



INVERTER GROUND- FAULT DETECTION “BLIND SPOT” AND MITIGATION METHODS

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EXECUTIVE SUMMARY

This final report in the Solar America Board for Codes and Standards (Solar ABCs) “blind spot” series concludes a research program into an important safety issue associated with the design of many U.S. photovoltaic (PV) systems. This safety issue came to light during studies of two well-publicized PV system fires—the first on April 5, 2009, in Bakersfield, California, and the second on April 16, 2011, in Mount Holly, North Carolina.

Based on evidence found at these two fires, traditional, fuse-based ground fault protection schemes do not detect certain ground faults that can occur in grounded PV systems. These undetected faults fall within a detection “blind spot” inherent in the design of most U.S. PV installations.

Over the last twelve months, Solar ABCs has led a broad industry- and stakeholder-based working group to research this problem and evaluate the effectiveness of various mitigation strategies. This research built on earlier work that provided a basic explanation of the cause of the detection blind spot. It includes results of field research conducted to characterize basic array wiring impedance properties and their effects on ground fault detection, circuit modeling, and analyses of high and low impedance faults that may occur throughout the array. It also includes a technical review of the effects of ground fault detection blind spots on different array topologies (grounded, ungrounded, and grounded through the alternating current connection).

Included in this report are recommendations for operational strategies and equipment retrofits that can increase ground fault detection sensitivity and reduce the risk of fire in new and retrofit applications. Early results from large PV systems that have been retrofitted with the recommended protective devices indicate that these devices can substantially reduce the detection blind spot without requiring redesign of the system. The major mitigation strategies and equipment retrofit options presented in this report include:

- following proper installation techniques with close attention to wire management,
- performing routine preventative maintenance to identify and resolve progressive system damage,
- introducing data acquisition and system monitoring at a level sufficient to determine if system integrity has degraded and unscheduled maintenance is required, and
- installing differential current sensors and PV array insulation monitoring devices that can be incorporated into the data system to alert operators to potential problems in advance of conditions that may lead to fire.

Based on the investigations reported here, it is recommended that PV systems with damaged conductors be identified and repaired as soon as possible. It then becomes the task of system operators to weigh the cost of increased system inspections and retrofit hardware against the potential cost and damage of a fire.

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INTRODUCTION

This report presents results of a research program that started with the publication in January 2012 of a Solar America Board for Codes and Standards (Solar ABCs) white paper, *The Ground-Fault Protection BLIND SPOT: A Safety Concern for Larger Photovoltaic Systems in the United States*. The white paper introduced an important safety concern in the design of many U.S. photovoltaic (PV) systems, namely conditions that can lead to undetected faults in grounded PV array conductors.¹ This concern came to light during investigations into the role of ground faults in the ignition of two well-publicized PV system fires—the first on April 5, 2009, in Bakersfield, California, and the second on April 16, 2011, in Mount Holly, North Carolina.

PV inverter ground fault protection requirements, methods, and limits have been a significant point of discussion nationally and internationally for some time, and 97 are presently under revision. Under requirements of the *National Electrical Code*[®] (*NEC*), ground fault protection is required of most PV installations in the United States. The 2014 *NEC* revision cycle is being finalized and Solar ABCs members were instrumental in developing and building consensus for updating PV ground fault protection requirements in the latest code.

Under requirements of the Underwriters Laboratories (UL) 1741 standard, inverters with ground fault detection are evaluated for compliance with specific ground fault detection and interruption tests unless they are marked to indicate that separate ground fault protection must be installed. When investigations uncovered evidence for persistent but undetected ground faults as a condition leading to some PV fires, concern grew about whether the maximum fault current allowed for grounded PV systems during fault conditions is sufficient to protect PV systems from ground faults. Solar ABCs convened a broad industry- and stakeholder-based working group to investigate this concern and to develop a ranked list for effective mitigation methods where needed. The working group developed a research program to:

- investigate—through data sharing with major utilities and PV operating companies—the likelihood of undetected “blind spot” faults occurring in the field;
- demonstrate and characterize the fault current detection “blind spot” in several large, fielded PV inverters;
- measure the impedance of array wiring and equipment grounding conductors in large, fielded PV systems to support modeling and analysis tasks;
- develop accurate simulation models of arrays and systems with high and low impedance faults occurring throughout the array and assess their effects on fault current magnitude and detectability;
- analyze the ground fault detection capabilities of three different PV system types installed in U.S. residential, commercial, and utility-scale PV installations—array ungrounded, array directly grounded (one pole connected to earth), and array (one pole) referenced to ground through a (resistive) connection to the alternating current (AC) ground; and
- provide a list of operational procedures that can reduce the risk of fire as well as a list of retrofit actions that can be taken to increase the sensitivity of electronic ground fault detection.

¹Technically, the ground fault detector/interrupter is blind to other faults too, e.g., high impedance faults. For details, see Sandia National Laboratories technical report, “Photovoltaic Ground Fault and Blind Spot Electrical Simulations,” Sandia National Laboratories Technical Report, 2013, <http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND2013-3459-Photovoltaic-Ground-Fault-and-Blind-Spot-Electrical-Simulations.pdf>

Based on the results presented in this report, PV system owners will have to evaluate both the benefits of system retrofits and the risks associated with not implementing various mitigation strategies. Equipped with this understanding, owners will be able to decide which, if any, corrective actions they will implement.

This report is presented in six sections:

- Section 1 is a high-level discussion of the different ground fault detection methods used in different PV array topologies today.
- Section 2 presents a summary of the field test evaluation program performed by Solar ABCs to document and characterize ground fault detection limitations in fielded inverters. Included in this section are additional results of long-term (months, years) monitoring of leakage currents in PV systems in California and North Carolina that reflect the effects of weather conditions (humidity and lightning) on leakage current magnitude.
- Section 3 presents modeling used to examine the effects of reducing the amperage of the ground fault fuse on ground fault detection sensitivity.
- Section 4 presents a matrix of mitigation methods and equipment that can reduce or eliminate the ground fault detection blind spot.
- Section 5 presents an overview of the ongoing revisions to the major codes and standards affecting PV inverters and PV ground fault protection products.
- Section 6 presents conclusions.

¹Technically, the ground fault detector/interrupter is blind to other faults too, e.g., high impedance faults. For details, see Sandia National Laboratories technical report, “Photovoltaic Ground Fault and Blind Spot Electrical Simulations,” Sandia National Laboratories Technical Report, 2013, <http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND2013-3459-Photovoltaic-Ground-Fault-and-Blind-Spot-Electrical-Simulations.pdf>

SECTION 1—OVERVIEW OF PV SYSTEM GROUND FAULT DETECTION METHODS

PV systems may be wired in several different configurations with respect to system grounding. The direct current (DC) side of the system may be directly grounded (e.g., one pole connected to earth) or ungrounded, or the array may be grounded through a connection to the AC side ground. Systems also may or may not have galvanic isolation between the DC and AC sides. These design factors influence a system's fault tolerance and response to ground faults, and add complexity to properly implementing ground fault protection. This section addresses the various PV system types seen in U.S. residential, commercial, and power plant PV installations, and their ground fault detection techniques and capabilities.

Grounded Isolated DC Arrays

The most common configuration seen in U.S. residential and commercial PV systems today is the grounded DC array with galvanic isolation from the AC interconnection. This configuration is determined by the inverter, which in most cases grounds the DC side by connecting one pole of the array to ground through a fuse or other overcurrent protection (OCP) device. Under certain conditions, the *NEC* also allows grounded systems in which the array is connected directly to ground without an OCP device, but these are far less common in practice. Galvanic isolation is typically achieved through the use of an isolation transformer interface between the inverter's electronic AC output and the utility connected AC terminals of the unit. Some smaller inverters achieve galvanic isolation using a high-frequency transformer in the DC switching circuit rather than at the utility interface.

The UL 1741 standard specifies the maximum OCP requirements for ground fault detection and interruption in PV inverters. As shown in Table 1, these specifications are dependent on the size of the inverter.

Table 1

UL 1741 Ground Fault Detection Specifications vs. Inverter DC Rating

Inverter DC Rating (kW)	Maximum Ground Fault Current (Amps)
0-25	1
25-50	2
50-100	3
100-250	4
>250	5

Note: kW = kilowatts

Prior to the creation of this table, the standard had no ground fault interruption requirements at all. This change was adopted following instances in which single ground faults on ungrounded array conductors resulted in arcing between cables and metallic conduit. This arcing can result in fire. The OCP settings in the table generally protect well against such faults, but are also rated conservatively to avoid nuisance trips from array leakage current. However, field incidents suggest that additional technical review of these ratings may be useful to most effectively detect or interrupt high impedance faults or faults occurring on the grounded conductor.

A fault between a grounded conductor and ground creates a parallel path for current in that circuit. As shown in Figure 1, some portion of the string current flows in the intended circuit conductors, and some portion flows in the parallel ground circuit between the array and the pole-ground connection in the inverter. Often, the combined impedance of the fault and the ground path is greater than that of the circuit conductors, in which case the ground fault current will be low. In the Figure 1 example, a string current (e.g., 6 amps [A] nominal) divides such that less than half ($< 3A$) is flowing in the ground circuit back from the inverter. In this example, with a large inverter and a 5A ground fault interrupt fuse, the fault can exist indefinitely without blowing the fuse. The presence of this undetected fault can result in arcing and fire if a second, subsequent ground fault occurs on the ungrounded conductor.

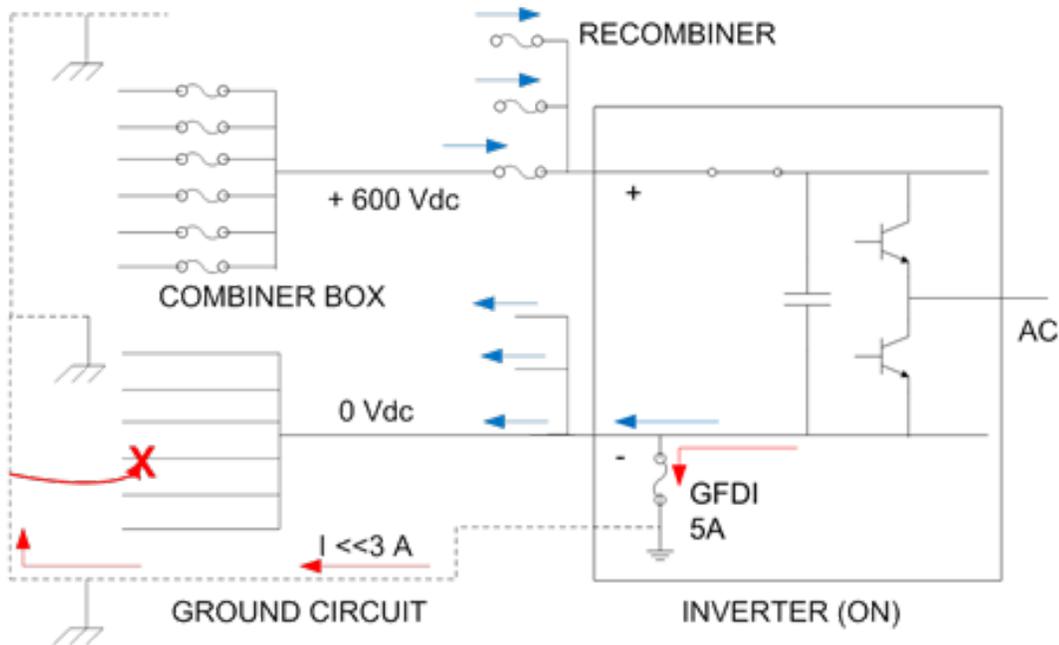


Figure 1. Grounded conductor fault occurring on a PV string or source circuit conductor. Note that Vdc = voltage direct current, AC = alternating current, GFDI = ground fault detector/interrupter, and A = amperes.

