The Bakersfield Fire

A Lesson in Ground-Fault Protection

By Bill Brooks, PE

On Sunday afternoon, April 5, 2009, smoke was seen rising from the roof of a big box store, home to a 383 kW PV array, in Bakersfield, California. The store manager quickly investigated, finding one row of eight modules on fire and a smaller fire some 200 feet away. Fire extinguisher in hand, the manager soon realized this was a job for the fire department. A 911 call was placed at 4:15 pm and first responders were on-site 5 minutes later.

The subsequent investigator's report, which is named after the retail store, is the most widely read incident report related to PV systems. The fact that this retail establishment, which has been very supportive of the PV industry, inadvertently lent its name to a two-alarm fire is both unfortunate and unwarranted. For this reason, I refer to this incident as the *Bakersfield Fire.* Similarly, the product manufacturer and installer, while not without fault, are also not ultimately to blame for this fire. Therefore, in the analysis that follows certain manufacturer and installer-specific details particular to the PV system in Bakersfield have intentionally been changed. The generic circuit diagrams used here represent the majority of PV systems deployed in North America.

It is important not to get lost in the details of this specific installation. Instead, I want to emphasize an underlying problem, one that is endemic to all grid-connected PV systems larger than 30 kW that have been built in the past 5 years. The "thermal event" that occurred on April 5, 2009, is clearly cause for alarm. More alarming, however, is the fact that it could happen again.

THE INVESTIGATOR'S REPORT

The investigator's report on the Bakersfield Fire is quite good, even if it does not tell the whole story. It is available on numerous websites, most notably the National Fire Protection Agency website (see Resources). The author of the report is Pete Jackson, an electrical specialist for Kern County, California, and the chief electrical inspector for the City of Bakersfield. Both the Kern County and the Bakersfield Fire Departments responded to the fire.

I had the pleasure of meeting Mr. Jackson. He was particularly familiar with this installation, since he was the person who performed the project plan review. His report on the roof fire provides a reasonable outline of the events that transpired and the fire department's response to those


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events. It includes two requirements and three recommendations intended to improve the safety of the Bakersfield PV installation and other similar installations.

In summary, the following corrective items were required:

1. Perform high-voltage insulation testing on all PV array conductors.
2. Use expansion joints in long conduit runs while ensuring that these are properly installed.

The actions recommended in the report include:

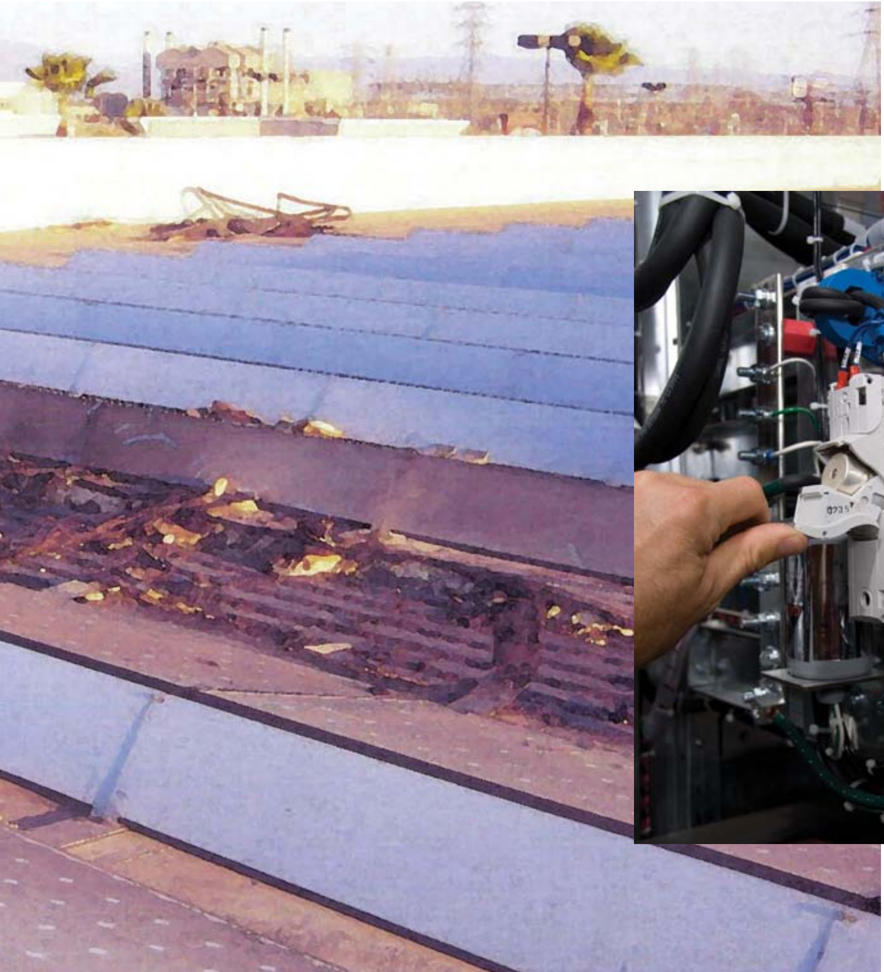
1. Check the ampacity of all conductors to see that they comply with the temperature requirements of Table 310.15(B)(2)(c) found in the 2008 *National Electrical Code.*
2. Install disconnect switches at or near the combiner boxes so that it is possible to deenergize power in the large feeders that run from combiner boxes to the inverter.
3. Reconfigure the combiner boxes and feeder conductors for a maximum of 100 amps per PV output circuit, so that the feeder fuses will be more likely to open under fault conditions.

