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CERTS MICROGRID LABORATORY TEST BED

Test Plan Section 6.0
Microgrid Test Bed System Checkout
(Static Switch)

APPENDIX I

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CERTS MICROGRID TEST REPORT

SECTION 6.0

“Microgrid Test Bed System Checkout
(Static Switch)”

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1.0 INTRODUCTION

A series of tests were performed on the CERTS Microgrid by American Electric Power at the Walnut test site in Groveport, Ohio with support from Lawrence Berkeley National Laboratory, Sandia National Laboratory, TECOGEN, The Switch (originally Youtility), Distributed-Energy (originally Northern Power) and University of Wisconsin. These tests were designed to demonstrate the CERTS Microgrid concepts of control and protection while connected to the utility electrical system and isolated (i.e., referred to as “islanded” from it). This paper describes the tests that were performed in Section 6.0 “Procedure – Microgrid Test Bed System Checkout” of the CERTS Micro-grid Test Plan.

2.0 BACKGROUND

The CERTS Microgrid Concept is an advanced approach for enabling integration of, in principle, an unlimited quantity of DER (e.g., distributed generation (DG), energy storage, etc.) into the electric utility grid. A key feature of a microgrid is its ability to separate and island itself from the utility system, during a utility grid disturbance. This is accomplished via intelligent power electronic interfaces and a single, high-speed, switch which is used for disconnection from the grid and synchronization to the grid. During a disturbance, the DER and corresponding loads can autonomously be separated from the utility’s distribution system, isolating the microgrid’s load from the disturbance (and thereby maintaining high level of service) without harming the integrity of the utility’s electrical system. Thus, when the utility grid returns to normal, the microgrid automatically synchronizes and reconnects itself to the grid, in an equally seamless fashion. Intentional islanding of DER and loads has the potential to provide a higher level of reliability than that provided by the distribution system as a whole.

What is unique about the CERTS Microgrid is that it can provide this technically challenging functionality without extensive (i.e., expensive) custom engineering. In addition, the design of the CERTS Microgrid provides a high level of system reliability and great flexibility in the placement of DER within the microgrid. The CERTS Microgrid offers these functionalities at much lower costs than traditional approaches by incorporating peer-to-peer and plug-and-play concepts for each component within the microgrid.

The original concept was driven by two fundamental principles: 1.) A systems perspective was necessary for customers, utilities, and society to capture the full benefits of integrating DER into an energy system; and 2.) The business case for accelerating adoption of these advanced concepts will be driven, primarily, by lowering the up-front cost and enhancing the value offered by microgrids.

Each innovation was created specifically to lower the cost and improve the reliability of small-scale DG systems (i.e., installed systems with capacities ranging from less than 100kW to 1000kW). The goal was to increase and accelerate realization of the many benefits offered by small-scale DG, such as their ability to supply waste heat at the point of need or to provide a higher level of reliability to some but not all loads within a facility. From an electric utility perspective, the CERTS Microgrid Concept is attractive because it recognizes that the nation's distribution system is extensive, aging, and will change over time which impacts power quality. The CERTS Microgrid Concept enables high penetration of DG systems without requiring re-design or re-engineering of the utility's distribution system.

Prospective applications of the CERTS Microgrid include industrial parks, commercial and institutional campuses, situations that require uninterrupted power supplies and high power quality, CHP systems, Greenfield communities, and remote applications. In short, wherever economic and DG location considerations indicate the need for multiple DG units within a (or among) site, the CERTS Microgrid offers the potential for a much more reliable, flexible, and lower cost solution compared to traditional engineering approaches for integrating DG.

3.0 MICROGRID TESTBED SETUP

The CERTS Microgrid Test Bed is operated at 480/277 volts (i.e., three-phase, four-wire) and consists of three TECOGEN Generators at 480 volts capable of producing 60kW plus 60kVAr (Gen-set A1, Gen-set A2 and Gen-set B1) and four load banks (Load Bank 3, Load Bank 4, Load Bank 5 and Load Bank 6) capable of consuming 100kW plus 20kVAr each, as shown in Figure 2. Each of the generators are connected to an 112kVA isolation transformer and interfaced to the CERTS Microgrid through an inverter, developed by The Switch, where the algorithms for the CERTS Microgrid controls are embedded. . A semiconductor switch made by S&C Electric Company, known as the static switch, connects the CERTS Microgrid to the utility grid. Load Banks 3 – 5 are the local loads in zones located beyond the static switch; and Load Bank 6 is a customer load in Zone 6 located on the utility side of the static switch.



Figure 1 - CERTS Microgrid Aerial Photo

There are 6 zones in the Test Bed with Zones 2 - 6 contained within the CERTS Microgrid design and Zone 1 being the utility interface and referred to as the point-of-common coupling (PCC) to the grid. Each zone is protected by a Schweitzer SEL-351 relay. Faults of varying magnitude can be applied to each zone through an additional breaker which allows fault application and removal.

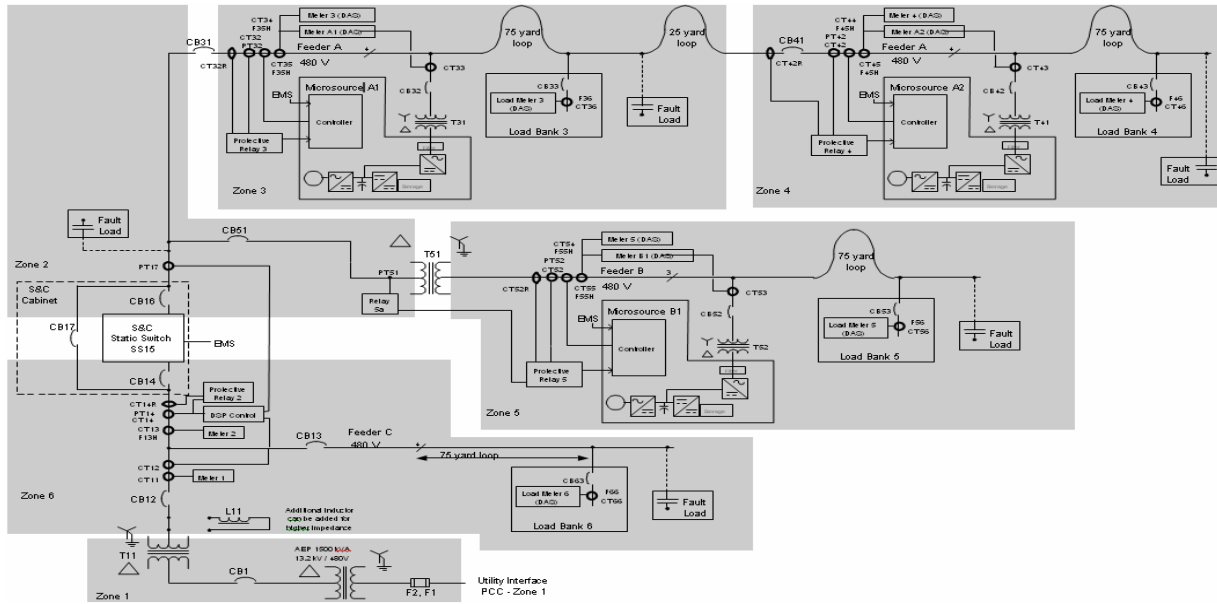


Figure 2 - One Line Diagram of CERTS Microgrid Test Bed

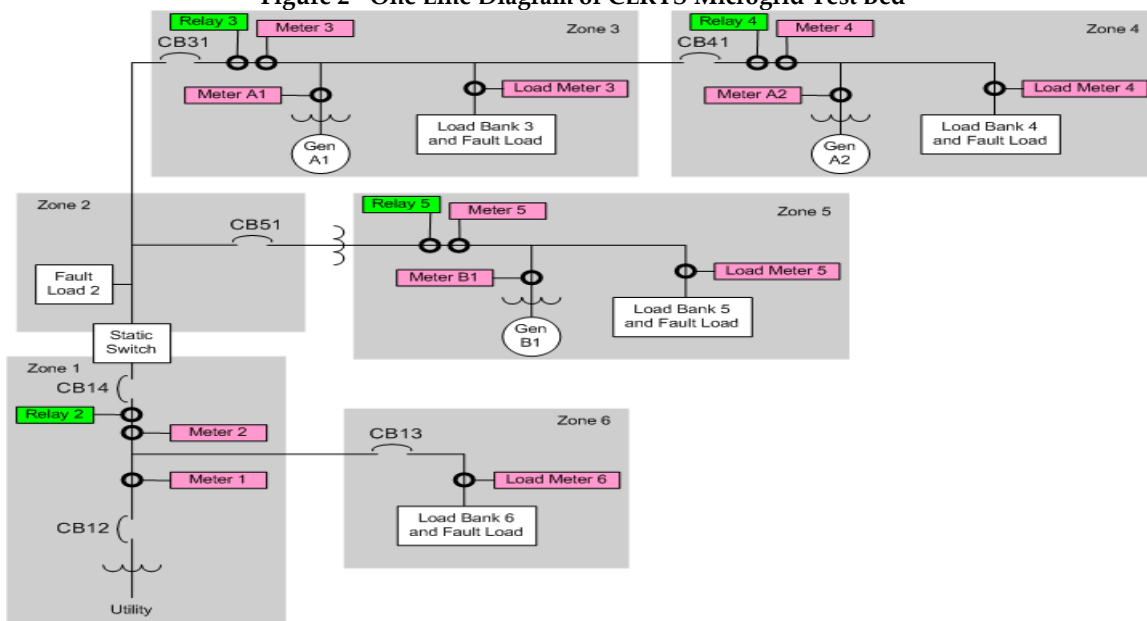


Figure 3 - Simplified diagram of Test Bed showing Meter and Relay locations

There are twelve PML ION 7650 meters placed throughout the microgrid and shown in Figure 3, which monitor electrical system conditions, plus acquire phase current and voltage waveforms; and calculate RMS values of voltage, current, active power, reactive power, and frequency.

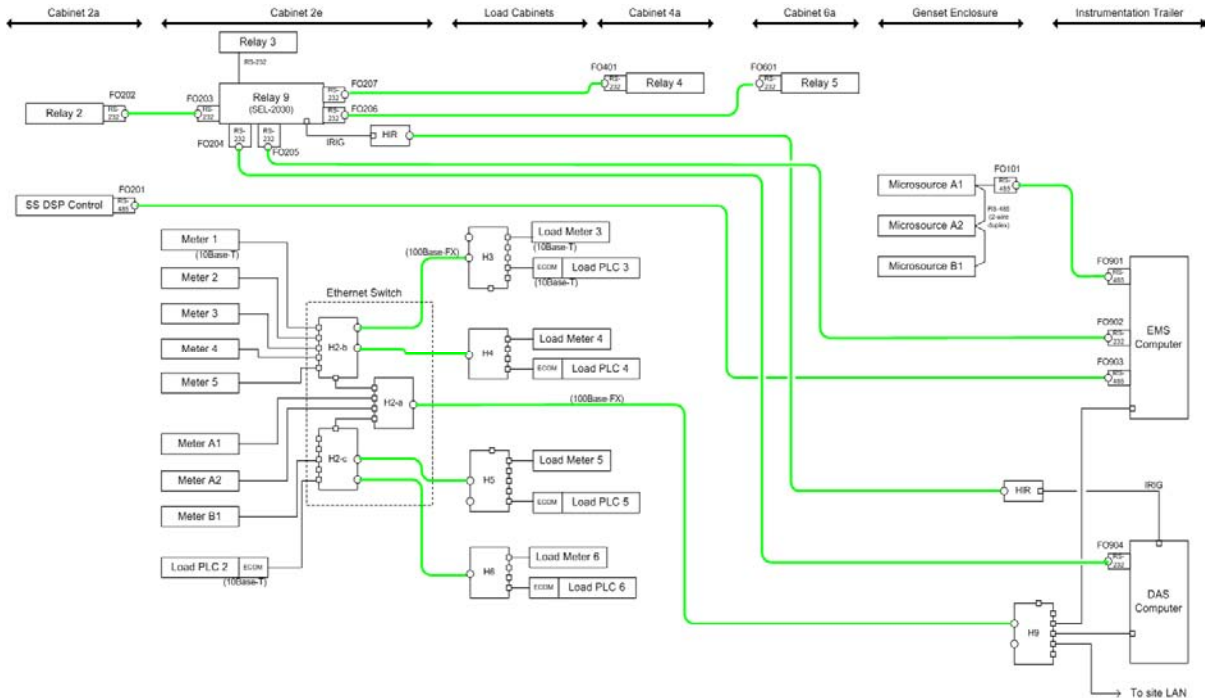


Figure 4 - Diagram of DAS & EMS Data networks

An Ethernet network was provided as shown in Figure 4, for communications between all meters, load control PLCs, and the Data Acquisition System (DAS) computer, using fiber-optic links and switches. The DAS and Energy Management System (EMS) computers were also networked into the local Dolan Local Area Network (LAN) and to a secure Website with user ID and password protection. Additional serial links, using fiber optic converters, connect all relays, static switch Digital Signal Processor (DSP) controller, and TECOGEN Gen-set controls to the EMS computer.