Grounded conductor faults on the larger PV output cables (between the combiner box and recombiner or inverter) have a better chance of creating high enough currents to trip a ground fault detector/interrupter (GFDI) fuse, but in some cases, fault impedance may still be sufficient to keep the fault current below the trip rating.

This blind spot problem is not an inherent limitation in the grounded/isolated system configuration, but rather an unintended consequence of the prevailing GFDI method used to deal with multiple faults. The solutions identified later in this report can provide increased sensitivity for detection/interruption capabilities similar to those found in systems using other grounding configuration.

Ungrounded Isolated Systems

The most common array configuration installed outside the United States is ungrounded. That is, neither the positive nor negative DC pole is directly bonded to ground. An ungrounded DC system may have galvanic isolation between the DC and AC side or it may be non-isolated. Large three-phase systems more commonly have galvanic isolation, either with a built-in low voltage transformer or an external medium voltage transformer. The latter approach with medium voltage transformers is also becoming common in U.S. power plants.

As we have discussed, the ground fault detection blind spot is much less applicable in ungrounded systems that incorporate isolation monitoring and lower ground fault thresholds. Without an intentionally grounded array conductor, ground faults on either conductor are easy to identify with appropriately chosen and properly adjusted isolation measurement devices. However, an ungrounded array with inadequate attention paid to ground faults is susceptible to dramatic failures the same way a grounded system is under the blind spot scenario. Figure 2 shows the schematic for an ungrounded array with an isolated inverter. The poles are not explicitly referenced to ground, but if measured with a voltmeter, a healthy array will tend to have a balanced positive and negative voltage around zero potential.

Ground fault detection in ungrounded arrays is typically achieved by measuring the insulation resistance of each pole relative to ground (commonly referred to as Iso measurements). In a healthy, moderate sized array, the Iso resistance should be in the hundreds or thousands of kilo-ohms (kohm). A ground fault is detected when the impedance to ground of either pole drops to a low level. There are different trip thresholds depending on the inverter and size of the array, but faults of one kohm or less are unambiguously detected and flagged as faults. This is one of the more sensitive and robust methods of ground fault detection.

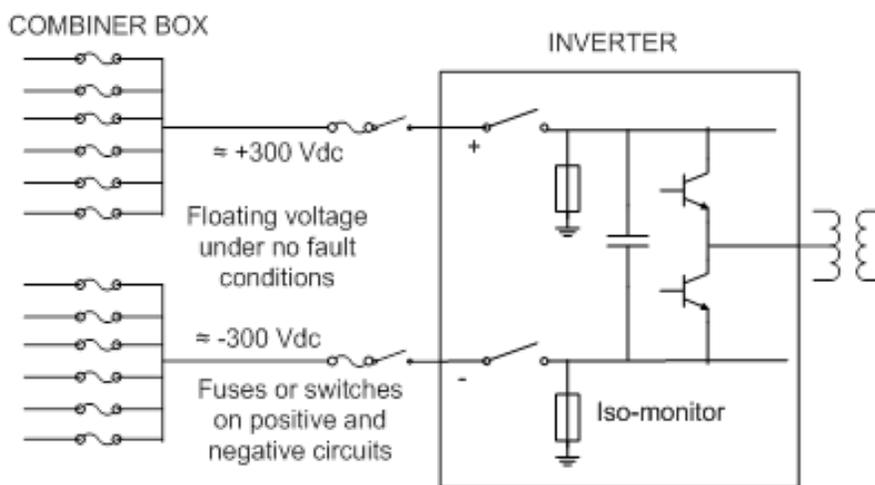


Figure 2. Ungrounded array with AC isolation. Note that Vdc = voltage direct current.

The action taken following fault detection is important. The first fault will not cause any fault current to flow. This is only true with isolated inverters. Non-isolated inverters will cause large fault currents from the utility. Effectively, the ground fault has turned an ungrounded system into a grounded system. But,

as with the blind spot fault, if a subsequent fault occurs on the opposite pole, a short circuit is created that may not be readily interrupted by the array OCP devices. Therefore, it is essential to respond to a first fault in an ungrounded system as one would in a grounded system by either shutting the inverter down or isolating the portion of the array that has the fault.

UL issued a Certification Requirement Decision (CRD), on July 29, 2012, that includes requirements for *Isolated Inverters Intended for Use with Ungrounded PV Arrays*.² This CRD includes PV array isolation measurement requirements prior to inverter operation and also includes low level ground fault current trip limits based upon the kilovolt-amps (kVA) size of the inverter. This CRD results in a significant increase in ground fault detection sensitivity and improvement in response time. Multiple inverters from several manufacturers have already been listed for compliance with this CRD.

Ungrounded, Non-Isolated Systems

As mentioned above, ungrounded DC arrays may also be operated without galvanic isolation from the AC wiring. These are known as non-isolated systems. The circuit configuration for non-isolated systems is similar to the one shown in Figure 2, but without the AC transformer. The impact is that during operation, the DC pole voltages relative to ground vary in response to inverter switching devices connecting and disconnecting the DC bus to the AC poles. So, while the PV array/DC input is not directly bonded to ground, its voltage relative to ground fluctuates at the inverter switching frequency. A grounded DC system cannot use a non-isolated inverter because the PV ground bond connection would cause a short circuit for the ground-referenced AC utility connection through the inverter as soon as the inverter began operating.

As with ungrounded isolated systems, the blind spot phenomenon (ground fault in the grounded conductor) is not applicable, because there is no grounded conductor. Ground fault detection is achieved differently than with the isolated systems. When the inverter is first turned on, or in the mornings before the inverter begins operation, an isolation measurement is performed on both the PV array positive and negative poles. If a low impedance to ground is detected (as defined in the ungrounded isolated case), the inverter will stop operating and indicate a ground fault. The fault must be located and cleared before the inverter can operate.

When the inverter is operating, Iso measurements cannot be taken because of the continually changing voltage reference on each pole to ground. Therefore, a residual current measurement is made, generally on the AC side, to look for any imbalance in current going in versus current going out. This will detect faults within the inverter as well as ground faults in the DC system. Because the fault current is sourced on the AC side, the residual current detection can be highly sensitive to ground faults. This two-pronged approach to identifying faults both before and during operation is one of the more robust GFDI detection methods available for any system topology.

²UL 1741. (2010, January 28). Edition 2. New sections 109 to 112.

UL issued a CRD on April 26, 2010, that includes requirements for *Non-Isolated EPS Interactive PV Inverters Rated Less Than 30kVA*.³ These requirements were written to be consistent with European requirements for non-isolated PV inverters and an early draft of the International Electrotechnical Commission (IEC) 62109-2. The requirements include PV array isolation measurements requirements prior to inverter operation. They also include multiple low milliamp (mA) level ground fault current trip limits and trip times. These requirements are similar to the protection methodologies used by IEC-compliant residual current detector (RCD) products such as those provided by the Bender protection relay. Multiple inverters from several manufacturers have already been listed for compliance with this CRD. Non-Isolated inverter requirements for systems larger than 30 kilovolt-amperes (kVA) are included in IEC 62109, which is in the process of being adopted in the United States as UL 62109 to replace UL 1741 for PV inverters and other PV power electronics.

Hybrid Designs (e.g., Grounded Non-Operating, Non-Isolated Operating)

At least one major inverter manufacturer employs a hybrid grounding approach. This manufacturer's bipolar inverter operates with half of the PV array connected as a negative-grounded system, and the other half connected as a positive-grounded system. When the inverter is not operating (not sourcing AC power to the grid), the positive and negative array neutrals are isolated from each other and functionally grounded using GFDI fuses as described in the section on grounded isolated systems. When the inverter is operating and producing power, the neutrals of the positive and negative arrays are referenced to the AC neutral/ground of the utility interface (see Figure 3). The AC ground referencing is not a hard connection, but is achieved through the switching circuitry in the power conversion stage of the inverter. This method ensures that the neutral circuits are effectively held to low and safe potential levels relative to ground.

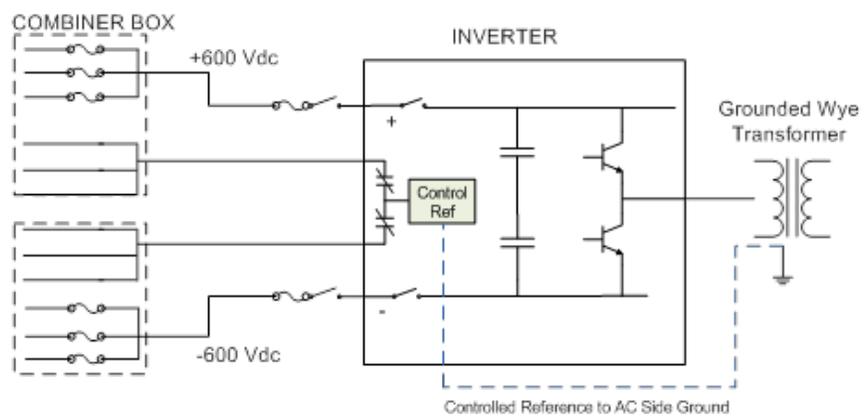


Figure 3. Grounding approach in hybrid bipolar inverter during operation (offline grounding not shown). Note that Vdc = voltage direct current and AC = alternating current.

³UL 1741. (2010, January 28). Edition 2. New proposed sections 87 to 100.

