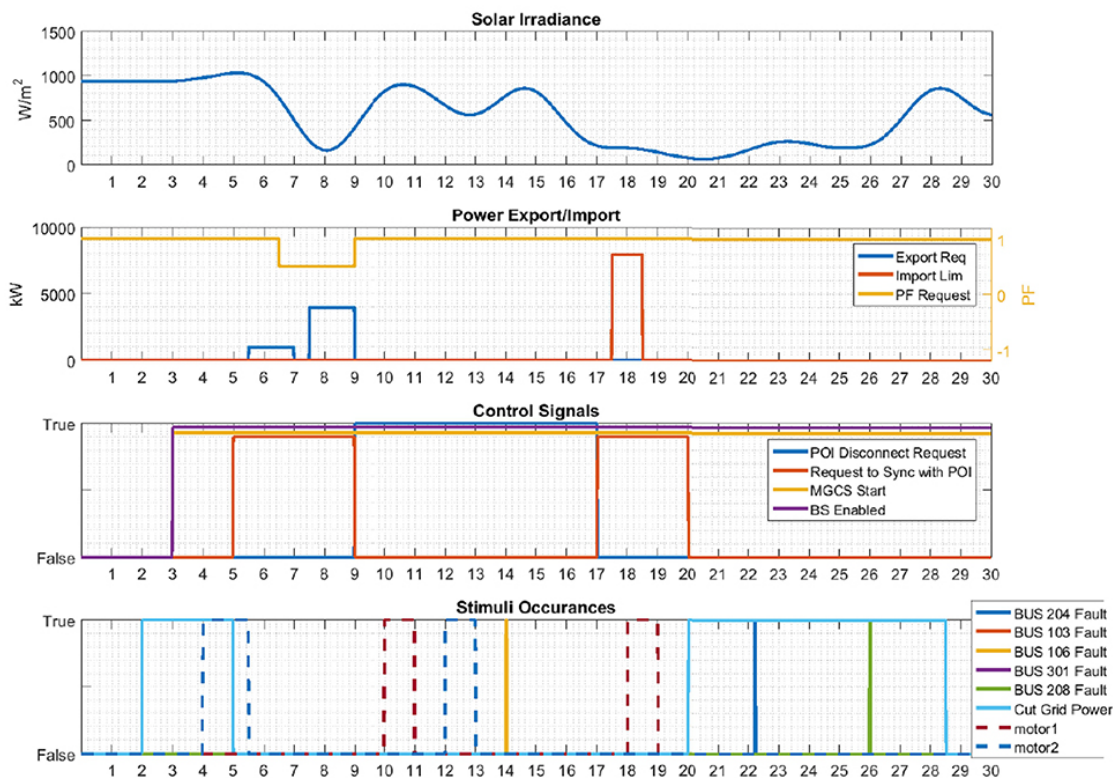


Figure 5 Standardized Test Sequence

At initialization of the real-time simulation, all three microgrid feeders are importing power from the grid. At 2 minutes into the test, the grid power is cut (see the light blue trace in the bottom plot), which causes Feeder 1 to black out unless the diesel genset is running and the microgrid controller can shed load fast enough to avoid tripping the genset. At 3 minutes, a black start enabled control signal (the purple trace in the second plot up from the bottom) is received by the microgrid controller from the distribution management system, which allows all DERs to start and pick up load. At subsequent points, requests are sent from the distribution management system to the microgrid controller to synchronize at the PCC, disconnect from the PCC, or honor a particular real power flow condition across the PCC. The application of faults on several buses assesses the microgrid controllers' reaction to protective relay events.

7 LESSONS LEARNED

Key lessons learned in this project include:

- Significant time is needed to configure and test the communication and data model interfaces to power converter and genset controllers.
- The C-HIL prototyping system needs to include at least one of each hardware device until the C-HIL modeling team becomes intimately familiar with the hardware devices and can model them accurately on future projects.
- Automated test sequences need to be developed that thoroughly test all edge conditions to expose emergent interdependent control behaviors and carefully preserve test results.
- Synchronization coordination is essential to avoid damaging field equipment. Test the edges of the synchronization window, especially for large phase angle offsets. Unlike industrial power systems, community microgrids may consider load shedding to assist synchronization.
- The planned revision to IEEE 1547 benefits microgrid stability during transition events.

8 DISTRIBUTION STATEMENT

Approved for public release: distribution unlimited.

This material is based upon work supported by the Department of Energy under Air Force Contract No. FA8721-05-C-0002 and/or FA8702-15-D-0001. Any opinions, findings, conclusions or recommendations expressed in this material are those of the author(s) and do not necessarily reflect the views of the Department of Energy.

BIBLIOGRAPHY

- [1] K. G. Ravikumar, S. Manson, S. K. Raghupathula, T. Alghamdi, and J. Bugshan, "Complete Power Management System for an Industrial Refinery," proceedings of the 62nd Annual Petroleum and Chemical Industry Technical Conference, Houston, TX, October 2015.
- [2] Electric Power Hardware-in-the-Loop Controls Consortium Repository, "Electric Power Hardware-in-the-loop Controls Collaborative." Available: github.com/PowerSystemsHIL/EPHCC.
- [3] Massachusetts Institute of Technology Lincoln Laboratory, 2017 Microgrid & DER Controller Symposium. Available: www.ll.mit.edu/mission/engineering/2017-Microgrid-Symposium.html.