4.0 PROPOSED TEST PLAN

The CERTS Microgrid Test Plan was developed by the CERTS Microgrid Team to demonstrate the unique concepts of control and protection of the CERTS Microgrid. This test plan was reviewed by a Technical Advisory Committee outside the CERTS Microgrid Team and then implemented by American Electric Power. CERTS Microgrid Test Plan consists of 12 sections with 5 of them detailing desired tests, starting at section 6.0, to demonstrate the controls and concepts of the CERTS Microgrid. The other 7 sections pertain to safety procedures, equipment calibration, and documentation. Each section of the test plan is described below.

- Section 1 – “Purpose, References, and Definitions” describes the purpose of the test plan, helpful references for further explanation of how the test bed was created, and definitions used through out the test plan.

- Section 2 – “Responsibilities” informs personnel of their responsibilities while working on or near the CERTS Microgrid test site.
- Section 3 – “Training - Team Members” lists the mandatory training needed by personnel before they can work on or near the CERTS Microgrid test site.
- Section 4 – “Procedure – CERTS Microgrid Test Bed Lockout/Tagout” entails how to safely shut down the equipment and lockout/tagout the closest upstream disconnect to work on or near equipment.
- Section 5 – “Procedure – General” is the daily procedures performed at the CERTS Microgrid Test Site, prior to performing a test from Section 6 through Section 10.
- Section 6 – “Procedure – Microgrid Test Bed System Checkout” was designed to check control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. The goal is to assure that the test bed is operating and ready to perform the tests described in the remaining sections of the test plan document.
- Section 7 – “Validate Protection Settings & Initial Fault Testing” is designed to examine a preliminary set of fault (i.e. overload simulating a fault) condition tests to ensure protection and safety of the Micro-grid test Bed, while performing other planned tests. The goal is to test and adjust protection settings to achieve the most ideal conditions and protection design.
- Section 8 – “Procedure – Reduced System Tests” is a limited set of tests to build confidence that the Gen-set inverter controls are working correctly. This includes unit control, zone control, and mixed power controls, in conjunction with limit controls and synchronized closing of the static switch. These tests are based on the TECOGEN/THE SWITCH factory acceptance testing.
- Section 9 – “Procedure – Demonstration Tests of Control Power Flow” demonstrates the flexibility of the Micro-grid both grid connected and islanded for different loads, power flows and impact on the utility.

- Section 10 – “Procedure – Test Difficult Loads” determines operation limits of the Micro-grid (i.e. power quality, protection and inverter limits) with low pf loads, motor loads, harmonic loads and unbalance loads.
- Section 11 - “Hazards & Mitigation” informs the personnel of hazards that may exist while working on or near the CERTS Micro-grid test site and how to mitigate them.
- Section 12 – “Quality Assurance” ensures quality for the acquiring data results by providing a checklist reminder for personnel.

5.0 TESTS PERFORMED IN SECTION 6.0

Prior to each test day, the person in charge performed a job safety briefing (JSB) with barricades and test setup inspected for safety and compliance. A minimum of two people were on-site during each planned test.

Visual and audible alarms were used to warn persons that energized testing was being performed in the Microgrid Test Bed area. The visual alarm consisted of a portable red flashing light, located between the Control Trailer and Gen-set Enclosure. An audible alarm, consisting of a portable wireless motion detector, was located at the front gate of the Walnut Test Site with the fence gate “Closed”, not locked, and audible alarm in the trailer operational during test(s).

Barricades were set up around the Micro-grid Test Bed area (i.e., saw-horse style barricades with a “Red” plastic chain surrounded the test area containing the Gen-set Enclosure, Micro-grid switching cabinets, plus load and fault bank cabinets).

Prior to performing tests, the Test Engineer or Technical Consultant verified that all personnel and visitors were properly protected and in assigned locations. Personnel were in or adjacent to the Control Trailer while tests were being performed. All nonessential personnel either left the main site or were sheltered in the Control Trailer.

For all tests the following waveforms were captured and recorded in the DAS for voltage (V) and current (I). From these waveforms real power (kW), reactive power (kVAr), and frequency (freq) were post calculated by the PQView software. Frequency measurements in this report should be used for steady state information and not used for transient analysis, due to the calculation and filtering methods employed. Below is a list of the meters capturing this data.

- Meters 1, 2, 3, 4 & 5
- Load Meters 3, 4, 5, & 6
- Meters A1, A2 & B1
- Meter 2 also measures the voltage across the static switch on phase A

Schweitzer event reports were also captured for each event, along with breaker and static switch status, such as Open or Close.

The first sets of tests came from section 6.0 where the static switch's controls and operation were checked, all three Gen-sets basic power and voltage controls were verified for correct operation, and a preliminary check of the protection scheme that was later tested in section 7.0. The static switch function tests checked the operation of the static switch, to assure it and its DSP control were operating as designed. This section included tests of dead-bus and synchronized closing, reverse power, and IEEE 1547 protective relay functions.

A synchronized closing test of the static switch was required to verify that when conditions were within synchronization limits set in the EMS, the static switch performed a synchronized close and thus provided a smooth connection transition. The de-energized bus (dead-bus) reclose test's goal was to verify that the static switch can close when de-energized bus conditions exist on the Gen-set side of the static switch; and that the dead-bus reclose algorithm requires user intervention (i.e., Operator needs to "Enable" the dead-bus reclose using pushbutton in the EMS).

The reverse power tests consisted of three tests: three-phase reverse power condition test, single-phase reverse power condition test, and anti-islanding Micro-grid settings reset test. Both three-phase and single-phase reverse power condition tests were required to verify the reverse power functionality of the static switch and confirm that the static switch islands the microgrid for a three-phase or single-phase reverse power condition. The anti-islanding Micro-grid settings reset test was needed to verify that if a reverse power event occurred, due to a mismatch of Gen-set settings (i.e., total Gen-set power is greater than Microgrid load), the static switch will lockout and go to the "Fault" state, where user intervention is required.

The next goal was to verify the reconnection timers of the static switch (i.e., set by default at 300 seconds based on IEEE Standard 1547-2003). The length of time is programmed into the control system and designed to prevent reconnection from island to utility-connected mode until after the utility source voltage returns to nominal steady state conditions.

6.0 ANALYSES OF TEST RESULTS

6.1 SECTION 6 – MICROGRID TEST BED SYSTEM CHECKOUT

6.1.1 System Start-Up and Synchronized Closing of Static Switch

Performance Goal:

Verify that when conditions are appropriate (within synchronization limits set in the EMS), the switch can perform a synchronized closing and thus give smooth closing transitions.

Initial Setup:

Gen-set A1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833Hz/kW

MG Voltage Command = 277V

Load Bank 3 = 40kW (13.3kW per phase)

Load Bank 6 = 40kW (13.3kW per phase)

After Gen-set A1 was running for a few minutes and supplied power to Load Bank 3, the test was started with a “Start” command from the EMS.

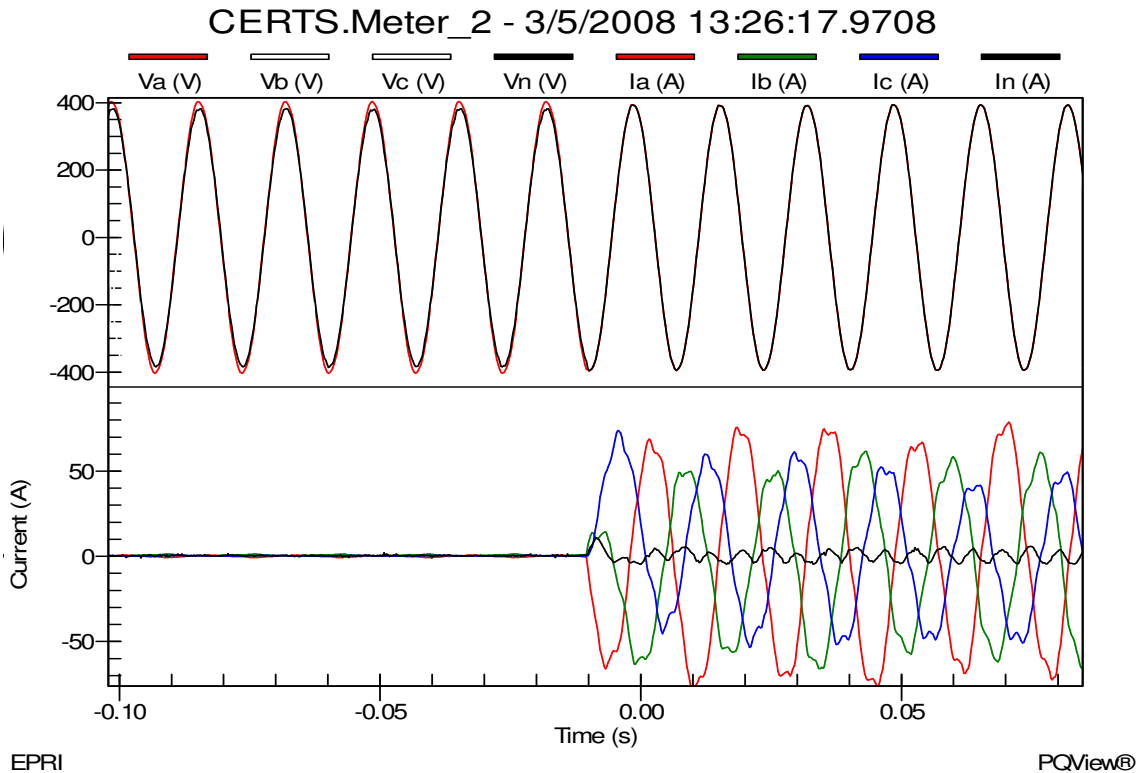


Figure 5a - A phase voltage waveforms and current at Meter 2 on the Microgrid during a synchronized "Close" of the static switch

When electrical system conditions met established criteria, the static switch did a synchronized "Close". A smooth voltage transition occurred from island to utility-connected mode. This transition occurred relatively quickly, after the "Start" command with the A-phase voltage waveforms at Meter 2 shown in Figure 5a. It can be seen that the utility A-phase voltage (red) closely matches the microgrid A-phase voltage (black) prior to synchronization. The transition occurred at approximately minus 0.01 seconds.

After the static switch closed and steady state conditions were established, the power flow at Meter 1, Meter 2, and Meter A1 was approximately 52kW, 16kW, and 20kW, respectively and the frequency stabilized, as shown in Figure 5b from 59.86Hz to the grid frequency of 60.01Hz.

The resistive load banks in each test zone were nominally rated with deviations from nominal expected due to changes in ambient temperature, per phase voltages, heat rise based on duration of test, etc. Thus, during this test the load banks were set at 13.3kW

per phase (i.e., approximately 40kW), but in reality the actual kW value recorded at Load Meter 3 and at load Meter 6 was approximately 36kW.

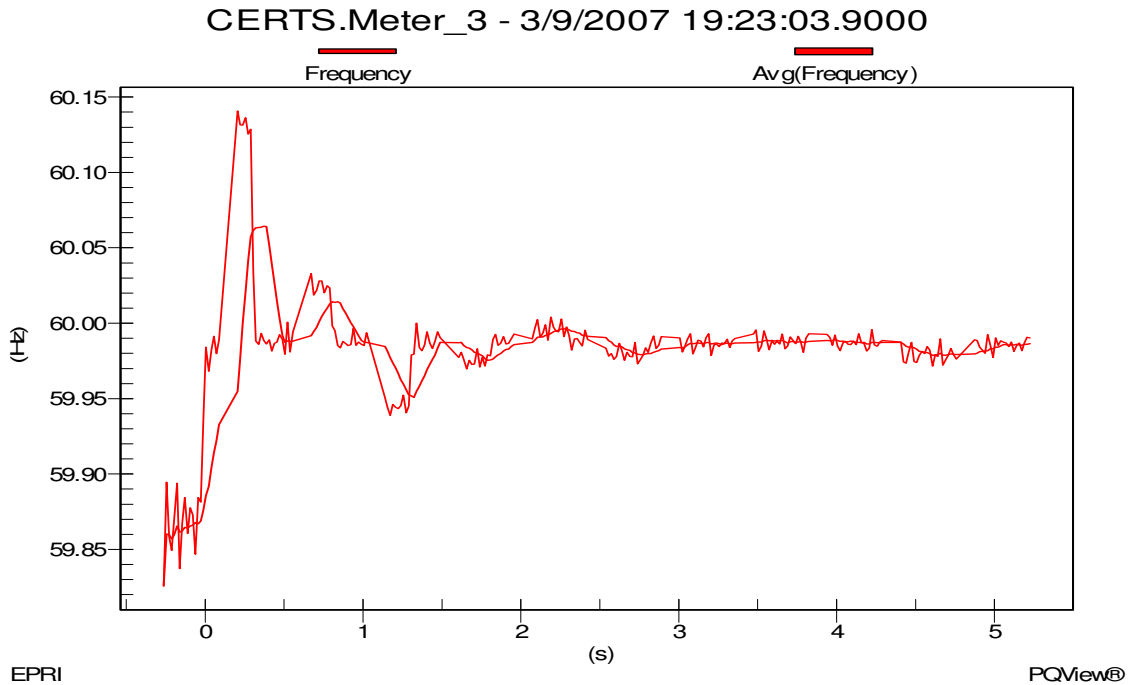


Figure 5b - Change in frequency during a synchronized close of the static switch, during the transition from island to utility-connected mode.