A low AC voltage is superimposed on the neutral to ground circuit, which enables fairly sensitive ground fault detection. A ground fault on a grounded string conductor causes fault current to flow from the AC side (a much greater source of current than the PV array) and this can be significant enough to be detected in the inverter either as a DC ground fault or a zero-sequence AC fault. The hybrid bipolar inverter has demonstrated this sensitivity, notably in project startup situations where string conductor faults cause trips and must be identified and cleared before the system can be put into operation.

During field tests at a site with a hybrid inverter, the inverter tripped in response to grounded string conductor faults with zero impedance, but was inconsistent with a fault impedance setting of one ohm or greater. There are many factors that drive the level of sensitivity within a given array, but field results indicate that, although not as sensitive as some of the other methods recommended in this report, the hybrid inverter can provide greater sensitivity in ground fault detection than the standard grounded-isolated inverter configuration.

SECTION 2—ARRAY AND INVERTER FIELD TEST RESULTS

The overarching goals of the field test program were to demonstrate and characterize the ground fault detection blind spot. A formal test plan was drafted and reviewed by Solar ABCs members and the GFDI working group. The major objectives of field testing were:

- Use megger testing to determine the presence of ground faults in any existing array positive and negative conductor (array floating) and measure the impedance of the equipment grounding conductor.
- Use an RCD to measure the normal operational differences in current (i.e., the presence of leakage current) flowing in positive and negative array conductors (array operating).
- Use an oscilloscope to measure magnitude of AC waveforms on the ground fault fuse during normal system operation (array operating).
- Introduce an intentional, “controlled” ground fault into the grounded conductor of an array (or string). Verify that the inverter does not detect the fault and continues to operate. Measure the fault current directly at the site of the fault and through the ground fault fuse (array operating). Use an oscilloscope to measure and record AC waveforms on the ground fault fuse circuit during this test.

Throughout the testing phase, an effort was made to test a wide variety of inverters to demonstrate either the universality of the detection blind spot or to identify inverters with advanced ground fault detection circuitry that were resistant to the blind spot phenomenon.

Instrumentation and Special Equipment

Creating an intentional fault within a large PV array is dangerous and has the potential to ignite a fire. For safety and repeatability, a dedicated piece of equipment was designed for creating faults between the array’s grounded conductor and equipment ground. This device, referred to as a ground fault appliance (GFA) is shown in Figure 4. The GFA includes a fused disconnect switch and can connect to array wiring through an inline T-cable (with either MC3 or MC4 connectors). It was used to sequentially introduce any of four preset values of resistance (short circuit, 1 ohm, 5 ohms, 10 ohms) between an array conductor and ground. The schematic for the GFA in its installed condition is shown in Figure 5.



Figure 4. Ground fault appliance with T-cables and meter used to introduce ground faults within an array.

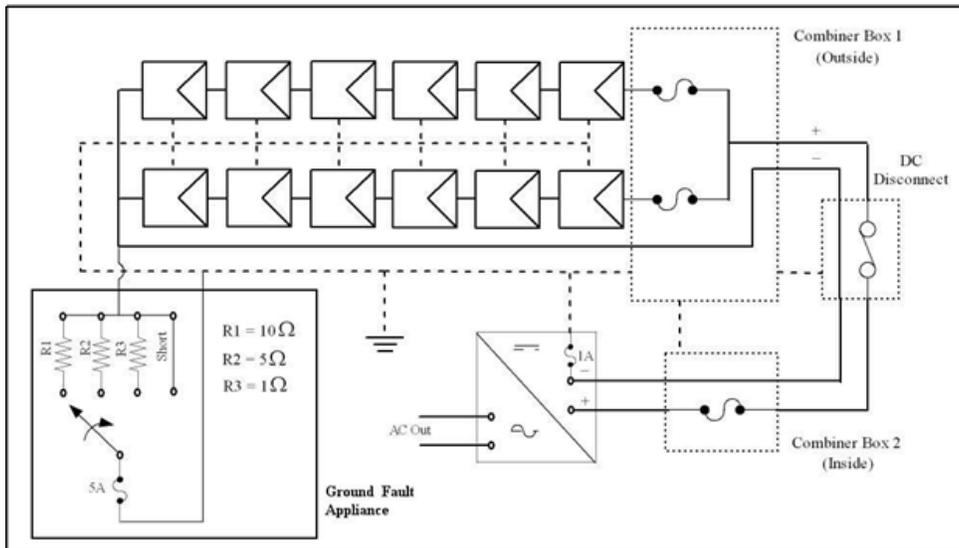


Figure 5. Schematic diagram of the ground fault appliance installed for testing. Note that DC = direct current, AC = alternating current, and Ω = ohm.

The GFA includes a built-in 5A:50 millivolt (mV) precision current shunt for measuring fault current at the array. The 5A:50mV precision current shunt will effectively change the fault resistance from 0, 1, 5, and 10 ohms to a slightly larger value (0.01, 1.01, 5.01, 10.01 ohms) based on the shunt resistance (0.01 ohm for the 5A:50mV). The switches and other components in the GFA will also have some internal resistance. In all the cases, this value falls into the noise of the resistance of the equipment grounding conductor (EGC) path.

For measuring fault currents at the inverter, an RCD (Bender RCMS460-D-2) was used. Before testing, both the positive and negative conductors from selected strings were routed through the RCD's current transducer. During normal operation, the current in both conductors of a string will be equal. The RCD measures and reports any difference between the two currents. A measured difference represents current flowing outside one of the conductors (e.g., through module frames, the EGC, etc.). Current outside the conductor can be the result of either normal module leakage current or fault current from any source such as modules, wiring, combiners, etc.

Results of Field Testing

Field tests were conducted on PV systems at the following sites:

- Sandia National Laboratories, Albuquerque, New Mexico (March 2012);
- Fontana, California (May 2012);
- Union City, California, and Fresno, California (June 2012); and
- San Leandro, California, and Davis, California (August 2012).

Twelve inverters from eight different manufacturers were tested during this program. In every case, the test involved introducing a ground fault into one of the grounded conductors of the array through four steps of decreasing resistance, from 10 ohms to short circuit. Most of the inverters tested continued to operate normally in the presence of all of the introduced faults. In two cases, the inverter under test operated normally with the higher resistance faults, then tripped offline once fault resistance decreased and fault current rose beyond its detectability threshold.

Test Results—Residential-Scale Inverters

The first tests were conducted on residential-scale inverters at Sandia National Laboratories (Sandia). Sandia engineers provided access to the Distributed Energy Technologies Laboratory (DETL). Design of the DETL is unique and allowed a single array to be used for testing a selection of four different inverters. Table 2 shows results of testing one of the inverters (identified only as Inverter C in this report), a 5 kilowatt (kW) single phase unit. During testing, fault current was measured both at the array with a shunt in the faulted circuit and at the inverter with an RCD around array positive and negative conductors.

All four residential-scale inverters continued normal operation in the presence of a ground fault between a grounded circuit conductor and the grounding system with current at or below their ground fault fuse values (1A in all cases). One inverter continued operation until fault current reached approximately 850 mA when it tripped offline without blowing the 1A ground fault fuse. This inverter uses a current transducer on the ground fault circuit in addition to the inline 1A fuse.

Table 2

Ground Fault Current Measurements, Residential-Scale Inverter C (Sandia)

Ground Fault Resistance Value	Fault Current at the Array (Fluke meter)	Residual Current at the Inverter (Bender Device)	Inverter Operating (Y/N)
10 Ω	51 mA	47 mA	Y
5 Ω	96 mA	91 mA	Y
1 Ω	40 mA	342 mA	Y
0 Ω (short)	850 mA	>600 mA	Y

Note: Ω = ohm, mA = milliampere

Test Results—Commercial-Scale Inverters Operating With Partial Arrays

Several rounds of tests were conducted on large PV systems and inverters. These tests were made possible by the generous partnership of two companies, Southern California Edison (SCE) and SunPower Corporation. SCE provided the support of an SCE electrician and access to several PV systems that the utility owns and operates. SunPower provided similar access and service to several systems that the company has installed and operates for others. SunPower engineers also conducted supplemental tests in support of this project and shared test results with Solar ABCs.

Between one and three strings were used to energize the inverter during most tests. As before, ground fault current was measured at the site of the fault (in the array) and at the inverter (via the RCD). Figure 6 shows the RCD (Bender) current transducer installed around a single string during testing. Figure 7 shows the installation of the GFA within a string combiner box on the roof. In this case, the GFA was used to introduce controlled ground faults within the combiner box.



Figure 6. Bender current transducer installed around positive and negative string conductors

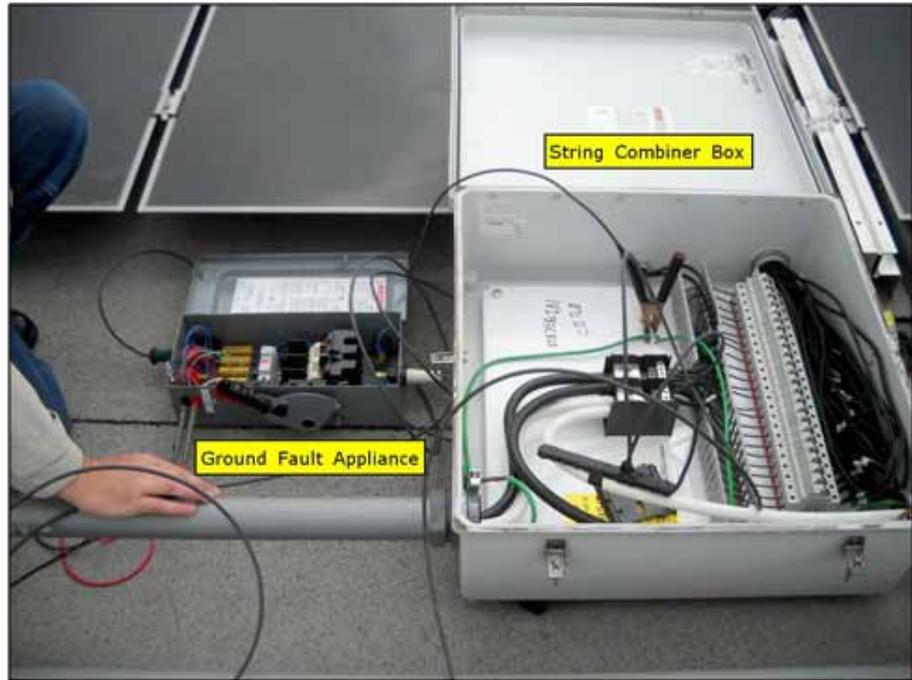


Figure 7. Ground fault appliance installed in string combiner box during testing.

