CERTS MICROGRID PHASE TWO TEST REPORT

The CERTS Microgrid Laboratory Test Bed project has undergone phase one testing at the Walnut test site by American Electric Power (AEP). Phase one testing demonstrated the stable operations of the CERTS control algorithms when transitioning between electrical utility connected and islanded operation, satisfying difficult loads such as motor starts while in islanded operation, and detecting faults within the microgrid and utility using a sequence component protection scheme. Each test from this phase one resulted satisfactory which prompted a new phase of testing to be performed. The next phase of testing deemed phase two testing included a continuation test for power quality, generator and load diversity, inverter fault current contribution, and protection tests moving the measurements closer to the gen-sets. Test descriptions, set-up, and results from the phase two testing are reported in this document.

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1.0 Introduction

The CERTS microgrid has completed phase one of testing which resulted in successful tests that proved the static switch control, sequence component protection scheme, power flow control of unit and feeder operation, difficult and motor loads, and black start capability. Continuation testing from phase one was performed on the CERTS microgrid including a continuous test run, inverter fault current contribution, and protection testing. The tests methodology and results are reported in this document.

2.0 Project Objectives

The objectives of the phase one continuation testing include the following:

- Continuous Run
  - Test microgrid Response to disturbance of utility electrical grid quantifying power quality and reliability
  - Vary generators and loads within the microgrid
  - Demonstrate power factor correction and VAR control at PCC
- Inverter Fault Current Contribution
  - Quantify and control fault current contribution
- Retest Phase One Section 7.0 Protection Testing
  - Verify correct operation of protection scheme when the measurement points are moved from the PCC to the generators.

3.0 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.

4.0 Microgrid Test bed 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.

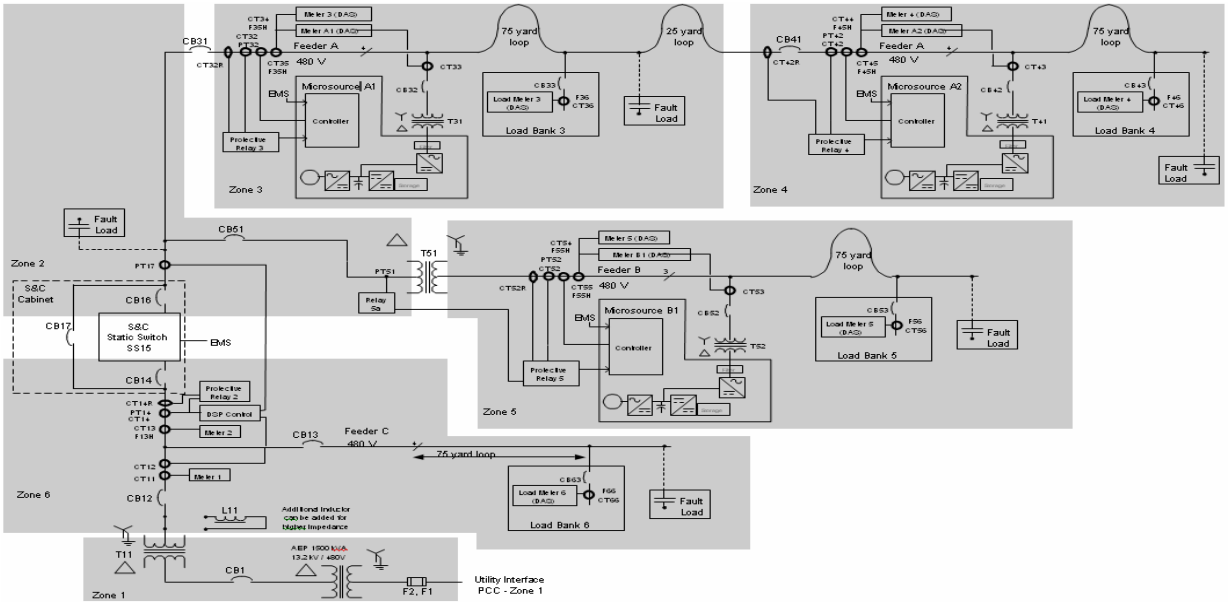

Figure 2 - One Line Diagram of CERTS Microgrid Test Bed

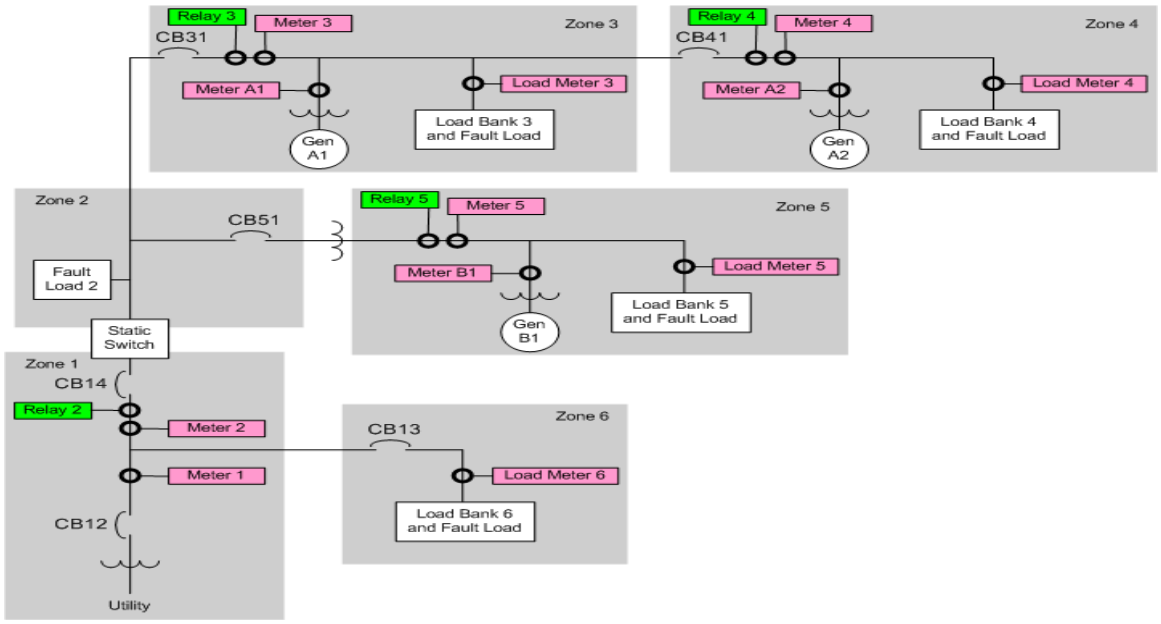

Figure 3 - Simplified diagram of Test Bed showing Meter and Relay locations

There are twelve PML ION 7650 meters placed through out 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.

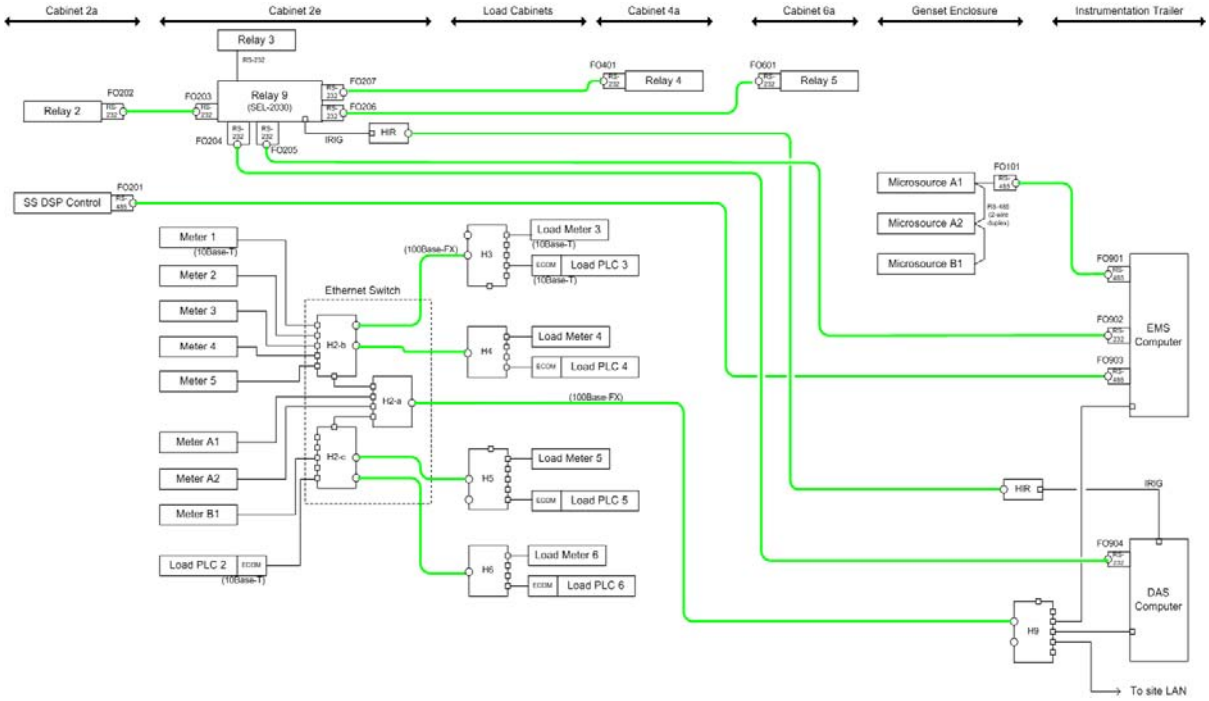

Figure 4 - Diagram of DAS & EMS Data networks

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.