While I wholeheartedly support the two corrective actions and the first two recommendations, they do not convey the whole story, nor will these measures prevent a repeat of the Bakersfield Fire. While the third recommended action would help reduce the fire hazard associated with a similar event, this would likely not have prevented the Bakersfield Fire because it does not address the fundamental problem.

GROUND-FAULT PROTECTION BLIND SPOT

The problem exposed by the Bakersfield Fire is that large inverters manufactured since 2005 employ ground-fault equipment that lifts the grounded conductor in the event of a ground fault. In practice, this is fine as long as it eliminates the only return path for the ground-fault currents. However, if a return path exists in the source-circuit conductors, a 30 kW array is capable of delivering approximately 100 amps of fault current, which is enough to burn a 12 AWG conductor.

Prior to 2005, Trace Technology 3-phase inverters sensed the grounded conductor-to-ground connection, shutting the inverter down if the current got above 10 amps. These older inverters did not interrupt the fault path; the ground fault would remain after the inverter shut down. Subsequently, however, Article 690.5 in the 2008 *NEC* required that most PV systems include a ground-fault protection (GFP) scheme that both detects and interrupts the fault. As a result, 3-phase inverter designs started employing a ground-fault fuse, similar to the 1 amp GFP fuse used in residential string inverters. A large inverter, however, might use a 4 amp GFP fuse, since large arrays can have over 1 amp of current flowing in the equipment ground at full irradiance under normal operating conditions. Using a fuse with a lower trip setting could cause many larger arrays to nuisance trip the GFP circuit, shutting down the whole PV system when no problem exists. Unfortunately, it is precisely this larger GFP fuse rating that created the opportunity for the Bakersfield Fire.



Shawn Schreiner

GFP blind spot The leading theory regarding the root cause of the Bakersfield Fire is that a fault-to-ground in a grounded current-carrying source-circuit conductor went undetected by the inverter's ground-fault protection device.