Ground fault testing was conducted on 500 kW, 225 kW, and 200 kW inverters from four manufacturers. In all cases, inverters continued normal operation in the presence of introduced ground fault between a grounded conductor and the grounding system with current at or below their ground fault fuse values (5A in all cases). Table 3 presents results of the ground fault testing on one 500 kW inverter. These results are typical of most of the tests performed.

Table 3

Ground Fault Current Measurements, Industrial-Scale Inverter 2 (SCE)

Ground Fault Resistance Value	Fault Current at the Array (Fluke meter)	Residual Current at the Inverter (Bender)	Fault Current Through the Inverter Ground Fault Fuse Shunt (Fluke meter)	Inverter Operating (Y/N)
10 Ω	97 mA	98 mA	93 mA	Y
5 Ω	159 mA	167 mA	157 mA	Y
1 Ω	660 mA	>600 mA	689 mA	Y
0 Ω (short)	3,880 mA	>600 mA	3,910 mA	Y

Note: Ω = ohm, mA = milliampere

Test Results—Commercial-Scale Inverters Operating With Full Arrays

Although testing with a reduced number of strings was desirable for safety reasons, engineers from SunPower used a full array to retest one of the systems that had been tested earlier using only a few strings. This system was chosen for retest specifically because its inverter incorporates electronic ground fault detection circuitry in addition to the ground fault fuse. The retest was performed to investigate whether, in a real-world situation with full array current available, the ground fault detection threshold will be reached quickly and sustained operation in the presence of the fault will be as likely to occur. Table 4 presents results of testing Industrial-scale Inverter 1 in August when only three strings of the array were used to energize the inverter. Table 5 presents results of retesting this inverter in November with the full 500 kW array enabled.

Table 4

Ground Fault Current, Three Strings Enabled, Industrial-Scale Inverter 1 (SunPower)

Ground Fault Resistance Value	Fault Current at the Array (Fluke meter)	Inverter Operating (Y/N)
10 Ω	50 mA	Y
5 Ω	60 mA	Y
1 Ω	160 mA	Y
0 Ω (short)	1.02A	Y

Note: Ω = ohm, mA = milliampere, A = ampere

Table 5

Ground Fault Current, Full Array Enabled, Industrial-Scale Inverter 1 (SunPower)

Ground Fault Resistance Value	Fault Current at the Array (Fluke meter)	Inverter Operating (Y/N)
10 Ω	520 mA	Y
5 Ω	1.14A	Y
1 Ω	2.90A	Y
0 Ω (short)	-	Inverter Tripped

Note: Ω = ohm, mA = milliampere, A = ampere

Testing demonstrated that ground fault currents are larger when the full array is enabled. Ground fault simulation program with integrated circuit emphasis (SPICE) modeling by Sandia scientists also shows that the likelihood of a ground fault being detected improves with an increasing number of strings in the circuit. The indication is that for inverters, which sense ground faults through electronic circuitry (and not simply a fuse), testing with the full array is necessary to obtain valid results for the sensitivity of the inverter's ground fault detection. Even under full array conditions, sustained operation in the presence of a non-zero ohm ground fault was still observed.

Test Results—Measurement of Equipment Grounding Conductor Impedance

The EGC for a PV array connects all exposed metal of the array to a copper conductor that is bonded to earth ground at the inverter. Therefore, current flowing in the EGC can follow the copper conductor or any of the parallel paths represented by array frames, racks, or metal conduit. During field testing, measurements were made to determine the impedance of the EGC in a given PV system.

This system uses a positive grounded array. During testing, one string of the array was opened at the positive end. The first measurement taken was of the impedance through the positive home run wiring of this string, to the inverter, and back via the return through the EGC. Figure 8 shows the schematic for this circuit.

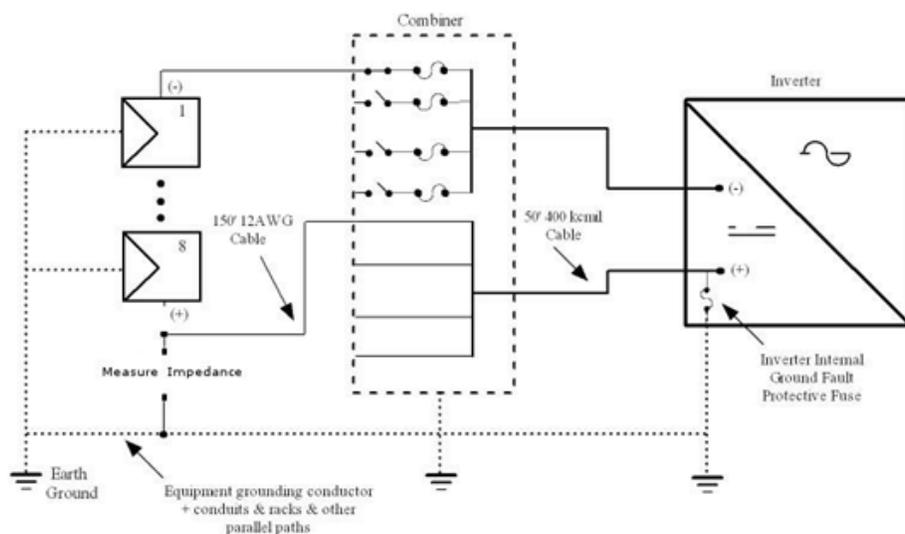


Figure 8. Impedance measurement of array positive home run wiring through inverter and EGC return. Note that AWG = American wire gauge and kcmil = thousand circular mils.

The home run wiring consisted of approximately 150 feet of 12 American wire gauge (AWG) cable to a combiner box followed by approximately 50 feet of 400 thousand circular mils (kcmil) cable from this box to the inverter. The return path was through the equipment grounding conductor and any grounded components of the system. The impedance measured for this circuit was 0.34 ohm. The resistance of the two cables (the positive conductors) was then calculated based on data sheet values of ohms/ft times the estimated length of each cable. Figure 9 shows the calculated resistances of the cables in this circuit and the resulting calculated resistance of the return path from the inverter through the EGC. Resistance of the return path (EGC) is estimated to be 0.041 ohm.

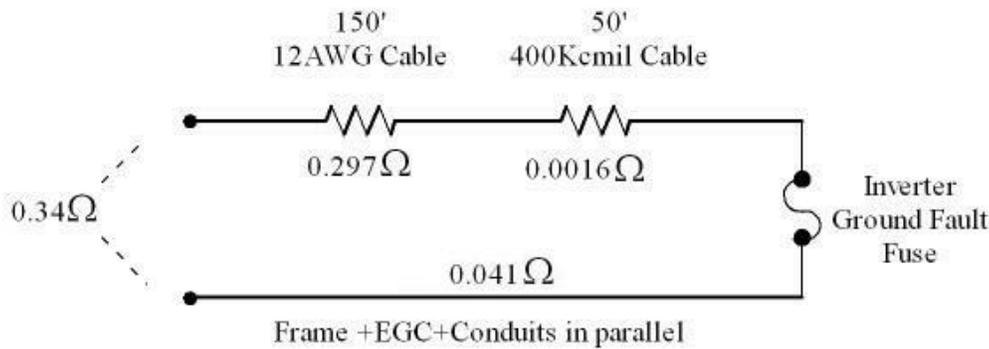


Figure 9. Derived impedance values for positive home run cabling and EGC return. Note that Ω = ohm, AWG = American wire gauge, kcmil = thousand circular mils, and EGC = equipment grounding conductor.

Test Results—PV Array Leakage Current Monitoring

A PV array may introduce current into the EGC as a result of a fault (an unintended connection between conductor and ground) or from the unavoidable flow of current through non-ideal insulating materials of the cables, PV modules, and other array components. This current is referred to as leakage current. One challenge for every inverter is that it must reliably disconnect under true fault conditions without incurring “nuisance” trips from leakage currents. Studies of module leakage current⁴ show that it is small relative to the array output current and is a function of moisture, array voltage, and temperature. We can estimate an expected maximum value for typical array-level leakage currents if we assume the modules have met the standard UL 1703, IEC 61646, or IEC 61215. Modules that meet these standards must demonstrate least 40 megaohms per square meter isolation to their grounded frame. For a typical module of approximately 1.2 square meters operating at 600 volts (V), the module would yield approximately 11 microamperes per kW. Therefore, we would expect a 500 kW array (of new modules) to experience a maximum of approximately 56 mA of leakage current.

Few studies have been performed in the United States to record leakage currents occurring under normal conditions in grounded PV systems. However, two U.S. companies that responded to early concerns regarding blind spot detection by installing RCDs on selected PV systems were able to supply leakage current data for this report.

In response to the Mount Holly fire in April 2010, Duke Energy elected to install RCDs on all of Duke’s roof-mounted and several ground-mounted PV systems in North Carolina. Solar ABCs is grateful to Duke Energy for making data available from these sites, which include 14 inverters with a total of 45 array segments representing about 3.5 megawatts of PV. The circuit sizes for the Duke systems ranged from 50 kW to 161 kW. All monitored systems were crystalline silicon technology that included both standard and back-contact cell constructions.

⁴ del Cueto and McMahan, *Analysis of Leakage Currents in Photovoltaic Modules under High-Voltage Bias in the Field*, Prog. Photovolt: Res. Appl. 2002; 10:15-28

SunPower Corporation also elected to install RCDs on several PV systems that it has installed and continues to operate. For this report, SunPower generously made available data and analyses of the data for four inverters monitored at two different sites.

Before discussing the results of leakage current monitoring by RCDs, it deserves note that in August 2011, one of the RCDs installed by Duke Energy tripped its inverter offline as a result of a fault that was subsequently found to have occurred on a grounded conductor. That fault was immediately repaired. One week later the system tripped on a second fault. This one was identified as having occurred on a non-grounded conductor. This sequence of events is identical to those that initiated the Mount Holly fire. In this case, detection and repair of the first fault on the grounded conductor likely prevented another fire.

SunPower Data

SunPower Corporation provided data from two different sites in California. Site One operates at 1,000 V maximum and uses two 750 kW inverters. Site Two operates at 600 V maximum and uses two 500 kW inverters from a different manufacturer than Site One. Analysis of these data is ongoing, but some results can be reported here.

Figure 10 shows the data recorded by the RCD at Site One on a typical high irradiance day. Figure 11 shows the data recorded on a low irradiance day. The ground current presented in these figures was filtered with a moving average window to remove noise introduced by the RCD installed at this site.

Recorded data from this site show that ground current ramps up initially with PV system voltage to approximately 7 to 10 mA, but it does not stop once system voltage stabilizes. Ground current continues to increase to 15 mA as system current increases with irradiance. Experiments in which the inverter transitioned from offline to inverting showed this 5 mA increase as a step function, indicating it is directly related to inverter current magnitude as opposed to module temperature (which does not change in a similar stepwise pattern).