5.0 Continuous Run Executive Summary

This test setup operated the microgrid in grid connected mode non-stop for a little over one month (latter part of March to the latter part of April and again for the first week in October) evaluating the microgrid response to utility disturbances, microgrid power reliability, automated power factor correction, and generator/load diversity. Throughout the continuous run test, the generators and loads within the microgrid were adjusted automatically through the Energy Management System (EMS) and Load Control System (LCS). This allowed for a diversity of generators and loads within the microgrid while maintaining power quality and a power factor close to unity at the point of common coupling (PCC) of the microgrid.

There are two conditions used for evaluating the power quality of the CERTS microgrid. The first is the basic function of a microgrid, if the electrical utility grid loses power, the static switch would open based on IEEE 1547 requirements and the microgrid would isolate itself from the rest of the grid. Load Bank 6 is outside the protected microgrid and must ride through the power loss while the loads within the protected microgrid at the time would virtually see no transient thus improving the reliability and power quality to those loads. The second potential condition is a slight disturbance on the electrical utility grid such as a voltage sag or swell which falls outside the IEEE 1547 requirements. Loads that ride through this slight disturbance would experience a transient such as visible flicker in lighting. During a voltage swell the lights would brighten and similarly during a voltage sag the lights would dim. Loads within the protected microgrid with local generation would not experience this disturbance thus improving the power quality delivered to that load. This functionality is seen in the industry as an uninterruptible power supply (UPS) which generally is a battery or capacitor based device that allows typically for a 5 minute ride through during the disturbance.

During this testing a sole utility disturbance was captured. This was an 83% voltage sag on the utility system lasting approximately one second in total duration. The microgrid Static Switch was able to detect and separate the sensitive loads of the microgrid from the utility disturbance. Because of this the microgrid loads only experienced a 94% voltage sag for 1.5 cycles. This is a dramatic improvement and is within the ITIC Curve for sensitive electronic loads.

The electrical reliability of the microgrid sections and components was quantified with some interesting results. The generating equipment, although prototypical, achieved an average reliability of 73%. The primary reason for shutdown dealt with digital communication between the internal components of the genset. The overall reliability of electrical supply was increased through the addition of generating equipment. However the overall reliability of each section of the microgrid was less than that of a traditional utility fed bus. The reason for this deals with the sensitive protection scheme employed to quickly detect and isolate bus faults. While the scheme is capable of protecting equipment from damage it is poorly coordinated with downstream equipment protection and results in the loss of larger than necessary sections. This effectively reduces the reliability of protected microgrid sections with the worse sections furthest from the utility connection.

A power factor correction and VAR control algorithm was added to the microgrid and evaluated during the continuous run. The gen-sets online would adjust their real and reactive power output based on the power factor at the PCC of the CERTS microgrid. This testing was able to confirm that automated power factor correction can be successfully accomplished. The Energy Management System was able to compensate for the reactive demands of the loads by adjusting the set points of the generators. Uncontrolled the average power factor was 0.79 with large deviations during certain periods of time. Employing the automated correction the power factor was 0.92 which is within the range generally considered acceptable by a utility.

The final area of interest dealt with the generation and load diversity. During this continuous run period the loads and gensets were automatically dispatched by individual software agents. These agents were given a base load profile for electrical kW, kVar and thermal demand. They were also given the freedom to deviate from this base profile by a certain amount. This allowed for the bounded but random generation of a large number of load flows within the microgrid. In total the system operated through approximately 27, 300 load changes and approximately 5,800 generation dispatches. This large number of successfully load flows demonstrates the robust nature inherent in CERTS control algorithms.

The continuous run test phase was performed to collect information on a number of long term operational characteristics of the CERTS Microgrid, such as Power Quality and response to grid disturbances. The testing was performed in two sections, 3/27/09 – 4/27/09 and 10/02/09 – 10/10/09, totaling approximately 1026 hours. The testing consisted of operating the genset and load bank equipment based on simulated load profiles. The Static Switch was also automated to allow for unattended operation. The meter data collection system was also setup in such a way as to capture system disturbances such as voltage swells and sags. The extent of data collected included disturbance captures and genset and load operational logs. This data was later scrutinized for events of interest.

Distribution Disturbances

One distribution disturbance event was captured on 8/28/2009 at 14:17. The event appears to be an A phase to B phase to Ground fault. The depth of the voltage sag is mild and the duration short term. The cause was either an intermittent fault like a tree contact or a distant fault which was cleared by a downstream recloser. To our knowledge no upstream distribution protection equipment operated to clear this fault. This fault resulted in an 83% Voltage sag to phases A and B of the distribution supply. Also an associated neutral current can be seen.

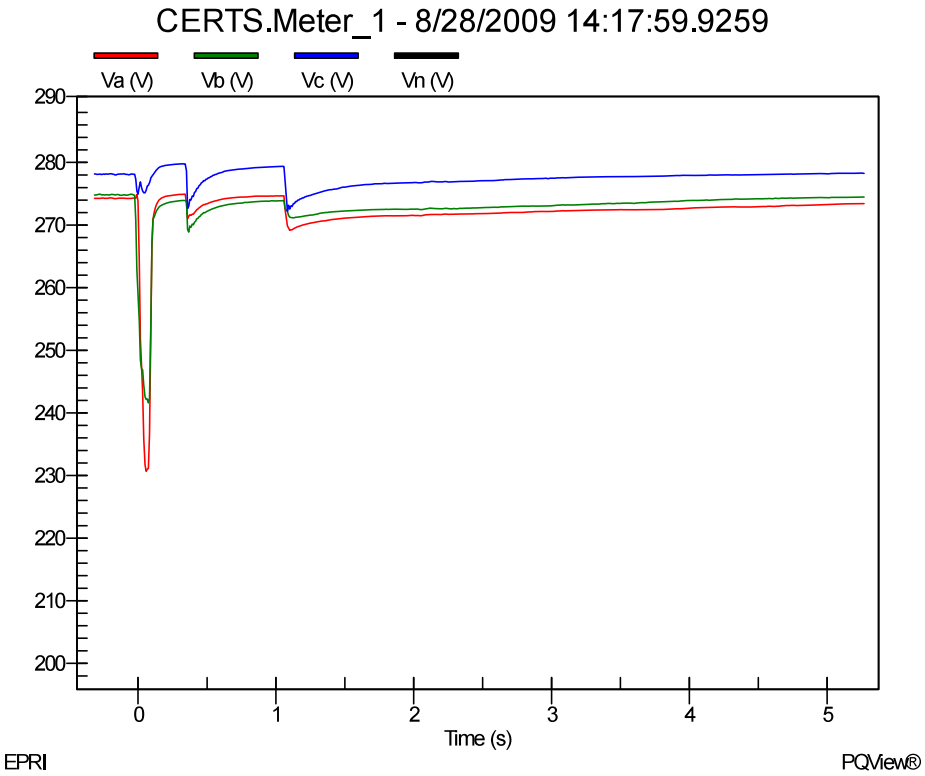

Figure 5: Distribution Sag Event Captured at Meter 1

The unprotected load in Load Bank 6 of 18kW experiences the full 83% voltage sag event lasting over a 1.5 second window.