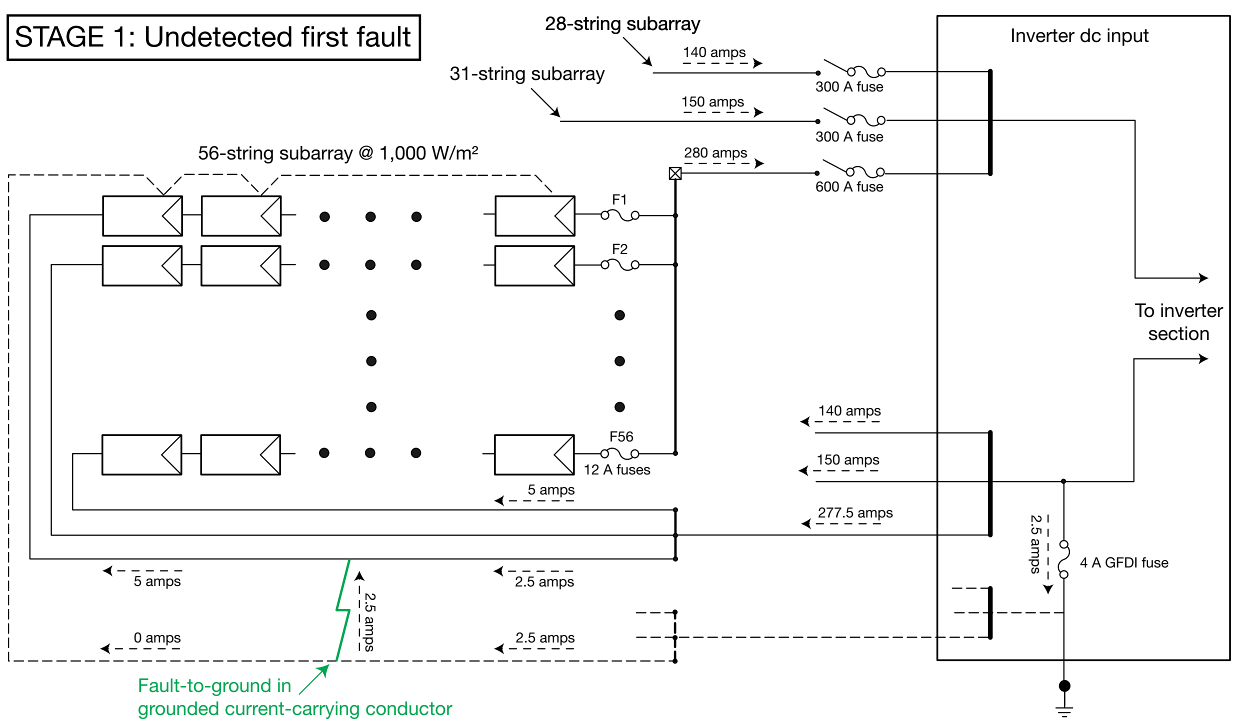
Ground-fault detection and interruption. This GFP method presupposes that it will detect the first fault in the system. If any fault exists prior to opening the ground-fault fuse, the GFP system is ineffective. Not only that, but it can actually make the situation worse than taking no action at all.

If a fault occurs on a string-level grounded current-carrying conductor on a larger system, the ground-fault current generated cannot exceed a few amps. This is due to the fact that there is very little voltage pushing the current. In the event of a fully bolted ground fault, for example, there is very little resistance between the grounded conductor and the equipment-grounding conductor (EGC). It is unlikely in this scenario to get more than half the source-circuit current, or 3 to 4 amps, through the fault, as illustrated in Figure 1. The reason that a maximum of 3 to 4 amps flows through the fault is that the operating current of 6 to 8 amps can, at best, split evenly between the grounded conductor and the EGC. This is because both the grounded conductor and the EGC have similar resistance back to the common connection point, which is at the GFP fuse.

Another way to look at this is that if the conductors are sized properly, Ohm's Law dictates the current flow in the EGC. If the circuit to the inverter has a 2% voltage drop and half the drop is on the grounded conductor side of the circuit, then there is a 1% voltage drop in this side of the system, or a drop of 3 volts on a 300 Vdc system. According to one of the expressions of Ohm's Law, resistance in a circuit is equal to the voltage drop divided by the current ($R = V \div I$). Therefore, a 6-amp circuit will have a resistance of 0.5 ohms ($R = 3\ V \div 6\ A = 0.5\ \Omega$). Since the source-circuit EGC is sized no larger than the current-carrying conductors, and the feeder conductor EGC—sized according to *NEC* Table 250.122—is much smaller than the feeder conductors, the resistance of the EGC will always be higher than that of the current-carrying conductors.