Ground current data for Site One show infrequent, short duration spikes of 30 to 45 mA. These spikes appear in the records as single data points. SunPower programmed the RCDs to sample data once every 15 seconds. Single point spikes in ground current, therefore, indicate a transient with a duration less than 15 seconds. These transients appear to be most prevalent at the beginning and end of the day. The source of these spikes in the recorded ground current is not yet known, but is believed to be caused by the inverter turning on and off.

The SunPower data show little or no increase in ground current with moisture. Ground current recorded during rainfall showed no difference from data recorded on dry days.

Data analysis continues for Site Two. Similar trends have been observed, although the magnitude of ground current at Site Two is roughly three times that of Site One when the inverter is operating.

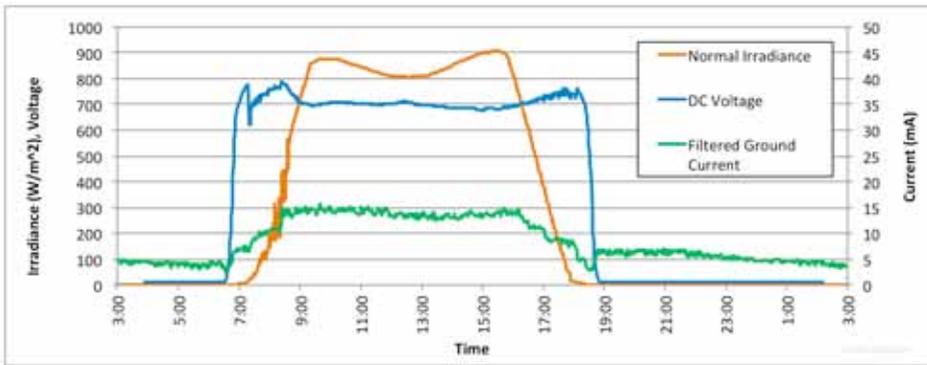


Figure 10. Ground current for typical high irradiance Day—approximately 15 mA.

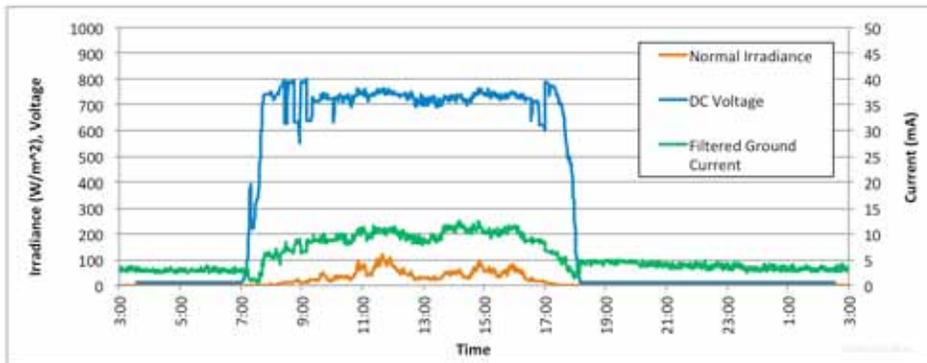


Figure 11. Ground current for typical low irradiance day—approximately 10 mA.

Duke Energy Data

Among the 45 PV array segments from which data were gathered by Duke Energy, the various RCDs were programmed to make logger recordings at 10%, 35%, 70%, and 75% change between each ground current reading and the previous one. The reason for the different settings was related to the monitoring requirements associated with each site. A setting of 35% change was found to be a value that is sensitive enough for short-term data monitoring while taking between one and three months to fill the logger buffer (300 data points before overwriting the oldest records with new ones).

The RCDs on the Duke Energy-owned systems default trip setpoint was 300 mA, but after extensive testing, most RCDs were set to trip the inverter offline when ground current exceeded 60 mA. Among the many sites, the ground current records from the RCDs typically recorded ground current readings in the 20 to 50 mA range. However, some elevated readings were also recorded at times at some sites. Because many of these high current readings were recorded at night, it was hypothesized that they were associated with lightning and electrical storm activity in the area of the PV system. To confirm this hypothesis, Duke Energy cross-referenced the periods of high ground current against a storm activity database in which time, location, and current levels of lightning strikes are recorded. This analysis showed that many periods of elevated ground current readings were positively correlated with recorded activity of storms and lightning in the affected area. However, because the clocks in the RCDs were not set to the atomic clock time standard, the RCD data cannot be positively correlated to known lightning strikes.

Current sensors for the different Duke Energy RCDs were installed around varying numbers of array string conductors (i.e., they were monitoring array segments of different sizes). Figure 12 shows the highest RCD ground current readings normalized to present mA per kilowatt of monitored array.

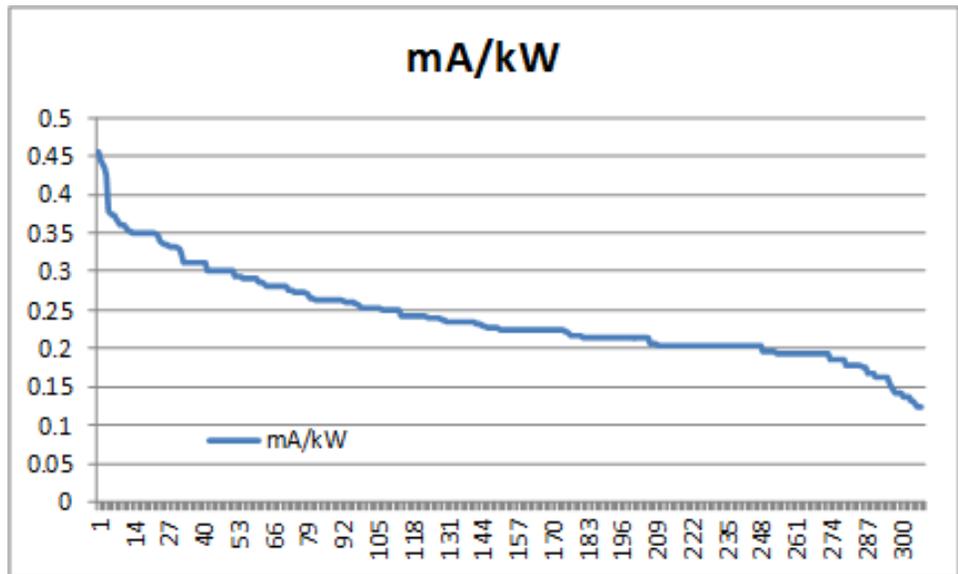


Figure 12. Highest recorded ground current—Data normalized to show current per kilowatt of array. Note: mA/kW = milliamp per kilowatt.

Based on the calculated values of ground current per kilowatt of array segment, the array segment size needed to cause a 300 mA trip was calculated, shown in Figure 13. This calculation assumes that all of the data recorded during a storm event causes a simultaneous flow of current and results in a conservative assumption.

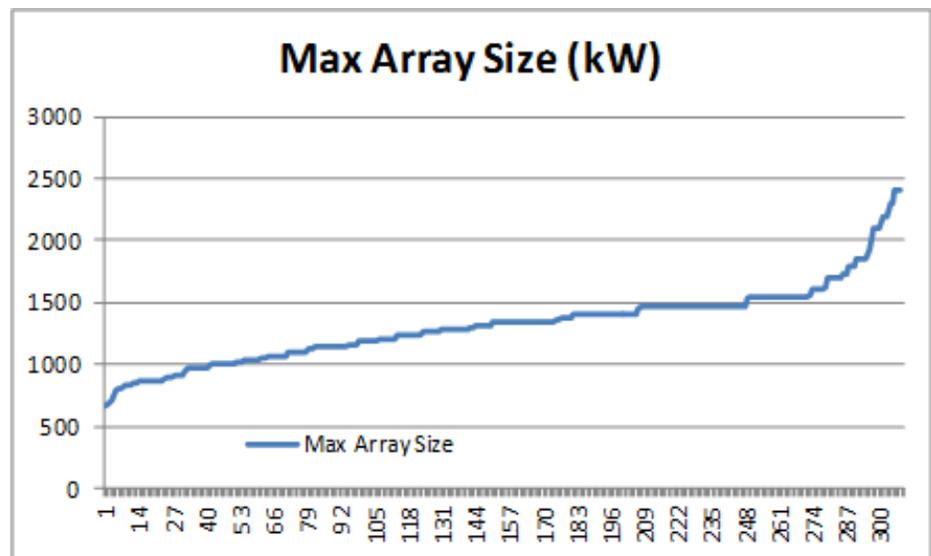


Figure 13. Array size required to produce a 300 mA ground current. Note that kW = kilowatt.

When establishing fault current trip limits, the effects of lightning on ground current must also be considered. Figure 14 shows an inverter (designated CK2) that had elevated ground current readings during major storm activity. The plot shows the magnitude and polarity of the lightning current based on lightning strike data recorded in the immediate vicinity. Ground currents increase before lightning activity initiates and may be due to current dissipation from the array prior to local lightning strikes. Alternatively, the more distant lightning strikes near large transmission lines adjacent to the facility may induce the observed current. Regardless, it is clear from the examination of the data that lightning has a direct impact on the ground current readings.

Because lightning and its impacts are very short in duration, its effects can be filtered out by extending the measurement duration. SunPower programmed their measurement devices to record 10 second moving averages before determining a trip had occurred. A moving average such as this effectively eliminates false trips due to short duration lightning transients. Additional research in lightning prone areas is needed to bear out this assumption.