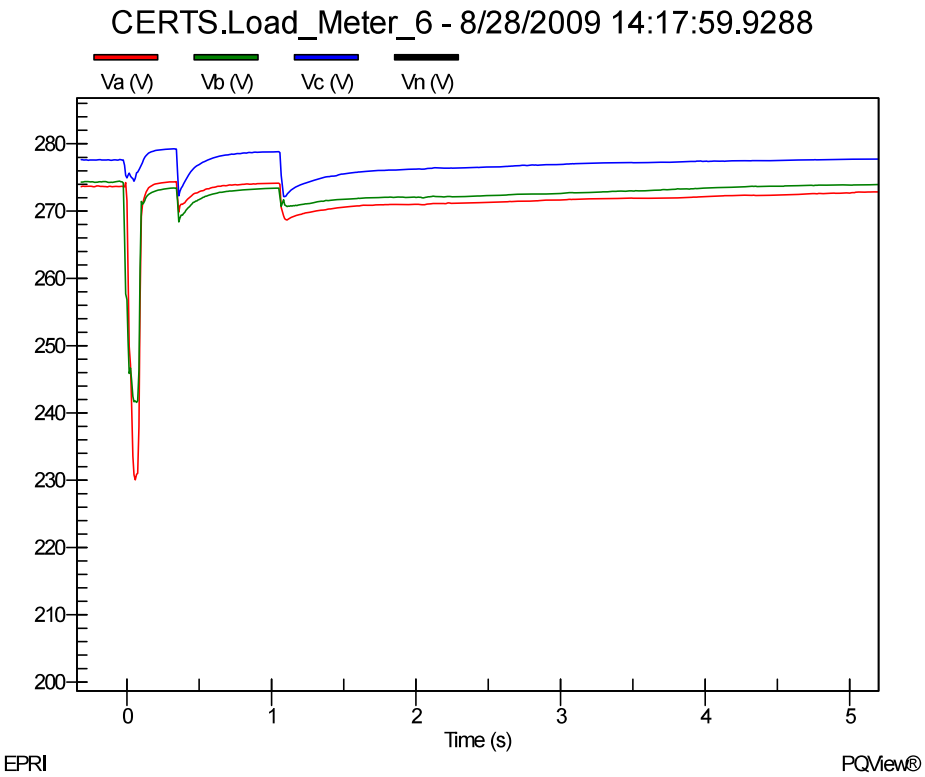

Figure 6: Distribution Sag Event as Experienced by Unprotected Load Bank 6

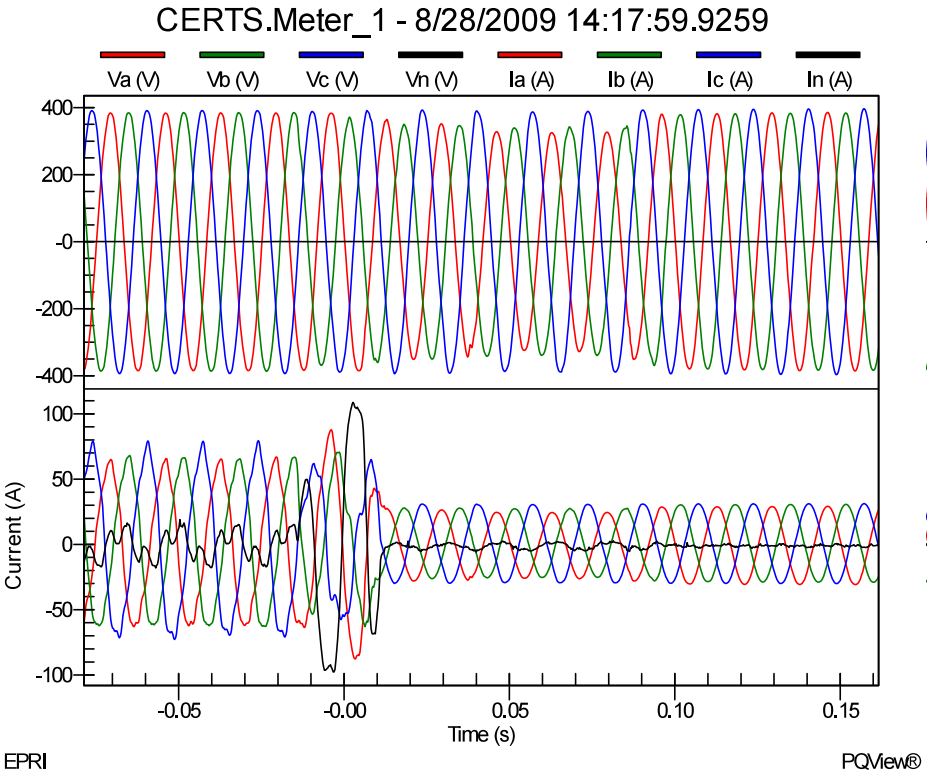

Figure 7: Voltage and Current at the PCC during the Distribution Sag Event

The time from fault, thru detection, to clearing appears to be ~25msec. At this point the voltage within the islanded microgrid recovers having only experienced 1.5 cycles of sag.

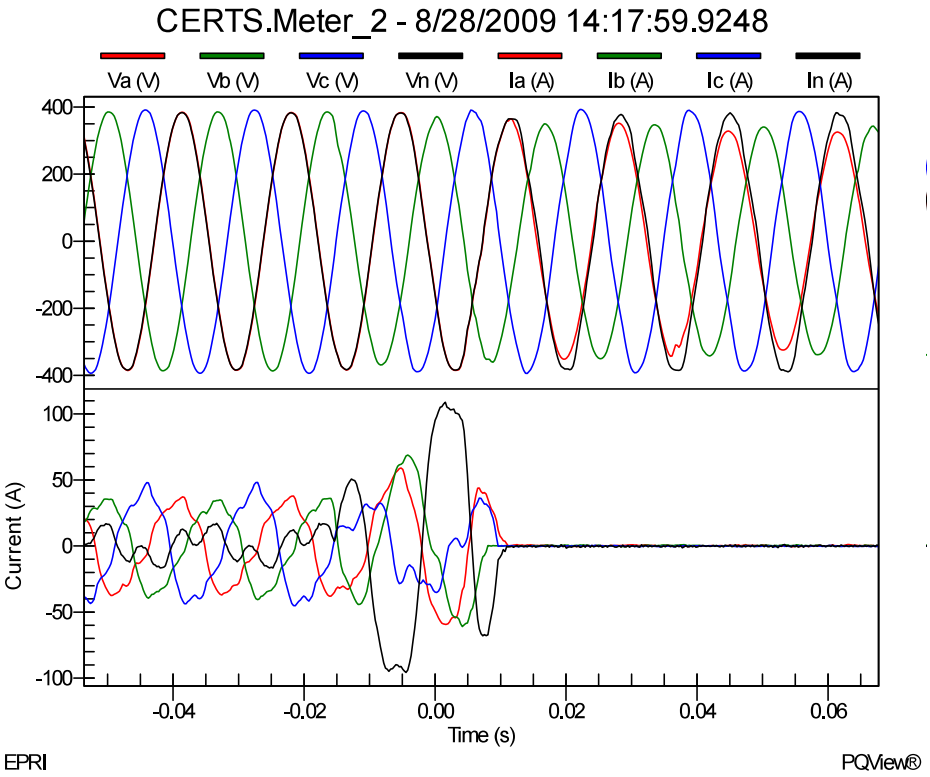

Figure 8: Voltage and Current at the Static Switch during the Distribution Sag Event

The load closest to the SS, Load Bank 2 of 8kW and 6kVar, experiences a voltage sag for approximately 1.5 cycles to 94%. The difference in sag percent from the utility entry point to the protected section of the microgrid bus is attributed primarily to the impedance of connection cabling and the Static Switch.

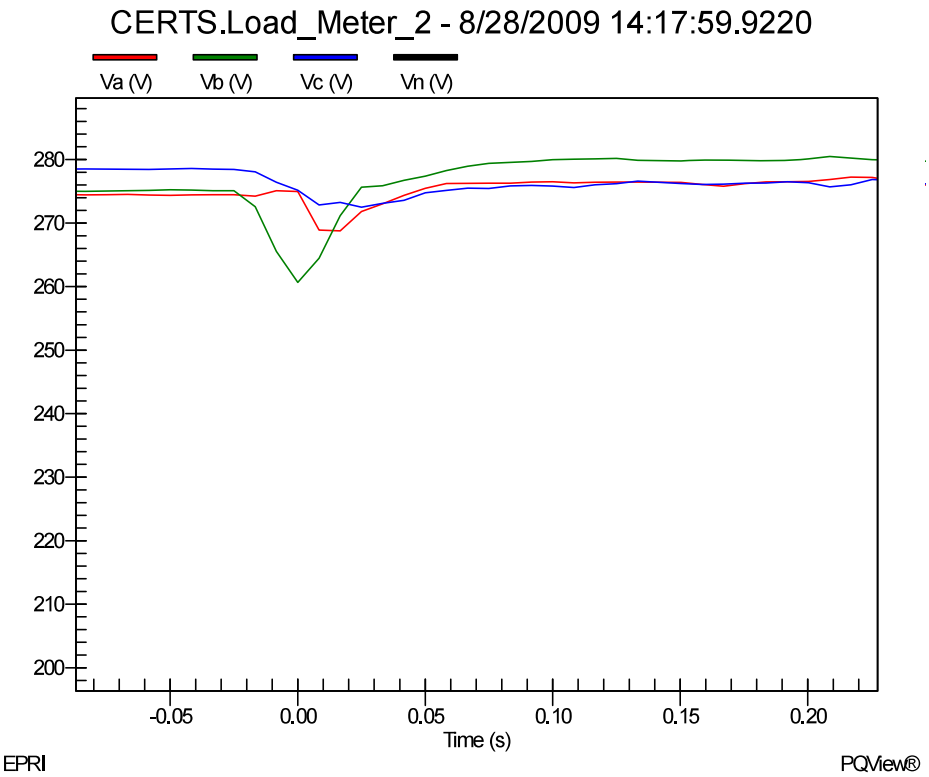

Figure 9: Close Up Examination of the Voltage Sag Experienced inside the Microgrid.

Load Bank 3 of 18kW, experiences a 95% voltage sag for 1.5 cycles. The load furthest from the SS, Load Bank 4 of 18kW, experiences a similar voltage sag for approximately 1.5 cycles to 95%. This 1% improvement over that of the protected section entry point can be attributed to cabling impedance and the microgrid source immediately adjacent.

