April/May 2014

PV Source-Circuit Wiring | Winter Commissioning

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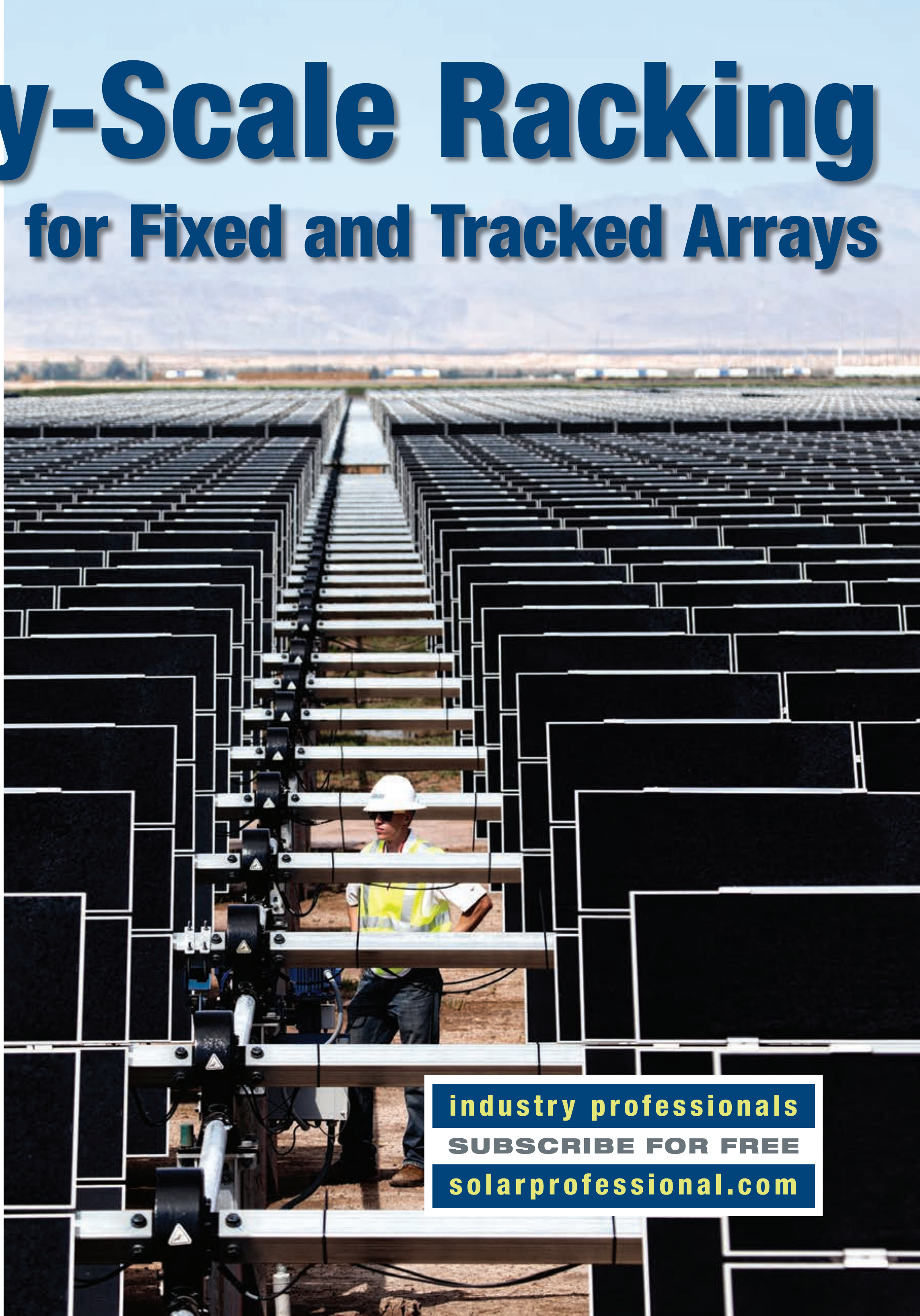

2014 *National Electrical Code*
Notable Changes for Design & Installation Professionals

Solar Energy Storage Systems
Emerging Technologies, Markets & Applications for Battery Storage

Interview:
James Worden
Solectria Renewables
Andrew Worden
GameChange Racking

Silver Ridge Power
Mount Signal Solar
Calexico, CA

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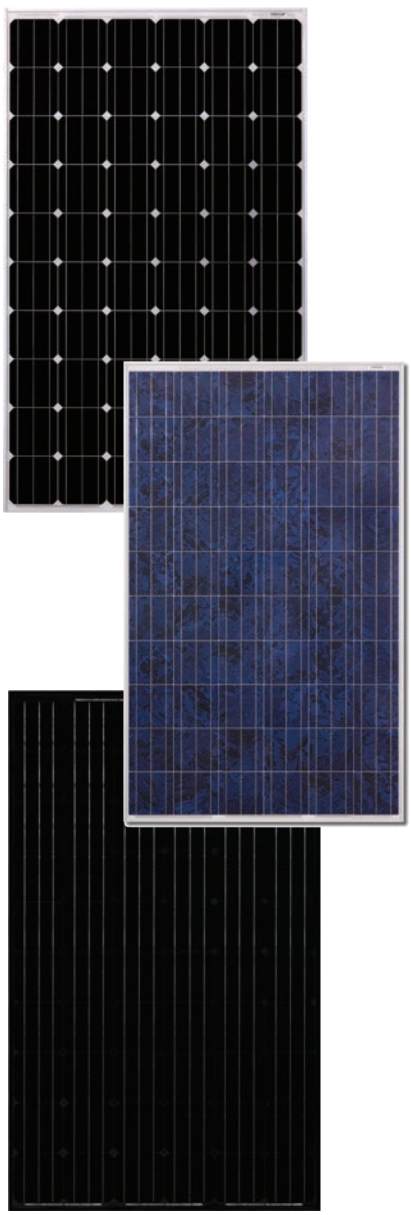
CANADIAN SOLAR MODULES PRODUCE UP TO 6.4% MORE REAL WORLD POWER PER YEAR THAN LEADING COMPETITOR MODULES OF THE SAME NAMEPLATE POWER



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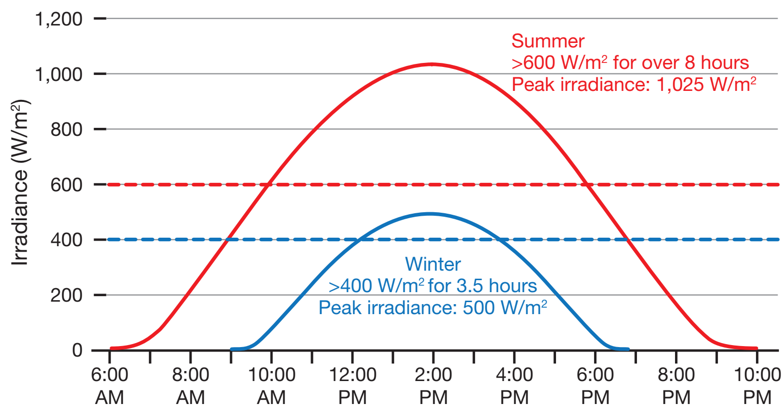

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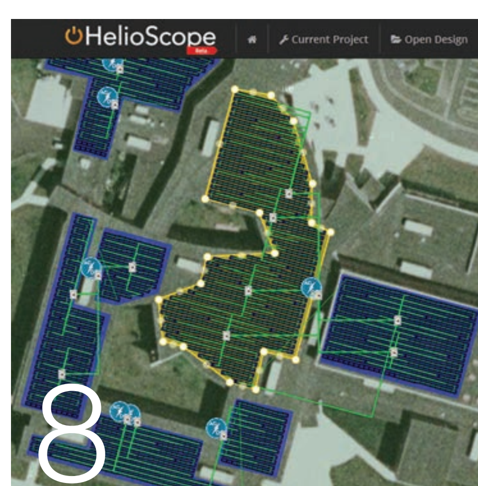
ON THE COVER

Array Technologies team member Ben Theune inspects the DuraTrack HZ single-axis tracking system deployed at the 265.7 MWdc Mount Signal Solar project in Calexico, California. Silver Ridge Power (formerly AES Solar) is the project developer. Using more than 3 million First Solar modules and scheduled for completion in 2014, the PV plant will be one of the world's largest single-axis tracking systems.

Photo: Courtesy Array Technologies



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Contributors

Experience + Expertise

Claude Colp, a NABCEP Certified PV Installation Professional, is an engineering consultant and digital strategist at Solar Design Associates. Since 2008, Colp has designed and managed on- and off-grid PV, microgrid, solar thermal, and zero-net-energy buildings. He holds a BSCET from the Wentworth Institute of Technology and an MBA from Boston College.

Rebekah Hren has more than a decade of PV industry experience. She is a North Carolina–licensed electrical contractor, NABCEP Certified PV Installation Professional and IREC Certified PV Instructor. With expertise in residential and large-scale system integration, Hren has been a project engineer for solar farm developer O2 Energies since 2009.

Tommy Jacoby is the principal at Jacoby Solar Consulting, based in Austin, Texas, where he provides PV design, consulting and installation services for projects from complex battery backup to large-scale grid-tied applications, as well as third-party commissioning services. Jacoby is a NABCEP Certified PV Installation Professional and an IREC Certified PV Instructor.

Brian Mehalic is a NABCEP Certified PV Installation Professional and ISPQ-certified PV instructor with more than a decade's experience in designing, installing, servicing and inspecting PV systems. Mehalic is a curriculum developer and instructor for Solar Energy International and North Carolina State University, and an independent consultant.

Michael Vance is a project manager for PowerStream Solar. He has more than 25 years of experience as a master electrician in the US and Canada and has designed, built and commissioned more than 10 MW of commercial solar in Ontario. Vance is a certified Project Management Professional and NABCEP Certified PV Installation Professional.

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Folsom Labs Launches Solar Design Software

[San Francisco, CA] HelioScope software, developed by Folsom Labs, integrates PV system design and performance modeling into a single tool to reduce the time required for project design and energy analysis. The cloud-based software enables sales, engineering and finance teams to use the same platform, as well as seamlessly share project details with subcontractors and vendors. HelioScope allows users to define PV modules and inverters to automatically populate an array field and generate conductor, combiner box and inverter quantities, and output a full bill of materials. The software's flexibility allows users to quickly modify and copy a design, and to make comparisons to assist in engineering and economic decisions. Integration with Google SketchUp supports advanced shade calculations. HelioScope utilizes worldwide TMY data, geo-located array information and product-specific PAN files to accurately estimate energy production. DNV GL has independently verified HelioScope's energy production values to be within 1% of PVsyst simulations.

Folsom Labs / 415.729.4050 / folsomlabs.com

SolarEdge Updates Product Line

[Fremont, CA] SolarEdge has introduced two optimizer products and has enhanced its commercial inverter line. The company's 3-phase inverter models are now UL 1699B compliant, meeting the standard's arc-fault detection and interruption requirements. Compliant inverters began shipping on January 15, 2014. (Inverters shipped prior to the new listing can receive firmware upgrades for full compliance.) SolarEdge's 3-phase inverters are now shipping with a preassembled ac/dc disconnect switch. SolarEdge has also released two new power optimizer models for commercial applications. The P700 optimizer is designed for two 72-cell modules in series and is compatible with the SolarEdge 3-phase inverter models. The P405 is optimized for thin-film modules and replaces the existing OP400-EV. Branch cables are required to configure modules in parallel prior to the P405 optimizer.

SolarEdge / 877.360.5292 / solaredge.us

GameChange Racking Introduces Pour-in-Place Ballasted Mount

[New York, NY] GameChange Racking has released a new ballasted racking system for ground-mounted arrays. The Pour-in-Place system includes leave-behind plastic forms, rail supports, rails and top-down module-mounting clamps. The system can support either one or two rows of modules in portrait orientation with a 15°–30° tilt angle. Forms are typically placed every 13 feet and hold the rail supports in place prior to the concrete pour. The racking supports and rails can be adjusted independently to account for minor elevation changes between forms. The module rails utilize top-down clamps, and the system includes module-bonding strips. GameChange provides array layouts and wet-stamped drawings for permit applications in most states. The Pour-in-Place system is rated for up to 120 mph winds and 60 psf snow loads.

GameChange Racking / 212.359.0205 / gamechangeracking.com


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RBI Solar Acquires ProtekPark Solar

[Cincinnati, OH] RBI Solar, a provider of ground- and roof-mounted PV racking systems and mounting solutions, has completed the acquisition of ProtekPark Solar, a manufacturer and installer of solar carport structures. RBI Solar will distribute ProtekPark Solar's carport systems, which include single slope, inverted and long-span products. The acquisition allows RBI Solar to expand its single-source value chain approach into the solar carport market and grow into new geographical markets while maintaining its headquarters in Cincinnati. RBI Solar will continue ProtekPark Solar's practice of developing a site-specific solar structure based on client needs and project economics.

RBI Solar / 513.242.2051 / rbisolar.com

SMA America Introduces PV Plant O&M Services

[Rocklin, CA] SMA's Solar Asset Management portfolio of services is designed to support PV plant owners by maximizing system performance and longevity. The O&M service is available in three plans: Preventative, Proactive and Performance. Preventative packages include inverter and BOS visual inspections, thermal analysis of electrical equipment, annual inverter maintenance and comprehensive maintenance reports. Proactive plans include array maintenance, inspection of alarm events, minor repairs, increased reporting frequency and emergency response. Performance packages include design review, 30-day validation tests and enhanced reporting. For flexible and customized O&M solutions, SMA also offers individual services such as array cleaning, pest management and vegetation control.

SMA America / 916.625.0870 / sma-america.com

Industrial Control Direct Offers UL 508I–Certified DC Disconnects from IMO

[Arlington, TX] IMO's new dc disconnects are now available from Industrial Control Direct. The switches come in a variety of configurations, from two to eight poles, with multiple options to place switching contacts in series and parallel. The switches can be mounted within user-provided cabinets or preinstalled in NEMA 1 or NEMA 3R enclosures. The rotary switches are lockable in the off position and have rated ampacity values of 16 A–58 A at 600 Vdc.

Industrial Control Direct / 817.375.0023 / industrialcontroldirect.com

Cost-Saving PV Source-Circuit Wiring Method

Ideally, project design documents explicitly describe the expected module-to-module wire management practices crews should use in the array field. When this is not the case, field technicians are left to develop and implement their own wire management solutions. These ad hoc solutions are not always *Code* compliant and may compromise project reliability.

For example, lead lengths on landscape-oriented modules are often too short to allow for proper wire management. When performing due diligence on PV systems with landscape-oriented modules prior to system commissioning, I have come across module leads that did not comply with the conductor bending radius requirements found in *NEC* Section 300.34. I have even discovered module leads pulled so taut that the conductor insulation split at the cable gland, effectively voiding the product warranty.

Portrait-oriented modules present a different wire management challenge. When adjacent modules are connected in series, the module leads are longer than necessary. Where this excess wire is not managed properly, it increases the likelihood of conductor or J-box damage, which could result in a ground fault or an arcing fault. The traditional approach to wiring a portrait-oriented PV array is to use some combination of labor and hardware to manage excess wire. For example, the installers might coil up the excess lead length and use module wire clips to hold everything in place.

But what if it were possible to pick up the slack in the PV array wiring and put it to good use? Here, I present a simple source-circuit wiring technique for portrait-oriented PV arrays that can turn the liability associated with excess module lead length into a cost-savings opportunity. Since there is no consensus industry term, I refer to this technique as *leapfrog wiring*.

Daisy Chain vs. Leapfrog Wiring

Standard practice for module-to-module wiring is to connect adjacent modules in a daisy chain, as shown in Figure 1a. Excess module lead length is often coiled up and organized using some type of PV cable clip. Where modules in the same string are mechanically mounted in the same row, the positive and negative homerun connections invariably wind up on opposite ends of the mechanical assembly.

Given adequate module lead length, leapfrog wiring can be used to connect portrait-oriented PV modules in series, as shown in Figure 1b. In this scenario, the excess module lead is used to leap over adjacent modules, so that every other module in the row is connected in series until the end of the row is reached. At that point, the source-circuit wiring circles back and picks up the skipped modules. Both the positive and negative homerun connections wind up on one end of the row of modules.

While the leapfrog method of stringing modules in series is not a new concept, it appears that installers are by and large unfamiliar with this option. Only one of the integrators I spoke with in Massachusetts

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Figure 1a: Representative 72-cell PV module source circuit connected in series using conventional daisy chain wiring

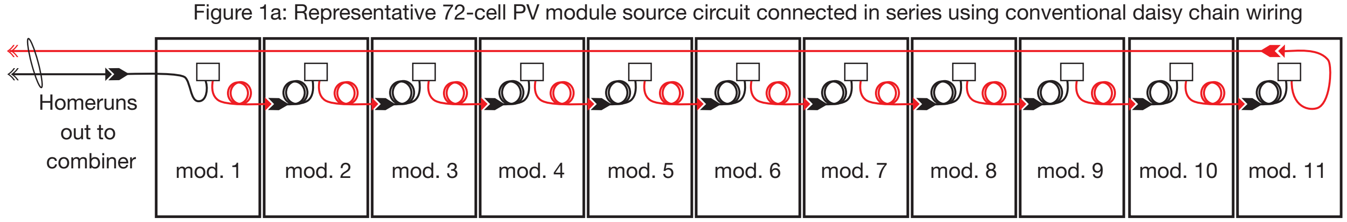
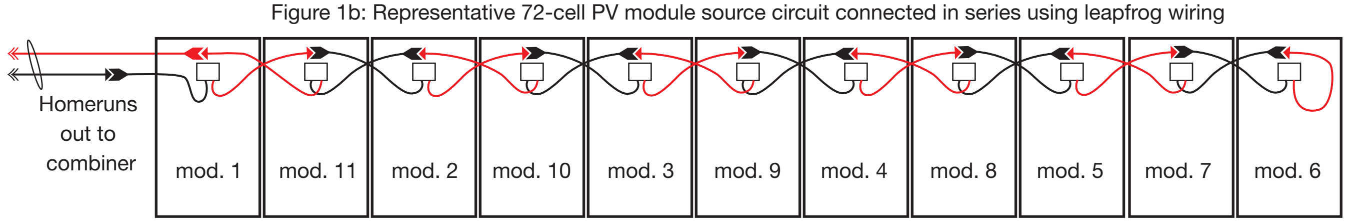


Figure 1b: Representative 72-cell PV module source circuit connected in series using leapfrog wiring



Figures 1a & 1b Whereas the source circuit in Figure 1a (top) is connected using conventional daisy chain wiring, the series string in Figure 1b (bottom) is connected using leapfrog wiring. The modules are numbered according to the order in which they are electrically connected.

was aware of this wiring strategy. In my experience, nearly every 60- or 72-cell module with a lead length of 1,100 mm or longer can accommodate leapfrog wiring. However, very few 60-cell PV modules meet this lead length requirement. Also, note that lead length is not the only determining factor, since the mounting system is often used to facilitate wire management. Before specifying this wiring method, the system designer must verify that the lead length is adequate after accounting for conductor routing as it relates to the racking system.

Guaranteed Cost Savings

Traditional daisy chain wiring results in excess module lead length that installers must manage using module wire clips or wire ties, as well as one long homerun wire that they need to manage. With the leapfrog wiring method, there is no excess lead length apart from one module-to-module connection in the middle of the string (at the end of the row); further, the total length of the homerun wiring is reduced by roughly the width of the row of modules. As a result, each source circuit requires fewer PV cable clips.

Using leapfrog wiring with 72-cell modules, you can expect to save \$10–\$15 per string in sub–600 V PV systems and \$17–\$23 per string in 1,000 V PV systems. Since each 72-cell PV module is roughly 3 feet wide, leapfrog wiring will reduce the length of your homerun conductor by roughly 33–36 feet per string in 600 V designs and 51–60 feet per string in 1,000 V designs. If you are paying \$0.25 per foot for PV Wire, then you stand to save \$8.25–\$9 per 600 V string and \$12.75–\$15 per 1,000 V string. In addition, you can expect to save one or two cable clips per module at perhaps \$0.20 each. You can easily modify these assumptions to account for your company's preferred hardware solutions and the associated costs, which will vary based on purchase volume.

While the material cost savings associated with leapfrog wiring may not seem that significant on small systems, they are very compelling at scale. The leapfrog wiring method can reduce material costs by more than \$20,000 on a 5 MW PV system that uses 72-cell modules. The numbers are even better if you are using qualified 60-cell PV modules. Note that system quality is in no way compromised; the associated cost savings amount to found money.

Is Leapfrogging Faster?

Based on the half-dozen conversations I had with industry experts, opinions differ as to whether leapfrog wiring is faster than traditional daisy chaining. On one hand, some feel that the labor required for both wire management methods is the same. On the other, some have speculated that the labor savings associated with leapfrog wiring could be on the order of 1 minute per module. In this scenario, the potential labor savings on a 5 MW system designed using 295 W modules is nearly 16,950 minutes, which is more than 282 person-hours. Since installer rates vary so greatly, I leave it to you to put a dollar amount on the potential labor savings.

Additional Considerations

If you plan to use leapfrog wiring, be sure to verify that the module lead length is adequate. Back in 2008, Solar Design Associates often designed projects using 60-cell Sharp 200 W–208 W modules, which boasted a module lead length of 1,300 mm—long enough that we could confidently specify leapfrog wiring regardless of module orientation. In the years since, lead lengths have gotten shorter as module manufacturers have continually worked to cut costs. Today it is unusual to find 72-cell modules with a lead length greater than 1,200 mm, and 60-cell modules with a lead length greater than 1,100 mm are even more rare. The ratio of lead length to module width determines whether leapfrog wiring is an option.

Quality control and consistency are also practical considerations. I worked on a project recently where leapfrog wiring was specified but could not be performed in the field. While the spec sheet for AUO's EcoDuo PM240P00 module indicated a module width of 950 mm and a module lead length of 1,000 mm, electricians in the field discovered that some module leads were as short as 850 mm, which rendered leapfrog wiring infeasible.

Where leapfrog wiring is deployed as an alternative to conventional daisy chaining, it needs to be transparent to future O&M providers. The project design documents must clearly indicate as-built wiring conditions. This information is critical for service technicians, especially those troubleshooting a ground fault.

Given these additional considerations, some installers may conclude that the benefits of leapfrog wiring are not worth deviating from business as usual. Nevertheless, it is a novel approach to reducing project costs—and you can never have too many arrows in your quiver of project design and deployment strategies.

—Claude Colp / Solar Design Associates / Harvard, MA / solardesign.com

Winter Commissioning

Commissioning PV systems in winter months presents many challenges to gathering useful and valid data. It is difficult, if not impossible, to follow industry-standard commissioning practices—such as those outlined in IEC 62446—when irradiance levels are low and unstable, or when snow covers the modules. According to Cameron Steinman, PE, the president of Endura Energy, an Ontario-based solar consulting firm: "Winter weather is unpredictable, and this negatively impacts resourcing, as commissioning is typically rescheduled multiple times."

Nonetheless, a PV system may need to be commissioned whether conditions are ideal or not. (See Figure 1 for the time-of-year impacts on irradiance levels.) Contractors have construction deadlines and year-end goals to meet. Performance payments may be at stake. Owners and developers need to beat expiration dates for tax incentives or feed-in tariff contracts.

This article details a two-step process for winter commissioning. Tests in the first phase verify system safety and can be performed at any time. When appropriate irradiance levels are available—perhaps in early spring—technicians can undertake the second phase, which includes performance tests and measurements.