The first full scale test on the Microgrid Test Bed and synchronizing an islanded microgrid to the utility required a thorough review of the electrical conditions and affects of the corresponding algorithms designed into the CERTS Microgrid Concept. Thus, the following paragraphs provide a more extensive review and focus-in on the kW and kVAr load flows in Test Zone 3 which occurred before and after the transition from island to utility-connected mode.

Figure 5c includes the single-phase and three-phase load being served in Zone 3 of the microgrid. When in island mode and prior to synchronization, Gen-set A1 at Load Meter 3 was serving 33.75kW with A, B and C phases being 11.15kW, 11.35kW and 11.25kW, respectively. After synchronizing to the utility grid, the load at Load Meter 3 increased to 35.4kW with A, B and C phases being 11.95kW, 11.75kW and 11.70kW, respectively.

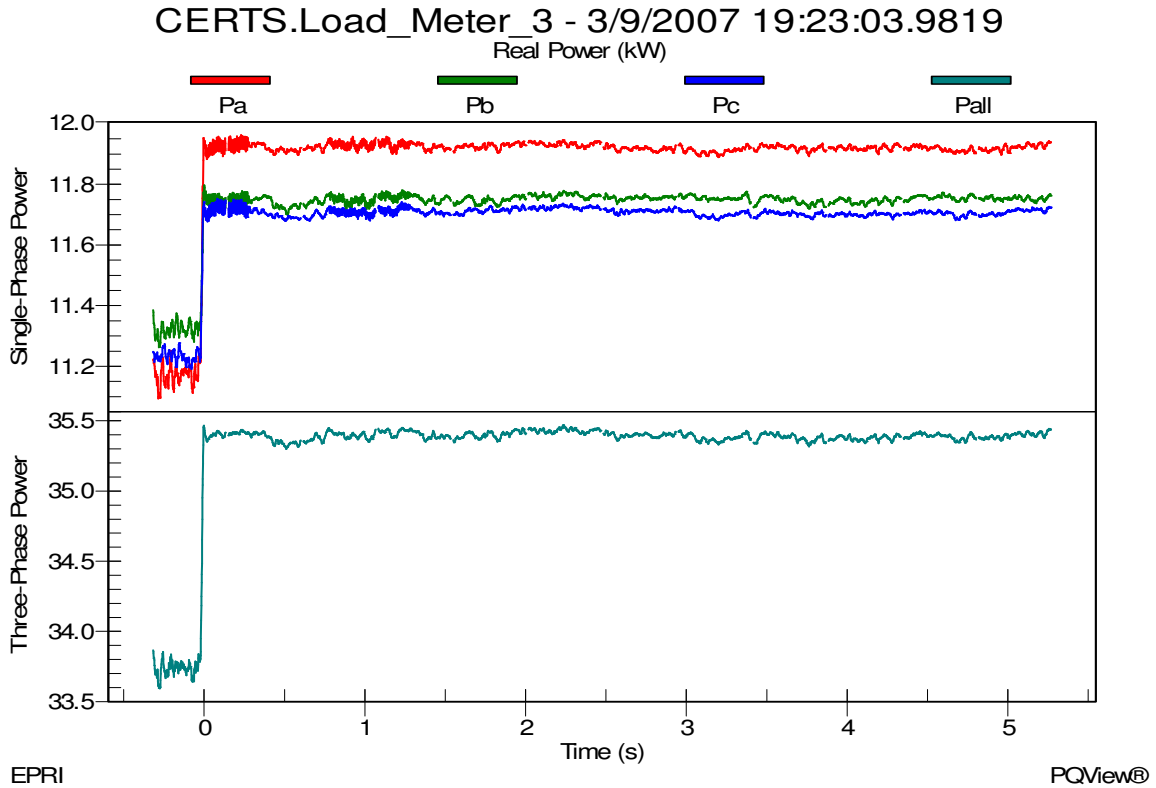


Figure 5c - Single and three phase kW load in Zone 3 at Load Meter 3

The increase in kW load at Load Bank 3 can be attributed to the slight change in the per phase voltages when interconnected to the utility grid. As illustrated in Figure 5d, A-phase RMS voltage was below B and C phases when the microgrid was in island mode, but is above B and C phase voltages when connected to the utility grid.

Prior to synchronization, Figure 5e show A-phase voltage at the point of common coupling (PCC) being higher at 283V with B and C phase voltages at 280V. After the microgrid synchronized to the utility grid, each of the phase voltages dropped at the PCC with A-phase reducing to approximately 280V, and B and C phases reducing to approximately 277V. These voltages are similar to the voltages at Meter 2 and closely match the voltage change at Load Bank 3.

With the slight change in kW load explained at Load Bank 3, the question remains as to how much of the microgrid's protected load is being served from the Gen-set A1 and how much is being served from the utility grid.

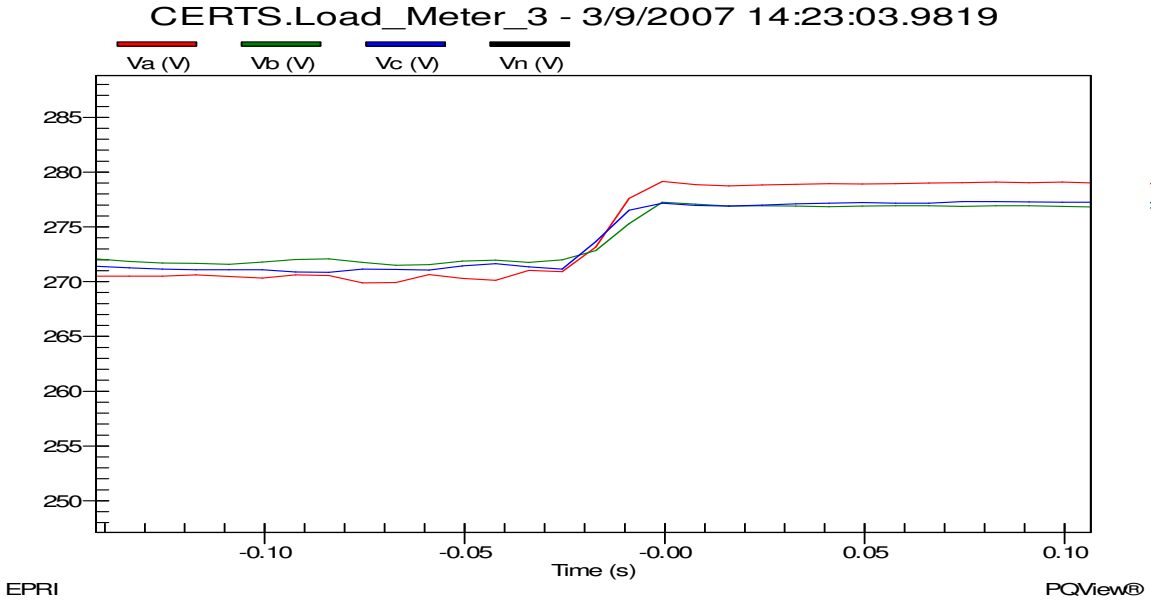


Figure 5d - RMS voltage at Load Bank3, during the transition from island to utility-connected mode.

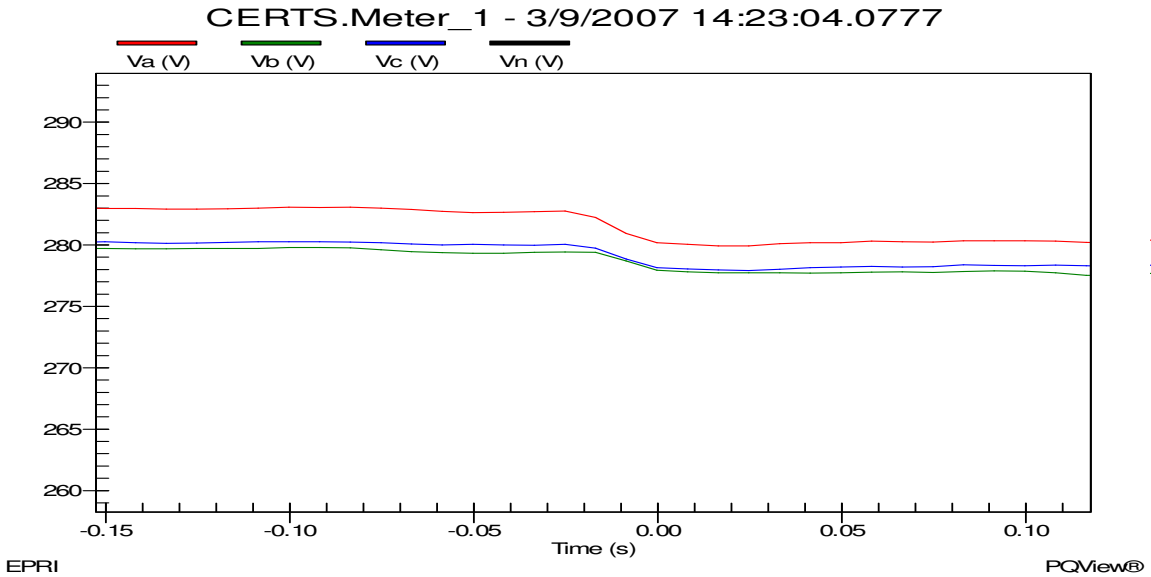


Figure 5e - RMS voltage on grounded-wye, 480/277 volts, side of T11 transformer during the transition from island to utility-connected mode

Figure 5f shows the change in kW load being served from the utility at Meter 2 when the microgrid is interconnected to the utility grid. As indicated, after the static switch closed, the total three phase load increased from 0kW to 16kW with A, B and C phase loads increasing from 0 to approximately 5.5kW, 4.0kW and 6.5kW, respectively.