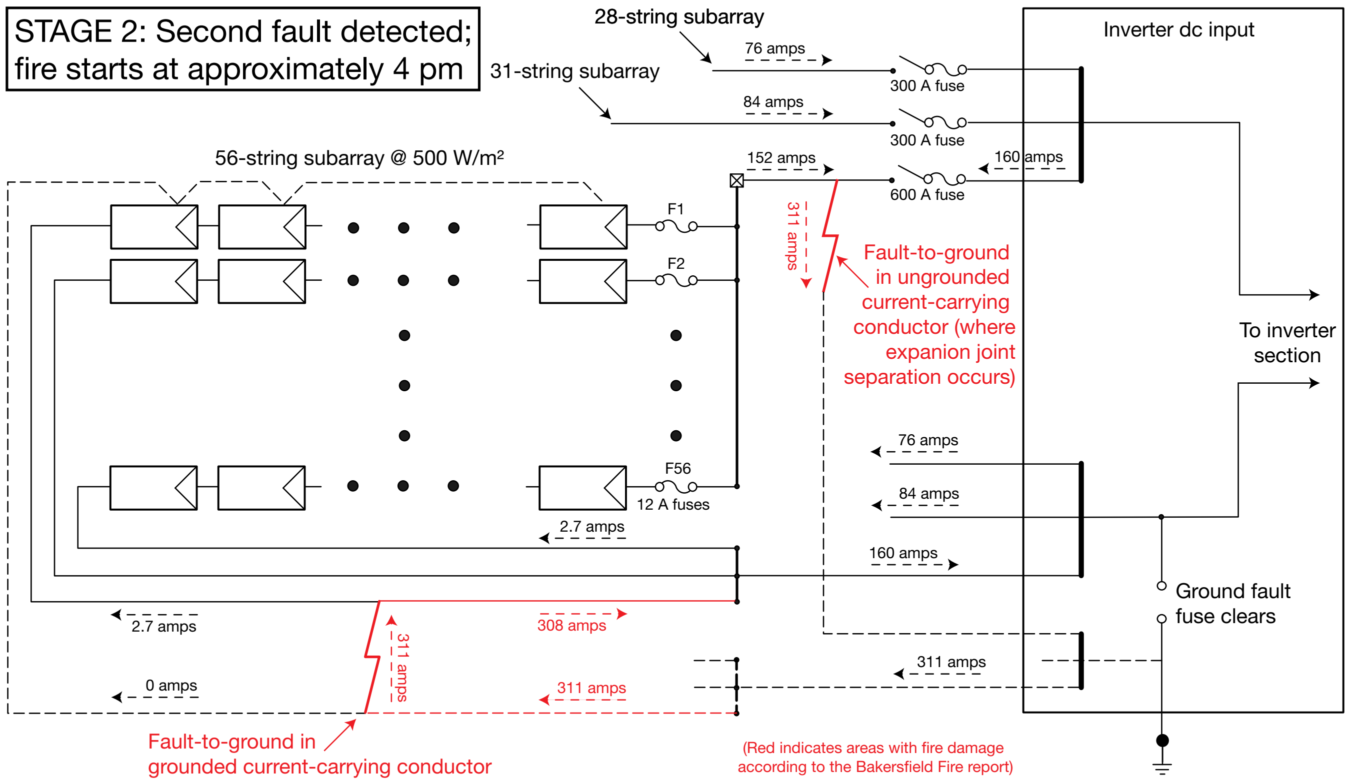
If the faulted source-circuit current is, at best, split evenly between the current-carrying conductor and the EGC, then we have a problem. The ground-fault fuse on many large inverters is rated at 4 amps; meanwhile, most of the large format 6-inch cell modules have operating currents below 8 amps. If the source-circuit current is split between the current-carrying conductor and the EGC, the fault current on the EGC is less than the GFP trip point. As a result, this type of fault lives on forever, until the fateful day when the ungrounded conductor faults.

The perfect storm. Grounded source-circuit conductors make up one quarter to one half of all current-carrying conductors in a PV system, and existing GFP detectors are blind to them if they are set higher than about 3 amps. Since the GFP device cannot see a fault in the grounded conductor for larger systems, operation continues even though the status of the system has gone from "safe" to "fire hazard." Invariably, one fault eventually results in a second fault. If the next fault occurs in a large feeder circuit carrying 100 amps or more, CONTINUED ON PAGE 66



Courtesy Brooks Engineering

Figure 1 An undetected fault between a grounded current-carrying conductor and the equipment-grounding conductor will persist indefinitely without tripping the GFP. Absent proper commissioning procedures, this first fault can exist from the time of installation forward.