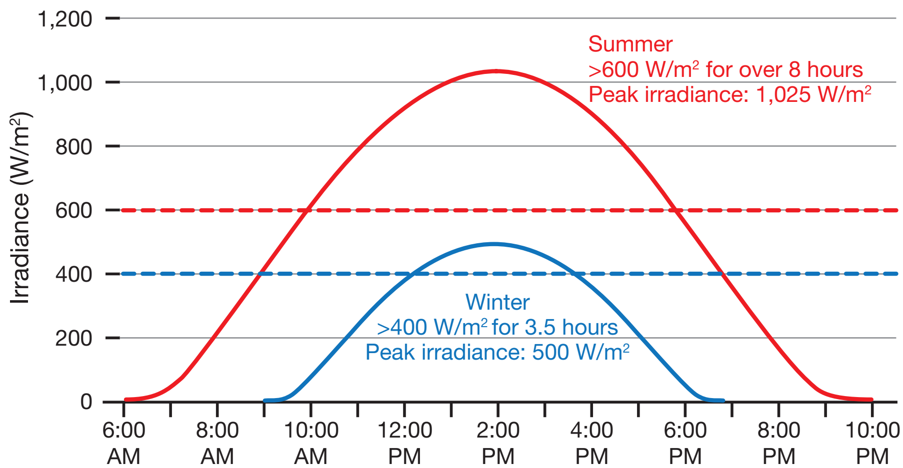


Figure 1 This figure is based on a review of historical weather data for Ontario, Canada, and details the best-case stable irradiance levels for winter and summer months.

Phase 1: Safety Tests

Table 1 outlines the activities performed in the first phase of winter commissioning, in the recommended order of completion. Here I provide some brief application notes. These activities are discussed in greater detail in previous *SolarPro* magazine articles: "PV System Commissioning" (October/November 2009) and "Data Acquisition System Installation and Commissioning" (April/May 2013).

Inspect and photograph. The inspection process should follow IEC Standards 62446 and 60364-6, which detail verification requirements for grid-connected PV systems in particular and low-voltage electrical systems in general. The goal is to verify that system components are installed according to the engineered drawings and per the manufacturer's instructions. This inspection includes verifying that all bolted connections—mechanical and electrical—have been torqued to manufacturer-recommended values. In addition to checking for visible signs of damage, commissioning agents verify that the installation complies with applicable safety codes and standards. They also photograph the as-built condition of the installation, including all major BOS equipment, using a high-resolution camera for the project's records.

Table 1: Phase 1 of Winter Commissioning

Activities	Required tools
Inspect & photograph	Torque wrench & digital camera
Insulation resistance test	Megohmmeter
Earth continuity check	Digital multimeter
Polarity check	Digital multimeter
V_{oc} and I_{sc} measurements	Digital multimeter with current clamp
AC voltage measurements	Digital multimeter
Inverter start-up	Installation manual
Infrared (IR) thermal imaging	IR camera, irradiance & clamp meters
DAS commissioning	See *SolarPro,* April/May 2013

Safety tests Commissioning agents can perform these verification tests and measurements at any time, even when irradiance levels are low, and they will ensure basic system safety.

Insulation resistance test. Commissioning agents test each installed cable with a megohmmeter and record the results. These tests require technicians to isolate conductors from the common bus and from the common ground. (See "Standardizing PV System Documentation and Verification,"

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SolarPro magazine, February/March 2012, for minimum acceptable insulation resistance values for PV circuits.) [Editor's note: Ideally, technicians will complete insulation resistance tests prior to terminating the cables to avoid having to disassemble all of the connections later.]

Earth continuity check. Earth continuity is essential for the proper operation of ground-fault and overcurrent-protection devices. Commissioning agents use a digital multimeter (DMM) or similar tool to verify the continuity of the equipment-bonding conductor to the system ground. On smaller systems, it may be possible to clip one test lead to a module frame and the other directly to the system ground. Otherwise, a series of tests must be performed, accounting for each component and grounding conductor, to verify the continuity of the equipment bonding back to the system ground.

Polarity check. Commissioning agents verify the polarity of all dc cables, using a DMM or similar tool. This is one of the simplest and most important of the safety commissioning tests. Several rooftop fires involving PV systems have been traced back to reverse polarity.

V_{OC} and I_{SC} measurements. After verifying the polarity, commissioning agents complete open-circuit voltage (V_{OC}) and short-circuit current (I_{SC}) tests. They look for consistency in the measured values, with a maximum variance of ±5% across all strings in the same source-circuit combiner box and across all PV output circuits in an array combiner.

For V_{OC} measurements, commissioning agents must remove the fuses for each string and remove the grounded PV output-circuit conductor from its terminal lug in the combiner box, typically the negative pole, to isolate it from the rest of the array. The agents then take the following measurements and record their values: positive-to-negative, positive-to-earth and negative-to-earth. The measurements to earth should be equal, and should be approximately half of the V_{OC} measured between the positive and negative conductors. If they are not, there may be a ground fault in the module-to-module connections.

While I_{SC} measurements at irradiance levels below 600 W/m^2 carry little value in terms of verifying system performance, they are relatively easy to gather in combination with V_{OC} measurements. I_{SC} measurements at least provide some indication that the array will function properly under load.

Infrared (IR) thermal imaging. Once the inverter is commissioned and the system is operational, commissioning agents inspect the dc combiners with an IR camera. Many system failures occur at source-circuit and array combiners. IR thermography can identify any high-resistance connections before they can cause problems.

Ideally, circuits should be operating at or above 65% of maximum load when agents are using an IR camera for inspections, as higher-current levels make it easier to discern temperature differences. Unfortunately, irradiance levels during winter months seldom permit this. A more reasonable target irradiance for winter commissioning purposes is 400 W/m^2, which meets minimum criteria for acceptability, according to IEC 62446: "Irradiance in the plane of the array should be greater than 400 W/m^2 and sky conditions should be stable."

Table 2: Phase 2 of Winter Commissioning

Activities	Required tools
I-V curve tracing	I-V curve tracer
Performance measurements	Digital multimeter with current clamp
Power output verification	See *SolarPro,* Oct/Nov 2013
Infrared (IR) thermal imaging	IR camera, irradiance & clamp meters

Performance tests Commissioning activities that verify proper system performance require higher irradiance levels and must be postponed until early spring.

Phase 2: Performance Tests

Table 2 outlines the activities performed in the second phase of winter commissioning, in the recommended order of completion. Since these performance tests require higher irradiance levels than the safety tests, commissioning agents also perform a follow-up IR imaging inspection under ideal test conditions. The second phase of winter commissioning requires all of the tools used in Phase 1 plus a high-quality I-V curve tracer.

I-V curve tracing. Paul Hernday's article "Field Applications for I-V Curve Tracers" (*SolarPro* magazine, August/September 2011) explains why PV installers should perform I-V curve traces on every PV system they commission; it also provides detailed instructions for doing so. I-V curve tracing requires a stable plane of array irradiance greater than 600 W/m^2. The closer the irradiance is to 1,000 W/m^2, the better the results will be. Measured values should be corrected to STC or PTC to compare them to expected results.

Performance measurements. Once commissioning agents have completed I-V curve traces for all strings, the next step is for them to measure maximum power voltage (V_{MP}) and maximum power current (I_{MP}) for each PV output circuit, both in the array combiners and at the inverter dc input bus. They should compare these values to expected values, given the temperature and irradiance measurements taken at the time of commissioning. The agents then take voltage and current measurements on the ac side of the system, at the inverter output bus and each disconnect switch or circuit breaker up to the point of interconnection.

Power output verification. Commissioning agents now use the data gathered during the performance tests to compare the actual power output to the expected power output. They need to quantify both the dc power input (kW_{DC}) and the ac power output (kW_{AC}), and compare these measured values to expected values, once again correcting for actual temperature and irradiance. The expected power output can either be calculated from field measurements or modeled using software programs like PVsyst.

Infrared thermal imaging. The thermal imaging completed during Phase 1 focused on those terminations with the highest frequency of failure. That preliminary inspection, due to the low operational current available at the equipment, typically reveals only the most poorly made connections with extremely high resistance. To conduct a proper thermal imaging inspection, the equipment terminations must carry a sufficient load, preferably more than 65% of the maximum load possible, to properly stress the contacts.

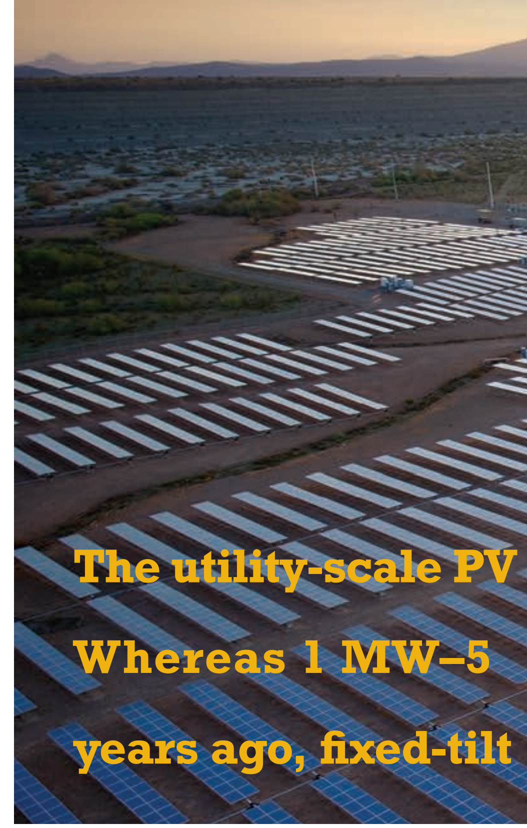
According to Michael Guest, PE, an engineer at Giffin Koerth Forensic Engineering: "It is necessary to return to site when there is sufficient irradiance to stress connections to ensure system quality and safety." The minimum acceptable irradiance level for IR inspection is 600 W/m^2. Ideally, commissioning agents can correct any thermal anomalies discovered in the field and reimage them to verify that they eliminated any potentially dangerous conditions. If it is not possible to correct the issue right away, agents should isolate the circuit from the array until an electrician can make the necessary repairs. Commissioning agents then need to return to the facility to document the correction with a new thermal image.

While balancing financial demands with safety is always a delicate act, Guest notes, "System performance alone is not a guarantee of system quality." By separating safety-related commissioning steps from those that confirm system performance, commissioning agents can raise the confidence level that a PV array is safe to operate under load. This permits system owners to begin generating revenue and meet financial deadlines without compromising safety.

—Michael Vance / PowerStream Solar / Vaughan, ON / powerstreamsolar.ca

UTILITY-SCALE PV GROUND-MOUNT RACKING SOLUTIONS

Industry Input & Opinions



By Tommy Jacoby

Utility-scale ground-mounted projects range from less than a megawatt to several hundreds of megawatts. Project developers deploy both fixed-tilt and tracking arrays. Foundations for some projects may penetrate the earth or require excavation, whereas other sites may require less-invasive solutions or a combination of approaches.

Product designs and solutions continue to evolve to reduce installation time for the racking system and modules. These technologies can include preassembled components and parts (including racks or small groups of modules), integrated grounding solutions and higher tolerances for foundation-to-rack connections. Many manufacturers are moving to steel and away from more-expensive aluminum. Racking systems may be ARRA compliant, listed to UL 2703 or UL 3703, and certified by third-party agencies to meet wind, snow load or other code requirements. (UL 3703 is the tracking system equivalent of UL 2703 for fixed-tilt systems.)

For large projects, most racking manufacturers offer services including geotechnical studies, system design and engineering, bonding certification, off- and on-site construction support, project management and complete EPC services. Manufacturers provide varying warranties with optional extensions to meet project needs or timelines.

To better understand the current utility-scale ground-mount racking options for fixed and tracked arrays, I contacted manufacturers and EPC contractors who specialize in this sector of the PV industry. We discussed trends, features, design and best-practice considerations.

Industry Trends

How have utility-scale ground-mount racking systems changed in recent years?

"Some racking systems have become more efficient from a construction perspective—fewer parts and tools required. Several new racking companies have entered the market, which is great for the industry. However, many of the newer systems are not nearly as elegant as evolved designs from a veteran racking manufacturer. The creation of UL 2703 has been key for decreasing installation time while reducing the number of EGC terminations and potential failure points."

—David Del Vecchio, senior engineer, Strata Solar, stratasolar.com

"Utility-scale ground-mount systems have moved away from welded connections and replaced them with fasteners. In addition, foundation techniques that utilize less concrete have become available to help reduce material costs. From a construction standpoint, the system designs are more adaptable to sloped terrain and utilize preassembled components, helping reduce labor time in the field."

—Jason Grissom, construction manager, SunEdison, sunedison.com

"In recent years, tracking companies have gone to great lengths to improve the quality and cost of these technologies. Trackers are more reliable, more durable and more cost effective than ever before, and we're seeing these improvements pay off as the global market for trackers continues to expand."

—Jay Johnson, VP of business development, Exosun, exosun.net

"Utility-scale racking systems have moved toward using mono-post designs and fewer parts to reduce installation time and cost. Improved post designs, such as a channel with return and increased contact surface area, reduce embedment-depth requirements. In addition, manufacturers are replacing aluminum with galvanized steel to reduce material costs."

—Andrew Barron Worden, CEO, GameChange Racking, gamechangeracking.com

Courtesy Array Technologies

"Racking systems of all types are becoming more advanced, with integrated features such as wire management, automated grounding and preassembly becoming more prevalent. All of these features are intended to help drive down BOS, labor and soft costs, therefore resulting in more-profitable installations for developers, installers and EPCs."

—Steve Daniel, EVP of sales and marketing, Solar FlexRack, solarflexrack.com

What services and product features are most important when selecting a utility-scale ground-mount racking system and manufacturer?

"In no particular order, we value a racking system that utilizes a minimal variety of parts and tools, easily adapts to sloping terrain and has a high post-drive tolerance. Other important factors include installation time, grounding methodology, UL 2703 listing, wire management features, price per watt and the manufacturer's response time and support."

—David Del Vecchio, Strata Solar

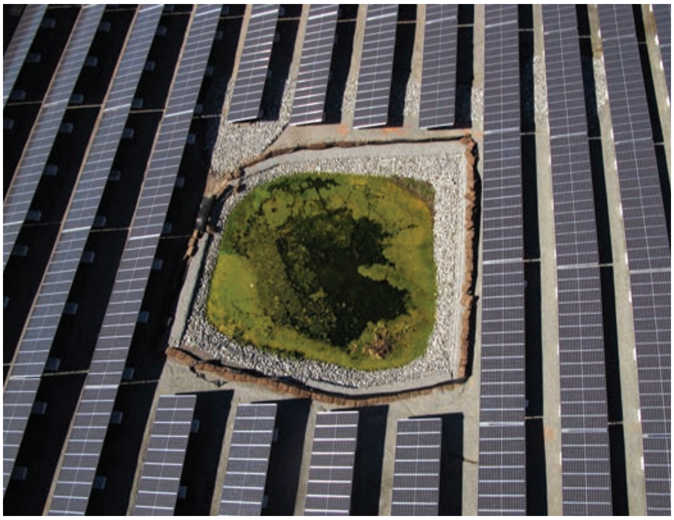
"The racking system needs to last the expected project life with minimal cost to maintain and operate. It is fundamental that the proper design categories be applied, specifically ASCE Design Occupancy Category II and Importance Factor 1, which apply 25-plus-year design considerations to ensure long-term structural integrity even during major weather events. Other considerations, such as designing for the site-specific wind load without relying solely on wind-stow devices, are key to increasing uptime and longevity and minimizing maintenance.

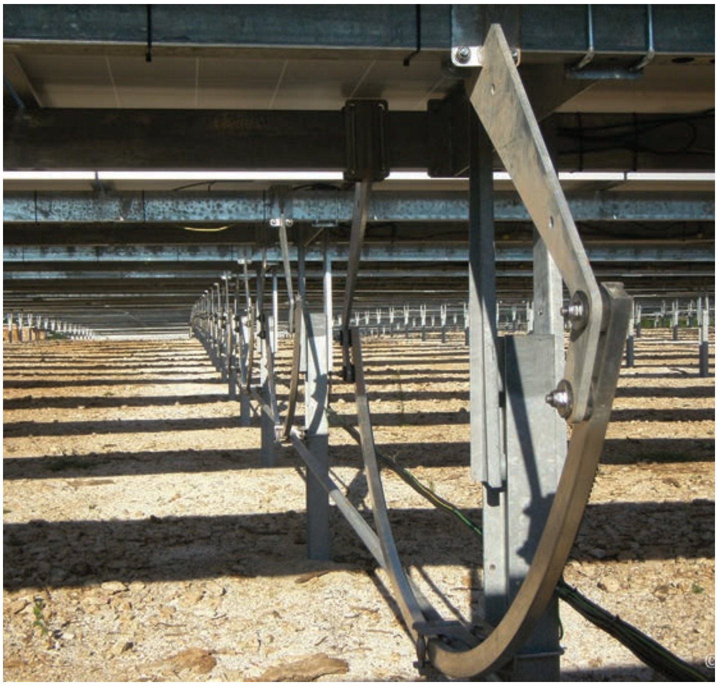
"Reliability, ease of installation and product cost all contribute to the lowest possible LCOE [levelized cost of energy], which is normally the primary objective for PV project investors. The racking system needs to install quickly and be designed so that installation quality can remain at a high level even with a wide range of worker skill levels. High person hours per MW not only add cost to a project but also result in lost opportunity costs [because the installer cannot take on other projects]. Lastly, the first key to service is to select a product that requires very little, if any."

—Eb Russell, VP of sales, Array Technologies, arraytechinc.som

"System developers and EPC contractors should look for a provider with a track record of reliability and a strong project portfolio. Products should offer a boost in production that justifies any up-front investment. Other factors to consider are

Utility-scale ballasted ground-mount This utility-scale ground-mounted PV installation uses a ballasted design from Solar FlexRack. The system is designed around a retention pond that helps manage water runoff.


Courtesy Solar FlexRack



Courtesy Exosun

Exosun Exotrack HZ The Exotrack HZ is low maintenance and can increase production by 25% in some locations compared to a fixed-tilt racking system.

the time and resources required for installation, and potential O&M costs over the lifetime of the system—ideally, 25 or more years. Additionally, product certifications from trusted third parties offer an assurance of product safety and durability."

—Jay Johnson, Exosun

"Look for a racking manufacturer who provides quick and reliable delivery services, and offers turnkey installation services and a 20-year warranty. The racking system should have a simple design that requires few parts, to reduce installation time, and provide adjustable connections in all three planes to allow for variations in terrain."

—Andrew Barron Worden, GameChange Racking

"Bankability is always the primary concern, but many developers look for the total package of engineering, installation, bonding certifications, longer warranties and as little risk as possible during the installation."

—Tom Racioppo, product manager, Schletter, schletter.us

"You need a clear understanding of the complexities that are inherent in utility-scale projects as there is a lot more to racking than what meets the eye. You need to ensure that the racking partners you choose manufacture a solid, well-built rack that can endure the 20 to 25 years that the system needs to be functioning, and [that the manufacturer can] provide all of the professional engineering services required for a successful installation—including stamped drawing packages, accurate loading and structural analysis calculations and foundation design services.

"Your racking provider should also be able to review geotechnical reports and provide accurate post-embedment depths. Providers who can visit your jobsite with their own employees and perform professional pull testing to determine the most accurate soil conditions have an advantage. Ongoing field services, such as technical supervision and installation training, are also important."

—Steve Daniel, Solar FlexRack

Design Considerations

What are critical considerations and best practices when selecting, designing and laying out a utility-scale ground-mount system?

"Among key considerations are site shading, geotechnical studies, proximity to point of interconnection, length of required wire runs, ground contour, environmental concerns, proximity to populated areas and potential issues with permitting.

"In Prime Solutions' experience, best practices to employ during the design and execution of utility-scale ground-mounted systems include collaborating with the local community and utility, having a strong working relationship with key equipment vendors, and maintaining a high level of communication—inclusive of all key stakeholders—throughout the design and construction process."

—Will May, CEO, Prime Solutions, primesolutions-inc.com

"While panel orientation is the most important factor for fixed-tilt applications, ground coverage ratio, or GCR—the ratio between the PV modules' area and the total ground area—is the most crucial consideration for the smart design of a tracker-equipped system. This calculation determines the proper tilt for each table to avoid panel-on-panel shading; the greater the GCR, the smaller the tilt required. With a proper tilt based on GCR calculations, solar trackers are shown to yield better output levels than fixed-tilt systems.

"Additionally, when considering cost, it is imperative to weigh short-term budget requirements against long-term return on investment. For example, tracking systems may increase the initial cost of a project, but this additional investment should pay for itself quickly through increased system output. Payback will be especially lucrative for tracking systems in regions with high land costs or utility-imposed time-of-use rates."

—Jay Johnson, Exosun

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"The size and shape of the field help determine the locations for inverters and other equipment for proper engineering and electrical purposes, and for access to equipment for repairs and maintenance. Size and shape of property also determine how to best fit the required system size on the available area. The larger and more square the field is, the better the wind tunnel testing results will be, which will help reduce the amount of material required."

—Tom Racioppo, Schletter

"Many factors need to be well understood, analyzed and considered in this process, including string sizing, module orientation, tilt angle and minimum ground clearance from the bottom of the module. All these factors will go into determining the GCR for the site. A racking solution that can be customized to the jobsite gives you the best layout possible."

—Steve Daniel, Solar FlexRack

"When selecting a utility-scale racking system, it's essential to choose the right partner—from quality, service, delivery and balance-sheet perspectives. These systems carry 20- to 30-year warranties that are typically not insured. Given that reality, you need to be sure that your racking manufacturer will be around for the long term. Secondly, it's important to choose the right product from a cost perspective, taking into account hardware, installation and O&M costs.

"A product design that is flexible enough to support a range of configurations, depending on a project's unique ground conditions and environment, is also important. It's valuable to work with a manufacturer that possesses the structural engineering expertise and wind, snow and seismic understanding to optimize product design by zone, such as taking advantage of the wind shielding properties of external zones of the array to reduce the material required in internal zones of the array."

—Yury Reznikov, VP of products and strategy, SunLink, sunlink.com

Fixed-Tilt vs. Tracking Options

A fixed-tilt ground-mount racking system has no moving parts. Foundation options include driven piles, concrete piers, helical screws, ballast trays and pour-in-place ballast systems. A minimum of 8–10 feet of clearance between rows is typical to permit construction and O&M vehicles to pass between rows.

Courtesy GameChange Racking

Pour-in-place ballast This pour-in-place form from GameChange Racking minimizes the need for heavy equipment and machinery to transport and place ballast blocks.

Courtesy Schletter

GAYK pile driver This GAYK Hydraulic Ram sold by Schletter can drive posts up to 19' long into the earth at a rate of 250 per day.

A racking system's form factor—or number of portrait- or landscape-oriented modules per column—dictates the height of the array, and thus the minimum spacing between rows required to avoid interrow shading. Refer to Table 1 for a list of manufacturers that offer fixed-tilt ground-mount PV racking systems.