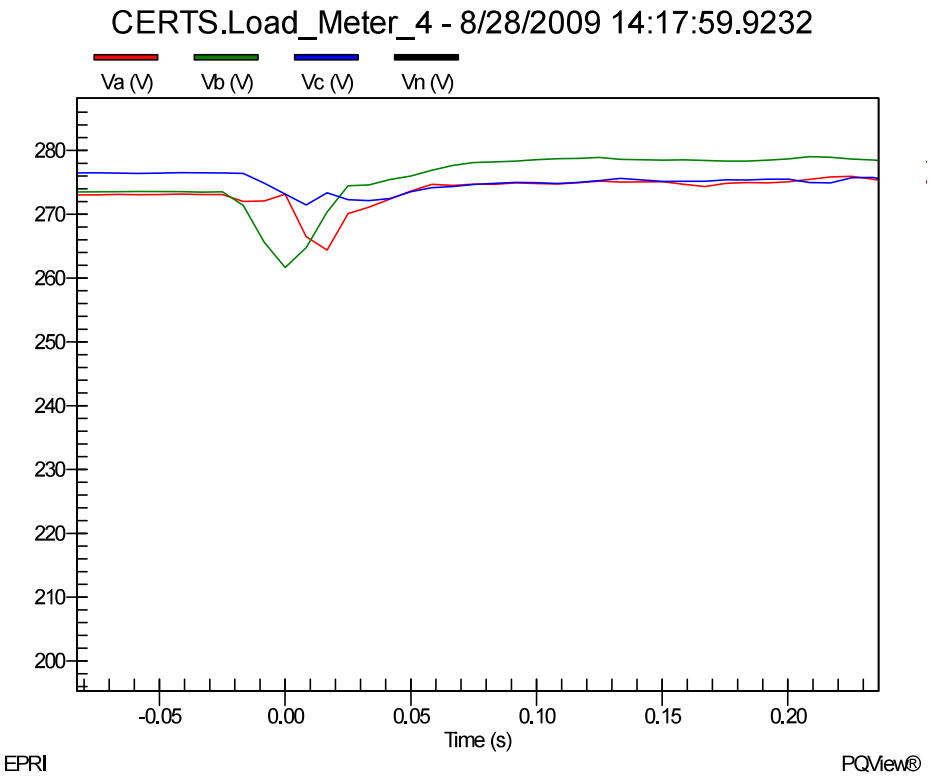

Figure 10: Close Up Examination of the Voltage Sag Experienced at Load Bank 4. Genset A2 was the only genset online at the time and it supported the microgrid bus once the SS opened.

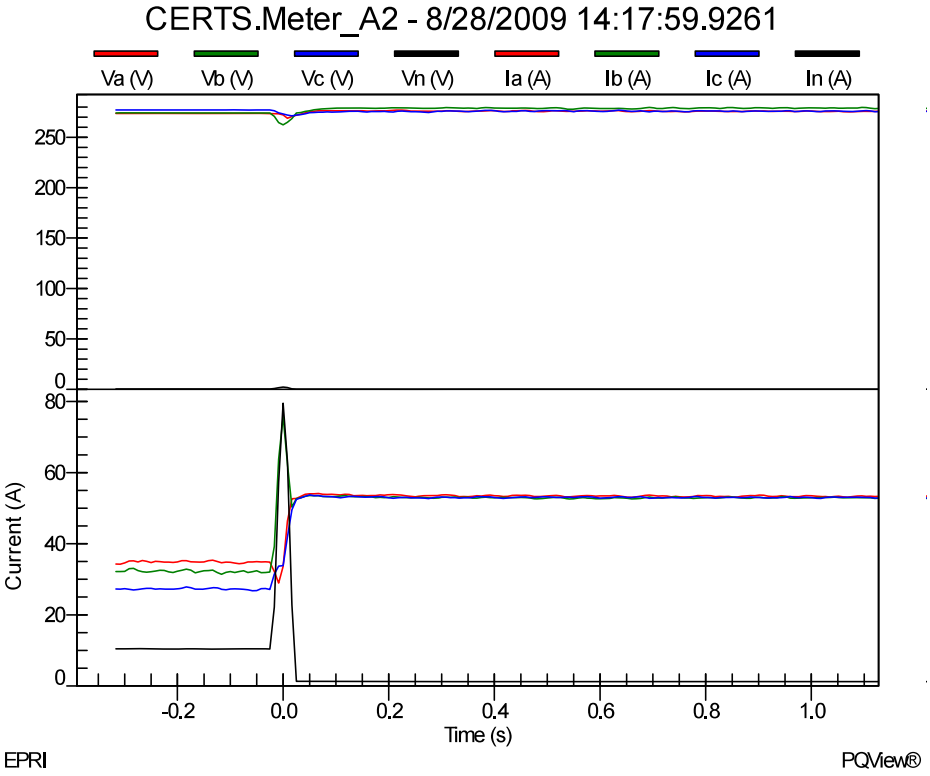

Figure 11: Voltage and Current during Distribution Sag Event at Genset A2.

Reliability

One important characteristic examined during the continuous run testing dealt with quantifying the reliability of the various sections of a microgrid. Assessments of reliability for the generating equipment as well as each individual zone have been made. The definition of reliability used below is; Reliability = Run Hours / (Run Hours + Forced Outage Hours).

Genset Reliability

The genset equipment is considered prototypical and the reliability of the individual machines was not considered a top priority. Because of this the information collected is considered not representative of the commercialized version of this equipment, the Tecogen INV-100 Co-gen unit.

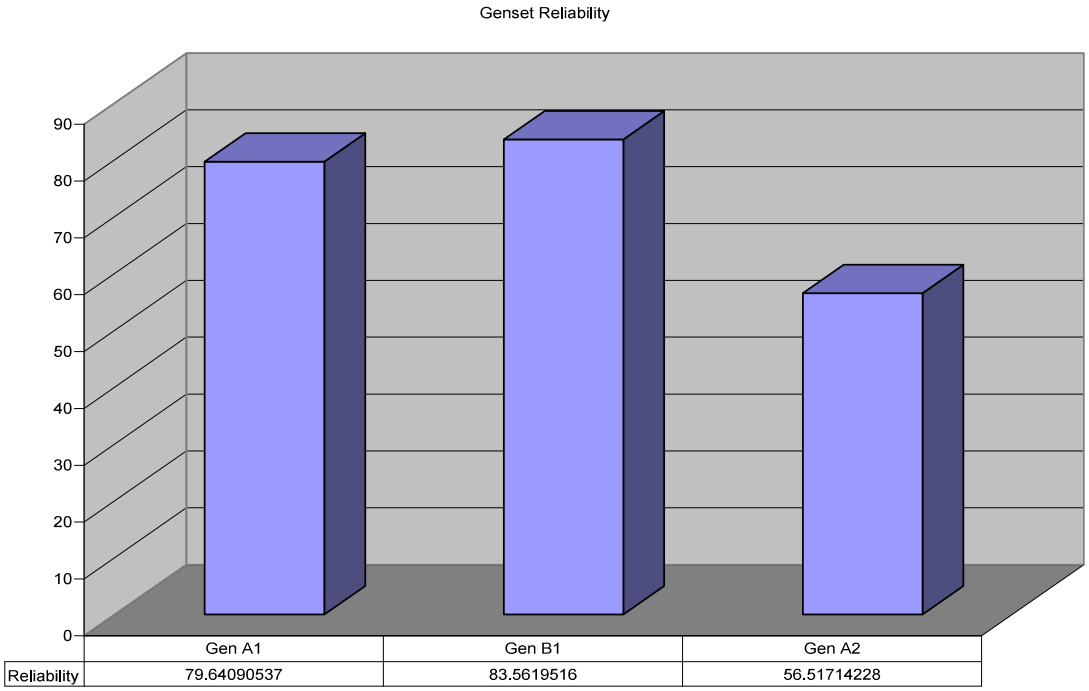

Figure 12: Genset Reliability Comparison

The generating equipment is considered identical in construction and programming, we have no explanation as to why Genset A2 is an outlier. The alarms from each forced outage were captured and tabulated below.

Genset Alarms

Shutdown Alarm	Genset A1	Genset B1	Genset A2
CAN Bus Comms Failure Fault	5	5	8
Low Water Pressure Fault	1		7
Boost Fault	6		1
DC Overvoltage Fault	3	1	
Power Supply Fault	1		
Overload Fault		1	1
Logic Voltage Fault		1	
No Field Signal Fault		1	

Figure 13: Genset Shutdown Alarms

The reliability of each zone is a combination of the reliability of the utility and generating sources as well as the protection and load equipment within that zone. Because of this the zone furthest into the system is likely to be the least reliable.