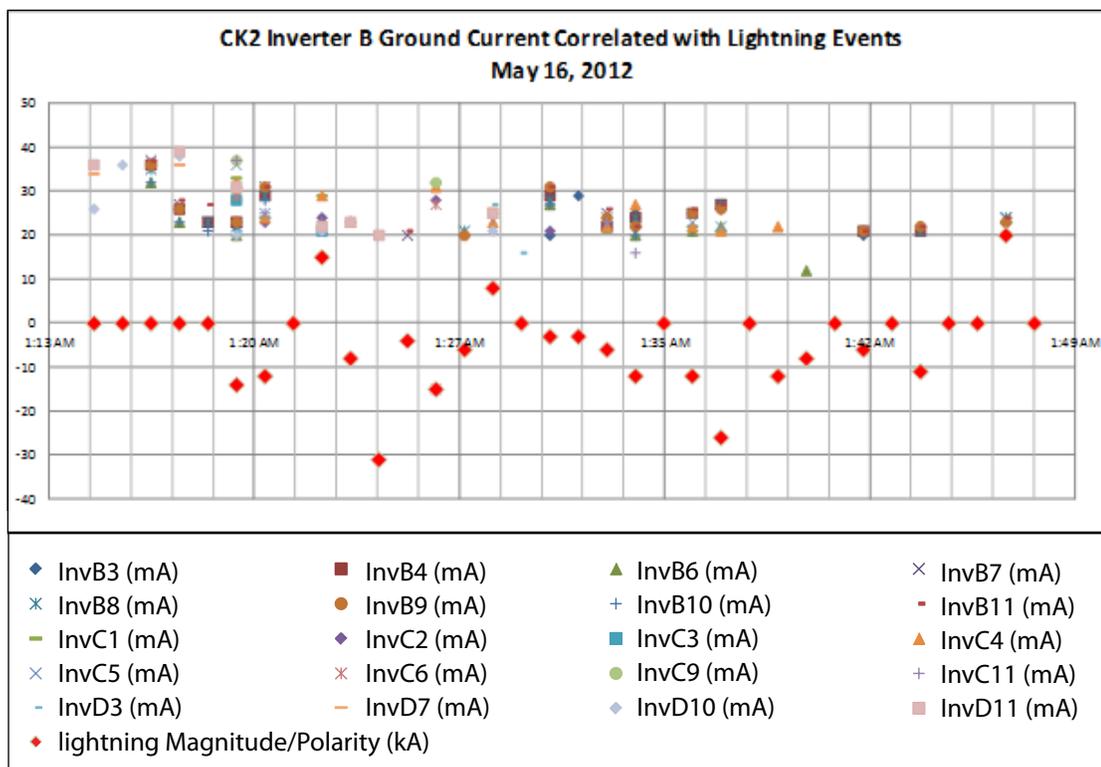


Figure 14. Effects of lightning on ground current for Duke Energy system CK2.

SECTION 3—GROUND FAULT BLIND SPOT MODELING AND SIMULATIONS

Theoretical treatment of blind spot faults and their effect on ground fault current has been explored at Sandia using both analytical and simulation methods. This section of the report draws from two recent publications by Sandia scientists. The first, a Sandia technical report,⁵ introduces the array model in detail and explores the effects of both ground faults and blind spot faults on module and array operation. The second, a Solar ABCs Report,⁶ focuses solely on blind spot faults and the inherent limitations of traditional fuse-based GFDIs.

In both of these works, circuit analysis was used to verify an analytical equation for the GFDI current in the grounded conductor fault scenario. This analytical solution shows that GFDI current is a function of array size, parasitic cabling impedances, module leakage current, and GFDI resistance. The analytical solution was corroborated with circuit simulations using SPICE. Figure 15 shows an example of current flow from a SPICE simulation for a 101-string array with a 1 ohm blind spot fault and a 1A GFDI fuse. For this array state, the GFDI current is below the 1A fuse threshold, indicating an undetected blind spot fault.

⁵Flicker, J. & Johnson, J. (2013). *Photovoltaic Ground Fault and Blind Spot Electrical Simulations*. Sandia National Laboratories Technical Report. <http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND2013-3459-Photovoltaic-Ground-Fault-and-Blind-Spot-Electrical-Simulations.pdf>

⁶Flicker, J. & Johnson, J. (2013). *Analysis of Fuses for “Blind Spot” Ground Fault Detection in Photovoltaic Power Systems*. Solar ABCs. www.solarabcs.org/blindspot

Fuse Resistance vs. Fuse Rating of Various Fuse Types

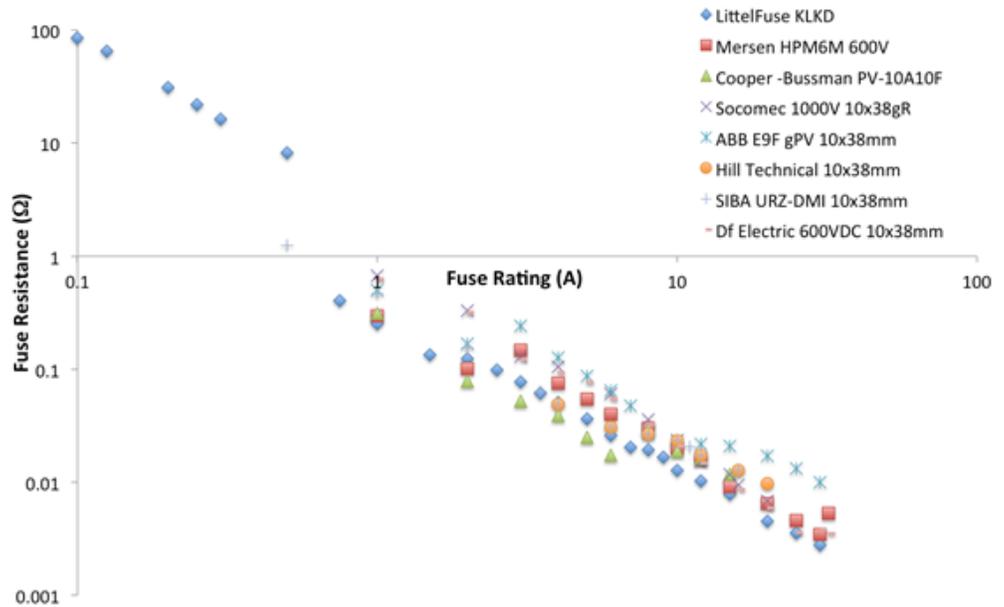


Figure 16. GFDI resistance vs. rating for a variety of 10x38 mm (“midget”) fuses by various PV fuse manufacturers. Note that Ω = ohm, A = amperes, and V = volts.

Theoretical results indicate that the decreased GFDI trip point is more than offset by the increase in GFDI resistances. Figure 16 shows a graph of GFDI current vs. array size for GFDI ratings of 0.5A (8.16 ohms), 1A (0.252 ohm), 2A (0.124 ohm), and 5A (0.0363 ohm) and fault resistances of 0.1 and 1 ohm for both theoretical calculations (dashed lines) and SPICE simulations (points). Only the 1A (red) and 2A (purple) GFDIs are able to detect the blind spot (denoted by the grey triangles) for a 0.1 ohm fault due to a balance between GFDI rating and resistance. The 5A GFDI (orange) has a low resistance, but the trip point is high. The 0.5A GFDI (blue) has a low trip point, but the resistance is too high and prevents sufficient fault current flow through the GFDI to trip it. The Sandia modeling results suggest that, to decrease the ground fault blind spot, the optimal value for a fuse-based GFDI would be maximum 1A fuse for all array sizes.

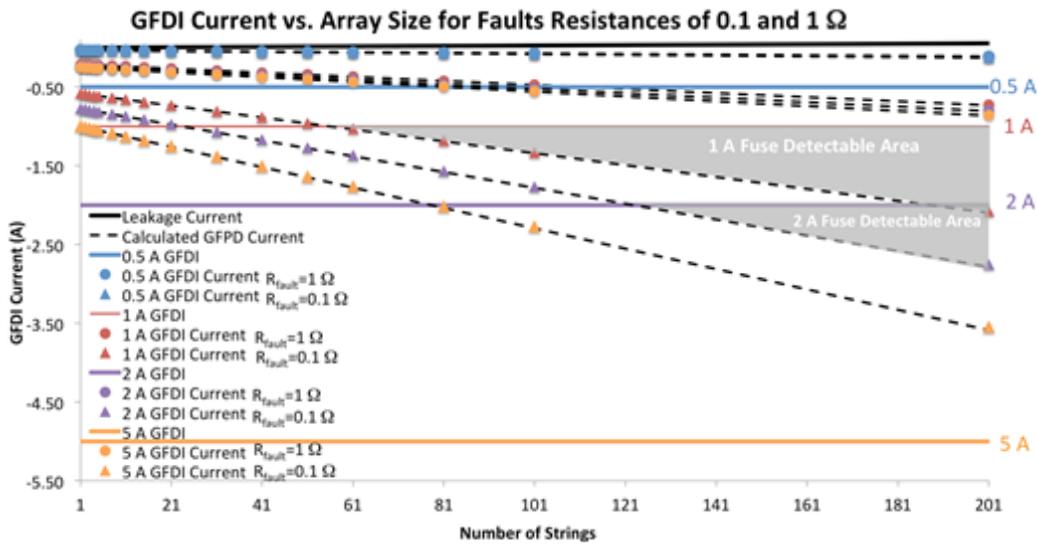


Figure 17. Graph of GFDI current vs. array size for various GFDI and fault resistances. Note that the color of the line indicates GFDI resistance. Blue traces denote 0.5A (8.16 ohms), red traces denote 1A (0.252 ohm), purple traces denote 2A (0.124 ohm), and the orange traces denote 5A (0.0363 ohm). Only the 1A and 2A fuses have both a low enough sensitivity and resistance to trip due to the blind spot fault. The region where I_{GFDI} is larger than the trip point is gray.

The modeling presented here does not include effects from any other sources of current that may flow through the GFDI such as leakage from cables, AC noise, or radio frequency (RF) noise from the array. These sources are not well characterized, but are believed to have contributed to the original field ground circuit measurements that were the basis for the existing UL 1741 fuse rating limits. A thorough characterization of these sources will be an important step in determining the nuisance trip potential of reduced fuse ratings.

SECTION 4—MITIGATION METHODS AND EQUIPMENT

This section presents a list of mitigation methods and associated equipment that are available to PV system owners to reduce system susceptibility to the ground fault blind spot. Some choices are inexpensive while others can require thousands of dollars per inverter to implement. Pros and cons of each option are included in the matrix of mitigation methods (Table 6). The options in the matrix are shown in preferential order according to the authors' consensus understanding of effectiveness and value.

The authors of this report stress two important warnings that must be observed before any mitigation methods are attempted. The first is that only trained and qualified personnel should ever work on PV systems and inverters. Hazardous voltage and current can exist at any time in PV systems and untrained personnel must never be allowed to inspect, test, or modify any system components or wiring.

The second warning concerns mitigation methods involving inverters. Only items that are specifically detailed in the installation instructions of an inverter can be installed without first contacting the manufacturer. Modifications to any certified product may affect its certification and warranty. As there is no one single answer or solution to address this, it is always best to contact the inverter manufacturer before attempting any modifications to a certified product. Moreover, the manufacturer may be aware of the ground fault issue and may have already developed a retrofit option. In any case, no site owner should ever attempt to modify, update, or install any equipment inside an inverter without contacting the inverter manufacturer first and receiving approval. Consideration should be given to the impact on product warranty and safety certification before modifications are implemented. Modified equipment may be subjected to a field evaluation to determine compliance with product safety standards.