Tracking systems follow the sun to optimize PV production throughout the day and thus generate more energy per kW than do fixed-tilt arrays. They can be used to optimize energy production to maximize the benefits of increased time-of-day, time-of-use or time-of-delivery rates. Single-axis tracking systems rotate around a horizontal,

Fixed-Tilt Ground-Mount Racking Manufacturers

Vendor	Headquarters	Phone	Website
Advanced Solar Photonics	Lake Mary, FL	407.804.1000	advancedsolarphotonics.com
Advanced Solar Products	Flemington, NJ	908.751.5818	advancedsolarproducts.com
AP Alternatives	Ridgeville Corners, OH	419.267.5280	apalternatives.com
Applied Energy Technologies (AET)	Clinton Township, MI	586.466.5073	aetenergy.com
Array Technologies	Albuquerque, NM	855.872.2578	arraytechinc.com
Clenergy	San Diego, CA	858.790.8014	clenergy.us
Cooper B-Line	Houston, TX	877.586.8607	cooperindustries.com
Conergy	Denver, CO	888.396.6611	conergy.us
CRC Solar	Moundridge, KS	800.457.8837	crcsolar.com
Creotecc Solar Mounting Systems	Scotts Valley, CA	831.438.9000	creotecc.us
Daetwyler Clean Energy	Huntersville, NC	704.659.7474	daetwylerce.com
DPW Solar	Albuquerque, NM	505.889.3583	dpwsolar.com
Exosun	South San Francisco, CA	415.422.9625	exosun.net
First Solar	Tempe, AZ	877.850.3757	firstsolar.com
GameChange Racking	New York, NY	212.359.0205	gamechangeracking.com
GenMounts	Flemington, NJ	908.788.7750	www.genmounts.com
Haticon Solar	Ontario, CA	866.489.4472	haticonsolar.com
Ideematec U.S.A.	San Francisco, CA	415.248.7806	ideematec.de
IOI Solar	Middleburg Heights, OH	440.260.0000	ioisolar.com
IronRidge	Hayward, CA	800.227.9523	ironridge.com
KB Racking	San Francisco, CA	888.661.3204	kbracking.com
Mecasolar	West Sacramento, CA	916.374.8722	mecasolar.com
Mounting Systems	West Sacramento, CA	855.731.9996	usa.mounting-systems.info
NU-Cell Technologies	West Monroe, LA	318.397.4147	nu-cellsolar.com
Orion Solar Racking	Commerce, CA	310.409.4616	orionsolarracking.com
PanelClaw	North Andover, MA	978.688.4900	panelclaw.com
Patriot Solar Group	Albion, MI	517.629.9292	patriotsolargroup.com
Polar Racking	Toronto, ON	519.915.7600	polarracking.com
Professional Solar Products	Oxnard, CA	805.486.4700	prosolar.com
PV Racking	Southampton, PA	610.990.7199	pvracking.us
RBI Solar	Cincinnati, OH	513.242.2051	rbisolar.com
Schletter	Shelby, NC	888.608.0234	schletter.us
S:FLEX	Sheridan, CO	303.522.3974	sflex.com
SnapNrack	San Luis Obispo, CA	877.732.2860	snapnrack.com
Solar FlexRack	Youngstown, OH	888.380.8138	solarflexrack.com
SolarWorld	Camarillo, CA	805.388.6590	solarworld-usa.com
Solstice Manufacturing	Flemington, NJ	908.284.0096	solsticemanufacturing.com
SunLink	San Rafael, CA	415.306.9837	sunlink.com
SunModo	Vancouver, WA	360.844.0048	sunmodo.com
Sun Storage	Joseph, OR	541.426.5999	sunstorage.org
Solarpark	San Leandro, CA	510.483.7200	solarparkusa.com
TerraSmart	Estero, FL	239.362.0211	terrasmart.com
Unirac	Albuquerque, NM	505.242.6411	unirac.com
Zilla	Lafayette, CO	855.670.1212	zillarac.com

Table 1 This table provides contact information for manufacturers of fixed-tilt ground-mount racking systems. To be well suited for utility-scale partnerships, manufacturers should provide products with integrated grounding, wire management and other time-saving installation features in addition to offering geotechnical, design, engineering and on-site construction support.

Single- and Dual-Axis Tracking System Manufacturers

Vendor	Headquarters	Phone	Website	Type of tracking system offered	
				Single-axis	Dual-axis
AllEarth Renewables	Williston, VT	802.872.9600	allearthrenewables.com		x
Array Technologies	Albuquerque, NM	855.872.2578	arraytechinc.com	x	x
BYD	Los Angeles, CA	213.748.3980	byd.com	x	
Exosun	South San Francisco, CA	415.422.9625	exosun.net	x	x
First Solar	Tempe, AZ	877.850.3757	firstsolar.com	x	
Ideematec U.S.A.	San Francisco, CA	415.248.7806	ideematec.de	x	
Kinematics Manufacturing	Phoenix, AZ	623.780.8944	kinematicsmfg.com	x	x
Mecasolar	West Sacramento, CA	916.374.8722	mecasolar.com	x	x
Morgan Solar	Toronto, ON	416.203.1655	morgansolar.com		x
Ontrack Solar	Dallas, TX	214.466.7984	ontracksolar.com		x
Orion Solar Racking	Commerce, CA	310.409.4616	orionsolarracking.com	x	
Patriot Solar Group	Albion, MI	517.629.9292	patriotsolargroup.com	x	x
PV Trackers	Bend, OR	541.389.1359	pvtrackers.com		x
QBotix	Menlo Park, CA	650.521.0286	qbotix.com		x
Solar FlexRack	Youngstown, OH	888.380.8138	solarflexrack.com	x	
Solaria	Fremont, CA	510.270.2500	solaria.com	x	
Sonnen Systems	Mississauga, ON	416.305.2977	sonnensystems.com		x
SPG Solar	Petaluma, CA	800.815.5562	spgsolar.com	x	
SunPower	San Jose, CA	800.786.7693	us.sunpower.com	x	
Sun Storage	Joseph, OR	541.426.5999	sunstorage.org		x
Solarpark	San Leandro, CA	510.483.7200	solarparkusa.com	x	
The Solar Tracker Company	Hampton, NJ	908.713.1569	thesolartrackercompany.com	x	
Unirac	Albuquerque, NM	505.242.6411	unirac.com	x	
USTSOLAR	Sacramento, CA	916.446.0023	ustsolar.com	x	

Table 2 This table provides contact information for companies that manufacture single-axis and dual-axis ground-mount tracking systems. For large projects, tracker manufacturers typically provide engineering and construction support and commissioning services to ensure the system is properly designed and constructed.

tilted or vertical axis. Dual-axis tracking systems rotate around two axes, tracking the sun more accurately than does a single-axis system. A dual-axis system yields the most energy per kW. See Table 2 for manufacturers of tracking systems.

In areas with high wind or snow loads, tracking systems typically require stronger—or more—foundations and components than do fixed-tilt systems. Up-front and O&M costs are higher with tracking systems, but the increased energy production may be worth the investment.

Do you recommend fixed-tilt or tracking systems for utility-scale ground-mount applications? What factors influence which type of system is best for a project?

"Many factors determine whether a fixed system or a tracked system should be installed at any given site. Analyzing the increased power harvest in conjunction with the PPA structure, land costs, and construction or topography challenges factor into the decision. Many people focus on the perceived reliability delta between fixed versus tracked systems. This should be negligible if the tracker system is well designed.

"In most medium-sunny to sunny regions of the world, such as the Southwest, Rocky Mountain and Southeast regions of the US, and barring any insurmountable terrain issues, choosing a single-axis tracker is usually a no-brainer. In less sunny areas of the country, an LCOE analysis comparison between a single-axis tracker and a fixed-tilt system should be completed to make an informed decision. A proper comparative LCOE analysis considers—at a minimum—the following factors to determine which system will provide the lowest cost of energy: energy production; installed cost; land cost; O&M costs; reliability, uptime and structural failure risk assessment; and time-of-day rate multipliers."

—Eb Russell, VP of sales, and Ron Corio, CEO, Array Technologies

"Tracking systems can deliver significant performance and financial benefits to utility-scale ground-mount system owners as compared to fixed-tilt systems. However, you must take into account several factors when designing the right system for a given project. For any ground-mounted installation, site topography and historical weather patterns have a major impact on system output, so you should carefully analyze them. When deciding between fixed-tilt and tracking systems, other factors to consider include the size of the project site, potential gains in energy harvest, LCOE and expected rate of return on investment. When it comes to utility-scale ground-mount systems, horizontal single-axis trackers are the most commonly deployed."

— Jay Johnson, Exosun

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Courtesy Array Technologies

Achieving scale Silver Ridge Power developed this 265.7 MWdc PV plant, which is one of the world's largest single-axis array tracking systems. Over 3 million First Solar modules are deployed on Array Technologies trackers at the Calexico, California, site.

"Fixed-tilt systems became the dominant choice several years ago, mainly because of decreased up-front cost and low maintenance requirements. Lately, with the cost coming down and maintenance issues being minimized for trackers, the additional power generation created from tracking systems now [makes them] a very competitive option to fixed tilt. The return-on-investment period has shortened and more energy gets generated over the life of the project."

—Tom Racioppo, Schletter

"The decision to use a fixed-tilt or a tracking system depends on numerous factors, including the project location; the available direct normal irradiance, or DNI; the presence or absence of a time-of-use utility rate structure; and the financial nature of the PPA. Utility-scale tracking systems tend to make sense in areas such as California, as its utilities offer higher payments for the produced energy during peak load periods in summer months. Fixed-tilt systems are found more in the eastern US, as these utilities do not tend to have time-of-use rates. Other factors that come into play are wind and snow loads at the project site, the topography of the site—fixed-tilt systems generally have greater adjustability than tracking [systems]—and the O&M costs of a fixed-tilt versus a tracking system."

—Steve Daniel, Solar FlexRack

When your company employs tracking systems, are they typically single- or dual-axis systems? What primary factors influence this decision?

"For large-field utility-scale projects, single-axis horizontal trackers make sense over other tracking geometries for the following reasons: Single-axis horizontal trackers shade in one direction only and therefore provide the highest energy density of any tracker geometry for a large-field system. These tracking systems can approach GCRs comparable to [those of] fixed-tilt systems. Because they are generally low profile and supported by multiple columns, the size of the structure and foundation are smaller when compared to tilted-up single-axis tracker geometries. Single-axis horizontal trackers are typically less complex and can be mechanically linked together to minimize active components to maximize performance and reliability and minimize long-term maintenance issues. Finally, these tracking systems typically deliver the most efficient use of materials and therefore the shortest energy payback period for a PV power plant.

"Europe has had extensive experience with complicated dual- and single-axis tracking systems. These complex systems were installed during periods of higher module prices and high feed-in tariffs. They are generally complicated, with many small motors, position sensors and complex controls. Some have experienced structural issues. Mostly they have proven to be unreliable and too costly to maintain. They have therefore eventually become expensive, unoptimized 'fixed' racks that put projects at financial risk.

"This negative tracker experience in Europe created a perceived problem with all trackers and became a hurdle that manufacturers had to overcome to gain customer acceptance. The key to success is to use proper, well-tested structural designs, coupled with low complexity, minimization of active parts and proven mechanical drives, to ensure maximum uptime, minimum maintenance and long-term performance to successfully meet the financial goals of the project."

—Ron Corio, Array Technologies

Addressing Site Conditions and Challenges

Utility-scale projects are subject to a variety of conditions and challenges that can be addressed during design and construction to help maximize the return on investment by avoiding production losses due to equipment or foundation failures, shading from overgrown vegetation, vandalism or theft. With proper engineering assessments, system designers can enhance the foundation design and layout as well as racking system components to address sites with high wind or snow loads. To minimize plant growth that can shade modules, it is best practice to plant ground cover or install a weed-inhibiting medium. Lastly, it is interesting to

Installing a Utility-Scale Ground-Mount PV System on a Superfund Site

The Maywood Solar Farm is an 8 MWac PV facility constructed and operated by Hanwha Q CELLS. As part of Indianapolis Power & Light's Rate Renewable Energy Production Program, the utility-scale ground-mounted system will produce an estimated 14,600 MWh of electricity annually over the 15-year PPA term.

The solar farm is located on 46 acres of relatively flat industrial land within the city limits of Indianapolis on a US Environmental Protection Agency (EPA) Superfund site. From 1921 to 1972, the site functioned as a creosote wood treatment facility for railroad ties. Creosote leached into the soil and groundwater. In 1984, the site was listed on the EPA's National Priorities List. The PV project required a tailored solution to minimize soil disturbance and potential hazards to site construction workers.

Beginning in 1992, the site was remediated, and has since successfully completed three EPA Five-Year Reviews. The site is currently in monitoring-only status that allows for light industrial use. Hanwha Q CELLS worked in concert with the EPA, the Indiana Department of Environmental Management and the site owner, Vertellus Specialties, to develop and execute a soil disturbance mitigation plan. The plan included a variety of design and construction approaches to address potentially hazardous site conditions and ensure worker safety. The measures used to minimize soil disturbance included clearing and grubbing procedures, the use of cable tray for the electrical collector system, pole-mounted medium-voltage equipment and a highly flexible implementation strategy for the ground-mount racking system.


Courtesy Hanwha Q CELLS

Aboveground array conductors
Due to safety concerns with excavating on a Superfund site, installers used cable tray systems to support and route conductors within this utility-scale ballasted ground-mount system.

With a total dc system capacity of 10.86 MW, the PV array consists of 36,556 Q.Pro L Series 72-cell polycrystalline modules. The solar farm includes eight 1 MW GE Brilliance PowerStation Skids with integrated dc recombiners, ac transformers and auxiliary power. The medium-voltage interconnection uses a gang-operated switch, recloser, fused cutouts and metering equipment. For the racking system, Hanwha Q CELLS partnered with Solar FlexRack (SFR). The solar modules are mounted at a 20° tilt facing due south on SFR's FlexRack utility ground-mount racking system. The racking foundation system utilizes a combination of SFR SmartPosts and concrete ballasts. In addition to serving as the foundation for the racking system, the SFR SmartPosts function as cable tray support members, which allowed installers to avoid trenching and reduced the number of ground penetrations.

The racking system implementation strategy that Hanwha Q CELLS and SFR developed used a matrix for adapting the racking system foundation to field conditions. This matrix included specific guidance on pile outboard and inboard tolerance to avoid subsurface features, and soil disturbance minimization procedures for pile refusal and concrete ballast installation.

—Bernie Blazier, senior project engineer, Hanwha Q CELLS

consider how EPC contractors protect and secure such large sites against theft and vandalism.

What techniques can you employ on sites with high wind or snow loads?

"You can address single-axis tracking sites with high wind loads by reducing the span of the module row, increasing torque-tube strength, applying additional harmonic dampers to exterior rows, and lowering the profile of the system by reducing post height or positioning modules in a single-in-landscape configuration.

"For high snow loads, you can increase the torque-tube strength, reduce the overall number of modules per drive to minimize the total overhung weight load, and apply high-clearance module clamps or rails to account for deflection."

—Eb Russell, Array Technologies

"Generally, fixed-tilt systems are employed on sites with high wind or snow loads. Most tracking systems must move into a flat-stow position at high wind speeds, which eliminates the tracking advantage. High snow loads increase stress on structural members and components, so tracking systems require additional steel and other materials, driving up costs and reducing the financial benefits.

"Fixed-tilt racking pitched at a higher tilt angle sheds snow well. In high snow areas, you must leave open space between modules in the north-south direction for CONTINUED ON PAGE 32


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drainage between modules. Without this gap, snow accumulates on the modules for long periods of time, reducing power output and potentially causing damage to the panel when freezing occurs."

—Steve Daniel, Solar FlexRack

What is the ideal ground-cover medium for utility-scale ground-mount sites?

"From a botanical point of view, this depends on where the site is located and its plant hardiness zone. Qualitatively speaking, low-growing perennial ground cover like Dutch white clover is a good option due to its minimal mature plant height. Such species reduce mowing and general landscaping requirements. The challenge is establishing these covers among the clutches of the invasive endemic species that already inhabit the site."

—David Del Vecchio, Strata Solar

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Design Requirements for PV Tracking Systems

It is important to understand the meaning of ASCE Occupancy Categories and their effects on structural design. In selecting an Occupancy Category (OC), designers are choosing the mean recurrence interval they are designing for. As an OC goes up, the wind speed for which you are designing the system increases since the wind recurrence interval widens. An OC I design wind interval is limited to 25 years, while an OC II design wind interval is extended to 50 years. A PV project with an expected design life of 25-plus years will almost certainly exceed an OC I wind speed. Assuming that you apply typical structural factors to the tracker, you can convert this to a probability of failure based on statistical wind data, summarized in Table 1.

Failure Risk Based on Occupancy Categories

ASCE Occupancy Category (OC)	Structural strength	Failure risk per year	Failure risk per 25 years
OC II, proper design	100%	0.2%	4.1%
OC I, proper design	87%	0.3%	6.9%
OC II, poor design	80%	0.5%	11.8%
OC I, poor design	70%	1.3%	27.0%
OC I, very poor design	50%	5.6%	76.0%

Table 1 Applying less-conservative design techniques increases the structural failure risk of array tracking systems.

As part of our fundamental design philosophy at Array Technologies (ATI), we design our single-axis horizontal solar tracker, the DuraTrack HZ, to OC II, Importance Factor 1. We think this is essential to secure the investments made in the structure and maintain its serviceability over the design life of the tracker and the project as a whole.

Another important consideration is to design the tracker for full-design wind speed and at all possible tracking positions. Relying solely on the tracker's wind-stow capability—although a nice safety feature—is not fail-proof, and the designer should back it up with another power source such as an uninterruptible power supply. Designing to rely solely on wind stow is tempting because it can reduce structural requirements considerably, but it can also significantly increase risk.

Courtesy Array Technologies

Horizontal single-axis tracker Array Technologies has observed strong field performance from its DuraTrack HZ, with nearly 2 GW installed to date.

Swinerton Builders recently installed ATI's DuraTrack HZ at four projects in Kern County, California, totaling 63 MWdc. Recent wind events in this area left our trackers undamaged.

—John Williamson, engineering manager, Array Technologies

Project Summary

Project details	
EPC contractor	Swinerton Builders
System size	63 MWdc total, four individual projects
Location	Kern County, CA
Module type	Yingli 72-Cell Module (YGE-U72-YL300P-35b)
Racking system	DuraTrack HZ single-axis horizontal solar tracker
Foundation type	I-Beam
Row spacing	Variable between projects
Module orientation	1 in portrait
Estimated annual kWh	183,960,000
Unique design considerations	100 mph wind speed

Table 2 This table summarizes the project details for four projects installed in Kern County, CA, using ATI's DuraTrack HZ horizontal single-axis tracking system.

"In general, desert ground cover or small gravel is ideal. Small gravel costs more, but it is particularly effective at minimizing plant life that could potentially shade the array, and it provides valuable erosion control for the site."

—Jason Grissom, SunEdison

What types of security measures are used to protect utility-scale ground-mount projects?

"After construction is complete, utility-scale ground-mount projects are typically secured with fences containing barbed wire and security cameras with infrared capabilities. Customers requiring a heightened level of security may use modules with a security fastener, built-in serial numbers or markings that list the project owner. The customer usually dictates the level of security, which typically depends on the size, location and significance of the project."

—Paul Aggarwal, VP of operations, Cupertino Electric, cei.com

"In addition to fencing, utility-scale ground-mount systems use stand-alone camera systems and fence disturbance products to provide security and prevent intrusion."

—Will May, Prime Solutions

Courtesy SunLink

Installing on a landfill These precast concrete ballast blocks from SunLink allowed Borrego Solar to install this utility-scale ground-mount project on an existing landfill without penetrating the earth.

Concluding Thoughts

Partnerships between EPC contractors and manufacturers improve the efficiency and quality of utility-scale ground-mounted projects. These benefits help achieve the LCOE needed to keep utility-scale PV generation competitive. Despite significant improvement in product offerings and services from utility-scale fixed-tilt and tracking manufacturers, feedback from users in the field is always essential to developing elegant solutions.

Do you need additional features or services from utility-scale ground-mount racking system manufacturers?

"Many fixed-tilt racking systems require installers to climb on ladders above the modules to securely fasten them to the racking structure. Making the attachment accessible from underneath the module would significantly improve safety and installation time.

"In addition, manufacturer warranties often exclude failures due to corrosion, which forces contractors to hire corrosion protection engineers to develop corrosion-protection solutions. It would be extremely beneficial from a cost and management perspective if racking system manufacturers would provide corrosion-protection solutions that are covered by their warranty.

"Another way that racking system manufacturers could increase [the value of their products] is by offering packaging and transportation solutions to minimize on-site storage concerns."

—Paul Aggarwal, Cupertino Electric

"It is important that racking manufactures work to develop a variety of foundation styles that are suitable for the many different soil types an EPC contractor encounters during construction to avoid additional—and often unexpected—costs of drilling or ballasting."

—Will May, Prime Solutions

"Wire management integrated into the initial product design and a defined grounding point with supplied grounding hardware would be very useful. Such features would reduce the amount of time spent in the field searching for or developing solutions."

—David Del Vecchio, Strata Solar

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Courtesy NFPA

Understanding the NEC 2014 and Its Impact on PV Systems

By Rebekah Hren and Brian Mehalic

The continued safety, growth and success of the solar industry requires that PV systems be designed and installed to meet the minimum standards set forth in *NFPA 70,* which is more commonly known as the *National Electrical Code.* It is always exciting when a new version of the *NEC* is finally available, as this document represents the culmination of years of hard work by many individuals and organizations. It also sets the stage for evolving design and installation practices. The goal of these changes is to make PV systems safer for building owners and occupants, service technicians and first responders. While an updated edition of the *NEC* is published every 3 years, adoption dates for new editions vary significantly by state or local jurisdiction.

The National Fire Protection Association (NFPA) was established in 1896 with the goal of reducing the burden of fire and other hazards. Since 1911, this nonprofit organization has sponsored development of the *NEC,* which documents mandatory and permissive standards meant for enforcement by governmental bodies that have legal jurisdiction over electrical installations. The *Code* is a consensus document developed from public input. While volunteer members of technical committees known as *Code-Making Panels (CMPs)* vote on all additions, deletions or other changes to the *NEC,* the *Code*-making process includes a public review and comment period. (For more information on this process, see "Code Red: Notable Changes in the 2011 *NEC,*" *SolarPro* magazine, April/May 2011.) CMP No. 4 is responsible for Article 690, "Solar Photovoltaic (PV) Systems," and Article 705, "Interconnected Electric Power Production Sources," which are of particular interest to PV system designers and installers, as well as Articles 225, 230, 692 and 694.

Regardless of when the local AHJ officially adopts the 2014 edition of the *National Electrical Code,* PV system designers and installers need to stay up to date with the most recent *Code* requirements, since these invariably influence product development and drive industry best practices.

Here we focus on the most significant *NEC 2014* changes related to the design and deployment of PV systems, particularly those found in Articles 690 and 705. We also discuss some general *Code* changes from Chapters 1 through 4. Since the scope of this article is selective rather than encyclopedic, there are many *NEC 2014* changes that we do not touch on. Unless logic dictates otherwise, we discuss the revised *Code* sections in numerical order.

Note that the usual caveats apply. As discussed in *NEC* Section 90.1(B), simply meeting the minimum requirements outlined in the *NEC* is no guarantee that an electrical installation will prove adequate. For a PV system to perform efficiently and reliably over time or to be aesthetically pleasing, PV system designers and installers may need to adhere to industry best practices that exceed minimum *Code* requirements. The final arbiter regarding the acceptability of electrical equipment and installation methods is always the local AHJ. While we interviewed members of CMP No. 4 and other industry subject matter experts to help explain the intent and implications of some of the most intricate *NEC 2014* revisions, the interpretations presented here are just well-informed opinions come inspection time. Ultimately, the opinion that matters is the AHJ's.

General *Code* Changes

As outlined in Section 90.3, *NEC* Chapters 1 through 4 apply generally to all electrical installations and are modified or supplemented by the special requirements found in Chapters 5 through 7.

ARTICLE 100 "DEFINITIONS"

Though referred to in numerous other Articles, prior to *NEC 2014,* the definition of a *photovoltaic system* resided in Article 690. As part of the 2014 cycle of revisions, the *NEC* Technical Correlating Committee (TCC) directed CMP No. 4 to move the definition of *solar photovoltaic system* from Section 690.2 to Article 100, which includes terms that are used in two or more Articles. In the process, CMP No. 4 eliminated the word *solar* from the definition and added the abbreviation *PV* to set the stage for its use elsewhere. As a result, a new entry in Article 100 defines a *photovoltaic (PV) system* as: "The total components and subsystem that, in combination, convert solar energy into electric energy suitable for a connection to a utilization load. "

SECTION 110.21(B) "FIELD-APPLIED HAZARD MARKINGS"

Electrical systems in general, and PV systems in particular, require numerous plaques, labels, directories and signs. In practice, the materials that contractors use for field-applied signs or labels range from the clearly inadequate (laminated paper used in outdoor locations) to exemplary (engraved metal). Further, different contractors and facility operators tend to use different styles for labels, in terms of both the label color and the text color, size and font.

While field-applied labels and signs are inherently project and application specific, Section 110.21(B) seeks to standardize marking requirements for improved safety. The

Courtesy HellermannTyton

Adequate warning An informational note under Section 110.21(B)(1) clarifies that ANSI Z535.4-2011 provides guidelines for suitable font sizes, colors and symbols for field-applied hazard markings. This warning label from HellermannTyton conforms to this ANSI standard for "Product Safety Signs and Labels."

intent of the new language is to more effectively identify and communicate potential hazards in the field by improving the consistency with which *Code*-mandated hazard labels are deployed. In effect, these labels must provide adequate warning, be permanently affixed and be sufficiently durable.

Per Section 110.21(B)(1), field-applied hazard markings "shall adequately warn of the hazards using effective words and/or colors and/or symbols." Per 110.21(B)(2), the label "shall be permanently affixed to the equipment or wiring method." While this section also states that hazard markings in general "shall not be handwritten," an exception is provided for specific portions of the label or marking that are variable or subject to change. Lastly, per 110.21(B)(3), the label "shall be of sufficient durability to withstand the environment involved."