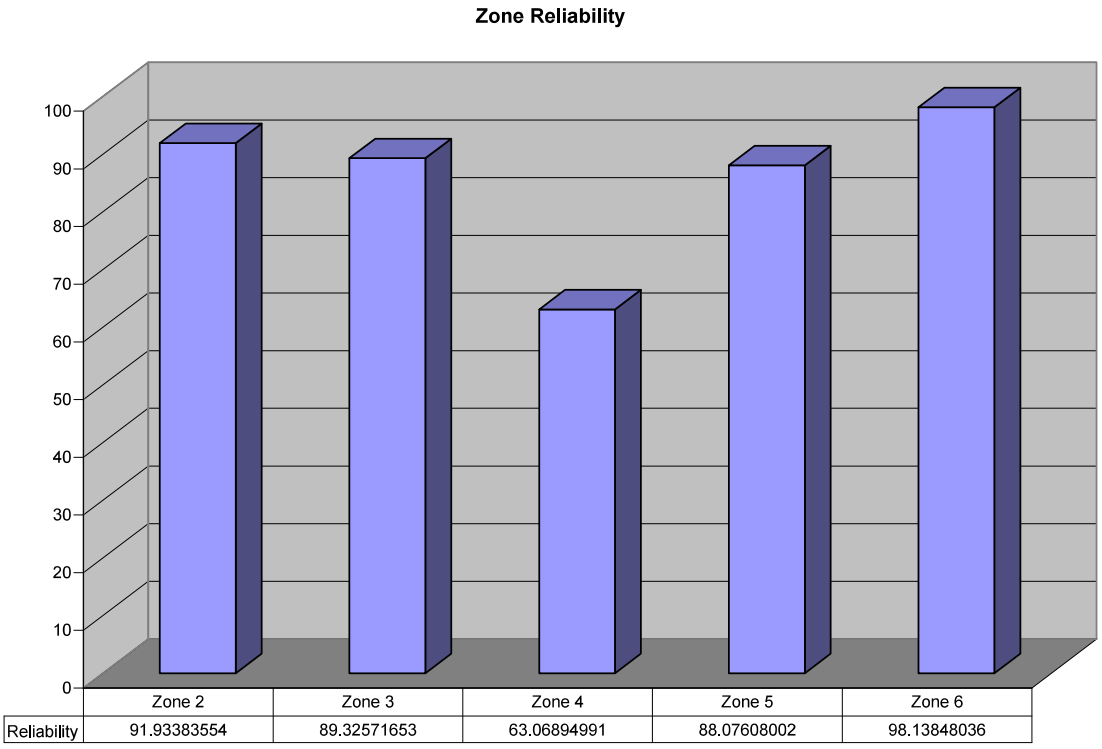

Figure 14: Zone Reliability Comparison

Zone 6 is outside of the protected area of the microgrid and relies solely on the utility supply. This zone employs traditional phase over-current protection which is coordinated to remove faults with the least amount of interruption. Zone 2 has the best reliability of the protected areas. However due to the sensitive nature of the protection employed and the lack of a generating asset in this zone the reliability is less than that of the utility system. Zones 3 and 5 are both a level deeper into the protected area of the microgrid and display similar reduced reliabilities. Finally Zone 4 is the deepest zone electrically from the utility grid. This zone is the least reliable due to the protection scheme and the fact that it contains genset A2, which itself is dramatically less reliably. This is further compounded by an operational philosophy which requires downstream zones to be tripped off line to an upstream but separable fault. This is a requirement as the feeder breakers are presently not considered a point of resynchronization to the greater microgrid.

The sensitive protection scheme coupled with shunt trip feeder breakers is the primary contributor to the overall reduced reliability. This type of protection is effective at clearing both major and minor faults quickly but is not properly coordinated with downstream minor protecting devices. The sensitive, fast feeder protection operates not only clearing the fault but also needlessly de-energizing large sections of the electrical bus.

Typical downstream protection is of a phase over-current design, generally due to its inexpense and insensitivity to inrush and unbalance. This type of protection is less sensitive to low grade faults and requires more fault time to operate. Because the majority of faults occur in connected equipment, these lesser breakers are the expected clearing devices of choice. Feeder breaker protection is typically reserved for major faults, such as bus faults, which occur less frequently. The sensitive, fast feeder protection operates not only clearing the fault but also needlessly de-energizing large sections of the electrical bus. Because of this an alternative method for protection is recommended.

Before beginning this testing, the initial hypothesis was that the protected areas of the microgrid would have superior reliability, above that of the utility system. This turned out to be incorrect and therefore a predictive calculator of the various reliabilities was constructed. This tool incorporates a very basic reliability calculation which can be further refine to contain greater detail of the CERTS microgrid. It does, however, provide an approximate result to reflect how adjustments in individual variables can affect the entire system.

Reliability Calculations

Electrical reliability of an islanded bus employing multiple, equally reliable generators.

$$\binom{n}{k} r^k(t)(1-r(t))^{n-k} \quad \text{Where,} \quad \binom{n}{k} = \frac{n!}{k!(n-k)!} \quad \text{, and } n \geq k$$

Electrical reliability of the paralleled utility and microgrid buses.

$R_{MB}(t) = R_{US}(t) + R_{DG}(t) - R_{US}(t) * R_{DG}(t)$ Where, $R_{MB}(t)$ = Reliability of the Microgrid Bus, $R_{US}(t)$ = Reliability of the Utility Supply, and $R_{DG}(t)$ = Reliability of the Distributed Generation.

Electrical reliability of the Zones

$R_Z(t) = R_{SB}(t) * R_L(t)$ Where, $R_Z(t)$ = Reliability of the Zone, $R_{SB}(t)$ = Reliability of the Sourcing Bus, $R_L(t)$ = Reliability of the Load

	Variables	
Generator Reliability	rdg(t)=	0.7
Number of Distributed Generators	n=	3
Minimum Number of DG Required to meet Load Demand	k=	3
Utility Grid Reliability	ru(t)=	0.9933
Reliability of the Load	rl(t)=	0.988
Islanded Microgrid Reliability due to DG alone		0.343
Reliability of Microgrid due to DG and Utility		0.9955981
Reliability of bus in each Microgrid Zone (=Reliability of Load * Reliability of Sourcing Bus)		
Zone 1		0.9933
Zone 2		0.983650923
Zone 3		0.971847112
Zone 4		0.960184946
Zone 5		0.971847112
Zone 6		0.9813804

Figure 15: Spreadsheet Estimator for Zone Reliability

Power Factor Correction at the Point of Common Coupling

Another important characteristic examined dealt with the customer power factor at the point of common coupling. From the first phase of testing it was observed that the customer power factor was rather low and depended highly on what the dispatched voltage setpoint of the microgrid equipment was. Also even with the voltage dispatched to match the utility voltage the operational kVars would flow from the utility when grid connected. Generally this is not a problem however because much of the kW load was being provided for by the distributed generation only a small amount of kW load was being placed on the utility. The larger kVar vs kW load made the power factor at the customer meter very poor. Customers with a persistently poor power factor will usually incur penalties and can potentially be refused electrical service. Because of this it was desirable to use the existing Energy Management System to control the reactive power being drawing from the utility. This motivation is two fold, one to avoid problems with the utility and two to potentially sell an ancillary service to the utility.

Because kVar usage is measured on 15 minute intervals this is a good fit for the global intelligence of the Energy Management System and it timing also does not require high speed correction. The EMS system can make the decisions of how many kVars are required and from where they should be generated. The below graph compares two periods of time; one with power factor correction enabled and a second without. The average power factor improved to 0.928 from 0.795, approximately 16.7%. It is also worth noting that a common trigger point for the requirement of customer power factor correction is 0.9.

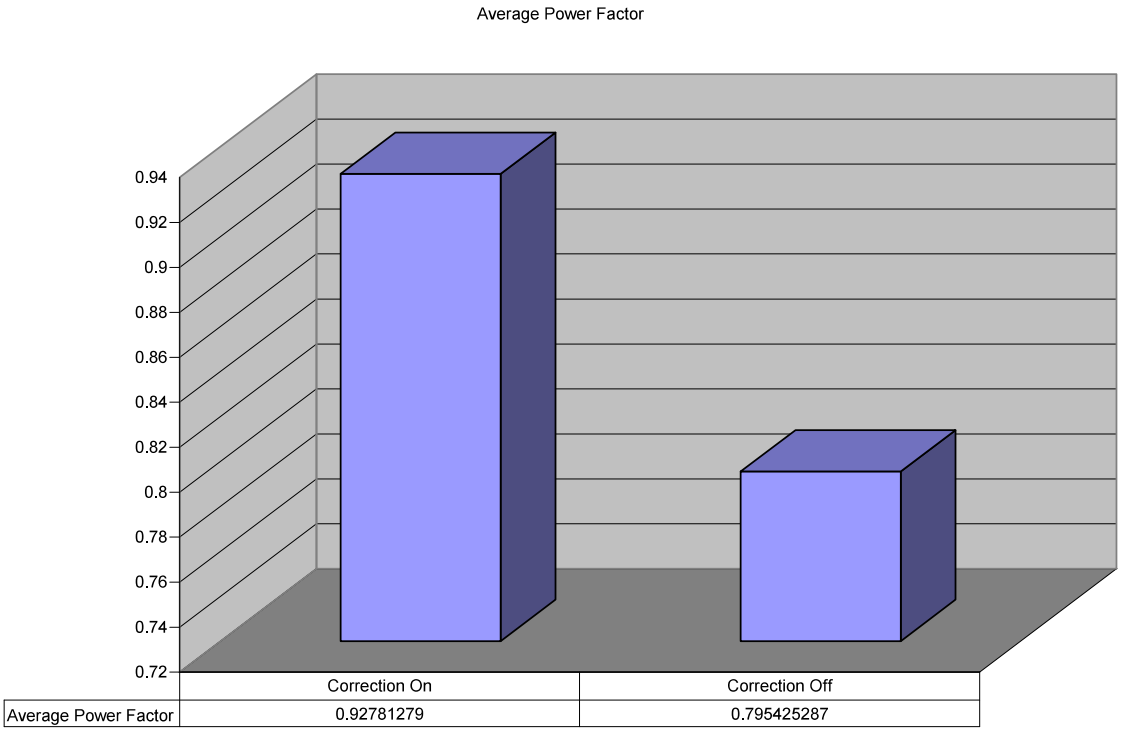

Figure 16: Power Factor Correction Comparison

The final area of interest deals with the automation of the load and genset equipment. During this continuous run period these systems were automatically operated by individual agents. These agents were given a base load profile for electrical kW, kVar and thermal demand. They were also given the freedom to deviate from this base profile by a certain amount. This allowed for the bounded, random generation of a large number of load flows within the microgrid. In total the system operated through approximately 27, 300 load changes and approximately 5,800 generation dispatches.