Table 6

Matrix of Blind Spot Mitigation Methods

Mitigation Method	Effect	Cost	Pros	Cons	Additional Notes
1. Install residual current detector (RCD) on positive and negative array wiring and connect to alarm	Major increase in the sensitivity and flexibility of ground fault detection	Moderate to High	Use of RCDs has already been shown to detect and prevent blind spot conditions Allows operator to decide if alarm requires immediate action and reduces impact of false trips	Requires rewiring of array conductors through current sense doughnuts and interfacing with some type of monitoring Does not interrupt the fault current May require installation of a new enclosure to access existing conductors	Alarm signals a fault; It takes no other action
2. Install residual current detector (RCD) on positive and negative array wiring and connect to inverter emergency stop input (if available) or shunt trip breaker	Major increase in the sensitivity and flexibility of ground fault detection	Moderate to High	Use of RCDs has already been shown to detect and prevent blind spot conditions Interrupts fault current for grounded conductor faults Could be used to shut down contact combiners (if used) to make array safe	Requires rewiring of array conductors through current sense doughnuts False trips could shut down inverter causing loss of system availability Wiring the RCD trip signal into the inverter may impact inverter certification	Inverter manufacturer must approve this modification if field wiring to emergency stop not accommodated in listing and instructions
3. Install electronic current sense relay in ground fault fuse circuit	Major increase in the sensitivity and flexibility of ground fault detection	Moderate	Relays can be programmed to trigger on current and duration levels	Requires rewiring of ground fault fuse circuit False trips could shut down inverter causing loss of system availability Wiring the RCD trip signal into the inverter may impact inverter certification	Inverter manufacturer must approve this modification
4. Install isolation monitor, implement periodic checks	Capable of detecting low insulation conditions and ground faults	High	Prevents inverter start up until faults are corrected	Coordination with inverter logic needed to implement ground bond disconnect prior to test	Due to complexities with this process, inverter manufacturers have been reluctant to retrofit this function into existing systems IEC 62109, the UL 1741 CRD for non-isolated arrays, and the UL 1741 CRD for isolated ungrounded inverters, all require that these inverters perform an array isolation check prior to operation and at least one time per day
5. Reduce the ground fault fuse size	Minor increase in the sensitivity of ground fault detection	Low	Easy, inexpensive retrofit	Not as sensitive as electronic ground current monitoring May conflict with other inverter functionality May impact inverter certification	Contact the inverter manufacturer to confirm if or what lower current values of fuse can be used with a specific inverter
6. Annual operations and maintenance practices (including string and megger testing)	Capable of identifying blind spot faults	Moderate (but recurring)	Annual operation and maintenance (O&M) inspections are necessary for many reasons beyond blind spot O&M can find undetected faults and degraded insulation	Requires routine visit by technicians to perform tests Faults that occur between inspections may still go undetected	In dry conditions it is possible for damaged cables to go undetected by the megger tests so it is best performed with the system wet
7. Implement arc-fault current interruption (AFCI)	AFCI installed in array or string combiner boxes can isolate circuits when arc is detected	High (expected)	Isolating strings when arc is detected may lessen fault severity	AFCI may not be able to detect blind spot faults and series AFCIs are not evaluated for response to arcing faults to ground	Implementation is increasing slowly because of the limited commercial availability of AFCI products

Mitigation Method 1—Install Residual Current Detector (RCD) on Positive and Negative Array Wiring and Connect to Alarm

Differential current sensors, also known as residual current detectors or RCDs, are a commonly installed piece of equipment used to retrofit existing inverters and systems. RCDs used for this purpose need to be rated for use with AC and DC currents, and they need to be rated or set to an appropriate trip current level. A common way to deploy RCDs is to place the sensing transducer around both positive and negative conductors entering the inverter. Transducer sizes are available for monitoring cables as small as two 10 AWG conductors up to four 500 kcmil conductors. Multiple transducers can also be used on larger systems. Although the highest resolution of differential current is possible when individual sensors monitor single subarray conductor pairs, multiple circuits from the array can be bundled and run through a single current transducer of the RCD. Cost and desired sensitivity must be considered to determine the monitoring solution for a given system.

The setting of an RCD requires an understanding of typical ground current under normal conditions. Because many plant owners and operators are concerned about system operation and availability, one option is to respond to a detected fault by triggering an alarm rather than stopping the inverter. By using an alarm, a low threshold can be chosen for the RCD ground fault detection without incurring lost production from false detections. When the alarm is set, the output of the RCD can be monitored to see if the reading was a legitimate fault or if there was a false alarm. When a plant is getting false alarms, the alarm threshold can be raised to reduce this.

Based on study of the storm data from North Carolina, sufficiently long data averaging should be employed to disregard storm-related, transient currents while still capturing persistent ground fault currents. Most important, the baseline ground current of the system needs to be assessed and used for establishing the appropriate trip setting for this method. The baseline data presented in this paper illustrates that normal ground current values are system dependent and can vary with the inverter type and climate.

Mitigation Method 2—Install Residual Current Detector (RCD) on Positive and Negative Array Wiring and Connect to Emergency Stop of Inverter

A variation of the previous mitigation method is to wire the trigger of the RCD into the emergency stop function of an inverter. This method creates concern about false trips by the RCD, because it directly controls inverter shutdown. With each inverter trip, field technicians must be dispatched to confirm whether there is a fault, to repair the fault if it exists, and to return the system to operation. This method requires a good understanding of normally occurring ground currents so that the trip current setting of the RCD can be sufficiently high to prevent false alarms. As was discussed in the section on lightning effects, one method to prevent short-term transient current effects on an RCD is to set the RCD to average readings over 10 seconds before initiating a shutdown. For an RCD that has this averaging feature, short-term transients can be effectively differentiated from longer-term ground faults.

Mitigation Method 3—Electronic Current Sensing Relay

As noted above, it is not necessary to measure differential current in the array conductors in order to achieve increased ground current detection sensitivity. An electronic current sensor-controlled relay can be installed in the circuit between earth ground and the grounded conductor (in series with the ground fault fuse). This method is feasible for larger inverters, which often use a separate wire to perform this ground bonding function. (Smaller inverters, on the other hand, make these connections through circuit boards and cannot be monitored in this way.) Such devices are available with detection sensitivities down to 5 mA and with programmable delay settings. This method requires the sensor output to control a relay connected to the inverter's emergency stop input or a shunt trip relay in the system. As with all inverter modifications or upgrades mentioned in this report, the inverter manufacturer must be consulted prior to implementing this mitigation solution as it may affect the inverter or its certification.

Similar to methods 1 and 2, the trip setting for this method needs to be informed by the baseline ground currents observed with the system. It is also beneficial to have the ground current values logged in a data acquisition system.

Mitigation Method 4—Isolation Monitor and Periodic Check

An isolation monitor is a device that measures the resistance of a circuit to earth. Incorporating and using an isolation monitor with ungrounded, isolated PV arrays is becoming a common safety practice. In the United States, where most PV systems have a ground bond connection on either the positive or negative conductor, this practice is more difficult. The connection to earth is often made through an OCP device used to sense ground current and limit this current by isolating circuits that exceed specified ground current limits. To use an isolation monitor in a grounded system like those prevalent in the United States, the grounding connection must be opened before the isolation monitor can take the PV array isolation reading. After this, if the array isolation resistance measurement exceeds a minimum acceptable threshold (indicating no fault has been detected), the array is allowed to reconnect the ground bond and the inverter can start AC power export.

The ground bond disconnect function, array isolation test, and array ground bond reconnect process requires coordination with inverter logic for a DC-grounded inverter. Due to complexities with this implementation and concerns about possible certification impact, some inverter manufacturers have been reluctant to retrofit this function into existing systems.

For future grounded system designs, one option recommended by Solar ABCs is that inverters employ an isolation check before operation as specified in IEC 62109 and UL 1741 CRDs. The existing standard (IEC 62109) for non-isolated arrays requires that an array isolation check be made prior to operation of PV arrays. During inverter operation, residual current detection is required. The combined effect of these two requirements substantially reduces the probability of two ground faults existing simultaneously in the array.

IEC 62109-2 is currently being revised to address this issue and prevent duplication and/or continuation of this blind spot susceptibility. It is expected that IEC 62109-2 will be revised to either require grounded isolated inverters to perform a PV array isolation measurement prior to AC power export (similar to non-isolated inverters) or to perform some other function consistent with mitigation methods 1, 2, or 3. Several Solar ABCs members participate in groups that maintain both UL 1741 as well as the IEC 62109-1 and -2 standards, and are working to address these ground fault monitoring and response concerns in upcoming revisions to these standards.

Mitigation Method 5—Reduce the Size of the Ground Fault Fuse

A simple and inexpensive solution to improving fault detection is to reduce the fuse current rating on ground fault protection devices that use a fuse in their detection scheme. Fuses can cost as little as a few dollars up to \$150, but do not require any field rewiring to implement. Such fuses must be rated for DC circuit interruption. Fuses rated for AC voltage only will not be sufficient.

Modeling by Sandia (presented in Section 3) shows that reducing the ground fault fuse size for large inverters from 5A to 1A provides a marked increase in the sensitivity of the circuit to detect blind spot faults. However, while reducing fuse size from 5A to 1A can provide up to five times better blind spot protection, this is still roughly ten times less sensitive than the electronic fault current sensing methods discussed in Mitigation Methods 1-3

The inverter manufacturer must approve the replacement of a 5A fuse with a smaller one. This approval can either be in the form of a statement included in the manufacturer's documentation (allowing for a range of fuse sizes), or a letter from the manufacturer stating that a smaller fuse of the same voltage rating is permitted. As stated earlier, the modeling conducted to date does not attempt to address effects from other sources of current that may flow through the GFDI, such as leakage from cables, AC side noise, or RF noise from the array. The potential remains that, for some inverters, reducing fuse size may result in unanticipated nuisance trips.

Mitigation Method 6—Regular Operations and Maintenance

The methods above focused on various options for directly detecting or mitigating blind spot faults. This section discusses indirect measures that can improve system safety and reduce the potential for fires resulting from blind spots or other faults.

It is difficult to understate the importance of regular operations and maintenance (O&M) of a PV system when it comes to enhancing safety. Even if advanced detection and mitigation techniques are not implemented by system owners, O&M measures are the best way of identifying wiring problems early before they evolve into dangerous situations. Visual inspection of a PV array and its associated wiring is the first step in identifying potential failures like those that result from sharp edges in contact with conductors or stresses created by thermal expansion and contraction of conduit and conductors on rooftops. Preventive maintenance procedures that require annual inspections for these types of problems can effectively prevent many wear conditions in field wiring from degrading into ground faults.