Courtesy Brooks Engineering

Figure 2 Thermal expansion in a long conduit run housing PV output-circuit conductors causes an expansion joint to fail and damage a large (500 MCM) ungrounded output cable. The resulting high-magnitude ground-fault currents quickly clear the ground-fault fuse in the inverter. After the ground connection is lifted at the inverter, the available ground currents return through the fault in the grounded source-circuit conductor (through the array-bonding hardware and the metal conduit parts) to the fault in the ungrounded output conductor. Because the grounded conductor is unfused, these high-magnitude fault currents continue without interruption.

as shown in Figure 2, then the GFP fuse instantly opens, removing the main ground connection on the array.

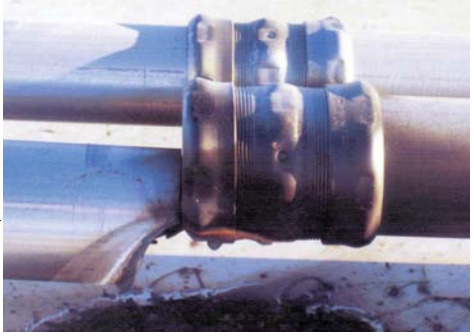
However, this is exactly what *should not* happen if there is already a fault in the array. Now, instead of having a large equipment-grounding conductor to carry the fault current, a 10 or 12 AWG source-circuit conductor has to carry the entire return current. This means that the short-circuit current now has to return through the point where the first undetected fault occurred, as shown in Figure 2. Within several seconds that conductor can get so hot that the insulation on the conductor melts or catches fire. The fire is then driven into whatever flammable material is in proximity to the wire, such as the flammable PV module backsheet or any flammable roof materials.

As the Bakersfield Fire persisted, it appears that multiple faults occurred in the source-circuit wiring, which caused several string fuses to see excessive reverse currents. These fuses would have been clearing as the sun was beginning to go down, which could have reduced the fault-current flow below the threshold at which it was capable of sustaining a fire. However, without corrective action, new fires could have started the following day as sunlight levels exceeded the condition when the initial fire occurred.

MISLEADING MESSAGES FROM THE BAKERSFIELD FIRE

One might ask, how did such a dangerous situation go unnoticed? Until the Bakersfield Fire, very few people believed that this set of events could happen. In fact, many still believe that this is a "two-fault" event that engineers generally are not required to design for. I disagree.

The idea that this scenario could repeat itself many times is not only plausible, but it is very likely. A dangerous blind spot exists—making up one quarter to one half of all large system wiring—insofar as it is possible for a first fault to be present in a grounded source-circuit conductor yet invisible to the GFP device. The first fault could exist at installation if proper commissioning tests are not done. Since ground faults are the most common faults in an array—and 50% of these faults may go undetected in the source-circuit conductors on larger PV systems—we have a real problem. The Bakersfield Fire is very easy to repeat experimentally. Unfortunately, the recommendations from industry experts in the wake of the Bakerfield Fire miss the point. The most often expressed concerns are the proper use of expansion joints, the importance of array segmenting disconnects and the need for arc-fault protection in rooftop PV systems.



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Uninterrupted fault The failure of an improperly specified and installed expansion joint likely triggered the Bakersfield Fire. However, if this had been the first fault in the system, the GFP device would have been able to detect and interrupt the fault before any damage was done.

Expansion joints. The first commonly accepted lesson from the Bakersfield Fire is that we need to focus on providing expansion joints for raceways. This is a good recommendation, since improper techniques by both installer and inspector probably resulted in the feeder fault that drove the fire. Nevertheless, all the best expansion joints in the world will not eliminate the risk of future fires.

Segmenting disconnects. Another commonly accepted message is that disconnects would have solved the problem. I helped to develop the new language in Article 690.16(B) of the 2011 *NEC,* which is now in print, requiring disconnects within sight of combiner boxes. However, these segmenting disconnects could not have stopped the Bakersfield Fire. Disconnects on the PV output circuits would have helped with cleanup and overhaul operations only.

Arc-fault circuit protection. The Bakersfield Fire is also often used as the poster child for why we need arc-fault detectors. Unfortunately, arc-fault detectors would have done nothing to prevent this fire. The Bakersfield Fire was caused by a ground fault that turned into a massive ground fault, which only later turned into a fire with arcing. By the time the arcing started, the fire was in full swing. Arc-fault detectors are not the whole answer, since most arc faults start as ground faults—just as occurred in Bakersfield.