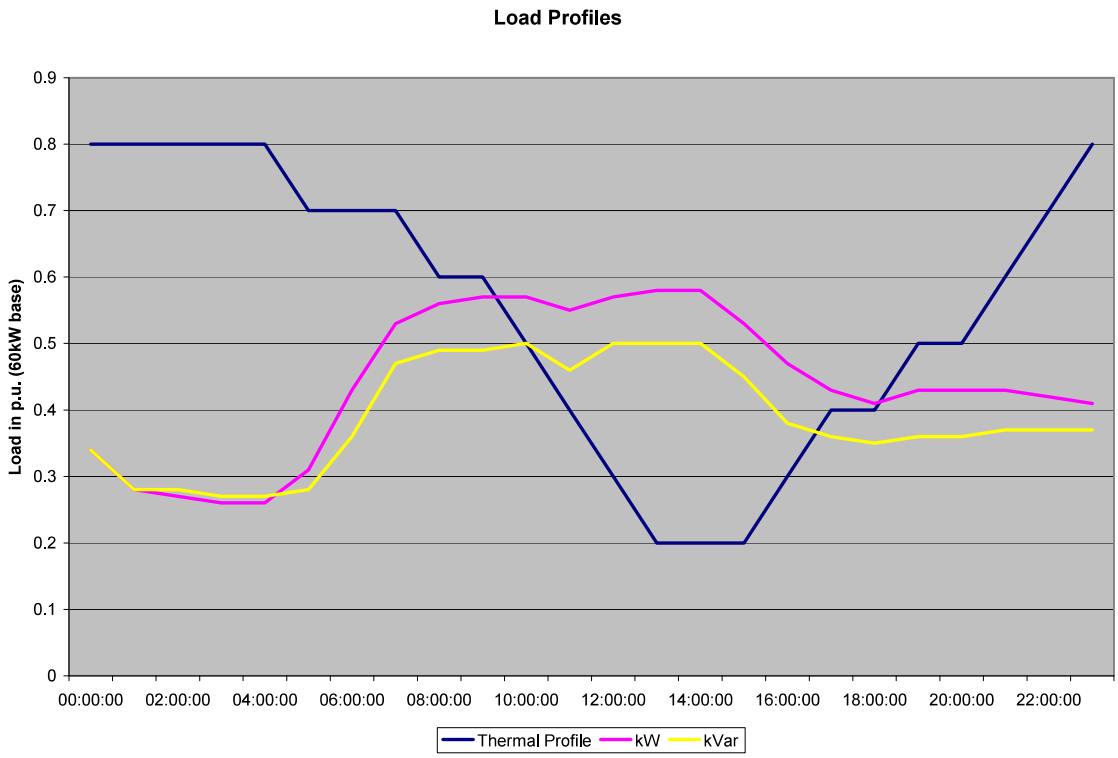

Figure 17: The Base Load Profiles for Thermal, kW, and kVar Demand.

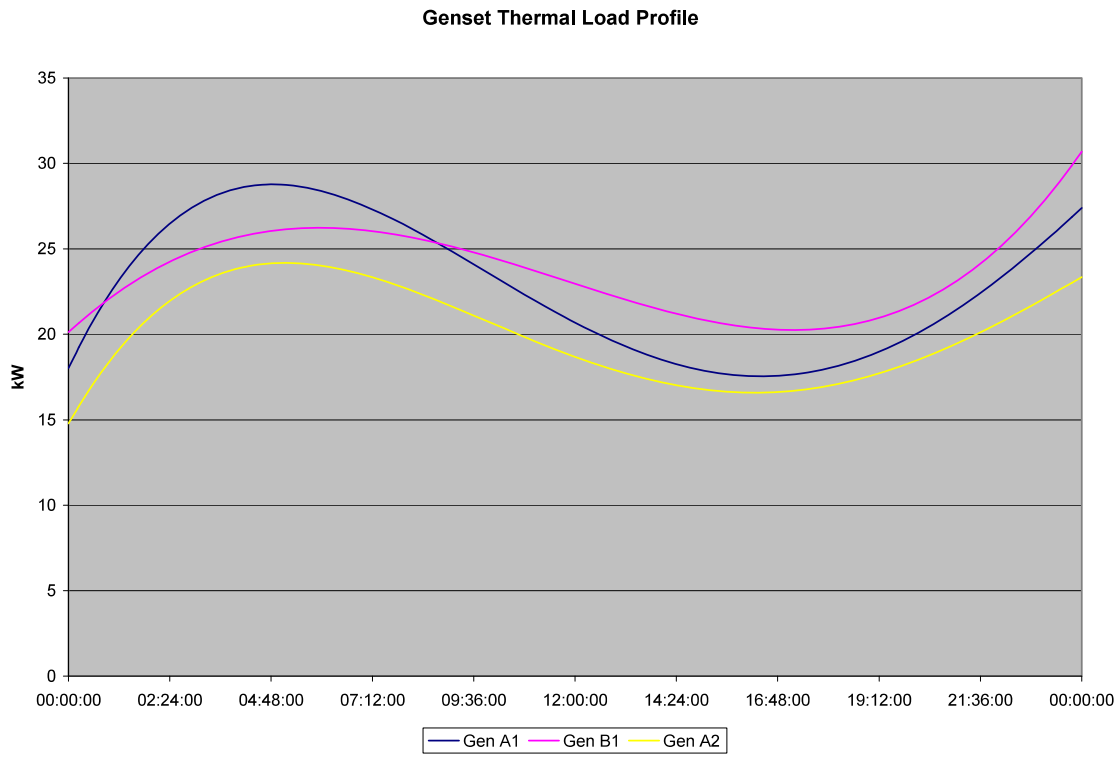

Figure 18: Averaged Measured Thermal Load Profile for each Genset

A general deviation from the base profile can be seen in the early morning hours of operation by all three gensets. This was characteristic was inadvertently caused to maintain compliance with the IEEE 1547 standard at the point of common coupling. The base thermal demand profile was constructed around a customer with higher thermal demand in the late evening and early morning hours, similar to a customer space heating requirement in the winter season. The thermal generation and therefore electrical generation was high enough to frequently offset the entire electrical demand at the point of common coupling. Because the chosen technique for anti-islanding detection within the CERTS microgrid is a minimum real power import the static switch would open each time power was exported to the utility for more than two seconds. Finally the static switch was automated to re-dispatch the generators to a lower set point and resynchronize to the utility system. This effectively lowered the generation dispatch to match that of the electrical load in the late evening and early morning hours of interest. As a consequence, a customer with this particular thermal and electrical demand would need to make adjustments to their system operation to ensure there energy demands were met continuously.