Note that labeling and marking requirements found throughout the *Code*—including many of those in Article 690—now refer back to Section 110.21(B). While the adequacy

Not handwritten According to new language in Section 110.21(B)(2), field-applied hazard labels—like the ones on this dc disconnect—cannot be handwritten, except for those portions of a label that are variable or could be subject to change.

Courtesy Sun Light & Power

and durability of field-applied hazard markings is potentially subjective, two informational notes in this section refer to the *American National Standard for Product Safety Signs and Labels* (see Resources), otherwise known as ANSI Z535.4-2011, for application guidelines. This standard includes guidelines for appropriate colors based on signal words such as "Danger," "Warning" or "Caution." It describes the letter style and size required for a label's signal word panel and message panel, as well as location requirements related to visibility. It also addresses durability, in terms of label life expectancy and replacement requirements. Except where more stringent local requirements apply, AHJs are likely to accept labels and signs designed to meet this ANSI standard.

Todd Fries is a member of CMP No. 4 and the marketing manager for identification systems at HellermannTyton. Regarding material durability, Fries explains: "The *NEC* and other codes, like the *International Fire Code,* do not specify a unit of time that a label must withstand the environment. Typically, these codes simply state that the label must be suitable for the environment where it is installed. This does not mean that the label must last the life of the installation. Everything wears out over time, including PV modules, inverters and other system components. However, Article 10.2.2 of ANSI Z535.4-2011 does state that a label shall be replaced when it becomes unreadable."

To protect against premature failures and recurring replacement costs, Fries recommends that system integrators request label-material durability information and accelerated aging test data from the product vendor or manufacturer.

SECTIONS 210.5(C) AND 215.12(C)
"IDENTIFICATION OF UNGROUNDED CONDUCTORS"

A subgroup of a dc task group established by the *NEC* TCC developed new language for these sections to specifically address conductor identification in dc applications. According to the *National Electrical Code Committee Report on Proposals (ROP)* (see Resources), the intent of these changes is to standardize the polarity identification schemes used across different dc electrical applications, including electrical vehicle charging, small wind systems, dc microgrids and PV systems. It is important to recognize that these new identification requirements apply to ungrounded branch circuit [210.5(C)(2)] and feeder [215.12(C)(2)] conductors in dc utilization (load) circuits only. CMP No. 4 rejected a proposal to add these color-coding requirements to Section 690.4(B), noting: "The proposed wiring method is too prescriptive and may disallow other legitimate marking methods."

According to Greg Ball, a principal engineer with DNV GL Renewables, "PV source and output circuits should not be confused with dc branch circuits and feeders in a way that supersedes Article 690." Whereas feeders *supply* power to branch circuits, PV output circuits *aggregate* power from

PV source circuits. These circuits may be analogous, but they are not identical. Since Article 690 refers to Article 210 only in relation to dc utilization circuits—circuits supplying dc loads, in other words—the ungrounded dc branch-circuit conductor identification requirements in Section 210.5(C)(2) do not apply to PV source circuits. Likewise, the ungrounded dc feeder conductor identification requirements in Section 215.12(C)(2) do not apply to PV output circuits.

ARTICLE 490 "EQUIPMENT OVER 1,000 VOLTS, NOMINAL"

Whereas previous editions of the *Code* defined *high voltage* in Article 490 as "more than 600 volts, nominal," *NEC 2014* changed this definition to "more than 1,000 volts, nominal." Other articles throughout the *Code* generally echo this revision. For example, while the title of Part IX of Article 690 previously read "Systems over 600 Volts," it now reads "Systems over 1,000 Volts." This voltage threshold increase will likely have more of an impact on the way PV systems are designed and deployed in the future than any other general *Code* change in *NEC 2014.*

The High-Voltage Task Group (HVTG) established by the TCC proposed making this *Code*-wide change to address the higher dc system voltages that are common in wind generation and PV systems. As noted in the *National Electrical Code Committee Report on Comments (ROC),* PV systems "are currently being installed at dc voltages over 600 V up to and including 1,000 V, 1,200 V, 1,500 V and 2,000 Vdc." To keep the *Code* in sync with evolving product standards and installation practices, the HVTG determined that the *Code*-wide approach was called for, starting with Article 490.

The rationale behind the HGTV's proposal for the new 1,000-volt threshold is explained in the *ROC:* "If the *NEC* does not adequately address systems over 600 volts, some other standard will. If we want to control the future safety of installations over 600 volts, we need to address these issues today." The HGTV also notes: "Moving the *NEC* threshold from 600 volts to 1,000 volts will not, by itself, allow the immediate installation of systems at 1,000 volts. Equipment must first be tested and found acceptable for use at the higher voltage(s)."

In other words, elevating the high-voltage threshold does not magically turn 600-volt–rated equipment into 1,000-volt–rated equipment. Not only does equipment used in 1,000-volt systems need to be evaluated and listed at 1,000 volts, but so do the meters, tools and personal protective equipment installers use. It is also important for PV system designers and

Courtesy Fluke and KNIPEX

1,000 V rated? In *NEC 2014,* the threshold for higher-voltage equipment and requirements has been increased from 600 volts to 1,000 volts. While this will pave the way for 1,000-volt PV systems, safety personnel and service technicians need to ensure that equipment used in the field—including meters and tools—is appropriately rated.

installers to note that references to 600 volts were not universally changed to 1,000 volts throughout the entire *Code.* For example, Part II of Article 110 is still titled "600 Volts, Nominal, or Less" and Part III is still "Over 600 Volts, Nominal." This means that pre-existing voltage thresholds for working space requirements and minimum distances from live parts and so forth are carried over into the new *Code* edition. Further, the maximum allowable PV system voltage for one- and two-family dwellings is still 600 Vdc, as stated in Section 690.7(C). (For more information on designing and deploying *Code*-compliant 1,000-volt PV systems, see "1,000 Vdc Utilization Voltages in Nonresidential PV Applications," *SolarPro* magazine, April/May 2013.)

PV-Specific *Code* Changes

Articles in *NEC* Chapter 6 apply to "Special Equipment," and Article 690 applies specifically to PV systems. Section 690.3 specifies that the mandatory and permissive requirements in Article 690 may modify those found in Chapters 1 through 4: "Wherever the requirements of other articles in this *Code* and Article 690 differ, the requirements in Article 690 shall apply."

SECTION 690.5 "GROUND-FAULT PROTECTION"

As stated in the *ROC,* "Undetected ground faults on grounded conductors have caused several fires in PV systems over the last decade." The best documented of these PV fires occurred in Bakersfield, California, on April 5, 2009. (See "The Bakersfield Fire: A Lesson in Ground-Fault Protection," *SolarPro* magazine, February/March 2011.) Rather than wait for product safety standards to address the blind spot in inverter ground-fault detection that caused fires such as this, CMP No. 4 unanimously accepted a proposal to add the following new language (emphasis added) to Section 690.5(A)(1): "[The ground-fault protection system shall] be capable of detecting a ground fault in the PV array dc current-carrying conductors and components, *including any intentionally grounded conductors.*"

Bill Brooks, the principal at Brooks Engineering and a member of CMP No. 4, notes: "PV system designers must either select inverters with this functionality or add it as part of the system design." Generally speaking, the ground-fault detection blind spot is unique to grounded inverters and does not affect ungrounded, non-isolated inverters, which include the UL code "TL" (for transformerless) in their listing. A technical report published by the Solar America Board for Codes and Standards (SolarABCs) details seven possible ground-fault detection and mitigation methods that apply when an inverter does not meet Section 690.5(A)(1), several of which installers can deploy in the field (see Resources).

Ball, one of the authors of the SolarABCs report, is optimistic that system integrators will have a range of compliant products to choose from by the time *NEC 2014* is widely adopted. He explains: "Non-isolated single and 3-phase string inverters already provide the necessary protection. Manufacturers of small- to mid-sized grounded inverters should be able to implement residual current detection or periodic insulation resistance check methods reasonably quickly. For PV systems based around large central inverters, there should be dc output-circuit combiners available that have detection and isolation capabilities, even if the inverter itself does not. The challenge in the near term is that integrators may need to work with dc combiner manufacturers to develop *NEC 2014*–compliant ground-fault protection solutions." CONTINUED ON PAGE 42

He continues: "I am personally interested to see if high-accuracy electronic sensing of the line-to-ground connection in grounded systems can be implemented effectively, especially in large central inverters. We've already seen this approach work in resistively grounded systems using modules prone to PID [potential induced degradation]. If it works for large central inverters, it could be a more cost-effective approach than using multiple residual current detectors on individual dc feeders, since simpler single-pole current transformers could instead be used at the feeder level for arc-fault and reverse-current detection."

Since periodic insulation resistance testing—usually performed daily at start-up—is one method that inverter manufacturers may use to detect ground faults, permissive language was added to Section 690.5(A) that allows the inverter to temporarily open the grounded conductor for measurement purposes. This new language addresses concerns that some AHJs have voiced related to ungrounding a grounded conductor, albeit temporarily.

Exception. Note that *NEC 2014* provides only one exception to Section 690.5, which applies to ground- or pole-mounted PV systems isolated from buildings with no more than two paralleled source circuits. The previous *Code* edition provides a second exception for PV systems in non-residential applications

Courtesy PowerSecure Solar

Ground-fault detector PowerSecure Solar has developed and deployed custom ground-fault detection solutions for its large-scale PV projects. In addition to providing ground-fault detection for intentionally grounded conductors per Section 690.5(A)(1), the assembly shown here is also a contactor power supply that can initiate rapid shutdown per Section 690.12.

where installers sized the equipment-grounding conductor in accordance with Section 690.45. This second exception and the related text in Section 690.45(B) were deleted as part of the 2014 revisions. The remaining exception covers very few PV systems.

SECTION 690.9 "OVERCURRENT PROTECTION"

Section 690.9(A) now provides additional clarification regarding the proper location of overcurrent protection devices (OCPDs). Since PV modules and utility-interactive inverters are inherently current limited, overcurrent risk in PV systems is associated with parallel-connected circuits. On the dc side of the system, the risk comes from PV source or output circuits that are connected in parallel. On the ac side of the system, the risk of encountering significantly higher currents comes from the utility grid or inverter output circuits aggregated in parallel. Per Section 690.9(A), all of the ac and dc circuits in a PV system must be protected at the source "of significantly higher current." Thus PV source circuit series fusing is located in combiner boxes, PV output circuit fusing is required in subarray combiners or recombiners, and overcurrent protection for ac circuits is required at the point of interconnection, or where multiple inverters are connected in parallel.

Rating. Whereas Section 690.9(C) previously allowed OCPDs sized in 1-ampere increments up to 15 amps, this language was stripped from *NEC 2014.* Per Section 240.6(A), standard sizes in the sub-15 ampere range are now 1, 3, 6 and 10 amps. This alters the implementation of Section 240.4(B), "Overcurrent Devices Rated 800 Amperes or Less," such that a 15 A fuse can now protect a 14 AWG or larger conductor with a rated ampacity over 10 amps.

Listed for PV. The most meaningful change in this section is found in Section 690.9(D), which now requires the use of "listed PV overcurrent devices" in "PV source and output circuits." While these devices must be accessible, they are not required to be readily accessible.

In the *ROP,* Timothy Zgonena, a principal engineer at Underwriters Laboratories, notes: "Unlike the US power grid and traditional rotating machine power sources with high levels of potential fault current, PV arrays are a high-impedance power source with much lower fault current capability." He continues: "Considerable research and development work has yielded published national and international requirements for overcurrent protective devices that address the specific needs of PV circuits. There are presently UL requirements for the certification of both fuses [UL 2579] and circuit breakers [UL 489B] specifically for dc PV systems."

SECTION 690.10 "STAND-ALONE SYSTEMS"

While Section 408.36(D) generally requires that back-fed plug-in–type circuit breakers be secured in place using an additional fastener, Section 705.12(D)(5) specifically provides an exemption for circuit breakers back-fed from listed utility-interactive inverters, which have a touch-safe ac output circuit absent grid power. New language added to Section 690.10(E) clarifies that this exemption does not apply to those circuit breakers back-fed from stand-alone or multimode inverters that are energized absent grid power. Note that a new definition in Section 690.2 describes a *multimode inverter* as "having the capabilities of both the utility-interactive and the stand-alone inverter." As such, Section 705.12(D)(5) covers the utility-interactive output of a multimode inverter, whereas Section 408.36(D) covers its stand-alone output.

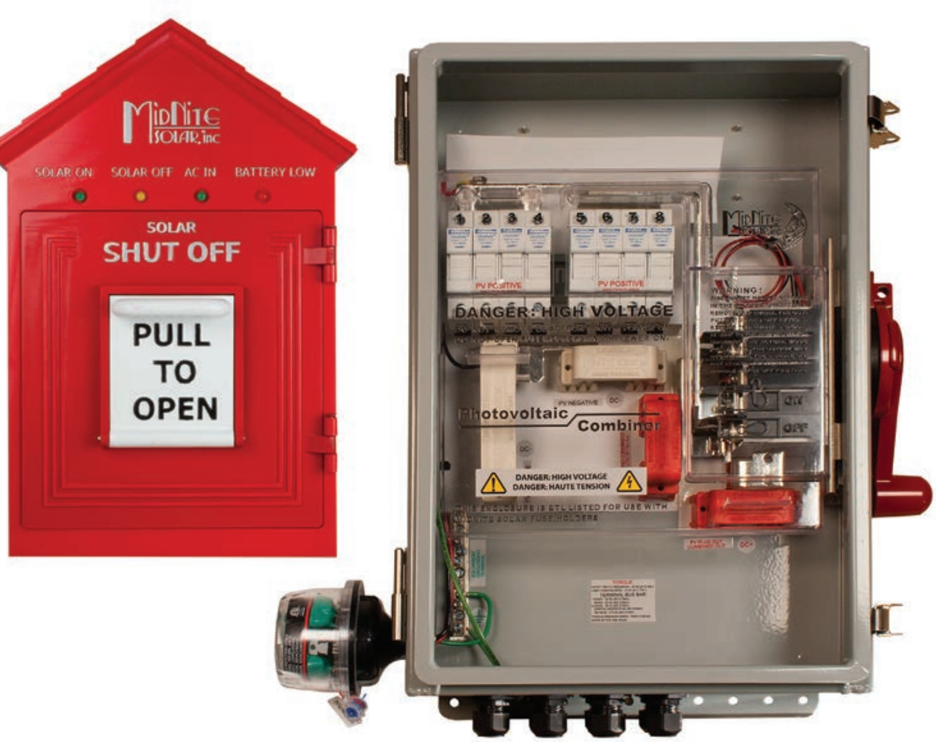
SECTION 690.11 "ARC-FAULT CIRCUIT PROTECTION (DIRECT CURRENT)"

Series arc-fault protection requirements for dc PV circuits were first introduced in *NEC 2011*. However, these requirements applied specifically to PV systems with a maximum system voltage greater than or equal to 80 Vdc, and with dc circuits on or entering a building. In *NEC 2014,* these requirements are expanded to *all* PV systems with a maximum system voltage ≥80 Vdc, regardless of location. As explained in the *ROP:* "PV arc faults in ground-mounted PV arrays can result in grass and brush fires. Such fires can result in deaths and significant property damage, which can be prevented with PV arc-fault protection." Note that the arc-fault protective device must be listed for use in dc PV systems. The applicable product safety standard is UL 1699B, "Photovoltaic (PV) DC Arc-Fault Circuit Protection."

These expanded dc arc-fault protection requirements have immediate and significant implications for PV system designers and installers. When Section 690.11 was originally introduced in 2011, there were no listed devices with which to meet the new dc arc-fault requirements, which slowed adoption and enforcement. For example, Colorado's Department of Regulatory Agencies began enforcing dc arc-fault circuit protection requirements for PV permits issued only after July 1, 2013, even though the state had formally adopted *NEC 2011* 2 years earlier, on July 1, 2011. Now that listed PV arc-fault protection means are available, there is no reason to expect a delay in adoption or enforcement of the expanded *NEC 2014* requirements.

Where the arc-fault protective device is located is largely a function of PV system size and architecture. Listed string inverters with integral dc arc-fault circuit protection are already available from several manufacturers, including Fronius, Power-One, SMA America and SolarEdge. While central inverter manufacturers are less likely to integrate dc arc-fault circuit protection directly into their products, PV system designers can specify combiner box–level solutions that provide this functionality. For example, SolarBOS offers listed 12- or 16-input arc-fault combiner boxes. If they are appropriately listed, dc-to-dc converters like Tigo Energy's module maximizer may be able to provide module-level dc arc-fault protection.

PV system designers and integrators should continue to follow the development and availability of listed PV arc-fault protection devices. Over time, the range of listed options will certainly increase,



Courtesy MidNite Solar

Solar shutoff MidNite Solar's Birdhouse (left) is a ground-level control device or kill switch for a PV array. It allows first responders to de-energize dc circuits in the proximity of the array, as required in Section 690.12, by opening contactors in rooftop combiners (right).

as many manufacturers—including Eaton, E-T-A, Sensata Technologies, Texas Instruments and others—are working to develop cost-effective solutions to meet this growing market demand.

SECTION 690.12
"RAPID SHUTDOWN OF PV SYSTEMS ON BUILDINGS"

The rapid shutdown requirements in Section 690.12 are arguably the most important (and contentious) additions to *NEC 2014*. According to *Code* expert John Wiles, the senior research engineer at the Southwest Technology Development Institute, "The rapid shutdown requirements in 690.12 will have significant and far-reaching impacts on PV system designs and the design of PV equipment."

As originally proposed, for improved electrical and fire safety, Section 690.12 would have required module-level emergency shutdown capabilities for PV systems on buildings. However, the consensus language that was ultimately accepted—developed by members of the CMP No. 4 Firefighter Safety Task Group, the Solar Energy Industries Association (SEIA) Codes and Standards Working Group and the PV Industry Forum—requires that conductors associated with a PV system, whether ac or dc, be able to be de-energized on demand, so that any portion of the conductors that remain energized do not extend more that 10 feet from the PV array or more than 5 feet within a building.

As explained in the *NEC 2014 Handbook:* "First responders must contend with elements of a PV system that remain energized after the service disconnect is opened. This rapid-shutdown requirement provides a zone outside of which the potential for shock hazard has been mitigated. Conductors more than 5 feet inside a building or more than 10 feet from an array will be limited to a maximum of 30 V and 240 VA within 10 seconds of shutdown."

Equipment options. While the equipment used to perform rapid shutdown must be listed and identified, it does not have to be listed specifically for the purpose of rapid shutdown of PV systems. For example, string inverters located on a commercial rooftop within 10 feet of a PV array would meet the requirements of Section 690.12, as would microinverters or ac PV modules installed on the roof of a residence. In both instances, if first responders were to shut down power to the premises, there would be no uncontrolled energized conductors beyond 10 feet of the array.

Listed contactor combiner boxes provide another means of meeting Section 690.12 using off-the-shelf components. Simply locate the contactor combiner boxes within 10 feet of the PV array and find a suitable location for the control switch or button. The contactors will open upon loss of utility power or in the event that the control switch is operated. The voltage and power limits in Section 690.12 still allow for 24-volt control circuits, which can be used to operate contactors in dc combiner boxes and allow for *Code* compliance in the event that the rapid shutdown is initiated by means other than opening the service disconnect. Another design option is to specify dc-to-dc converters that comply with the rapid shutdown requirements for PV systems on buildings.

Identification and location. The power-source identification requirements for facilities with rapid shutdown are found in Section 690.56(C). A permanent plaque or directory must be provided that includes the following text:

**PHOTOVOLTAIC SYSTEM EQUIPPED
WITH RAPID SHUTDOWN**

This label must be reflective, with white capitalized letters (⅜ inch or taller) against a red background. These formatting requirements are consistent with those found in the *2012 International Fire Code*. Reflective labels are intended to both alert first responders to potential hazards—such as conduits containing PV source or output circuits [see 690.31(G)(4)]—and allow them to quickly identify the means for de-energizing these circuits. Ideally, additional language will specify the appropriate shutdown procedure and a directory will identify the extent of the controlled circuits.

Courtesy HellermannTyton

Reflective labels required Per Sections 690.31(G)(3) and (4), wiring methods and enclosures containing PV power-source conductors must be marked with a reflective warning label like the one shown here. The rapid shutdown label required per Section 690.56(C) must also be reflective for ease of identification by first responders.

While the *Code* does not specify where the control point for rapid shutdown equipment is to be located, this is not an oversight. According to Brooks, who submitted the original proposal, the lack of specificity is intended to provide integrators and AHJs with the flexibility to determine the best location for each site. Brook explains: "Since the goal of rapid shutdown is firefighter safety, the ideal control point for the rapid shutdown system is wherever fire service personnel will go to shut off electricity to the site in the event of an emergency. Most of the time, the electric utility control point is at the service disconnecting means. However, there may be situations where the fire department's utility control point for a facility is not the location of the service disconnecting means. Rather than requiring a specific location, Section 690.12 allows for flexibility."

Because PV systems vary considerably in terms of configuration and architecture, this design flexibility is important. For PV systems without energy storage, designers may choose to initiate rapid shutdown whenever utility voltage is lost. In this scenario, PV system circuits on or in a building are controlled whenever a disconnect or circuit breaker in the inverter output circuit is opened, the utility meter is pulled, the main service disconnect is opened, there is a general grid outage and so forth. However, PV systems with energy storage will require a different approach, one that ensures that battery circuits and backup loads shut down only during an emergency and not simply whenever utility voltage is lost.

Courtesy Sun Light & Power

Section 690.12 compliant One of the simpler ways to comply with the rapid shutdown requirements in Section 690.12 is to locate interactive inverters within 10 feet of PV arrays mounted on buildings.

ARTICLE 690 PART III, "DISCONNECTING MEANS"

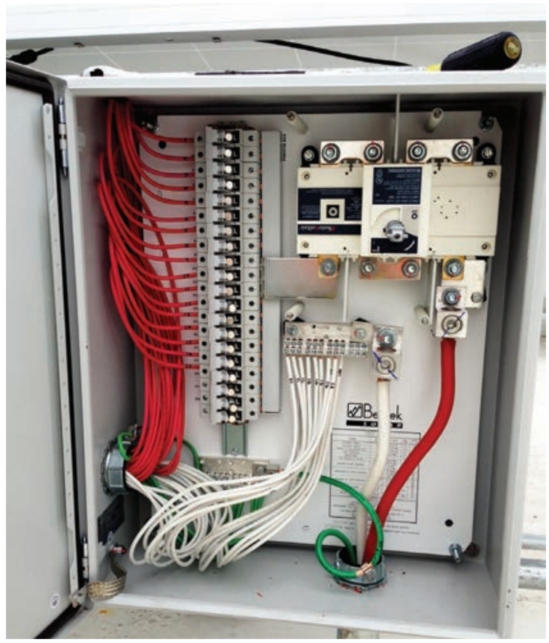
CMP No. 4 implemented a series of revisions to Part III of Article 690 with the goal of making the article easier to use by grouping similar requirements for PV systems together. In previous *Code* editions, requirements related to PV system disconnecting means have been difficult to parse. The lack of clarity was largely due to the way that the requirements were organized.

Jerry Flaherty, an electrical inspector from Long Island, New York, gets to the root of the problem in a detailed substantiation found in the ROP: "[In *NEC 2011,]* 690.13, 690.14 and 690.15 are very confusing requirements. 690.13 is titled 'All Conductors,' yet this article only refers to dc conductors. 690.14 is titled 'Additional Provisions' and is a combination of photovoltaic (PV) system requirements and photovoltaic (PV) power source requirements. 690.15 is titled 'Disconnection of Photovoltaic Equipment,' which logically should be under 'Additional Provisions.'" Flaherty concludes: "A photovoltaic system (usually) requires two disconnects, one on the PV source power (dc) and one on the whole PV system after the inverter, charge controller or before the load. It seems logical to separate these disconnects into two articles and the common requirements into a third article."