SETTING THE RECORD STRAIGHT

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Wire management. Some industry stakeholders have suggested that the wire management methods used on the Bakersfield PV system increased the likelihood of damage to the source-circuit conductors. The management of conductors in PV arrays is in serious need of an upgrade. Many large rooftop installations have bundles of wire lying on the roof surface. Not only can the roof be abrasive, but also the cables often dam dirt and debris that can damage the roof. Many of these wiring systems also have sharp metal edges—in some cases, as parts of devices intended to serve a protective function—or paver bricks that dig into the cable insulation. These low-cost, substandard wiring methods have to stop if we truly expect PV systems to last 25 years. As it is now, while the modules may last that long, many array wiring systems have no chance of standing that test of time.

Lack of field experience. Another problem brought to light by the Bakersfield Fire is a general lack of industry field experience. Most of the grid-connected PV systems in the US were built within the past 5 years. As a result, most designers and contractors have extremely limited field experience. Installed capacity, in this case, is no substitute for time in the field. Experience needs to be measured in years rather than in megawatts. If a firm has spent little time designing or installing PV systems, all megawatts suggest is that they have potentially made lots of mistakes.

Since PV is still very much an emerging technology, this is an important distinction to make. For example, say a representative from a Spanish company tells me it has a 50 MW portfolio of PV projects. This may mean only that the company participated for 1 year in the Spanish PV market explosion, which was a better example of what *not* to do than a shining moment in the history of PV. My intent here is not to pick on the Europeans, but rather to stress that experience is relative and contextual. Experience in Germany, therefore, does not necessarily correlate directly with experience in US markets. Given that irradiance and temperature is so much lower in Germany than in California, for example, a problem may take twice as long to surface in Germany. A German company with hundreds of megawatts installed and 10 years of experience might have the equivalent of only 5 years of experience in California.

Nevertheless, the sheer magnitude of installed PV capacity in Germany represents a significant body of learning. Why is it that PV fires are not a problem in Germany, the world's largest PV market? One reason is that the Germans generally have better wire management practices. More importantly, however, they do ground-fault detection very differently—and better.

GFP methods. The proper usages of expansion joints and segmenting disconnects are important lessons learned from the Bakersfield Fire, as are the importance of conductor-temperature calculations and improved wire management methods. However, the primary message to the codes and standards community is that we need to change the way we design and test our GFP circuits. Good array design and installation practices can certainly reduce the possibility of faults—but it is impossible to totally eliminate faults in systems that are intended to operate for 25 years, regardless of how much O&M is performed. The way to eliminate the fire hazard associated with ground faults is with GFP devices that can detect faults in the source-circuit grounded conductor. Better yet, build PV arrays that do not have a grounded conductor at all.

In fact, the only way to get ground-fault detection below 1 amp as part of the GFP scheme for large PV systems is to *unground* or *resistively ground* the array circuit, just as they do in Europe and Japan. Contemporary European inverters, for example, can detect changes in ground current as low as 300 mA, which is an order of magnitude more sensitive than our solidly grounded systems. It is also sensitive enough to effectively detect faults in just about all array types, including many low-current thin-film systems, which are inherently more challenging applications.


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Undetected fault The possibility of an undetected first fault in PV source-circuit conductors underscores the importance of proper commissioning procedures and improved wire management practices throughout the industry.

fault current, and providing an indication of the fault." The Bakersfield Fire is evidence that there is a blind spot when it comes to the detection of ground faults in grounded source-circuit conductors on larger PV systems.

At present, the *NEC* does not necessarily need to be changed. There is an option available for PV systems installed on "other than dwelling units" that designers can use on larger commercial systems. Exception No. 2 to Article 690.5 states: "PV arrays installed at other than dwelling units shall be permitted without ground-fault protection where the equipment-grounding conductors are sized in accordance with 690.45." Meanwhile, 690.45(B) states that without GFP, the EGC must be sized at twice the ampacity of the current-carrying conductor ampacity. While this is potentially a big conductor, it is also a safe way to operate the system. However, utilizing this exception requires bypassing the GFP fuse on large inverters, and most manufacturers would have to certify a workaround for their existing inverters.