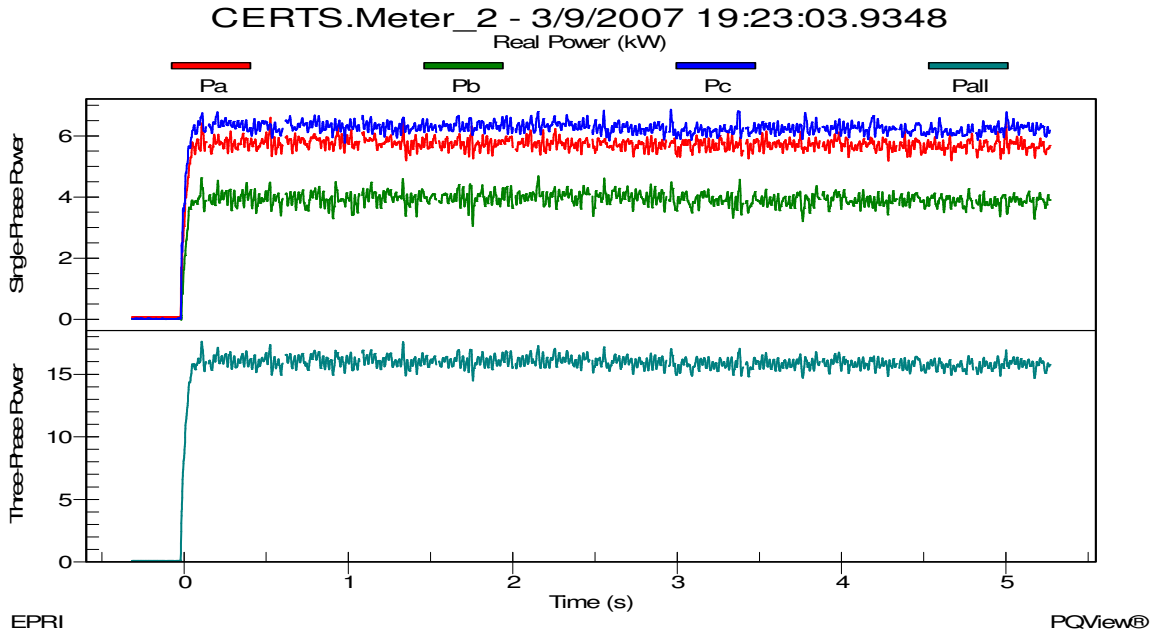


Figure 5f - The kW change at Meter 2 when served from the utility grid

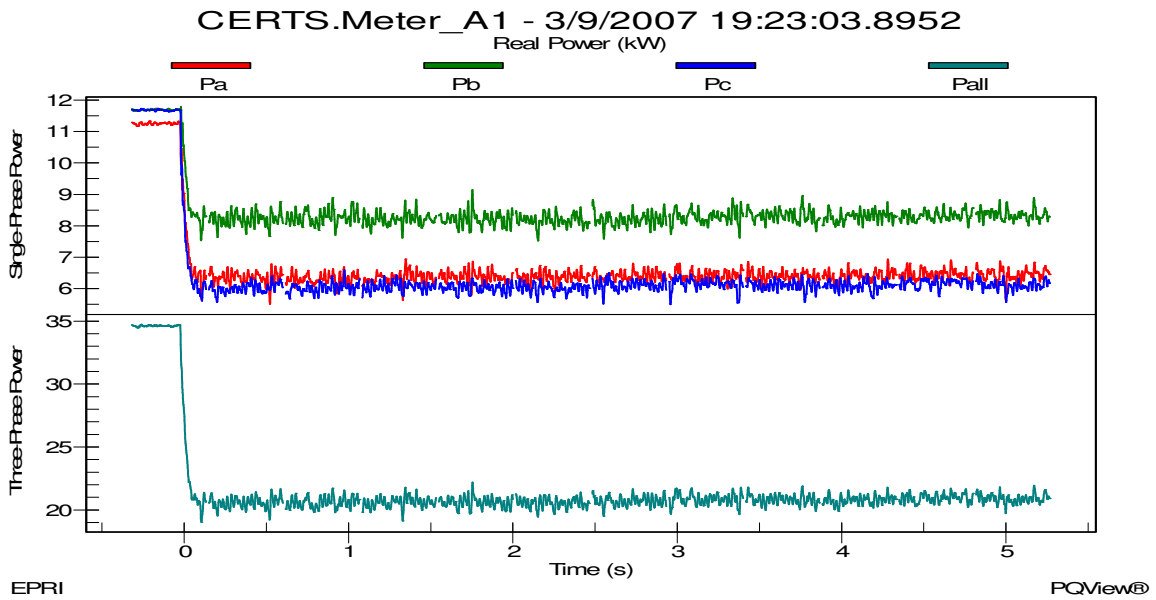


Figure 5g - The kW change at Meter A1 on the output of Gen-set A1

Figure 5g shows the corresponding change in kW output of Gen-set A1 at Meter A1, after the transition from island mode to utility-connected mode. As illustrated, the three-phase kW output of Gen-set A1 changed from approximately 34.6kW to 20kW with A-phase changing from approximately 11.2kW to 6kW; B-phase changing from 11.7kW to 8kW, and C-phase changing from 11.7kW to 6kW.

Note the 20kW value was the original Unit Power output set point in the controller of Gen-set A1. When in island mode, Gen-set A1 had sufficient capacity to serve the 35kW of load in Zone 3; and when the static switch synchronized with the utility grid, Gen-set A1 reduced its kW output to the selected set-point value.

Once the synchronization criteria were within limits, the static switch closed, connecting the microgrid to the utility. After this connection Gen-set A1 adjusted its frequency to match that of the utility grid, as shown in Figure 5b. This increase in frequency caused Gen-set A1 to reduce its real power output to the unit power mode set-point of 20kW, as shown in Figure 5g. Finally, Gen-set A1 reactive power output transitioned from producing to absorbing power in response to the increased voltage of the utility in an attempt to lower the microgrid nominal voltage of 277 volts, as shown in Figure 5h.

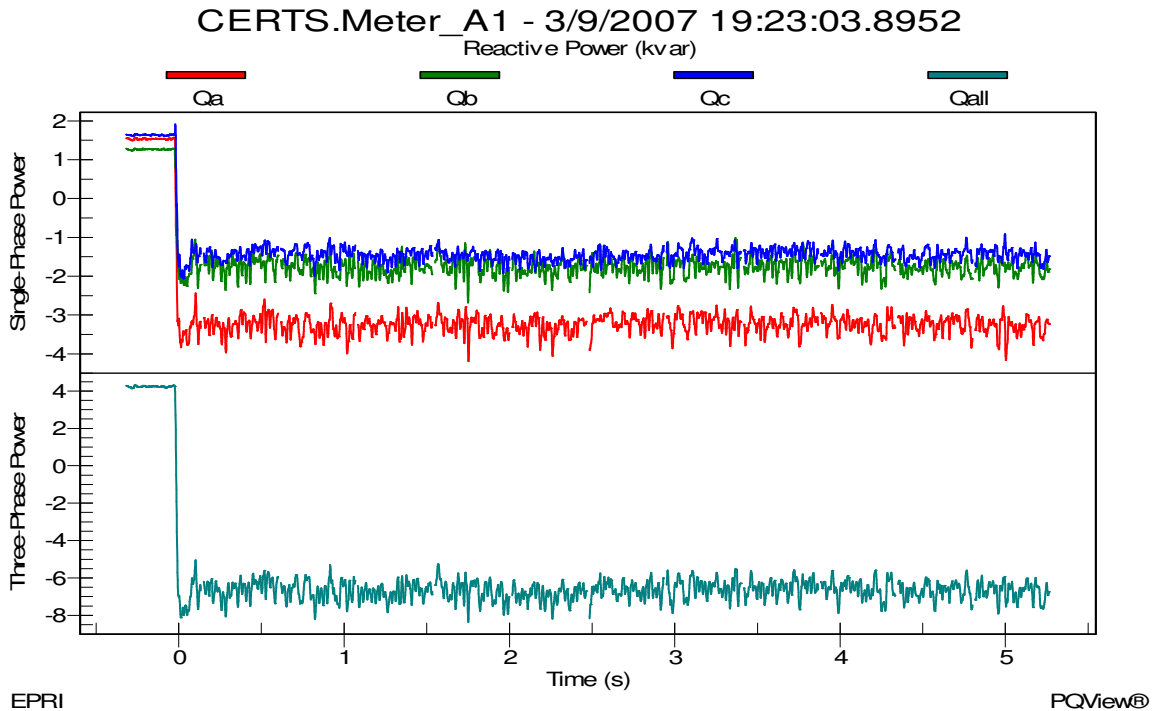


Figure 5h - The kVAr change at Meter A1 on the output of Gen-set A1

Figure 5h shows the inverter adjusting the total kVAr value at Gen-set A1 from +4kVAr when in island mode to approximately -7kVAr when utility-connected. For the static switch to synchronize with the utility grid, A-phase voltage needed to be raised high on the Microgrid than the voltages on phases B and C. This is evident in Figure 5h, where the kVAr change in A-phase was much greater (i.e., almost twice the kVAr change) than in phases B and C. Thus, the voltages raised and frequency adjusted on the Microgrid,

as designed in the algorithm (i.e., MG Power/Frequency Droop setting), for the static switch to synchronize with the utility grid.

6.1.2 Loss of Utility Source Test

Performance Goal:

Verify that the microgrid detects and islands itself upon the loss of the utility source upstream of the PCC. This is detected in two ways: first, for a large load loss on the utility system an under-voltage event will occur; and second, for a small load loss a reverse power event will occur. Once the utility voltage returns to the IEEE 1547 limits, verify the proper operations of the reconnection timers (set by default to 300 seconds based on IEEE 1547 standards).

Initial Setup for large loss on utility system:

Gen-set A1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Load Bank 3 = 40kW

Load Bank 6 = 20kW

AEP Load Bank = 500kW

After Gen-set A1 was running for a few minutes and supplying power to Load Bank 3, a synchronized “Close” of the static switch was initiated. Once synchronized, the microgrid was connected to the utility grid with a separate AEP Load Bank connected to the electrical system between transformer T11 and circuit breaker CB1 with 500 kW of additional load being served from the utility through breaker CB1.

Figure 6a shows the voltage waveform results when breaker CB1 to the utility grid was “Opened/Tripped”. It can be seen that the voltage collapses quickly causing the static switch to open and the microgrid load remains served by the Gen-set A1. Likewise, Figure 6b shows the current waveforms at Meter A1 when breaker CB1 was opened, the microgrid islanded in approximately 2 cycles. Note, Gen-set A1 current waveform increased to approximately 500 amperes, peak, which is well beyond its design rating. The EMS indicated that an under-voltage PQ event did occur and that a static switch

opened, successfully. During this event the under-voltage relay of CB-51 operated, de-energizing Zone 5 in the test bed.

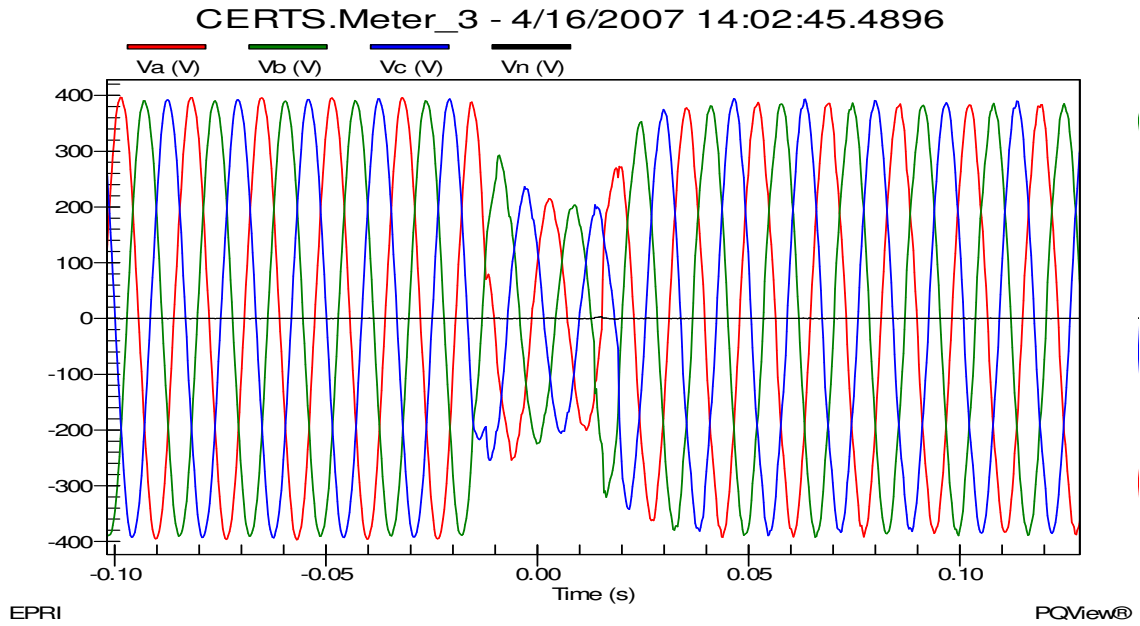


Figure 6a - Meter 3 voltage waveform during breaker CB1 opening and the microgrid islanded within 2 cycles

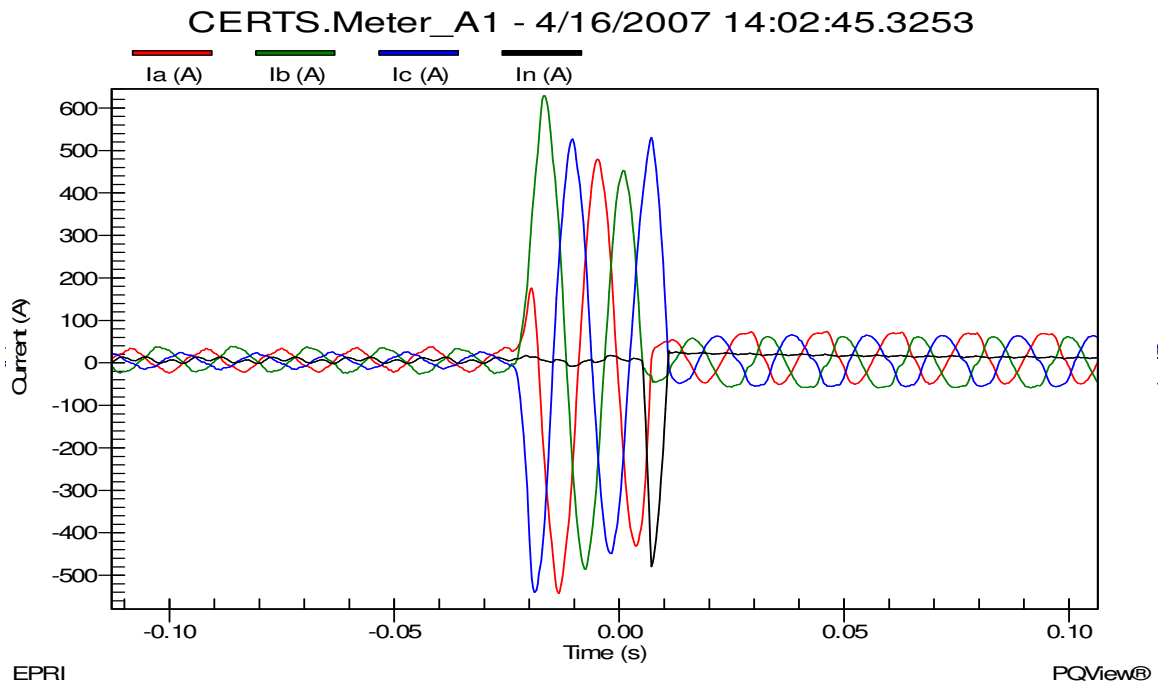


Figure 6b - Current waveforms at Meter A1 during breaker CB1 opening

Load on the AEP Load Bank was reduced to 0kW and the utility grid was reconnected by a manual “Close” of breaker CB1. After CB1 was closed, the IEEE 1547 voltage test did shut-off and the static switch did not immediately attempt to reconnect, since the reconnection timer was set to 300 seconds. After 300 seconds, the static switch did a synchronized “Close” and the microgrid transitioned from island mode to utility-connected mode of operation. Figure 6c shows kW load at Meter 2 increasing from 0kW to approximately 28kW from the utility grid. Coincidentally, kW load at Meter A1 decreased from 34.5kW to 10kW, as shown in Figure 6d.