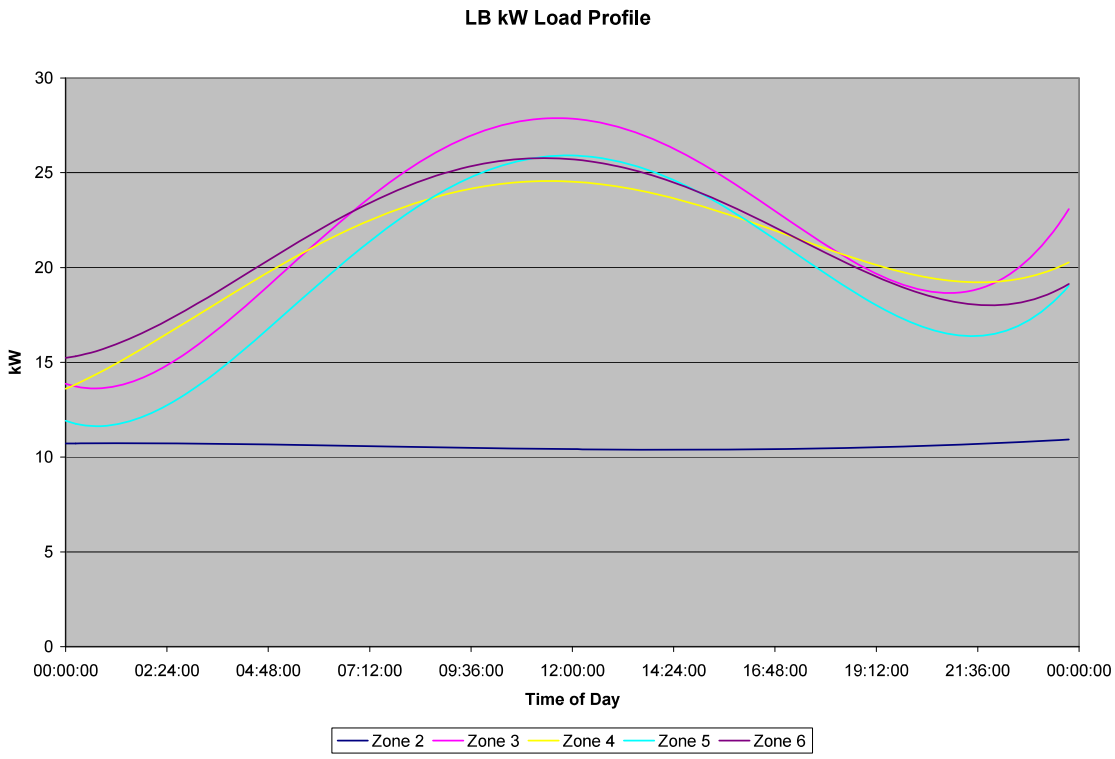

Figure 19: Averaged Measured kW Profiles for each Load Bank

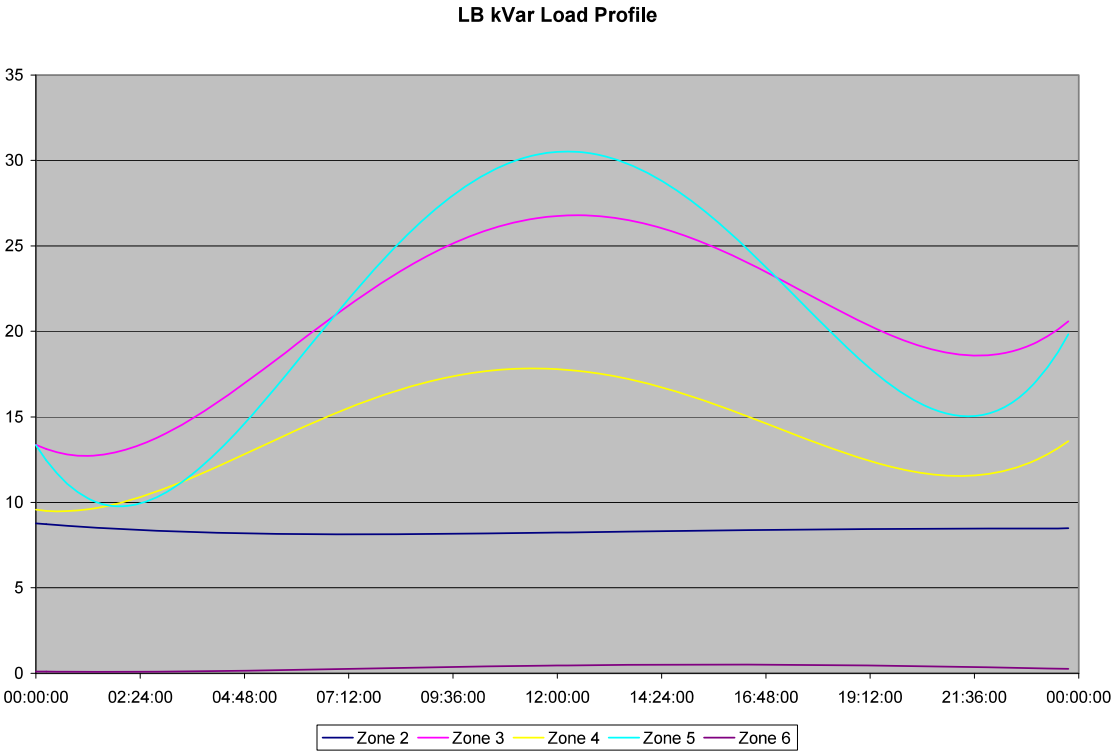

Figure 20: Averaged Measured kVar Profiles for each Load Bank

As point of interest, the averaged measured kVar profile shows the kVar demand of Load Bank 6 is flat at near zero for the entirety of the continuous run testing. This problem was tracked to an open breaker on the reactive load bank which went unnoticed during the testing.

6.0 Inverter Fault Contribution Executive Summary

In the phase one testing of the CERTS microgrid, test 6.1.2 was performed which the main objective was to insure that the static switch would open during a three phase reverse power condition. Such a condition can develop when a section of a distribution circuit is islanded after an upstream utility protection device opens. The test involved placing a large electrical load connected outside of the microgrid system. An upstream utility protection device was opened islanding this electrical load with the microgrid. This leads to an outflow of electrical power from the microgrid sources feeding the distribution load until the microgrid protection opens, separating the microgrid from the utility system. During this event the expected result was that the genset would increase its current output to approximately two times its rated current, approximately 240 amps peak, based on a 90 KVa rating.

Interestingly the results showed that the genset output current peaked closer to 600 amps or a little over four times the rated current. At the time this result was unexpected although it has since been explained. The typical fault current contribution from an inverter source is ~2 times the rated current of the inverter. The reason for the high fault current contribution here was due to the fact that the inverter was actually rated 2 times larger than the engine driven generator power rating. The gen-sets were nominally rated at 60kW + j60kVAR however the inverter design was rated at 125kW + j125kVAR. In any case this led to the question as to whether or not the fault current contribution of the microgrid genset equipment could be controlled to a known adjustable level. Generally with voltage source devices similar to the microgrid equipment this can be difficult and usually results in tripping the source device offline. Because one goal of the CERTS microgrid is to improve the reliability of energy delivery it is desirable that the microgrid source equipment successfully ride through an event of this nature. With this in mind it is also important to understand and be able to predict the fault current that will be delivered into a utility fault.

The fault current contribution was adjusted by developing a control within the inverter that would limit and ultimately determine the fault current contribution of an inverter. By controlling this current it allowed the gen-set to remain online supplying power to the microgrid local loads after the initiating fault was cleared. This testing repeated the test procedure 6.1.2 previously preformed to demonstrate control over the microgrid source fault current. With the same 500 kW load applied to the utility connection an upstream protection device is opened. In each case the microgrid SS detects the event and opens in approximately 2 cycles or less. The control software of the microgrid source is adjusted each time to demonstrate varying levels of fault current. The software adjustments were controlled by two variables, SA Loop and Percent Surge. SA Loop is the stand alone current control loop enable which turns the current control on or off. %Surge is related to the level at which the current is limited.

Below are the tabulated results of the tests. Genset A1 without current control had a maximum recorded current of 669 Amps. Genset A1 was able to successfully reduce its current contribution when the current control was enabled, as seen in Table 1.

A1 Kw	A2 kW	LB3 kW	LB4 kW	LB6 kW	%Voltage Sag	Percent Surge	Peak I	Shut Down	Fault type
20		**40**		**20**	**71**	**n/a**	**669**	**Yes**	**Boost**
20		**40**		**20**	**54**	**95**	**516**	**Yes**	**Boost and PCS**
20		**40**		**20**	**41**	**60**	**440**	**No**	
20		**40**		**20**	**54**	**80**	**498**	**No**	
20		**40**		**20**	**52**	**88**	**502**	**No**	
					79-A1		**415-A1**		**Overfield, Boost**
20	**20**	**40**	**40**	**20**	**81-A2**	**n/a**	**377-A2**	**Yes**	**and PCS**
20		**40**		**20**	**37**	**60**	**454**	**No**	
	20	**40**		**20**	**43**	**60**	**388**	**No**	
							380-A1		
20	**20**	**40**	**40**	**20**	**67-90**	**n/a**	**337-A2**	**Yes**	**Boost and PCS**

Table 1: Initial Test Setup, % Voltage Sag, and Peak Current

The largest change in peak current resulted from enabling the current control with a 95 Percent Surge value. At this setting a 23% reduction in peak current was observed. The lowest set point tested was a 60 Percent Surge resulting in a 38% total reduction in peak current. A comparison was also made between Genset A1 and Genset A2 at the 60 Percent Surge level. The fault current levels were similar but not equal. A portion of the difference in current contribution between the two gensets can be attributed to the difference in connecting cable impedance.

For all tests conducted at 60, 80 and 88 Percent Surge levels the genset was able to remain online through the duration of the event and continue to carry the islanded microgrid loads after the SS opened. Tests with SA Loop enabled and greater than an 88 Percent Surge or with SA Loop disabled resulted in the microgrid source shut down. Interestingly this is a different result than that of the first phase of testing in April of 2007. Then a similar test was performed on Genset A1 using the same load bank, distribution load and genset settings. The results of that test can be seen in Table 3. As indicated, the peak current then was 622 amps as compared to 669 amps on the recent test. Then voltage then sagged to 51 percent of pre-trigger values where as to 71 percent in the recent test.

Percent Surge	Genset	VArms pre-test	VBrms pre-test	VCrms pre-test	VArms during sag	VBrms during sag	VCrms during sag	Peak I	%Vsag
SA Loop Disabled	A1	267	268	272	189	212	188	**669**	71
95	A1	266	267	270	182	144	170	**516**	54
88	A1	266	267	270	139	139	156	**502**	52
80	A1	267	267	271	143	160	162	**498**	54
60	A1	266	266	269	110	143	137	**440**	41
60	A1 Retest	267	268	271	136	151	100	**454**	37
SA Loop Disabled	A1	270	271	273	229	215	231	**415**	79
	A2	270	270	273	241	219	239	**377**	81
SA Loop Disabled	A1 Retest	271	272	274	229	197	209	**380**	72
	A2 Retest	271	271	273	231	200	211	**337**	73
60	A2	271	272	275	118	156	133	**388**	43

Table 2: RMS Voltages before and during the test

Table 2 shows the voltage RMS on each phase prior to each test, followed by the minimum voltage recorded on each phase during the test. This table also shows that the peak current did decrease with a decrease in Percent Surge set point.

Percent Surge	Genset	VArms pre-test	VBrms pre-test	VCrms pre-test	VArms during sag	VBrms during sag	VCrms during sag	Peak I	%Vsag
SA Loop Disabled	A1	280	277	278	151	165	141	**622**	51

Table 3: RMS Voltages before and during the test of April 2007

The results of these tests indicate that the fault current contribution can be controlled by the genset equipment. They also demonstrate an approximately linear relationship between the Percent Surge and the fault current contributed. However if the value for Percent Surge is projected to 0, the fault current contribution is projected to be approximately 325 amps, not 0 amps as intuition would suggest. A similar relationship may exist past a Percent Surge value of 100. In this case the term Percent Surge is misleading and should be better connected to a deliverable value of fault current contribution.