This also does not help existing installations where the EGC is sized according to *NEC* Table 250.122 as allowed in 690.45(A). So how do we fix the hundreds of existing installations that fit this description? One solution that would make existing arrays much safer is if they were retrofitted with a circuit at the inverter that would lift the grounded conductor each morning and test for ground faults on the grounded conductor prior to starting the inverter. This is exactly what inverters in Europe are required to do. While this retrofit would not make arrays quite as safe as European-style systems, which can also detect small ground-current changes when the inverter is operating, it would be a large improvement over what we have today. CONTINUED ON PAGE 70

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HOW TO FIX THE PROBLEM

The *NEC* does not dictate how to do ground-fault protection. It simply states that GFP shall be provided, unless the system meets the exceptions found in Article 690.5. It is clear, however, that the existing GFP systems on large PV inverters are out of compliance with the 2008 *NEC* and later editions. Article 690.5 requires that the GFP "device or system shall be capable of detecting a ground-fault current, interrupting the flow of the

It would not be surprising if the codes and standards regarding GFP were soon changed as a result of the hazard exposed by the Bakersfield Fire. One change that clearly must take place is in UL 1741, the "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources." This is the UL standard that inverters are listed to. The current standard does not require the morning ground resistance test, but the language of the standard could be changed to include this or other improved ground-fault detection strategies. I am pushing for a change to the UL 1741 standard as soon as possible, and I urge inverter manufacturers to join me. In the meantime, there is nothing to stop inverter manufacturers from adding the morning ground resistance test, as an additional capability, to products listed to the current UL 1741 standard.


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Next steps While arc-fault detection will undoubtedly lead to safer PV installations, it could not have prevented the Bakersfield Fire. The first priority, therefore, is to improve the sensitivity of our ground-fault protection circuits.

MOVING INTO A SAFER FUTURE

The current hazardous situation—and the incomplete information and analysis in the wake of the Bakersfield Fire—cannot continue. It is unacceptable for the poor level of ground-fault safety in our large PV systems to persist. Improving ground-fault safety is the highest priority for safer systems. Ultimately, however, we need to move toward safer PV systems on a variety of levels.

Moving to ungrounded or resistively grounded systems is an important first step in better fault detection. Inverters that meet the requirements of *NEC* Article 690.35, which pertains to "Ungrounded Photovoltaic Power Sources," are identified by listing agencies as *ungrounded inverters* and have GFP circuits that are tested to the same requirements as the safer European inverters. Unfortunately, only a few smaller inverters are currently listed this way, including inverters from Exeltech, Power-One, SolarEdge and the new TL (transformerless) product line from SMA. While this is not much help on large PV systems, there is nothing preventing the manufacturers of larger inverters from using transformers with ungrounded arrays, just as they do in Europe. In fact, since most of the inverter manufacturers selling products in the US are also serving the European market, they already have the inverters we need—they are just selling them overseas.

Once we have better GFP systems, the newly required arc-fault detectors will effectively cover the majority of remaining operating fire hazards. There has been much talk about arc-fault detection in recent years, often in the context of the Bakersfield Fire, where it probably could not have prevented the fire. However, preventing arc faults is a legitimate concern, and arc-fault detectors would eliminate hazards associated with module junction box failures that have occurred over the past few years, which no GFP can solve. The 2011 *NEC* requires series arc-fault detectors in all systems with a maximum system voltage above 80 volts. No certified products have this capability for the simple reason that the certification tests have not yet been finalized. Arc-fault detectors will probably be on the market by mid-2011.

Moving beyond these two key steps requires a fundamental change in how we install PV arrays. There is much buzz about module-level power electronics, for example, which are expected to accomplish numerous power conditioning and safety tasks. Although I believe moving to module-level power electronics is a logical progression in the way we build PV arrays, especially on buildings, there are many technical and cost issues to overcome. Several companies are already marketing products that they claim are "firefighter and fire safe." But the industry has yet to define what the word *safe* really means.

There is no question that future PV systems will be more efficient, less expensive, more reliable and, best of all, safer. How we get there will be an exciting journey, requiring the best minds in the PV industry from all around the globe. I do not expect to suffer from boredom any time soon, and neither should you.

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Resources

National Fire Protection Agency / nfpa.org

Bakersfield Fire Investigator's Report / nfpa.typepad.com/files/target-fire-report-09apr29.pdf