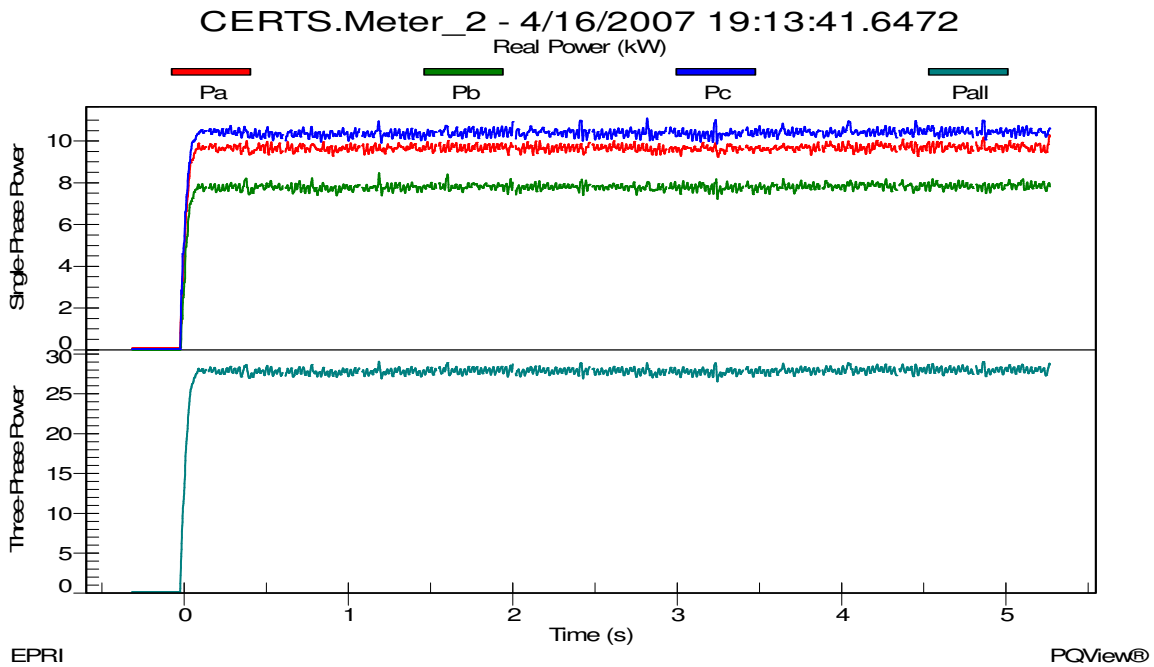


Figure 6c - Meter 2 load during synchronized close of the static switch

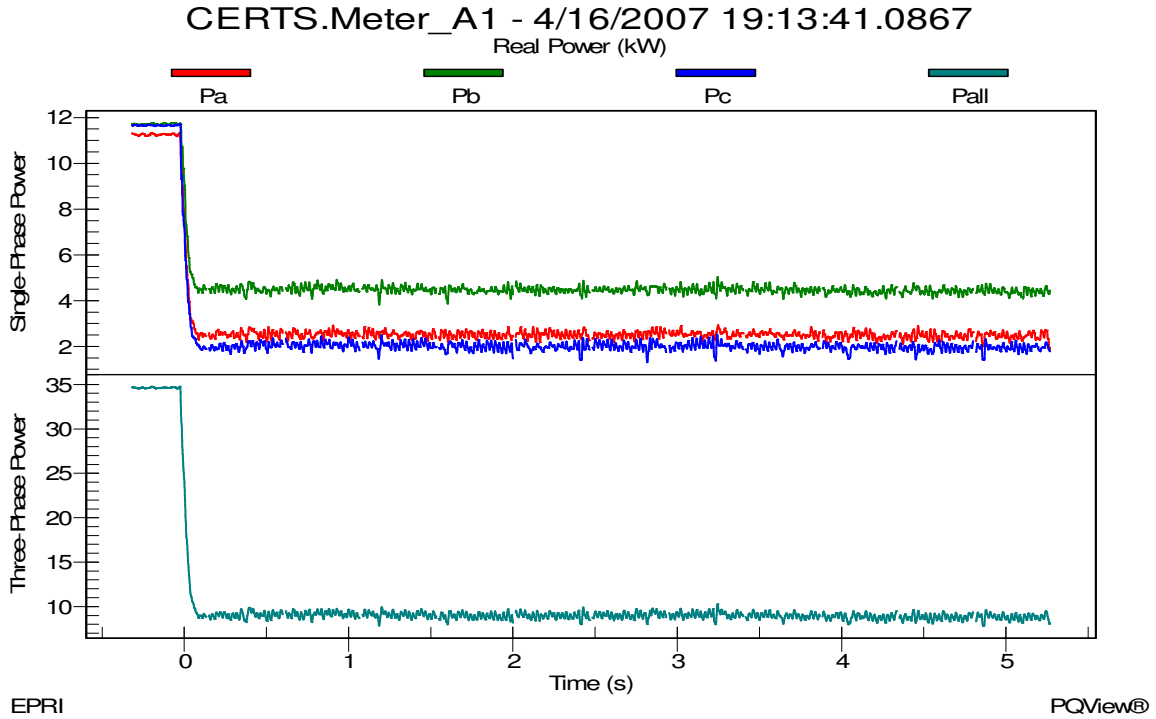


Figure 6d - Meter A1 load when microgrid transitioned from island mode to utility-connected mode
 Figures 6e and 6f show the kW load changes in Zone 3 at Load Meter 3 and kVAR changes at Meter A1, respectively, when the microgrid transitioned from island mode to utility-connected mode.

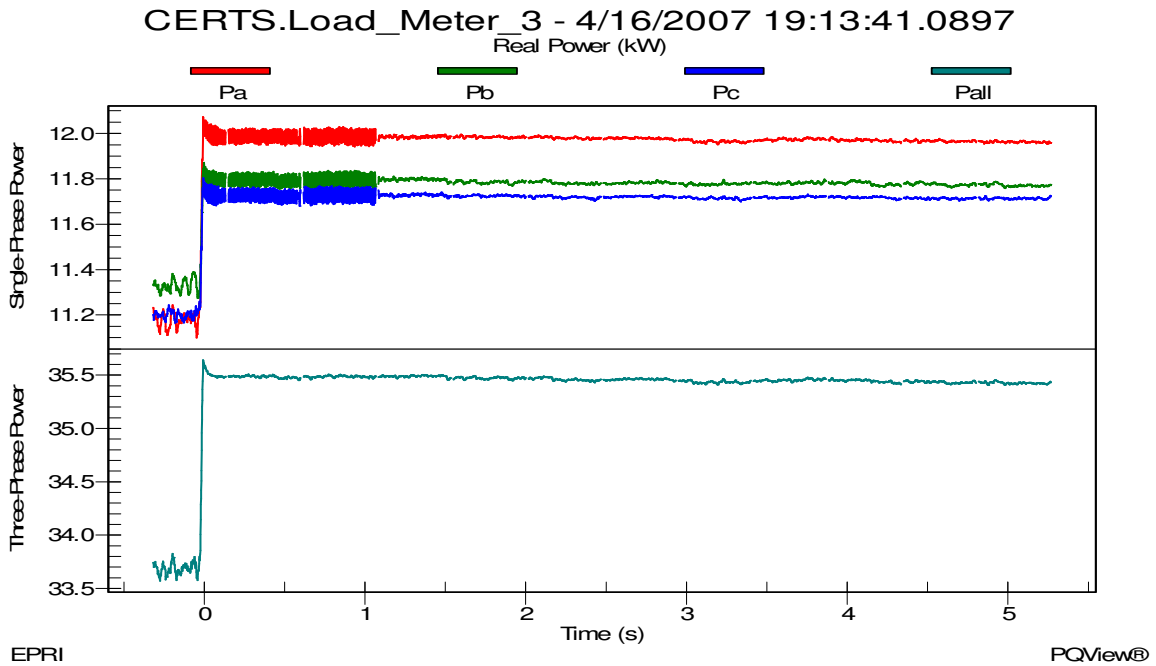


Figure 6e - Zone 3 load when microgrid transitioned from island mode to utility-connected mode

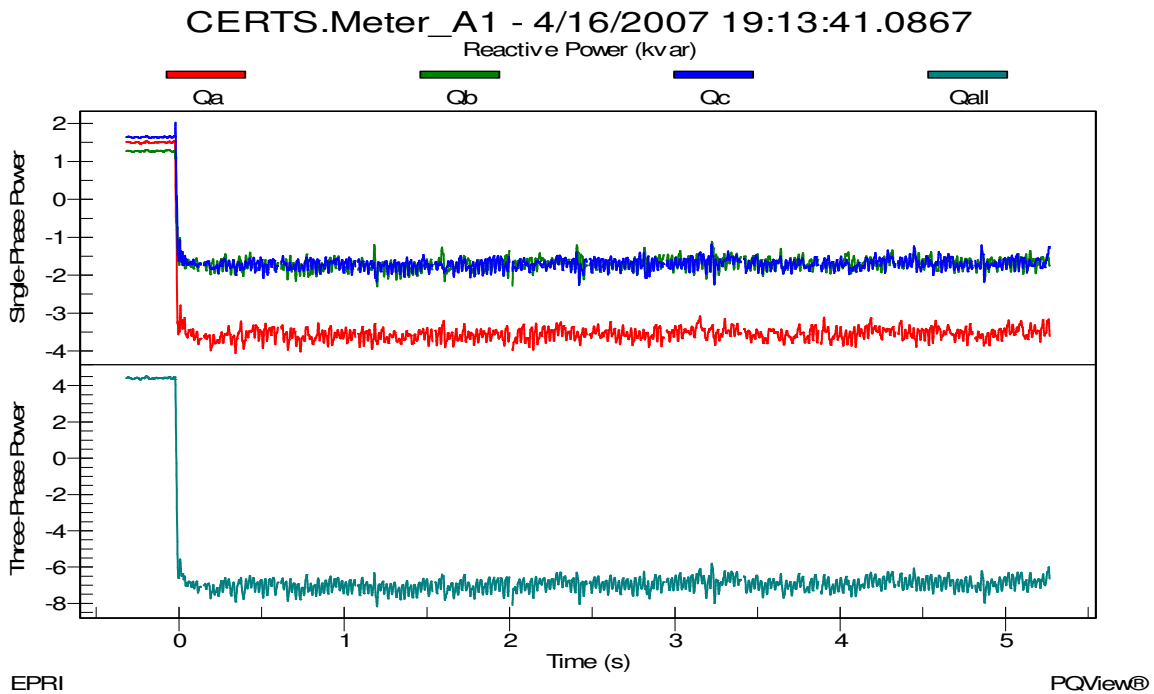


Figure 6f - kVAR changes in Zone 3 when Microgrid transitioned from island mode to utility-connected mode.

Figure 6f shows the inverter adjusting the total kVAR value at Gen-set A1 from +4.5kVAR when in island mode to -7kVAR when utility-connected. For the static switch to synchronize with the utility grid, A-phase voltage on the microgrid needed to be raised higher than the voltages on phases B and C. In Figure 6f the kVAR change in A-phase was much greater than in phases B and C. Thus, the voltages raised and the frequency adjusted on the microgrid, as designed in the algorithm, for the static switch to synchronize with the utility grid.