When a system is first installed, best practice dictates that insulation testing (megger testing) be carried out on all DC and AC conductors prior to energizing the system. This is a simple test using a handheld device that imposes a short-term voltage on an open circuit and measures its resistance to ground. When all cable insulation is intact, a very high resistance reading is recorded (high megaohms to gigaohms). However, partial or complete cable insulation failure results in increased current to ground through the failure point and the megger resistance reading is lowered. "Low" for 600 V and 1,000 V cables without PV modules in the circuit is typically anything below 100 megaohms, according to the National Electrical Testing Association. As such, this is a good method for finding high-resistance ground faults that would not be detected by an inverter's existing ground fault protection.

Megger testing effectiveness in non-shielded cables is limited and will only detect faults with a conduction path. Also, if a damaged cable is dry with an air gap separating it from grounded metal, megger testing will not detect the insulation damage. It is recommended that a conductive medium (e.g., surfactant solution) be introduced prior to megger testing to improve its detection capabilities. Introducing a conductive medium can be challenging for some arrays, but experience has shown that it provides a marked increase in the ability to find intermittent faults.

Given the limitations of insulation testing, it is important to caution system owners and operators that annual testing is not sufficient to mitigate the blind spot issue. Field experience shows that insulation testing can and does find certain ground faults not identified by existing inverter GFDIs. Also, newer insulation testing devices with lower voltage settings (e.g., 50 V) can be used to find leaking surge arrestors, which is a common cause of power loss in aging PV systems.

Another important annual O&M procedure is string voltage and current testing. This standard test is usually performed at commissioning to ensure that each PV module string is producing proper voltage and current relative to other strings. Open circuit voltage is tested with the inverter off by isolating each string. String current can either be tested short-circuit, or the maximum operating current can be measured with the inverter operating. Series measurements of current using the current setting of a multi-meter can be used and are generally more accurate, but small current clamps with low-current ratings can also be used.

String open circuit voltage measurements lower than normal can be indicative of ground faults in ungrounded conductors, failed bypass diodes, or shorted cells. Low current measurements can be an indication of soiled modules, blown fuses, or poor (high-resistance) electrical connections. The latter, if left to persist and worsen, can result in overheating and burning at the failing connection. Any abnormal measurement should be followed up with closer inspection of the modules and connections in the affected string.

Other routine O&M steps that can help reduce the incidence or impact of blind spot ground faults include:

- visual and manual inspection of combiner box interiors, looking for signs of water or debris buildup; heat damage on insulation; staining of connectors, baseplates, and enclosures; and loosened string conductor connections;
- visual and manual inspection of the string wiring, looking for pinch-points, sections tightly pulled against racking or wireway equipment, or buildup of debris around the wiring;
- checking the torque on field connections in string and array combiner boxes to verify proper connections;
- inspection of modules for discoloration from overheating or burn marks;
- thermal imaging of module and, if accessible, the intermodule wiring (this can be particularly effective at catching weakened, high resistance connections between pigtail connectors or at the junction box); and
- thermal imaging of field and manufacturer terminations in combiners and inverter while operating to identify any high operating temperatures resulting from poor connections.

Solar ABCs will be publishing a full report on O&M recommendations later in 2013.

Mitigation Method 7—Use of Arc-Fault Detection

DC arc-fault detection is a protection measure on its way to becoming a standard feature in PV systems. Series DC arc-fault protection (arc-fault current interruption or AFCI) was introduced as a requirement in the 2011 NEC for rooftop systems and will be required for all systems (with limited exceptions) in the 2014 version. Although PV AFCI product availability and installations are increasing, there are still relatively few products commercially available. At this time, there is at least one inverter manufacturer selling products with AFCI functionality listed, five standalone PV AFCI devices listed for compliance with UL Outline 1699B, and more are on the way.

The PV AFCI standalone devices can be located at various points throughout the array and they can be added to the designs of PV combiner boxes. Series AFCI addresses series-arcs or arcing current that is flowing in the normal current path of the PV circuit. For example, a poor pigtail connection between modules can worsen to the point where there is no longer physical contact between the connectors but current arcs across the air gap. This type of fault is neither a ground fault nor a line-to-line fault and therefore is not detected by any of the ground fault measures discussed in this report. (Arcs that occur to ground or line-to-line are called parallel arcs.) Apart from ground faults, series arcs are probably the next largest cause of fires in PV systems in the United States, which is why codes and standards have moved towards AFCI requirements.

Systems incorporating combiner box level AFCI are not protected against blind spot ground faults but they may reduce the impact of the second fault and possibly even prevent fire. Combiner box AFCI could possibly have minimized the impact of the Bakersfield fire, for example. In that system, a blind spot fault occurred on a grounded string conductor in the array that went undetected. The subsequent ungrounded conductor fault occurred on a large feeder circuit cable, shorting and arcing to a conduit. Fault current flowed from each array combiner box to the conduit fault to ground, through the ground circuit, and back through the faulted grounded conductor circuit to the modules.

Figure 18 shows a system schematic depicting this scenario. If series AFCI with automatic disconnecting capability had been present in each of the combiner boxes, they should have all detected the arcing in what had become a closed series circuit through the ground path. With the inverter faulted offline and ground fault interrupt fuse blown, there is no parallel path outside of the fault loop. As such, if all combiner box circuits opened on AFCI detection, there would be no more source of current to the ungrounded conductor fault, and arcing would have ceased.

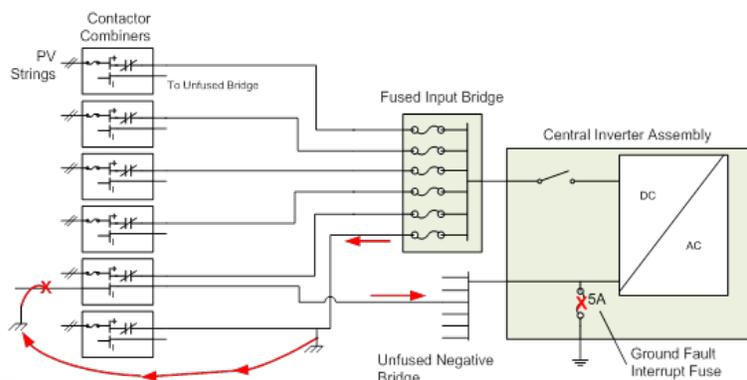


Figure 18. Example of blind spot fault scenario mitigated by combiner box level arc-fault protection.

This illustrates an example in which AFCI contactors are in the current path of the fault. If the ground current loop is outside the AFCI path, the interruption is not effective. This is the case, for example, if the grounded conductor and ungrounded conductor fault both occur on strings connected to the same combiner box. Fault current would continue to circulate in the strings even if the combiner box contactor opens.

SECTION 5—OVERVIEW OF CHANGES COMING TO CODES AND STANDARDS IMPACTING GROUND FAULT PROTECTION

What follows are brief discussions of ongoing revisions to the major codes and standards affecting PV inverters and PV ground fault protection products.

The **2014 NEC** process is near completion. Several items were introduced during this code cycle to address issues related to the ground fault blind spot. Of particular interest are the changes in 690.5, 690.35, and 690.41. The new requirements for PV GFDI eliminate the improper reference for ground fault protection to respond to ground fault current. They also require that a ground fault protection system be capable of detecting a ground fault throughout the PV array, system components, and DC current-carrying conductors, including any intentionally grounded conductors. It is also required a ground fault protection system to be specifically listed for providing PV ground fault protection. The system grounding section has been reorganized to clarify the various types of system grounding arrangements that exist in PV system designs. Each different type of system requires different approaches for detecting ground faults and preventing the damaging effects of ground faults.

IEC 62109-1 is the international equivalent of UL 1741, and covers the general requirements for PV power conversion and electronic equipment. IEC 62109-2 is a secondary document that addresses PV inverter specific requirements and is to be used in conjunction with IEC 62109-1. IEC 62109-2 includes the ground fault protection requirements for PV circuits. These standards are being adopted internationally for PV inverters, converters, and other PV electronic equipment. Based in part on the preliminary findings of Solar ABCs ground fault investigations, the ground fault protection requirements in IEC 62109-2 are being revised.

At the last UL 1741 Standards Technical Panel (STP) meeting, the STP agreed to develop and adopt a **United States-based version of IEC 62109**. A UL 62109 International Harmonization Committee was established and tasked with developing the U.S. national difference intended to address critical issues related to United States-specific installation codes as well as U.S. equipment and component standards. UL 62109-1 was sent out for comment, and UL is addressing the STP comments they received in preparation for the upcoming ballot draft, which will be sent out in the summer of 2013. The UL 62109-2 draft will incorporate the U.S. national differences that include revised requirements for additional protection of grounded isolated applications to address this blind spot condition—for example, regular array isolation measurements.

The previously mentioned CRDs provide methodologies for manufacturers to build and certify PV inverter products that include PV array isolation measurement methodologies, more sensitive ground fault detection schemes, and faster clearing/response times to ground faults. As the STP intent is to adopt UL 62109 to replace UL 1741 for PV product safety certifications, the new/updated ground fault protection requirements will be in UL 62109-2. If there are delays in the adoption of the UL 62109-2, a proposal to revise UL 1741 may be needed to incorporate the new/updated ground fault protection requirements.

SECTION 6—CONCLUSIONS

PV system owners must weigh the costs and benefits of any additional protection. Ultimately, the decision to employ any safety measure is a function of the potential consequences of doing nothing. Although losses from fires caused by PV systems have been historically quite low relative to the number of systems in the field, this field experience is not necessarily indicative of future losses. As systems age, ground faults and arc-faults can be expected to increase in number and potentially in consequences. Equipped with the knowledge in this report, PV system owners, designers, and installers will be able to more effectively make correct decisions about what measures to employ and when those measures are cost-effective.

ACRONYMS

AC	alternating current
AFCI	arc-fault current interruption
AWG	American wire gauge
DC	direct current
DETL	Distributed Energy Technologies Laboratory
DOE	U.S. Department of Energy
EGC	equipment grounding conductor
GFA	ground fault appliance
GFDI	ground fault detector/interrupter
IEC	International Electrotechnical Commission
kcmil	thousand circular mils
kohm	kilo-ohm
kVA	kilovolt-amps
kW	kilowatt
mA	milliamp
mV	millivolt
NEC	<i>National Electrical Code®</i>
OCP	overcurrent protection
PV	photovoltaic
RCD	residual current detector
RF	radio frequency
SCE	Southern California Edison
Solar ABCs	Solar America Board for Codes and Standards
SPICE	simulation program with integrated circuit emphasis
STP	Standards Technical Panel
UL	Underwriters Laboratories
V	volt



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