While the revised language in Article 690, Part III, still leaves room for improvement, the general clarity of intent is greatly improved in *NEC 2014.*

Section 690.13. Where a PV system supplies a building or other structure, this section requires a means of disconnecting "all ungrounded dc conductors of a PV system from all other conductors in a building or other structure." According to explanatory comments in the *NEC 2014 Handbook:* "These requirements generally prohibit long runs of PV source and output circuits inside a building before reaching the required disconnect." However, an exception is provided for PV source and output circuits installed according to Section 690.31(G). Note that per Section 690.13(G), the PV system disconnecting means shall consist of no more than six switches or circuit breakers, which must be grouped together when mounted in separate enclosures.

Section 690.15. Significantly expanded in *NEC 2014,* this section applies specifically to equipment disconnecting means for isolating PV equipment—including inverters, batteries, charge controllers and dc combiners—from



Courtesy Sun Light & Power

DC combiners The term *direct-current combiner* now appears in the Section 690.2 definitions. Per Section 690.4, all dc combiners must be listed specifically for PV applications. Also, a load-break–rated disconnect is now required within 6 feet of a rooftop-mounted dc combiner per Section 690.15(C). This listed 20-circuit disconnecting combiner from Bentek meets both requirements.

ungrounded conductors from all power sources. It contains some familiar content. For example, Section 690.15(A) now includes the requirements related to utility-interactive inverters mounted in locations that are not readily accessible. Section 690.15(B) offers a clarification: some equipment—such as overcurrent protection, dc-to-dc converters and isolating switches—is permitted on the PV side of the PV disconnecting means.

One of the most significant changes in Part III is found in Section 690.15(C), which requires a load-break–rated disconnect within 6 feet of roof-mounted dc combiners. This disconnecting means must be located on the dc output of the combiner box. While the dc combiner disconnect is allowed to be remotely operable, it must have local provisions for manual operation. The allowance for remote operation facilitates the use of listed contactor combiners to meet the rapid shutdown requirements in Section 690.12, while local operation of the dc combiner disconnect will also benefit PV technicians, who will be able to manually segment the array during commissioning and maintenance.

Section 690.16. Though ground-mounted combiner boxes are conspicuously absent from the new language in Section 690.15(C), disconnecting means will still be required within sight of dc combiners in ground-mounted applications to meet the pre-existing requirements in

Section 690.16. In short, Section 690.16(A) requires disconnecting means from all sources of supply for fuses that are energized on both ends, such as paralleled fuses in PV source and PV output combiners. Section 690.16(B) requires fuse-servicing disconnects on PV output circuits within line of sight of the fuses. While the fuse servicing disconnecting means can be integral with the fuseholder, it must comply with Section 690.17.

Section 690.17. This section is now titled "Disconnect Type." Section 690.17(A) details allowable types of manually operable disconnecting means for ungrounded PV conductors. The list of devices allowed when specifically *marked* for use in PV systems includes industrial control switches (the subject of UL 98B), molded-case circuit breakers and switches (the subject of UL 489B), and enclosed and open-type switches (the subject of UL 508I). Unlike the terms *listed* and *identified,* the term *marked* is not defined in the *NEC,* and is therefore subject to AHJ interpretation. Additionally, certain listed dc-rated devices are allowable, including molded-case circuit breakers and switches that are not marked with "line" and "load," enclosed and open-type switches, and low-voltage power circuit breakers.

Since Section 690.17(A) refers specifically to dc-rated devices, it follows that this section does not apply to inverter ac equipment disconnects, but rather to PV power source disconnects and dc equipment disconnects. The disconnecting means for ungrounded PV conductors may be remotely operable, provided that they can be manually operated in the event of a power supply failure.

According to subsections (B), (C) and (E), the PV disconnecting means shall simultaneously disconnect all ungrounded supply conductors, shall be externally operable and indicate whether it is open or closed, and shall have an adequate interrupt rating. While disconnecting the grounded conductor is generally not allowed, the exceptions previously found in Section 690.13 are now relocated to Section 690.17(D). Also, while connectors are still allowed as ac or dc disconnecting means per the exception to Section 690.17(E), they must now be listed and identified "for use with specific equipment," such as the microinverter or dc-to-dc converter to which they are attached.

SECTION 690.35 "UNGROUNDED PHOTOVOLTAIC POWER SYSTEMS"

While mostly unchanged, this section now allows you to use metallic multiconductor cables (Type MC) as PV source-circuit conductors, in addition to those methods previously allowed. Moreover, ground-fault protection devices for ungrounded dc PV systems must be listed and must detect faults in the dc current–carrying conductors.

SECTION 690.41 "SYSTEM GROUNDING"

This section was substantially revised for *NEC 2014* and now details system-grounding requirements for ungrounded PV systems, grounded two-wire PV systems and grounded bipolar systems. Note that grounded two-wire and bipolar PV systems are now specifically allowed to be impedance grounded. An additional provision allows the use of "other methods that accomplish equivalent system protection in accordance with 250.4," provided the equipment is "listed and identified for the use."

These expanded system-grounding options are an improvement over the language used previously, which required that grounded PV systems be "solidly grounded." However, most grounded PV systems are not *solidly grounded,* as defined in Article 100, but are connected to ground via a fuse or circuit breaker that is part of a listed inverter's ground-fault CONTINUED ON PAGE 50

Green light for cable tray Per Section 690.31(C)(2), listed PV Wire of all sizes can be installed outdoors in cable trays, provided the cables are supported at 12-inch intervals or less and secured every 4.5 feet or less.

Courtesy Sun Light & Power

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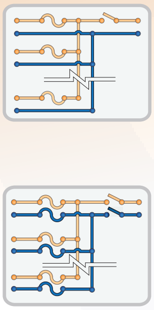

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detection and interruption scheme. According to Wiles' substantiation in the *ROC:* "Removing the 'solidly' requirement makes the *Code* language consistent with the PV inverters and other equipment that are manufactured and listed to UL Standards where an overcurrent device is allowed to make the dc grounding bonding jumper a part of the *NEC*-required ground-fault protection device."

SECTION 690.47 "GROUNDING ELECTRODE SYSTEM"

This section includes some relatively minor revisions for clarity, as well as one major addition that some *Code* experts have condemned as unsafe.

Ungrounded PV systems. In prior *Code* cycles, there was some confusion regarding grounding-electrode conductors for ungrounded systems. Section 690.47(B) now specifically allows use of an ac equipment-grounding system as the ground-fault–detection reference for ungrounded PV systems. In addition, Section 690.47(C)(3) states that a combined dc grounding-electrode conductor (GEC) and ac equipment-grounding conductor (EGC) can be installed for ungrounded systems. This combined dc GEC and ac EGC is sized in accordance with Section 250.122—as an EGC, in other words—and is not required to be larger than the largest ungrounded phase conductor. Note that this combined grounding conductor must still be unspliced or irreversibly spliced.

As an example, if a non-isolated inverter's ac output circuit back-feeds a 30 A circuit breaker, the combined dc GEC and ac EGC between the inverter and the service panel can be sized per Table 250.122, which specifies 10 AWG copper based on the OCPD rating. Further, the combined dc GEC and ac EGC is never required to be larger than the ungrounded phase conductors of the PV system. This allows the combined grounding conductor to be sized smaller than the minimum dc GEC size of 8 AWG that Section 250.166 would otherwise require. When these sections are applied together, it is clear that non-isolated (transformerless) inverters used in ungrounded PV systems do not require a dc GEC sized per Section 250.166 to be run to a dc grounding electrode. Instead, an unspliced conductor acting as the ac EGC can be used to meet the grounding electrode system requirements for ungrounded PV systems.

"D" is for danger? The requirements found in Section 690.47(D) have been controversial since they were first added to the *Code* in 2008. (See "Additional Electrodes for Array Grounding," *SolarPro* magazine, October/November 2008.) Some industry stakeholders pointed out that the requirements did little to improve system safety and they significantly increased costs, especially on smaller PV systems. Others complained that the section was poorly written, included language ripe for misinterpretation and contained requirements that were difficult to enforce or comply with. As a result, many industry veterans were pleased when this language was removed from *NEC 2011.* Unfortunately for them, Section 690.47(D) reappears in *NEC 2014,* only with a twist this time—a one-word change that has inspired a new set of detractors.

Whereas the 2008 version of Section 690.47(D) required "additional electrodes for array grounding," the 2014 version requires "additional *auxiliary* electrodes for array grounding." According to a substantiation in the *ROC,* the intent of adding the term *auxiliary* was to signal that "this grounding electrode is not required to be tied into the premises' grounding-electrode system; and if multiple grounding electrodes are installed, they do not need to be bonded together by a dedicated bonding conductor." The substantiation concludes by noting that the dc EGC "will serve to bond the electrodes in the PV array together. A separate bonding conductor would be duplicative."

Not everyone agrees with this assessment. Mike Holt, the founder of Mike Holt Enterprises, is a *Code* expert and electrical training specialist. According to a 26-minute YouTube video presentation (see Resources), Holt's opinion is that "690.47(D) needs to be immediately removed from the *Code*. It is the only *Code* rule I am aware of that was added to the *Code* that makes an installation unsafe."

The safety problem, as Holt sees it, is that the 2014 version of Section 690.47(D) references Section 250.54, "Auxiliary Grounding Electrodes," meaning that system integrators do not need to incorporate the required auxiliary electrode into the premises' grounding-electrode system. As a result, in the event of a lightning strike there could be a difference in potential, or voltage, between an auxiliary electrode and the grounding-electrode system. If that occurred, the difference in potential would induce current in the EGC path. Not only is equipment in this path at risk of damage from lightning-induced surges, but also people could be exposed to a shock hazard, either due to direct contact with an inadvertently energized circuit component or due to a *side flash,* which occurs when lightning jumps from one object to another.

Brooks concurs with Holt's assessment: "If the AHJ requires an additional electrode on a building with an existing electrode, then you should bond the new electrode to the existing electrode following the requirements of Section 250.53. You should make this bond at ground level, not over the top of the building. Making the bond any place other than ground level is asking for lightning damage."

Brooks continues: "My basic interpretation is that all buildings with an existing electrode do not require this additional *auxiliary* electrode because of Exception 2. The building electrode applies to the whole building. So regardless of the physical placement of a ground rod, there is no place on a structure with an electrode that can be farther than 6 feet from the premises' wiring electrode. An uncontroversial example of this is an Ufer ground that is attached to reinforcing steel in the concrete. A reasonable person would agree that the whole slab is part of the grounding system."

PART VIII "STORAGE BATTERIES"

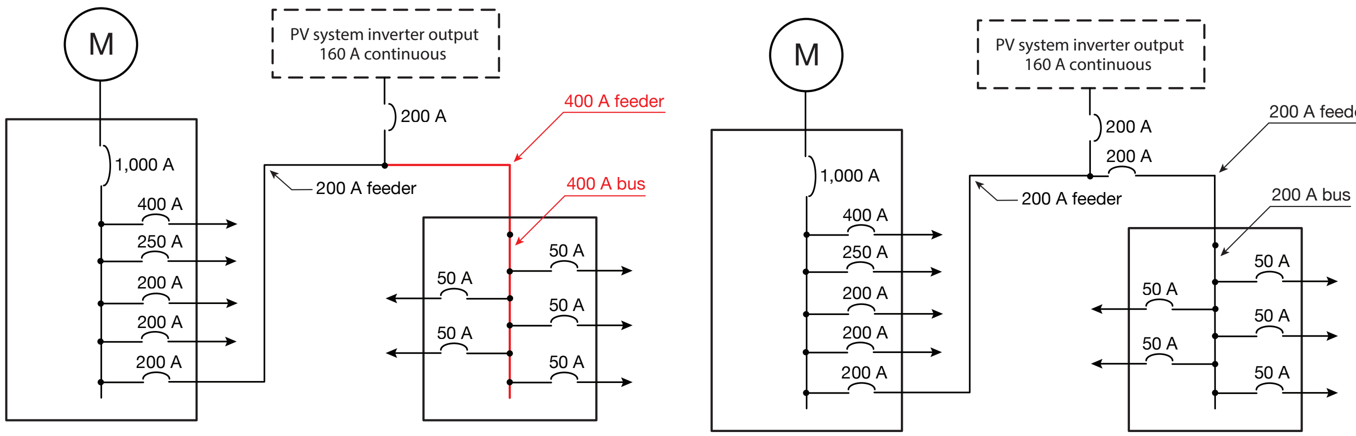
While battery requirements may eventually be moved wholesale to Article 480, the TCC recommended against including this change in the 2014 cycle of revisions, to allow time for further study and avoid unintended consequences. The most significant changes made in the interim relate to the installation of disconnects and OCPDs for battery circuits.

Disconnects and overcurrent protection. Section 690.71(H) is new in *NEC 2014.* It describes five requirements that apply to battery circuits that are more than 5 feet in length or that pass through a wall or partition. Per Subsection (1), a fused disconnecting means or circuit breaker must be installed at the end of the circuit closest to the batteries, since these are the source of potential fault currents. Per Subsection (2), where a fused disconnecting means is used, the connection from the battery must be made on the line side of the device, since these terminals will be energized even when the switch is in the off position. Per Subsection (3), OCPDs or disconnects are not allowed in battery enclosures "where explosive atmospheres can exist." This applies to lead-acid batteries, for example, which off-gas hydrogen.

The two other requirements apply when equipment components are not located within sight of one another (per *in sight from* definition in Article 100). Where connected equipment is not within sight of the batteries, Subsection (4) requires that a second equipment-service disconnect must be located at the charge controller, inverter or other connected device. Lastly, Subsection (5) states that where the energy storage disconnecting means is not located within sight of the ac and dc disconnecting means for the PV system, each disconnecting means requires a placard or directory indicating "the location of all disconnecting means."

PART IX "SYSTEMS OVER 1,000 VOLTS"

The general changes associated with raising the 600-volt threshold to 1,000 volts do not address the challenges of deploying PV systems that operate above 1,000 volts. Specifically, while PV Wire is a listed wire type, it is not yet included as a Chapter 3 wiring method. Section 690.81, "Listing," is new to *NEC 2014* and addresses this issue. It clarifies that where listed direct-burial PV Wire is used for systems above 1,000 volts, it is to be installed with a minimum cover of 30 inches, according to Table 300.50, column 1, provided that the circuit does not exceed 2,000 volts.



Courtesy Brooks Engineering

Figures 1 and 2 *NEC 2014* provides two methods of making a connection to a feeder at a location other than the end opposite the primary OCPD. On one hand, the portion of the feeder on the load side of the inverter-output connection can be protected via conductor upsizing per Section 705.12(D)(2)(1)(a), as shown in Figure 1 (left); on the other, it can be protected using an OCPD, as shown in Figure 2 (right).

As explained in a substantiation in the *ROP:* "It is common practice in large utility-scale solar installations to direct-bury 2,000 V–rated conductors used to carry power from combiner boxes to the inverter. Since these installations are not accessible to the public and maintenance is controlled by the facility owner, direct-buried single-conductor installations are appropriate." Section 690.81 allows for this practice as long as the PV Wire product is listed for direct burial.

Note that Part IX does not apply to PV systems with a maximum system voltage of 1,000 Vdc or less. Where listed direct-burial PV Wire is used for systems that operate below 1,000 volts, Table 300.5 applies, which requires a minimum cover of 24 inches.

Interconnection *Code* Changes

Article 705, "Interconnected Electric Power Production Sources," specifies the requirements related to electric power production sources that operate in parallel with the utility. The most significant changes in this article relate to expanded options for interconnecting utility-interactive inverters in a *Code*-compliant manner. There is also new language that effectively requires arc-fault protection for microinverter and ac module systems, as well as a new section related to the location of overcurrent protection.

SECTION 705.12(D)(2) "BUS OR CONDUCTOR AMPERE RATING"

This section is substantially changed in the 2014 *Code*. The new language was originally proposed during the 2011 cycle of revisions, but was held out for further study. The revisions address interconnection issues that installers and AHJs have brought up over many *Code* cycles.

For improved clarity, the revised content is separated into three categories: feeders, taps and busbars. Note that in *NEC 2014* the ampere rating of OCPDs supplying power to a conductor or busbar is no longer used as the basis of Section 705.12(D)(2) ampacity calculations. Instead, these calculations are based on 125% of the inverter output-circuit current.

Feeders. Article 100 defines the term *feeder:* "All circuit conductors between the service equipment, the source of a separately derived system, or other power supply source, and the final branch-circuit overcurrent device." As an example, a conductor connected to a 200 A breaker in a main service panel on one end and to the terminals of a 200 A main-lug–only (MLO) subpanel on the other is a feeder.

When an inverter output circuit connection is made to a feeder (and the busbar in the MLO panel) somewhere on the length of the feeder that is not at the opposite end from the primary OCPD, there will be a portion of the feeder that could be subject to current from two sources of supply—the utility service and the inverter output. According to Section 705.12(D)(2)(1), there are two *Code*-compliant ways of connecting an inverter output circuit to a feeder "at a location other than the opposite end of the feeder from the primary source overcurrent device." The first option, described in Subsection (a), is to protect the portion of the feeder on the load side of the inverter output connection by installing a feeder with an ampacity that is not less than the sum of the main OCPD and 125% of the inverter output-circuit current, as shown in Figure 1. The second option, per Subsection (b), is to protect the feeder on the load side of the inverter connection by using an OCPD that is not rated greater than the feeder ampacity, as shown in Figure 2.

Taps. According to Section 240.2, a tap conductor is defined as "a conductor, other than a service conductor, that has overcurrent protection ahead of its point of supply that exceeds the value permitted for similar conductors that are protected as described elsewhere in 240.4." Section 240.21(B) provides the numerous rules pertaining to taps. Note that the ampacity requirements for tap conductors up to 10 feet in length differ from those for tap conductors that are more than 10 feet but not above 25 feet in length. Except in rare situations that are unlikely to pertain to PV applications, a conductor of more than 25 feet located inside a building cannot be considered a tap.

Pre-exiting taps or taps added to a feeder with a PV supply source must be sized per 705.12(D)(2)(2) and 240.21(B), based on the sum of 125% of the inverter(s) output-circuit current plus the feeder OCPD rating. See Figure 3 for an example tap conductor calculation. Note that inverter output-circuit conductors, which must not have an ampacity less than the rating of the circuit OCPD, cannot meet the definition of a tap conductor.

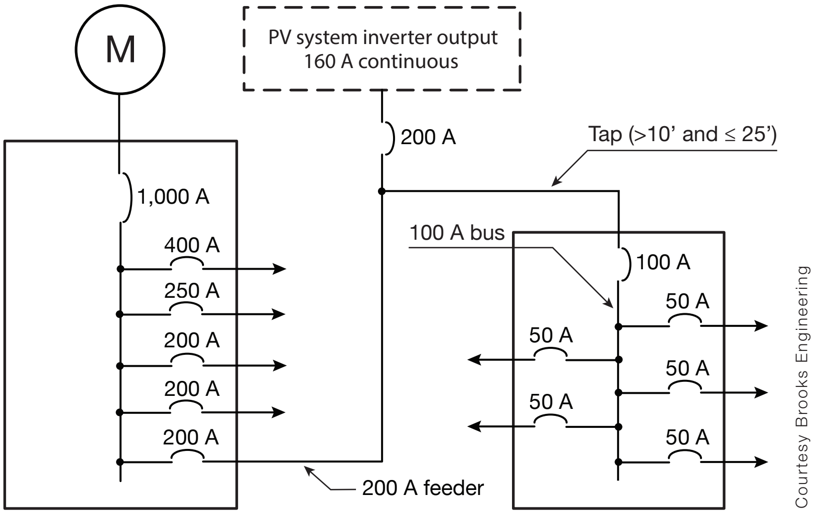


Figure 3 Since this tap is between 10 and 25 feet in length, its ampacity must not be less than 1/3 the sum of 125% of the inverter output-circuit current plus the feeder OCPD rating, as detailed in Sections 705.12(D)(2)(2) and 240.21(B)(2)(1). The tap ampacity calculation is: ((160 A x 125%) + 200 A) x 33% = 132 A.

Busbars. Four different methods can now be used to determine the required busbar rating for switchboards and panelboards supplied by both a PV and a utility source. These methods provide system designers and installers with more flexibility than ever when it comes to making a *Code*-compliant interconnection at a busbar.

Option 1: As described in Subsection (a), the ampacity rating of the busbar cannot be less than the sum of 125% of the inverter(s) output-circuit current plus the rating of the OCPD protecting the busbar. An informational note clarifies that this general rule applies regardless of the number or location of loads or interconnected sources.

Option 2: This is described in Subsection (b) and is what many in the industry refer to as the "120% rule." In this scenario, the sum of 125% of the inverter(s) output-circuit current plus the rating of the OCPD protecting the busbar is allowed to equal up to 120% of the busbar rating—provided that the two sources are located at opposite ends of the busbar that contains loads. Additionally, the following permanent warning label is required at back-fed breakers:

WARNING:
INVERTER OUTPUT CONNECTION;
DO NOT RELOCATE
THIS OVERCURRENT DEVICE.

Option 3: Subsection (c) specifies that the sum of the overcurrent devices connected to loads and supplies—excluding the rating of the main overcurrent device protecting the busbar—must be limited to an amount less than or equal to the rating of the busbar. The most likely application for this option is at inverter aggregation panels (also known as inverter combiner or accumulation panels), which have long been a potential point of contention for system integrators and AHJs. When this option is employed, a warning label must be applied on the equipment that reads:

WARNING:
THIS EQUIPMENT FED BY MULTIPLE SOURCES.
TOTAL RATING OF ALL OVERCURRENT
DEVICES, EXCLUDING MAIN SUPPLY
OVERCURRENT DEVICE, SHALL NOT EXCEED
AMPACITY OF BUSBAR.

Option 4: Subsection (d) applies specifically to multiple-ampacity busbars or center-fed panelboards, which have long been a source of confusion as previous methodologies did not adequately address them. This new method allows load-side connections in these types of panels, provided that the interconnection is designed under "engineering supervision," which must include fault studies and busbar load calculations. This method should alleviate concerns that some AHJs have had about whether to allow load-side connections in center-fed panels, which are very common in some

Courtesy Sun Light & Power

Inverter accumulation panel The panelboard on the right is used to combine five inverter output circuits. If sized per Section 705.12(D)(2)(3)(c), the sum of the individual breakers in the panel (excluding the rating of the OCPD protecting the busbar), whether supply or load, must not exceed the ampacity of the busbar.

areas of the country. These connections are clearly allowed, provided that the proper due diligence is performed.

SECTION 705.12(D)(6) "WIRE HARNESS AND EXPOSED CABLE ARC-FAULT PROTECTION"

As detailed in Section 690.11, dc arc-fault circuit protection requirements do not cover PV systems with a maximum system voltage of less than 80 Vdc. While this effectively exempts ac modules and microinverter systems from dc arc-fault requirements, new language in *NEC 2014* addresses the potential for ac arc faults in these types of systems.

According to Zgonena's substantiation for the *ROP*, "Single and multiple utility-interactive inverter systems, such as ac modules and microinverters, can have significant amounts of exposed PV ac wiring (harnesses and cables) that are often exposed to movement, abuse and degradation due to weathering and rodents." He continues: "These factors can lead to insulation breakdown and broken conductors that can lead to series and parallel arc faults."

Section 705.12(D)(6), therefore, requires arc-fault protection for exposed wires, harnesses and inverter output-circuits rated 240 V or less and 30 amperes or less. This covers the vast majority of listed microinverters and ac modules. Note that ac arc-fault circuit interrupter (AFCI) capabilities could be integrated into the microinverter or ac module or provided using a dedicated OCPD, such as an AFCI breaker listed for back-feeding.

Zgonena writes: "AC AFCI equipment and requirements are being developed that include existing ac AFCI protection combined with additional back-feed requirements for this specific purpose." He elaborates, "Single-pole AFCI devices not marked 'line' and 'load' can be back-fed since they have been tested for back-feeding."

Brooks points out that it could prove difficult to meet these particular arc-fault protection requirements in 208 Vac commercial applications. He explains: "Most ac AFCI equipment is designed for 120/240 Vac residential applications, since the existing *Code* requirements for ac arc-fault protection apply specifically to circuits in dwellings. As a result, there are no off-the-shelf AFCI circuit breakers for 480 or 208 Vac applications." While microinverter or ac module systems intended for 480 Vac interconnections are exempt from Section 705.12(D)(6), those that interconnect at 208 Vac are subject to the requirements. Until listed 2- and 3-pole 208 Vac AFCI circuit breakers are available for back-fed applications, or the requisite protection is integrated into the microinverter, AHJs could waive these requirements in commercial applications per Section 90.4.