The test below verifies that the microgrid detected and islanded itself upon the loss of the utility source upstream of the PCC for a small load loss with a reverse power event occurring.

Initial Setup for small loss on utility system:

Overload-Load Bank = 85kW

Load Bank 4 = 60kW

Load Bank 6 = 10kW

Reverse Power Set-point = 10kW (i.e., import 3.33kW per phase)

In Figure 6g a large load of approximately 135kW is removed from the microgrid. Only a small amount of load remains beyond the PCC (i.e., actually less than 10kW) in Load Bank 6. After two seconds a reverse power event occurs and the static switch opens. This demonstrates that any load below the reverse power set-point for more than two seconds will initiate an anti-islanding event.

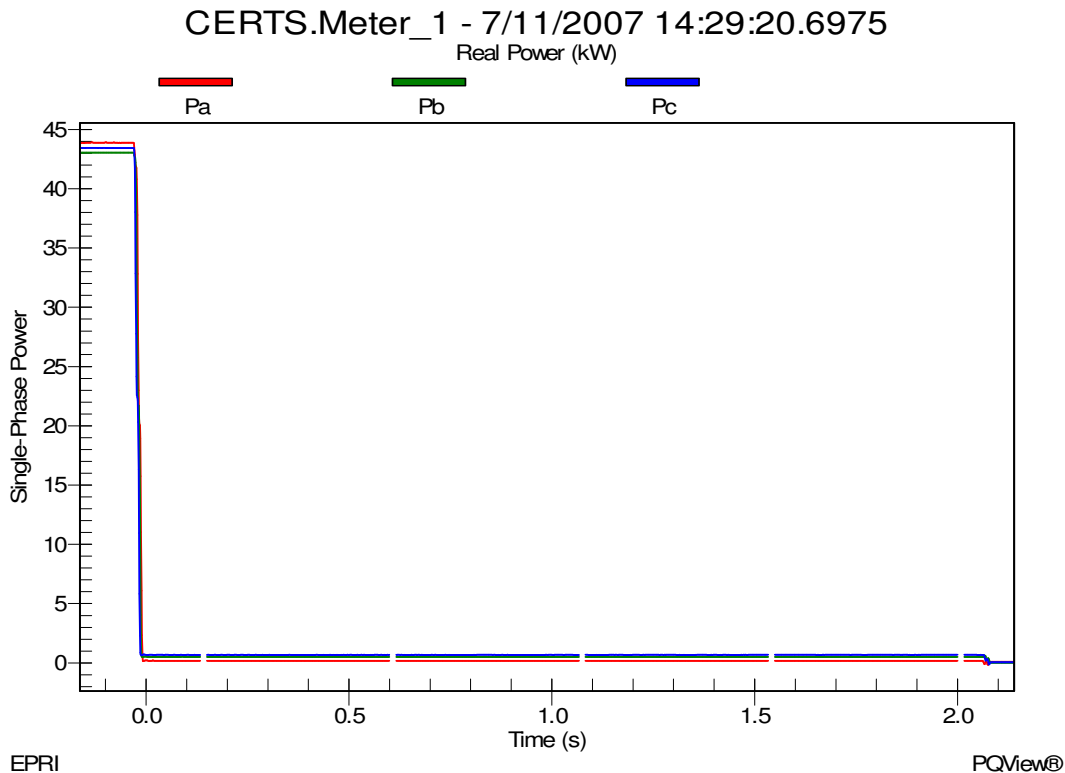


Figure 6g – Single-phase kW at PCC when microgrid load was below reverse power set-point of 10kW.

6.1.3 Single-Phase Reverse Power Test (Simulate Loss of Phase)

Performance Goal:

Verify that the static switch islands the microgrid when a reverse power condition, due to an open-phase occurs.

Initial Setup:

Gen-set A1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Reverse Power Setting = 10kW

Load Bank 3 = 40kW

Load Bank 6 = 40kW

After the Gen-set A1 was running for a few minutes and supplying power to Load Bank 3, a synchronized “Close” of the static switch was initiated. After the static switch closed and steady-state conditions established, the microgrid and Load Bank 6 were connected to the utility grid.

This test began by removing the load on A-phase of Load Bank 6, shown in Figure 7a, with approximately 23.7kW remaining (i.e., 11.85kW in each of the two phases). While maintaining 0kW on A-phase of Load Bank 6, the kW load on A-phase of Load Bank 3 was reduced from approximately 11.8kW to 4kW, which in turn reduced the kW load on the A-phase at Meter 1 at the PCC to below the set threshold of 3.3kW, shown in Figure 7b. This created a reverse power condition on A-phase and opened the static switch.

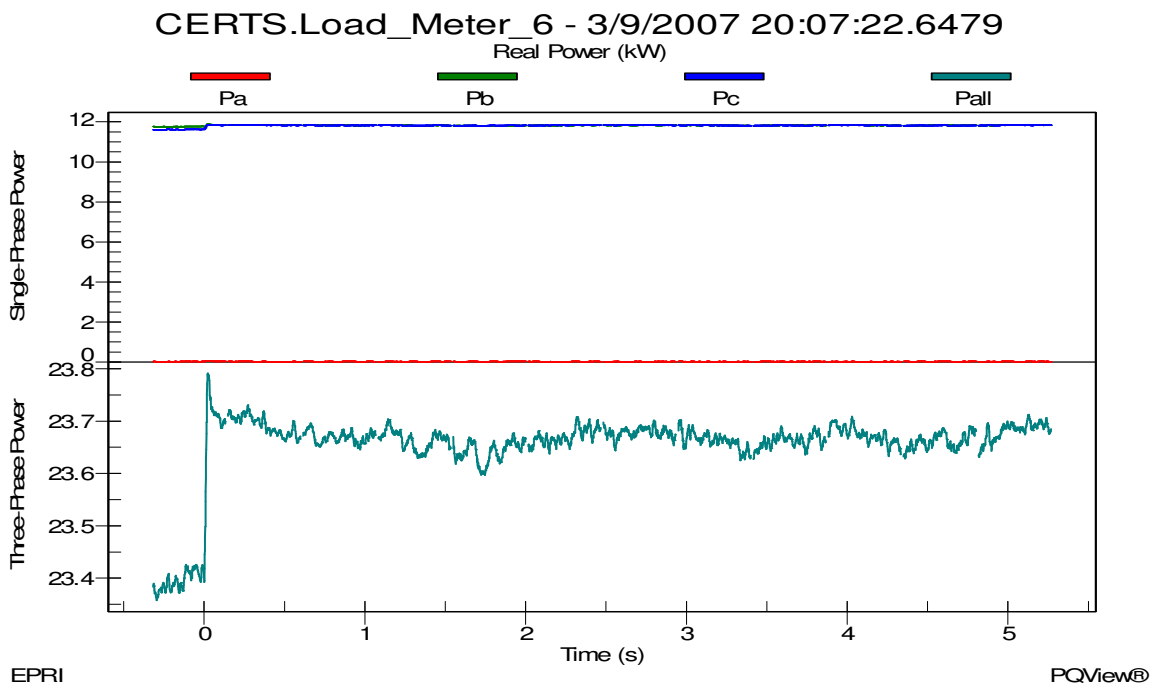


Figure 7a - Load Bank 6 real power before and after the static switch opened.

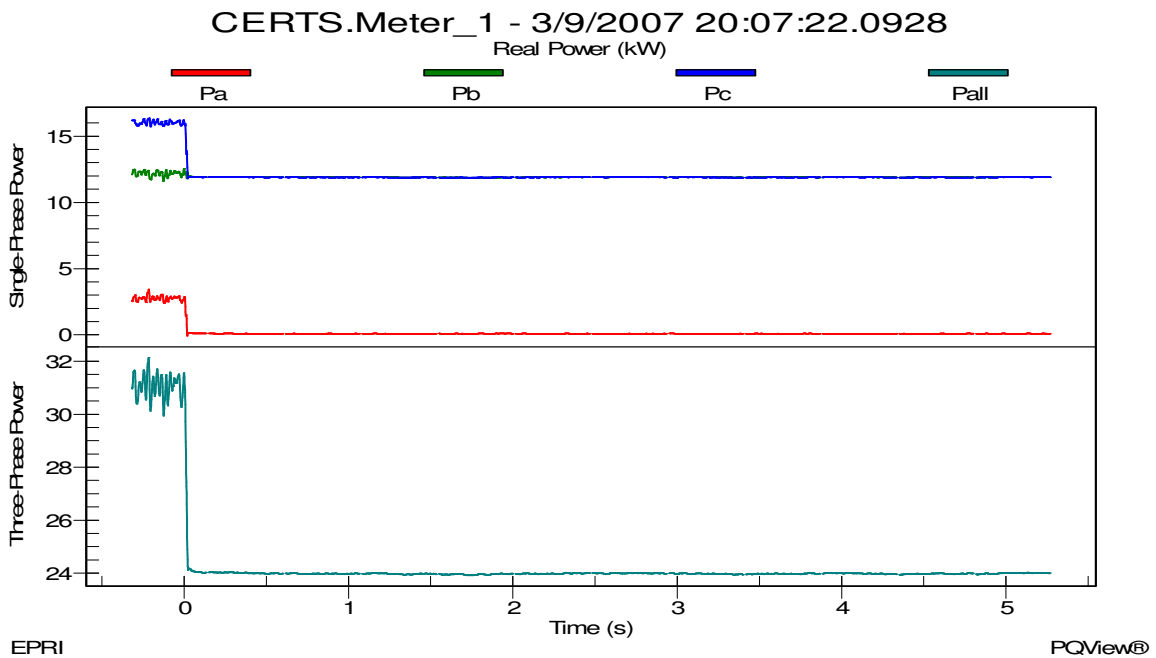


Figure 7b - Load change at Meter 1 when static switch opened on reverse power

Once the static switch opened and voltage remained on the utility side of the switch, the load at Meter 1 decreased from approximately 31kW to 24kW, serving only Load Bank 6. A review of the sequence of actions which took place revealed that the static switch went to a lockout condition and fault condition in EMS (i.e., the DSP stopping the S&C PES switch and opening CB14). The EMS did indicate a "Fault" condition and the "Reverse power Anti-islanding Alarm did turn "On".

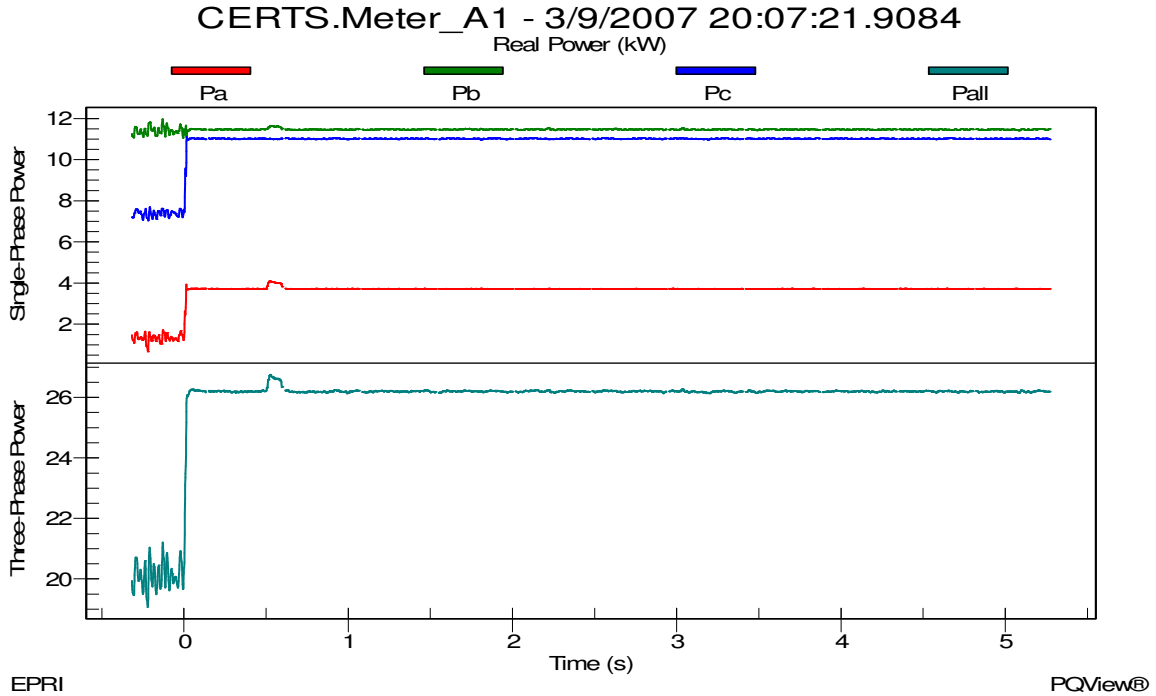


Figure 7c - Gen-set A1 kW load change when Microgrid was islanded

After the static switch opened, Gen-set A1 successfully picked up the Microgrid load remaining in Load bank 3. Figure 7c shows the change in kW load at Meter A1 when the static switch opened. Note, even though the Gen-set setting was 20kW, generator output was unbalanced on a per phase basis. This could lead to complication when operating the microgrid near the reverse power set-point at the PCC.

| Monitoring Location | Phase-A (kW) Before/After | Phase-B (kW) Before/After | Phase-C (kW) Before/After |
|----------------------------|--------------------------------------|--------------------------------------|--------------------------------------|
| Meter 1 | 3.0/0 | 12.0/12.0 | 16.0/12.0 |
| Load Meter 6 | 0/0 | 11.8/12.0 | 11.6/11.8 |
| Meter 3 | 2.5/0 | 0.5/0 | 4.2/0 |
| Meter A1 | 1.5/3.8 | 11.5/11.7 | 7.5/11.2 |
| Load Meter 3 | 3.8/3.5 | 11.8/11.5 | 11.6/11.0 |

Table 1 - Microgrid kW loading before/after the static switch opened

Although the output power set-point of Gen-set A1 was set at 20kW, the remaining load on the microgrid was approximately 26kW. Table 1 shows the relative change in kW load beyond the static switch before and after the static switch opened. Note the kW difference between Meter A1 and Load Meter 3 can be attributed to the voltage drop and electrical loss in the 225 feet of conductor between Load Bank 3 and A1 source, as well as

transformer T51. In addition to kW load and voltage changes, the change in frequency when the microgrid was islanded is shown in Figure 7d. This figure shows the frequency changed from approximately 59.99 Hz to 59.95 Hz after the microgrid was islanded.