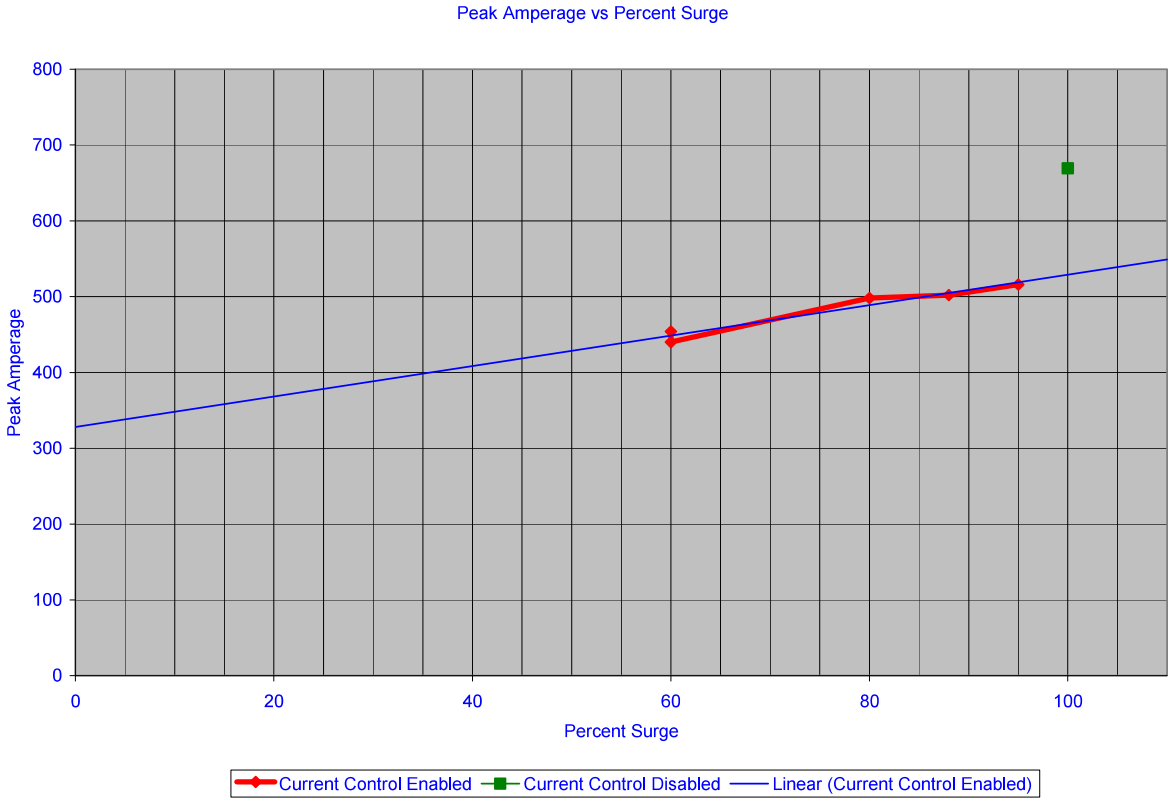

Figure 21: Peak Current vs Percent Surge

7.0 Protection Executive Summary

In the second phase of microgrid testing the measurement points of protection equipment was relocated. Originally the protection was designed to measure the voltage and current as it enters each zone of the microgrid from the utility source. In this phase the protection instead measured the voltage and current as it enters each zone of the microgrid from each microgrid generation source. In theory this would allow the genset manufacturer to incorporate the necessary microgrid protection directly into the genset equipment with no additional protection equipment required, a value add, cost cutting measure. A comparison between the utility source and generator source protection schemes was made. In both protection schemes the protection set points remained the same.

Testing was performed to verify phase-to-ground and phase-to-phase overload fault protection. I^2t protection was not retested as it should remain unaffected by the changes in the protection scheme. These tests were performed in each zone with all gensets being utilized at different times. These tests were to verify zero-sequence, negative-sequence, or residual over-current protection trips. To perform this testing the measurement points for each relay were relocated from the feeder entrance to that of the generator entrance on zones 3, 4, and 5.

Utilizing the same test procedures from the protection testing of phase one the repeated tests in phase two show some differing results.

In test procedure 7.7 of the previous phase this fault was detected and cleared by the protection scheme. In the recent phase none of the protection relays tripped for the fault in Zone 3, and Genset B1 also remained online.

In test procedure 7.8 of the previous phase this fault was detected and cleared by the protection scheme, CB51 opened and Genset B1 shutdown properly. In the recent phase none of the protection relays tripped for the fault in Zone 5, and Genset B1 also remained online.

In test procedure 7.13 of the previous phase the Static Switch opened on negative sequence, and all other breakers remained closed. Also Gensets A1 and A2 remained online. In the recent phase all of the protection relays tripped for the fault in Zone 3, Genset A1 and A2 shutdown.

In test procedure 7.14 of the previous phase this fault was detected and cleared by the protection in Zone 4, the Static Switch and CB41 opened with Genset A2 shutting down. In the recent phase all of the protection relays tripped for the fault in Zone 4, and Gensets A1 and A2 shutdown.

In test procedure 7.15 of the previous phase none of the protection relays tripped for the fault in Zone 2, and Genset B1 also remained online. In the recent phase all of the protection relays tripped for the fault in Zone 2, with the exception of relay 4, Genset A1 and B1 shutdown.

In test procedure 7.16 of the previous phase this fault was detected and cleared by the protection in Zone 5 and the Static Switch and CB51 opened shutting down Genset B1. In the recent phase all of the protection relays tripped for the fault in Zone 5 with the exception of relay 4, and Genset A1 and B1 shutdown.

Test	LB3 kW	LB4 kW	LB6 kW	Fault	Zone	SS	Relay 3	Relay 4	Relay 5	Genset A1	Genset A2	Genset B1
7.5	40		40	28kW A-G	3	G/I	G/I	R	R	SE	N/A	N/A
7.6	40	40	40	28kW A-G	3	G/I	R	R	R	SE	SE	N/A
7.7	40		40	28kW B-G	3	R	R	R	R	N/A	N/A	R
7.8	40	40	40	28kW B-G	5	R	R	R	R	R	N/A	R
7.9	40	40	40	28kW B-G	4	G/I,NS	R	RG/IT	R	R	SE	N/A
7.10	40	40	40	28kW C-G	2	G/I	RG/I	R	UV	SE	N/A	SE
7.13	40	40	40	84kW A-B	3	NS	NST	NST	UV	SE	SE	N/A
7.14	40	40	40	84kW A-B	4	NS	NST	NST	UV	SE	SE	N/A
7.15	40	40	40	84kW A-B	2	NS	NST	R	NST	SE	N/A	SE
7.16	40	40	40	84kW A-B	5	NS	NST	R	NST	SE	N/A	SE
7.15R	40	40	40	84kW A-B	2	NS	NST	R	NST	SE	N/A	SE

Key

G/I=Ground Over current
NS = Negative Sequence
NST = Negative Sequence Timed
R = Remained Connected
RG/I =Residual Ground Over Current
OU = Opened Reason Not Recorded
RG/IT =Residual Ground Over Current Timed
SE = Shutdown External (Relay Tripped)
UV = Under voltage
N/I = Neutral Over Current
N/A =Not Used

Table 4: Phase two tabular results of protection testing with measurement points located at the generator entrance on zones 3, 4, and 5.

Test	LB3 kW	LB4 kW	LB6 kW	Fault	Zone	SS	Relay 3	Relay 4	Relay 5	Genset A1	Genset A2	Genset B1
7.5	40		40	28kW A-G	3	G/I	G/I	R	R	SE	N/A	N/A
7.6	40	40	40	28kW A-G	3	G/I	G/I	N/I	OU	SE	SE	N/A
7.7	40		40	28kW B-G	3	NS	R	R	G/I	N/A	N/A	SE
7.8	40	40	40	28kW B-G	5	R	R	R	G/I	R	N/A	SE
7.9	40	40	40	28kW B-G	4	G/I	R	G/I	R	R	SE	N/A
7.10	40	40	40	28kW C-G	2	G/I	G/I	R	UV	SE	N/A	SE
7.13	40	40	40	84kW A-B	3	NS	R	R	R	R	R	N/A
7.14	40	40	40	84kW A-B	4	NS	R	NS	R	R	SE	N/A
7.15	40	40	40	84kW A-B	2	R	R	R	R	R	N/A	R
7.16	40	40	40	84kW A-B	5	NS	R	R	NST	R	N/A	SE

Key

G/I=Ground Over current
NS = Negative Sequence
NST = Negative Sequence Timed
R = Remained Connected
RG/I =Residual Ground Over Current
OU = Opened Reason Not Recorded
RG/IT =Residual Ground Over Current Timed
SE = Shutdown External (Relay Tripped)
UV = Under voltage
N/I = Neutral Over Current
N/A =Not Used

Table 5: Phase one tabular results of testing with points of measurement located at the feeder entrance.

8.0 References

[1] Eto, Joseph, Robert Lasseter, Ben Schenkman, John Stevens, Harry Volkommer, Dave Klapp, Ed Linton, Hector Hurtado, Jean Roy, Nancy Jo Lewis, Consortium for Electric Reliability Technology Solutions (CERTS). 2008. *CERTS Micorgrid Laboratory Test Bed*. California Energy Commission, Public Interest Energy Research Program. CEC-500-2008-XXX.