SECTION 705.31 "LOCATION OF OVERCURRENT PROTECTION"

This new section limits the length of unprotected conductors in supply-side interconnections to 10 feet, due to safety concerns. According to a substantiation provided by CMP No. 4 in the *ROP:* "Often, when connections are made to, or ahead of, existing service-entrance equipment, space limitations do not allow for a disconnecting means with overcurrent protection to be adjacent to the service entrance equipment and still have proper working clearances. Consequently, many of the required disconnects with overcurrent protection are being installed remote from the service entrance equipment."

Though subject to fault current from the utility, these conductors are not protected by the utility transformer's primary OCPD(s). The CMP concludes: "A fault on these conductors will likely result in a violent, explosive conductor vaporization and potential equipment damage or complete burn down." The unanimous decision to limit the unprotected conductor length to 10 feet mitigates this safety hazard.

Where the overcurrent protection for the parallel power production equipment is located more than 10 feet from the point of connection, an exception allows the use of cable limiters to provide short-circuit protection. Note that these cable limiters must be installed "at the point where the electric power production conductors are connected to the service." A cable limiter is different than a fuse in that it isolates a conductor in response to short-circuit current only and does not provide overload protection. Due to space constraints, it may prove easier to install cable limiters at a service entrance in accordance with this exception rather than install a fused disconnecting means within 10 feet.

Courtesy Sun Light & Power

Location of OCP The new Section 705.31 requires that overcurrent protection for power-production source conductors, such as the fuses inside the disconnect on the right, be located within 10 feet of the point of interconnection, which in this case is at the switch gear on the left.

The addition of Section 705.31 brings the guidance for PV supply-side connections into closer agreement with requirements in Article 230 pertaining to service disconnecting means. For example, Section 230.70(A) requires that service disconnecting means be located at "a readily accessible location outside of a building or inside nearest the point of entrance of the service conductors." Section 230.91 further requires that overcurrent protection be integral to or immediately adjacent to the service disconnecting means. Note that where disconnecting means for PV power production sources are located within 10 feet of the main service disconnecting means, they could be used, in conjunction with contactor combiners or other equipment, to initiate rapid shutdown for PV systems on buildings.

Call for Proposals for *NEC 2017*

In addition to being transparent and well documented, the *Code*-making process is open to the general public. The call for public input for *NEC 2017* is currently under way. If you have a proposal, simply complete the online form (see Resources), and submit it by November 7, 2014. As the saying goes, "If you are not at the table, you could be on the menu."

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Brian Mehalic / Solar Energy International / Winston-Salem, NC / brian@solarenergy.org / solarenergy.org

Resources:

ANSI Z535.4-2011: American National Standard for Product Safety Signs and Labels, ANSI, 2011, http://bit.ly/1eDKH4d

Ball, Greg, et al, "Inverter Ground-Fault Detection 'Blind-Spot' and Mitigation Methods," Solar America Board for Codes and Standards, solarabcs.org/about/publications, June 2013

National Electrical Code Committee Report on Proposals: 2013 Annual Revision Cycle, NFPA, 2013, http://bit.ly/1czpjg8

National Electrical Code Committee Report on Comments: 2013 Annual Revision Cycle, NFPA, 2013, http://bit.ly/ZY2pbn

"NEC 2014 Solar—Additional Auxiliary Electrodes for Array Grounding," MikeHoltNEC YouTube Channel, http://bit.ly/1fkUqjQ

NFPA 70 Call for Public Input, open through 11.07.2014, http://bit.ly/LUv2Xq

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Emerging Technologies, Markets and Applications

The current buzz surrounding solar energy storage has been gradually building for the last two years. How the storage market will grow and evolve, and how quickly, is not yet clear. However, one thing is certain—the solar industry is entering a dynamic new phase of solar storage market and application development. Established power electronics and battery vendors are positioning themselves for the expected business growth, and new start-ups fueled by successive rounds of funding are aiming to capture a piece of the anticipated market surge.

Today, industry conversations about solar storage often include references to "early market issues." This may leave integrators who have been at it for a decade or two rather perplexed. Through the 1980s and most of the 1990s, if you were working in solar, you were working with batteries. The introduction of power electronics that allowed utility-interactive systems to operate *without* batteries was a key advancement that facilitated the mainstreaming of PV generation in the US over the last decade. However, by many accounts PV systems with integrated storage are starting to come full circle, and, in a sense, what is old is new again.

Utility rate structures, gradual shifts in how the utility grid is managed, maintained and upgraded, and regulatory changes are creating new applications and opportunities for PV systems with integrated storage. Furthermore, customer-sited and utility-scale storage will likely become a design requirement for renewables integration in regions with high distributed generation (DG) penetration levels to help manage the impact of variable energy sources on these regional utility grids.

For this article, I conducted interviews with industry stakeholders, including representatives of power electronics vendors, and design and integration firms, to compile a range of perspectives on solar storage, primarily related to utility-interactive applications. My goal was to identify the technological and market developments that are creating a predominantly bullish industry attitude toward the future of solar energy storage in North America.

Eric Carlson

Senior director of grid systems integration, SolarCity, solarcity.com

What markets and applications provide an optimal value proposition for PV systems with integrated storage? How will this evolve over time?

Battery energy storage devices clearly have capabilities that make them attractive as an energy and capacity resource. A PV and storage battery system can provide value on many levels. Storage can provide backup power to homes and businesses, or it can cut peak-demand charges. Energy storage can be used in addition to renewable generators to provide firm peak capacity to the grid. If a grid operator is looking at an area where it might need to replace or increase the capacity of equipment, it could put a battery or batteries in place to meet the demand instead of the traditional infrastructure. Energy storage can also provide frequency regulation and other services that offer value to the grid.

One of the most developed markets for grid-connected energy storage is in commercial retail peak-demand reduction. Because utility tariffs place a high value on reducing demand, especially at peak times, there is an economic incentive to deploy energy storage in certain locations. The optimal candidate for a PV system integrated with energy storage is a commercial site with peak demand occurring during or just after daylight hours and with a high-demand charge, typically from $12 to $20 per kW during peak hours. These customers are typically in either California or the Northeast US. However, across the US, demand charges are increasing at an even steeper rate than energy prices. As more utilities rely on demand charges to help smooth out customer load curves and recover costs, energy storage will become economically viable for more and more customers.

Is SolarCity seeing an increase in customer interest in storage systems? If so, what are the market drivers?

We're in the pilot phase of our home energy storage system offering in California. We have more than 300 customers

GY

Storage

By Joe Schwartz

either installed or under contract to install storage within that limited pilot, and we hope to expand the scope soon. We see increasing interest in home storage systems, and the most common driving factor is the desire for backup power. As storms and other climate-related disasters have increased in intensity in recent years, more people are interested in securing their own energy to avoid hardships.

In December 2013, SolarCity launched its DemandLogic energy storage system for businesses. How does this system operate, and what is the value proposition for the customer?

SolarCity DemandLogic, developed with advanced battery technology from Tesla Motors, allows businesses to cut energy costs by using stored electricity to reduce peak demand. The solution can also provide backup power to mission-critical systems such as cash registers and select lighting in storefronts during grid outages. DemandLogic storage includes learning software that automates the discharge of stored energy to optimize utility savings for customers.

We currently offer our DemandLogic product in areas of California serviced by Pacific Gas & Electric and Southern California Edison, areas of Massachusetts serviced by NSTAR and areas of Connecticut served by Connecticut Light & Power. We chose these markets due to the high costs of demand charges in those areas.

Why does SolarCity utilize lithium-ion batteries in its utility-interactive solar storage systems? What is the price premium compared to valve-regulated lead-acid (VRLA) batteries?

Lithium-ion battery technology provides many advantages over VRLA. First of all, lithium-ion energy storage systems are typically able to achieve a greater number of charge and discharge cycles during their lifetime. This is particularly important in commercial applications where the battery may be cycled frequently to reduce site demand or provide ancillary services to the grid.

Another consideration when designing storage products, for both residential and commercial markets, is the physical size of the system. For residential customers, a product that can be wall mounted is critical to ease of installation and permitting. Our residential systems are almost all mounted on garage walls. SolarCity gives customers backup power without taking up valuable space. Space constraints are also a concern for commercial customers. The lithium-ion products provide a compact and self-contained solution that can be located indoors or outdoors. Additionally, lithium-ion batteries do not require regular servicing, making them a convenient solution from a customer perspective and much less expensive to maintain.

Although there is a price premium to lithium-ion batteries in the short term, the longer life span and increased cycles, the greater energy density and the limited ongoing costs make them preferable to VRLA for both commercial and residential applications.

What policy shifts or utility cost-structure changes will significantly impact the projected growth of storage systems in the US?

Because we are in the nascent stages of the market, incentives like the Self-Generation Incentive Program in California are critically important to drive scale, which will in turn bring costs down. However, the biggest policy changes that will drive the market for energy storage are the reduction of regulatory barriers to building and interconnecting energy

Courtesy Ameresco Solar

AC-coupled water pumping Grid-integrated battery systems are getting a lot of attention, but opportunities for large stand-alone battery-based systems abound. This municipal water pumping system by Ameresco Solar uses a 67 kW array and ac-coupled SMA Sunny Boy and Sunny Island inverters for power conditioning and diesel-generator integration. The system runs 25 HP pumps and distributes water throughout 30-plus miles of distribution channels.

storage systems. This includes streamlining the interconnection process, reducing undue technical burdens on system designs—which do not exist for PV alone or for any other generating technology—and reducing the excess fees and charges that many utilities are attempting to apply to projects that involve energy storage. Once these barriers are reduced, opening up ancillary service markets to aggregated storage capacity is critical to enable storage to offer its full value to the grid and to end customers.

How will financing mechanisms such as leases and PPAs impact the deployment of solar storage?

Financing storage systems is crucial to widespread deployment. SolarCity pioneered the solar lease, and we rolled out our DemandLogic commercial storage system with a similar leasing structure. The lease simply makes it possible for more customers to adopt solar, and now storage, without the hefty up-front costs of purchasing a system outright.

Courtesy Magnum Energy and MidNite Solar

Battery-based equipment Magnum Energy and MidNite Solar are two vendors selling power electronics and integration equipment that can be used in residential and small commercial stand-alone and grid-connected PV systems with battery backup.

Darren Hammell

Cofounder and chief strategic officer, Princeton Power Systems, princetonpower.com

What products does Princeton Power Systems offer for utility-interactive PV with integrated storage?

We offer turnkey energy storage systems that combine advanced batteries, converters and controllers. Our power converters can integrate multiple battery banks, and solar, wind and fossil fuel generators with a single converter. The converters can export power and can also run off-grid in an islanded mode while still meeting UL 1741 requirements. Our inverters include many smart-grid features such as peak shaving algorithms, programmable demand response and frequency regulation. We also offer a site controller that aggregates multiple inverters and other assets, and allows a single point of monitoring and control. Our converters are available in power levels of 10 kW–500 kW and can be paralleled into multimegawatt systems.

What battery technologies are compatible with Princeton equipment?

We help our customers choose the best battery for their application and have existing systems in the field with advanced batteries from manufacturers such as Deka/East Penn, Dow Kokam, General Electric, Saft, Samsung, Tesla Motors, ViZn Energy and many others. Our converters are compatible with most chemistries due to their wide operating voltage range of 36 Vdc–600 Vdc.

Are you seeing any emerging trends in the battery technologies that the solar industry is deploying?

Most of the available battery types that are in reliable, cost-effective packages from reliable suppliers have been on the market for several years, though the costs have come down considerably. Many of the newer battery technologies that companies are heavily marketing are not yet ready for wide deployment.

Lithium-ion batteries are now widely available, have exceptional efficiency and performance, and have come down in price significantly over the last few years. The major manufacturers of electric vehicles have all chosen lithium-ion chemistries for their vehicles, which is driving costs down and increasing performance. Other unique chemistries, such as the GE Durathon battery, are also commercially available at attractive price points. Lead-acid batteries are still the most common since they have much lower initial costs, but there are many operating scenarios where their lifetime costs may be more expensive than those of other battery types.

What markets and applications provide an optimal value proposition for PV systems with integrated storage? How will this evolve over time?

PV with storage is ideal in on-grid settings where backup power and resiliency are important, such as community centers, municipalities, schools and other public settings. Adding storage to PV installations can create stand-alone microgrids that are critical to communities in the event of outages caused by storms, wildfires or other events. Grid-connected systems with storage can also provide peak demand reduction, demand response, frequency regulation or other lucrative services.

Where do you think the US solar storage market is headed?

Princeton Power Systems works in three main sectors—microgrids, energy storage systems and electric vehicle charging—that all utilize the same underlying platform. In 2013, we deployed more than 11 MW of these systems in commercial and industrial applications, and we expect this to increase dramatically in 2014. We believe that demand for residential systems may increase in 2014, but it will take longer for widespread adoption in this segment.

There is a huge interest in microgrid systems in the Northeast, especially after the devastation caused by Superstorm Sandy. There is also a large demand across California due to wildfires, high energy costs and other factors. Customers are becoming increasingly aware that one battery system can provide a number of different services. After recent FERC [Federal Energy Regulatory Commission] orders, legislation in California targeting stationary storage and resiliency efforts in the Northeast, we are on the verge of seeing an extraordinary increase in the demand for stationary storage systems with PV.

What are the major obstacles to the expansion of solar storage systems in the US?

Many new storage technologies are not yet ready for deployment. At the same time, many high-performing technologies have been tested and proven, and have recently achieved significant cost reductions and scale. Educating customers about what is available on the market and being able to show existing systems that have been operating in the field should go a long way toward accelerating deployment of energy storage. Costs must continue to come down, and customers must continue to demand access to DG in net metering scenarios without excessive tariffs on DG adoption. Regulations must continue to support storage and allow storage owners to be compensated for the benefits they provide.

To be attractive, energy storage must be cost effective and provide value. Understanding the various revenue streams available in particular applications, choosing the right technology to take advantage of them, and designing and operating the system properly are important. If the industry makes misleading performance claims or designs systems that do not operate as advertised, we risk alienating customers at an important point in market development.

Mark Hardin

Director of product marketing, Xtreme Power, xtremepower.com

What markets and applications provide an optimal value proposition for PV systems with integrated storage? How will this evolve over time?

To date, the majority of the market for PV systems integrated with an Xtreme Power Energy Storage System [ESS] has been island grids hoping to lower energy costs by displacing costly fossil-fueled energy with cleaner, less expensive renewable generation such as PV. These grids are usually smaller and less robust than mainland grids and cannot reliably absorb the rapid, uncontrollable fluctuations in power output associated with renewable generation. Therefore the island utilities require the renewable developers to include some method of reducing intermittency, or ramp control from the ESS, and provide grid-support functions such as frequency response and voltage support.

The value proposition is when the levelized cost of PV combined with an ESS is less than the cost of the fossil-fueled alternative generation and/or additional grid support services that may be required. Xtreme Power has seen this market grow from the Hawaiian Islands to include Alaska, Puerto Rico and various Caribbean locations. While this fractured market will continue to grow, new opportunities are taking shape in California and other mainland grids where forecasts indicate that the level of PV and renewable penetration will reach a tipping point that will require the unique operating attributes of energy storage systems. In addition, the increasing cost of demand charges and proliferation of behind-the-meter PV offer potentially lucrative savings for commercial and industrial customers interested in utilizing an ESS combined with PV to reduce metered demand and maximize the potential savings of PV generation.

What customer requirements do utility-interactive solar storage systems meet? What are the key market drivers?

Typical customer requirements are ramp control, or reducing the volatility of the intermittent output from PV generation, and various grid-support applications such as frequency response, frequency regulation, voltage support and responsive reserves. Customers are interested in these applications primarily to meet requirements outlined in a PPA to connect the solar project and deliver power. They are also interested in improving grid stability and reducing wear and tear on conventional generators, by using the energy storage systems' ability to deliver power quickly and accurately, to help with frequency or voltage fluctuations that high levels of renewable penetration may be causing.

However, in larger, more rigid grids with lower levels of renewable penetration, the customer may not request some applications. Future customer requirements will evolve to solve the issue most adeptly illustrated by the CA-ISO "duck chart" graph. This graph shows the very steep and large load ramp-up period utilities will face when solar generation is declining and load is increasing in the early evening hours. Utilities are already looking to flatten their load curve by charging up solar storage systems during solar peak output in the midday period, and discharging during the early evening hours when solar generation is dropping and load is increasing. This time-shifting application is well suited for solar energy storage systems.

What policy shifts or utility cost-structure changes will significantly impact the deployment of storage systems in the US?

Energy storage systems can be a great source for capacity in resource-constrained areas where additional generation is not feasible due to permitting, siting or other reasons, and a full-blown transmission or distribution build-out is highly cost prohibitive. However, to qualify for capacity, many utilities require a 4-hour duration that can make storage systems quite expensive. If the utilities alleviated the constraint to 1 or 2 hours, then the economics for this application could be very interesting, especially considering all the other grid-level services the system can provide. If the generic, one-size-fits-all requirement of 4 hours for capacity payments can be intelligently revised, developers and utilities may open an excellent market for PPA-type storage projects owned by the developer, and controlled and paid for on a fixed-price basis by the utility.

In addition, it will be interesting to see how utilities change tariff structures to compensate for lost revenue associated with the proliferation of DG. An increase in demand charges can play right into the hands of energy storage systems that can quickly discharge to reduce the metered maximum demand on the customer's meter, and charge during periods of low demand to generate demand savings for the customer. If demand charges do continue to increase, the market for behind-the-meter energy storage will certainly see significant growth.

What are the major obstacles to the expansion of solar storage systems in the US?

An obvious obstacle is still the cost of the systems. This will continue to decline with improvements in battery technology. However, creating market structures that truly enable the unique benefits of energy storage systems to realize a monetary value is also critical. FERC Order 755 is a terrific example of how a market structure is being revised to truly value grid assets that can respond more quickly and accurately, such as energy storage systems, to provide frequency regulation.

[Editor's note: Xtreme Power filed for bankruptcy protection after our interview was completed.]

Tristan Kreager

Manager of hybrid energy solutions, SMA America, sma-america.com

What products does SMA America offer for utility-interactive solar storage systems and stand-alone microgrids?

SMA manufactures the Sunny Island, a grid-forming, bidirectional, utility-interactive or stand-alone inverter/charger with a 48 Vdc battery bus. Each unit is rated at 4.5 kW

Courtesy OutBack Power

Battery backup OutBack Power is streamlining its products to simplify battery-based system design, sales and installation. The company's Radian inverter models are suitable for utility-interactive and stand-alone systems. OutBack also offers VRLA batteries and enclosures for grid-backup applications.

or 6 kW and can be networked in various configurations to the MW scale. This solution works in either utility-interactive or stand-alone microgrids. Residential systems range from a single 4.5 kW Sunny Island up to a 24 kW Sunny Island cluster with a 30 kW PV array. Commercial solar storage systems are under development as the market matures. Currently, a single cluster of Sunny Islands in either a 3-phase or split-phase configuration is our fully UL-compliant limit [13.5 kW or 24 kW of load, 36 kW–48 kW of PV, 480 kWh of storage].

As system size increases, a piece of synchronizing switchgear called a Multicluster Box [MCB] is used. Currently, the MCB is not listed for utility interactivity. However, utilizing external transfer switches that are listed for that purpose makes large-scale projects feasible. In the US market, SMA offers the MCB12, which incorporates 12 Sunny Islands configured in four 3-phase clusters. This allows for system capacities of 72 kW of Sunny Islands, 110 kW of PV and nearly 2 MWh of batteries. For even larger projects, SMA offers the MCB36, which is configured for European grids [230/400 Vac, 50 or 60 HZ] and is CE listed. Using voltage transformers, US projects can be built with up to 216 kW of load, 360 kW of PV and 8 MWh of batteries. Our utility-scale storage solutions are custom engineered based on our Sunny Central technology and are primarily aimed at facilitating advanced grid-management requirements.

What markets and applications provide an optimal value proposition for PV systems with integrated storage?

Storage plays a role in many markets, but is most commonly applied in the residential and commercial space where it is most cost effective. In a general sense, that is any place where the cost of energy exceeds the life cycle cost of a PV and battery system. Historically, this meant off-grid or remote microgrids where the cost of transmission made PV and batteries the least expensive option. However, decreasing PV costs over the last several years opened new applications, with PV and batteries merging with diesel grids. Now the hurdle is battery costs. There are various battery technologies that are driving life cycles up and capital costs down, achieving better LCOE [levelized cost of energy]. Those are the macro market drivers.

Other ancillary attributes make energy storage worth considering regardless of least-cost economics, the biggest of which is backup power. In the residential market, it doesn't matter if the grid is cheaper when the grid has failed, because backup power is about security, not economic payback. Economics are more of a concern in commercial applications. One exciting application in the commercial space utilizes energy storage to reduce peak-demand charges. Loads are monitored and, when a customer is near a penalty threshold, stored energy is pushed into the load center, keeping the customer under the penalty.

Areas of regulatory compliance, such as markets with heavy PV penetration on certain feeders as in Hawaii, are making energy storage attractive. Due to the intermittency of PV during weather events, some utility markets such as Puerto Rico are using energy storage to smooth power delivery. Europe is incentivizing the concept of "self-consumption," utilizing modest battery banks and smart-load monitoring to increase the percentage of PV energy used locally, minimizing impact and fluctuations on the grid.

Do you have any insights on the status of the solar energy storage market in Germany?

Germany has incentivized storage as a way to increase renewable energy penetration. The primary driver in the German market isn't security from storms, it's pure economics. The German policy model has created a system where consumption of PV power generated on-site is financially more advantageous than selling the power back to the grid. This focus on home energy management utilizes storage to time shift consumption to times when it's most economically viable for the consumer and most beneficial for the grid operator.

How are recent challenges to state net metering laws impacting the growth trajectory of solar storage?

Net metering has been a pillar of support for the US PV industry. It's been critical to the growth of the grid-tied market. Should it go away or new policies affect its economics, on-site storage could become an alternative much in the way Germany's market operates. In a paradoxical way, any erosion of net metering is good for the storage market. Any increase in cost or hassle makes the relative cost of adding storage seem more palatable.

How will California's Assembly Bill 2514 impact the deployment of solar storage systems in the state?

The mandate of storage will obviously impact both the consumer and utility sides, as outlined within the bill. We have noticed that this bill has already accelerated deployment of solar storage systems. By establishing guidelines and securing a potential market, it allows investment in the segment, spurring technological advances and leading to real volumes.

What are the major obstacles to the rapid expansion of the sales and deployment of solar storage systems in the US?

Certainly, the industry must address the cost of batteries and associated maintenance concerns, through either policy support or financial mechanisms like PPAs or leases. Likewise, the industry needs to work with grid operators so utilities benefit from the application of storage technologies, whether they are residential, commercial or utility scale. Advancements in the integration of grid, loads and renewable energy control systems are necessary. Finally, most installers are still inexperienced in storage technologies and are reluctant to sell into that space.

Leesa Lee

Senior director of marketing, Stem, stem.com

What are the components of the Stem system? How does the system operate?

The Stem system is a modular, integrated storage solution that includes predictive analytics and advanced energy storage to reduce electricity bills for commercial and industrial customers. The system works by predicting usage and strategically charging and discharging the on-site battery to reduce peak loads. Power is not exported to the utility grid. The Stem system is installed indoors behind the utility meter in parallel with a customer's distribution equipment.

How does the Stem system assist grid-direct PV systems?

Stem helps PV customers in three ways. The system reduces demand charges, particularly with respect to the volatility of solar production. It provides energy during the "shoulder" peak periods when consumption is still high but PV production has diminished. Finally, it future-proofs against tariff changes.

In what markets and regions does Stem offer storage systems? What is the installed capacity?

Stem currently focuses on marketing to the Californian and Hawaiian markets and has more than 7 MW of storage under contract to be deployed. We're also working with utilities to deploy aggregated storage.

What are the key drivers in customer interest?