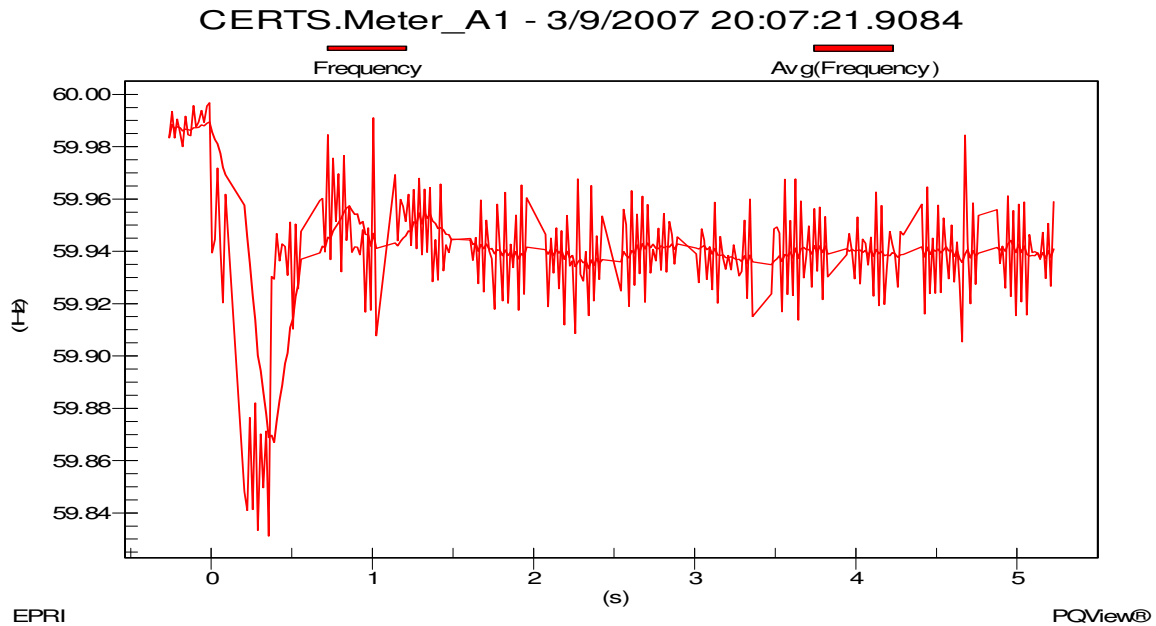


Figure 7d - Frequency change on the Microgrid after being islanded

The reverse power single phase condition was removed by bringing all A-phase loads at Zone 6 and at Zone 3 back to pretest conditions (i.e., 40kW each). The reverse power anti-islanding Alarm was turned “Off”. Note the static switch needed to be “Reset” to return it to service, because to the EMS this was a mis-dispatch of the generation within the microgrid. Also, the static switch did not wait for the 300 seconds to reconnect to the utility grid, since voltage remained on the utility side of the static switch. Once all event and alarms were cleared, a “Start” command was initiated on the EMS and a synchronized closing of the static switch was observed. (Note the 300 seconds reconnect time was proven during later tests on the microgrid, satisfying this requirement.)

6.1.4 Reverse Power, Anti-Islanding Microgrid Setting Reset Test

Performance Goal:

Verify that if a reverse power event occurs, due to a mismatch of Gen-set settings (Total Gen-set power > microgrid load), the static switch will lockout and go to the “Fault” state, where user intervention is required.

Initial Setup:

Gen-set A1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Reverse Power Setting = 10kW

Load Bank 3 = 40kW

After Gen-set A1 was running for a few minutes and supplying power to Load Bank 3, a synchronized “Close” of the static switch was initiated. As soon as the static switch closed and steady-state conditions established, the microgrid was connected to the utility grid with the total power flow at Meter 1 approximately 18kW.

When the test began the power measurement at Meter 1 was 18kW. Waited 5 seconds with no reverse power trip occurring (i.e., value was above the minimum 10kW threshold value). Then, reduced load at Load Bank 3 by 5kW, waited about 5 seconds and no reverse power trip occurred. Reduced load at Load Bank 3 by an additional 5kW and the static switch opened, after the second 5kW load reduction. Once the static switch opened, shown in Figure 8a, the Event Logger recorded a reverse power event, DAS was triggered and data was recorded. The EMS entered a “Fault” state, opening CB14, and the “Reverse Power Anti-islanding Microgrid Settings Reset” alarm turned “On”.

Although the output power set-point of Gen-set A1 was set at 20kW, the remaining load on the microgrid was approximately 28.5kW, which was successfully served by Gen-set A1. Table 2 shows the relative change in kW load per phase in the microgrid before and after the static switch opened. As mentioned earlier, the kW differences can be attributed to the voltage drop and electrical loss in the microgrid. In addition to load and voltage changes, the frequency changed from approximately 59.99 Hz to 59.95 Hz after the Microgrid was islanded.

| Monitoring Location | Phase-A (kW) Before/After | Phase-B (kW) Before/After | Phase-C (kW) Before/After |
|----------------------------|--------------------------------------|--------------------------------------|--------------------------------------|
| Meter 1 | 3.2/0 | 2.0/0 | 4.0/0 |

| | | | |
|--------------|----------|----------|----------|
| Meter 3 | 3.0/-0.2 | 1.3/-0.5 | 3.4/-0.5 |
| Meter A1 | 6.7/9.3 | 8.2/9.6 | 6.2/9.6 |
| Load Meter 3 | 9.6/9.0 | 9.4/9.1 | 9.4/9.1 |

Table 2 - Microgrid kW loading before/after the static switch opened

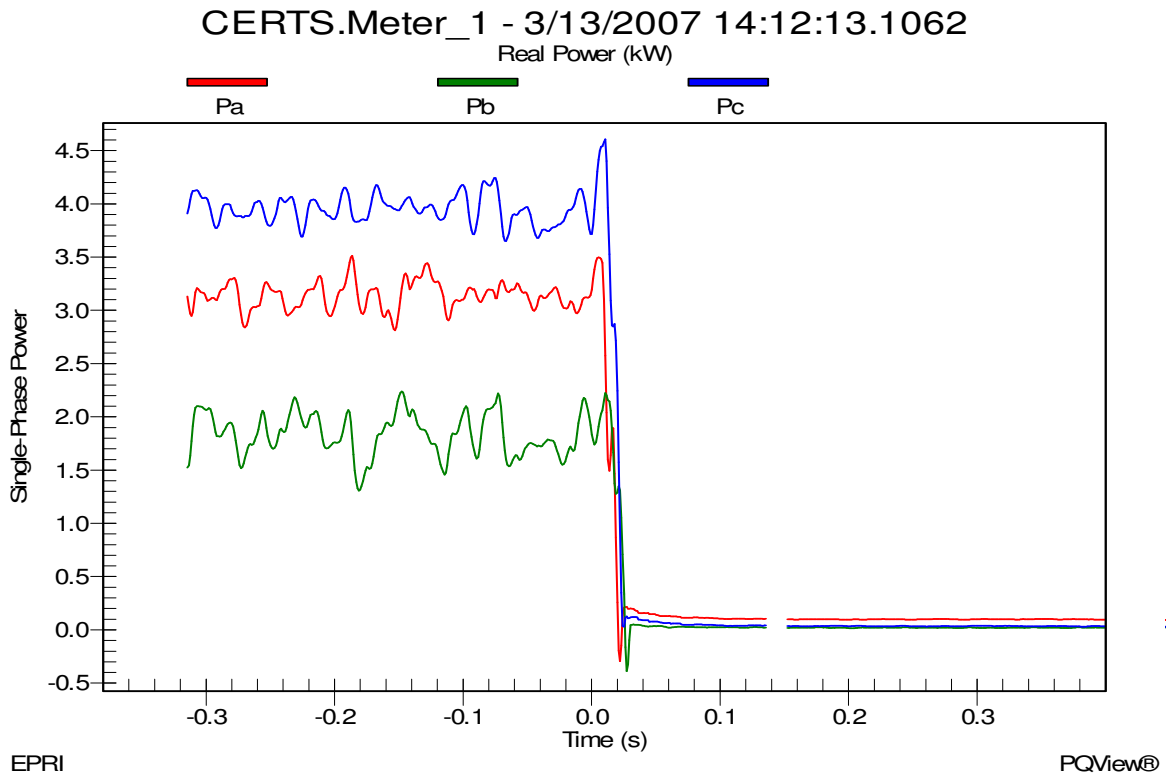


Figure 8a – Meter 1 load decrease after the static switch opened.

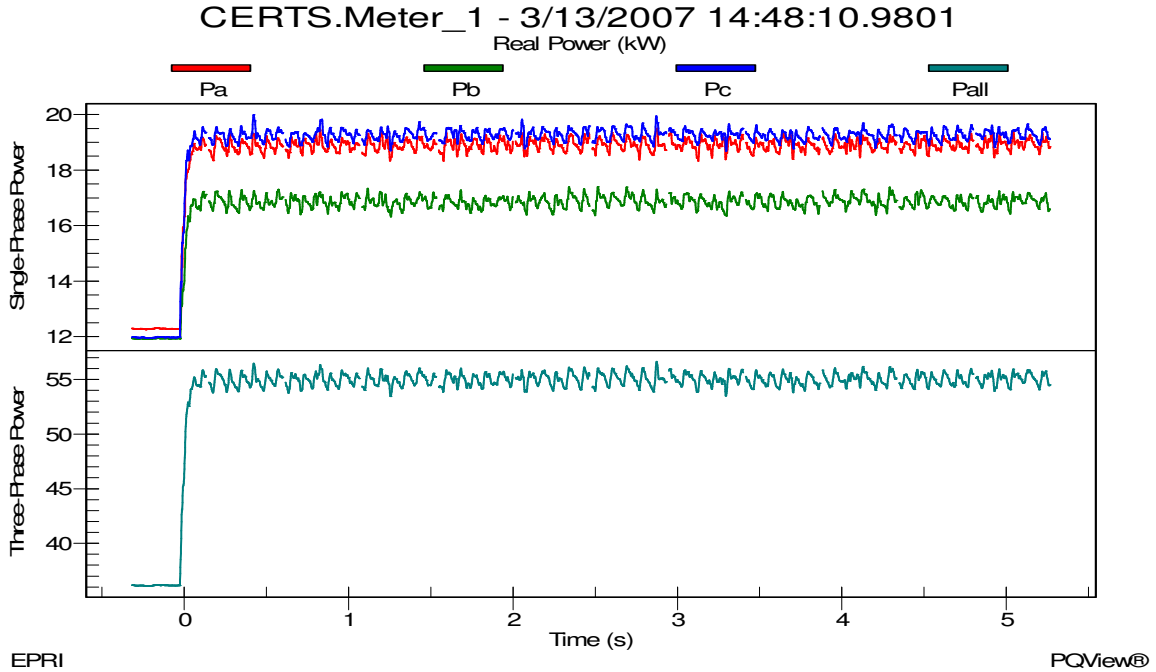


Figure 8b – Load increase at Meter 1 during synchronized close of static switch.