Demand charges currently are the key driver. To reduce demand charges, businesses need to manage peak usage effectively. Despite detailed rate-structure information, it is challenging for even the most conscientious business owner to manage peak loads. Deploying PV can reduce base loads, but peaks that result in high demand charges can still occur, especially if the PV production is volatile. As utilities need to recoup more of their infrastructure costs through higher charges on peak loads, behind-the-meter storage can play a large role in addressing the resulting demand charges experienced by end customers.

What battery technology does the Stem system use? What is the expected cycle life of the battery pack?

The Stem system uses lithium-ion phosphate batteries. They were chosen for their combination of energy density and safety. These batteries are under warranty for 10 years.

What financing opportunities are available for the Stem system?

The Stem Zero program offers zero-down financing. Customers can get a Stem system with no money down, a fixed, low monthly payment and flexible options after the term ends. Given the nascent nature of the solar storage space, customer awareness and education are the biggest tasks that we have ahead of us at Stem. Awareness among solar developers and installers is a vital part of our marketing efforts for 2014.

Tom Leyden

CEO, Solar Grid Storage, solargridstorage.com

What are the components of the Solar Grid Storage PowerFactor solar-plus-storage system?

Solar Grid Storage PowerFactor systems have building blocks of 250 kW and 500 kW. A combination of these can be deployed for PV projects with arrays starting at 150 kW and building up to the MW scale. Our enclosures include all the components needed for solar CONTINUED ON PAGE 66

plus storage, including a dual-use inverter, battery storage, controls, disconnects and safety devices. We typically use lithium-ion batteries that can be sourced from several well-known and bankable suppliers such as LG, Panasonic and Samsung.

What markets and applications currently provide an optimal value proposition for PV systems with integrated storage? How do you see this evolving over time?

Solar-plus-storage systems add value to traditional solar arrays by enabling benefits such as emergency power, peak-demand reduction, improved power quality, ramp-rate control, load shifting and grid services. Optimizing a system's capability depends on what market you're in. California, for example, has high-demand charges that storage can mitigate, and PJM Interconnection's ancillary-services market provides a premium for the fast-reacting power that batteries can provide. Many states are exploring what they can do to encourage distributed storage, and we expect opportunities to sprout up in these areas as well. Because solar plus storage is such a flexible asset, it will be well positioned to optimize value as the regulatory, utility and financial environments evolve over the next few years.

Courtesy Princeton Power Systems

Commercial-scale inverter/chargers Princeton Power Systems manufactures 10 kW, 30 kW, 100 kW and 500 kW power-conditioning equipment for solar storage projects. Specific configurations are available for a range of applications including microgrids, facility-backup power, grid-frequency regulation and PV integration support.

What is the unique value proposition of the Solar Grid Storage PowerFactor system?

The company has developed a business model that allows batteries to be added to commercial PV installations while lowering costs and adding benefits. Our PowerFactor systems perform all standard PV functions while enabling innovative uses of solar energy, such as delivering emergency power during outages, reducing demand charges and helping grid operators balance power. We either sell our inverter/storage assets to the system owner or finance them separately, providing the inverter as a service. In both cases, Solar Grid Storage operates and maintains the system.

What policy shifts or utility cost-structure changes will significantly impact the growth of storage systems in the US?

FERC Orders 755 and 784 require grid operators and utilities to develop programs aimed at delivering fast-reacting services that help balance and stabilize the grid. The orders establish an equitable framework for on-grid energy storage to participate in the open-energy market. They outline compensation guidelines and evaluation strategies for independent system operators [ISOs], implementing technologies that balance the grid, stabilize power and improve resiliency. They also address market inequities that often favor older methods of balancing demand and mandate that ISOs and utilities take into account speed and accuracy when evaluating grid stabilization technologies.

Solar Grid Storage is advocating for other accommodating policies such as financial incentives for solar plus storage. We believe there is a good case to be made for regulated utilities to invest in solar-ready inverter/storage systems, which would allow the solar industry to plug into systems already paid for and interconnected by the utility.

What are the major obstacles to the expansion of the sales and deployment of solar storage systems in the US?

Many of the historic barriers to adding storage to solar are crumbling. The public's keen interest in electric vehicles and the accompanying demand for robust, energy-dense and less expensive batteries is driving growth in battery sales and bringing the cost down. Add to that the emerging market in grid-level storage, and you have the conditions for profitable, rapid growth for battery suppliers. As we've seen in the solar industry, as costs go down, deployment goes up. Competition forces suppliers to produce better storage technologies that will last longer and cost less.

Barriers to large-scale deployment remain. While FERC is clearing the way on the grid-services regulatory front, local regulations can still prevent the solar-plus-storage connection. For example, there is some confusion about net metering with solar storage systems, particularly when a system also provides grid services. A bad interpretation of the codes could hold up revenue for underwriting the additional storage component of PV projects.

The final barriers to innovation are market based. How do you get the valuable new benefits of solar plus storage deployed cost effectively? The answer from our perspective is combining flexible technology with business models that find ways to monetize multiple benefits. This requires regulatory flexibility for sure, but also financial mechanisms that can attract capital at reasonable rates, even if the technology combinations are relatively new and untested. We believe the prospects for solar plus storage will improve with good operational experience, enabling funding sources to grow more comfortable with this new asset class.

David Love

Account executive, Ameresco Solar, amerescosolar.com

What is Ameresco Solar's history with solar storage systems?

A significant portion of our business is battery based, from small single-battery systems to larger off-grid hybrid applications. While we certainly develop grid-tied systems, the more interesting projects tend to be battery based. For example, we recently completed a 67 kW off-grid project to operate a municipal water system near Peach Springs, Arizona. The remote ac-coupled system operates multiple pumps during daylight hours and also charges a 6,000 Ah at 48 Vdc VRLA battery bank to operate the pumps and controls overnight. We selected Deka Unigy II sealed AGM batteries due to the compact footprint and good product track record. The system pumps 20,000 gallons per day over a pipeline network that is more than 30 miles long.

How can financing mechanisms accelerate the deployment of solar storage systems?

In the past, a barrier to battery-based systems was finding lenders that would offer a loan with a long-enough term at a reasonable rate across all US states and territories. Ameresco Solar now offers a solar loan through our installers for all residential solar projects, including battery backup and off-grid applications. The term of up to 15 years with zero down allows for a reasonable monthly payment, especially compared to the operating costs of fossil-fueled generators.

What markets and applications currently provide an optimal value proposition for PV systems with integrated storage? How will this evolve over time?

Change is the only constant. Currently we see a desire for off-grid and battery-backup systems. With a change in utility pricing, policy or utility availability, however, we will see new markets appear. The promised new battery technology may find a place at the table as well. Emerging markets will be in Hawaii due to the high cost of utility power and grid saturation there, as well as in California. For some commercial customers with critical loads, I can see the advantages for a standby battery bank to bridge the load between the utility and a backup generator. These systems are often large, and the end user needs to value the continuous power and be willing to pay a premium for that service.

What are the major obstacles to the expansion of the sales and deployment of solar storage systems in the US?

One obstacle for residential and small commercial projects is simply training electricians and designers to size systems and set expectations for the end user. Most people do not understand the current limitations related to the size and cost of a lead-acid battery bank. While we see some newer battery technologies making progress on the size, weight and cycle life, standard lead-acid batteries are still an economical choice for many applications. People should not wait for the "magic battery" to appear, since it has been "just around the corner" for a long time. It's better to complete the system now.

Tom McCalmont, PE

President, McCalmont Engineering, mccalmontengineering.com

What is McCalmont Engineering's history with solar storage? Are you seeing an increase in customer interest in these systems?

As an engineering firm specializing in large-scale solar projects, we often see interest in integrating energy storage [ES] with PV projects. There has been a significant uptick in this interest during the last 2 years. We believe this increased interest is the result of three parallel drivers: need, cost and technology.

The obvious solar advantages of simplicity, no moving parts, lack of toxicity, and "free fuel" have recently been augmented by falling prices to bring great economics to solar projects. However, solar suffers from one significant disadvantage, which is intermittency. We categorize intermittency in terms of three distinct challenges:

Courtesy M. Lyou

Residential lithium-ion battery This home-scale battery-backup system is part of SolarCity's residential home energy storage pilot program in California. The system utilizes a 12.7 kW PV array in conjunction with a Schneider Electric Conext XW inverter/charger and a wall-mounted 10 kWh lithium-ion battery from Tesla Motors.

First, intermittency that is associated with variable resources, such as clouds over solar arrays: This type of intermittency can introduce dramatic swings in solar power delivery in which anything from 1% to 90% of the resource can suddenly drop off or come back on line.

Second, intermittency that is associated with variable load and demand spikes: Solar and renewables are designed to deliver energy, or kWh, but they do not do a good job of delivering power, or kW. In some cases, load is coincident with renewable generation, such as air conditioning loads, which generally peak when solar plants are producing the most. However, many loads are not coincident with solar. Demand peaks due to manufacturing or EV charging occur throughout the day or night, not necessarily when solar is delivering at maximum.

Third, ramp-ups and ramp-downs that occur during shoulder periods: ISOs in states with high renewable portfolio standards are very concerned with how to spin up and spin down reserve power plants in proportion to the fast increases or decreases in delivered renewable power, as large numbers of solar power plants either come on line in the morning or go offline in the evening.

All three types of intermittency are growing problems for grid management as more solar comes on line. The use of conventional gas peaker plants to mitigate the intermittency is not a scalable solution for utilities and would require constructing new peaker plants in proportion to the growth of solar power plants, reducing the positive climate impacts of solar. The deployment of an ES system along with each solar power plant can address intermittency.

The second important driver is lowering the cost of delivered power. This takes two forms—the declining costs of both PV and ES systems, and the low capacity factors of solar systems.

As the market has demonstrated over the last 5 years, declining PV costs drive an ever-expanding market, creating economies of scale that lead to even further cost reductions. This same transformation is occurring for ES systems, although the market is still in its early stages. We believe battery and ES system prices will continue to decline over the next decade as the market continues to grow and drive down costs further.

A second, more subtle form of cost reduction is the possibility of increasing the energy capacity available through combined PV plus ES systems. Solar power plants are notoriously underutilized. Given the daily and seasonal bell curves of solar production, solar systems are designed for close to their maximum potential energy generation annually. For example, a 100 MW solar power plant is typically designed for no more than 120%–130% of that figure at its dc inputs, and it will operate at the full 100 MW only a relatively few hours out of a year. Throughout a typical year—including nighttime hours—a typical solar plant may produce no more than 15%–20% of its theoretical maximum energy yield, or its capacity factor. Contrast that with a large coal or nuclear power plant, which may operate at a capacity factor of 50%–80%. However, if you were to augment that PV plant with an ES system, it gives you the opportunity to increase its capacity factor—to operate the plant for more hours of the year—in effect reducing its cost per kWh. This idea is still relatively new, but shows promise for further innovation.

New battery and storage technologies are moving out of the lab into the real world, and these will improve performance and drive down costs simultaneously. In addition, new approaches for delivery of the combined energy from PV and ES systems with algorithms and applications that manage the energy delivery of both in an integral fashion are being developed.

For example, with a combined PV and ES system, it's possible to square off the shoulder periods of a typical solar day from the traditional Gaussian bell-shaped curve to one that looks more like a square wave. With such a production curve, it is much simpler for ISOs and utilities to manage ramp-up and ramp-down periods in the mornings and evenings. If they can predictably and reliably determine when the PV system will come on line or go off-line, utilities can turn off or dispatch their peaker plants accordingly. There is less chance of a sudden load demand creating a brownout, because the transition from peaker power to solar power can happen within a few minutes rather than over an hour or two.

What kinds of battery technologies are you specifying in solar storage systems?

Systems must be designed and specified based on the application they are designed to serve. For backup power and off-grid applications, for instance, lead-acid batteries are still one of the best choices. They have a relatively short cycle life of typically 1,000 cycles or less, but they do extremely well in situations for which you need large amounts of reserve power at low cost. Lead-acid batteries can last for approximately 7–10 years if they are operated and maintained well.

Lithium-ion batteries, however, with their much longer cycle life—typically 10,000 cycles or more—and tolerance to "short" cycles, are ideally suited to applications that require frequent partial discharging and charging, such as demand reduction or frequency response applications in which you may discharge and recharge the batteries more often than once per day. In such applications, lithium-ion batteries can also last for 10 years or more, if well cared for. And while they are more expensive than lead-acid batteries in initial capital outlay, they are, in fact, quite comparable in cost when measured in dollars per kWh delivered over their lifetime.

How will California's Assembly Bill 2514 impact the deployment of solar storage systems in the state? Does it have any nationwide implications?

AB 2514 should prove to be the right ignition source for the market at the right time, much like the California Solar Initiative [CSI] program created a runway for driving down costs and increasing system adoption for the PV industry from 2007 through 2013. This effect won't be immediate, and as was the case with the CSI, the early market will develop more slowly than the later market. As with many things that start in California, the rest of the country learns from our mistakes and successes, and adopts the ideas that work. This trend should prove true for ES systems as well, as the many benefits of their deployment are further proved economically and logistically.

What new business models will be required to accelerate the deployment of solar storage systems?

It may not be so much a shift to new business models as it will be an emergence of new technologies that are deployed through well-understood existing business models. We believe the approaches to ES that have been the standard-bearers for the past 20 years lack imagination. Traditional ES approaches have emerged out of what was technologically possible and affordable two decades ago. Therefore, the traditional ES approach is primarily for off-grid and backup applications based on lead-acid batteries. New approaches and technologies are rapidly supplanting and augmenting this approach, including new types of batteries with longer cycle lives, new applications like demand reduction and frequency regulation, and evolutions in technology that are driving down costs.

Ben Peters

Director of solar finance and policy, REC Solar, recsolar.com

What is REC Solar's history with solar storage? Are you seeing an increase in customer interest in these systems?

When our company was founded in 1997, solar plus battery storage was one of our primary system types. With the increase in severe storms and questions of grid resiliency, many customers have asked about incorporating storage into their solar project, and this trend will continue.

The most significant growth will come from customer-sited commercial projects. The key factor driving this interest is not the desire to pay for backup power, but the ability to reduce the electric bill with a financed technology package. The continual increase in commercial demand charges requires a new way of designing solar systems. Co-locating storage technology with a solar project significantly expands the portions of a customer's electric bill that we are able to reduce or eliminate entirely once the system is installed and producing electricity.

The final growth segment is in developing DG-sized projects that incorporate energy storage. These projects are typically less than 20 MW and directly interconnected to the distribution system. Programs mandated by the CPUC [California Public Utilities Commission], PJM grid operators and most recently the Puerto Rico Electric Power Authority are the start of what should be a significant redesign of our electric infrastructure.

What markets and applications currently provide an optimal value proposition for PV systems with integrated storage? How will this evolve over time?

Current technology and project economics for solar-plus-storage technology are well suited for mid-market commercial customers and those with relatively low kWh usage or high demand charges. Another subset of customers has a desire to utilize renewable energy, but is not able to site large enough PV arrays at their locations. We are able to increase our value proposition by including additional savings and customer benefits that could not be achieved with a traditional grid-direct net-metered system. A good example are the projects we are designing in Hawaii and Puerto Rico, which allow us to incorporate larger dc systems and generation potential, but still maintain the ability to comply with strict interconnection requirements. Our ability to quickly and cost-effectively install systems on these island grids will be the first step in the continued evolution and availability of microgrid solutions that are powered by clean energy.

What policy shifts or utility cost-structure changes will significantly impact the projected growth of storage systems in the US?

Courtesy Solar Grid Storage

Grid-level storage Vendors such as Solar Grid Storage are developing systems and financial products to help customers, including utilities, invest in large-scale solar storage. Potential applications include emergency power, peak-demand reduction, improved power quality, ramp-rate control, load shifting and additional grid services.

The fastest growth in storage systems will come from behind-the-meter commercial applications. The growth in storage will continue as long as the current trend in utility-rate tariff regulation is maintained. Solar does an excellent job of eliminating energy charges but needs storage technology to guarantee demand-charge reduction. Policies and rate changes that have occurred over the last several years have shifted much of a commercial customer's utility cost onto demand- and capacity-related charges, and now we have a technology solution to address that. Industrial- and residential-rate tariffs can follow this trend, and a good example is the debate surrounding net energy metering policies. If the savings value of a net energy metering credit is compromised, the value of a storage-coupled system will be even more compelling.

Our industry needs to ensure that we have continued access to the grid and that solar customers are not penalized for the advantages they provide to our utility system. As technology is implemented to provide real-time capacity benefits, we need a policy and regulatory framework to ensure these benefits are fairly valued. The ability to participate in a capacity market or a fast-response frequency regulation program are good examples of policies that the solar industry needs to support.

How can financing mechanisms accelerate the deployment of solar storage systems?

Financing for solar-plus-storage systems is available and will be a major portion of the market. The long-term benefits of storage technology can outweigh the capital investment. It is simply a matter of having the right partners who understand the best application and use of the technology. Fortunately, we are working with several experienced parties to address this evolution within the solar industry. Guaranteed demand reduction is a compelling offer for our customers, and now we can attack most parts of an electric bill and offer significant savings with a simple financing program.

Guaranteeing demand-charge reduction will allow companies to make inroads with customers. This concept is similar to a production guarantee, which is now an industry standard. Solar companies must adapt to meet the needs of their customers, most of whom are primarily looking to save money on their utility bill without the up-front cost of ownership. Solar-plus-storage technologies will enable solar companies to offer demand charge reduction guarantees while maintaining the bankability required by the investment community.

What are the major obstacles to the expansion of the sales and deployment of solar storage systems in the US?

The biggest obstacle to greater storage deployment is the lack of companies that have a fully integrated technology solution that is cost effective and ready for financing. Most customers are not willing to host design experiments, and our industry needs to sell the tangible benefits of this technology. We have been successful with the REC Solar Storage Partnership Program, educating our solar customers on the benefits of solar plus storage, and working with companies to handle different aspects of the project, from a design, construction, finance or management perspective. This value-added services package is one way to address early stage deployment barriers. Our solar customers are becoming increasingly sophisticated in understanding the savings potential of additional technology solutions, and our industry needs the ability to offer a bankable solution from a familiar brand and a well-known provider.

Phil Undercuffler

Director of strategic platforms, OutBack Power, outbackpower.com

What products does OutBack Power offer for utility-interactive solar storage systems?

OutBack Power manufactures the Radian inverter series for grid-interactive battery-backup applications and off-grid systems, as well as several models of our grid-interactive FX Series inverter/chargers. Two specific Radian models, the soon-to-be-released GS8048A (8 kW) and GS4048A (4 kW) utility-interactive multimode inverter/chargers, include an advanced GridZero AC input mode for self-generation and self-consumption programs. In 2013, we introduced an AC-Coupling Center that provides stable electromechanical coupling of grid-direct string and microinverters with OutBack's Radian battery-based inverters. OutBack also offers two VRLA battery lines and integrated battery racks with code-compliant string disconnecting means.

What markets and applications currently provide an optimal value proposition for PV systems with integrated storage?

PV integrated with energy storage has existed since the very beginning of solar, providing power beyond the reach of the grid. Although during the last decade the grid-connected PV market eclipsed this market in size, it remains strong and healthy, with solid growth driven by the true cost of energy rather than by easily disrupted incentives, financial structures and regulatory barriers. As an example, with the expanding need for data, Internet connectivity and cellular service, we've seen strong growth in the industrial off-grid market, since the costs of PV energy are a fraction of that of diesel-fueled generation.

When it comes to the grid-connected market, most designers have considered grid-tied with battery backup [GTBB] to be the only option for a system consisting of PV, grid and batteries. Certainly, with increasing numbers of extreme weather events, more homeowners are requesting solar with backup to achieve both power stability and reliability. As more designers learn about the easy-to-install options available for GTBB, we've seen increasing growth into the grid-connected market. However, OutBack Power believes the greatest opportunity is in the growth of systems that provide benefits every day for both the grid and the system owner, rather than only in the event of a utility outage or future disaster.

Courtesy Stem

Demand-charge reduction Stem, a California-based start-up, offers equipment that is installed behind the utility meter in parallel with a customer's distribution equipment. The system works by predicting usage and strategically charging and discharging the on-site battery to reduce peak loads.

The grid-connected solar market traditionally has focused on energy production and lowering the overall LCOE. However, what the grid and therefore we as a society face today is a variability or intermittency issue—intermittency of both production and load. The value of PV-generated kWh has become commoditized and is decreasing in value, while cost impacts of variability are rapidly increasing. For instance, the value of a kWh is measured in pennies, where the impact of demand charges is measured in dollars. Energy storage can provide designers the ability to reduce the impact of demand charges due to load surges or solar variability, in addition to being able to sell traditional kWh. That increases the value of a traditional PV system, providing developers a robust mechanism to improve the economics of PV.

How will California's Assembly Bill 2514 impact the deployment of solar storage systems in the state?

This is a great opportunity. California has a clear mandate to reduce greenhouse gas [GHG], and solar is a key component in meeting that goal. However, we need to address many issues to achieve this goal, one of which is solar variability. The traditional way for utilities to meet variability in load is to add more spinning reserve to the grid. We cannot generate our way out of solar variability. Aside from the additional GHG emissions that would result, there is a point of diminishing returns that cannot be avoided. A 250 kW energy storage device can provide the same performance benefit to the grid as a MW turbine because it can operate as both a generator and a load, and it can operate at full-rated capacity in either direction.

How are recent challenges to state net metering laws impacting the growth trajectory of solar storage?

It's no secret that the electric utilities view solar as a disruptive challenge, and many have been active both politically in framing existing net metering programs as "cross-subsidies" that shift the burden onto ratepayers without solar, as well as logistically in terms of creating new barriers to PV interconnection. This is unfortunate, as energy storage can provide a substantial benefit to the utilities by optimizing operations of their network and reducing variability caused by solar and loads, a point some utilities have admitted themselves. Many regions are approaching the point of grid parity. Some areas like Hawaii have surpassed grid parity, with the LCOE of PV power well below the cost of utility CONTINUED ON PAGE 74

power. The more utilities create barriers to solar, the more likely customers are to look for other options. Thirty years ago, a regulated monopoly provided phone service, and the only options available were wall mount and desktop. Today, customers have multiple options for telecommunication, and many customers no longer choose to have a landline phone service. Will energy follow a similar path?

You recently met with utility representatives in Hawaii to discuss the impact of high DG penetration. Can you share any insight from these meetings?

It's clear that the Hawaiian utilities want to solve this problem. More than any other region, they are buffeted by variability, due to their island grid, changes in solar insolation and wind, and exposure to diesel-fuel price volatility. There is a great opportunity to learn from the developments happening in Germany, California and Hawaii, share lessons, and explore opportunities to increase renewables, as well as provide greater reliability by incorporating solutions that reduce variability on the grid.

Sau Ngosi, PE

Director of off-grid engineering, Schneider Electric Solar Business, schneider-electric.com

Joe Vosburgh

Director of marketing and product management for utility-scale inverters, Schneider Electric Solar Business

What products does Schneider Electric currently offer for utility-interactive solar storage systems?

SN: Schneider offers the Conext XW platform of inverter/chargers and charge controllers for PV-hybrid storage systems. System capacities are scalable from 4.5 kW to 36 KW and well suited for both residential and commercial applications.

Does Schneider Electric have plans to develop high-capacity power conditioning equipment for large commercial and utility-scale solar storage applications in the US?

JV: Yes. Schneider Electric is focused on delivering a complete solution that enables the utility customer to employ MW-scale energy storage in support of a full range of DG and advanced grid services applications.

Do you have any insights on the status of solar energy storage in Germany? What is driving the deployment of solar storage there?

SN: Germany's grid storage subsidy is a drop in the ocean compared to its now scaled-down FIT [feed-in tariff] incentive scheme. Uptake has been modest at best, with about 1,720 applications for funding by the end of 2013. The biggest perceived obstacle to adoption is how the program is structured to require an interface for external system access for grid operators to affect grid loading and unloading functions. According to *PV Magazine,* installers are reporting that up to 75% of consumers installing battery-based systems are opting out of the subsidy due to their objections to the requirement for external control. This is a potential barrier to increased deployment.

How will California's Assembly Bill 2514 impact the deployment of solar storage systems in the state?