Load Bank 3 and 6 were each set at 40kW. All events and alarms were cleared. The static switch successfully synchronized and reconnected after the “Start” command was initiated with load at Meter 1 increasing from approximately 36kW to 55kW, shown in Figure 8b. During this test the first trigger was noted on reset of the static switch, and the second trigger was caused after the static switch was issued the start command and successfully closed. Likewise, during this transition from island to grid-connected mode, Gen-set A1 decreased its output from 35kW to 18kW, shown in Figure 8c, and frequency increased from 59.86 Hz to 60.01 Hz shown in Figure 8d.

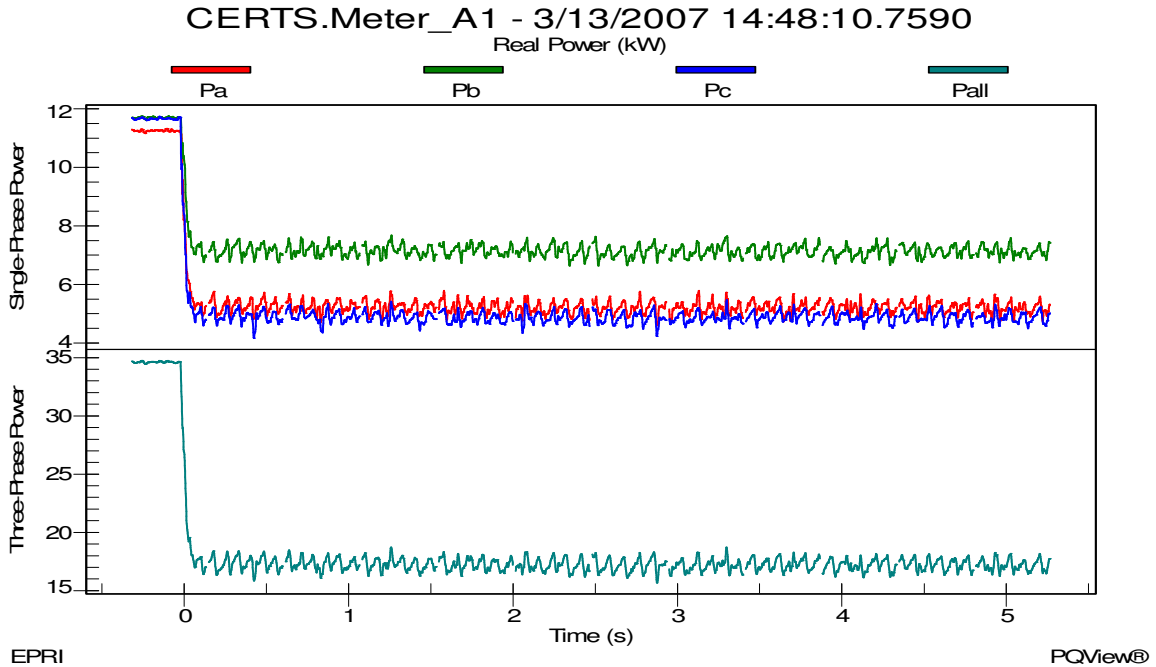


Figure 8c - Gen-set A1 output during synchronized close of static switch

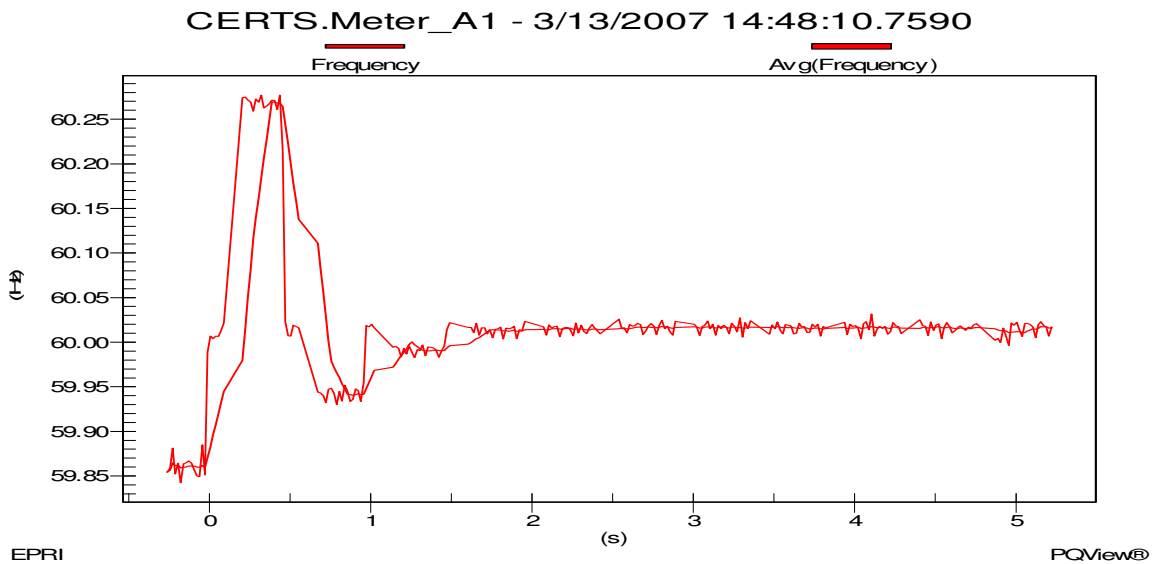


Figure 8d - Frequency on the Microgrid during synchronized close of static switch

6.1.5 De-energized Bus (Dead Bus) Reclose Test

Performance Goal:

Verify that the static switch can close when de-energized bus conditions ($< 15V$) on the DG side are measured and that the Dead Bus Reclose algorithm requires user intervention (i.e. Operator needs to “Enable: the Dead Bus Reclose using pushbutton in the EMS).

Initial Setup:

Gen-set A1 = Unit Power Control

Output Power Command = 20kW

MG Power/Frequency Droop = -0.0833 Hz/kW

MG Voltage Command = 277V

Relay Settings = A (Delayed)

Load Bank 3 = 40kW

Load Bank 6 = 40kW

After a few minutes, the “Manual Open” command was removed in the EMS and the static switch remained in the “Open” position. Then a “Dead-Bus Reclose”. This Dead-Bus Reclose event was captured in the Event Logger with the change in load at Meter 1 increasing from 36kW to 75kW, shown in Figure 9a. Note, prior to the static switch closing, Meter 1 is serving Load Bank 6 in Zone 6.

During the Dead-Bus Reclose of the microgrid, Figure 9a shows the expected kW inrush, due to transformer T51 (i.e., 112.5kVA rated) which is connected within the microgrid.

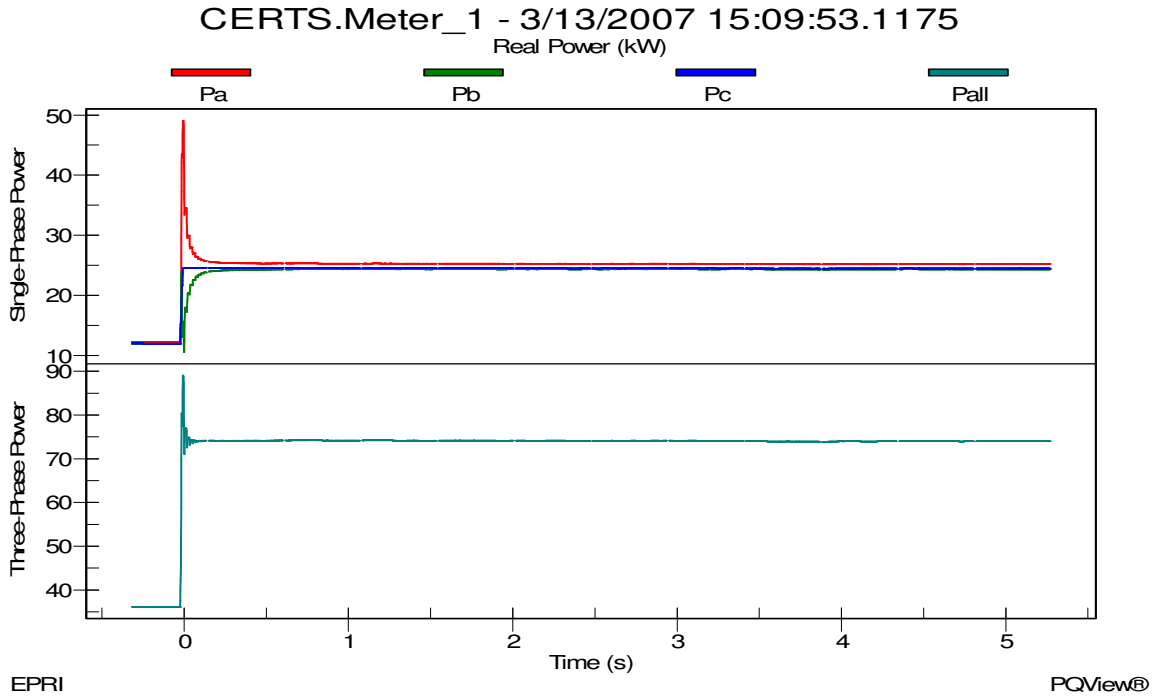


Figure 9a - Load increase at Meter 1 (PCC) during a Dead-Bus Reclose of the static switch

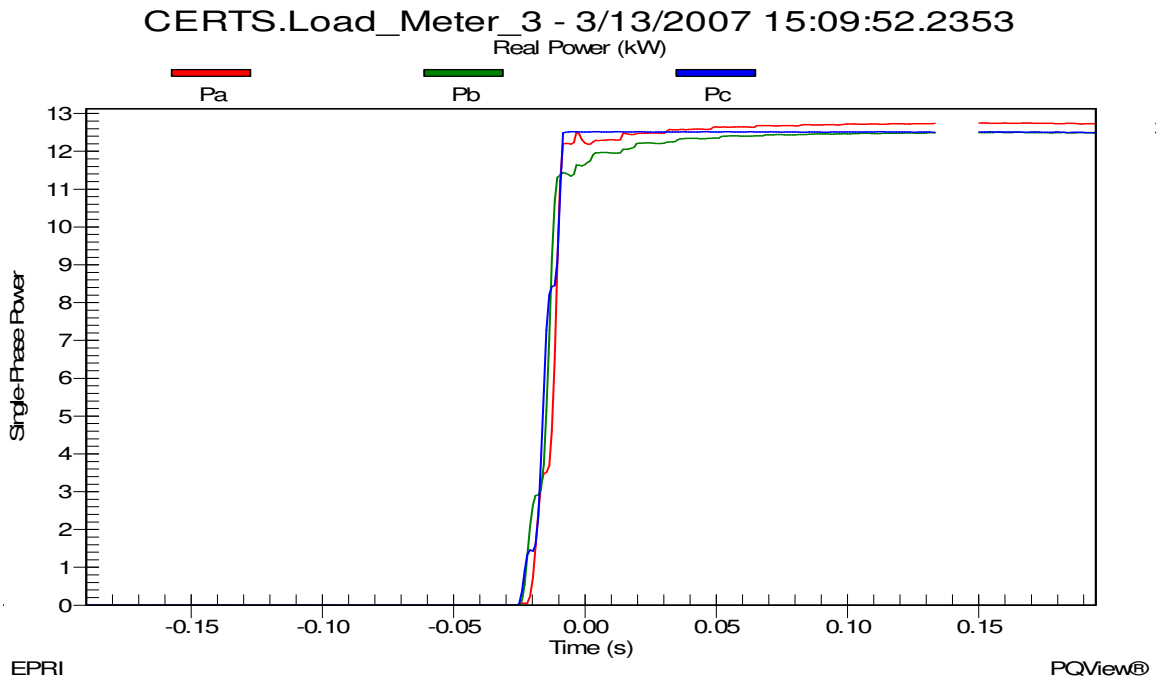


Figure 9b - Load Bank 3 connected in the Microgrid during a Dead-Bus Reclose of the static switch

Load Bank 3 was also connected in the microgrid and set at 40kW (i.e., 13.3kW per phase), but the actual load was approximately 38kW with minimal inrush, shown in Figure 9b, when energized and connected to the utility grid.

After this testing was performed the protection settings were revised, increasing their sensitivity. The updated protection settings no longer allow for a Dead-Bus close to take place successfully, due to the transformer inrush currents.

7.0 CONCLUSION

The series of tests performed in section 6.0 validated the proper control and operation of the static switch, basic power and voltage control of the Gen-sets, and a preliminary check of the protection scheme. These tests provided confidence that the static switch would provide protection and fast disconnect from the utility for the CERTS microgrid during a disturbance for future tests.

One interesting test came during the large load condition in the “Loss of Utility Source Test” in section 6.1.2 where 6 p.u. current was recorded before the Gen-set turned off which seems high but was expected. The inverters on the Gen-sets are 125kVA rated which is twice the rating of the Gen-sets but were artificially limited to half. Also, the inverters were set up to deliver 2.5 p.u. fault current which is approximately 550A peak. This is the close to the 6 p.u. current recorded during the test.