SN: Though AB 2514 has set the stage to bootstrap what could be the addition of significant storage-based capacity to the Californian grid, the three targeted investor-owned utilities [IOUs] are still in the process of working out implementation interconnection requirements specific to energy storage systems to allow connection to the grid. The CPUC regulates these policies with each respective IOU, and once they are in place, there should be significant uptake in deployment of storage systems for the IOUs to meet procurement targets set forth in the bill.

What are some recent developments in solar storage in locations with high DG penetration, such asr Hawaii?

JV: Hawaii is actively exploring and piloting MW-scale energy storage applied specifically to frequency regulation and renewables integration. They have a very unique challenge with respect to a range of island grids and a very high penetration of renewables. Therefore, they are one of the jurisdictions in the US that stands to gain the most benefit from the implementation of MW-scale energy storage for not only frequency regulation, but also load management, voltage support, reactive power support, power ramping and voltage, and frequency ride-through.

What markets and applications currently provide an optimal value proposition for PV systems with integrated storage?

JV: Frequency regulation combined with renewables smoothing and shifting will dominate the early storage deployment landscape and currently offers the most demonstrable value proposition. This is largely due to a range of recent FERC orders that monetize—or define an asset class and market for—energy storage systems for use in these applications. As penetration and deployment for these core applications occurs, and as price per kWh continues to come down for advanced battery technologies, and cyclic life and reliability continue to improve, applications will expand to include peak-load management and advanced ancillary services.

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Interview An Experienced Perspective

James Worden, Solectria Renewables **Andrew Worden,** Barron Partners and GameChange Racking

From Power Electronics to Racking Systems: Perspectives on Equipment Development, Manufacturing and Deployment

While there are a few notable instances of brothers working in the solar industry, it is uncommon. James and Andrew Worden are two such brothers. They operate distinct companies and apply their product development, manufacturing and business expertise to specific solar product classes and market segments.

In 1989, James Worden and his wife, Anita, cofounded Solectria Corporation, a developer and manufacturer of electric and hybrid vehicle components. They sold the business in 2005 and launched Solectria Renewables, shifting their focus to the design and production of PV inverters. Today, Solectria Renewables offers an extensive inverter product line, as well as performance monitoring and BOS components. James holds a BS in mechanical engineering from Massachusetts Institute of Technology (MIT) and serves as Solectria's CEO.

Andrew Worden is the CEO and founder of GameChange Racking. He is also the chairman, CEO and majority investor of Barron Partners, a global cleantech investment firm, and the CEO of Soltas Energy, an EPC that develops and finances commercial and utility-scale PV projects (this company is in the final stages of being sold). Andrew graduated from Harvard University with a BA in physical sciences and studied engineering at MIT. He also studied finance and marketing at the MIT Sloan School of Management.

Courtesy Solectria Renewables

James Worden, Solectria Renewables James has more than 25 years of power electronics engineering and manufacturing experience. In 2005, he and his wife, Anita, cofounded Solectria Renewables. Today, Solectria offers an extensive inverter product line, performance monitoring and BOS components.

James Worden
Solectria Renewables

SP: Since its founding in 2005, Solectria Renewables has continually expanded its inverter product family. What is the chronology of the company's inverter model introductions?

JW: Our first product was a 10 kW 3-phase commercial inverter that was originally UL listed in 2004 while we were still in the electric vehicle business. This inverter grew to become the PVI 10–15KW product line that is still sold today. The second introduction was our residential line, which started with 1.8 kW and 2.5 kW products and gradually grew to include models up to 7.5 kW. We introduced our PVI 50–100KW product family in 2005. Through the years we have continually upgraded each of these lines with new technologies, features and options. Our goal is to develop highly integrated inverter systems, increase system reliability, and reduce the total installed cost and labor at PV jobsites. Solectria inverter features include standard ac and dc disconnects, ac service entry ratings, and RS-485 and Ethernet communications. We have added fully integrated factory-built and tested options, many suggested by our customers, such as stainless steel enclosures, air filters, string combiners and subcombiners or recombiners. We introduced the first solar subcombiners that utilize circuit breakers, eliminating the

Solectria equipment is designed to operate for more than 20 years, so easy preventative maintenance and service are critical design features.—James Worden

need for external dc disconnects, as well as subarray monitoring, revenue-grade monitoring and even options for different disconnect orientations. In 2010, we launched our Smart Grid Inverter (SGI) line of 225 kW–500 kW inverters with the highest level of grid integration in the industry for this size inverter. In 2011, we brought our Megawatt Solar Stations to market. Last year, we introduced a new line of 3-phase transformerless string inverters ranging from 14 kW to 28 kW. This year we are rolling out a completely new line of transformerless 3.8 kW–7.6 kW residential inverters and 500 kW–750 kW 1,000 Vdc utility-scale inverters with external transformers.

SP: Are there technical advantages to integrating Solectria's monitoring products and BOS equipment with Solectria inverter systems?
JW: Historically, we offered products closely related to the inverter because we could design and build a cost-competitive product. In 2007, we introduced SolrenView web-based monitoring, and in 2008 we introduced string combiners. However, our inverters were always agnostic to monitoring and combiner solutions. Going forward, that is changing a bit, as more controls and monitoring are being requested and required in the combiner box, such as arc-fault detection, string monitoring and rapid shutdown. An integrated, complete solution has more synergy.

SP: How does Solectria address an inverter's reliability and serviceability during its design phase?
JW: Solectria Renewables emphasizes reliability and serviceability as top-level goals at all phases of design. We have the benefit of 25 years of power electronics engineering and manufacturing experience from our electric vehicle history. Electric vehicle power electronics needed to be reliable and lightweight, and to operate in the harshest of conditions. These same features serve us well today. Lightweight products are easier to service. The field-swappable sealed power stage used in our central inverters increases reliability and durability and greatly reduces service time. This keeps uptime at a maximum in the rare event that a problem occurs. Solectria equipment is designed to operate for more than 20 years, so easy preventative maintenance and service are critical design features. For hardware design, MTBF [mean time between failures] and useful life targets are carefully developed and measured for optimal life and low-failure rates. For software, robust implementation of features such as automatic recovery from disturbances and rejection of site-specific issues such as system variation are critical goals. Solectria has developed extensive reliability guidelines for all designs from our decades of high-power inverter experience. Reliability tests are performed on every design, including HALT [highly accelerated life test], long-duration testing and environmental stress testing.

SP: In October 2013, Solectria launched its 1,000 Vdc SGI 500XTM and SGI 750XTM central inverters. How rapidly do you expect system designs to transition to 1,000 Vdc in the US, and in what market segments in particular? Do you see any significant obstacles to this transition?
JW: Solectria has always taken the position that one size does not fit all. This is why we offer one of the most comprehensive product suites today, including a large array of 600 Vdc products. We have added 1,000 Vdc units in both 3-phase string inverters and 500 kW–750 kW central inverter models. The 1,000 Vdc adoption will depend on local electrical and safety codes. Large-scale ground-mounted projects have and will continue to be the first adopters. Economic forces move developers to 1,000 Vdc, but compliance with electrical and safety codes always wins. Currently, 600 Vdc systems are established, proven reliable and economic, and for these reasons they will continue to be a significant segment of the market.

SP: California's Rule 21, which is currently being revised, addresses interconnection, operation and metering requirements for distributed generators. What is your perspective on the Rule 21 revision effort and the advancement of smart-grid inverter capabilities?
JW: Solectria Renewables is a strong supporter of advanced grid interface requirements such as California's Rule 21. We are active in the development of the new requirements to ensure optimal implementation in our products. Solectria has multiple advanced pilot programs with utilities in California and elsewhere to prove performance to the new Rule 21 requirements. Many of our customers have been asking for more smart-grid capabilities that are not currently allowed under IEEE 1547. One example is active grid-voltage regulation to avoid inverter tripping on high-line or higher-impedance ac output circuits. Many customers in this situation could get higher overall system energy output when the inverter is capable of scaling back output power slightly to avoid driving the ac line above trip limits at high-irradiance levels.

SP: Have Solectria central inverters been deployed in locations with high levels

of distributed generation (DG)? What special considerations do these applications present, and how is Solectria addressing them?
JW: We have deployed many inverters to areas with high DG penetration. We currently support adjustable maximum power limiting to help meet interconnection requirements, programmable ramp up/down rates for power production and customizable power factor configurations. Many other smart-grid features are in development and reliability validation for next-generation requirements such as Rule 21. High DG penetration will require more-advanced integration and communication with the grid and will help make the grid more robust.

SP: What is your perspective on central versus distributed systems? Do you expect distributed designs to gain traction in utility-scale projects?
JW: You never install solar in the same place twice, and each deployment has a unique set of challenges. In some cases, the challenges are best addressed with a central inverter; in some cases, with multiple string inverters. The dynamics of each installation dictate the right solution. Solectria's ability to offer cost-competitive solutions in 14 kW–28 kW 3-phase string inverters for 600 Vdc and 1,000 Vdc designs increases the number of situations where this becomes a viable or even preferred solution. Using large central inverters for utility-scale plants is still the dominant approach. We expect that to remain consistent. Medium-size fully integrated 50 kW–500 kW central inverters are perfect for systems where a transformer is required or desired, or where designers prefer fewer individual inverters at a site.

SP: Does Solectria have plans to develop products that integrate solar energy storage? If so, what market segment will be the initial focus?

Courtesy GameChange Racking

Andrew Worden, GameChange Racking Andrew is the CEO and founder of GameChange Racking, which manufactures roof, ballasted ground-mount and post-driven ground-mount racking structures for commercial and utility-scale projects. He is also the chairman, CEO and majority investor of Barron Partners, a global cleantech investment firm.

JW: Solectria Renewables is poised to provide state-of-the-art hardware that can integrate with either short- or long-term energy storage. The technology in our inverters today can support any number of storage solutions. Due to our background in electric vehicles, rapid vehicle charging stations are a particular interest.

Andrew Worden
Barron Partners and GameChange Racking

SP: You serve in an executive capacity at Barron Partners and GameChange Racking. How do the companies complement one another under your oversight?
AW: Barron Partners has invested more than $480 million since 2002, most heavily in cleantech manufacturing companies. This background allowed Barron to build contacts in the finance community that help us provide capital introduction services to GameChange Racking's customers. With our background in metal fabrication at Barron, and my combined educational background in engineering and finance, I saw an opportunity to build an extraordinary PV structure company. We founded GameChange Racking on the premise of bringing double value to customers: labor cost savings from fast install plus cost-effective racks. We were able to validate many generations of products for roof and ground systems on our own plants, greatly accelerating the product development curve. Once we felt that we had well-developed products at a very compelling value, we initiated ETL testing to the UL 2703 and UL 467 standards, and wind tunnel testing. We launched the company to the marketplace about a year ago, and the market has enthusiastically received our products. We have

grown dramatically, with rapid sales growth nationwide for our roof systems, ballasted ground-mount and post-driven ground-mount systems.

SP: Over the last several years, numerous companies have entered what appears to be a crowded racking manufacturing space. Considering these market conditions, how do you differentiate GameChange's products?
AW: Our products enable fast installation due to patented engineering innovations, such as GameChange's Pour-in-Place ballasted ground-mount technology, a snap-together roof system and a seamless-fit post-driven system that eliminates all brackets. We offer value pricing for high-quality products that carry a 20-year warranty. Additionally, we offer racking system engineering stamps in 31 US states.

SP: GameChange offers low-slope roof, and post and ballasted ground-mount racking systems. Are you seeing a significant growth trend in one product line or a particular application?
AW: All systems are showing dramatic growth for GameChange; however, the Pour-in-Place Ballasted Ground system is a substantial innovation. As such, we are seeing the largest potential growth rate in that product.

SP: What efforts is GameChange making to drive cost out of commercial and utility-scale racking systems and their installation?
AW: Our product designs eliminate racking system components, which in turn speeds installations and drives down installation costs. Our purchasing power reduces costs through bulk metal buying. In addition, we utilize certain methods that greatly reduce labor cost in manufacturing.

SP: Where are GameChange Racking's manufacturing and warehousing facilities located? Why were these particular locations selected?
AW: Manufacturing and warehousing locations are selected based on proximity to customers and on local labor rates. GameChange Racking manufactures its products at facilities in Kansas, Massachusetts, Ohio and Texas, and warehouses in Kansas and Massachusetts.

SP: What is the status of GameChange's UL 467 and UL 2703 certifications?
AW: We have completed ETL testing to the UL 467 and UL 2703 standards for all of our roof and ground-mount systems. Also, in January we completed wind tunnel testing for our complete

> My roots as an investment fund manager have helped me understand what solar investors require: total system cost reduction while meeting the demands for bankability.—Andrew Worden

product line. Wind tunnel testing is becoming increasingly important for customers to see that their support structure vendor has accurate loading data to correctly engineer structure material strength as well as ballasting and embedment requirements.

James and Andrew Worden

SP: Why did you decide to enter the solar industry? Was one of you instrumental in getting the other involved?
JW: I had been involved in renewables since I was in high school. I built a solar electric car that inspired me to move on to engineering and MIT. I focused on electric vehicles for many years after MIT as the cofounder of Solectria Corporation, along with my wife and partner, Anita. We were fortunate enough to build a successful business. Solectria engineers were experts in power conversion, so it was a natural progression to offer a solar inverter that could be used to power your home and recharge your car. In 2005, we sold the electric vehicle segment of Solectria to focus entirely on PV inverters and accessories for the solar space. I look back over the past 25 years and feel like the luckiest person alive. I have been able to lead a great team, creating US manufacturing jobs, pioneering some of the most advanced solar technology today and knowing we are having a positive impact on the planet.
AW: Barron Partners has had investments in the solar industry and metal fabrication since 2004, primarily because we believed that cleantech was the right thing to do ethically and that it would eventually become cost-effective competition for fossil and nuclear energy. Over the last 8 years, I watched James and Anita lead Solectria at a dramatic growth rate despite high solar module prices, which piqued my interest in PV. When module prices dropped under $1.50 per watt, I saw that the numbers were penciling out to invest in solar projects and that the time had arrived for PV to really scale. We started Soltas Energy as a wholly owned subsidiary of Barron Partners and built many rooftop and ground-mounted solar plants, ranging from 370 kW to 3.5 MW in capacity. As Soltas built these plants, we felt that there was a lack of cost-effective, easy-to-install PV support structure solutions. We have now signed an agreement to sell all of our operating power plants and to exit that business to focus totally on GameChange Racking.

SP: What is the level of your involvement in each other's business ventures? Do you work together on specific system installations?
JW: Solectria Renewables and Andrew's businesses are separate and have no relation (no pun intended). That being said, my brother and I are in complementary segments of the business, so we don't have the same competitive interests as we had in high school, when we both liked the same girl, but I digress. Andrew and I are both committed to the betterment of the industry as a whole. In our minds, the success of the solar industry is good for everyone. We share ideas on how the industry can become more cost competitive, while maintaining a healthy long-term business proposition.
AW: We help each other brainstorm about general industry trends and how to help customers meet their PV system needs. We have no active involvement in each other's businesses. However, our products are often installed in the same projects, which is great to see.

SP: What are your short- and long-term goals for advancing the North American PV industry? What key issues does the industry need to address?
JW: There is no doubt that cost is always at the front of everyone's mind. We have come a long way, and in many regions, solar is already at grid parity. The solution will not be a single component; it will be overall system designs becoming more cost effective. Streamlining soft costs as well as BOS costs will propel the industry to the next level. Educating customers about the value of solar is also critical. Many people do not fully understand the true value that solar offers. Of course there's the value of the renewable power generation, but there is also an incredible set of grid control features we can offer utilities that can offset other capital investments and improve grid quality and reliability. As an industry, we can offer a distributed energy generation model that future generations will be proud of.
AW: My roots as an investment fund manager have helped me understand what solar investors require: total system cost reduction while meeting the demands for bankability. Now that module prices have dropped dramatically but stabilized, BOS cost reduction is the hotspot requirement for PV to reach grid parity more widely. At GameChange, we are fortunate to be able to make a difference for our customers because we offer systems that are not only cost effective, but also fast to install. This has been a critical differentiator in closing our larger customers, who are not accepting overpriced industry offerings just because certain companies are bankable. ⏚

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Solar Thermal Systems
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Apr 25
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Prime Solutions

Somers Solar Center

Courtesy Prime Solutions (3)

Overview

EPC: Prime Solutions, primesolutions-inc.com

DEVELOPERS: HelioSage Energy, heliosage.com; CleanPath Ventures, cleanpath.com

DATE COMMISSIONED: December 2013

INSTALLATION TIME FRAME: 180 days

LOCATION: Somers, CT, 41.6°N

SOLAR RESOURCE: 4.4 kWh/m²/day

ASHRAE DESIGN TEMPERATURES: 90°F 2% average high, -4°F extreme minimum

ARRAY CAPACITY: 7.4 MWdc, 4.999 MWac

ANNUAL AC PRODUCTION: 10,557 MWh

The 7.4 MWdc/4.999 MWac Somers Solar Center is located on approximately 75 acres of privately held farmland in Somers, Connecticut. Upon commissioning in late December 2013, the Somers Solar Center became the largest solar facility in New England, producing enough electricity to supply approximately 1,400 homes. Connecticut Light & Power purchases the electricity generated under a 20-year power purchase agreement. The property owner receives annual lease payments in return for housing the project.

HelioSage Energy and CleanPath Ventures developed the project; and Prime Solutions, an energy-engineering firm headquartered in New Milford, Connecticut, was the EPC contractor. Designing the system required a coordinated effort with Connecticut Light & Power. Prime Solutions also collaborated with the Connecticut Department of Energy and Environmental Protection (DEEP) to develop a detailed storm water management plan.

The site includes numerous rolling hills, and a protected watershed bifurcates the area. The project team had to address the resulting technical hurdles to ensure that the system would meet its projected production numbers and to satisfy restrictions imposed by several governing agencies. For example, a directive from the Connecticut Siting Council limited tree trimming, and DEEP's storm water management plan imposed additional restrictions related to grading and soil disturbance.

Teams from Prime Solutions and Array Technologies collaborated to develop a site plan with three separate arrays that utilizes the terrain-following capabilities of the tracking system. This design allowed Prime Solutions to optimize the system's production capacity,

minimize shading from the protected tree line and effectively level the system to minimize interrow shading. Array Technologies' DuraTrack HZ single-axis trackers were critical in allowing Prime Solutions to design a system with minimal impact on the existing site topography while ensuring that the system met required production values.

Due to short design and construction time lines and regulatory constraints, Prime Solutions recommended a capacity for the project of just under 5 MWac. This eliminated the necessity for a lengthy transmission study that ISO New England would have required. The resulting 4.999 MWac system size allowed a faster approval time by Connecticut Light & Power and ISO New England. The final power conditioning system design includes four 1 MW AE Solar Energy (AESE) Open TX PowerStations with two AE 500TX inverters per skid. An additional 999 kW AESE Open NX PowerStation utilizes three AE 333NX inverters. A 1,000 kVA 480/277 to 23 kV transformer is integrated with each of the five power stations.

> "Prime Solution's successful design and on-time completion of the Somers Solar Center project is a shining example of our team's technical expertise and execution capabilities in delivering utility-scale projects."
> *—William May, CEO, Prime Solutions*

Equipment Specifications

MODULES: 23,150 Kyocera KD320GX-LFB, 320 W STC, +5/-3%, 7.99 Imp, 40.1 Vmp, 8.6 Isc, 49.5 Voc

INVERTER STATIONS: 23 kV medium-voltage interconnection, five power stations total with one 1,000 kVA 480/277 to 23 kV transformer per station; four AE Solar Energy 1 MW Open TX PowerStations with two AE 500TX inverters per power station (500 kW, 600 Vdc maximum input, 310–595 MPPT range, 3-phase 480 Vac output); one custom AE Solar Energy 999 kW Open NX PowerStation with three AE 333NX inverters (333 kW, ±600 Vdc maximum input, ±330–±550 Vdc MPPT range, 3-phase 480 Vac output); 4.999 MWac inverter capacity total

ARRAY: 10 modules per source circuit (3,200 W, 7.99 Imp, 401 Vmp, 8.6 Isc, 495 Voc), 13–16 source circuits per combiner, 15 combiners per inverter (typical), 7.4 MWdc array capacity total

ARRAY INSTALLATION: Tracked ground mount, 32 Array Technologies DuraTrack HZ Solar Trackers, single-axis, gear drive, one 1.5 HP motor per tracker, algorithm with GPS input tracking method

SOURCE CIRCUIT COMBINERS: 150 Eaton SC24P, NEMA 4, 15 A fuses

SYSTEM MONITORING: DECK Monitoring with weather station, inverter-mounted Shark production meters and ION utility generation meter

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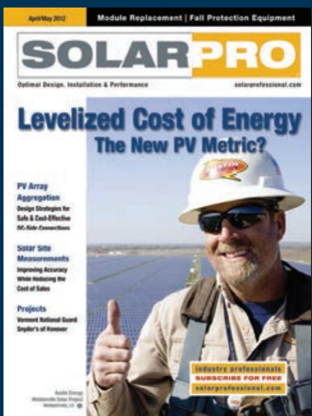
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American Solar

Spies Residence

Overview

DESIGNER: Paul Swanson, American Solar, americanpv.com

LEAD INSTALLER: Robert Hileman, American Solar

DATE COMMISSIONED: July 26, 2013

INSTALLATION TIME FRAME: 3 days

LOCATION: Chandler, AZ, 33.3°N

SOLAR RESOURCE: 6.5 kWh/m²/day

ASHRAE DESIGN TEMPERATURES: 109°F 2% average high, 34°F extreme minimum

ARRAY CAPACITY: 4.68 kWdc

ANNUAL AC PRODUCTION: 7,500 kWh (projected)

Equipment Specifications

MODULES: 18 LG Electronics LG260S1C-G3, 260 W STC, +3/-0%, 8.61 Imp, 30.2 Vmp, 9.2 Isc, 37.9 Voc

INVERTER: Single-phase 120/240 Vac service, one SMA Sunny Boy 4000TL-US with Secure Power Supply, 4 kW, 600 Vdc maximum input, two MPP trackers, 175–480 Vdc rated MPPT range, 125–500 Vdc operating MPPT range

ARRAY: Two orientations. SW array: one six-module source circuit (1,560 W, 8.61 Imp, 181.2 Vmp, 9.2 Isc, 227.4 Voc); SE array: one 12-module source circuit (3,120 W, 8.61 Imp, 362.4 Vmp, 9.2 Isc, 454.8 Voc); 4.68 kWdc array total

ARRAY INSTALLATION: Monier S-Tiles installed on Tru-Flow drain-through battens, 90# mineral-surface rolled roofing underlayment, Quick Mount PV Quick Hook flashed tile mounts, IronRidge Standard rail; SW array: 223°azimuth, 18° tilt; SE array: 133° azimuth, 18° tilt

SYSTEM MONITORING: SMA Sunny Webbox, SMA Sunny Portal web interface

Courtesy American Solar (2)

Jeff Spies, the senior director of business development at Quick Mount PV, contracted American Solar to install a PV system at his residence. The system employs one of the first SMA 4000TL-US inverters installed in the US. This non-isolated inverter features two MPP trackers and a Secure Power Supply function that provides up to 12 amps of backup power at 120 Vac, given that there is sufficient solar irradiance.

American Solar's licensed roofing contractor division refurbished the 16-year-old roof and relocated plumbing and gas vent stacks to create space for the array. The SMA 4000TL-US's dual MPP channels and wide operating MPPT range made it possible to locate a 3,120 W array on a southeast-facing roof and a 1,560 W array on the southwest-facing garage roof.

To ensure that the home's tile roof would last the 30-year life of the array, American Solar installed a 90# mineral-surface rolled roofing underlayment. Tru-Flow drain-through battens speed rainwater drainage, which extends underlayment life. Ventilation upgrades include Boral vented eave risers and O'Hagin roof vents. The crew used Quick Mount PV's Quick Hook flashed tile mounts in conjunction with IronRidge Standard mounting rail, providing for an attractive finished appearance. (For details on similar installations, see "Tile Roof Applications," *SolarPro* magazine, October/November 2013.)

"Since I work for the leading manufacturer of code-compliant flashed PV mounts, I understand the long-term cost benefits of installing a new roof under the array. When choosing an installer, I looked no further than American Solar. The company did a great job installing a system that offers excellent performance."

—Jeff Spies, Quick Mount PV

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